STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 13-E-0030 –	Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service.
CASE 13-G-0031 –	Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Gas Service.
CASE 13-S-0032 –	Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Steam Service.
CASE 13-M-0376 –	Petition of Consolidated Edison Company of New York, Inc. for Approval of Proposed Distribution of a Property Tax Refund.
CASE 13-M-0040 –	Petition of Consolidated Edison Company of New York, Inc. for Approval of Accounting Treatment of the Proceeds of the Proposed Sale of Property.
CASE 09-E-0428 –	Proceeding on Motion of the Commission as to the Rates, Changes, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service.

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JOINT PROPOSAL

THIS JOINT PROPOSAL ("Proposal") is made as of the 31st day of December 2013, by and among Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company"), New York State Department of Public Service Staff ("Staff"), New York Power Authority ("NYPA"), the City of New York (the "City" or "NYC"), the Utility Intervention Unit, Division of Consumer Protection, New York State Department of State ("UIU"), Consumer Power Advocates ("CPA"), New York Energy Consumers Council, Inc. ("NYECC"), Astoria Generating Company, L.P. ("AGC"), the Pace Energy and Climate Center ("Pace"), the Columbia Center for Climate Change Law ("CCCL"), the Environmental Defense Fund ("EDF"), NRG Energy ("NRG"), and other parties whose signature pages are or will be attached to this Proposal (collectively referred to herein as the "Signatory Parties").

Procedural Setting

Con Edison is currently operating under an electric rate order that established electric rates effective April 1, 2010,[1] and under a gas and steam rate order that established gas and steam rates effective October 1, 2010.[2] The 2010 Electric Rate Order established rates for the three years ended March 31, 2013 and the 2010 Gas and Steam Rate Order established rates for the three years ended September 30, 2013.

On January 25, 2013, Con Edison filed new tariff leaves and supporting testimony for new rates and charges for electric, gas and steam service effective on January 1, 2014 for the twelve-month period ending December 31, 2014. In that filing, the Company also included financial information for the two succeeding twelve-month periods in order to facilitate development of multi-year rate plans through settlement discussions in the event parties elected to do so.

Two administrative law judges were appointed to preside over the rate proceedings. Parties engaged in discovery, with the Company responding to over 2,600 formal discovery requests on the filings. A procedural conference was held in New York

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[1] Case 09-E-0428, Consolidated Edison Company of New York, Inc. – Electric Rates, *Order Establishing Three-Year Electric Rate Plan* (issued March 26, 2010) ("2010 Electric Rate Order").

[2] Cases 09-S-0794 & 09-G-0795, Consolidated Edison Company of New York, Inc. – Steam and Gas Rates, *Order Establishing Three-Year Steam and Gas Rate Plans and Determining East River Repowering Project Cost Allocation Methodology* (issued September 22, 2010) ("2010 Gas & Steam Rate Order" or "2010 Steam Rate Order" or "2010 Gas Rate Order" as applicable in context).

City on March 11, 2013. The procedural conference was immediately followed by a technical presentation by the Company on various aspects of the filing.

On March 22, 2013, a *Ruling on Schedule* was issued, providing dates for certain activities in this case, including the preliminary update, parties' testimony, rebuttal testimony and scheduling evidentiary hearings on the filings for July 22, 2013.

On March 25, 2013, the Company provided the parties with preliminary revenue requirement updates. On March 29, 2013, the Company provided supplemental testimony addressing the New York State Public Service Commission's ("Commission") February 14, 2013 Order regarding the PJM Open Access Transmission tariff.

On May 31, 2013, seventeen (17) parties filed testimony in response to the Company's filings. On June 21, 2013, the Company filed update and rebuttal testimony, including the presentation of the Company's formal revenue requirement update. Nine parties also filed rebuttal testimony on June 21, 2013.

By notice dated May 31, 2013, Con Edison notified all parties of the commencement of settlement negotiations on June 10, 2013.[3] Settlement negotiations began on June 10, 2013 and continued on June 17, June 19, June 27, and July 1, 2013.

On July 3, 2013, the parties agreed to cease discussing a potential settlement in order to prepare for hearings, which commenced on July 22, 2013. Hearings were held for ten consecutive days, ending on August 2, 2013. In total, 52 witnesses testified, comprising 2,420 pages of on-the-record testimony as well as over 10,000 pages of pre-filed testimony and 998 exhibits. Parties submitted initial briefs on August 30, 2013 and reply briefs on September 21, 2013.

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[3] This notice was filed with the Secretary to the Commission ("Secretary").

Settlement discussions resumed on October 9, 2013. On October 18, 2013, the Chief Administrative Law Judge assigned Administrative Law Judge Kimberly A. Harriman to act as a settlement judge for these proceedings.[4] The settlement judge participated in the parties' negotiating sessions. All negotiations were held either in person or via teleconference. Sessions were held on October 28, October 30-31, November 4-8, November 12-14, November 18, November 22, November 25-26, and December 3-6, 2013. All settlement negotiations were subject to the Commission's Settlement Rules, 16 NYCRR § 3.9, and appropriate notices for negotiating sessions were provided.

The parties' negotiations have been successful and have resulted in this Proposal, which is presented to the Commission for its consideration.

Overall Framework

The Signatory Parties have developed a comprehensive set of terms and conditions for a two-year rate plan for Con Edison's electric service as well as three-year rate plans for Con Edison's gas and steam services. These terms and conditions are set forth below and in the attached Appendices. Specifically, this Proposal addresses the following topics:

A. Term

B. Rates and Revenue Levels

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[4] By letter dated October 22, 2013, the Company agreed to a one-month extension of the statutory suspension period in all three proceedings subject to a "make-whole" provision that would keep the Company and its customers in the same position they would have been absent the extension. On November 19, 2013, the Company subsequently agreed to a second such extension through February 28, 2014. The second extension raised procedural issues under the Commission's policies and regulations related to subsequent rate filings by the Company absent multi-year rate plans in these proceedings. Accordingly, the second extension was conditioned upon the Commission's waiver of the limitations regarding selection of the historical test period in its *Statement of Policy on Test Periods in Major Rate Proceedings* and its granting a "make-whole" provision for the subsequent rate filings.

A. Term

The Signatory Parties recommend that the Commission adopt a two-year electric rate plan for Con Edison as set forth herein, effective as of January 1, 2014 and continuing through December 31, 2015 ("Electric Rate Plan"). The Signatory Parties also recommend that the Commission adopt three-year gas and steam rate plans for Con Edison as set forth herein, effective as of January 1, 2014 and continuing through December 31, 2016 ("Gas Rate Plan" and "Steam Rate Plan"). (Collectively, all three plans will be referred to as "Rate Plans").

In order to effectuate the changes in rates being effective as of a date earlier than the issuance of the Commission's order in these proceedings, the Company will recover or refund any revenue undercollections or overcollections, respectively, resulting from the extended suspension period. The Company will calculate any revenue adjustments as the difference between (i) sales revenues Con Edison would have billed at new rates during the extension of the suspension period and (ii) revenues for the same level of sales at current rates. The revenue adjustments will include all applicable surcharges, and will be subject to reconciliation in accordance with all applicable adjustment mechanisms (including revenue decoupling mechanisms, where applicable). In addition, the amortization of net deferrals reflected in the Commission's order will commence effective with the month of January 2014, on an earnings neutral basis. The financial true-up targets established in the Commission order in these proceedings will be applied to the extension of the suspension period.

For the purposes of this Proposal, Rate Year means the 12-month period starting January 1 and ending December 31; Rate Year 1 ("RY1") means the 12-month period starting January 1, 2014 and ending December 31, 2014; Rate Year 2 ("RY2") means the 12-month period starting January 1, 2015 and ending December 31, 2015; and Rate Year 3 ("RY3") means the 12-month period starting January 1, 2016 and ending December 31, 2016.

B. Rates and Revenue Levels

1. Electric

This Proposal recommends changes to the Company's electric delivery service rates and charges, including the fixed component of the Monthly Adjustment Clause ("MAC"), designed to produce a $76.192 million reduction in revenues on an annual basis starting in RY1 and a $123.968 million increase in revenues on an annual basis starting in RY2.

The Signatory Parties propose that these two base rate changes be implemented on a levelized basis to provide rate stability over the term of the Electric Rate Plan. The annual levelized revenue changes associated with T&D delivery revenue, the retained generation component of the MAC and purchased power working capital would be zero in each of RY1 and RY2.[5] Revenue changes by service class are shown in Appendix 20.

The Company will defer the amounts of the annual revenue requirement changes each Rate Year as shown in Appendix 1, page 7 of 7. PSC Account 456-Other Electric Revenues will be debited/credited with the offset recorded in PSC Account 256 – Regulatory Liabilities. Interest on the outstanding balance will accrue at the Other Customer Provided Capital Rate. The estimated amount to be deferred for the benefit of customers at December 31, 2015 is approximately $30.1 million.

Since the annual levelized rate changes would result in lower base rates at the end of the two-year term of the Electric Rate Plan than they would otherwise be under a non-levelized approach, $47.776 million of the levelized change in RY2 will be effectuated in RY2 via class-specific temporary credits. Such credits would only be effective for the duration of RY2. The credits, which will be shown on statements filed separately from the Company's rate schedules, will be credited in the same manner as if they were credited in non-competitive delivery base rates. Therefore, RY2 delivery rates will be set to reflect revenues that are $47.776 million greater than the RY2 revenue level. During RY2, the $47.776 million will be offset by the temporary credits. At the end of RY2, the temporary credits will expire and the delivery rates will remain in effect.

The Company will continue to recover on an annual basis $248.8 million through the Rate Adjustment Clause ("RAC") pending a Commission determination in Case 09-M-0114.

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[5] The levelized rate changes are inclusive of interest on the deferred rate decrease calculated at the 2014 Other Customer-Provided Capital Rate of 3.0 percent. The Company will calculate the change in interest for any change in the Other Customer-Provided Capital Rate in 2015, and defer the difference for surcharge or credit to customers, as applicable.

The major components of the electric revenue requirements underlying this Proposal are set forth in Appendix 1. These revenue requirements are net of the amortizations of various customer credits and debits on the Company's books of account that have previously been deferred by the Company. The list of deferred customer credits and debits to be applied during the Electric Rate Plan is attached as Appendix 4.

a. Monthly Supply Charge and Monthly Adjustment Clause

The Company will continue to recover all prudently-incurred supply and supply-related costs, including, but not limited to, power purchase costs and the embedded costs of retained generation through the Market Supply Charge ("MSC")/MAC mechanism.[6]

b. RDM

The Revenue Decoupling Mechanism ("RDM") prescribed by the Commission in Cases 07-E-0523, 08-E-0539 and 09-E-0428, subject to the modifications described in this paragraph and paragraph G.1.j., will remain in effect unless and until changed by Commission Order, except for restating RDM targets for the Rate Year commencing January 1, 2016 to reflect the expiration of the temporary credits discussed in paragraph B.1 above, if the Company does not file for new base delivery rates to be effective within fifteen (15) days after the expiration of RY2. These restated RDM targets will remain in effect until the next time base delivery rates are changed (*i.e.*, continuation of the RDM mechanism unless and until changed by the Commission is premised upon the RDM targets being reset each time base delivery rates are changed).

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[6] For costs, charges, and credits covered by the language of the MSC/MAC adjustment mechanisms, the Company will continue to recover such costs and charges, and provide such credits, as incurred, by reflecting these charges, costs and/or credits in monthly statements filed pursuant to these adjustment mechanisms.

Consistent with the RDM mechanism in effect: (i) any interim charges/credits associated with the RDM reconciliations of actual versus targeted revenues for periods commencing on and after January 1, 2014 will become effective on the first day of the month in which they become effective, and (ii) any RDM deferrals will accrue interest as specified in section F.2 below. The costs of the Low Income Program will be reconciled through the RDM as discussed in Section J.

The currently-effective RDM is modified commencing with the effective date of the Electric Rate Plan as follows: (1) revenues associated with reactive power demand charges will be included in the RDM calculations; (2) for purposes of RDM reconciliations, Service Classification ("SC") 2 and SC6 will be combined as one class; and (3) for purposes of RDM reconciliations, SC5 and SC9 will be combined as one class.

During the course of this Rate Plan, the Company through a tariff filing, or any party by petition to the Commission, may propose an adjustment to the currently-effective RDM targets if the Company or such party, as applicable, believes that circumstances are resulting in anomalous results unduly impacting certain customers. Any proposed changes to RDM targets are to be revenue neutral to the Company.

c. Spent Nuclear Fuel Litigation Costs

In order to resolve issues in these proceedings regarding the Company's proposal to recover approximately $10.2 million of outside legal fees related to a suit brought against the United States Department of Energy ("DOE") respecting the DOE's obligation to dispose of spent nuclear fuel at the Indian Point nuclear generating station, the electric revenue requirements for RY1 and RY2 reflect recovery of fifty (50) percent of that amount (*i.e.*, $5.1 million) over three years.

The Signatory Parties recommend that the Commission authorize the Company to record on its books of account at the time of the Commission's adoption of this Proposal, a regulatory asset in the amount of $5.1 million, and to commence amortization of those deferred balances over three (3) years effective as of January 1, 2014.

d. Sale of John Street Property

In order to resolve issues in these proceedings regarding the sale of a Company property on John Street in Brooklyn, NY, including the amount of the gain realized by the Company upon the sale of that property[7] to be credited to customers, the electric revenue requirements reflect a credit to customers of $1.645 million in each of RY1 and RY2 representing the amortization, over three years, of $4.935 million.

The accounting treatment for the sale of the property is set forth in Appendix 12. The Signatory Parties recommend that the Commission approve such accounting and deem the resolution of this matter in this Proposal to resolve all matters pertaining to Case 13-M-0040.[8]

e. PJM OATT Charges

In 2008, Con Edison contracted with PJM Interconnection L.L.C. ("PJM") for a 1000 MW firm transmission service pursuant to PJM's Open Access Transmission Tariff ("OATT"), which service commenced on May 1, 2012. In June 2012, the Company commenced recovery of these PJM OATT charges through the MAC. On July 9, 2012, the Company made a filing with the Commission explaining the basis for the Company's recovery of the PJM OATT charges through the MAC. On February 14, 2013, the

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[7] The sale was consummated on August 19, 2013.

[8] *Petition of Consolidated Edison Company of New York, Inc. for the Approval of Accounting Treatment of the Proceeds of the Proposed Sale of Property.*

Commission issued an *Order Denying Petition for Recovery of Charges* in Case 09-E-0428 ("PJM OATT Order") and noted that the Commission expected the Company to demonstrate its prudence in contracting for this PJM OATT service and the appropriate recovery mechanism for these charges in this electric rate proceeding. On March 18, 2013, the Company filed a petition for rehearing of the PJM OATT Order ("PJM OATT Rehearing Petition").

Pursuant to the PJM OATT Order, the Company submitted testimony in these proceedings demonstrating the prudence of contracting for the PJM OATT service and proposing a recovery mechanism for these charges.

The Signatory Parties agree that the Company demonstrated prudence in contracting for the PJM OATT service; recommend full recovery of all PJM OATT charges for this service incurred for the period commencing January 1, 2014; recommend partial recovery of PJM OATT charges incurred for the period prior to January 1, 2014; and support the allocation of these charges as set forth below as a reasonable resolution of the issues related to the allocation of PJM OATT charges among Con Edison customers and NYPA, as more fully set forth below.[9]

For the period commencing January 1, 2014 and unless and until changed by the Commission, the Company will recover all PJM OATT rates and charges associated with the 1000 MW firm transmission service. The allocation of the monthly PJM OATT rates and charges between Con Edison customers (recoverable through the MAC) and NYPA (recovered through a separate surcharge for the PJM OATT costs), shall be based on the percentage allocation of T&D revenues included in the revenue allocation for each Rate

[9] For rate design purposes, the Company refers to NYPA separately from other Con Edison customers and customer classes. However, it should be understood that NYPA is a customer of Con Edison.

Year, as shown in Appendix 20. Should the allocation to NYPA exceed $4.6 million in any Rate Year, any excess in that year will instead be collected from Con Edison customers through the MAC.

For the period commencing May 1, 2012 and ending December 31, 2013, the Signatory Parties recommend resolving the issues raised in the PJM OATT Rehearing Petition as follows:

1. The Company will recover over the 10-month period March 2014 through December 2014, PJM OATT charges incurred by the Company during the period April 1, 2013 through December 31, 2013, net of the amount of PSEG wheeling charges recovered by the Company in base delivery rates during this same nine-month period. At the time of this Proposal, the amount is estimated to be $20 million. The actual amount will be available during 2014.

2. These PJM OATT charges will be allocated between Con Edison customers and NYPA based on the percentage allocation of transmission and distribution delivery revenues reflected in electric base rates in effect during the same period. See Appendix 20.

3. The amounts allocable to Con Edison customers will be recovered through the MAC and the amounts allocable to NYPA will be recovered through a separate surcharge.

4. The Company will forgo recovery of PJM OATT charges incurred during the period May 2012 through March 2013.

5. Upon Commission adoption of this Joint Proposal, the PJM OATT Rehearing Petition shall be deemed withdrawn.

Accordingly, the Signatory Parties recommend that the Commission authorize the Company to record on its books of account at the time the Commission adopts this Proposal, a regulatory asset for the charges described above, and to commence amortization of the deferred balance over the ten-month period described above. The Company will amend its tariffs to expressly provide for the recovery of PJM OATT charges through the MAC and through a separate NYPA surcharge.

f. Other Charges

The Signatory Parties agree that whenever the Company is or will be subject to governmental or regional transmission organization ("RTO") transmission and/or generation-related charges, costs or credits (*e.g.*, FERC, NYISO, PJM, EPA[10]) not already listed in or otherwise covered by the then-effective MAC/MSC tariff language, the Company may make a tariff filing with the Commission providing for recovery of such charges/costs, or application of these credits, through the MAC/MSC mechanism and/or comparable adjustment mechanism. The proposed tariff amendment may include charges/costs/credits applicable to the period prior to the effective date of the tariff amendment.

2. <u>Gas</u>

This Proposal recommends changes to the Company's retail gas sales and gas transportation service rates and charges, designed to produce a $54.602 million reduction in revenues on an annual basis starting in RY1, a $38.620 million increase in revenues on an annual basis starting in RY2, and an additional $56.838 million increase in revenues on an annual basis starting in RY3.[11]

The Signatory Parties propose that these three base rate changes be implemented on a levelized basis to provide rate stability over the term of the Gas Rate Plan. The annual levelized revenue changes would be zero in each of RY1, RY2 and RY3.[12] Changes in revenues by service class are shown in Appendix 21.

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[10] Environmental Protection Agency ("EPA").

[11] Unless specifically stated otherwise in this Proposal, the terms "customers" and "base rate" with respect to gas apply to the Company's firm gas customers, excluding interruptible gas customers, CNG, bypass and power generation customers served under SC 9 and off-peak firm customers.

[12] The levelized rate changes are inclusive of interest on the deferred rate decrease calculated at the 2014 Other Customer-Provided Capital Rate of 3.0 percent. The Company will calculate the change in interest

The Company will defer the amounts of the annual revenue requirement changes each Rate Year, as shown in Appendix 2, page 10 of 10. PSC Account 495 – Other Gas Revenues will be debited/credited with the offset recorded in PSC Account 254 – Regulatory Liabilities. Interest on the outstanding balance will accrue at the Other Customer-Provided Capital Rate. The estimated amount to be deferred for the benefit of customers at December 31, 2016 is approximately $32.265 million.

Since the annual levelized rate changes would result in lower base rates at the end of the three-year term of the Gas Rate Plan than they would otherwise be under a non-levelized approach, $40.856 million of the levelized change in RY3 will be effectuated in RY3 via class-specific temporary credits. Such credits would only be effective for the duration of RY3. The credits, which will be shown on statements filed separately from the Company's rate schedules, will be credited in the same manner as if they were credited in non-competitive delivery base rates. Therefore, RY3 delivery rates will be set to reflect revenues that are $40.856 million greater than the RY3 revenue level. During RY3, the $40.856 million will be offset by the temporary credits. At the end of RY3, the temporary credits will expire and the delivery rates will remain in effect.

The Company will continue to recover on an annual basis $32.0 million through the Rate Adjustment Clause ("RAC") pending a Commission determination in Case 09-M-0114.

The major components of the gas revenue requirements underlying this Proposal are set forth in Appendix 2. These revenue requirements are net of the amortizations of

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for any change in the Other Customer-Provided Capital Rate in future years, and defer the difference for surcharge or credit to customers, as applicable.

various customer credits and debits on the Company's books of account that have previously been deferred by the Company. The list of deferred customer credits and debits to be applied during the Gas Rate Plan is attached as Appendix 4.

a. Revenue Per Customer ("RPC") Mechanism

The revenue decoupling mechanism ("RDM") established for gas service in Case 06-G-1332 and 09-G-0795, subject to the modifications described in this paragraph and paragraph G.2.c. will remain in effect unless and until changed by Commission Order.

Delivery revenues from service provided to the Company's firm customers will be subject to reconciliation pursuant to the RPC Mechanism set forth in Appendix 6. The currently-effective RPC Mechanism is modified commencing with the effective date of the Gas Rate Plan to include the revenues from customers converting from oil-to-gas that were subject to a separate reconciliation mechanism under the gas rate plan established in Case 09-G-0795, which separate reconciliation mechanism will not be continued under this Gas Rate Plan. Details of the RPC Mechanism are included in Appendix 6.

b. Monthly Rate Adjustment/Gas Cost Factor

The Company will recover all supply and supply-related costs through the Monthly Rate Adjustment ("MRA")/Gas Cost Factor ("GCF") mechanisms. Load Following costs will be recovered through the MRA.[13]

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[13] The Company recovers various costs and charges, and provides certain credits, through the GCF, MRA and Weighted Average Cost of Capacity ("WACOC"). For costs, charges, and credits covered by the language of these adjustment mechanisms, the Company will continue to recover such costs and charges, and provide such credits, as incurred, by reflecting these charges, costs and/or credits in monthly statements filed pursuant to these adjustment mechanisms.

c. Non-Firm Revenues

The revenue requirement for each Rate Year reflects a base rate revenue imputation of $65 million attributable to Non-Firm Revenues. For each Rate Year, the following revenues constitute "Non-Firm Revenues:"

1. Net base revenues[14] derived from

    a. Customers receiving interruptible service under SC 12 Rate 1 and SC 9 Rates B and D; and

    b. Power generation customers[15] receiving interruptible or off-peak firm service, including off-peak firm service under SC 9 Rate D(2) or special negotiated contract; the New York Power Authority (in excess of $3.1 million per Rate Year, which is the level reflected in base rates); interruptible or off-peak firm service to Company-owned power generation, steam, and steam-electric plants; and existing, new, and divested power generation facilities owned by third parties pursuant to, for example, SC 9 Rate D(1); and

2. Net revenues derived from the use of interstate pipeline capacity for capacity releases;[16] for or by customers taking service under off-peak firm SC 12 Rate 2; for or by interruptible or off-peak firm customers taking service under negotiated bypass SC 9 Rate D (1); for SC 19 and bundled sales; and other off-system transactions (*e.g.*, gas supplied to the Company's steam and steam/electric plants); and

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[14] Net base revenues mean total revenues less the following, as applicable: taxes, actual cost of gas (reflecting, for example, hedging costs and gas supplier take-or-pay charges), cash-out charges and credits, and any revenues included in total revenues related to reimbursements for facility costs associated with providing service, including metering and communication equipment, service pipes and lines, service connections, main extensions, measuring and regulating equipment and system reinforcements and other facilities as necessary to render service.

[15] For the purposes of this Section B.2.c, power generation customers do not include cogeneration or other customers taking off-peak firm service under SC 12 Rate 2 or SC 9 Rate C.

[16] Net capacity release revenues means the credits afforded the Company from releasing capacity to third parties excluding (i) capacity release revenues applicable to capacity releases to firm customers and/or ESCOs serving firm customers under the Company's capacity release program that became effective November 1, 2001 and any amended, extended, or superseding programs ("Capacity Release Service Program"), and (ii) the demand charges recovered through the Winter Bundled Sales Service ("WBSS").

3. Gas balancing revenues derived from gas balancing services provided to SC 9 and 12 interruptible and off-peak firm customers, CNG, bypass and power generation customers and SC 20 marketers serving SC 9 transportation customers.

The Company will retain 100 percent of the first $65 million of Non-Firm Revenues achieved during each Rate Year of the Gas Rate Plan.

If Non-Firm Revenues are less than $65 million in any Rate Year, the Company will (i) defer on its books of account for future recovery from customers, with interest, the amount by which Non-Firm Revenues are less than $65 million and (ii) surcharge firm customers that amount in the subsequent Rate Year (*i.e.*, for 100 percent of the difference between $65 million and the amount actually achieved).

For Non-Firm Revenues above $65 million in any Rate Year, firm customers will be credited with 85 percent of the amount above $65 million beginning in the subsequent month.

The Company may implement a surcharge or credit to customers at the commencement of any Rate Year for a projected variation in revenues from the target level of revenues (*i.e.*, $65 million), up to $25 million, in order to minimize the annual reconciliation of actual revenues as compared to target revenues in any Rate Year. At least two weeks prior to the Company's implementing such a surcharge or credit, the Company will provide Staff work papers underlying such surcharge or credit in order to afford Staff an opportunity to raise with the Company any concerns that Staff has with the size of the surcharge or credit.[17] Any such surcharge or credit will be implemented over a 12-month period.

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[17] The Company will provide notice to interested parties of such a surcharge or credit.

d. Lost and Unaccounted For Gas

The calculation for Lost and Unaccounted for Gas established by the 2010 Gas Rate Order is modified effective January 1, 2014, as set forth in this section.

During RY1, RY2 and RY3, Line Loss Factor ("LLF") will be calculated in three steps as follows:

1. Losses = metered supplies into the system (Total Pipeline Receipts + LNG Withdrawals + Total Receipts from New York Facilities) less metered deliveries to customers (Retail Sales and Transportation Deliveries + Deliveries to Generation + Gas Used for Company Purposes and CNG + LNG Injections + Total Heater & Compressor Consumption + Total Deliveries to New York Facilities).

2. Adjusted Line Loss = Losses minus the contribution to the system line loss from generators.

3. LLF = Adjusted Line Loss divided by Citygate receipts adjusted for generation.

In order to determine if the Company receives an incentive/pays a penalty for the annual LLF achieved commencing with the 12-month period ending August 31, 2014, the Company will compare the LLF level for such period to a target derived from the five-year rolling average of LLFs from the five previous September 1 through August 31 periods. If the LLF is within two standard deviations of the rolling prior five-year average target, no incentive/penalty will arise. If the LLF is greater than two but less than four standard deviations above the rolling prior five-year average, then a penalty will be assessed according to the tariff. If the LLF is between two and four standard deviations below the rolling prior five-year average, then an incentive will be provided to the Company according to the tariff. For RY1, the rolling prior five-year average level is included in Appendix 25 and the LLF for the 12-month period ending August 31, 2014 will be compared to that target. For RY2 and RY3, the target will be reset each year based on the average of the preceding five (5) years' LLFs.

The Factor of Adjustment (“FOA”) applicable to each Rate Year will be used to determine the monthly Gas Cost Factor applicable to sales customers and the amount of gas to be retained by the Company from SC 9 transportation quantities as an allowance for losses. The FOA is derived from the average of the preceding five (5) years’ LLFs and is reset for each Rate Year. The FOA applicable to RY1 is 1.0206.

Appendix 25 provides a sample calculation of the determination of the potential benefit or cost to the Company.

As described in Section K, the Company will perform a line loss study applicable to power generators and initiate discussions with New York Facilities companies. The Signatory Parties recognize that the generators’ contribution may be increased or decreased during the term of the Gas Rate Plan based upon the outcome of the study; any increase or decrease in the contribution by generators will decrease or increase, respectively, the line loss responsibility of other customers. The Signatory Parties also recognize that the lost and unaccounted for gas mechanism could change during the term of this Gas Rate Plan as a result of the New York Facilities collaborative.

e. Transco Heater/Odorization Project

The Company presented plans to contract with Transcontinental Gas Pipe Line ("Transco") to construct, own and operate certain natural gas heaters and supplemental odorization equipment ("Transco heater/odorization project"), to reimburse Transco for the costs of this project through means of a FERC-approved surcharge, and for the

Company to recover these FERC-approved charges through the Company's GCF, MRA and/or its WACOC charged to gas marketers.

The Signatory Parties support the Transco heater/odorization project as the preferred alternative for the Company to address the Company's need for natural gas heaters and supplemental odorization equipment. The Signatory Parties also recommend that the FERC-approved charges designed for Transco to recover its costs of providing these equipment and services be recovered by the Company through the GCF, MRA and/or WACOC.

Transco will make a filing with FERC to seek authorization to collect from Con Edison charges designed to recover the costs of the Transco heater/odorization project payable by Con Edison. The Company will (and other interested parties, including Staff, may) participate in the FERC proceeding established to set just and reasonable rates for this service. Following FERC's determination of a just and reasonable rate, the Company shall submit a tariff filing to the Commission to collect through the GCF, MRA and/or WACOC the charges approved by FERC. The tariff filing shall, among other things, demonstrate the reasonableness of the charges payable by the Company to Transco for the heater/odorization project, the proposed recovery period for the capital costs reflected in the FERC-approved charges (which could be longer than the recovery period adopted by FERC for Transco's recovery of its capital costs), and how the Company plans to allocate these FERC-approved charges as among the GCF, MRA and WACOC. Recovery of these FERC-approved charges, including any charges that may be incurred by the Company prior to Commission action on the Company's tariff filing, would commence consistent with the Commission's determination of the Company's tariff filing.

The Signatory Parties agree that whenever the Company is or will be subject to other FERC-approved charges, costs or credits not already listed in or otherwise covered by the then-effective tariff language for these adjustment mechanisms, the Company will make a tariff filing with the Commission to provide for recovery of these costs or charges, or application of these credits, through the GCF, MRA and/or WACOC. The proposed tariff amendment may include charges/costs/credits applicable to the period prior to the effective date of the tariff amendment.

f. Oil-to-Gas Conversions

i) Oil to Gas Incentive program

The Company's program of providing financial incentives to residential and commercial customers to encourage their conversion from oil use to gas use shall continue to be funded through an MRA surcharge up to a maximum of $1.465 million per Rate Year. The gas sales forecast and RDM targets underlying the gas rates in this Proposal reflect sales projected to result from this program.

The Company will submit a report to the Secretary within sixty (60) days of the end of each of RY1, RY2 and RY3, on activities under this program during the prior Rate Year, including program descriptions and the amounts of incentives committed and/or disbursed, and the number of customers and estimated sales in the aggregate by service classification. The Company will maintain a list of recipients of $500 or more for inspection by Staff.

ii) Oil-to-Gas Conversions in New York City and Area Growth

NYC promulgated rules in 2011 requiring buildings in New York City that need a boiler operation permit to operate their heating systems, to phase out the use of heavy heating oil, known as "No. 6" and "No. 4" fuel oil, by 2015 and 2030, respectively. NYC's new rules allow such buildings to switch to No. 2 heating oil, biodiesel, or natural gas. NYC itself maintains a fuel-neutral stance and provides, through its Clean Heat marketing arm, guidance on the selection of fuels to building owners, including the use of No. 2 heating oil or biodiesel as alternates to natural gas.

The Company will perform the following activities to foster and further facilitate oil-to-gas conversions:

1. The Company will provide milestones/timelines to each applicant. These milestones will be available in general format on the Web and specifically available to each applicant by logging onto the Web portal ("Project Center") and tracking their respective case, as well as through various pieces of correspondence sent to each applicant that provide further detail unique to their case.

2. The Company will file with the Secretary, on a quarterly basis, to commence at the end of the first quarter of 2014, a report on aggregated data with respect to conversion activity. The report will redact any customer-identifying data and will include the number of work requests received, the number of cases that are deemed "active" or "progressing," services installed and awaiting customer completion and completed conversions. The report will include only conversion applications within the following counties: New York, Bronx, and Queens. The Company will report the fuel type as the type of fuel indicated as being used on the premises from the report issued by the New York City Department of Environmental Protection and shared with the Company in April 2011.

3. The Company will provide maps, with appropriate disclaimers, of all the anticipated Area Growth Zones for the duration of the program (which is expected to conclude no later than 2020) and will make it available on its website no later than April 30, 2014. The Company already has a map of the Area Growth Zones for RY1 available on www.conEd.com/gasconversions. The disclaimers will explain that the Area Growth Zones are subject to change and that maps (other than for the immediately following Rate Year) should not be considered certain and

will likely be subject to future amendments. The Company accepts no responsibility for the purchase of gas-burning equipment or work performed in the building by the customer based on the issuance of these projected zones, and maps are not a guarantee of service installation in the respective zones.

4. The Company will review and grant requests in writing by applicants made before the expiration of the sixty-day period, for an additional thirty days, or less if requested, to complete the customer commitment portion of the conversion upon the applicant explaining the need for additional time. The Company reserves the right to reject requests that would adversely impact its operations or other customers.

5. Additional detail of the breakdown of costs will be provided to applicants receiving an order of magnitude cost to connect to the Company's gas system. Specifically, the Company will provide details on the footage of main/service required to serve the customer. The Company will clarify language already provided on the service determination that the order of magnitude cost will be further refined following a point of entry meeting (also referred to as an initial field visit) and detailed cost estimates will be provided at that time to any customer who wishes to continue their conversion. The Company will clarify this process by describing this detail in its overall description of process on its website.

The Company will also report on a quarterly basis, to the Secretary and NYC, any permitting issues it encounters that affect the installation of regulators, mains or services to serve the population of customers seeking to convert from heating oil to natural gas. These permits may be issued by any agency of the City of New York, but will typically include: NYC Department of Transportation, NYC Department of Buildings, NYC Department of Design and Construction, NYC School Construction Authority, NYC Department of Parks and Recreation. Customer identifying data shall be redacted.

g. Vent Line Protection Device Testing

The Company will retain an independent third-party to annually perform random testing on five (5) percent of installed vent line protection devices beginning in 2015. The Company will file with the Secretary the results of the testing within sixty (60) days of the end of 2015 and 2016.

3. **Steam**

This Proposal recommends changes to the Company's retail steam sales and steam transportation service rates and charges, designed to produce a $22.358 million reduction in revenues on an annual basis starting in RY1, a $19.784 million increase in revenues on an annual basis starting in RY2, and an additional $20.270 million increase in revenues on an annual basis starting in RY3.

The Signatory Parties propose that these three base rate changes be implemented on a levelized basis to provide rate stability over the term of the Steam Rate Plan. The annual levelized revenue changes would be zero in each of RY1, RY2 and RY3.[18]

The Company will defer the amounts of the annual revenue requirement changes each Rate Year as shown in Appendix 3, page 10 of 10. PSC Account 615 – Miscellaneous Steam Revenues will be debited/credited with the offset recorded in PSC Account 254 – Regulatory Liabilities. Interest on the outstanding balance will accrue at the Other Customer-Provided Capital Rate. The estimated amount to be deferred for the benefit of customers at December 31, 2016 is approximately $8.158 million.

Since the annual levelized rate changes would result in lower base rates at the end of the three-year term of the Steam Rate Plan than they would otherwise be under a non-levelized approach, $17.696 million of the levelized change in RY3 will be effectuated in RY3 via class-specific temporary credits. Such credits would only be effective for the duration of RY3. The credits, which will be shown on statements filed separately from the Company's rate schedules, will be credited in the same manner as if they were

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[18] The levelized rate changes are inclusive of interest on the deferred rate decrease calculated at the 2014 Other Customer-Provided Capital Rate of 3.0 percent. The Company will calculate the change in interest for any change in the Other Customer-Provided Capital Rate in future years, and defer the difference for surcharge or credit to customers, as applicable.

collected in base rates. Therefore, RY3 base rates will be set to reflect revenues that are $17.696 million greater than the RY3 revenue level. During RY3, the $17.696 million will be offset by the temporary credits. At the end of RY3, the temporary credits will expire and the base rates will remain in effect.

The Company will continue to recover on an annual basis $6.0 million through the Rate Adjustment Clause ("RAC") pending a Commission determination in Case 09-M-0114.

The major components of the steam revenue requirements underlying this Proposal are set forth in Appendix 3. These revenue requirements are net of the amortizations of various customer credits and debits on the Company's books of account that have previously been deferred by the Company. The list of deferred customer credits and debits to be applied during the Steam Rate Plan is attached as Appendix 4.

a. Gas Additions for 59th Street and 74th Street Steam Generating Stations

The capital projects to add gas-firing capability to the Company's 59th Street and 74th Street Steam Generating Stations were placed in service on a phased-in basis and customers began receiving the benefit of the fuel cost savings the project produced during 2013.[19] The 2010 Steam Rate Order did not provide funding for these projects but did contemplate that the Company may undertake them and provided the opportunity for recovery of carrying charges on these investments commencing when these facilities were placed into service.

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[19] The 59th Street project was phased into service during May and June 2013 and the 74th Street project was phased into service during September, October and December 2013.

This Proposal reflects recovery, over three years, of fifty (50) percent of the carrying charges of approximately $1.7 million that the Company incurred during 2013. The projects are included in the steam rate base.

The Signatory Parties recommend that the Commission authorize the Company to record on its books of account at the time the Commission adopts this Proposal, a regulatory asset in the amount of the $0.855 million and to commence amortization of that deferred balance over three (3) years effective as of January 1, 2014.

b. Fuel Adjustment Clause ("FAC")

Any variations between the actual cost of fuel and the cost of fuel reflected in rates will continue to be recovered through the FAC. The Company will continue to charge or credit the annual reconciliation of the steam fuel expenses and revenues through the FAC.[20]

The Company will continue to recover all costs associated with oil storage and handling through the FAC, except Company labor costs and some off-site storage costs.

The Company will recover through the FAC its fuel costs associated with the actual Steam System Variance to the extent such costs are not recovered in base rates. The Steam System Variance reconciliation mechanism established by the 2004 Steam Rate Order[21] and set forth in the steam tariff will continue, except that the levels above and below which the Company and customers will share variance related fuel costs will be as follows: if the variance is greater than 4,000 MMlb in any Rate Year, the Company

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[20] The Company recovers various costs and charges, and provides certain credits, through the FAC. For costs, charges, and credits covered by the language of this adjustment mechanism, the Company will continue to recover such costs and charges, and provide such credits, as incurred, by reflecting these charges, costs and/or credits in monthly statements filed pursuant to this adjustment mechanism.

[21] Case 03-S-1672, Consolidated Edison Company of New York, Inc. – Steam Rates, *Order Adopting the Terms of a Joint Proposal* (issued September 27, 2004) ("2004 Steam Rate Order").

will recover 90 percent of the variance-related fuel costs in excess of 4,000 MMlb; and if the variance is less than 3,600 MMlb in any Rate Year, the Company will retain 10 percent of the variance-related fuel cost savings less than 3,600 MMlb. The Company's exposure for unrecovered variance-related fuel costs will not exceed $5 million in any Rate Year. In no event will the Company retain more than $5 million in variance-related fuel cost savings in any Rate Year.

The FAC includes a section entitled Special Monthly Adjustments, which provides for recovery through the FAC of "the Steam system's allocable share of Clean Air Act ("CAA") Section 185 fees" pursuant to the Commission's Order in Case 09-S-0794 (Section 8.4(h), Leaf 53).

The Signatory Parties agree that when the Company becomes subject to additional environmental programs, for example, EPA's Cross State Air Pollution Rule, that result in allowance costs or credits, the Company will make a tariff filing with the Commission providing for recovery or credit through the FAC of such costs or credits, respectively, by applying for similar treatment currently afforded to Section 185 fees. The proposed tariff amendment may include charges/costs/credits applicable to the period prior to the effective date of the tariff amendment.

c. Base Cost of Fuel

The usage charges in each class will reflect a decrease of $2.700 per Mlb to be made to the current base cost of fuel of $10.049 per Mlb. The adjustment to the base cost of fuel is based on: (i) the actual monthly fuel costs and equivalent sales for the 12 months ended November 2013, and (ii) the Company's forecasted monthly fuel costs and equivalent sales for RY1. The average cost of fuel for the 24-month period is equal to the quotient of the total monthly fuel costs for the period and the total equivalent sales for the same period. Any unrecovered deferred fuel costs resulting from any such change in the base cost of fuel will be reflected in the fuel reconciliation.

d. Uncollectible Accounts

The steam revenue requirements for each of RY1, RY2 and RY3 reflect an annual allowance for uncollectible accounts write-offs in the amount of $425,000. If the Company's actual steam uncollectible accounts write-offs during RY1, RY2 and RY3 exceed $2.5 million in aggregate, the Company will be allowed to defer for future recovery from customers the amount by which the aggregate write-offs exceed $1.275 million.

e. Steam Trap/Cap Replacements

Effective January 1, 2014, the Company will cease performing inspections under the trap cap inspection program, which was previously performed as a follow-up to the annual trap replacement program. This program required the Company to remove the cap and visually inspect the trap for debris between four and eight months after a trap replacement. The installation of new trap assemblies with strainer components have significantly reduced the amount of debris and visual clogging of the traps found during these visual inspections. Estimated O&M savings of $200,000 associated with the elimination of this program is included in the steam revenue requirement.

4. **Common Items**

a. Productivity

For each Rate Year the electric, gas and steam revenue requirements each reflect an annual one (1) percent productivity adjustment.[22] The revenue requirements also

[22] For electric, $14.7 million in RY1 and $7.0 million in RY2. For gas, $2.8 million in RY1, $1.3 million in RY2 and $1.4 million in RY3. For steam, $1.5 million in RY1, $0.7 million in RY2 and $0.7 million in

reflect productivity adjustments related to the Company's implementation of the Finance and Supply Chain Enterprise Resource Project ("Project One"),[23] in addition to proposed cost savings associated with various Company project and programs.

With respect to Project One, within ninety (90) days of the end of calendar years 2015 and 2016, the Company will file a report with the Secretary indicating and explaining the total capital investments made and O&M expense incurred to support Project One. The report will also include an estimated range of labor cost savings realized during the preceding year that resulted from the Company's implementation of Project One. The initial report in 2015 will include the labor cost savings, if any, for the period beginning in July 2012, when Project One was implemented, through December 2014.

b. Sales Forecasts

The sales and delivery revenue forecasts used to determine the revenue requirement for each of RY1, RY2 and RY3 are set forth in Appendices 5, 6 and 7, respectively. For purposes of this Proposal, the sales and delivery revenue forecasts for electric, gas and steam are each based on the use of a 10-year weather normal for the period through December 2012.

C. <u>Computation and Disposition of Earnings</u>

Following each of RY1 and RY2 for electric and each of RY1, RY2 and RY3 for gas and steam, Con Edison will compute, separately, the earned rate of return on common

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RY3. The calculation of the Company's labor expense adjusted for productivity among other factors is set forth in Appendix 28.

[23] For electric, $2.7 million in RY1 and in RY2. For gas, $0.4 million in RY1, RY2 and RY3. For steam, $0.2 million in RY1, RY2 and RY3.

equity for its electric, gas and steam businesses for the preceding Rate Year. The Company will submit to the Secretary these computations of earnings no later than sixty (60) days after the end of each Rate Year.

1. **<u>Electric Earnings Sharing Threshold</u>**

For electric, if the level of earned common equity return for any Rate Year exceeds 9.8 percent ("Electric Earnings Sharing Threshold"), the amount in excess of the Electric Earnings Sharing Threshold will be deemed "shared earnings" for the purposes of this Proposal. One-half of the revenue requirement equivalent of any shared earnings above 9.8 percent but less than 10.45 percent will be deferred for the benefit of electric customers and the remaining one-half of any such shared earnings will be retained by the Company; seventy-five (75) percent of the revenue requirement equivalent of any shared earnings equal to or in excess of 10.45 percent but less than 10.95 percent will be deferred for the benefit of electric customers and the remaining twenty-five (25) percent of any shared earnings will be retained by the Company; and ninety (90) percent of the revenue requirement equivalent of any shared earnings equal to or in excess of 10.95 percent will be deferred for the benefit of electric customers and the remaining ten (10) percent of any shared earnings will be retained by the Company.

2. **<u>Gas and Steam Earnings Sharing Threshold</u>**

For gas and steam, if the level of earned common equity return for any Rate Year exceeds 9.9 percent ("Gas and Steam Earnings Sharing Threshold"), calculated separately, the amount in excess of the Gas and Steam Earnings Sharing Threshold will be deemed "shared earnings" for the purposes of this Proposal. One-half of the revenue requirement equivalent of any shared earnings above 9.9 percent but less than 10.55 percent will be deferred for the benefit of gas or steam customers as applicable and the remaining one-half of any such shared earnings will be retained by the Company; seventy-five (75) percent of the revenue requirement equivalent of any shared earnings equal to or in excess of 10.55 percent but less than 11.05 percent will be deferred for the benefit of gas or steam customers as applicable and the remaining twenty-five (25) percent of any shared earnings will be retained by the Company; and ninety (90) percent of the revenue requirement equivalent of any shared earnings equal to or in excess of 11.05 percent will be deferred for the benefit of gas or steam customers, as applicable, and the remaining ten (10) percent of any shared earnings will be retained by the Company.

3. **Earnings Calculation Method**

For each Rate Year, for purposes of determining whether the Company has earnings above the Electric Earnings Sharing Threshold or the Gas and Steam Earnings Sharing Threshold:

a. The calculation of return on common equity capital will be "per books," that is, computed from the Company's books of account for each Rate Year, excluding the effects of (i) Company incentives and performance-based revenue adjustments; (ii) the Company's share of property tax refunds earned during the applicable Rate Year; (iii) any other Commission-approved ratemaking incentives and revenue adjustments in effect during the applicable Rate Year; (iv) the amount of expense for awards under the Company's Executive Incentive Program; and (v) the following amounts representing a portion of expense and rate base carrying charges for the Company's Supplemental Retirement Income Plan: $9.7 million for electric, $1.6 million for gas and $0.8 million for steam. In addition, with respect to steam only, the net revenue effect during the applicable Rate Year of steam sales related to colder-than-normal weather or the steam sales reduction related to warmer-than-normal weather will be excluded from the calculation of return on common equity as calculated in the manner described in Appendix 14. Furthermore, the net income effects during RY1 of the Company recording the regulatory assets related to PJM OATT charges, spent nuclear fuel litigation costs and adding gas-firing capability to the Company's 59th Street and 74th Street Steam Generating Stations as provided in this Proposal will be excluded from the calculation of return on common equity.

b. Such earnings computations will reflect the lesser of: (i) an equity ratio equal to fifty (50) percent, or (ii) Con Edison's actual average common equity ratio. Con Edison's actual common equity ratio will exclude all components related to "other comprehensive income" that may be required by generally accepted accounting principles; such charges are recognized for financial accounting reporting purposes but are not recognized or realized for ratemaking purposes.

c. If the Company does not file for new electric base delivery rates to take effect within fifteen (15) days after the expiration of RY2, the Electric Earnings Sharing Threshold and the other electric earnings sharing thresholds will continue until base electric delivery rates are reset by the Commission. For gas and steam, if the Company does not file for new base delivery rates to take effect within fifteen (15) days after the expiration of RY3, the Gas and Steam Earnings Sharing Threshold and the other earnings sharing thresholds for gas and steam will continue until base gas and steam delivery rates, as applicable, are reset by the Commission. Such calculation will be performed on an annual basis in the same manner as set forth above. Revenue targets (*e.g.*, revenue per customer factors for gas) and trued-up expenses contained in

Appendices 5, 6, 8, 9 and 10 will be based on RY2 levels for electric and RY3 levels for gas and steam.

d. To the extent any stay-out period is less than twelve (12) months, the earnings sharing calculation will be in accordance with the methodology illustrated in Appendix 13.[24]

4. **<u>Disposition of Shared Earnings</u>**

For electric, gas and/or steam earnings above the related Electric Earnings Sharing Threshold or Gas and Steam Earnings Sharing Threshold in any Rate Year, the Company will apply fifty (50) percent of its share and the full amount of the customers' share of electric, gas and/or steam earnings above the sharing threshold that would otherwise be deferred for the benefit of customers under this Proposal, to reduce respective deferred under-collections of SIR costs. In the event the amount of shared earnings for electric, gas and/or steam available to reduce respective deferred under-collections of SIR costs exceeds the amount of such deferred under-collections, the Company will apply the amount of the excess to reduce other deferred costs. The Company's annual earnings report will include the amount, if any, of deferred undercollections of SIR costs written down with the Company's and the customers' respective shares of earnings above the earnings sharing thresholds. If applicable, the Company's annual earnings report will identify any other deferred costs reduced by application of shared earnings and the amount of shared earnings used for that purpose.

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[24] Under the methodology set forth in Appendix 13, actual rate base during the stay-out period is adjusted to reflect the effect of seasonal variations of sales on earnings. The earnings sharing calculation for the nine-month stay-out period for electric under Case 09-E-0428 and the three-month stay-out period for gas under Case 09-G-0795 and for steam under Case 09-S-0794 will be in accordance with a methodology under which no adjustment is made to the actual rate base during the stay-out period.

D. Capital Expenditures and Net Plant Reconciliation

Projected capital expenditures for electric, gas and steam are set forth in Appendix 27.

1. Electric

a. Net Plant Reconciliation

The electric revenue requirements for RY1 and RY2 reflect the average net plant balances set forth in Appendix 8 for the following net plant categories: (1) Transmission and Distribution (including Municipal Infrastructure Support expenditures) ("T&D"); (2) Storm Hardening; and (3) Other (comprised of capital expenditures for Electric Production and Shared Services allocable to Electric) (collectively, "Average Electric Plant In Service Balances").

The Average Electric Plant In Service Balances reflect a level of capital expenditures supported by various capital programs and projects. The Company, however, has the flexibility over the term of the Electric Rate Plan to modify the list, priority, nature and scope of its capital programs and projects.

The Company will defer for the benefit of customers the revenue requirement impact (*i.e.*, carrying costs, including depreciation, as identified in Appendix 8) of the amount by which the Company's actual expenditures for electric capital programs and projects result in actual average net plant (excluding removal costs) that is less than the amount included in the Average Electric Plant In Service Balances (excluding removal costs), as set forth in Appendix 8, for RY1 and RY2 for each net plant category as provided herein.[25]

With respect to the T&D category within the Average Electric Plant In Service Balances, there will be no deferral of the revenue requirement impacts attributable to actual average net plant within the T&D Reliability component of the T&D net plant category ("T&D Reliability component") being less than the T&D Reliability net plant balances set forth in Appendix 8 for RY1 and RY2 ("T&D Reliability Plant In Service Balances") provided that (i) the actual average T&D Reliability net plant is at least 85 percent of the amount of T&D Reliability Plant In Service Balances ("85% Threshold") and (ii) the sum of the actual average net plant for the Storm Hardening category and the T&D Reliability component ("Actual Storm Hardening and T&D Reliability Plant Total") is at least equal to the sum of the amount included in the Average Electric Plant In Service Balances for the Storm Hardening category and the T&D Reliability Plant in Service Balances set forth in Appendix 8 ("Allowed Storm Hardening and T&D Reliability Plant Total"). If a deferral attributable to the T&D reliability component would be required because (i) was satisfied but (ii) was not satisfied, such deferral will be the lesser of (a) the revenue requirement impact associated with the T&D Reliability component net plant balance or (b) the revenue requirement impact associated with the amount by which the Actual Storm Hardening and T&D Reliability Plant total is less than the Allowed Storm Hardening and T&D Reliability Plant Total.

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[25] The revenue requirement impact will be calculated by applying an annual carrying charge factor for the applicable net plant category (see Appendix 8) to the amount by which the actual was below the amount included in the Average Electric Plant In Service Balances.

With respect to the Storm Hardening category within the Average Electric Plant In Service Balances, there will be no deferral of the revenue requirement impacts attributable to actual average net plant within the Storm Hardening category being less than the amount included in the Average Electric Plant In Service Balances ("Storm Hardening Plant In Service Balances") provided that (i) the actual average Storm Hardening net plant is at least 85 percent of the amount of the Storm Hardening Plant In Service Balances ("85% Threshold") and (ii) the Actual Storm Hardening and T&D Reliability Plant Total is at least equal to the Allowed Storm Hardening and T&D Reliability Plant Total. If a deferral attributable to the Storm Hardening category is required because (i) was satisfied but (ii) was not satisfied, such deferral will be the lesser of (a) the revenue requirement impact associated with the Storm Hardening net plant balance or (b) the revenue impact associated with the amount by which the Actual Storm Hardening and T&D Reliability Plant total is less than the allowed Storm Hardening and T&D Reliability Plant total.[26]

With respect to the Storm Hardening category of the Average Electric Plant In Service Balances, the Commission's order regarding RY2 Storm Hardening programs in response to the Company's September 1, 2014 Storm Hardening report (see section D.4 below) may call for Storm Hardening capital expenditures in RY2 in an amount more or less than the amount reflected in the Storm Hardening category of the Average Electric Plant In Service Balances for RY2.

If the Commission's order calls for RY2 Storm Hardening capital expenditures greater than the amount reflected in the Storm Hardening category of the Average

[26] See examples at the end of Appendix 8.

Electric Plant In Service Balances for RY2, the net plant reconciliation mechanism will continue to apply as described herein and the Company will defer for future collection from customers the revenue requirement impact (*i.e.*, carrying costs, including depreciation, as identified in Appendix 8) of the amount of average net plant resulting from the additional capital expenditures.

If the Commission's order calls for RY2 Storm Hardening capital expenditures less than the amount reflected in the Storm Hardening category of the Average Electric Plant In Service Balances for RY2, the Company will recalculate the Storm Hardening category of the Average Electric Plant In Service Balances for RY2 using such lower capital expenditures and (1) use that recalculated average net plant balance as the net plant amount for the Storm Hardening category of the Average Electric Plant In Service Balances for RY2 and (2) defer for the future credit to customers the revenue requirement impact (*i.e.*, carrying costs, including depreciation, as identified in Appendix 8) of the difference between the average net plant balance for the Storm Hardening category of the Average Electric Plant In Service Balances for RY2 and the recalculated amount.

The reconciliations to Average Electric Plant In Service Balances for RY1 and RY2 will be cumulative within each of the net plant categories; that is, a revenue requirement impact deferral will be required under this provision only if the actual average net plant balances for the 24-month period covered by the Electric Rate Plan for a category of the Average Electric Plant In Service Balances is below the amount for the category included in the Average Electric Plant In Service Balances over such period as shown on Appendix 8.

b. Capital Expenditures for Brooklyn Networks Load Growth

Following the closure of the record in these proceedings, the Company's analysis of summer 2014 peaks loads in Brooklyn networks identified peak demand growth in sections of Brooklyn that will require capital investment in order to maintain reliability, with investments beginning in 2014. To the extent practical, the Company will utilize non-traditional programs that facilitate use of distributed resources to reduce the identified investment needs. The nature of the programs that may be utilized by the Company will seek to further the deployment of advanced technologies, and could include utility and customer-side resources. The Company will meet with Signatory Parties before implementation to discuss the contemplated solutions, providing sufficiently detailed technical and cost information as to its analysis and proposed solutions so that interested Signatory Parties can meaningfully evaluate the Company's proposed solutions and provide feedback.

c. Smart Grid

The electric revenue requirements reflect base rate recovery of Smart Grid costs as of the beginning of RY1 and termination of the MAC surcharge approach to recovery established by the Commission in its October 19, 2010 order in Case 09-E-0310.[27] Smart Grid Investment Grant projects will be treated in the same manner as other capital projects (*i.e.*, based on estimated cost and plant in service date) and Smart Grid Demonstration Grant expenditures will be treated as a deferred cost. Amortization of estimated deferred Smart Grid Demonstration Grant costs through December 31, 2013 is reflected in electric revenue requirements at $3.28 million per year.

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[27] The Company's final surcharge reconciliation report is due during March 2014.

The Company will defer for future disposition by the Commission any variation between the amount of Smart Grid Demonstration Grant costs recovered during the Electric Rate Plan and the actual amount as of the beginning of RY1. The Company will also defer for future disposition by the Commission, Smart Grid surcharges collected from customers after January 1, 2014, as will occur due to electric rate changes resulting from these proceedings occurring after, but effective as of, that date.

d. Indian Point 2 Contingency Plan

The Electric Rate Plan revenue requirements do not reflect any of the Company's costs for transmission projects approved by the Commission in its November 4, 2013 order in Case 12-E-0503 ("Indian Point Contingency Plan Order").[28] The Company may seek cost recovery authorization for such projects from the Commission. Accordingly, the Signatory Parties intend that Commission adoption of this Proposal does not preclude or otherwise limit the Company's rights to seek such authorization from the Commission for these projects by surcharge, by increase to base rates, or by other means, as determined by the Commission. The Signatory Parties also intend that adoption of this Proposal not preclude or otherwise limit the Company's recovery of Energy Efficiency, Demand Reduction and CHP costs as contemplated by the Indian Point Contingency Plan Order. Similarly, adoption of this Proposal does not preclude or otherwise limit any rights any Signatory Party may have with respect to any authorization sought by the Company for recovery of Indian Point Contingency Plan projects and/or Energy

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[28] Case 12-E-0503, Proceeding on Motion of the Commission to Review Generation Retirement Contingency Plans, *Order Accepting IPEC Reliability Contingency Plans, Establishing Cost Allocation and Recovery, and Denying Requests for Rehearing* (issued November 4, 2013).

Efficiency, Demand Reduction and CHP costs contemplated by the Indian Point Contingency Plan Order.

e. Outage Management Pilot

As part of its storm hardening projects, the Company will begin implementation of a two-phase pilot program in 2014 to test the ability of a networked Automated Meter Reading ("AMR") and/or Advanced Metering Infrastructure ("AMI") system to assist in more timely identification of customer outages and improve overall outage response and efficiency. Phase One of the pilot program will seek to leverage existing AMR meter assets in County of Westchester ("Westchester County") to improve outage management capabilities through the use of new data collection infrastructure and network management software. This phase will include a field trial involving meters in two circuits to preliminarily evaluate the viability and feasibility of the concept and the usefulness of the technology for outage management purposes.

Phase One is expected to last six to ten months, dependent on system conditions, and will include approximately 6,200 electric meters on two high-priority circuits. Existing AMR meters and new data collection hardware and software will be used to provide event information that will be evaluated for its usefulness in outage management. The Company will evaluate the data generated in Phase One to determine whether to move forward with Phase Two.

If the Company determines to move forward with Phase Two, Phase Two would consist of expanded and longer duration testing in two areas – one in Westchester County and one within New York City. The areas will be selected based on their outage history during storm events and other salient factors. Within Westchester County, the number of circuits monitored would be increased to include approximately 30,000 meters. Within

New York City, the size and number of areas will be selected to include an appropriate mix of customer types (*e.g.*, single family homes, multi-family dwellings, apartment buildings). Con Edison will further develop software interfaces to assist in managing the larger meter populations and the compatibility of the AMR and/or AMI technologies for this purpose. The Phase Two program for Westchester would be included in the Company's September 1, 2014 storm hardening filing (see section D.4 below). The Phase Two program for New York City would either be included in the September 1, 2014 storm hardening filing or addressed as part of the Company's next electric rate filing. The Company will make a summary evaluation of the pilot available to interested parties.

f. Reporting Requirements

The Company will provide annual reports relating to capital expenditures in the manner set forth in Appendix 23.

2. **<u>Gas</u>**

a. Net Plant Reconciliation

The gas revenue requirements for RY1, RY2 and RY3 reflect the net plant balances set forth in Appendix 9 for the following net plant categories: 1) Delivery (including Municipal Infrastructure Support expenditures), and 2) Storm Hardening (collectively, "Average Gas Plant In Service Balances").

The Average Gas Plant In Service Balances reflect a level of capital expenditures supported by various capital programs and projects. The Company, however, has the flexibility over the term of the Gas Rate Plan to modify the list, priority, nature and scope of its gas capital programs and projects.

The Company will defer for the benefit of customers, subject to adjustment under the reconciliation mechanism regarding oil to gas conversions described below, the revenue requirement impact (*i.e.*, carrying costs, including depreciation, as identified in Appendix 9) of the amount by which the Company's actual expenditures for gas capital programs and projects result in average net plant (excluding removal costs) that is less than the amount included in the Average Gas Plant In Service Balances (excluding removal costs), as set forth in Appendix 9, for RY1, RY2 and RY3 for each net plant category as provided herein.[29]

The Company may defer on its books of account for future recovery from customers the carrying charges (including depreciation) on average net plant in service (excluding removal costs) resulting from municipal infrastructure support-related capital costs up to $10 million annually incurred due to: (a) projects of the City of New York or any other governmental entity or entities for the purposes of increasing the resiliency to storms of any form of public facility, machinery, equipment, structure, infrastructure, highway, road, street, or grounds,;(b) NYC Department of Environmental Protection ("DEP") Combined Sewer Overflow projects;[30] (c) change in customary practice relating to interference (*e.g.*, responsibility for costs associated with New York City transit

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[29] The revenue requirement impact will be calculated by applying an annual carrying charge factor for the applicable average net plant in service category (see Appendix 9) to the amount by which actual net plant was below the amount included in the Average Gas Plant In Service Balances.

[30] The DEP is required under a 2005 Order on Consent to reduce combined sewer overflows ("CSOs") from its sewer system to improve the water quality of its surrounding waters, such as Flushing Bay, Jamaica Bay, and tributaries to the East River, Long Island Sound, and Outer Harbor. Under the 2005 Consent Order, the DEP has completed Waterbody/Watershed Facility Plans, which are the initial phase of CSO planning, and are required to construct various grey infrastructure projects, and develop Long-Term Control Plans. In 2011, the New York State Department of Environmental Conservation and DEP identified numerous modifications to the CSO Consent Order, including integration of green infrastructure and substitution of more cost-effective grey infrastructure, and agreed to fixed dates (beginning in June 2013 and continuing through December 2017) for submittal of the Long-Term Control Plans. (http://www.dec.ny.gov/chemical/77733.html).

projects); and/or (d) all other public works or municipal infrastructure projects with a projected total cost in excess of $100 million, to the extent the Company's capital expenditures up to $10 million related to those activities result in total actual Delivery average net plant in service (excluding removal costs) exceeding the Delivery category of the Average Gas Plant In Service Balance in any or all Rate Years.

With respect to the Storm Hardening category of the Average Gas Plant In Service Balances, the Commission’s order regarding RY2 and RY3 Storm Hardening programs in response to the Company’s September 1, 2014 Storm Hardening report (see section D.4 below) may call for Storm Hardening capital expenditures in RY2 and/or RY3 in an amount more or less than the amount reflected in the Storm Hardening category of the Average Gas Plant In Service Balances for RY2 and/or RY3.

If the Commission’s order calls for RY2 and/or RY3 Storm Hardening capital expenditures greater than the amount reflected in the Storm Hardening category of the Average Gas Plant In Service Balances for RY2 and/or RY3, the net plant reconciliation mechanism will continue to apply as described herein and the Company will defer for future collection from customers the revenue requirement impact (*i.e.*, carrying costs, including depreciation, as identified in Appendix 9) of the amount of average net plant resulting from the additional capital expenditures.

If the Commission’s order calls for RY2 and/or RY3 Storm Hardening capital expenditures less than the amount reflected in the Storm Hardening category of the Average Gas Plant In Service Balances for RY2 and/or RY3, the Company will recalculate the Storm Hardening category of the Average Gas Plant In Service Balances for RY2 and/or RY3 using such lower capital expenditures and (1) use that recalculated average net plant balance as the net plant amount for the Storm Hardening category of the Average Gas Plant In Service Balances for RY2 and/or RY3 and (2) defer for the future credit to customers the revenue requirement impact (*i.e.*, carrying costs, including depreciation, as identified in Appendix 9) of the difference between the average net plant balance for the Storm Hardening category of the Average Gas Plant In Service Balances for RY2 and/or RY3 and the recalculated amount.

The reconciliations to Average Gas Plant In Service Balances for RY1, RY2 and RY3 will be cumulative within each of the net plant categories; that is, a revenue requirement impact deferral will be required under this provision only if the actual average net plant balances for the 36-month period covered by the Gas Rate Plan for a category of the Average Gas Plant In Service Balances is below the amount for the category included in the Average Gas Plant In Service Balances over such period as shown on Appendix 9.

b. Oil to Gas Conversions Net Plant Reconciliation Adjustment

The Average Gas Plant In Service Balances reflect the following forecasted capital expenditures for Company service installations for oil-to-gas ("OTG") conversions for Nos. 4/6 fuel oil customers for RY1, RY2 and RY3:

i. $53.8 million for RY1 for 640 OTG conversions.

ii. $69.0 million for RY2 for 646 OTG conversions.

iii. $56.1 million for RY3 for 466 OTG conversions.

Over the term of the Gas Rate Plan, if the Company installs less than 90 percent of its service installation targets and spends less than 90 percent of its forecasted capital expenditures for Nos. 4/6 service installation targets, the Company will defer for the benefit of customers carrying charges on the difference between an average net plant balance assuming the forecasted capital expenditures for OTG conversions and the actual average net plant based on the actual lower capital expenditures for OTG conversions.[31]

Over the term of the Gas Rate Plan, if the Company installs 90 percent or more of its service installation targets but spends less than 90 percent of its forecasted capital expenditures for Nos. 4/6 service installation targets, the Company will defer for the benefit of customers carrying charges on the difference between an average net plant balance assuming the forecasted capital expenditures for OTG conversions and the actual average net plant based on the actual lower capital expenditures for OTG conversions.

Over the term of the Gas Rate Plan, if the Company installs less than 90 percent of its service installation targets but spends 90 percent or more of its forecasted capital expenditures for Nos. 4/6 fuel oil-to-gas service installation targets, there will be no carrying charges deferred for the benefit of customers; however, in this event, the Company will file a report with the Secretary annually on why the capital expenditures were higher than forecasted, and why the number of installations were lower than forecasted, with a root cause analysis of why (*e.g.*, among other things, because of a higher concentration of customers who converted in more expensive zones such as Manhattan), and what change in plans, if any, the Company proposes for the next gas Rate Year.

If the reconciliation mechanism related to gas net plant described in section (a) above results in revenue requirement impacts to be deferred for the benefit of customers related to the Delivery category of the Average Gas Plant In Service balances, and the

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[31] See Appendix 9.

reconciliation mechanism in this section (b) also results in revenue requirement impacts to be deferred for the benefit of customers, the two calculations will be reconciled so that there is no double-count regarding any net plant for which carrying charges are to be deferred for the benefit of customers.

c. Leak-Prone Pipe Replacement in Flood Prone Zones[32]

In order to improve system resiliency, separate and apart from the Company's safety-related program to remove leak-prone pipe addressed in Appendix 17, the Company will remove at least the following amounts of leak-prone pipe in areas encompassed by the 100-year flood plain as established by FEMA:[33]

RY1 – 2 miles
RY2 – 3 miles
RY3 – 4 miles

During the term of the Gas Rate Plan, the 100-year floodplain in New York City will be as shown on FEMA's Preliminary Flood Insurance Rate Maps ("FIRMs") and updated when FEMA issues Final FIRMs. Within Westchester County, the geographic scope of such removals will be the 100-year floodplain as shown on FEMA's Advisory Base Flood Elevation Maps, and updated when FEMA issues Preliminary Work Maps, Preliminary FIRMs, and Final FIRMs, for the County.

Over the term of the Gas Rate Plan, a minimum of six miles of leak-prone pipe in flood prone zones will be replaced in Manhattan.

[32] This program has the added benefit of moving towards the objective of reducing the potential release of methane into the atmosphere, which is described on page 58 of the New York Energy Highway Blueprint.

[33] Federal Emergency Management Agency ("FEMA").

d. Reporting Requirements

The Company will provide annual reports relating to capital expenditures in the manner set forth in Appendix 23.

3. Steam

a. Net Plant Reconciliation

The steam revenue requirements for RY1, RY2 and RY3 reflect the net plant balances set forth in Appendix 10 for the following net plant categories: (1) steam production and steam distribution (including Municipal Infrastructure Support expenditures) ("P&D"), and (2) Storm Hardening (collectively, "Average Steam Plant In Service Balances").

The Average Steam Plant In Service Balances reflect a level of capital expenditures supported by various capital programs and projects. The Company, however, has the flexibility over the term of the Steam Rate Plan to modify the list, priority, nature and scope of its steam capital programs and projects.

The Company will defer for the benefit of customers the revenue requirement impact (*i.e.*, carrying costs, including depreciation, as identified in Appendix 10) of the amount by which the Company's actual expenditures for steam capital programs result in actual average net plant (excluding removal costs) that is less than the amount included in the Average Steam Plant In Service Balances (excluding removal costs) as set forth in Appendix 10 for RY1, RY2 and RY3 for each net plant category as provided herein.[34]

With respect to the Storm Hardening category of the Average Steam Plant In Service Balances, the Commission's order regarding RY2 and RY3 Storm Hardening

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[34] The revenue requirement impact will be calculated by applying an annual carrying charge factor for the applicable average net plant in service category (see Appendix 10) to the amount by which actual net plant was below the amount included in the Average Steam Plant In Service Balances.

programs in response to the Company's September 1, 2014 Storm Hardening report (see section D.4 below) may call for Storm Hardening capital expenditures in RY2 and/or RY3 in an amount more or less than the amount reflected in the Storm Hardening category of the Average Steam Plant In Service Balances for RY2 and/or RY3.

If the Commission's order calls for RY2 and/or RY3 Storm Hardening capital expenditures greater than the amount reflected in the Storm Hardening category of the Average Steam Plant In Service Balances for RY2 and/or RY3, the net plant reconciliation mechanism will continue to apply as described herein and the Company will defer for future collection from customers the revenue requirement impact (*i.e.*, carrying costs, including depreciation, as identified in Appendix 10) on the amount of average net plant resulting from the additional capital expenditures.

If the Commission's order calls for RY2 and/or RY3 Storm Hardening capital expenditures less than the amount reflected in the Storm Hardening category of the Average Steam Plant In Service Balances for RY2 and/or RY3, the Company will recalculate the Storm Hardening category of the Average Steam Plant In Service Balances for RY2 and/or RY3 using such lower capital expenditures and (1) use that recalculated average net plant balance as the net plant amount for the Storm Hardening category of the Average Steam Plant In Service Balances for RY2 and/or RY3 and (2) defer for the future credit to customers the revenue requirement impact (*i.e.*, carrying costs, including depreciation, as identified in Appendix 10) of the difference between the average net plant balance for the Storm Hardening category of the Average Steam Plant In Service Balances for RY2 and/or RY3 and the recalculated amount.

The reconciliations to Average Steam Plant In Service Balances for RY1, RY2 and RY3 will be cumulative within each of the net plant categories; that is, a revenue requirement impact deferral will be required under this provision only if the actual average net plant balances for the 36-month period covered by the Steam Rate Plan for a category of the Average Steam Plant In Service Balances is below the amount for the category included in the Average Steam Plant In Service Balances over such period as shown on Appendix 10.

b. Unplanned Steam Investment

Without limiting the Company's right to petition the Commission for any purpose regarding electric, gas or steam, the Signatory Parties recommend that a deferral petition submitted pursuant to this provision should not be rejected by the Commission solely on the grounds that the amount of the proposed investment is not material.

Con Edison may petition the Commission to defer for later recovery the carrying charges associated with an unplanned capital investment in its steam production plant of $5.0 million or more, provided that: (i) the project is due to circumstances outside the Company's control; (ii) the capital expenditures are made during the term of the Steam Rate Plan; (iii) the inclusion of the unplanned capital investment results in actual net plant for the P&D category of the Average Steam Plant In Service Balances exceeding the levels set forth in Appendix 10; and (iv) the Company has considered its flexibility to reprioritize steam production capital projects within the net plant levels set forth in Appendix 10. As indicated above, although any such petition is subject to the materiality, incremental, and earnings criteria applied by the Commission to deferral petitions, for purposes of this Proposal, the Signatory Parties recommend that a deferral petition submitted pursuant to this provision should not be rejected by the Commission solely on the grounds that the amount of the proposed investment is not material.

c. Reporting Requirements

The Company will provide annual reports relating to capital expenditures in the manner set forth in Appendix 23.

4. **Storm Hardening and Resiliency Collaborative**

The Signatory Parties support, and ask the Commission to direct, the continuation of the Storm Hardening and Resiliency Collaborative as set forth below.[35]

During these proceedings, a number of parties, including the Company and Staff, participated in a collaborative to examine the Company's storm hardening proposals presented in these proceedings and to exchange and discuss information, ideas, and proposals on resiliency-related issues that the parties presented in testimony filed in these proceedings ("Storm Hardening and Resiliency Collaborative"). The Department of Public Service designated the Administrative Law Judge Eleanor Stein to preside over the work of the collaborative. On December 5, 2013, the Company filed with the Secretary a report describing the activities of the collaborative, the Company's proposals for capital programs and projects to storm harden its electric, gas, and steam systems, and proposals by various working groups within the collaborative for additional initiatives to improve the resiliency of the Company's systems. On January 10, 2014, various parties to the collaborative may file with the Secretary comments on the Company's report and other issues related to the collaborative, as they deem appropriate.

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[35] The Storm Hardening and Resiliency Collaborative is comprised of the following four working groups: Working Group 1 is the Storm Hardening Design Standards and 2014 Projects group, Working Group 2 is the Alternative Resiliency Strategies group, Working Group 3 is the Natural Gas System Resiliency group, and Working Group 4 is the Risk Assessment / Cost Value Analysis group.

The electric, gas and steam delivery rates and charges recommended by this Proposal reflect projected expenditures in RY1 and RY2 to storm harden the Company's electric system and projected expenditures in RY1, RY2 and RY3 to storm harden the Company's gas and steam systems.

With respect to RY1, the Signatory Parties recommend that the Commission accept the forecasted storm hardening expenditures reflected in the proposed electric, gas and steam delivery rates without change. The net plant reconciliation mechanisms described in sections D.1, D.2, and D.3 above are designed to address the rate impacts of any difference between forecasted and actual expenditures.

With respect to projected expenditures in RY2 to storm harden the Company's electric system and projected expenditures in RY2 and RY3 to storm harden the Company's gas and steam systems, the Signatory Parties propose to replicate the process followed by Working Group 1 of the Storm Hardening and Resiliency Collaborative to further consider the Company's proposed storm hardening plans for RY1. Specifically, in June 2014 and 2015, the Company would initiate discussions with Staff and interested parties to discuss the Company's planned expenditures for storm hardening for RY2 and RY3, respectively. On or before September 1, 2014 and 2015, the Company would file with the Commission a report on the collaborative discussions, including the Company's recommended storm hardening projects and programs for 2015 and 2016, respectively. Staff and interested parties would have the opportunity to file comments on such report with the Commission. The Commission would determine the extent to which, if any, the Company should modify its planned storm hardening projects and programs for RY2 and RY3 by order issued on or before December 31, 2014 and 2015, respectively. The net plant reconciliation mechanisms described in sections D.1, D.2 and D.3 above are designed to address the rate impacts of any change in the net plant targets for storm hardening that may result from any such Commission directive, as well as any rate impacts of any difference between forecasted and actual expenditures

In addition to further evaluation of the Company's current forecasted expenditures to storm harden its electric, gas and steam systems in RY1, RY2 and RY3 as described above, the Signatory Parties recognize that the Company may undertake other projects and programs that may be presented to the Commission as a result of ongoing collaborative discussions by Working Groups 1 through 4 of the Storm Hardening and Resiliency Collaborative. Since the electric, gas and steam delivery rates recommended by this Proposal do not (and could not reasonably) reflect any incremental costs associated with new or additional initiatives that the Commission may encourage or otherwise direct, the Signatory Parties recommend that the Commission authorize the Company to recover the incremental costs associated with any such initiative(s), whether by surcharge, deferral, and/or such other means as the Commission may determine.

E. Reconciliations

The Company will reconcile the following costs and related items to the levels provided in rates, as set forth in Appendices 8, 9, and 10. Variations subject to recovery from or to be credited to customers will be deferred on the Company's books of account over the term of the Rate Plans, and the revenue requirement effects of such deferred debits and credits, as the case may be, will be addressed in future rate proceedings, except as addressed in section C.4. above.

1. **<u>Property Taxes (Electric, Gas and Steam)</u>**

If the level of actual electric, gas or steam expense for property taxes, excluding the effect of property tax refunds (as defined in section F. 3), varies in any Rate Year from the projected level provided in rates for that service, which levels are set forth in Appendices 8, 9 and 10, ninety (90) percent of the variation will be deferred and either recovered from or credited to customers, subject to the following cap: the Company's ten (10) percent share of property tax expenses above or below the level in rates is capped at an annual amount equal to ten (10) basis points on common equity for each Rate Year. The Company will defer on its books of account, for recovery from or credit to customers, one hundred (100) percent of the variation above or below the level at which the cap takes effect.

The Company will not be precluded from applying for a greater share of lower than forecasted property tax expenses (including the period beyond RY2 for electric and RY3 for gas and steam) if its extraordinary efforts result in fundamental taxation changes and produce substantial net benefits to customers.

2. **<u>Municipal Infrastructure Support (Other Than Company Labor) (Electric, Gas and Steam)</u>**

If actual non-Company labor Municipal Infrastructure Support expenses (*e.g.*, contractors costs) vary from the level provided in electric, gas and/or steam rates for any Rate Year, which levels are set forth in Appendices 8, 9, and 10, one hundred (100) percent of the variation below the target will be deferred on the Company's books of account and credited to customers, and eighty (80) percent of the variation above the target within a band of thirty (30) percent (*e.g.*, for electric a maximum deferral of $20.4

million for RY1)[36] will be deferred on the Company's books of account and recovered from customers. Expenditures above the target plus thirty (30) percent are not recoverable from customers except as follows: if actual electric, gas and/or steam non-Company labor Municipal Infrastructure Support expenses (*e.g.*, contractors costs) vary from the respective level provided in rates above the target plus thirty (30) percent, and such increased expenses are due to (a) projects of the City of New York or any other governmental entity or entities for the purposes of increasing the resiliency to storms of any form of public facility, machinery, equipment, structure, infrastructure, highway, road, street, or grounds, (b) the New York City DEP Combined Sewer Overflow projects, and/or (c) all other public works or municipal infrastructure projects with a projected total cost in excess of $100 million, eighty (80) percent of the variation above the target plus thirty (30) percent that is attributable to the above-described projects will be deferred on the Company's books of account for future recovery from electric, gas and/or steam customers as applicable.

In addition, if there is a change in law, rules or customary practice relating to interference (*e.g.*, responsibility for costs associated with New York City transit projects), the Company will have the right to defer such incremental costs pursuant to section L.2.

3. **Pensions/OPEBs (Electric, Gas and Steam)**

Pursuant to the Commission's Pension Policy Statement,[37] the Company will reconcile its actual pensions/Other Post-Employment Benefits ("OPEBs") expenses to the

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[36] RY1 rate allowance for interference of $84.8 million x 80 percent x 30 percent = $20.4 million.

[37] Case 91-M-0890, In the Matter of the Development of a Statement of Policy Concerning the Accounting and Ratemaking Treatment for Pensions and Post-Retirement Benefits Other Than Pensions, *Statement of Policy and Order Concerning the Accounting and Ratemaking Treatment for Pensions and Post-Retirement Benefits Other Than Pensions* (issued September 7, 1993) ("Pension Policy Statement").

level allowed in electric, gas and steam rates as set forth in Appendices 8, 9, and 10. For purposes of the reconciliation, the following annual amounts of expense related to the Supplemental Retirement Income Program will be deducted from the Company's actual pension/OPEBs expense: $4.65 million for electric, $0.63 million for gas and $0.34 million for steam.

The Pension Policy Statement provides that companies may seek prospective interest accruals or rate base treatment for amounts funded above the cost recoveries included in rates.[38] During the term of the Rate Plans, the Company may be required to fund its pension plan at a level above the rate allowance pursuant to the annual minimum pension funding requirements contained within the Pension Protection Act of 2006. The Company, its actuary and the parties are unable to predict with certainty if the minimum funding threshold will exceed rate recoveries during the term of the Rate Plans. In lieu of a provision in this Proposal addressing the Company's additional financing requirements should it be required to fund its pension plan above the level provided in rates during the term of these Rate Plans, the Proposal does not preclude the Company from petitioning the Commission to defer the financing costs associated with funding the pension plan at levels above the current rate allowance should funding above the rate allowance be required; the Company's right to obtain authority to defer such financing costs on its books of account will not be subject to requirements respecting materiality.

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[38] See Pension Policy Statement, Appendix A, page 16, footnote 3.

4. **Environmental Remediation (Electric, Gas and Steam)**

Actual expenditures for site investigation and remediation allocated to Con Edison's electric, gas or steam business,[39] including expenditures associated with former manufactured gas plant sites ("MGP"), Superfund and 1994 DEC Consent Order Appendix B sites ("SIR costs"), will be deferred on the Company's books of account and amortized as shown on Appendix 4. The deferred balances subject to interest will be reduced by accruals, insurance recoveries, associated reserves, deferred taxes and amounts included in rate base (see Appendices 1, 2, and 3). Effective January 1, 2014, the amortization period for SIR costs will be five (5) years.

5. **Long Term Debt Cost Rate (Electric, Gas and Steam)**

As set forth in Appendices 1, 2 and 3, the weighted average cost of long term debt during the term of the Rate Plans is 5.17 percent for RY1, 5.23 percent for RY2 and 5.39 percent for RY3. As set forth in Appendices 8, 9 and 10, included in those weighted average cost rates is 0.38 percent in RY1, 1.11 percent in RY2 and 2.42 percent in RY3 for Variable Rate Debt (*i.e.*, the Company's entire tax-exempt portfolio). The Company will be allowed to true-up its actual weighted average cost of Variable Rate Debt during RY1, RY2 and RY3 to the cost rates for Variable Rate Debt reflected in Appendices 8, 9 and 10. In the event the Variable Rate Debt[40] is refinanced with tax-exempt or taxable debt (which may include retiring the Variable Rate Debt) prior to January 1, 2016 for

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[39] These costs are the costs Con Edison incurs to investigate, remediate or pay damages (including natural resource damages, with respect to industrial and hazardous waste or contamination spills, discharges, and emissions) for which Con Edison is deemed responsible. These costs are net of insurance reimbursements (if any); nothing herein will require the Company to initiate or pursue litigation for purposes of obtaining insurance reimbursement, nor preclude or limit the Commission's authority to review the reasonableness of the Company's conduct in such matters.

[40] The cost of Variable Rate Debt includes the costs of any credit support measures, such as letter of credit or bond insurance.

electric and January 1, 2017 for gas and steam (including under circumstances not contemplated by the Commission's *Order Authorizing Issuance of Securities*, issued December 17, 2012, in Case 12-M-0401, and therefore requiring Commission authorization), the Company will include its costs associated with the refinancing of the Variable Rate Debt in the amounts to be reconciled.

6. **Major Storm Cost Reserve**

a. Electric

i) Major Storm Reserve Funding

The Company's annual electric revenue requirements provide funding for the major storm reserve of $21.4 million in each of RY1 and RY2.[41] Except as provided herein, all incremental major storm costs will be charged to the major storm reserve. To the extent that the Company incurs incremental major storm damage costs in excess of $21.4 million in either Rate Year, the Company will defer on its books of account expenses in excess of the $21.4 million for future recovery from customers. To the extent that the Company incurs major storm damage expenses less than $21.4 million in either Rate Year, the Company will defer any variation less than $21.4 million for the benefit of customers. All major storm expenses are subject to Staff review.

ii) Non-Superstorm Sandy Deferred Major Storm Costs

The Company's annual electric revenue requirements provide for $26.1 million in each of RY1 and RY2 reflecting a three-year amortization of previously incurred incremental major storm costs (net of insurance and other recoveries) due to major storms, other than for Superstorm Sandy, in excess of collections for major storm reserve

[41] A "major storm" is defined in 16 NYCRR Part 97 as a period of adverse weather during which service interruptions affect at least ten (10) percent of the Company's customers within an operating area and/or results in customers being without electric service for durations of at least twenty-four (24) hours.

funding. The deferred amounts for non-Superstorm Sandy Storm Costs remain subject to Staff review.

iii) Superstorm Sandy Deferred Costs

The Company's annual electric revenue requirements provide for recovery of incremental major storm costs (net of insurance proceeds received to date) incurred due to Superstorm Sandy and charged to the major storm reserve of $81.4 million in each of RY1 and RY2 reflecting a three-year amortization of such costs. The commencement of recovery of Superstorm Sandy costs in these proceedings is without prejudice to the final amount of such costs that might ultimately be determined. The deferred amounts for Superstorm Sandy Storm Costs remain subject to Staff review.

iv) Costs Chargeable to the Major Storm Reserve

Except as provided herein, the Company will continue its current accounting practices respecting the identification of incremental non-capital major storm costs that are charged to the major storm reserve.

Effective January 1, 2014, the Company will cease charging stores handling, telecommunication and transportation (other than fuel) overheads to the major storm reserve. This change will not apply to any major storm that has affected or does affect the Company's electric system prior to January 1, 2014.

Effective January 1, 2014, the Company is authorized to charge to the major storm reserve up to $3.0 million per calendar year for costs incurred to obtain the assistance of contractors and/or utility companies providing mutual assistance in reasonable anticipation that a storm will affect its electric operations to the degree meeting the criteria of a major storm as defined in 16 NYCRR Part 97 but which ultimately does not do so.

Effective January 1, 2014, the Company will begin excluding from costs chargeable to the major storm reserve an amount equal to two (2) percent of the costs incurred (net of insurance and other recoveries) due to the occurrence of a major storm after that date.

Effective January 1, 2014, the Company will be able to charge costs against the major storm reserve for a period up to 30 days following the date on which the Company is able to serve all customers.

Effective January 1, 2014, following a major storm occurring after that date for which the Company forecasts a period of more than thirty (30) days following the date on which the Company is able to serve all customers to fully restore the system to normal operation, the Company may file a petition with the Commission that will include: (i) a plan for full system restoration, including restoration milestones ("system restoration plan") and (ii) a request for authorization to defer costs incurred in accordance with the system restoration plan beyond thirty (30) days following the date on which the Company is able to serve all customers (*i.e.*, the costs not automatically chargeable to the major storm reserve) for later recovery from customers. Recovery of costs incurred subsequent to that thirty-day period following the date on which the Company is able to serve all customers will not be subject to the requirement that the costs be material under the Commission's guidelines for determining whether the deferral of costs will be authorized ("materiality requirement"). Upon completion of the work necessary to restore the system to normal, the Company may file with the Commission, in the proceeding established to consider the Company's deferral petition, an estimate of the total costs incurred to restore the system to normal operation, broken out between costs during the period that they are chargeable to the major storm reserve and costs incurred during the period that they are the subject of the deferral petition. Costs will be estimated where, for example, costs are subject to final billings from vendors, contractors and utility companies that provided mutual assistance. If the Company seeks recovery of costs incurred during a time period that exceeds the originally forecasted period of time to restore the system to normal operation (*e.g.*, the Company's system restoration plan contemplated a 60-day period and restoration took 90 days), the Company will include with its cost estimate filed with the Commission a demonstration that such extension was in customers' interests (*e.g.*, more cost-effective) and/or was the result of extenuating circumstances (*e.g.*, circumstances not reasonably foreseeable when the system restoration plan was developed, including for example, an intervening storm or other event).

b. Steam

i) Steam Superstorm Sandy Costs

The Company's steam revenue requirements reflect recovery, over three years, of approximately $7.0 million of incremental costs due to the effects of Superstorm Sandy on the Company's steam system. Such costs are the subject of a Company petition to defer such costs that is pending before the Commission in Case 13-S-0195.[42] This provision is without prejudice to the Commission's determination in Case 13-S-0195 and the associated revenues are subject to refund. The Company will defer for future recovery from customers any amount by which the amount of costs approved for deferral in Case 13-S-0195 exceeds the amount reflected in rates in these proceedings. Nothing in

[42] Case 13-S-0195, *Petition of Consolidated Edison Company of New York, Inc for Authorization to Defer Incremental Costs Associated with the Restoration of Steam Service Following Superstorm Sandy*.

this Proposal is intended to be nor should be construed to be prejudicial to any party's right to rehearing of and further challenge to the Commission's determination on the pending petition.

7. **Non-Officer Management Variable Pay (Electric, Gas and Steam)**

The electric, gas and steam revenue requirements reflect the amounts of expense for the Company's Non-Officer Management Variable Pay Program for each service by Rate Year as shown on Appendices 8, 9, and 10. The Company will defer for future credit to customers, the amount by which the actual expense by service in any Rate Year is less than the amount shown on Appendices 8, 9, and 10 for that service for that Rate Year.

The Company will reflect the changes to safety, reliability and customer service performance metrics adopted within this Proposal in the Safety and Reliability and Customer Service Index portions of the Management Variable Pay Plan.

When the Company undertakes a comparative study of its compensation/benefits to support the next rate case, the Company will conduct the study so as to achieve at least fifty (50) percent matching of positions, or more, to the extent practicable, in a blended peer group of Utilities and New York Metropolitan employers and will describe the process by which the Company matches its positions to the positions of the peer group employers, including an explanation for the exclusion of any Company positions from the analysis in the comparative study. The Company will meet with Staff to discuss the composition of the peer group to be used in the study.

8. **Workers Compensation Insurance (Electric, Gas and Steam)**

The Company will defer for later credit to or recovery from customers, the full amount by which changes to the New York State Workers Compensation insurance laws included in the 2013 – 2014 New York State Budget and related implementing regulations of the Workers Compensation Board result in the Company's workers compensation insurance expense varying from the expense reflected in the revenue requirements. The amount of any such deferral will be calculated separately for electric, gas and steam.

9. **ERRP Major Maintenance Cost Reserve (Electric)**

The Company's electric base rates reflect amounts for East River Repowering Project ("ERRP") Maintenance Costs of $7.159 million for RY1 and for RY2. To the extent that over the term of the Electric Rate Plan, the Company incurs cumulative ERRP Maintenance Costs more or less than the sum of the amounts provided in rates plus the reserve available as of January 1, 2014, the Company will defer any variation on its books of account for future recovery from or for credit to customers.

10. **Other Transmission Revenues (Electric)**

The Company's revenue requirements include annual revenue targets for Transmission Congestion Contracts ("TCC") of $90.0 million; Transmission Service Charges ("TSC") of $7.0 million; and grandfathered transmission wheeling contracts ("GTWC") of $8.8 million as shown on Appendix 8. Annual variations between the TCC, TSC and GTWC revenue targets and actual amounts will be passed back or recovered as appropriate through the MAC.

11. **Brownfield Tax Credits (Electric)**

The Company's electric revenue requirements do not reflect any New York State tax benefits from Brownfield environmental tax credits. The Company will defer on its books of account all Brownfield tax credits received for future credit to customers.

12. **NEIL Dividends (Electric)**

The Company's electric revenue requirements do not reflect any dividends the Company might receive from the Company's Nuclear Electric Insurance Limited ("NEIL") insurance policy. The Company will credit electric customers with any such dividends received through the MAC.

13. **Proceeds from the Sales of SO_2 Allowances (Electric and Steam)**

The Company's electric and steam revenue requirements do not reflect any proceeds from the sale of SO_2 allowances that might be received. Any such proceeds that are received will be deferred on the Company's books of account for future credit to customers. The allocation of such proceeds between steam and electric will continue to be computed according to the method established in the *Order Determining Revenue Requirement And Rate Design*, issued September 22, 2006, in Case 05-S-1376.

14. **Adjustments for Competitive Services (Electric and Gas)**

The Company will continue to reconcile competitive service charges in accordance with current tariff provisions. Competitive service charges consist of the supply-related and credit and collections-related components of the MFC, the credit and collections component of the POR discount rate, the Billing and Payment Processing Charge, and Metering Charges (electric only).

15. **Pipeline Integrity Costs – New York Facilities Charges (Gas)**

The New York Facilities Agreement is a joint operating agreement between Con Edison and National Grid, which provides for the sharing of certain costs. Among the costs to be shared are the costs that Con Edison and National Grid incur to comply with federal requirements that require gas companies, like Con Edison and National Grid, to develop and implement an integrity management program for their affected gas facilities using in-line inspection, hydro or pressure testing, or direct assessment. The Company's projected share of National Grid's pipeline integrity costs are reflected in the gas rates for RY1, RY2 and RY3, at estimated annual amounts of $583,000, $595,000, and $607,000, respectively, as shown on Appendix 9. The Company will defer on its books of account, for recovery from or credit to customers, the difference between payments made to National Grid for pipeline integrity programs and the amount included in gas rates.

16. **Research and Development Expense (Gas and Steam)**

Research and Development ("R&D") expenses reflected in the revenue requirements for each of RY1, RY2 and RY3 for gas and for steam are set forth in Appendices 9 and 10 ("target levels"). In the event the Company's actual R&D expenses for gas or steam are less than the target level for a particular Rate Year, the Company will defer on its books of account the amount of such under spending for future credit to customers, subject to any such deferred amount being reduced by up to the amount of actual expenditures in any and all subsequent Rate Years that exceeds the target level for that Rate Year(s) by not more than 20 percent.[43]

The Company has the flexibility over the term of the Gas Rate Plan and Steam Rate Plan to modify the list, priority, nature and scope of the R&D projects to be undertaken.

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[43] For example, if actual spending in RY1 is $300,000 below the target level, the Company will defer that amount for future credit to customers. If the target level for RY2 is $1 million, and actual spending in RY2 is $1,150,000, the deferred credit will be reduced by the extra $150,000 spent. However, if the actual spending in RY2 is $1,300,000, the deferred credit will be reduced only by $200,000. A separate, but similar, reconciliation will be performed for RY3, up to the amount of any remaining deferred credit.

17. **Discontinued Reconciliations**

a. Deferred Income Taxes – 263A (Electric, Gas and Steam)

The deferral of interest on differences between the actual deferred Section 263A tax benefits that result from the Section 263A deduction under the Simplified Service Cost Method and the amount allowed by the Internal Revenue Service ("IRS") will cease effective January 1, 2014. The underlying issue between the Company and the IRS concerning the calculation of the amount of such tax deductions has been resolved and the projections of income tax expense and deferred tax rate base reflected in the electric, gas and steam revenue requirements under this Proposal reflect that resolution.

b. No. 4 and No. 6 Fuel Oil to Gas Conversions (Gas)

The deferral authorization established by the 2010 Gas Rate Order for firm delivery revenues, O&M expenses and carrying costs (full return on investment and depreciation) associated with changes in laws, rules and or regulations directly or indirectly reducing the use of No. 4 and/or No. 6 fuel oil will cease effective January 1, 2014. Such revenues and costs have been forecasted in these proceedings and are reflected in the gas revenue requirement in this Proposal.

c. Preferred Stock Redemption Savings

The deferral of the revenue requirement effect of savings, net of costs, resulting from the Company having refunded all of its preferred stock in May 2012 will cease effective January 1, 2014.[44] The refund of the preferred stock is reflected in the capital structure and cost of capital underlying the electric, gas and steam revenue requirements in this Proposal.

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[44] Such deferral is required by the Commission's *Order Enhancing Financing Authority*, issued January 20, 2012, in Case 08-M-1224.

d. Capital Expenditures

The mechanisms under the 2010 Electric Rate Order and the 2010 Gas and Steam Rate Order under which actual capital expenditures are compared to capital expenditure targets are terminated under this Proposal.

18. **<u>Additional Reconciliation/Deferral Provisions</u>**

In addition to the foregoing reconciliation provisions (*i.e.*, paragraphs E.1 through E.16), along with all other provisions of this Proposal embodying the use of a reconciliation and/or deferral accounting mechanism, all other applicable existing reconciliations and/or deferral accounting will continue in effect through the term of these Rate Plans and thereafter until modified or discontinued by the Commission, except for those expressly identified in this Proposal for termination. Continuing reconciliation and/or deferral accounting mechanisms include, but are not limited to, Financial Accounting Standards ("FAS") 109 taxes, Regional Greenhouse Gas Initiative ("RGGI") costs associated with Company-owned generation, System Benefits Charges, Energy Efficiency Portfolio Standard charges, Demand Side Management ("DSM") costs, MTA taxes, New York Public Service Law §18-a regulatory assessment, the MSC/MAC, MRA/GCF and FAC mechanisms, as well as the cost of the Low Income customer charge discount (discussed below) as they may be applicable to electric, gas and/or steam operations.

As of the time of this Proposal, through insurance and other recoveries, the Company has recovered amounts in excess of costs and interest related to the Company's World Trade Center ("WTC")-related capital costs that the Company has deferred, as set forth in Appendix 4. The revenue requirements reflect the amortization of the over recovery, over three years, by annual credits of $17.5 million for electric and $5.8 million for gas. The steam revenue requirement reflects the recovery over three years of $1.5 million for steam, or an annual amount of $0.5 million. The Company's WTC-related capital costs allocated to electric, gas and steam will continue to be deferred in accordance with Case 08-E-0539, Case 06-G-1332, and Case 07-S-1315, respectively, and be subject to interest at Con Edison's allowed pretax Allowance for Funds Used During Constriction rate of return. The Company will continue to seek recovery for all future WTC costs from governmental agencies and insurance carriers. All recoveries will be applied to reduce the deferred balance, except to the extent that the Company is required to use insurance proceeds to reimburse government entities.

F. <u>Additional Rate Provisions</u>

1. <u>Depreciation Rates and Reserves</u>

a. Depreciation Rates (Electric, Gas and Steam)

The average services lives, net salvage factors and life tables used in calculating the depreciation reserve and establishing the revenue requirements for electric, gas and steam service are set forth in Appendix 11.

The average service lives, net salvage factors and life tables have been agreed to for the purposes of this Proposal, but such agreement does not necessarily imply endorsement of any methodology for determining any of them by any Signatory Party.

b. Electric Reserve Deficiency

With respect to electric, the amortizations of the book depreciation reserve deficiency of approximately $10.8 million per year authorized by the Commission in Case 07-E-0523 and approximately $6.4 million per year authorized by the Commission in Case 09-E-0428 will cease as of the beginning of RY1.

c. Gas Net Salvage Caps

With respect to gas, the existing limitations (*i.e.*, caps) on negative net salvage costs that are chargeable to the gas depreciation reserve for both Steel Mains accounts (transmission and distribution) and the Services account will cease. Correspondingly, gas O&M rate allowances providing for negative net salvage costs above the amounts chargeable to the gas depreciation reserve for those accounts will also cease. The approach of capping the negative net salvage costs chargeable to the gas depreciation reserve and providing an associated gas O&M rate allowance for negative net salvage costs above the cap will continue for both Cast Iron Mains accounts (transmission and distribution).

2. **<u>Interest on Deferred Costs</u>**

The Company is required to record on its books of account various credits and debits that are to be charged or refunded to customers. Unless otherwise specified in this Proposal or by Commission order, the Company will accrue interest on these book amounts, net of federal and state income taxes, at the Other Customer-Provided Capital Rate published by the Commission annually. FAS 109 and MTA tax deferrals are either offset by other balance sheet items or reflected in the Company's rate base and will not be subject to interest.

3. **<u>Property Tax Refunds and Credits</u>**

a. Prospective Refunds and Credits

Property tax refunds allocated to electric, gas and/or steam that are not reflected in the respective Rate Plans and that result from the Company's efforts, including credits against tax payments or similar forms of tax reductions (intended to return or offset past overcharges or payments determined to have been in excess of the property tax liability appropriate for Con Edison), will be deferred for future disposition, except for an amount equal to fourteen (14) percent of the net refund or credit, which will be retained by the Company. Incremental expenses incurred by the Company to achieve the property tax refunds or credits will be offset against the refund or credit before any allocation of the proceeds is calculated. The deferral and retention of property tax refunds and incentives will be subject to an annual showing in a report to the Secretary by the Company of its ongoing efforts to reduce its property tax burden, in March of each Rate Year. Additionally, the Company is not relieved of the requirements of 16 NYCRR §89.3 with respect to any refunds it receives.

b. New York City Property Tax Refund

On August 22, 2013, the Company notified the Commission, pursuant to 16 NYCRR § 89.3, of having received a property tax refund from the City of New York in the amount of $140 million as a result of settlement following many years of litigation concerning property taxes over many tax years.[45] The settlement relates to property taxes on electric and steam properties. In accordance with the property tax refund sharing provisions under the 2010 Electric Rate Order and 2010 Steam Rate Order, the Company's filing requested that the refund less costs to achieve the refund be shared eighty-six (86) percent to customers and fourteen (14) percent to the Company. On that basis, customers would be entitled to approximately $119.9 million (approximately $85.0 million for electric and approximately $34.9 million for steam) and the Company would retain approximately $19.5 million. Staff has reviewed the Company's August 22, 2013 filing and has conducted discovery on it.

[45] Case 13-M-0376, *Petition of Consolidated Edison Company of New York, Inc. for Approval of Proposed Distribution of a Property Tax Refund.*

The settlement agreement between the Company and the City references a Company commitment to pursue $140 million of Storm Resiliency Work on any combination of the Company's systems over a three-year period that commenced January 1, 2013. Staff advised the Company and the City that this element of the tax settlement agreement raised concerns within the Department of Public Service. For example, the Department was concerned that the settlement agreement could be read as an attempt to limit the Commission's authority to determine the application of these tax refund dollars. The City and the Company advised, and confirm by executing this Proposal, the tax settlement agreement was not intended to establish any limitations on the Commission's rights to act on tax refund petitions, and that the tax settlement agreement does not, nor is it intended to, prescribe or restrict the manner in which the Commission may apply the customers' share of this tax refund or to prescribe the allocation of these tax refund dollars to any specific cost(s) incurred by the Company in providing service to customers, including any costs for "Storm Resiliency Work" as defined in the agreement.[46]

The Signatory Parties recommend that the Commission resolve Case 13-M-0376 in these proceedings consistent with the treatment of the refund in this Proposal. With respect to electric, such treatment is to credit electric customers $28.33 million in each of RY1 and RY2 representing the electric customer share of the refund of $85.0 million being amortized over three years. With respect to steam, such treatment is to credit steam customers $11.63 million in each of RY1, RY2 and RY3 representing the steam customer share of the refund of $34.9 million being amortized over three years. These credits to

[46] Although the tax settlement agreement references (at the City's request) a Company commitment to pursue $140 million of Storm Resiliency Work on any combination of the Company's systems over a three-year period that commenced January 1, 2013, the Company, at the time of agreement, already anticipated making Storm Resiliency Work investments well in excess of that amount.

customers would be accompanied by the Company retaining approximately $19.5 million.

4. **Allocation of Common Expenses/Plant**

During the term of the Rate Plans, common expenses and common plant will be allocated according to the percentages reflected in the electric, gas and steam revenue requirement calculations, as shown in Appendix 15. Should the Commission approve different common allocation percentages for electric, gas and/or steam service prior to the next base rate case for the electric, gas and/or steam businesses, the resulting annual revenue requirement impacts will be deferred for future recovery from or credit to customers.

5. **Use of Corporate Name**

Upon Commission adoption of this Proposal, the Company's Standards of Competitive Conduct are hereby amended in accordance with Appendix 26, which provides that the Company will not allow any non-affiliate entity to use the name "Con Edison," or trade names, trademarks, service marks or derivatives of the name "Con Edison," subject to the exceptions stated in Appendix 26.

G. Revenue Allocation/Rate Design

1. Electric

a. Revenue Allocation

The allocation of the delivery revenue change for each Rate Year is explained in detail in Appendix 20.[47] The revenue allocation reflects among other things, that the

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[47] Except as otherwise indicated herein and in Appendix 20, the allocation of the delivery revenue increase is based on the Company's Embedded Cost of Service ("ECOS") study. The resulting revenue allocation has been agreed to for the purposes of this Proposal, but such agreement does not necessarily imply endorsement of the methodology or results of the ECOS study by any Signatory Party.

NYPA class, solely as a result of this Proposal, will be assigned an additional $9,000,000 before adjusting for any rate change in RY1, and a further $9,000,000 before adjusting for any rate change in RY2. The NYPA revenue allocation is not the result of the use of any particular methodology or of a particular embedded cost of service study tolerance band. The surplus/deficiency revenue adjustments allocable to NYPA and each of the Con Edison classes in each Rate Year are shown on Tables 1 and 2 of Appendix 20. The Company will also apply the net deficiency to surplus classes as shown on Table 1A of Appendix 20.

The proposed base electric delivery rates in the Company's next electric rate filing will be premised upon an ECOS study using calendar year data that is no more than two years prior to the calendar year in which the filing is made, *i.e.*, if the Company files at any time in 2015, the proposed rates will be premised upon a 2013 ECOS study year.

Following issuance of a Commission order in these proceedings, the Company will continue discussions with interested parties with regard to whether any additional, more current, data will further inform the next ECOS study and/or the proposed revenue allocation. For its next electric rate filing, the Company will (i) re-evaluate its cost of service methodologies related to how the Company classifies and allocates customer costs and (ii) provide a more detailed explanation of supporting ECOS and rate design work paper documentation, which will include a process flow chart (including a basic explanation of the purpose of each file and cross-references of the underlying data sources), a table of acronyms used, a table of contents and index of files. Following its next electric rate filing, the Company will conduct, for interested parties, a walk-through of the ECOS study and rate design underlying the proposed electric base delivery rates.

b. Rate Design

This Proposal establishes new competitive and non-competitive electric delivery service rates, including changes to provisions of the MAC. The rates implementing this Proposal will be developed as set forth in Appendix 20.

c. Make-Whole Provision

The Company will recover shortfalls and refund over-collections that result from the extension of the suspension period in Case 13-E-0030 through a "make-whole" provision. The January and February revenue differences will be recovered or credited, with interest, over ten (10) months (*i.e.*, March 2014 through December 2014).

The revenue difference associated with Con Edison customers includes:

> (a) differences associated with non-competitive transmission and distribution revenue, which will be collected or credited through a Delivery Revenue Surcharge over ten (10) months commencing March 1, 2014 and shown on the Statement of Delivery Revenue Surcharge, to be described in General Information Section 26 of the Company's electric tariff;
>
> (b) uncollectible expense differences associated with MAC and MSC charges, which will be collected through the Adjustment Factor - MAC and the MFC, respectively, over a one-month period; and
>
> (c) differences associated with (i) competitive supply-related and competitive credit and collection-related components of the MFC, including purchased power working capital, (ii) revenues for Metering Services charges, (iii) revenues for Billing and Payment Processing charges, and (iv) the credit and collection-related component reflected in

the discount rate under the Purchase of Receivables program, which will be collected or credited through the next reconciliation of the Transition Adjustment.

The revenue difference associated with NYPA will be recovered or credited, with interest, as a fixed monetary amount billed monthly to NYPA and shown on the Statement of PASNY Delivery Revenue Surcharge.

Allowed Pure Base Revenue through February 2014 will be based on targets set in Case 09-E-0428. As described above, shortfalls resulting from the extension of the suspension period will be collected through the Delivery Revenue Surcharge. Revenue targets commencing March 1, 2014, will be based on revenue targets set in Case 13-E-0030.

d. VTOU Rates

A new voluntary time of use ("VTOU") rate (*i.e.*, SC 1 Rate III) will be offered in which the off-peak period will be midnight (12 a.m.) to 8 a.m. Customers that elect the VTOU rate as retail access customers and then switch to full service must remain on the VTOU rate as full service customers for one year from the date of the switch. Customers that elect the VTOU rate as full-service customers must remain on the VTOU rate as full-service customers for one year from the date of the switch.

The rate will include a "price" guarantee for full-service or retail access customers registering a Plug-in Electric Vehicle ("PEV") with the Company. The guarantee will apply for a period of one year commencing with the first full billing cycle after the customer registers the PEV with the Company. Under the price guarantee, the customer will not pay more over the course of the one-year period than it would have paid under the SC1 Rate I rates. This comparison will be made on a total bill basis for full service customers and on a delivery-only basis for retail access customers. The delivery-related component of customer credits provided under the price guarantee will be recovered through the RDM (from SC1 customers). The commodity-related component of such customer credits will be recovered through the MAC.

The Company is conducting a pilot related to Electric Vehicle load in single-family residential premises and will expand the program to up to 50 participants. The pilot is focused on testing the usage of metering technology and an evaluation of participants' responsiveness to peak demand information. The Company will issue a report evaluating the accuracy and usefulness of the metering technology and make a proposal for next steps, as appropriate, by March 31, 2015.

The Company will propose a stand-alone PEV charger rate designed for residential customers in its next rate filing. Such rate may be included in SC1, SC2, or another SC.

Subject to any Commission action on the Storm Hardening and Resiliency Collaborative and continuation of Working Group 2, the Company will propose for discussion a pilot, and the basis for such pilot, that includes a time sensitive rate (that is not limited to, or focused specifically on, PEVs) as part of Working Group 2.

Customer charges for the existing SC1 VTOU rate (*i.e.*, SC1 Rate II) will remain at the current level to minimize bill impacts for this class. SC1 Rate II will be closed to new applicants as of March 1, 2014.

e. SC9 Max Rate

Effective March 1, 2014, the SC9 Max Rate will not be applicable to new customers. For existing customers, the SC9 Max Rate will be increased by 33 percent in RY1 and 67 percent in RY2. This rate will be eliminated effective January 1, 2016.

f. SC1 Special Provision D (Water Heating)

Effective March 1, 2014, this rate will not be extended to new applicants and will terminate on the earlier of (i) the date on which all three remaining customers elect to stop receiving service under this special provision, or (ii) December 31, 2023.

g. Standby Rates

The current provision for a 12.1 percent O&M charge for Standby Service will remain unchanged during the term of the Electric Rate Plan.[48]

Contract Demand for service under Standby Rates may be set by the Company or by the customer. The standby tariff requirement of final approval of the Contract Demand by the Company for customers who install DG "ahead-of-the-meter" will remain unchanged.[49] For customers who install DG "behind-the-meter," the Contract Demand shall be as follows: (i) customers installing DG and taking service as of March 1, 2014 in *existing* buildings that do not require an upgrade,[50] may continue to set the Contract Demand, subject to the penalty mechanism set forth in the standby tariff (including the reset for exceeding the customer-selected Contract Demand), and Con Edison has no authority to approve or modify the customer-set Contract Demand,[51] and (ii) customers who install DG in new construction or upgraded premises on or after March 1, 2014, may continue to set the Contract Demand, but the Company will have authority to approve or modify the Contract Demand to meet the customer's maximum potential demand, and

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[48] PSC No.10 – Electricity, Consolidated Edison Company of New York, Inc., 20.2.1(A)(2), Leaf 154.

[49] The Company has authority to approve or modify the Contract Demand for these customers. *Id.*, 20.4.3(B), Leaf 166.

[50] Upgrading existing service occurs when a standby customer requires additional electric service to meet a higher load or increased capacity requirements regardless of the output of the customers' generating facility. Interconnection facilities and reinforcement necessary for the installation and operation of the DG is not considered upgrading existing service.

[51] *Id*., 20.4.3, Leaf 163, 20.4.3(A)(1) and (3), Leaf 164.

there will be no penalty to the customer for the customer exceeding the customer-selected Contract Demand.

The Company has recently developed and made public a DG Guide for 2 to 20 MW ("Guide"). The Company will include a reference to the Guide in the electric, gas and steam tariffs. When necessary and appropriate, and upon at least thirty (30) days' notice to Staff, the Signatory Parties and to other potentially interested parties by means of the Company's Distributed Generation website,[52] the Company may implement changes to the Guide.

Nothing in this Proposal precludes any Signatory Party from proposing to the Commission a generic proceeding to review the Commission's standby rates policy. The Signatory Parties agree to not oppose a proposal to undertake a generic standby rates proceeding and reserve all rights to participate in such proceeding without limitation. If, as a result of the generic proceeding the Commission directs a change in standby rates to take effect before new base electric delivery rates are set, the Company will be permitted at the time of any such rate changes to make rate adjustments to offset the revenue effect, if any, of any changes to electric standby rates being less than the amount assumed in setting rates.

h. Business Incentive Rate ("BIR")

i) Current Allocations.

The Comprehensive Package Program under the BIR provides for 205 MW of BIR power to be allocated to NYC and 40 MW to be allocated to Westchester. As of

[52] http://www.coned.com/dg/

December 2013, 129.3 MW of NYC's allocation and 19.2 MW of Westchester's allocation are unsubscribed.

ii) Changes to the BIR Program:

a. Expansion of Biomedical Research Facility Access.

1) Prior to 2010, Rider J included the allocation of 20 MW to biomedical research. As of April 1, 2010, Rider J included an allocation of 40 MW to biomedical research. Under this Proposal, the total allocation for biomedical research is increased to 60 MW (subject to paragraph 2) below), with the additional 20 MW coming from NYC's unsubscribed allocation.

2) If, during the term of the Electric Rate Plan, the biomedical portion becomes fully subscribed and there are additional applicants with a demonstrated need for biomedical research BIR, NYC will reallocate up to an additional 10 MWs of its unsubscribed allocation to biomedical research and the Company will file tariff amendments to implement such allocation.

3) The Company's compliance filing will reflect changes to clarify Rider J.

iii) Recharge New York Allocations

NYC or Westchester may use participation in the Recharge New York ("RNY") program as a qualifying program under which it grants BIR benefits under the "comprehensive package of economic incentives," provided, however, that the BIR allocation shall not extend beyond the period of the customer's participation in the RNY program.

iv) NYC Superstorm Sandy Business Incentive Rate

Rider J will be expanded to include a NYC Superstorm Sandy program with the aim of revitalizing small businesses and non-profit organizations in designated areas affected by Superstorm Sandy as set forth below.

a) Scope. A "Superstorm Sandy BIR customer" will be defined as a small business or non-profit organization in a Sandy affected area as described below. Hotels, retail establishments and restaurants may be eligible for a BIR discount only under the NYC Superstorm Sandy BIR program and not under any other provision of Rider J.

b) Eligibility. The NYC Superstorm Sandy BIR program is available to small retail businesses that have already received post-Sandy support from one or more NYC-sponsored loan and grant programs funded with Community Development Block Grant-Disaster Recovery funds in the Company's service territory and to small non-profit organizations that operate a non-profit organization pursuant to section 501(c) of the Internal Revenue Code, provided such business or non-profit organization: (i) employs fewer than ten employees; (ii) is located in any of the following areas directly affected by Superstorm Sandy:

1. Southern Manhattan (below Chambers Street and the 100 year flood zones on the West and East side of Manhattan up to 42nd Street);

2. East and South Shores of Staten Island from approximately Fort Wadsworth to Totenville;

3. Brooklyn-Queens Waterfront (coastal neighborhoods from Sunset Park to Long Island City);

4. Southern Brooklyn (Coney/Brighton Peninsula plus inundated mainland areas, including Gerritsen Beach, Sheepshead Bay and Gravesend); or

5. South Queens (bay-lying areas, including Broad Channel, Howard Beach, Old Howard Beach and Hamilton Beach);

and (iii) is an existing SC 2 or SC 9 customer. The applicant must provide documentation to NYC EDC demonstrating its eligibility, and NYC EDC must certify the applicant's eligibility to the Company.

c) Allocation. 5 MW shall come from NYC's unsubscribed allocation.

d) Application. A small business or non-profit customer may apply for an allocation of Superstorm Sandy BIR as described above to commence on or after March 1, 2014 for SC9 large commercial customers and on or after July 1, 2014 for SC2 small commercial customers. Applications to commence service under this component of the BIR Program will be accepted through June 30, 2015.

f. Billing. The Company will modify its billing system to accommodate SC2 NYC Superstorm Sandy BIR customers by July 1, 2014.

g. Term. The maximum term for a NYC Superstorm Sandy BIR discount is three years.

h. Maximum Discount. The maximum discount for NYC Superstorm Sandy BIR customer is $50,000 over the customer's term of service (*i.e.*, up to a maximum of three years).

i. Energy Audits. NYC Superstorm Sandy BIR customers are exempt from obtaining an energy efficiency/audit survey as a prerequisite for a BIR allocation.

i. Marginal Cost Study (MCOS)

The marginal cost study, originally submitted by the Company and subsequently modified by Staff, forms the basis for the Excelsior Jobs Program and the BIR discounts shown below:

SC 2 - 36% (SC2 customers are eligible for a BIR discount only under the NYC Superstorm Sandy Business Incentive Rate described above).

SC 9 - 49%

SC 9 TOD - 45%

j. Tariff Changes

In addition to the tariff changes required to implement various provisions of this Proposal, a number of tariff changes will be made as summarized below. The specific language of the changes will be shown on tariff leaves to be filed with the Commission.

1. Implement revenue neutral changes in SCs 2 and 9 that were originally intended to commence April 1, 2014 pursuant to Case 09-E-0428, concurrently with the commencement of rates in this proceeding.

2. Phase out the demand reduction that has been available to General – Large customers with electric space heating (SC9 Special Provision D);

3. Establish coincident demand billing in lieu of additive demand billing for customer accounts with demands over 500 kW or

greater if all meters on the account measure and record kW and kVar interval data as part of the reactive power program;

4. Establish standby rates applicable to wholesale generators that take distribution service for station use in SC9 and in P.S.C. No. 12 – Electricity, based on a FERC decision;

5. Increase the amount of compensation payable for losses due to power failures under General Rule 21.1 of the electric tariff;

6. Eliminate both the Schedule for Economic Development Delivery Service, P.S.C. No. 11 – Electricity, and SC 15 – Delivery Service to Governmental Agencies in P.S.C. No. 10;

7. Establish deadlines for applications for series metering (Riders E and F);

8. Clarify how charges are prorated and adjustments are applied to customer bills;

9. Amend Special Provision A of SC9 with respect to redistribution of service under that SC to remove a prohibition applicable only in certain areas of the service territory and clarify that "tenants" occupying less than ten (10) percent of the space served at low tension refers to "residential" tenants;

10. State that export of electric energy and power in accordance with SC 11 – Buy-back must comply with Company protocols if in excess of 1 MW in any hour and provide payment rate information;

11. Change the reconciliation of the RDM Adjustment and collection/refund periods to reflect a change in the rate year from April through March to January through December. The difference for the six-month period ending December will be collected/refunded over the six months commencing February, and the difference for the six-month period ending June will be collected/refunded over the six months commencing August;

12. Update the percentages used for handling costs and for corporate overheads in the definition of costs associated with Special Services to reflect current costs;

13. Add reactive power demand charges to the definition of Pure Base Revenue;

14. Update the timeline for reactive power meter installations, as indicated in the Company's July 5, 2012 Plan update filed with the Commission in Case No. 08-E-0751;
15. Revise the calculation of customers' contribution to total construction costs that exceed $2 million;
16. Update the Factor of Adjustment for Losses to reflect a 5-year average loss factor of 5.9%;
17. Update some of the charges for Special Services at Stipulated Rates;
18. Amend General Rule 5.2.4 to include the manner in which the Company calculates Excess Distribution Facilities charges; and
19. Make housekeeping changes to various other provisions of the Company's electric rate schedules, including the elimination of obsolete provisions.

2. **<u>Gas</u>**

a. Revenue Allocation

The allocation of the delivery revenue change for firm customers for each Rate Year is explained in detail in Appendix 21.[53] The surplus/deficiency revenue adjustments allocable to each of the Con Edison classes in each Rate Year are shown in Table 2 in Appendix 21. The proposed base gas delivery rates in the Company's next gas rate filing will be premised upon an ECOS study using calendar year data that is no more than two years prior to the calendar year in which the filing is made, *i.e.*, if the Company files at any time in 2016, the proposed rates will be premised upon a 2014 ECOS study year.

For its next gas rate filing, the Company will re-evaluate its cost of service methodologies related to how the Company classifies and allocates customer costs. In its

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[53] Except as otherwise indicated herein and in Appendix 21, the allocation of the delivery revenue increase is based on the Company's Embedded Cost of Service ("ECOS") study. The resulting revenue allocation has been agreed to for the purposes of this Proposal, but such agreement does not necessarily imply endorsement of the methodology or results of the ECOS study by any Signatory Party.

next gas rate filing, the Company will provide a more detailed explanation of supporting ECOS and rate design work paper documentation, which will include a process flow chart (including a basic explanation of the purpose of each file and cross-references of the underlying data sources), a table of acronyms used, a table of contents and index of files. Following its next gas rate filing, the Company will conduct, for interested parties, a walk-through of the ECOS study and rate design underlying the proposed gas base delivery rates.

b. Rate Design

This Proposal establishes new competitive and non-competitive gas delivery service rates. The rates implementing this Proposal will be developed as set forth in Appendix 21.

i) Firm Delivery Rates:

1. Weather Normalization Adjustment: The definition of normal heating degree days in General Information IX will be revised to reflect a ten-year period.

2. Manufacturing Incentive Rate ("MIR"): Applications will be accepted beginning January 1, 2014 and extending to December 31, 2015. The end date to receive discounts under the MIR will be extended to December 31, 2020 in order to allow customers to receive the full five (5) years of rate reductions. Funding for this program will remain at $3.0 million. The Company will defer for future credit to customers the difference between the actual discounts provided and $3.0 million. The existing tariff language pertaining to Company's ability to terminate discounts under this Rider will remain.

3. Millennium Fund: The Millennium Fund surcharge shall be reduced from $0.0174 per dekatherm to $0.015 per dekatherm.

4. Make-Whole Provision:

The Company will recover or refund any revenue under-collections or over-collections, respectively that result from the extension of the suspension period in Case 13-G-0031 through a "make-whole" provision. The January and February 2014 revenue over- or under-collections, will be refunded or recovered, with interest, over nine months, April 2014 through December 2014, except as otherwise discussed below:

(a) for classes subject to the RDM, over- or under-collection of delivery revenues will be refunded or recovered through an interim RDM adjustment over nine months beginning in April 2014. This interim adjustment will be determined by customer group by comparing the allowed revenues for January and February 2014 using the January and February RPC factors embedded in the third rate year annual RPC factors set in Case 09-G-0795 to the allowed revenues using the RPC factors for January and February 2014 embedded in the RY1 annual RPC factors set in this proceeding, Case 13-G-0031. This variation will be refunded or recovered through separate per therm adjustments applicable to each customer group over the nine months beginning April 2014. At least one week prior to the Company’s filing of this adjustment, the Company will provide Staff support for the underlying surcharge or credit adjustment;

(b) for classes not subject to the RDM, over- or under-collection of delivery revenues will be refunded or recovered through class-specific per therm adjustments over nine months commencing April;

(c) uncollectible expense under- or over-collection associated with MRA charges will be reconciled through the MRA for full service and transportation customers, as applicable, over a one-month period;

(d) Billing and Payment Processing charge under- and over- collections will be reconciled through the transition adjustment for competitive services included in the MRA for full service and transportation customers, as applicable, over a one-month period;

(e) uncollectible expense under- or over-collection associated with GCF charges will be reconciled through the MFC over a one-month period; and

(f) revenue under- or over-collection associated with (i) competitive supply-related and competitive credit and collection-related components of the MFC, including gas in storage working capital, and (ii) the credit and collection-related component reflected in the discount rate under the Purchase of Receivables program, will be reconciled through each component's respective annual reconciliation.

ii) Interruptible Delivery Rates:

The interruptible rate provisions are modified as follows:

a. SC12 Rate 1:

Rate 1 rates will continue to be set each month based upon market conditions and will consist of a block rate design with a monthly minimum charge. The monthly minimum charge for 3 therms will be set at $100 and will be phased-in in equal increments over the three Rate Years. The second, third and fourth rate blocks will cover the next 247 therms, the next 4,750 therms and usage greater than 5,000 therms, respectively.

The four priorities of service (Priority AB, Priority C, Priority D and Priority E) will be eliminated and replaced with a single blocked rate structure for each of the three customer categories, residential, non-residential and non-residential petroleum business tax ("PBT") exempt. The annual revenue reconciliation for sales customers will continue to be performed on a total bill basis.

b. SC12 Rate 2:

Rate 2 rates will be set at 8.0 cents per therm for one, two and three year contracts. The existing 1.0 cent per therm reduction for usage in excess of 500,000 therms per month will be retained. Existing customers will be charged the new rate after the expiration of their current contract term.

The provisions related to the prepayment for facilities will be modified to take into account the Rate 2 customer's guaranteed minimum bill delivery revenues in determining a Rate 2 applicant's cost responsibility. This guaranteed minimum bill delivery revenue for the period of the contract term will be used to offset the customer's cost responsibility for required facilities and thereby determine the applicant's required cost contribution.

c. Tariff and Operating Manual Changes

In addition to the tariff changes required to implement various provisions of this Proposal, a number of tariff changes will be made as summarized below. The specific language of the changes will be shown on tariff leaves to be filed with the Commission.

1. The reconciliation period for the Gas Facilities Cost Credit will be changed from a monthly period to a twelve-month period;

2. The calculation of the gas factor of adjustment and line loss incentive/penalty included in the Annual Surcharge or Refund Adjustment will be modified as discussed in section B.2.d. above;

3. Rider G (Empire Zone) eligibility requirements will be modified to recognize that the Rider is closed to new applicants due to the State no longer accepting applications for the Empire Zones program;

4. The definition of costs associated with Special Services Performed by the Company in General Information Section IV will be updated to reflect current costs and corporate overheads;

5. Customer groups subject to the Revenue Decoupling Mechanism will be modified to include customers who convert to firm gas service from No. 4 or No. 6 fuel oil;

6. The Company's cost responsibilities associated with main and service line extensions will be modified to allow 100 feet for each firm gas applicant on a common main (in lieu of "up to" 100 feet, *i.e.*, 100 feet multiplied by the number of applicants) who agree to connect at the same time;

7. The Company's cost responsibilities associated with main and service line extensions for multi-dwelling units having separately metered apartments taking gas service for heating will be for 100 feet per separately metered unit;

8. Tariff language will be changed consistent with Commission regulations to allow for refunds to both customers paying for a line extension via a surcharge as well as customers making upfront contributions to the cost of extension;

9. The Gas Sales and Transportation Operating Procedures Manual will be modified to extend the notice given to interruptible customers to curtail the use of gas to 8 hours, and to the maximum extent practicable, for such notice to be provided during business hours;

10. Change the reconciliation of the RDM Adjustment and collection/refund periods to reflect a change in the rate year from October through September to January through December. The difference for the twelve-month period ending December will be collected/refunded over the eleven months commencing February; and

11. Housekeeping changes will be made to various other provisions of its gas rate schedule, including the elimination of obsolete provisions.[54]

d. Transportation Balancing for Power Generators.

Changes to the gas balancing provisions applicable to power generators, effective March 1, 2014, are set forth in Appendix 24.

3. **Steam**

a. Revenue Allocation and Rate Design

A zero revenue increase for each Rate Year results in no change in the overall pure base revenue for each service class. No revenue realignment will be performed for any Rate Year since the Company's 2011 ECOS study indicates that the rate of return for all services classes are within the ± 10% tolerance band around the total system average rate of return.

"Present Rates" are the rates that became effective October 1, 2013 after removing the "Levelizing Adjustment" as directed by the Commission in its September 22, 2010 Order in Case 09-S-0974. Except for the usage charges, the other charges for each service class (*i.e.*, customer charge, demand charge, and contract demand charge) will be equal to those "Present Rate" charges effective October 1, 2013. The "Present Rate" usage charges for each service class effective October 1, 2013 will be decreased to reflect the $2.700 per Mlb decrease in the current $10.049 per Mlb base cost of fuel.

In its next steam rate filing, the Company will provide a more detailed explanation of supporting ECOS and rate design work paper documentation, which will

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[54] The Company will amend its pending tariff filing in Case 13-G-0186, which proposes to eliminate the Temperature Control ("TC") option for all interruptible customers. The Company will instead propose to eliminate the TC option for new interruptible customers and allow existing TC customers to continue utilizing the TC option. Once the Company amends its tariff filing, the City agrees to withdraw its opposition to the Company's filing.

include a process flow chart (including a basic explanation of the purpose of each file and cross-references of the underlying data sources), a table of acronyms used, a table of contents and index of files.

b. Make-Whole Provision

The Company will recover or refund any revenue under-collections or over-collections, respectively, that result from the extension of the suspension period in Case 13-S-0032 through a "make-whole provision." Any revenue over- or under-collections will be refunded or recovered, with interest, over nine months, April 2014 through December 2014.

c. Tariff Changes

In addition to the tariff changes required to implement various provisions of this Proposal, a number of tariff changes will be made as summarized below.

1. The Company will extend the period for accepting applications from SC2 and SC3 customers installing a new or replacement steam air-conditioning system under the current air-conditioning incentive program described in Special Provisions D and E through December 31, 2016;

2. The Company will update the charges in the steam rate tariff Section 4 "Special Services Performed by the Company for Customers for a Charge" (Leaves 39, 40, 41) as set forth in Exhibit 738 in these proceedings;

3. The Company will update steam rate tariff Section 3.3 "General Rules, Regulations, Terms and Conditions under Which Steam Service Will Be Supplied, Applicable to and Made a Part of All Agreements for Steam Service, Customer's Piping and Equipment" (Leaf 20), to identify the customer's obligation to document that its own piping and equipment are compliant with the NYC Codes and Regulations;

4. The Company will update tariff Leaf 51 to reflect the revised Base Cost of Fuel as discussed in section B.3.c above;

5. The Company will make housekeeping and other minor changes to various other provisions of its steam rate schedule such as summarizing riders applicable to each SC on one leaf, and updating Rider G to conform to its applicable filed SC rate.

4. **<u>Other</u>**

a. BPP Credit for Electronic Billing Customers

The Company will evaluate whether there are cost savings related to customers who agree to electronic billing. Based on that evaluation, the Company will determine whether a credit to the Billing & Payment Processing ("BPP") component is warranted and, if so, the appropriate amount of such a credit. If warranted, the Company will make a filing with the Commission by September 30, 2014 proposing a credit to the BPP component. The Signatory Parties agree that the Company should recover any incremental implementation costs associated with a BPP credit. Any information provided to customers with respect to electronic billing will include information regarding a credit if it is established.

H. <u>Performance Metrics</u>

Performance metrics designed to measure various activities that are applicable to the Company's Electric, Gas, Steam and Customer Service Operations, and assess negative rate adjustments where performance targets are not met, are set forth in Appendices 16, 17, 18 and 19.

I. <u>Customer Service/Retail Access Issues</u>

1. **<u>Outreach and Education</u>**

a. Customer Outreach and Education

Con Edison will continue to develop and implement outreach and education activities, programs and materials that will aid its customers in understanding their rights and responsibilities as utility customers. The Company will continue to survey its customers and to include appropriate questions in the surveys to evaluate its customer outreach program and identify areas where its outreach efforts could be further strengthened or improved. The Company will file a summary and assessment of its customer education efforts with the Secretary by September 30 of each Rate Year.

b. Email and Cell Numbers

The Company will continue to focus on and develop additional outreach efforts to assist in the collection of customer cell phone numbers and email addresses. With respect to its storm/outage related communications, the Company will continue to utilize blast emails that communicate safety and preparedness information prior to forecasted storms and heat events, and will develop opt-in text messages to provide customers with updated information during storms and other events.

c. Natural Gas Expansion

The Company will continue to provide increased natural gas-related outreach and education, including attending community events and providing robust website information that details, among other things, the process for converting to natural gas. The Company will increase education through social media, and continue to meet routinely with the City's Clean Heat marketing team, the Real Estate Board, plumbing and contracting communities, and individual buildings.

d. VTOU Efforts

The Company will include information related to its new VTOU rate on the coned.com website and in its Customer News bill insert. The Company will update its VTOU brochure and educate its employees to serve as advisors to customers who are interested in the rate. The Company will develop an online time-of-use calculator, which is intended to assist customers in deciding whether or not the new VTOU rate will benefit them within sixty (60) days of the issuance of an Order adopting this Proposal. The calculator will replace the existing time-of-use quiz on the Company's coned.com/tou webpage. The Company will also work with organizations such as the Greater New York Automobile Dealers Association and individual dealers in the Con Edison service territory in an attempt to obtain their assistance with educating new EV buyers about VTOU rates.

The Company will provide the following VTOU information to residential customers after service initiation: information on the new VTOU rate; where to find additional information (including a link to the calculator); and how to apply for the new VTOU rate.

Finally, the Company will provide written notification to existing SC1 VTOU customers of the availability of the new VTOU rate.

2. **Billing**

a. Capacity Billing for MHP Customers

Con Edison will take steps to change its method of calculating capacity charges for Mandatory Hourly Pricing ("MHP") customers from a calculation based on each customer's peak demand to a calculation based on each customer's installed capacity ("ICAP") Tags. Because of significant system modifications needed to implement such a change, the Company will begin training efforts to provide information on the new method to affected customers in the spring of 2015, for implementation in the spring of 2016.

b. Billing Working Group

Within sixty (60) days of the Commission's issuance of an order adopting this Proposal, the Company will initiate discussions with interested parties and work in good faith to:

1) address concerns raised in this proceeding related to the Company's billing of large customer accounts;

2) for large customer accounts, evaluate whether the Company can reasonably modify its system so that a customer can automatically see a new account number, under the customer's existing login, when the Company changes an account due to reading efficiency (*e.g.*, switching to a new trip number);

3) for large customer accounts, evaluate whether the Company can reasonably use its on-line platform to communicate certain information to the customer, such as i) information about a delayed billing, and ii) both old and new account numbers when an account number is changed; and

4) for aggregate billing data, evaluate whether the Company can reasonably modify its billing system to identify and sort data by building block and lot number, and, if so, whether the information should be provided at the standard tariff charge included in General Rule 17.5 or as a premium service with a higher charge to reflect the need for manual preparation of reports.

3. **MHP**

a. Customer Training

The Company will continue its MHP training efforts for both existing and new MHP customers and will continue to provide customers with information to assist them in better managing their energy usage and cost. The Company will continue to offer live seminars to provide information on hourly pricing and will incorporate in its seminars customer testimonials and simulations that demonstrate how shifts in a customer's energy usage towards off peak days/times have a direct benefit in lowering customer energy supply charges. The live seminars will also continue to focus on energy efficiency, distributed generation, and demand response. The Company will also archive on the Company's website webcasts/videos of outreach workshops. The Company will conduct a survey in 2014 of existing MHP customers to solicit feedback on ways to make the Company's energy management software package more appealing and useful to customers.

b. MHP Expansion

The Company will file a proposal to expand its MHP program to include customers with demands over 300 kW within twelve (12) months after the completion of reactive power meter installation. Such proposal will include an evaluation of the existing MHP program and may propose a phase-in or other staged approach of any MHP expansion. The Signatory Parties agree that the proposed electric delivery rates do not reflect any costs for the expansion of MHP and the Company should therefore receive full recovery of the incremental costs of any MHP expansion that the Commission may approve or direct.

4. **<u>Same Day Electric Service Reconnections</u>**

a. Weekday same-day reconnections

The Company will attempt same day electric service reconnection for residential electric customers whose service was disconnected for non-payment at the meter and who become eligible for reconnection by 5:00 p.m. Monday-Friday (*e.g.*, by making payment). This process does not include customers where the meter was removed or service was cut in the street. The Company will endeavor to restore service to such customers on the same day, to the extent practicable.

b. Reporting

The Company will file a report on residential same-day reconnections for each calendar quarter (the "reporting period"). Each report will be filed with the Secretary, with copies by email to interested parties, within thirty (30) days after the end of each reporting period. The report will indicate the number of residential electric customer reconnections issued by 5:00 p.m. Monday-Friday and the number of same-day reconnections attempts made to such customers.

5. **Distributed Generation**

The Company will pay the cost of purchasing and installing fault current mitigation technology where an over-duty circuit breaker condition exists or will exist with the addition of distributed generation ("DG") to Con Edison's system up to a total of $3 million annually. The Company would cover the cost of only the least expensive, effective fault current mitigation device. The Company would be responsible for replacing this device when still needed due to an over-duty circuit breaker condition, including replacements needed as a result of a blown fuse, age, and regular wear and tear, unless the Company can demonstrate that the equipment damage is based on the actions or equipment of DG operations. If over-duty breaker conditions no longer exist and the fault current mitigation device is no longer working, the Company would not be required to replace this device. The Company's incremental costs related to the purchase and installation of fault current mitigation technology will be deferred for recovery from customers.

The Company considers non-wires alternatives[55] in its planning process generally as follows. The Company includes DG greater than 2 MW (after evaluation for reliability) in its Ten-Year Load Relief Program planning process for substations. In addition, the Company plans its regional Distribution Engineering work based on an approximately 24-month time frame to allow consideration of customer-sited projects, like DG, with a longer lead-time (the Company had formerly planned work on a regional level on a six-month horizon).

The New York State Energy Research and Development Authority ("NYSERDA") is developing a report on microgrids. That report is expected to be completed in the spring of 2014. Within six (6) months of the issuance of the NYSERDA report, the Company will file with the Commission an implementation plan. The Company's plan will be subject to feasibility, cost-effectiveness, and recovery of incremental costs as determined by the Commission. In connection with its development of the implementation plan, the Company will convene a collaborative to consider whether the single customer limitation in the offset tariff[56] should be eliminated in order to expand the offset tariff to multiple customers seeking to offset the output of a DG facility against the customers' usage.

6. **<u>Retail Access Matters</u>**

a. Online Historic Bill Calculator

The Company will develop, in consultation with Staff and interested parties, an online historic bill calculator that would allow retail access customers to perform a

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[55] "Non-wires alternatives" refer to customer-sited Energy Efficiency measures, Demand Response measures, and DG.

[56] PSC No. 10 –Electricity, Consolidated Edison Company of New York, Inc. 20.2.1(B)(8)(1).

historical comparison of their prior year's ESCO bill compared to what they would have paid that year as a full service Con Edison customer. The calculator web page will include an explanation and disclaimers with respect to the comparison of ESCO pricing to utility pricing, and other items as necessary, that will be agreed to by Staff and the Company. The Company will make the calculator available to parties not less than ten (10) days prior to implementation. The Company will develop and implement the calculator as soon as practicable but no later than December 31, 2014.

b. NYISO Settlement

As part of its NYISO reconciliation system upgrade, the Company will modify its reconciliation method to be based on time-differentiated usage for non-interval metered customers taking service under a time of use rate. The Company expects that this upgrade will be complete by December 31, 2015.

c. ESCO Service Portability

The Company will begin working with energy service companies ("ESCOs") on enhancing ESCO service portability for residential customers within sixty (60) days of a Commission order adopting this Proposal. The Company will implement enhanced ESCO service portability for residential customers no later than December 31, 2014.

7. **Steam Outage Enhanced Customer Protections**

Following a storm event, the Company will suspend credit and collection activities, as well as the imposition of late payment charges, for a seven-day period for customers that the Company knows or reasonably believes experienced a steam service outage that exceeds five days.

As determined by an order of the Commission following a storm event that the federal government or New York State government declares to be an emergency (*e.g.*, a declaration is made by FEMA that a region is eligible for individual and public assistance after a storm), the Company will suspend credit and collection activity and the imposition of late payment charges for a fourteen day period for customers that experience a steam service outage that exceeds five days.

In each of the foregoing circumstances, the Company may continue to issue service termination notices and accept security deposits, where appropriate.

As determined by an order of the Commission following a storm event that the federal government or New York State government declares to be an emergency (*e.g.*, a declaration is made by FEMA that a region is eligible for individual and public assistance after a storm), the Company will provide a credit to the customer charge for customers that experience a steam service outage that exceeds five days. The credit will be equal to the daily value of the customer charge (*i.e.*, customer charge for the customer's SC divided by 30) multiplied by the number of days that steam service was not available from the Company.[57] Credits to customers will be issued within 75 days following service restoration. The Company will not seek recovery of credits issued in the above circumstance.

The above enhanced customer protections will not apply to Steam accounts where (i) the customer experienced a steam service outage of five days or less; or (ii) the customer was not taking steam service prior to the interruption of steam service by the Company (*e.g.*, a seasonal customer).

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[57] In no event will a customer get a credit for any day(s) following the Company's ability to resume steam service. For example, if the Company interrupts steam service for seven days following the storm event, but the customer is not able to take steam service until day ten following the storm, the customer will be entitled to a customer charge credit for seven days.

J. Electric and Gas Low Income Programs

The Company's Gas and Electric Low Income Programs consist of two components. First, during the term of the Electric Rate Plan and the Gas Rate Plan, and continuing thereafter unless and until changed by the Commission, the Company will provide a discount on certain rates and charges, depending on the program, to eligible and enrolled low income residential customers. Second, for this term of the Electric Rate Plan and the Gas Rate Plan, the Company will have a waiver of reconnection fee program.

1. Customer Enrollment

Qualifying Customers may enroll or be enrolled in the Low Income Program as follows:

First, the Company will continue its existing enrollment procedure for Utility Guarantee ("UG") and Direct Vendor ("DV") customers by the New York City Human Resources Administration ("HRA") or the Westchester County Department of Social Services ("DSS") (the "Agencies"). The Agencies can utilize a Company web application or submit a paper application to enroll a customer on UG or DV. Upon receipt of the electronic or paper application, the Company will update its customer records to indicate that the customer is enrolled in the Low Income Program.

Second, the Company will continue its existing enrollment procedure for Home Energy Assistance Program ("HEAP") recipients whereby the Company enrolls a customer when it receives payment associated with a HEAP grant.

Third, the Company will continue its existing procedure to enroll individual customers upon (a) individual customer application with appropriate documentation and/or (b) receipt of notification from the Agencies of eligibility through any qualifying program. In these cases, the Company will manually update its customer records to indicate that the customer is enrolled in the Low Income Program.

Finally, in April and October, the Company will initiate a semi-annual reconciliation of Company and Agency records by providing the agencies with files for the agencies to compare and advise as to whether the customer(s) qualify for the program.[58] By each June and December during the Electric and Gas Rate Plans, the Agencies shall provide the results of a reconciliation of (a) HRA and DSS records of recipients of benefits under Qualifying Programs for which they maintain records with (b) records provided by Con Edison of all SC1 electric residential customers and SC1 and SC3 gas residential customers.

For purposes of this procedure, reconciliation means that each Agency will, in a manner agreed upon by the Company and the Agency, identify those customers on the list provided by the Company that are then participating in any of the Qualifying Programs, except Supplemental Security Income ("SSI"). The Company will notify the parties if the reconciliation has not been completed by June and December, respectively. The Company will take prompt action to enroll or de-enroll customers on the basis of the data provided by the Agencies within thirty (30) days after receiving the data from the Agencies, including data received after the due date.

If the reconciliation with either or both Agencies is not completed within the time frame noted above, or the Company concludes at any time that the annual reconciliation process is impracticable, or one or both of the Agencies impose conditions on the process that impose on Con Edison more than *de minimis* additional administrative costs, the

[58] The Company will initiate the first semi-annual reconciliation for these Rate Plans in January 2014.

Company will notify the parties of this circumstance. The Company, Staff, UIU, NYC and Westchester will work to develop, to the extent necessary, an alternative means to efficiently and effectively identify and enroll Qualifying Customers. If an alternative method is developed, the Company will notify all the parties that an alternative method will be used and will explain the mechanics of the alternative method.

a. Electric Customer Qualification

To qualify for the Electric Low Income Program ("Electric Qualifying Customers"), a Rate I SC1 customer must (a) be enrolled in the DV or UG Program; or (b) be receiving benefits under any of the following governmental assistance programs: SSI, Temporary Assistance to Needy Persons/Families, Safety Net Assistance, Supplemental Nutrition Assistance Program; or (c) have received a HEAP grant in the preceding twelve (12) months ("Qualifying Programs"). Customers participating in the Company's current electric low income program at the time this Electric Rate Plan becomes effective will not be required to re-enroll in the Low Income Program described herein.

b. Gas Customer Qualifications

To qualify for the Low Income Program ("Gas Qualifying Customers"), an SC1 or SC3 customer must (a) be enrolled in the DV or UG Program; or (b) be receiving benefits under any of the following governmental assistance programs: SSI, Temporary Assistance to Needy Persons/Families, Safety Net Assistance, Medicaid, or Supplemental Nutrition Assistance Program; or (c) have received a HEAP grant in the preceding twelve (12) months ("Qualifying Programs"). Customers participating in the Company's current gas low income program at the time this Gas Rate Plan becomes effective will not be required to re-enroll in the Low Income Program described herein.

2. **Electric Low Income Discount Program**

Effective January 1, 2014, customers enrolling in the Electric Low Income Program and continuing participants will receive a $9.50 discount from the otherwise applicable customer charge. Except as provided below, the $9.50 discount will remain in effect for the duration of the Electric Low Income Program. The target cost of the discount component of the Low Income Program for the term of the Electric Rate Plan is $95 million.

No change will be made to the low income customer charge discount for the following Rate Year if the Company estimates for the current Rate Year, based on data through September of the current Rate Year (reported according to the data reporting requirements stated below), that the annual cost of the customer charge discounts is within ten (10) percent of $47.5 million (*i.e.*, between $42.8 million and $52.2 million).

The low income customer charge discount will be adjusted for RY 2 if the Company estimates, based on data through September of RY 1 (reported according to the reporting requirements stated below), that the one-year cost of the customer charge discounts differs by more than ten (10) percent of $47.5 million. In that case, the Company will make a compliance filing with the Commission thirty (30) days prior to the commencement of RY 2 to increase or decrease the low income discount for the following Rate Year, as applicable, by up to $0.50.[59] The amount of the adjustment(s) will be designed so that the total projected cost of the customer charge discount component of the Electric Low Income Program remains as close to the annual target cost plus/minus the ten percent tolerance band (*i.e.*, $42.8 million or $52.2 million) as is

[59] The maximum/minimum discount in RY2 would be $10.00/$9.00, respectively.

practicable. However, the Signatory Parties recognize that the variation in the number of customers could result in the total cost of the Electric Low Income Program rate discount being more or less, notwithstanding an adjustment of up to $0.50 in RY2.

If at least four (4) months prior to RY2, the Company estimates that the sum of (a) the aggregate actual electric low income discounts will exceed or be less than the $95 million target by more than twenty (20) percent (*i.e.*, more than $114 million or less than $76 million) over the term of this Electric Rate Plan, the Company will notify Staff and interested parties of such estimate and convene a meeting of the parties to discuss whether any action should be taken other than to implement the $0.50 adjustment. It is the intention of the Signatory Parties to conclude such discussion in time to enable one or more parties, either individually or collectively, to propose to the Commission that the Electric Low Income Program be modified effective on the commencement of the upcoming Rate Year.

3. **Gas Low Income Discount Program**

SC1 customers participating in the Gas Low Income Program on and after January 1, 2014 will continue to receive a $1.50 discount on their monthly minimum charge. SC1 low income customers will pay the same volumetric charges as non-low income SC1 customers. Accordingly, the rates reflect approximately $2.5 million as the annual cost for this aspect of the Gas Low Income Program.

SC3 customers participating in the Gas Low Income Program on and after January 1, 2014 will receive a discount of $0.4880 per therm for usage in the 4-90 therm block. SC3 low income customers will receive a $7.25 discount on their monthly minimum charge. Accordingly, the rates reflect approximately $8.4 million as the annual cost for this aspect of the Gas Low Income Program.

4. **Common Provisions**

a. Qualifying Customers

At any time during the terms of the Electric and Gas Rate Plans, the actual number of customers participating in the Low Income Programs may be more or less than the estimated numbers of customers assumed for purposes of establishing the discount targets. All Electric and Gas Qualifying Customers, without limit, will be accepted into the program.

b. Reconnection Fee Waivers

Effective January 1, 2014, the Company will waive its electric service reconnection fee no more than one time per customer during the term of the Electric Rate Plan and will waive its gas service reconnection fee no more than one time per customer during the term of the Gas Rate Plan for customers participating in the Low Income Program. The target cost of the reconnection fee waiver component is $1.0 million over the term of the Electric Rate Plan and $225,000 over the term of the Gas Rate Plan.[60] The Company may grant waivers to individual customers more than once, on a case-by-case basis and for good cause shown, provided that the Company does not forecast that it will exceed the program target for each of the Rate Plans.

If the Company forecasts, based on the quarterly reported data from at least the first six (6) months of a Rate Year, that the program target will be exceeded over the term of either Rate Plan, the Company will be permitted to make a compliance filing of tariff amendments, on not less than thirty (30) days' notice, which, over the course of the term of the Rate Plan, limit the waiver to no less than fifty (50) percent of the total

[60] If the Company does not file to increase rates to become effective after the expiration of either the Electric or Gas Rate Plans, then the reconnection fee waiver program would continue with annual caps of $500,000 and $75,000, respectively.

reconnection fee, so that the estimated cost of waived reconnection fees does not exceed the total projected cost for the Rate Plan. If the fee waiver is not reduced by the maximum amount by any single filing, the Company may make compliance filings for additional reductions. The Company's tariff leaves will state that each fee waiver program will end once the cost of these programs equals the targeted cost for each of the Rate Plans ($1.0 million for the Electric Rate Plan and $225,000 for the Gas Rate Plan). The Company will notify the parties if it projects that either program limit will be reached during the term of the Electric or Gas Rate Plans.

c. Cost Recovery

For RY1 of the Electric and Gas Rate Plans, the rates for all customer classes have been designed to recover the cost of providing the discounts discussed above. The Company will contribute up to an additional $50,000 in 2014, 2015 and 2016 towards the Agencies' mailing costs, not recovered in rates, to facilitate the semi-annual reconciliation. The Company will defer for future recovery amounts in excess of $50,000, but not greater than $100,000, that are incurred by the Agencies as part of the semi-annual reconciliation. The Company's contribution will be applied first to the Agencies' actual mailing costs. The Agencies will absorb their respective costs, if any, in excess of the aggregate $100,000 provided herein.

i) Electric

All under- and over-recoveries associated with the customer charge discounts, the waiver of reconnection fees, and $50,000 for the Agencies' administrative costs will be reconciled through the RDM from all customers subject to the RDM for the Electric Low Income Program. If the Electric Low Income Program continues beyond the term of the Electric Rate Plan, but the RDM as currently structured does not, continuation of the Low

Income Program will be contingent upon the implementation of an equivalent mechanism that provides for full reconciliation of the low income customer charges/discounts.

ii) Gas

The Company will recover from or credit to all firm customers, through the MRA, any difference between the actual amount of discounts provided to customers during any Rate Year and the approximately $10.9 million of discounts assumed for purposes of designing gas rates under this Gas Rate Plan. Any reconnection fees waived will be recovered through the MRA at the end of each Rate Year. Appendix 21 provides a detailed explanation of the low income reconciliation through the MRA.

d. Reporting Requirements

i) Electric

The Company will file a report on the Electric Low Income Program for each calendar quarter (the "Reporting Period"). Each report will be filed with the Secretary, with copies by email to parties to Case 13-E-0030, within thirty (30) days after the end of each Reporting Period. The following data will be reported as a snapshot of the program as of the last day of each Reporting Period, broken down by Westchester County and New York City participants: (a) the number of customers enrolled; (b) the number of low income customers in arrears; (c) the total amount in arrears; and (d) the average amount in arrears. In addition, the Company will report (i) the aggregate amounts of low income discounts to date for the Rate Year, (ii) the number of reconnections of low income customers for which fees were waived to date for the Rate Year and since the inception of the program, (iii) the aggregate amount of reconnection fees waived to date for the Rate Year and since the inception of the program, and, if applicable, (iv) the aggregate amount of arrears forgiven to date for the Rate Year. Each quarterly report issued during the term of the Electric Rate Plan will also include a summary of this data from all previous quarterly reports.

ii) Gas

The Company will file a report on the Low Income Program for each calendar quarter (the "Reporting Period"). Each report will be filed with the Secretary, with copies by email to parties to Case 13-G-0031, within thirty (30) days after the end of each Reporting Period. The following data will be reported as a snapshot of the program as of the last day of each Reporting Period, broken down by Westchester County and New York City participants, and by SC1 and SC3 participants: (a) the number of customers enrolled, segregated, by (i) Gas Qualifying Customers for whom the Company has received payment in the form of HEAP grants and (ii) all other Gas Qualifying Customers; (b) the number of low income customers in arrears; (c) the total amount in arrears; and (d) the average amount in arrears. In addition, the Company will report (i) the aggregate amounts of low income discounts to date for the Rate Year, (ii) the number of reconnections of low income customers for which fees were waived and (iii) the aggregate amount of reconnection fees waived to date for the Rate Year and since the inception of the program. Each quarterly report issued during the term of the Gas Rate Plan will also include a summary of these data from all previous quarterly reports.

K. <u>Studies and Reports</u>

1. **<u>Staffing Study</u>**

The Company will conduct a staffing study that will compare the Company’s use of contractors to the use of collective bargaining/union employees for utility functions that are currently performed by both union and contractor resources.

For each activity, or related group of activities, the study will include all underlying assumptions as well as all incremental costs applicable to the use of both contractors and Company employees (including, but not limited to, wages, fringes, hiring costs, insurance, taxes, overheads, costs associated with preparing and reviewing requests for proposals, negotiating agreements with contractors, processing contractor bills, training, administration and supervision).

The study will also include, where applicable, considerations other than cost (including, but not limited to, productivity, fixed costs, diverse work pool, spikes in employee levels and the flexibility needed to respond to fluctuating workloads).

The Company will send to Signatory Parties by January 31, 2014 a scope of work for the study and will consider, and incorporate to the extent practicable, comments that are not inconsistent with the study as described above. The study will compare six months of data collected from March 1, 2014 through August 31, 2014 and will be filed with the Commission by February 1, 2015.

2. **<u>Voltage Reduction Study</u>**

The Company will conduct an in-house study of its use of distribution system voltage reduction ("VR"), whether additional investment or revisions to current investment plans may reduce or avoid voltage reductions, and whether it is in customers' interest to make such investments. The study will examine:

a. Current Company policy for use of VR.

b. Industry standards for service voltage and use of VR.

c. Instances of use of VR over the last five years including reasons for VR implementation and outcome.

d. Analysis of root cause of component failures and efficacy of current programs to address them.

e. Analysis of correlation between VR implementation and network reliability, and relationship to current reliability capital programs.

f. Analysis of impacts of 5% and 8% VR on customer service voltage and compliance with power quality standards.

g. Review of existing studies known to the Company and/or provided by Staff or other Signatory Parties regarding impacts to customer equipment and operation, including (where available) but not limited to, existing studies regarding elevator control systems, elevator motors, industrial motors and motor control, large medical machines (*e.g.*, MRI machines) and the cooling equipment and power conditioners associated with such machines, refrigeration equipment used to store medication and other perishables and the cooling equipment used in data centers.

h. Role of load curtailment programs including demand response and customer appeals.

i. Projected capital costs to implement revision to current policy for use of VR.

The Company will file a report on the results of this study, including, recommended changes to such policy, if any, within six (6) months of a Commission order adopting this Proposal. If the Commission directs the Company to undertake any changes to the current Company policy for use of VR, the Company will be authorized to defer for later recovery from customers the carrying costs of additional capital expenditures and any O&M expenses to support reduction in the use of VR as approved by Commission, until such time as such costs are reflected in base rates.

3. **Gas Interruptible Study**

Within nine months of the Commission's issuance of an order adopting this Proposal, the Company shall perform, inclusive of input from Staff and interested parties, and file with the Commission a study examining the benefits and impacts of interruptible customers on the Company's system. If, as a result of this study, any party proposes changes to interruptible rates or terms of service and the Commission determines that changes to interruptible rates or terms of service should be implemented before new base gas delivery rates are set, the Signatory Parties propose that such changes be implemented on a basis that is revenue neutral to the Company.[61]

4. **Study on Use of Surcharge for Interruptible Customers**

The Company will conduct a survey (of a statistically relevant sample size) within its service territory on or before the conclusion of RY1, to determine interest, if any, on the use of surcharges for recovery of SC12 Rate 1 interruptible customer interconnection costs and will share the results of this survey (redacting customer-identifying data) by the end of the first quarter of RY2. In the absence of an agreement among all parties that using a surcharge will not impact Company forecasts underlying the Gas Rate Plan, the Signatory Parties agree not to seek a surcharge to the SC12 Rate 1 tariff to be effective prior to the effective date for rates established via the Company's next gas rate filing. If, however, there is agreement among all parties that using a surcharge will not impact Company forecasts underlying the Gas Rate Plan, any party may propose to the Commission a surcharge mechanism for SC12 Rate 1 customers for costs of interconnection to the Company's gas system. Nothing in this Gas Rate Plan will preclude parties from pursuing this issue on a generic basis in the Commission's Gas Expansion Proceeding in Case 12-G-0297.

5. **Line Loss Studies**

a. Generator Contribution Study

The Company will perform a study of the gas transmission system to re-evaluate the 0.3% contribution to the line loss to be made by generators during the Gas Rate Plan

[61] Nothing herein restricts the rights of the Company or any party from taking any position before the Commission with respect to proposed changes to interruptible rates or terms of service.

to determine whether the 0.3% contribution should be increased or decreased respectively. The Company will submit the findings of the study and, if applicable, any recommendations, to the Commission no later than December 31, 2014.

b. New York Facilities Collaborative

The Company will attempt to initiate discussions with National Grid to consider how deliveries over facilities subject to the New York Facilities Agreement should be treated for purposes of each gas company's LAUF mechanism. The Company will submit the results of any such discussions and, if applicable, any recommendations to the Commission no later than December 31, 2014.

6. **<u>Customer Service System Plan</u>**

The Company will develop its Customer Service System ("CSS") Application Plan, which will make specific recommendations for CSS replacement as well as provide a comprehensive analysis of the various alternatives to support current and future customer system needs. The Company will file its CSS Application Plan with the Commission by December 31, 2014.

7. **<u>Customer Preference Survey</u>**

The Company will hire a consultant to perform a customer survey that explores the attributes of customer service that customers most want and expect. The survey will be designed in consultation with Staff and interested parties and agreed to by Staff and the Company. The study sample will be representative of the Company's residential customer population. At a minimum, the scope of the study will include all current key performance indicators, as well as new technology offerings, such as on-line billing and payment, use of smartphone apps, and utility control of customer devices, such as smart thermostats. This effort will commence within sixty (60) days of a Commission order adopting this Proposal. A report based on the survey results will be filed with the Commission by December 31, 2014. The report would summarize the results of the survey, and identify action steps that can be taken to incorporate the findings regarding customer preferences into its customer service strategy.

8. **Hudson Avenue Study**

The book cost of the land and the undepreciated cost of facilities and equipment at the Hudson Avenue Generating Station ("Hudson Avenue") are reflected in the rate base underlying the steam revenue requirements under this Proposal.[62]

The Company will perform an analysis of issues raised in these proceedings and submit a study to the Commission within six (6) months of the issuance of the Commission's order in these proceedings, which may include proposed accounting and ratemaking for any action that the Company proposes.

The study will include, but not be limited to, consideration of potential uses of the portions of the property the Company proposed to be transferred from steam to electric, obtaining an appraisal for future utility use and for highest and best use of those portions of the property, each after any required demolition and remediation;[63] information as to the relative historical use of Hudson Avenue by electric and steam operations;[64] an assessment as to whether the property should be sold; an assessment of environmental

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[62] The book cost of the land is currently recorded on the Company's books of account as Electric Plant Held for Future Use. The Company will transfer that book cost to Steam Plant in Service. The undepreciated cost of the facilities and equipment is currently a component of Net Steam Plant in Service on the Company's books of account.

[63] The costs of environmental remediation and demolition will be assessed for each building/facility being considered for transfer from steam to electric (*i.e.*, excluding facilities that are part of electric plant in service) to the extent practicable.

[64] To the extent reasonably available, the study will include information as to when each building/facility was placed in service, the use of each building/facility by electric and/or steam and the duration of such use.

liabilities and demolition costs and an assessment of whether any transfer of any portion of Hudson Avenue from steam to electric should be at other than book cost as provided in the Commission's Uniform System of Accounts. Such study will present the estimated costs and anticipated benefits of any proposed action.

The Signatory Parties agree that areas of study need be pursued only to the extent reasonably practicable and quantifications are permitted to be ranges or orders of magnitude. Up to $100,000 of costs of any consultants that the Company may retain for purposes of the study will be deferred for future recovery from customers.[65]

9. **City Building Resiliency Task Force**

The City has established a Building Resiliency Task Force which is studying how to improve citywide infrastructure and building resiliency, as well as how to help communities become more resilient. In addition to Company participation in this task force by the Electric Department, the Company agrees to provide representatives from the Gas and Steam departments as well.

10. **First Responders**

Potential restrictions on motor vehicle traffic during storms and other emergencies can impede Company employee arrival at locations at which they are needed regarding the Company's response to large-scale interruption of electric, gas and/or steam service. The Signatory Parties support or do not oppose efforts by the Commission to facilitate, to the extent practicable, the designation of Company employees as first responders.

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[65] The Company reserves all of its rights to seek confidential treatment with respect to the study and associated information and data.

L. **Miscellaneous Provisions**

1. **Continuation of Provisions; Rate Changes; Reservation of Authority**

Unless otherwise expressly provided herein, the provisions of this Proposal will continue after RY2 for electric and RY3 for gas and steam, unless and until electric, gas or steam base delivery service rates are changed by Commission order. For any provision subject to RY1, RY2 and RY3 targets, the RY2 target for electric and the RY3 target for gas and steam shall be applicable to any additional Rate Year(s).

Nothing herein precludes Con Edison from filing a new general electric rate case prior to January 1, 2016, for rates to be effective on or after January 1, 2016 or from filing a new general gas and/or steam rate case prior to January 1, 2017 for new rates to be effective on or after January 1, 2017. Except pursuant to rate changes permitted by this subparagraph, the Company will not file electric rates to be become effective prior to January 1, 2016 or gas and/or steam rates to become effective prior to January 1, 2017.

Changes to the Company's base delivery service rates during the term of the Electric, Gas or Steam Rate Plan will not be permitted, except for (a) changes provided for in this Proposal; and (b) subject to Commission approval, changes as a result of the following circumstances:

a. A minor change in any individual base delivery service rate or rates whose revenue effect is *de minimis*, or essentially offset by associated changes within the same class or for other classes, provided however that the base electric delivery service rates applicable to the NYPA classes will not be increased in total. It is understood that, over time, such minor changes may be necessary and that they may continue to be sought during the term of the Electric, Gas or Steam Rate Plan, provided they will not result in a change (other than a *de minimis* change) in the revenues that Con Edison's base delivery service rates are designed to produce overall before such changes.

b. If a circumstance occurs which in the judgment of the Commission so threatens Con Edison's economic viability or ability to maintain safe, reliable and adequate service as to warrant an exception to this undertaking, Con Edison will be permitted to file for an increase in base delivery service rates at any time under such circumstances.

c. The Signatory Parties recognize that the Commission reserves the authority to act on the level of Con Edison's electric, gas and/or steam rates in the event of unforeseen circumstances that, in the Commission's opinion, have such a substantial impact on the range of earnings levels or equity costs envisioned by these Rate Plans as to render Con Edison's electric, gas and/or steam rates unreasonable or insufficient for the provision of safe and adequate service or just and reasonable rates.

d. Nothing herein will preclude Con Edison from petitioning the Commission for approval of new services, the implementation of new service classifications and/or cancellation of existing service classifications, or rate design or revenue allocation changes within or among the non-NYPA service classes.

e. The Signatory Parties reserve the right to oppose any filings made by the Company under this section.

2. **Legislative, Regulatory and Related Actions**

a. If at any time the federal government, State of New York, the City of New York and/or other local governments make changes in their tax laws (other than local property taxes, which will be reconciled in accordance with Section E.1) that result in a change in the Company's costs[66] in an annual amount, calculated and applied separately for electric gas and steam, equating to ten (10) basis points of return on common equity or more,[67] and if the Commission does not address the treatment (*e.g.*, through a surcharge or credit) of any such tax law changes, including any new, additional, repealed or reduced federal, State, City of New York or local government taxes, fees or levies, Con Edison will defer on its books of account the full change in expense and reflect such deferral as credits or debits to customers in the next base rate change subject to any final Commission determination in a generic proceeding prescribing utility implementation of a specific tax enactment, including a Commission determination of any Company-specific compliance filing made in connection therewith.[68]

b. If at any time any other law, rule, regulation, order, or other requirement or interpretation (or any repeal or amendment of an existing rule, regulation, order or other requirement) of the federal, State, or local government or courts, including a requirement that Con Edison refund its tax exempt debt, results in a change in Con Edison's annual electric, gas or steam costs or expenses not anticipated in the forecasts and assumptions on which the rates in this Proposal are based in an annual amount, calculated and applied separately for electric gas and steam, equating to ten (10) basis

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[66] Costs in this context include current and deferred tax impacts.

[67] For electric, such amounts are estimated to be $14.3 million in RY1 and $14.9 million in RY2. For gas, such amounts are estimated to be $2.9 million in RY1, $3.2 million in RY2 and $3.6 million in RY3. For steam, such amounts are estimated to be $1.5 million in RY1, $1.5 million in RY2 and $1.5 million in RY3.

[68] All Signatory Parties reserve all of their administrative and judicial rights in connection with such generic proceeding(s).

points of return on common equity or more,[69] Con Edison will defer on its books of account the full change in expense, with any such deferrals to be reflected in the next base rate case or in a manner to be determined by the Commission.

c. The Company will retain the right to petition the Commission for authorization to defer on its books of account extraordinary expenditures not otherwise addressed by this Proposal.

3. **Trade Secret Protection**

Nothing in this document prevents Con Edison from seeking trade secret protection under 16 NYCRR Part 6 for all or any part(s) of any document or report filed (or submitted to Staff) in accordance with the Rate Plans, or prohibits or restricts any other party from challenging any such request.

4. **Provisions Not Separable**

The Signatory Parties intend this Proposal to be a complete resolution of all the issues in Cases 13-E-0030, 13-G-0031 and 13-S-0032. It is understood that each provision of this Proposal is in consideration and support of all the other provisions, and expressly conditioned upon acceptance by the Commission. Except as set forth herein, none of the Signatory Parties is deemed to have approved, agreed to or consented to any principle, methodology or interpretation of law underlying or supposed to underlie any provision herein. If the Commission fails to adopt this Proposal according to its terms,

[69] For purposes of this Proposal, the ten (10) basis points return on common equity will be applied on a case-by-case basis and not to the aggregate impact of changes of two or more laws, rules, etc.; provided, however, that this threshold will be applied on a Rate Year basis to the incremental aggregate impact of all contemporaneous changes (*e.g.*, changes made as a package even if they occur or are implemented over a period of months) affecting a particular subject area and not to the individual provisions of the new law, rule, etc.

then the Signatory Parties to the Proposal will be free to pursue their respective positions in this proceeding without prejudice.

5. **Provisions Not Precedent**

The terms and provisions of this Proposal apply solely to, and are binding only in, the context of the purposes and results of this Proposal. None of the terms or provisions of this Proposal and none of the positions taken herein by any party may be referred to, cited, or relied upon by any other party in any fashion as precedent or otherwise in any other proceeding before this Commission or any other regulatory agency or before any court of law for any purpose other than furtherance of the purposes, results, and disposition of matters governed by this Proposal.

Concessions made by Signatory Parties on various electric, gas and steam issues do not preclude those parties from addressing such issues in future rate proceedings or in other proceedings.

6. **Submission of Proposal**

The Signatory Parties agree to submit this Proposal to the Commission and to individually support and request its adoption by the Commission as set forth herein. The Signatory Parties hereto believe that the Proposal will satisfy the requirements of Public Service Law §§65(1) and 79(1) that Con Edison provide safe and adequate service at just and reasonable rates.

7. **Effect of Commission Adoption of Terms of this Proposal**

No provision of this Proposal or the Commission's adoption of the terms of this Proposal shall in any way abrogate or limit the Commission's statutory authority under the Public Service Law. The Parties recognize that any Commission adoption of the terms of this Proposal does not waive the Commission's ongoing rights and responsibilities to enforce its orders and effectuate the goals expressed therein, nor the rights and responsibilities of Staff to conduct investigations or take other actions in furtherance of its duties and responsibilities.

8. **Further Assurances**

The Signatory Parties recognize that certain provisions of this Proposal require that actions be taken in the future to fully effectuate this Proposal. Accordingly, the Signatory Parties agree to cooperate with each other in good faith in taking such actions.

9. **Scope of Provisions**

No term or provision of this Proposal that relates specifically to one or more but not all of electric, gas and steam service, limits any rights of the Company or any party to petition the Commission for any purpose with respect to the service(s) not specified in such term or provision.

10. **Execution**

This Proposal is being executed in counterpart originals, and shall be binding on each Signatory Party when the counterparts have been executed.

IN WITNESS WHEREOF, the Signatory Parties hereto have affixed their signatures below as evidence of their agreement to be bound by the provisions of this Proposal.

CONSOLIDATED EDISON COMPANY
OF NEW YORK, INC.

Dated: 12/31/2013

By Robert Hoglund
Robert Hoglund

NEW YORK STATE DEPARTMENT OF
PUBLIC SERVICE

Dated: 12/31/13

By: Steven Kramer

Steven Kramer

Case 13-E-0030, et al.

NEW YORK POWER AUTHORITY

Dated: 12/27/13

By: ______________________

James F. Pasquale
Senior Vice President
Economic Development
and Energy Efficiency

THE CITY OF NEW YORK

Dated: December 31, 2013

By: ______________________________

Cas Holloway
Deputy Mayor for Operations

The City of New York is a Signatory to the Joint Proposal with one exception. The City does not support the use the Above Market Methodology to allocate the fuel costs for the East River Repowering Project and submits that the Public Service Commission should use the Incremental Methodology for such cost allocation.

THE UTILITY INTERVENTION UNIT
DIVISION OF CONSUMER
PROTECTION
NEW YORK STATE DEPARTMENT OF
STATE

Dated: December 31, 2013

Marcos Vigil, Deputy Secretary of State

CONSUMER POWER ADVOCATES

Dated: 12/30/13

By: Catherine Sitta

NEW YORK ENERGY CONSUMERS COUNCIL, INC.

Dated: 12/27/13

By: ______________________
Daniel M. Levin, Co-President

ASTORIA GENERATING COMPANY, L.P.

Dated: December 31, 2013

By: ______________________
David B. Johnson
Counsel to Astoria Generating
Company, L.P.

PACE ENERGY AND CLIMATE
CENTER

Dated: 12.30.2013 By: ______________________________

Staff Attorney, Andrea Cerbin, Esq.

THE COLUMBIA CENTER FOR
CLIMATE CHANGE LAW

Dated: December 31, 2013

By: ______________________

Ethan I. Strell, Esq.
Associate Director

THE ENVIRONMENTAL DEFENSE FUND

Dated: 12/30/13

By: James T.B. Tripp, Senior Counsel, Attorney

James T.B. Tripp, Senior Counsel
Elizabeth B. Stein, Attorney

NRG ENERGY, INC.

Dated: 12/31/2013

By: John Holtz

John Holtz
Director, Regulatory Affairs
NRG Retail Northeast
NRG Energy, Inc.

Consolidated Edison Company of New York, Inc.
Cases 13-E-0030, 13-G-0031, 13-S-0032

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Consolidated Edison Company of New York, Inc.
Case 13-E-0030
Electric Revenue Requirement
For The Twelve Months Ending December 31, 2014
$ 000's

	Rate Year 1 Forecast	Rate Change	Rate Year 1 With Rate Change
Operating revenues			
Sales revenues	$ 8,063,101	$ (76,192)	$ 7,986,909
Other revenues	211,802	(294)	211,508
Total operating revenues	8,274,903	(76,486)	8,198,417
Operating expense			
Fuel & purchased power costs	2,067,706	-	2,067,706
Operations & maintenance expenses	2,194,962	(686)	2,194,276
Depreciation	780,603	-	780,603
Taxes other than income taxes	1,501,065	(2,210)	1,498,855
Gain from disposition of utility plant	-	-	-
Total operating expenses	6,544,336	(2,896)	6,541,440
Operating income before income taxes	1,730,567	(73,590)	1,656,977
New York State income taxes	90,471	(5,225)	85,246
Federal income tax	374,894	(23,928)	350,966
Utility operating income	$ 1,265,202	$ (44,437)	$ 1,220,765
Rate Base	$ 17,322,778		$ 17,322,778
Rate of Return	7.30%		7.05%

Consolidated Edison Company of New York, Inc.
Case 13-E-0030
Electric Revenue Requirement
For The Twelve Months Ending December 31, 2015
$ 000's

Operating revenues	Rate Year 1 Forecast	Rate Year 2 Revenue/Expense Rate Base Changes	Rate Change	Rate Year 2 With Rate Change
Sales revenues	$ 7,986,909	$ (205,475)	$ 123,968	$ 7,905,402
Other revenues	211,508	(8,564)	477	203,420
Total operating revenues	8,198,417	(214,039)	124,445	8,108,823
Operating expense				
Fuel & purchased power costs	2,067,706	(237,512)	-	1,830,194
Operations & maintenance expenses	2,194,276	(48,570)	1,116	2,146,822
Depreciation	780,603	42,686	-	823,289
Taxes other than income taxes	1,498,855	65,553	3,595	1,568,003
Total operating expenses	6,541,440	(177,843)	4,711	6,368,308
Operating income before income taxes	1,656,977	(36,196)	119,734	1,740,515
New York State income taxes	85,246	(4,439)	8,501	89,308
Federal income tax	350,966	(20,748)	38,932	369,150
Utility operating income	$ 1,220,765	$ (11,009)	$ 72,301	$ 1,282,057
Rate Base	$ 17,322,778	$ 789,772		$ 18,112,550
Rate of Return	7.05%			7.08%

Consolidated Edison Company of New York, Inc.
Case 13-E-0030
Average Electric Rate Base
For The Twelve Months Ending December 31, 2014 and December 31, 2015
$ 000's

	Rate Year 1	Rate Year 2 Changes	Rate Year 2
Utility plant:			
Average Book Cost of Plant	$ 24,593,444	$ 1,244,291	$ 25,837,735
Non-Interest Bearing CWIP	705,456	93,511	798,967
Average Accumulated Depreciation	(5,512,572)	(465,598)	(5,978,170)
Net utility plant	19,786,328	872,204	20,658,532
Rate base additions:			
Working Capital	827,612	(11,708)	815,904
Excess Rate Base Over Capitalization	(161,123)	-	(161,123)
Unamortized Debt Discount/Premium/Expense	113,409	(7,300)	106,109
Deferred Fuel - Net of Income Taxes	77,341	(1,609)	75,732
Unbilled Revenues	100,494		100,494
Preferred Stock Expense	21,361	(771)	20,590
MTA Surtax - Net of Income Taxes	8,910	-	8,910
Early Retirement Termination Benefit (1999) - Net of Tax	1,587	(1,587)	-
Preliminary Survey & Investigation Costs	1,832	-	1,832
FIT Interest Refund	1,506	-	1,506
Rate base additions	992,930	(22,975)	969,955
Rate base deductions:			
Amounts Billed In Advance of Construction - Net of Tax	(706)	-	(706)
Customer Advances for Construction	(5,182)	-	(5,182)
Rate base deductions	(5,888)	-	(5,888)
Regulatory assets & liabilities (net of income taxes):			
Superstorm Sandy Restoration	132,223	(52,889)	79,334
SIR Deferral	106,105	(14,740)	91,365
Major Storm Charges	42,413	(16,965)	25,448
T&D Carrying Charge Deferral	41,079	(12,639)	28,440
Medicare Part D	15,208	(6,083)	9,125
ERRP Spare Parts Maintenance	12,543	(5,017)	7,526
Smart Grid	6,441	(2,132)	4,309
TSC Revenue (prior to April 2010)	5,197	(2,079)	3,118
Sale of SO2 Allowances	3,606	(1,442)	2,164
Nuclear Fuel Litigation	2,804	(1,121)	1,683
Reactive Power	1,951	(781)	1,170
263a Deferred Taxes	1,795	(718)	1,077
Interest - TSC Revenue	206	(82)	124
Emergency Demand Response / Demand Reduction Program	148	(59)	89
Gain on Sale of First Avenue Properties	27	(11)	16
Property Tax Deferrals	(143,237)	57,295	(85,942)
Property Tax Refunds	(50,846)	20,338	(30,508)
Interest Rate True-Up (Auction Rate / LT Debt)	(40,413)	16,165	(24,248)
World Trade Center (WTC)	(28,457)	11,383	(17,074)
Customer Cash Flow Benefits Bonus Depr	(20,180)	8,072	(12,108)
Carrying Charges (Net Plant Reconciliation)	(8,895)	3,558	(5,337)
Verizon Joint Use Poles	(8,148)	3,259	(4,889)
Customer Cash Flow Benefits Repair Allowance	(7,190)	2,876	(4,314)
Power for Jobs Tax Credit	(5,682)	2,273	(3,409)
Interference	(4,187)	1,675	(2,512)
Former Employee / Contractor Settlements	(3,327)	1,331	(1,996)
Electric Service Reliability Rate Adjustment	(2,817)	1,127	(1,690)
Preferred Stock Redemption Savings	(2,731)	1,092	(1,639)
Sale of Property - John Street	(2,673)	1,069	(1,604)
Carrying Cost - SIR Deferred Balances	(1,993)	797	(1,196)
Case 09-E-0428 Deferral	(1,416)	566	(850)
Energy Efficiency Program	(647)	259	(388)
DC Service Incentive	(501)	200	(301)
Reserve for "05-'08" Capital Expenditures	(441)	176	(265)
Targeted DSM	(317)	127	(190)
Electric - BIR Refunds	(182)	73	(109)
Furnace Dock Road Dam	(81)	32	(49)
Regulatory deferrals	37,386	16,984	54,370
Accumulated deferred income taxes			
ADR / ACRS / MACRS Deductions	(2,330,066)	(27,469)	(2,357,535)
Repair Allowance	(420,823)	(32,135)	(452,958)
Change of Accounting Section 263A	(370,686)	(13,132)	(383,818)
Vested Vacation	12,345	-	12,345
Prepaid Insurance Expenses	(2,934)	-	(2,934)
Unbilled Revenues	103,870	-	103,870
Contributions In Aid of Construction	26,583	-	26,583
Capitalized Interest	19,411	-	19,411
Repair & Maintenance Allowance - 02 - 06 IRS Audit	2,969	-	2,969
MTA	(18,529)	-	(18,529)
Amortization of Computer Software	(70,540)	(3,320)	(73,860)
Call Premium	(10,333)	-	(10,333)
Excess Deferred S.I.T.	(140,668)	-	(140,668)
Excess Deferred F.I.T.	(722)		(722)
Deferred S.I.T.	(287,855)	(385)	(288,240)
Accumulated deferred income taxes	(3,487,978)	(76,441)	(3,564,419)
Total Rate Base	$ 17,322,778	$ 789,772	$ 18,112,550

Consolidated Edison Company of New York, Inc.
Electric Case 13-E-0300
Average Capital Structure & Cost of Money
For the Twelve Months Ending December 31, 2014

RY1

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre Tax Cost %
Long term debt	50.54%	5.17%	2.61%	2.61%
Customer deposits	1.46%	1.25%	0.02%	0.02%
Subtotal	52.00%		2.63%	2.63%
Common Equity	48.00%	9.20%	4.42%	7.31%
Total	100.00%		7.05%	9.94%

RY2

Consolidated Edison Company of New York, Inc.
Electric Case 13-E-0300
Average Capital Structure & Cost of Money
For the Twelve Months Ending December 31, 2015

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre Tax Cost %
Long term debt	50.56%	5.23%	2.64%	2.64%
Customer deposits	1.44%	1.25%	0.02%	0.02%
Subtotal	52.00%		2.66%	2.66%
Common Equity	48.00%	9.20%	4.42%	7.31%
Total	100.00%		7.08%	9.98%

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
LONG TERM DEBT
Forecast - Rate Year Ended December 31, 2014

CECONY		Issue Date	Maturity Date	Amount Outstanding	Original Issue Amount	Premium or Discount	Expense of Issuance	Net Proceeds	Cost of Debt	Annual Cost
Debentures:										
2003 Series A	5.8750%	4/7/03	04/01/33	175,000,000	175,000,000	(1,022,000)	1,662,326	172,315,674	5.97%	10,281,250
2003 Series C	5.1000%	6/10/03	06/15/33	200,000,000	200,000,000	(336,000)	1,866,135	197,797,865	5.16%	10,200,000
2004 Series A	4.7000%	2/9/04	02/01/14	16,666,667	200,000,000	(360,000)	1,414,406	198,225,594	4.74%	783,333
2004 Series B	5.7000%	2/9/04	02/01/34	200,000,000	200,000,000	(538,000)	1,864,406	197,597,594	5.77%	11,400,000
2005 Series A	5.3000%	3/7/05	03/01/35	350,000,000	350,000,000	(1,193,500)	3,541,534	345,264,966	5.37%	18,550,000
2005 Series B	5.2500%	6/20/05	07/01/35	125,000,000	125,000,000	(731,250)	1,142,914	123,125,836	5.33%	6,562,500
2005 Series C	5.3750%	11/14/05	12/15/15	350,000,000	350,000,000	(805,000)	2,476,451	346,718,549	5.43%	18,812,500
2006 Series A	5.8500%	3/6/06	03/15/36	400,000,000	400,000,000	(60,000)	3,616,500	396,323,500	5.90%	23,400,000
2006 Series B	6.2000%	6/13/06	06/15/36	400,000,000	400,000,000	(756,000)	3,669,000	395,575,000	6.27%	24,800,000
2006 Series C	5.5000%	9/20/06	09/15/16	400,000,000	400,000,000	(1,540,000)	2,777,637	395,682,363	5.56%	22,000,000
2006 Series D	5.3000%	11/28/06	12/01/16	250,000,000	250,000,000	(710,000)	1,700,000	247,590,000	5.35%	13,250,000
2006 Series E	5.7000%	11/28/06	12/01/36	250,000,000	250,000,000	(712,500)	2,262,500	247,025,000	5.77%	14,250,000
2007 Series A	6.3000%	8/23/07	08/15/37	525,000,000	525,000,000	(2,924,250)	4,751,250	517,324,500	6.39%	33,075,000
2008 Series A	5.8500%	4/1/08	04/01/18	600,000,000	600,000,000	(264,000)	4,099,750	595,636,250	5.89%	35,100,000
2008 Series B	6.7500%	4/1/08	04/01/38	600,000,000	600,000,000	(1,758,000)	5,449,750	592,792,250	6.83%	40,500,000
2008 Series C	7.1250%	12/2/08	12/01/18	600,000,000	600,000,000	(2,148,000)	3,962,633	593,889,367	7.20%	42,750,000
2009 Series A	5.5500%	3/23/09	04/01/14	68,750,000	275,000,000	(217,250)	1,793,234	272,989,516	1.40%	3,815,625
2009 Series B	6.6500%	3/23/09	04/01/19	475,000,000	475,000,000	(693,500)	3,284,067	471,022,433	6.71%	31,587,500
2009 Series C	5.5000%	12/2/09	12/01/39	600,000,000	600,000,000	(2,268,000)	5,673,813	592,058,187	5.57%	33,000,000
2010 Series A	4.4500%	6/2/10	06/15/20	350,000,000	350,000,000	(759,500)	2,518,935	346,721,565	4.49%	15,575,000
2010 Series B	5.7000%	6/2/10	06/15/40	350,000,000	350,000,000	(1,701,000)	3,306,369	344,992,631	5.78%	19,950,000
2012 Series A	4.2000%	3/13/12	03/15/42	400,000,000	400,000,000	(1,424,000)	4,222,549	394,353,451	4.26%	16,800,000
2013 Series A	3.9500%	2/28/13	03/01/43	700,000,000	700,000,000	(4,872,000)	7,204,815	687,923,185	4.02%	27,650,000
2013 Series B	4.4500%	8/1/13	08/01/43	420,000,000	420,000,000	(1,386,000)	4,305,000	414,309,000	4.51%	18,690,000
2014 Series A	4.7000%	3/1/14	03/01/44	483,333,333	580,000,000	(2,778,200)	5,945,000	571,276,800	4.77%	22,716,667
2014 Series B	4.7000%	6/2/14	06/15/44	350,000,000	600,000,000	(2,880,000)	6,150,000	590,970,000	4.77%	16,450,000
				9,638,750,000	10,375,000,000	(34,837,950)	90,660,974	10,249,501,076	5.19%	531,949,375
Tax Exempt Debt Issue through New York State										
1999 Series A	VAR	7/10/01	05/01/34	292,700,000	292,700,000	-	4,577,677	288,122,323	0.46%	1,346,420
2010 Series A	VAR	11/9/10	06/01/36	224,600,000	224,600,000	-	4,803,976	219,796,024	0.26%	583,960
2001 Series B	VAR	10/18/01	10/01/36	98,000,000	98,000,000	-	1,169,324	96,830,676	0.46%	450,800
2004 Series A	VAR	1/22/04	01/01/39	98,325,000	98,325,000	-	1,534,332	96,790,668	0.46%	452,295
2004 Series B1	VAR	1/22/04	05/01/32	127,225,000	127,225,000	-	1,985,912	125,239,088	0.46%	585,235
2004 Series B2	VAR	1/22/04	10/01/35	19,750,000	19,750,000	-	307,066	19,442,934	0.46%	90,850
2004 Series C	VAR	11/5/04	11/01/39	99,000,000	99,000,000	-	1,834,951	97,165,049	0.26%	257,400
2005 Series A	VAR	5/19/05	05/01/39	126,300,000	126,300,000	-	1,842,329	124,457,671	0.26%	328,380
				1,085,900,000	1,085,900,000	-	18,055,567	1,067,844,433	0.38%	4,095,340
Subtotals				10,724,650,000	11,460,900,000	(34,837,950)	108,716,542	11,317,345,508	4.74%	536,044,715
Redemption of Preferred Stock										993,442
Unamortized Loss on Reacquired Debt Expense										9,936,729
Unamortized Debt Discount										1,889,616
Unamortized Issuance Cost of Debt										5,694,105
Total CECONY				10,724,650,000					5.17%	554,558,607

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
LONG TERM DEBT
Forecast - Rate Year Ended December 31, 2015

CECONY		Issue Date	Maturity Date	Amount Outstanding	Original Issue Amount	Premium or Discount	Expense of Issuance	Net Proceeds	Cost of Debt	Annual Cost
Debentures:										
2003 Series A	5.8750%	4/7/03	04/01/33	175,000,000	175,000,000	(1,022,000)	1,662,326	172,315,674	5.97%	10,281,250
2003 Series C	5.1000%	6/10/03	06/15/33	200,000,000	200,000,000	(336,000)	1,866,135	197,797,865	5.16%	10,200,000
2004 Series B	5.7000%	2/9/04	02/01/34	200,000,000	200,000,000	(538,000)	1,864,406	197,597,594	5.77%	11,400,000
2005 Series A	5.3000%	3/7/05	03/01/35	350,000,000	350,000,000	(1,193,500)	3,541,534	345,264,966	5.37%	18,550,000
2005 Series B	5.2500%	6/20/05	07/01/35	125,000,000	125,000,000	(731,250)	1,142,914	123,125,836	5.33%	6,562,500
2005 Series C	5.3750%	11/14/05	12/15/15	335,416,667	350,000,000	(805,000)	2,476,451	346,718,549	5.43%	18,028,646
2006 Series A	5.8500%	3/6/06	03/15/36	400,000,000	400,000,000	(60,000)	3,616,500	396,323,500	5.90%	23,400,000
2006 Series B	6.2000%	6/13/06	06/15/36	400,000,000	400,000,000	(756,000)	3,669,000	395,575,000	6.27%	24,800,000
2006 Series C	5.5000%	9/20/06	09/15/16	400,000,000	400,000,000	(1,540,000)	2,777,637	395,682,363	5.56%	22,000,000
2006 Series D	5.3000%	11/28/06	12/01/16	250,000,000	250,000,000	(710,000)	1,700,000	247,590,000	5.35%	13,250,000
2006 Series E	5.7000%	11/28/06	12/01/36	250,000,000	250,000,000	(712,500)	2,262,500	247,025,000	5.77%	14,250,000
2007 Series A	6.3000%	8/23/07	08/15/37	525,000,000	525,000,000	(2,924,250)	4,751,250	517,324,500	6.39%	33,075,000
2008 Series A	5.8500%	4/1/08	04/01/18	600,000,000	600,000,000	(264,000)	4,099,750	595,636,250	5.89%	35,100,000
2008 Series B	6.7500%	4/1/08	04/01/38	600,000,000	600,000,000	(1,758,000)	5,449,750	592,792,250	6.83%	40,500,000
2008 Series C	7.1250%	12/2/08	12/01/18	600,000,000	600,000,000	(2,148,000)	3,962,633	593,889,367	7.20%	42,750,000
2009 Series B	6.6500%	3/23/09	04/01/19	475,000,000	475,000,000	(693,500)	3,284,067	471,022,433	6.71%	31,587,500
2009 Series C	5.5000%	12/2/09	12/01/39	600,000,000	600,000,000	(2,268,000)	5,673,813	592,058,187	5.57%	33,000,000
2010 Series A	4.4500%	6/2/10	06/15/20	350,000,000	350,000,000	(759,500)	2,518,935	346,721,565	4.49%	15,575,000
2010 Series B	5.7000%	6/2/10	06/15/40	350,000,000	350,000,000	(1,701,000)	3,306,369	344,992,631	5.78%	19,950,000
2012 Series A	4.2000%	3/13/12	03/15/42	400,000,000	400,000,000	(1,424,000)	4,222,549	394,353,451	4.26%	16,800,000
2013 Series A	3.9500%	2/28/13	03/01/43	700,000,000	700,000,000	(4,872,000)	7,204,815	687,923,185	4.02%	27,650,000
2013 Series B	4.4500%	8/1/13	08/01/43	420,000,000	420,000,000	(1,386,000)	4,305,000	414,309,000	4.51%	18,690,000
2014 Series A	4.7000%	3/1/14	03/01/44	580,000,000	580,000,000	(2,778,200)	5,945,000	571,276,800	4.77%	27,260,000
2014 Series B	4.7000%	6/2/14	06/15/44	600,000,000	600,000,000	(2,880,000)	6,150,000	590,970,000	4.77%	28,200,000
2015 Series A	5.3000%	3/1/15	03/01/45	500,000,000	600,000,000	(2,688,000)	6,150,000	591,162,000	5.38%	26,500,000
2015 Series B	5.3000%	12/1/15	12/01/45	39,166,667	470,000,000	(2,105,600)	4,817,500	463,076,900	5.38%	2,075,833
				10,424,583,334	10,970,000,000	(39,054,300)	98,420,834	10,832,524,866	5.28%	571,435,729
Tax Exempt Debt Issue through New York State										
1999 Series A	VAR	7/10/01	05/01/34	292,700,000	292,700,000	-	4,577,677	288,122,323	1.35%	3,951,450
2010 Series A	VAR	11/9/10	06/01/36	224,600,000	224,600,000	-	4,803,976	219,796,024	0.77%	1,729,420
2001 Series B	VAR	10/18/01	10/01/36	98,000,000	98,000,000	-	1,169,324	96,830,676	1.35%	1,323,000
2004 Series A	VAR	1/22/04	01/01/39	98,325,000	98,325,000	-	1,534,332	96,790,668	1.35%	1,327,388
2004 Series B1	VAR	1/22/04	05/01/32	127,225,000	127,225,000	-	1,985,912	125,239,088	1.35%	1,717,538
2004 Series B2	VAR	1/22/04	10/01/35	19,750,000	19,750,000	-	307,066	19,442,934	1.35%	266,625
2004 Series C	VAR	11/5/04	11/01/39	99,000,000	99,000,000	-	1,834,951	97,165,049	0.77%	762,300
2005 Series A	VAR	5/19/05	05/01/39	126,300,000	126,300,000	-	1,842,329	124,457,671	0.77%	972,510
				1,085,900,000	1,085,900,000	-	18,055,567	1,067,844,433	1.11%	12,050,230
Subtotals				11,510,483,334	12,055,900,000	(39,054,300)	116,476,402	11,900,369,298	4.90%	583,485,959
Redemption of Preferred Stock										993,442
Unamortized Loss on Reacquired Debt Expense										9,936,729
Unamortized Debt Discount										2,025,566
Unamortized Issuance Cost of Debt										5,996,764
Total CECONY				11,510,483,334					5.23%	602,438,461

Consolidated Edison Company of New York, Inc.

Electric Case 13-E-0030

Calculation of Revenue Deferral / Temporary Billing Credit

For the Twelve Months Ending December 31, 2014, and December 31, 2015

$ 000's

	Twelve Months Ending			Cumulative
Revenue Requirement	Dec. 31, 2014	Dec. 31, 2015		Total
RY - 1	($76,192)	($76,192)		($152,384)
RY - 2	-	123,968		123,968
Total	$ (76,192)	$ 47,776	(a)	$ (28,416)
Annual Bill Changes	$ -	$ -		$ -
Rate change to be deferred	$ (76,192)	$ 47,776	(a)	$ (28,416)
Interest on deferred balance (b)	(690)	(948)		(1,638)
Net Deferral	$ (76,882)	$ 46,829		$ (30,054)

(a) If the Company does not file for new rates to be effective January 1, 2016, the RY2 "Temporary Rate Credit" of $47.776 million would expire and base rates would effectively increase by that amount. Deferred over collections of $30.054 million are available to offset a portion of this increase.

(b) Interest will be calculated at the other customer capital rate, which is updated annually. For 2014 the rate is 3.0%. The 3.0% rate was applied to the 2014 and 2015 average balance for purpose of this illustration.

Consolidated Edison Company of New York, Inc.
Case 13-G-0031
Gas Revenue Requirement
For The Twelve Months Ending December 31, 2014
$ 000's

Operating revenues	Rate Year 1 Forecast	Rate Change	Rate Year 1 With Rate Change
Sales revenues	$ 1,575,134	$ (54,602)	$ 1,520,532
Other revenues	30,296	(182)	30,114
Total operating revenues	1,605,430	(54,784)	1,550,646
Operating expense			
Fuel & purchased power costs	454,315	-	454,315
Operations & maintenance expenses	350,573	(491)	350,082
Depreciation	136,000	-	136,000
Taxes other than income taxes	258,478	(2,103)	256,375
Gain from disposition of utility plant	-	-	-
Total operating expenses	1,199,366	(2,594)	1,196,772
Operating income before income taxes	406,064	(52,190)	353,874
New York State income taxes	22,247	(3,706)	18,542
Federal income tax	102,519	(16,969)	85,549
Utility operating income	$ 281,298	$ (31,515)	$ 249,783
Rate Base	$ 3,520,553		$ 3,520,553
Rate of Return	7.99%		7.10%

Consolidated Edison Company of New York, Inc.
Case 13-G-0031
Gas Revenue Requirement
For The Twelve Months Ending December 31, 2015
$ 000's

Operating revenues	Rate Year 1 Forecast	Rate Year 2 Revenue/Expense Rate Base Changes	Rate Change	Rate Year 2 With Rate Change
Sales revenues	$ 1,520,532	$ 46,685	$ 38,620	$ 1,605,837
Other revenues	30,114	(559)	129	29,684
Total operating revenues	1,550,646	46,126	38,749	1,635,521
Operating expense				
Fuel & purchased power costs	454,315	20,595	-	474,910
Operations & maintenance expenses	350,082	(2,110)	348	348,319
Depreciation	136,000	10,847	-	146,847
Taxes other than income taxes	256,375	20,716	1,487	278,578
Gain from disposition of utility plant	-	-	-	-
Total operating expenses	1,196,772	50,048	1,835	1,248,655
Operating income before income taxes	353,874	(3,921)	36,914	386,867
New York State income taxes	18,542	(1,061)	2,621	20,101
Federal income tax	85,549	(6,782)	12,003	91,513
Utility operating income	$ 249,783	$ 3,922	$ 22,291	$ 275,253
Rate Base	$ 3,520,553	$ 342,103		$ 3,862,657
Rate of Return	7.10%			7.13%

Consolidated Edison Company of New York, Inc.
Case 13-G-0031
Gas Revenue Requirement
For The Twelve Months Ending December 31, 2016
$ 000's

	Rate Year 2 Forecast	Rate Year 3 Revenue/Expense Rate Base Changes	Rate Change	Rate Year 3 With Rate Change
Operating revenues				
Sales revenues	1,605,837	27,623	56,838	1,690,298
Other revenues	29,684	(632)	190	29,242
Total operating revenues	1,635,521	26,991	57,028	1,719,540
Operating expense				
Fuel & purchased power costs	474,910	25,053	-	499,963
Operations & maintenance expenses	348,319	(22,621)	512	326,210
Depreciation	146,847	13,283	-	160,130
Taxes other than income taxes	278,578	24,028	2,189	304,795
Gain from disposition of utility plant	-	-	-	-
Total operating expenses	1,248,655	39,743	2,700	1,291,098
Operating income before income taxes	386,867	(12,752)	54,327	428,442
New York State income taxes	20,101	(2,004)	3,857	21,955
Federal income tax	91,513	(8,040)	17,665	101,137
Utility operating income	275,253	(2,708)	32,806	305,350
Rate Base	$ 3,862,657	373,605		$ 4,236,261
Rate of Return	7.13%			7.21%

Consolidated Edison Company of New York, Inc.
Case 13-G-0031
Average Gas Rate Base
For The Twelve Months Ending December 31, 2014 and December 31, 2015
$ 000's

	Rate Year 1	Rate Year 2 Changes	Rate Year 2
Utility plant:			
Average Book Cost of Plant	$ 5,530,825	$ 482,675	$ 6,013,500
Non-Interest Bearing CWIP	194,810	(3,601)	191,209
Average Accumulated Depreciation	(1,343,657)	(106,633)	(1,450,290)
Net utility plant	4,381,978	372,441	4,754,419
Rate base additions:			
Working Capital	89,690	3,297	92,987
Unamortized Debt Discount/Premium/Expense	21,484	(1,383)	20,101
Gas Stored Underground - Non Current	1,239	-	1,239
Unbilled Revenues	55,910	-	55,910
Unamortized Preferred Stock Expense	4,046	(146)	3,900
MTA Surtax - Net of Income Taxes	3,175	-	3,175
Rate base additions	175,544	1,768	177,312
Rate base deductions:			
Excess Rate Base Over Capitalization	(23,655)	-	(23,655)
Customer Advances for Construction	(1,870)	-	(1,870)
Rate base deductions	(25,525)	-	(25,525)
Regulatory assets & liabilities (net of income taxes):			
SIR	19,740	(4,387)	15,353
Property Tax Deferrals	(7,888)	3,155	(4,733)
World Trade Center	(9,385)	3,755	(5,630)
Former Employee / Contractor Settlements	(3,212)	1,285	(1,927)
Interest Rate True-Up (Auction Rate / Long Term Debt)	(5,363)	2,145	(3,218)
Bonus Depreciation Interest	(9,797)	3,919	(5,878)
Repair Allowance Interest	(3,462)	1,385	(2,077)
Interference	(137)	55	(82)
Sanford Avenue Gas Explosion	(856)	343	(513)
Penalties on offpeak / interruptible customers	(720)	288	(432)
Pipeline Integrity	(1,173)	469	(704)
Gain on Sale of First Avenue Properties	(450)	180	(270)
EEPS	(354)	141	(213)
Carrying Cost - SIR Deferred Balances	(501)	200	(301)
Unauthorized Use Charge - Divested Stations	(271)	108	(163)
Property Tax Refunds	(164)	66	(98)
Oil To Gas Conversion	(77)	31	(46)
Preferred Stock Redemption Savings	(517)	206	(311)
Case 09-G-0795 Deferral	(801)	320	(481)
Medicare Part D	(225)	90	(134)
263a Deferred Taxes	(359)	144	(215)
Interest on deferred balances	(11)	5	(6)
Interest on deferred POR	48	(19)	29
Regulatory deferrals	(25,936)	13,884	(12,051)
Accumulated deferred income taxes			
ADR / ACRS / MACRS Deductions	(730,403)	(27,704)	(758,107)
Change of Accounting Section 263A	(84,802)	(5,254)	(90,056)
Repair & Maintenance Allowance	(99,785)	(12,084)	(111,869)
Excess Deferred FIT	(19,067)		(19,067)
Excess Deferred SIT	(571)		(571)
Vested Vacation	1,728	-	1,728
Prepaid Insurance Expenses	(463)	-	(463)
Unbilled Revenues	5,330	-	5,330
Contributions In Aid of Construction	2,135	-	2,135
Deferred State MTA	(3,429)		(3,429)
Capitalized Interest	1,448	-	1,448
Amortization of Computer Software	(13,816)	(1,699)	(15,515)
Call Premium	(998)	-	(998)
Deferred S.I.T.	(42,815)	751	(42,064)
Accumulated deferred income taxes	(985,508)	(45,990)	(1,031,498)
Total Rate Base	$ 3,520,553	$ 342,103	$ 3,862,656

Consolidated Edison Company of New York, Inc.
Case 13-G-0031
Average Gas Rate Base
For The Twelve Months Ending December 31, 2016
$ 000's

	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Utility plant:			
Average Book Cost of Plant	$ 6,013,500	$ 588,378	$ 6,601,878
Non-Interest Bearing CWIP	191,209	(69,685)	121,524
Average Accumulated Depreciation	(1,450,290)	(118,117)	(1,568,407)
Net utility plant	4,754,419	400,576	5,154,995
Rate base additions:			
Working Capital	92,987	4,326	97,313
Unamortized Debt Discount/Premium/Expense	20,101	-	20,101
Gas Stored Underground - Non Current	1,239	-	1,239
Unbilled Revenues	55,910	-	55,910
Unamortized Preferred Stock Expense	3,900	-	3,900
MTA Surtax - Net of Income Taxes	3,175	-	3,175
Rate base additions	177,312	4,326	181,638
Rate base deductions:			
Excess Rate Base Over Capitalization	(23,655)	-	(23,655)
Customer Advances for Construction	(1,870)	-	(1,870)
Rate base deductions	(25,525)	-	(25,525)
Regulatory assets & liabilities (net of income taxes):			
SIR	15,353	(4,387)	10,966
Property Tax Deferrals	(4,733)	3,155	(1,578)
World Trade Center	(5,630)	3,753	(1,877)
Former Employee / Contractor Settlements	(1,927)	1,284	(642)
Interest Rate True-Up (Auction Rate / Long Term Debt)	(3,218)	2,145	(1,073)
Bonus Depreciation Interest	(5,878)	3,919	(1,959)
Repair Allowance Interest	(2,077)	1,385	(692)
Interference	(82)	55	(28)
Sanford Avenue Gas Explosion	(513)	343	(170)
Penalties on offpeak / interruptible customers	(432)	288	(144)
Pipeline Integrity	(704)	469	(235)
Gain on Sale of First Avenue Properties	(270)	180	(90)
EEPS	(213)	142	(72)
Carrying Cost - SIR Deferred Balances	(301)	200	(101)
Unauthorized Use Charge - Divested Stations	(163)	109	(55)
Property Tax Refunds	(98)	66	(32)
Oil To Gas Conversion	(46)	31	(15)
Preferred Stock Redemption Savings	(311)	207	(105)
Case 09-G-0795 Deferral	(481)	321	(161)
Medicare Part D	(134)	90	(44)
263a Deferred Taxes	(215)	144	(72)
Interest on deferred balances	(6)	5	(1)
Interest on deferred POR	29	(20)	10
Regulatory deferrals	(12,051)	13,882	1,830
Accumulated deferred income taxes			
ADR / ACRS / MACRS Deductions	(758,107)	(25,047)	(783,154)
Change of Accounting Section 263A	(90,056)	(5,355)	(95,411)
Repair & Maintenance Allowance	(111,869)	(13,886)	(125,755)
Excess Deferred FIT	(19,067)		(19,067)
Excess Deferred SIT	(571)		(571)
Vested Vacation	1,728	-	1,728
Prepaid Insurance Expenses	(463)	-	(463)
Unbilled Revenues	5,330	-	5,330
Contributions In Aid of Construction	2,135	-	2,135
Deferred State MTA	(3,429)		(3,429)
Capitalized Interest	1,448	-	1,448
Amortization of Computer Software	(15,515)	(1,699)	(17,214)
Call Premium	(998)	-	(998)
Deferred S.I.T.	(42,064)	808	(41,256)
Accumulated deferred income taxes	(1,031,498)	(45,179)	(1,076,677)
Total Rate Base	$ 3,862,656	$ 373,605	$ 4,236,261

Consolidated Edison Company of New York, Inc.
Gas Case 13-G-0031
Average Capital Structure & Cost of Money
For the Twelve Months Ending December 31, 2014, December 31, 2015 and December 31, 2016

RY 1

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre Tax Cost %
Long term debt	50.54%	5.17%	2.61%	2.61%
Customer deposits	1.46%	1.25%	0.02%	0.02%
Subtotal	52.00%		2.63%	2.63%
Common Equity	48.00%	9.30%	4.46%	7.39%
Total	100.00%		7.10%	10.02%

RY 2

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre Tax Cost %
Long term debt	50.56%	5.23%	2.64%	2.64%
Customer deposits	1.44%	1.25%	0.018%	0.02%
Subtotal	52.00%		2.66%	2.66%
Common Equity	48.00%	9.30%	4.46%	7.39%
Total	100.00%		7.13%	10.06%

RY 3

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre Tax Cost %
Long term debt	50.58%	5.39%	2.73%	2.73%
Customer deposits	1.42%	1.25%	0.02%	0.02%
Subtotal	52.00%		2.74%	2.74%
Common Equity	48.00%	9.30%	4.46%	7.39%
Total	100.00%		7.21%	10.14%

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
LONG TERM DEBT
Forecast - Rate Year Ended December 31, 2014

CECONY		Issue Date	Maturity Date	Amount Outstanding	Original Issue Amount	Premium or Discount	Expense of Issuance	Net Proceeds	Cost of Debt	Annual Cost
Debentures:										
2003 Series A	5.8750%	4/7/03	04/01/33	175,000,000	175,000,000	(1,022,000)	1,662,326	172,315,674	5.97%	10,281,250
2003 Series C	5.1000%	6/10/03	06/15/33	200,000,000	200,000,000	(336,000)	1,866,135	197,797,865	5.16%	10,200,000
2004 Series A	4.7000%	2/9/04	02/01/14	16,666,667	200,000,000	(360,000)	1,414,406	198,225,594	4.74%	783,333
2004 Series B	5.7000%	2/9/04	02/01/34	200,000,000	200,000,000	(538,000)	1,864,406	197,597,594	5.77%	11,400,000
2005 Series A	5.3000%	3/7/05	03/01/35	350,000,000	350,000,000	(1,193,500)	3,541,534	345,264,966	5.37%	18,550,000
2005 Series B	5.2500%	6/20/05	07/01/35	125,000,000	125,000,000	(731,250)	1,142,914	123,125,836	5.33%	6,562,500
2005 Series C	5.3750%	11/14/05	12/15/15	350,000,000	350,000,000	(805,000)	2,476,451	346,718,549	5.43%	18,812,500
2006 Series A	5.8500%	3/6/06	03/15/36	400,000,000	400,000,000	(60,000)	3,616,500	396,323,500	5.90%	23,400,000
2006 Series B	6.2000%	6/13/06	06/15/36	400,000,000	400,000,000	(756,000)	3,669,000	395,575,000	6.27%	24,800,000
2006 Series C	5.5000%	9/20/06	09/15/16	400,000,000	400,000,000	(1,540,000)	2,777,637	395,682,363	5.56%	22,000,000
2006 Series D	5.3000%	11/28/06	12/01/16	250,000,000	250,000,000	(710,000)	1,700,000	247,590,000	5.35%	13,250,000
2006 Series E	5.7000%	11/28/06	12/01/36	250,000,000	250,000,000	(712,500)	2,262,500	247,025,000	5.77%	14,250,000
2007 Series A	6.3000%	8/23/07	08/15/37	525,000,000	525,000,000	(2,924,250)	4,751,250	517,324,500	6.39%	33,075,000
2008 Series A	5.8500%	4/1/08	04/01/18	600,000,000	600,000,000	(264,000)	4,099,750	595,636,250	5.89%	35,100,000
2008 Series B	6.7500%	4/1/08	04/01/38	600,000,000	600,000,000	(1,758,000)	5,449,750	592,792,250	6.83%	40,500,000
2008 Series C	7.1250%	12/2/08	12/01/18	600,000,000	600,000,000	(2,148,000)	3,962,633	593,889,367	7.20%	42,750,000
2009 Series A	5.5500%	3/23/09	04/01/14	68,750,000	275,000,000	(217,250)	1,793,234	272,989,516	1.40%	3,815,625
2009 Series B	6.6500%	3/23/09	04/01/19	475,000,000	475,000,000	(693,500)	3,284,067	471,022,433	6.71%	31,587,500
2009 Series C	5.5000%	12/2/09	12/01/39	600,000,000	600,000,000	(2,268,000)	5,673,813	592,058,187	5.57%	33,000,000
2010 Series A	4.4500%	6/2/10	06/15/20	350,000,000	350,000,000	(759,500)	2,518,935	346,721,565	4.49%	15,575,000
2010 Series B	5.7000%	6/2/10	06/15/40	350,000,000	350,000,000	(1,701,000)	3,306,369	344,992,631	5.78%	19,950,000
2012 Series A	4.2000%	3/13/12	03/15/42	400,000,000	400,000,000	(1,424,000)	4,222,549	394,353,451	4.26%	16,800,000
2013 Series A	3.9500%	2/28/13	03/01/43	700,000,000	700,000,000	(4,872,000)	7,204,815	687,923,185	4.02%	27,650,000
2013 Series B	4.4500%	8/1/13	08/01/43	420,000,000	420,000,000	(1,386,000)	4,305,000	414,309,000	4.51%	18,690,000
2014 Series A	4.7000%	3/1/14	03/01/44	483,333,333	580,000,000	(2,778,200)	5,945,000	571,276,800	4.77%	22,716,667
2014 Series B	4.7000%	6/2/14	06/15/44	350,000,000	600,000,000	(2,880,000)	6,150,000	590,970,000	4.77%	16,450,000
				9,638,750,000	10,375,000,000	(34,837,950)	90,660,974	10,249,501,076	5.19%	531,949,375
Tax Exempt Debt Issue through New York State										
1999 Series A	VAR	7/10/01	05/01/34	292,700,000	292,700,000	-	4,577,677	288,122,323	0.46%	1,346,420
2010 Series A	VAR	11/9/10	06/01/36	224,600,000	224,600,000	-	4,803,976	219,796,024	0.26%	583,960
2001 Series B	VAR	10/18/01	10/01/36	98,000,000	98,000,000	-	1,169,324	96,830,676	0.46%	450,800
2004 Series A	VAR	1/22/04	01/01/39	98,325,000	98,325,000	-	1,534,332	96,790,668	0.46%	452,295
2004 Series B1	VAR	1/22/04	05/01/32	127,225,000	127,225,000	-	1,985,912	125,239,088	0.46%	585,235
2004 Series B2	VAR	1/22/04	10/01/35	19,750,000	19,750,000	-	307,066	19,442,934	0.46%	90,850
2004 Series C	VAR	11/5/04	11/01/39	99,000,000	99,000,000	-	1,834,951	97,165,049	0.26%	257,400
2005 Series A	VAR	5/19/05	05/01/39	126,300,000	126,300,000	-	1,842,329	124,457,671	0.26%	328,380
				1,085,900,000	1,085,900,000	-	18,055,567	1,067,844,433	0.38%	4,095,340
Subtotals				10,724,650,000	11,460,900,000	(34,837,950)	108,716,542	11,317,345,508	4.74%	536,044,715
Redemption of Preferred Stock										993,442
Unamortized Loss on Reacquired Debt Expense										9,936,729
Unamortized Debt Discount										1,889,616
Unamortized Issuance Cost of Debt										5,694,105
Total CECONY				10,724,650,000					5.17%	554,558,607

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
LONG TERM DEBT
Forecast - Rate Year Ended December 31, 2015

CECONY		Issue Date	Maturity Date	Amount Outstanding	Original Issue Amount	Premium or Discount	Expense of Issuance	Net Proceeds	Cost of Debt	Annual Cost
Debentures:										
2003 Series A	5.8750%	4/7/03	04/01/33	175,000,000	175,000,000	(1,022,000)	1,662,326	172,315,674	5.97%	10,281,250
2003 Series C	5.1000%	6/10/03	06/15/33	200,000,000	200,000,000	(336,000)	1,866,135	197,797,865	5.16%	10,200,000
2004 Series B	5.7000%	2/9/04	02/01/34	200,000,000	200,000,000	(538,000)	1,864,406	197,597,594	5.77%	11,400,000
2005 Series A	5.3000%	3/7/05	03/01/35	350,000,000	350,000,000	(1,193,500)	3,541,534	345,264,966	5.37%	18,550,000
2005 Series B	5.2500%	6/20/05	07/01/35	125,000,000	125,000,000	(731,250)	1,142,914	123,125,836	5.33%	6,562,500
2005 Series C	5.3750%	11/14/05	12/15/15	335,416,667	350,000,000	(805,000)	2,476,451	346,718,549	5.43%	18,028,646
2006 Series A	5.8500%	3/6/06	03/15/36	400,000,000	400,000,000	(60,000)	3,616,500	396,323,500	5.90%	23,400,000
2006 Series B	6.2000%	6/13/06	06/15/36	400,000,000	400,000,000	(756,000)	3,669,000	395,575,000	6.27%	24,800,000
2006 Series C	5.5000%	9/20/06	09/15/16	400,000,000	400,000,000	(1,540,000)	2,777,637	395,682,363	5.56%	22,000,000
2006 Series D	5.3000%	11/28/06	12/01/16	250,000,000	250,000,000	(710,000)	1,700,000	247,590,000	5.35%	13,250,000
2006 Series E	5.7000%	11/28/06	12/01/36	250,000,000	250,000,000	(712,500)	2,262,500	247,025,000	5.77%	14,250,000
2007 Series A	6.3000%	8/23/07	08/15/37	525,000,000	525,000,000	(2,924,250)	4,751,250	517,324,500	6.39%	33,075,000
2008 Series A	5.8500%	4/1/08	04/01/18	600,000,000	600,000,000	(264,000)	4,099,750	595,636,250	5.89%	35,100,000
2008 Series B	6.7500%	4/1/08	04/01/38	600,000,000	600,000,000	(1,758,000)	5,449,750	592,792,250	6.83%	40,500,000
2008 Series C	7.1250%	12/2/08	12/01/18	600,000,000	600,000,000	(2,148,000)	3,962,633	593,889,367	7.20%	42,750,000
2009 Series B	6.6500%	3/23/09	04/01/19	475,000,000	475,000,000	(693,500)	3,284,067	471,022,433	6.71%	31,587,500
2009 Series C	5.5000%	12/2/09	12/01/39	600,000,000	600,000,000	(2,268,000)	5,673,813	592,058,187	5.57%	33,000,000
2010 Series A	4.4500%	6/2/10	06/15/20	350,000,000	350,000,000	(759,500)	2,518,935	346,721,565	4.49%	15,575,000
2010 Series B	5.7000%	6/2/10	06/15/40	350,000,000	350,000,000	(1,701,000)	3,306,369	344,992,631	5.78%	19,950,000
2012 Series A	4.2000%	3/13/12	03/15/42	400,000,000	400,000,000	(1,424,000)	4,222,549	394,353,451	4.26%	16,800,000
2013 Series A	3.9500%	2/28/13	03/01/43	700,000,000	700,000,000	(4,872,000)	7,204,815	687,923,185	4.02%	27,650,000
2013 Series B	4.4500%	8/1/13	08/01/43	420,000,000	420,000,000	(1,386,000)	4,305,000	414,309,000	4.51%	18,690,000
2014 Series A	4.7000%	3/1/14	03/01/44	580,000,000	580,000,000	(2,778,200)	5,945,000	571,276,800	4.77%	27,260,000
2014 Series B	4.7000%	6/2/14	06/15/44	600,000,000	600,000,000	(2,880,000)	6,150,000	590,970,000	4.77%	28,200,000
2015 Series A	5.3000%	3/1/15	03/01/45	500,000,000	600,000,000	(2,688,000)	6,150,000	591,162,000	5.38%	26,500,000
2015 Series B	5.3000%	12/1/15	12/01/45	39,166,667	470,000,000	(2,105,600)	4,817,500	463,076,900	5.38%	2,075,833
				10,424,583,334	10,970,000,000	(39,054,300)	98,420,834	10,832,524,866	5.28%	571,435,729
Tax Exempt Debt Issue through New York State										
1999 Series A	VAR	7/10/01	05/01/34	292,700,000	292,700,000	-	4,577,677	288,122,323	1.35%	3,951,450
2010 Series A	VAR	11/9/10	06/01/36	224,600,000	224,600,000	-	4,803,976	219,796,024	0.77%	1,729,420
2001 Series B	VAR	10/18/01	10/01/36	98,000,000	98,000,000	-	1,169,324	96,830,676	1.35%	1,323,000
2004 Series A	VAR	1/22/04	01/01/39	98,325,000	98,325,000	-	1,534,332	96,790,668	1.35%	1,327,388
2004 Series B1	VAR	1/22/04	05/01/32	127,225,000	127,225,000	-	1,985,912	125,239,088	1.35%	1,717,538
2004 Series B2	VAR	1/22/04	10/01/35	19,750,000	19,750,000	-	307,066	19,442,934	1.35%	266,625
2004 Series C	VAR	11/5/04	11/01/39	99,000,000	99,000,000	-	1,834,951	97,165,049	0.77%	762,300
2005 Series A	VAR	5/19/05	05/01/39	126,300,000	126,300,000	-	1,842,329	124,457,671	0.77%	972,510
				1,085,900,000	1,085,900,000	-	18,055,567	1,067,844,433	1.11%	12,050,230
Subtotals				11,510,483,334	12,055,900,000	(39,054,300)	116,476,402	11,900,369,298	4.90%	583,485,959
Redemption of Preferred Stock										993,442
Unamortized Loss on Reacquired Debt Expense										9,936,729
Unamortized Debt Discount										2,025,566
Unamortized Issuance Cost of Debt										5,996,764
Total CECONY				11,510,483,334					5.23%	602,438,461

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
LONG TERM DEBT
Forecast - Rate Year Ended December 31, 2016

CECONY		Issue Date	Maturity Date	Amount Outstanding	Original Issue Amount	Premium or Discount	Expense of Issuance	Net Proceeds	Cost of Debt	Annual Cost
Debentures:										
2003 Series A	5.8750%	4/7/03	04/01/33	175,000,000	175,000,000	(1,022,000)	1,662,326	172,315,674	5.97%	10,281,250
2003 Series C	5.1000%	6/10/03	06/15/33	200,000,000	200,000,000	(336,000)	1,866,135	197,797,865	5.16%	10,200,000
2004 Series B	5.7000%	2/9/04	02/01/34	200,000,000	200,000,000	(538,000)	1,864,406	197,597,594	5.77%	11,400,000
2005 Series A	5.3000%	3/7/05	03/01/35	350,000,000	350,000,000	(1,193,500)	3,541,534	345,264,966	5.37%	18,550,000
2005 Series B	5.2500%	6/20/05	07/01/35	125,000,000	125,000,000	(731,250)	1,142,914	123,125,836	5.33%	6,562,500
2006 Series A	5.8500%	3/6/06	03/15/36	400,000,000	400,000,000	(60,000)	3,616,500	396,323,500	5.90%	23,400,000
2006 Series B	6.2000%	6/13/06	06/15/36	400,000,000	400,000,000	(756,000)	3,669,000	395,575,000	6.27%	24,800,000
2006 Series C	5.5000%	9/20/06	09/15/16	316,666,667	400,000,000	(1,540,000)	2,777,637	395,682,363	4.40%	17,416,667
2006 Series D	5.3000%	11/28/06	12/01/16	229,166,667	250,000,000	(710,000)	1,700,000	247,590,000	4.91%	12,145,833
2006 Series E	5.7000%	11/28/06	12/01/36	250,000,000	250,000,000	(712,500)	2,262,500	247,025,000	5.77%	14,250,000
2007 Series A	6.3000%	8/23/07	08/15/37	525,000,000	525,000,000	(2,924,250)	4,751,250	517,324,500	6.39%	33,075,000
2008 Series A	5.8500%	4/1/08	04/01/18	600,000,000	600,000,000	(264,000)	4,099,750	595,636,250	5.89%	35,100,000
2008 Series B	6.7500%	4/1/08	04/01/38	600,000,000	600,000,000	(1,758,000)	5,449,750	592,792,250	6.83%	40,500,000
2008 Series C	7.1250%	12/2/08	12/01/18	600,000,000	600,000,000	(2,148,000)	3,962,633	593,889,367	7.20%	42,750,000
2009 Series B	6.6500%	3/23/09	04/01/19	475,000,000	475,000,000	(693,500)	3,284,067	471,022,433	6.71%	31,587,500
2009 Series C	5.5000%	12/2/09	12/01/39	600,000,000	600,000,000	(2,268,000)	5,673,813	592,058,187	5.57%	33,000,000
2010 Series A	4.4500%	6/2/10	06/15/20	350,000,000	350,000,000	(759,500)	2,518,935	346,721,565	4.49%	15,575,000
2010 Series B	5.7000%	6/2/10	06/15/40	350,000,000	350,000,000	(1,701,000)	3,306,369	344,992,631	5.78%	19,950,000
2012 Series A	4.2000%	3/13/12	03/15/42	400,000,000	400,000,000	(1,424,000)	4,222,549	394,353,451	4.26%	16,800,000
2013 Series A	3.9500%	2/28/13	03/01/43	700,000,000	700,000,000	(4,872,000)	7,204,815	687,923,185	4.02%	27,650,000
2013 Series B	4.4500%	8/1/13	08/01/43	420,000,000	420,000,000	(1,386,000)	4,305,000	414,309,000	4.51%	18,690,000
2014 Series A	4.7000%	3/1/14	03/01/44	580,000,000	580,000,000	(2,778,200)	5,945,000	571,276,800	4.77%	27,260,000
2014 Series B	4.7000%	6/2/14	06/15/44	600,000,000	600,000,000	(2,880,000)	6,150,000	590,970,000	4.77%	28,200,000
2015 Series A	5.3000%	3/1/15	03/01/45	600,000,000	600,000,000	(2,688,000)	6,150,000	591,162,000	5.38%	31,800,000
2015 Series B	5.3000%	12/1/15	12/01/45	470,000,000	470,000,000	(2,105,600)	4,817,500	463,076,900	5.38%	24,910,000
2016 Series A	5.9000%	3/1/16	03/01/46	666,666,667	800,000,000	(3,352,000)	8,200,000	788,448,000	5.99%	39,333,333
2016 Series B	5.9000%	12/1/16	12/01/46	41,666,667	500,000,000	(2,095,000)	5,125,000	492,780,000	5.99%	2,458,333
				11,224,166,667	11,920,000,000	(43,696,300)	109,269,383	11,767,034,317	5.25%	617,645,416
Tax Exempt Debt Issue through New York State										
1999 Series A	VAR	7/10/01	05/01/34	292,700,000	292,700,000	-	4,577,677	288,122,323	2.94%	8,605,380
2010 Series A	VAR	11/9/10	06/01/36	224,600,000	224,600,000	-	4,803,976	219,796,024	1.68%	3,773,280
2001 Series B	VAR	10/18/01	10/01/36	98,000,000	98,000,000	-	1,169,324	96,830,676	2.94%	2,881,200
2004 Series A	VAR	1/22/04	01/01/39	98,325,000	98,325,000	-	1,534,332	96,790,668	2.94%	2,890,755
2004 Series B1	VAR	1/22/04	05/01/32	127,225,000	127,225,000	-	1,985,912	125,239,088	2.94%	3,740,415
2004 Series B2	VAR	1/22/04	10/01/35	19,750,000	19,750,000	-	307,066	19,442,934	2.94%	580,650
2004 Series C	VAR	11/5/04	11/01/39	99,000,000	99,000,000	-	1,834,951	97,165,049	1.68%	1,663,200
2005 Series A	VAR	5/19/05	05/01/39	126,300,000	126,300,000	-	1,842,329	124,457,671	1.68%	2,121,840
				1,085,900,000	1,085,900,000	-	18,055,567	1,067,844,433	2.42%	26,256,720
Subtotals				12,310,066,667	13,005,900,000	(43,696,300)	127,324,951	12,834,878,749	5.02%	643,902,136
Redemption of Preferred Stock										993,442
Unamortized Loss on Reacquired Debt Expense										9,936,729
Unamortized Debt Discount										2,203,768
Unamortized Debt Expense										6,420,146
Total CECONY				12,310,066,667					5.39%	663,456,222

Consolidated Edison Company of New York, Inc.
Gas Case 13-G-0031
Calculation of Revenue Deferral / Temporary Billing Credit
For the Twelve Months Ending December 31, 2014, December 31, 2015 and December 31, 2016
$ 000's

	Twelve Months Ending				Cumulative
Revenue Requirement	Dec. 31, 2014	Dec. 31, 2015	Dec. 31, 2016		Total
RY - 1	($54,602)	($54,602)	($54,602)		($163,806)
RY - 2	-	38,620	38,620		77,240
RY - 3	-	-	56,838		56,838
Total	$ (54,602)	$ (15,982)	$ 40,856	(a)	$ (29,728)
Annual Bill Changes	$ -	$ -	$ -		$ -
Rate Change to be Deferred	$ (54,602)	$ (15,982)	$ 40,856	(a)	$ (29,728)
Interest on Deferred Balance (b)	(495)	(1,134)	(909)		(2,537)
Net Deferral	$ (55,097)	$ (17,116)	$ 39,947		$ (32,265)

Notes:

(a) If the Company does not file for new rates to be effective January 1, 2017, the RY3 "Temporary Rate Credit" of $40.856 million would expire and base rates would effectively increase by that amount. Deferred over collections of $36.265 million are available to offset a portion of this increase.

(b) Interest will be calculated at the other customer capital rate, which is updated annually. For 2014 the rate is 3.0%. The 3.0% rate was applied to the 2014, 2015, and 2016 average balance for purpose of this illustration.

Consolidated Edison Company of New York, Inc.
Case 13-S-0032
Steam Revenue Requirement
For The Twelve Months Ending December 31, 2014
$ 000's

Operating revenues	Rate Year 1 Forecast	Rate Change	Rate Year 1 With Rate Change
Sales revenues	$ 643,994	$ (22,358)	$ 621,636
Other revenues	97,230	(18)	97,212
Total operating revenues	741,224	(22,376)	718,848
Operating expense			
Fuel	169,057	-	169,057
Other Fuel Charges	1,989		1,989
Operations & maintenance expenses	203,837	-	203,837
Depreciation	76,886	-	76,886
Taxes other than income taxes	130,096	(613)	129,483
Total operating expenses	581,865	(613)	581,252
Operating income before income taxes	159,359	(21,763)	137,596
New York State income taxes	8,486	(1,545)	6,941
Federal income tax	30,558	(7,076)	23,482
Utility operating income	$ 120,314	$ (13,142)	$ 107,173
Rate Base	$ 1,510,530		$ 1,510,530
Rate of Return	7.97%		7.10%

Consolidated Edison Company of New York, Inc.
Case 13-S-0032
Steam Revenue Requirement
For The Twelve Months Ending December 31, 2015
$ 000's

Operating revenues	Rate Year 1 Forecast	Rate Year 2 Revenue/Expense Rate Base Changes	Rate Change	Rate Year 2 With Rate Change
Sales revenues	$ 621,636	$ 6,921	$ 19,784	$ 648,341
Other revenues	97,212	(744)	16	96,483
Total operating revenues	718,848	6,177	19,800	744,824
Operating expense				
Fuel	169,057	4,898	-	173,955
Other Fuel Charges	1,989	79	-	2,068
Operations & maintenance expenses	203,837	1,544	-	205,381
Depreciation	76,886	2,550	-	79,436
Taxes other than income taxes	129,483	8,952	542	138,977
Total operating expenses	581,252	18,023	542	599,817
Operating income before income taxes	137,596	(11,846)	19,258	145,007
New York State income taxes	6,941	(948)	1,367	7,360
Federal income tax	23,482	(2,344)	6,262	27,400
Utility operating income	$ 107,173	$ (8,554)	$ 11,629	$ 110,247
Rate Base	$ 1,510,530	$ 36,580		$ 1,547,110
Rate of Return	7.10%			7.13%

Consolidated Edison Company of New York, Inc.
Case 13-S-0032
Steam Revenue Requirement
For The Twelve Months Ending December 31, 2016
$ 000's

Operating revenues	Rate Year 2 Forecast	Rate Year 3 Revenue/Expense Rate Base Changes	Rate Change	Rate Year 3 With Rate Change
Sales revenues	648,341	12,683	20,270	681,294
Other revenues	96,483	1,728	16	98,227
Total operating revenues	744,824	14,411	20,286	779,521
Operating expense				
Fuel	173,955	12,730	-	186,685
Other Fuel Charges	2,068	192	-	2,260
Operations & maintenance expenses	205,381	(532)	-	204,849
Depreciation	79,436	2,977	-	82,413
Taxes other than income taxes	138,977	11,278	555	150,810
Total operating expenses	599,817	26,645	555	627,017
Operating income before income taxes	145,007	(12,234)	19,731	152,505
New York State income taxes	7,360	(1,071)	1,401	7,690
Federal income tax	27,400	(4,640)	6,416	29,176
Utility operating income	110,247	(6,523)	11,914	115,638
Rate Base	$ 1,547,110	$ 57,202		$ 1,604,312
Rate of Return	7.13%			7.21%

Consolidated Edison Company of New York, Inc.
Case 13-S-0032
Average Steam Rate Base
For The Twelve Months Ending December 31, 2014 and December 31, 2015
$ 000's

	Rate Year 1	Rate Year 2 Changes	Rate Year 2
Utility plant:			
Average Book Cost of Plant	$ 2,228,918	$ 53,781	$ 2,282,699
Non-Interest Bearing CWIP	66,470	23,040	89,510
Average Accumulated Depreciation	(456,219)	(54,836)	(511,055)
Net utility plant	1,839,169	21,985	1,861,154
Rate base additions:			
Working Capital	89,088	1,764	90,851
Unamortized Debt Discount/Premium/Expense	11,254	(725)	10,529
Unamortized Preferred Stock Expense	2,120	(76)	2,044
MTA Surtax - Net of Income Taxes	472	-	472
Rate base additions	102,934	963	103,896
Rate base deductions:			
Deferred Fuel	(4,627)	-	(4,627)
Excess Rate Base Over Capitalization	(21,330)	-	(21,330)
Customer Advances for Construction	(1,474)	-	(1,474)
Rate base deductions	(27,431)	-	(27,431)
Regulatory assets & liabilities (net of income taxes):			
Property Tax Deferrals	(9,168)	3,667	(5,501)
Property Tax Refund	(18,904)	7,561	(11,343)
Interest Rate True-Up (Auction Rate / LTD)	(3,465)	1,386	(2,079)
Carrying Charges - Plant Balances	(1,929)	772	(1,157)
Former Employee / Contractor Settlements	(1,770)	708	(1,062)
Bonus Depreciation - Interest	(8,809)	3,524	(5,285)
Repair Allowance - Interest	(203)	81	(122)
263a Deferred Taxes	(2,655)	1,062	(1,593)
Carrying Cost - SIR Deferred Balances	(120)	48	(72)
World Trade Center	816	(326)	490
Preferred Stock Redemption Savings	(271)	109	(162)
Interference	298	(119)	179
Case 09-S-0794 Deferral	(535)	214	(321)
SIR	5,424	(633)	4,791
Medicare Part D	31	(12)	19
Sale of SO2 Allowances	1,513	(605)	908
Interest on Deferred Balances	1,045	(418)	627
Steam Peak Reduction Collaborative	54	(21)	33
Superstorm Sandy Restoration	3,519	(1,408)	2,111
59th Street Gas Conversion	464	(179)	285
Regulatory deferrals	(34,666)	15,411	(19,255)
Accumulated deferred income taxes			
ADR / ACRS / MACRS Deductions	(303,810)	822	(302,988)
Change of Accounting Section 263A	(37,339)	(1,107)	(38,446)
Repair Allowance	(9,814)	(1,481)	(11,295)
Excess Deferred SIT	(271)		(271)
Vested Vacation	769	-	769
Prepaid Insurance Expenses	(206)	-	(206)
Unbilled Revenues	8,535	-	8,535
Contributions In Aid of Construction	1,793	-	1,793
Deferred State MTA	(1,474)		(1,474)
Capitalized Interest	5,943	-	5,943
Repair & Maintenance Allowance (IRS Audits)	2,142	-	2,142
Deferred S.I.T.	(35,744)	(12)	(35,756)
Accumulated deferred income taxes	(369,476)	(1,778)	(371,254)
Total Rate Base	$ 1,510,530	$ 36,580	$ 1,547,110

Consolidated Edison Company of New York, Inc.
Case 13-S-0032
Average Steam Rate Base
For The Twelve Months Ending December 31, 2016
$ 000's

	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Utility plant:			
Average Book Cost of Plant	$ 2,282,699	$ 79,677	$ 2,362,376
Non-Interest Bearing CWIP	89,510	19,267	108,777
Average Accumulated Depreciation	(511,055)	(58,865)	(569,920)
Net utility plant	1,861,154	40,079	1,901,233
Rate base additions:			
Working Capital	90,851	4,248	95,099
Unamortized Debt Discount/Premium/Expense	10,529	(518)	10,011
Unamortized Preferred Stock Expense	2,044	(76)	1,968
MTA Surtax - Net of Income Taxes	472	-	472
Rate base additions	103,896	3,654	107,550
Rate base deductions:			
Deferred Fuel	(4,627)	-	(4,627)
Excess Rate Base Over Capitalization	(21,330)	-	(21,330)
Customer Advances for Construction	(1,474)	-	(1,474)
Rate base deductions	(27,431)	-	(27,431)
Regulatory assets & liabilities (net of income taxes):			
Property Tax Deferrals	(5,501)	3,667	(1,834)
Property Tax Refund	(11,343)	7,561	(3,782)
Interest Rate True-Up (Auction Rate / LTD)	(2,079)	1,386	(693)
Carrying Charges - Plant Balances	(1,157)	772	(385)
Former Employee / Contractor Settlements	(1,062)	708	(354)
Bonus Depreciation - Interest	(5,285)	3,524	(1,761)
Repair Allowance - Interest	(122)	81	(41)
263a Deferred Taxes	(1,593)	1,062	(531)
Carrying Cost - SIR Deferred Balances	(72)	48	(24)
World Trade Center	490	(326)	164
Preferred Stock Redemption Savings	(162)	109	(53)
Interference	179	(119)	60
Case 09-S-0794 Deferral	(321)	214	(107)
SIR	4,791	513	5,304
Medicare Part D	19	(13)	6
Sale of SO2 Allowances	908	(605)	303
Interest on Deferred Balances	627	(418)	209
Steam Peak Reduction Collaborative	33	(22)	11
Superstorm Sandy Restoration	2,111	(1,407)	704
59th Street Gas Conversion	285	(192)	93
Regulatory deferrals	(19,255)	16,543	(2,712)
Accumulated deferred income taxes			
ADR / ACRS / MACRS Deductions	(302,988)	(304)	(303,293)
Change of Accounting Section 263A	(38,446)	(1,039)	(39,485)
Repair Allowance	(11,295)	(1,717)	(13,012)
Excess Deferred SIT	(271)		(271)
Vested Vacation	769		769
Prepaid Insurance Expenses	(206)	-	(206)
Unbilled Revenues	8,535	-	8,535
Contributions In Aid of Construction	1,793	-	1,793
Deferred State MTA	(1,474)	-	(1,474)
Capitalized Interest	5,943		5,943
Repair & Maintenance Allowance (IRS Audits)	2,142	-	2,142
Deferred S.I.T.	(35,756)	(14)	(35,770)
Accumulated deferred income taxes	(371,254)	(3,074)	(374,328)
Total Rate Base	$ 1,547,110	$ 57,202	$ 1,604,312

Consolidated Edison Company of New York, Inc.
Steam Case 13-S-0032
Average Capital Structure & Cost of Money
For the Twelve Months Ending December 31, 2014, December 31, 2015 and December 31, 2016

RY 1

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre Tax Cost %
Long term debt	50.54%	5.17%	2.61%	2.61%
Customer deposits	1.46%	1.25%	0.02%	0.02%
Subtotal	52.00%		2.63%	2.63%
Common Equity	48.00%	9.30%	4.46%	7.39%
Total	100.00%		7.10%	10.02%

RY 2

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre Tax Cost %
Long term debt	50.56%	5.23%	2.64%	2.64%
Customer deposits	1.44%	1.25%	0.02%	0.02%
Subtotal	52.00%		2.66%	2.66%
Common Equity	48.00%	9.30%	4.46%	7.39%
Total	100.00%		7.13%	10.06%

RY 3

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre Tax Cost %
Long term debt	50.58%	5.39%	2.73%	2.73%
Customer deposits	1.42%	1.25%	0.02%	0.02%
Subtotal	52.00%		2.74%	2.74%
Common Equity	48.00%	9.30%	4.46%	7.39%
Total	100.00%		7.21%	10.14%

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
LONG TERM DEBT
Forecast - Rate Year Ended December 31, 2014

CECONY		Issue Date	Maturity Date	Amount Outstanding	Original Issue Amount	Premium or Discount	Expense of Issuance	Net Proceeds	Cost of Debt	Annual Cost
Debentures:										
2003 Series A	5.8750%	4/7/03	04/01/33	175,000,000	175,000,000	(1,022,000)	1,662,326	172,315,674	5.97%	10,281,250
2003 Series C	5.1000%	6/10/03	06/15/33	200,000,000	200,000,000	(336,000)	1,866,135	197,797,865	5.16%	10,200,000
2004 Series A	4.7000%	2/9/04	02/01/14	16,666,667	200,000,000	(360,000)	1,414,406	198,225,594	4.74%	783,333
2004 Series B	5.7000%	2/9/04	02/01/34	200,000,000	200,000,000	(538,000)	1,864,406	197,597,594	5.77%	11,400,000
2005 Series A	5.3000%	3/7/05	03/01/35	350,000,000	350,000,000	(1,193,500)	3,541,534	345,264,966	5.37%	18,550,000
2005 Series B	5.2500%	6/20/05	07/01/35	125,000,000	125,000,000	(731,250)	1,142,914	123,125,836	5.33%	6,562,500
2005 Series C	5.3750%	11/14/05	12/15/15	350,000,000	350,000,000	(805,000)	2,476,451	346,718,549	5.43%	18,812,500
2006 Series A	5.8500%	3/6/06	03/15/36	400,000,000	400,000,000	(60,000)	3,616,500	396,323,500	5.90%	23,400,000
2006 Series B	6.2000%	6/13/06	06/15/36	400,000,000	400,000,000	(756,000)	3,669,000	395,575,000	6.27%	24,800,000
2006 Series C	5.5000%	9/20/06	09/15/16	400,000,000	400,000,000	(1,540,000)	2,777,637	395,682,363	5.56%	22,000,000
2006 Series D	5.3000%	11/28/06	12/01/16	250,000,000	250,000,000	(710,000)	1,700,000	247,590,000	5.35%	13,250,000
2006 Series E	5.7000%	11/28/06	12/01/36	250,000,000	250,000,000	(712,500)	2,262,500	247,025,000	5.77%	14,250,000
2007 Series A	6.3000%	8/23/07	08/15/37	525,000,000	525,000,000	(2,924,250)	4,751,250	517,324,500	6.39%	33,075,000
2008 Series A	5.8500%	4/1/08	04/01/18	600,000,000	600,000,000	(264,000)	4,099,750	595,636,250	5.89%	35,100,000
2008 Series B	6.7500%	4/1/08	04/01/38	600,000,000	600,000,000	(1,758,000)	5,449,750	592,792,250	6.83%	40,500,000
2008 Series C	7.1250%	12/2/08	12/01/18	600,000,000	600,000,000	(2,148,000)	3,962,633	593,889,367	7.20%	42,750,000
2009 Series A	5.5500%	3/23/09	04/01/14	68,750,000	275,000,000	(217,250)	1,793,234	272,989,516	1.40%	3,815,625
2009 Series B	6.6500%	3/23/09	04/01/19	475,000,000	475,000,000	(693,500)	3,284,067	471,022,433	6.71%	31,587,500
2009 Series C	5.5000%	12/2/09	12/01/39	600,000,000	600,000,000	(2,268,000)	5,673,813	592,058,187	5.57%	33,000,000
2010 Series A	4.4500%	6/2/10	06/15/20	350,000,000	350,000,000	(759,500)	2,518,935	346,721,565	4.49%	15,575,000
2010 Series B	5.7000%	6/2/10	06/15/40	350,000,000	350,000,000	(1,701,000)	3,306,369	344,992,631	5.78%	19,950,000
2012 Series A	4.2000%	3/13/12	03/15/42	400,000,000	400,000,000	(1,424,000)	4,222,549	394,353,451	4.26%	16,800,000
2013 Series A	3.9500%	2/28/13	03/01/43	700,000,000	700,000,000	(4,872,000)	7,204,815	687,923,185	4.02%	27,650,000
2013 Series B	4.4500%	8/1/13	08/01/43	420,000,000	420,000,000	(1,386,000)	4,305,000	414,309,000	4.51%	18,690,000
2014 Series A	4.7000%	3/1/14	03/01/44	483,333,333	580,000,000	(2,778,200)	5,945,000	571,276,800	4.77%	22,716,667
2014 Series B	4.7000%	6/2/14	06/15/44	350,000,000	600,000,000	(2,880,000)	6,150,000	590,970,000	4.77%	16,450,000
				9,638,750,000	10,375,000,000	(34,837,950)	90,660,974	10,249,501,076	5.19%	531,949,375
Tax Exempt Debt Issue through New York State										
1999 Series A	VAR	7/10/01	05/01/34	292,700,000	292,700,000	-	4,577,677	288,122,323	0.46%	1,346,420
2010 Series A	VAR	11/9/10	06/01/36	224,600,000	224,600,000	-	4,803,976	219,796,024	0.26%	583,960
2001 Series B	VAR	10/18/01	10/01/36	98,000,000	98,000,000	-	1,169,324	96,830,676	0.46%	450,800
2004 Series A	VAR	1/22/04	01/01/39	98,325,000	98,325,000	-	1,534,332	96,790,668	0.46%	452,295
2004 Series B1	VAR	1/22/04	05/01/32	127,225,000	127,225,000	-	1,985,912	125,239,088	0.46%	585,235
2004 Series B2	VAR	1/22/04	10/01/35	19,750,000	19,750,000	-	307,066	19,442,934	0.46%	90,850
2004 Series C	VAR	11/5/04	11/01/39	99,000,000	99,000,000	-	1,834,951	97,165,049	0.26%	257,400
2005 Series A	VAR	5/19/05	05/01/39	126,300,000	126,300,000	-	1,842,329	124,457,671	0.26%	328,380
				1,085,900,000	1,085,900,000	-	18,055,567	1,067,844,433	0.38%	4,095,340
Subtotals				10,724,650,000	11,460,900,000	(34,837,950)	108,716,542	11,317,345,508	4.74%	536,044,715
Redemption of Preferred Stock										993,442
Unamortized Loss on Reacquired Debt Expense										9,936,729
Unamortized Debt Discount										1,889,616
Unamortized Issuance Cost of Debt										5,694,105
Total CECONY				10,724,650,000					5.17%	554,558,607

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
LONG TERM DEBT
Forecast - Rate Year Ended December 31, 2015

CECONY		Issue Date	Maturity Date	Amount Outstanding	Original Issue Amount	Premium or Discount	Expense of Issuance	Net Proceeds	Cost of Debt	Annual Cost
Debentures:										
2003 Series A	5.8750%	4/7/03	04/01/33	175,000,000	175,000,000	(1,022,000)	1,662,326	172,315,674	5.97%	10,281,250
2003 Series C	5.1000%	6/10/03	06/15/33	200,000,000	200,000,000	(336,000)	1,866,135	197,797,865	5.16%	10,200,000
2004 Series B	5.7000%	2/9/04	02/01/34	200,000,000	200,000,000	(538,000)	1,864,406	197,597,594	5.77%	11,400,000
2005 Series A	5.3000%	3/7/05	03/01/35	350,000,000	350,000,000	(1,193,500)	3,541,534	345,264,966	5.37%	18,550,000
2005 Series B	5.2500%	6/20/05	07/01/35	125,000,000	125,000,000	(731,250)	1,142,914	123,125,836	5.33%	6,562,500
2005 Series C	5.3750%	11/14/05	12/15/15	335,416,667	350,000,000	(805,000)	2,476,451	346,718,549	5.43%	18,028,646
2006 Series A	5.8500%	3/6/06	03/15/36	400,000,000	400,000,000	(60,000)	3,616,500	396,323,500	5.90%	23,400,000
2006 Series B	6.2000%	6/13/06	06/15/36	400,000,000	400,000,000	(756,000)	3,669,000	395,575,000	6.27%	24,800,000
2006 Series C	5.5000%	9/20/06	09/15/16	400,000,000	400,000,000	(1,540,000)	2,777,637	395,682,363	5.56%	22,000,000
2006 Series D	5.3000%	11/28/06	12/01/16	250,000,000	250,000,000	(710,000)	1,700,000	247,590,000	5.35%	13,250,000
2006 Series E	5.7000%	11/28/06	12/01/36	250,000,000	250,000,000	(712,500)	2,262,500	247,025,000	5.77%	14,250,000
2007 Series A	6.3000%	8/23/07	08/15/37	525,000,000	525,000,000	(2,924,250)	4,751,250	517,324,500	6.39%	33,075,000
2008 Series A	5.8500%	4/1/08	04/01/18	600,000,000	600,000,000	(264,000)	4,099,750	595,636,250	5.89%	35,100,000
2008 Series B	6.7500%	4/1/08	04/01/38	600,000,000	600,000,000	(1,758,000)	5,449,750	592,792,250	6.83%	40,500,000
2008 Series C	7.1250%	12/2/08	12/01/18	600,000,000	600,000,000	(2,148,000)	3,962,633	593,889,367	7.20%	42,750,000
2009 Series B	6.6500%	3/23/09	04/01/19	475,000,000	475,000,000	(693,500)	3,284,067	471,022,433	6.71%	31,587,500
2009 Series C	5.5000%	12/2/09	12/01/39	600,000,000	600,000,000	(2,268,000)	5,673,813	592,058,187	5.57%	33,000,000
2010 Series A	4.4500%	6/2/10	06/15/20	350,000,000	350,000,000	(759,500)	2,518,935	346,721,565	4.49%	15,575,000
2010 Series B	5.7000%	6/2/10	06/15/40	350,000,000	350,000,000	(1,701,000)	3,306,369	344,992,631	5.78%	19,950,000
2012 Series A	4.2000%	3/13/12	03/15/42	400,000,000	400,000,000	(1,424,000)	4,222,549	394,353,451	4.26%	16,800,000
2013 Series A	3.9500%	2/28/13	03/01/43	700,000,000	700,000,000	(4,872,000)	7,204,815	687,923,185	4.02%	27,650,000
2013 Series B	4.4500%	8/1/13	08/01/43	420,000,000	420,000,000	(1,386,000)	4,305,000	414,309,000	4.51%	18,690,000
2014 Series A	4.7000%	3/1/14	03/01/44	580,000,000	580,000,000	(2,778,200)	5,945,000	571,276,800	4.77%	27,260,000
2014 Series B	4.7000%	6/2/14	06/15/44	600,000,000	600,000,000	(2,880,000)	6,150,000	590,970,000	4.77%	28,200,000
2015 Series A	5.3000%	3/1/15	03/01/45	500,000,000	600,000,000	(2,688,000)	6,150,000	591,162,000	5.38%	26,500,000
2015 Series B	5.3000%	12/1/15	12/01/45	39,166,667	470,000,000	(2,105,600)	4,817,500	463,076,900	5.38%	2,075,833
				10,424,583,334	10,970,000,000	(39,054,300)	98,420,834	10,832,524,866	5.28%	571,435,729
Tax Exempt Debt Issue through New York State										
1999 Series A	VAR	7/10/01	05/01/34	292,700,000	292,700,000	-	4,577,677	288,122,323	1.35%	3,951,450
2010 Series A	VAR	11/9/10	06/01/36	224,600,000	224,600,000	-	4,803,976	219,796,024	0.77%	1,729,420
2001 Series B	VAR	10/18/01	10/01/36	98,000,000	98,000,000	-	1,169,324	96,830,676	1.35%	1,323,000
2004 Series A	VAR	1/22/04	01/01/39	98,325,000	98,325,000	-	1,534,332	96,790,668	1.35%	1,327,388
2004 Series B1	VAR	1/22/04	05/01/32	127,225,000	127,225,000	-	1,985,912	125,239,088	1.35%	1,717,538
2004 Series B2	VAR	1/22/04	10/01/35	19,750,000	19,750,000	-	307,066	19,442,934	1.35%	266,625
2004 Series C	VAR	11/5/04	11/01/39	99,000,000	99,000,000	-	1,834,951	97,165,049	0.77%	762,300
2005 Series A	VAR	5/19/05	05/01/39	126,300,000	126,300,000	-	1,842,329	124,457,671	0.77%	972,510
				1,085,900,000	1,085,900,000	-	18,055,567	1,067,844,433	1.11%	12,050,230
Subtotals				11,510,483,334	12,055,900,000	(39,054,300)	116,476,402	11,900,369,298	4.90%	583,485,959
Redemption of Preferred Stock										993,442
Unamortized Loss on Reacquired Debt Expense										9,936,729
Unamortized Debt Discount										2,025,566
Unamortized Issuance Cost of Debt										5,996,764
Total CECONY				11,510,483,334					5.23%	602,438,461

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
LONG TERM DEBT
Forecast - Rate Year Ended December 31, 2016

CECONY		Issue Date	Maturity Date	Amount Outstanding	Original Issue Amount	Premium or Discount	Expense of Issuance	Net Proceeds	Cost of Debt	Annual Cost
Debentures:										
2003 Series A	5.8750%	4/7/03	04/01/33	175,000,000	175,000,000	(1,022,000)	1,662,326	172,315,674	5.97%	10,281,250
2003 Series C	5.1000%	6/10/03	06/15/33	200,000,000	200,000,000	(336,000)	1,866,135	197,797,865	5.16%	10,200,000
2004 Series B	5.7000%	2/9/04	02/01/34	200,000,000	200,000,000	(538,000)	1,864,406	197,597,594	5.77%	11,400,000
2005 Series A	5.3000%	3/7/05	03/01/35	350,000,000	350,000,000	(1,193,500)	3,541,534	345,264,966	5.37%	18,550,000
2005 Series B	5.2500%	6/20/05	07/01/35	125,000,000	125,000,000	(731,250)	1,142,914	123,125,836	5.33%	6,562,500
2006 Series A	5.8500%	3/6/06	03/15/36	400,000,000	400,000,000	(60,000)	3,616,500	396,323,500	5.90%	23,400,000
2006 Series B	6.2000%	6/13/06	06/15/36	400,000,000	400,000,000	(756,000)	3,669,000	395,575,000	6.27%	24,800,000
2006 Series C	5.5000%	9/20/06	09/15/16	316,666,667	400,000,000	(1,540,000)	2,777,637	395,682,363	4.40%	17,416,667
2006 Series D	5.3000%	11/28/06	12/01/16	229,166,667	250,000,000	(710,000)	1,700,000	247,590,000	4.91%	12,145,833
2006 Series E	5.7000%	11/28/06	12/01/36	250,000,000	250,000,000	(712,500)	2,262,500	247,025,000	5.77%	14,250,000
2007 Series A	6.3000%	8/23/07	08/15/37	525,000,000	525,000,000	(2,924,250)	4,751,250	517,324,500	6.39%	33,075,000
2008 Series A	5.8500%	4/1/08	04/01/18	600,000,000	600,000,000	(264,000)	4,099,750	595,636,250	5.89%	35,100,000
2008 Series B	6.7500%	4/1/08	04/01/38	600,000,000	600,000,000	(1,758,000)	5,449,750	592,792,250	6.83%	40,500,000
2008 Series C	7.1250%	12/2/08	12/01/18	600,000,000	600,000,000	(2,148,000)	3,962,633	593,889,367	7.20%	42,750,000
2009 Series B	6.6500%	3/23/09	04/01/19	475,000,000	475,000,000	(693,500)	3,284,067	471,022,433	6.71%	31,587,500
2009 Series C	5.5000%	12/2/09	12/01/39	600,000,000	600,000,000	(2,268,000)	5,673,813	592,058,187	5.57%	33,000,000
2010 Series A	4.4500%	6/2/10	06/15/20	350,000,000	350,000,000	(759,500)	2,518,935	346,721,565	4.49%	15,575,000
2010 Series B	5.7000%	6/2/10	06/15/40	350,000,000	350,000,000	(1,701,000)	3,306,369	344,992,631	5.78%	19,950,000
2012 Series A	4.2000%	3/13/12	03/15/42	400,000,000	400,000,000	(1,424,000)	4,222,549	394,353,451	4.26%	16,800,000
2013 Series A	3.9500%	2/28/13	03/01/43	700,000,000	700,000,000	(4,872,000)	7,204,815	687,923,185	4.02%	27,650,000
2013 Series B	4.4500%	8/1/13	08/01/43	420,000,000	420,000,000	(1,386,000)	4,305,000	414,309,000	4.51%	18,690,000
2014 Series A	4.7000%	3/1/14	03/01/44	580,000,000	580,000,000	(2,778,200)	5,945,000	571,276,800	4.77%	27,260,000
2014 Series B	4.7000%	6/2/14	06/15/44	600,000,000	600,000,000	(2,880,000)	6,150,000	590,970,000	4.77%	28,200,000
2015 Series A	5.3000%	3/1/15	03/01/45	600,000,000	600,000,000	(2,688,000)	6,150,000	591,162,000	5.38%	31,800,000
2015 Series B	5.3000%	12/1/15	12/01/45	470,000,000	470,000,000	(2,105,600)	4,817,500	463,076,900	5.38%	24,910,000
2016 Series A	5.9000%	3/1/16	03/01/46	666,666,667	800,000,000	(3,352,000)	8,200,000	788,448,000	5.99%	39,333,333
2016 Series B	5.9000%	12/1/16	12/01/46	41,666,667	500,000,000	(2,095,000)	5,125,000	492,780,000	5.99%	2,458,333
				11,224,166,667	11,920,000,000	(43,696,300)	109,269,383	11,767,034,317	5.25%	617,645,416
Tax Exempt Debt Issue through New York State										
1999 Series A	VAR	7/10/01	05/01/34	292,700,000	292,700,000	-	4,577,677	288,122,323	2.94%	8,605,380
2010 Series A	VAR	11/9/10	06/01/36	224,600,000	224,600,000	-	4,803,976	219,796,024	1.68%	3,773,280
2001 Series B	VAR	10/18/01	10/01/36	98,000,000	98,000,000	-	1,169,324	96,830,676	2.94%	2,881,200
2004 Series A	VAR	1/22/04	01/01/39	98,325,000	98,325,000	-	1,534,332	96,790,668	2.94%	2,890,755
2004 Series B1	VAR	1/22/04	05/01/32	127,225,000	127,225,000	-	1,985,912	125,239,088	2.94%	3,740,415
2004 Series B2	VAR	1/22/04	10/01/35	19,750,000	19,750,000	-	307,066	19,442,934	2.94%	580,650
2004 Series C	VAR	11/5/04	11/01/39	99,000,000	99,000,000	-	1,834,951	97,165,049	1.68%	1,663,200
2005 Series A	VAR	5/19/05	05/01/39	126,300,000	126,300,000	-	1,842,329	124,457,671	1.68%	2,121,840
				1,085,900,000	1,085,900,000	-	18,055,567	1,067,844,433	2.42%	26,256,720
Subtotals				12,310,066,667	13,005,900,000	(43,696,300)	127,324,951	12,834,878,749	5.02%	643,902,136
Redemption of Preferred Stock										993,442
Unamortized Loss on Reacquired Debt Expense										9,936,729
Unamortized Debt Discount										2,203,768
Unamortized Debt Expense										6,420,146
Total CECONY				12,310,066,667					5.39%	663,456,222

Consolidated Edison Company of New York, Inc.
Steam Case 13-S-0032
Calculation of Revenue Deferral / Temporary Billing Credit
For the Twelve Months Ending December 31, 2014, December 31, 2015 and December 31, 2016
$ 000's

	Twelve Months Ending				Cumulative
Revenue Requirement	Dec. 31, 2014	Dec. 31, 2015	Dec. 31, 2016		Total
RY - 1	($22,358)	($22,358)	($22,358)		($67,074)
RY - 2	-	19,784	19,784		39,568
RY - 3	-	-	20,270		20,270
Total	$ (22,358)	$ (2,574)	$ 17,696	(a)	$ (7,236)
Annual Bill Changes	$ -	$ -	$ -		$ -
Rate Change to be Deferred	$ (22,358)	$ (2,574)	$ 17,696	(a)	$ (7,236)
Interest on Deferred Balance (b)	(203)	(428)	(291)		(922)
Net Deferral	$ (22,561)	$ (3,002)	$ 17,405		$ (8,158)

Notes:

(a) If the Company does not file for new rates to be effective January 1, 2017, the RY3 "Temporary Rate Credit" of $17.696 million would expire and base rates would effectively increase by that amount. Deferred overcollections of $8.158 million are available to offset a portion of this increase.

(b) Interest will be calculated at the other customer capital rate, which is updated annually. For 2014 the rate is 3.0%. The 3.0% rate was applied to the 2014, 2015, and 2016 average balance for purpose of this illustration.

Consolidated Edison Company of New York, Inc.
Electric Case 13-E-0030
Amortization of Regulatory Deferrals
($000's)

	RY1	RY 2	12 months ending 12/31/2016
Regulatory Assets			
Superstorm Sandy Restoration	$ 81,368	$ 81,368	$ 81,368
SIR	36,275	43,075	49,875
Pensions / OPEBS	27,789	27,789	27,789
Major Storm Charges	26,100	26,100	26,100
T&D Deferral	19,445	19,445	19,445
Medicare Part D	9,359	9,359	9,359
ERRP Spare Parts Maintenance	7,719	7,719	7,719
Smart Grid Demonstration Grant	3,280	3,280	3,280
TSC Revenue	3,198	3,198	3,198
Sale of SO2 Allowances	2,219	2,219	2,219
Nuclear Fuel Litigation	1,706	1,706	1,706
Reactive Power	1,200	1,200	1,200
263a Deferred Taxes	1,105	1,105	1,105
Interest - TSC Revenue	127	127	127
Emergency Demand Response / Demand Reduction Prog.	91	91	91
Gain on Sale of First Avenue Properties	17	17	17
Total Regulatory Assets (a)	$ 220,998	$ 227,798	$ 234,598
Regulatory Liabilities			
Property Tax Deferrals	$ 88,146	$ 88,146	88,146
Property Tax Refunds	31,282	31,282	31,282
Interest Rate True-Up (Auction Rate / LT Debt)	24,870	24,870	24,870
World Trade Center	17,512	17,512	17,512
Customer Cash Flow Benefits Bonus Depr	12,419	12,419	12,419
Carrying Charges (Net Plant Reconciliation)	5,474	5,474	5,474
Verizon Joint Use Poles	5,014	5,014	5,014
Customer Cash Flow Benefits Repair Allowance	4,425	4,425	4,425
Power for Jobs Tax Credit	3,496	3,496	3,496
Interference	2,576	2,576	2,576
Former Employee / Contractor Settlements	2,047	2,047	2,047
Electric Service Reliability Rate Adjustment	1,734	1,734	1,734
Preferred Stock Redemption Savings	1,680	1,680	1,680
Sale of Property - John Street	1,645	1,645	1,645
Carrying Cost - SIR Deferred Balances	1,227	1,227	1,227
Case 09-E-0428 Deferral	872	872	872
Energy Efficiency Program	398	398	398
DC Service Incentive	308	308	308
Reserve for "05-'08" Capital Expenditures	272	272	272
Targeted DSM	195	195	195
Electric - BIR Refunds	112	112	112
Furnace Dock Road Dam	50	50	50
Total Regulatory Liabilities (b)	$ 205,754	$ 205,754	$ 205,754
Net (credits) / debits (a - b)	$ 15,244	$ 22,044	$ 28,844

Consolidated Edison Company of New York, Inc.
Gas Case 13-G-0031
Amortization of Regulatory Deferrals
($000's)

		RY1	RY 2	RY 3
	Regulatory Assets			
1	Pensions / OPEBS	$ 18,669	$ 18,669	$ 18,669
2	SIR	6,749	8,149	9,549
3	Interest on deferred POR	30	30	30
	Total Regulatory Assets (a)	$ 25,448	$ 26,848	$ 28,248
	Regulatory Liabilities			
1	Bonus Depreciation interest	$ 6,029	$ 6,029	$ 6,029
2	World Trade Center	5,775	5,775	5,775
3	Property Tax Deferrals	4,854	4,854	4,854
4	Interest Rate True-up	3,300	3,300	3,300
5	Repair Allowance Interest	2,131	2,131	2,131
6	Former Employee / Contractor Settlements	1,976	1,976	1,976
7	Pipeline integrity	722	722	722
8	Sanford Avenue Gas Explosion	527	527	527
9	Case 09-G-0795 Deferral	493	493	493
10	Penalties on Off-peak / interruptible customers	443	443	443
11	Preferred Stock Redemption Savings	318	318	318
12	Carrying Cost - SIR Deferred Balances	308	308	308
13	Gain on Sale of First Avenue Properties	277	277	277
14	263a Deferred Taxes	221	221	221
15	EEPS	218	218	218
16	Unauthorized Use Charge - Divested Stations	167	167	167
17	Medicare Part D	139	139	139
18	Property Tax Refund	101	101	101
19	Interference	84	84	84
20	Oil to Gas Conversion	47	47	47
21	Interest on deferred balances	7	7	7
	Total Regulatory Liabilities (b)	$ 28,137	$ 28,137	$ 28,137
	Net (credits) / debits (a - b)	$ (2,689)	$ (1,289)	$ 111

Consolidated Edison Company of New York, Inc.
Steam Case 13-S-0032
Amortization of Regulatory Deferrals
($000's)

		RY1	RY 2	RY 3
	Regulatory Assets			
1	Pensions / OPEBS	$ 10,030	$ 10,030	$ 10,030
2	Superstorm Sandy Restoration	2,166	2,166	2,166
3	SIR	1,854	2,295	2,736
4	Sale of SO2 Allowances	931	931	931
5	Interest on deferred balances	643	643	643
6	World Trade Center	502	502	502
7	59th Street Gas Conversion	285	285	285
8	Interference	183	183	183
9	Steam Peak Reduction Collaborative	33	33	33
10	Medicare Part D	20	20	20
	Total Regulatory Assets (a)	$ 16,647	$ 17,088	$ 17,529
	Regulatory Liabilities			
1	NYC Property Tax Refund	$ 11,633	$ 11,633	$ 11,633
2	Property Tax Deferrals	5,642	5,642	5,642
3	Bonus Depreciation - Interest	5,421	5,421	5,421
4	Interest Rate True-Up (Auction Rate / Long Term Debt)	2,132	2,132	2,132
5	263a Deferred Taxes	1,634	1,634	1,634
6	Carrying Charges - Plant balances	1,187	1,187	1,187
7	Former Employee / Contractor Settlements	1,089	1,089	1,089
8	Case 09-S-0794 Deferral	329	329	329
9	Preferred Stock Redemption Savings	167	167	167
10	Repair Allowance - Interest	125	125	125
11	Carrying Cost - SIR Deferred Balances	74	74	74
	Total Regulatory Liabilities (b)	$ 29,433	$ 29,433	$ 29,433
	Net (credits) / debits (a - b)	$ (12,786)	$ (12,345)	$ (11,904)

Consolidated Edison Company of New York

Case 13-E-0030

Electric Delivery Volume and Delivery Revenue

Twelve Months ending December 31, 2014 and December 31, 2015

	Delivery Volume - GWHs Twelve Months ending December 31st	
	2014	2015
Con Edison Customers	47,000	47,119
New York Power Authority	10,241	10,224
Recharge New York	745	745
Total Delivery Volumes	57,986	58,088

	Delivery Revenue at April 1, 2012 Rates - $000s Twelve Months ending December 31st	
Non Competitive	2014	2015
Con Edison Customers*	$4,416,234	$4,437,276
New York Power Authority	567,187	572,893
Recharge New York	36,681	36,681
Reactive Power	$1,045	$1,045
Total Delivery Revenues	$5,021,147	$5,047,895
Competitive		
Billing & Payment Processing	$34,469	$34,655
Metering	17,659	17,794
Merchant Function Charge	65,815	63,981
Sub Total Competitive Delivery Revenues	$117,943	$116,430
Total Delivery Revenues	$5,139,090	$5,164,325

* Excludes Low Income Discounts

Consolidated Edison Company of New York, Inc.
Electric Case 13-E-0030
Other Operating Revenues
($000's)

		RY1 12 months ending 12/31/2014	RY2 Adjustments	RY2 12 months ending 12/31/2015
1	TCC Credits	$ 90,000	$ -	$ 90,000
2	Late Payment Charges *	30,684	(314)	30,370
3	POR Discount	30,061	-	30,061
4	Rent from Electric Property	18,232	(324)	17,908
5	Interdepartmental Rents	15,768	695	16,463
6	Miscellaneous Service Revenues	14,458	304	14,762
7	Transmission of Energy	8,765	-	8,765
8	Transmission Service Revenues	7,000	-	7,000
9	Excess Distribution Facilities	3,312	70	3,382
10	Reserve for "05-'08" Capital Expenditures	3,189	(100)	3,089
11	Maint. of Interconnection Facilities	2,353	49	2,402
12	Sithe Agreement	1,698	(1,698)	-
13	The Learning Center Services	750	16	766
14	KeySpan Settlement Facilities Fee	726	15	741
15	ESCO Funding Fees	490	-	490
16	AreaWide Contract Fees	87	-	87
17	Substation Operation Services	56	-	56
18	Dishonored Check Fees	39	-	39
19	ESCO Internet Daily / Weekly	35	-	35
20	Transmission Netting Credit Adjustment	(259)	-	(259)
21	KeySpan Inside Del Credit	(692)	-	(692)
		$ 226,752	$ (1,287)	$ 225,465

* Includes late payment charges of ($293,000) and $477,000 in RY1 and RY2, respectively, related to revenue decreases and increases that the parties propose to levelize over the term of the Rate Plan.

Consolidated Edison Company of New York, Inc.
Gas Case 13-G-0031
Sales Revenues
$ 000's

	Twelve Months Ending December 31,	RY2 Sales	Twelve Months Ending December 31,	RY 3 Sales	Twelve Months Ending December 31,
Base Revenues (excl GRT)	2014	Gain/(Loss)	2015	Gain/(Loss)	2016
Service Classification 1	172,087	(1,312)	170,775	(1,330)	169,445
Service Classification 2 - Non-Heating	98,546	883	99,429	919	100,348
Service Classification 2 - Heating	169,621	1,429	171,050	1,819	172,868
Service Classification 2 - DG	4,275	2,175	6,450	901	7,351
Service Classification 2 - Contract	653	-	653	-	653
Service Classification 3	471,461	19,729	491,190	19,836	511,026
Service Classification 13	297	-	297	-	297
Service Classification 14	329	-	329	-	329
Service Classification 12 R2	12,779	-	12,779	45	12,824
NYPA Demand	3,096	-	3,096	-	3,096
Non-Firm Revenue Retained	65,000	-	65,000	-	65,000
Subtotal	998,143	22,904	1,021,047	22,189	1,043,236
Low Income Discount Adj.	1,299		1,299		1,299
Other Surcharges					
BPP	6,811	17	6,828	18	6,846
MFC - Supply	9,120	(2)	9,118	-	9,118
MFC - Credit & Collections	9,667	(2)	9,665	5	9,670
MFC - Uncollectable	3,492	184	3,676	199	3,875
MRA - Oil to Gas	1,393	8	1,401	15	1,416
MRA - Uncollectable	882	36	918	26	944
MRA - Credit	(460)	322	(138)	98	(40)
SBC	36,474	1,510	37,984	(20,821)	17,163
Load Following Charge	89,532	-	89,532	-	89,532
Fuel Revenue	365,244	20,272	385,516	24,955	410,471
GRT on Delivery Revenue	37,908	896	38,804	864	39,668
GRT on Competitive Revenues & Other Charges	2,455	68	2,523	(3)	2,520
Fuel tax	13,139	459	13,598	74	13,672
MRA Credit Tax	(15)	10	(5)	4	(1)
GRT on Low Income Discoutns	52	-	52	-	52
Subtotal	575,694	23,778	599,472	5,434	604,906
Grand Total	$ 1,575,136	$ 46,682	$ 1,621,818	$ 27,623	$ 1,649,441

Volumes (Therms)	2014	RY2 Sales Gain/(Loss)	2015	RY 3 Sales Gain/(Loss)	2016
Service Classification 1	43,740,000	(800,000)	42,940,000	(770,000)	42,170,000
Service Classification 2 - Non-Heating	186,540,724	1,560,724	188,101,448	1,610,724	189,712,173
Service Classification 2 - Heating	310,418,310	3,008,310	313,426,620	3,878,310	317,304,929
Service Classification 2 - DG	26,350,000	-	37,300,000	-	41,410,000
Service Classification 2 - Contract	12,350,000	-	12,350,000	-	12,350,000
Service Classification 3	693,857,364	34,847,364	728,704,729	34,687,364	763,392,093
Service Classification 13	970,000	-	970,000	-	970,000
Service Classification 14	190,000	-	190,000	-	190,000
Service Classification 12 R2	176,890,000		176,890,000	620,000	177,510,000
	1,451,306,398	38,616,398	1,500,872,797	40,026,398	1,545,009,195

Consolidated Edison Company of New York, Inc.
Gas Case 13-G-0031
Other Operating Revenues
($000's)

		RY1 12 months ending 12/31/2014	RY 2 Adjustments	RY2 12 months ending 12/31/2015	RY3 Adjustments	RY3 12 months ending 12/31/2016
1	Interdepartmental Rents	$ 6,181	$ 523	$ 6,704	$ 512	$ 7,216
2	Rents - New York Facilities	5,778	121	5,899	121	6,021
3	POR Discount (Revenue from ESCO)	5,696	-	5,696	-	5,696
4	Late Payment Charges *	5,167	285	5,452	282	5,734
5	R&D GAC Surcharge	1,960	-	1,960	-	1,960
6	Misc. Service Revenue	1,122	24	1,146	24	1,170
7	ESCO Funding Fees	487	-	487	-	487
8	NYPA Variable and Maintenance	381	8	389	8	397
9	Rents - Real Estate Rents	366	8	374	8	382
10	Gas Reconnect Fess	130	-	130	-	130
11	Learning Center Revenues	112	2	114	2	117
12	Miscellaneous	70	-	70	-	70
13	R&D Ventures	24	1	25	1	25
14	Reimbursement To KeySpan-Governor's Island	(49)	(1)	(50)	(1)	(51)
		$ 27,425	$ 970	$ 28,395	$ 957	$ 29,353

* Includes late payment charges of ($182,000), $129,000 and $190,000 in RY1, RY2 and RY3, respectively, related to revenue decreases and increases that the parties propose to levelize over the term of the Rate Plan.

Revenue Decoupling Mechanism

The revenue decoupling mechanism ("RDM") will continue to be based on a revenue per customer ("RPC") methodology for customer groups that are included in the RDM.

RPC Methodology:

Under the RPC methodology, Actual Delivery Revenue is compared, on a Rate Year basis, with Allowed Delivery Revenue, which is equal to the product of the average number of customers in the Rate Year and the Rate Year RPC Target for each customer group subject to the RDM. For RDM purposes one customer equals 360 days of service and is measured by the number of annual bills in a Rate Year where one bill equals 30 days of service ("Bill"). [1]

Applicability:

The RDM will apply to the following customer groups, including all customers taking service under SC No. 9 that would otherwise take service under such group:

- SC No. 2 –Rate 1;
- SC No. 2 –Rate 2;
- SC No. 3 customers with 1-4 dwelling units; and
- SC No. 3 customers with more than 4 dwelling units.

The groups include: (1) customers taking service under Rider G (Economic Development Zone); (2) all gas volumes associated with customers receiving air conditioning service under SC Nos. 2 and 3; and (3) SC No. 3 customers participating in the Low Income Program described in Section VI.B of the Proposal. The groups exclude: (1) customers who take service under Rider H (Distributed Generation Rate), Rider I (Gas Manufacturing Incentive Rate) and Rider J (Residential Distributed Generation Rate) and (2) customers receiving service under a firm by-pass rate and Excelsior Job customers.

[1] For RDM purposes, the annual number of bills in a Rate Year recognizes equivalent 30-day bills and that customers on average receive bills covering more than 30 days of service in a month and more than 360 days of service in each Rate Year. The definition of customer for RDM purposes does not reflect the actual number of customers subject to the RDM.

Actual Delivery Revenue:

For the purposes of the RDM, Actual Delivery Revenue, determined for each customer group, will be calculated as the sum of revenue derived from the base tariff rates applicable to SC Nos. 2 and 3, and from the associated SC No. 9 firm transportation tariff rates, and Weather Normalization Adjustment ("WNA") credits or surcharges. Actual Delivery Revenue will not include revenue derived from the RDM Adjustment described below.

SC No. 3 Actual Delivery Revenue will be adjusted to add back the computed cost of the rate discounts provided to Low Income customers based on the number of bills and actual therms delivered to Low Income customers in the two SC No. 3 customer groups. This adjustment will be the same as reported in the annual Low Income program reconciliation for these low income groups.

Actual Delivery Revenue in the third month of Rate Year 1 and in the first month of Rate Years 2 and 3 will be adjusted for the effect of proration of old and new rates on actual revenues. The Adjusted Actual Delivery Revenue for these months for each customer group will be calculated as follows:

1. Any WNA credits or surcharges will be subtracted from Actual Delivery Revenue.
2. Actual delivery revenues will then be reduced by the product of the number of bills times the minimum charge rate.
3. The resulting Actual Delivery Revenue will be adjusted by multiplying it by the ratio of one plus the percentage change in the volumetric rates divided by one plus half of the percentage change in the volumetric rate (Factor 1).
4. The resulting adjusted Actual Delivery Revenue will be increased by the amount reflected in step 2.
5. The WNA credits subtracted in step 1 above will be adjusted and added back, resulting in Adjusted Actual Delivery Revenue. Actual WNA revenues will be adjusted by one half of the percentage change between the old and new penultimate rates. Any impact in the third month of Rate Year 1 due to the change in the definition of normal weather from a 30 year average condition to a 10 year average condition will be captured in the reconciliation provisions of the Revenue Decoupling Mechanism

	RY1 Factor 1	RY2 Factor 1	RY3 Factor 1
SC No. 2 – Rate 1	1.0016	0.9928	0.9926
SC No. 2 – Rate 2	1.0186	1.0103	1.0100
SC No. 3 customers with 1-4 dwelling units	1.0136	0.9996	0.9997
SC No. 3 customers with more than 4 dwelling units	1.0136	0.9996	0.9997

RPC Targets:

The RPC Target for each customer group will be set for each Rate Year at 12 times the average Delivery Revenue per Bill, as shown in Table 2. The average Delivery Revenue per Bill is calculated by dividing the total Rate Year Delivery Revenues (revenue derived from the base rates applicable to SC Nos. 2 and 3, and from the corresponding SC No. 9 firm transportation rates) by the number of Bills in the Rate Year.

The Bills for the RPC Targets will be based on the forecasted Rate Year number of Bills used to set rates, as shown below:

	RY1	RY2	RY3
SC No. 2 – Rate 1	750,821	759,028	767,010
SC No. 2 – Rate 2	771,808	777,632	782,841
SC3 customers w/ 1-4 dwelling units	3,377,735	3,446,830	3,518,235
SC3 customers with more than 4 dwelling units	208,255	219,352	229,940

The Delivery Revenues, by customer class, that will be used to calculate the RPC Targets are shown below. For SC No. 3, the Delivery Revenues shown below are computed assuming all Low Income customers are billed at full rates.

	RY1	RY2	RY3
SC No. 2 – Rate 1	$101,466,241	$104,038,633	$106,658,287
SC No. 2 – Rate 2	$170,153,950	$169,498,142	$169,163,541
SC No. 3 customers with 1-4 dwelling units	$280,713,991	$282,592,773	$285,505,282
SC No. 3 customers with more than 4 dwelling units	$206,866,029	$224,845,497	$241,996,236

The RPC Targets for all rate years for each customer group are shown below.

	RY1	RY2	RY3
SC No. 2 – Rate 1	$ 1,621.69	$ 1,644.82	$ 1,668.69
SC No. 2 – Rate 2	$ 2,645.54	$ 2,615.60	$ 2,593.07
SC3 customers with 1-4 dwelling units	$ 997.29	$ 983.84	$ 973.80
SC3 customers with more than 4 dwelling units	$11,919.97	$12,300.53	$12,629.19

RDM Adjustment:

For each customer group subject to the RDM, the Company will, at the end of each Rate Year, compare Actual Delivery Revenue to the Allowed Delivery Revenue. To the extent that the Actual Delivery Revenue varies from the Allowed Delivery Revenue, the excess or shortfall will be refunded to or collected from customers through customer group-specific RDM Adjustments over an eleven-month period commencing in the second month following the end of each Rate Year.

The customer group-specific RDM Adjustments will be determined on a cents per therm basis by dividing the total revenue excess/shortfall for each customer group by the forecasted therm deliveries of the associated customer group for the period in which the RDM Adjustment is to be in effect.

Beginning with the first month following the end of each Rate Year, interest at the Other Customer Provided Capital Rate will be calculated for each month on the average of the current and prior month's cumulative revenue over- or under-collection (net of state and federal taxes) and will be included along with the over- or under-collection charged or credited to customers.

Interim RDM Adjustment:

The Company may implement an Interim RDM Adjustment whenever the Company determines that such a surcharge or credit adjustment is necessary to avoid a large over- or under-collection, based on the Company's projection for the Rate Year of forthcoming RDM reconciliation balances. At least two weeks prior to the Company's implementing an Interim RDM Adjustment, the Company will provide Staff work papers underlying such surcharge or credit adjustment in order to afford Staff an opportunity to raise with the Company any concerns that Staff has with the size and/or timing of the surcharge or credit adjustment.[2] Any Interim RDM Adjustment will be determined based on a 12-month recovery period. Revenues associated with Interim RDM Adjustments will be included in the annual RDM reconciliation.

Partial Year RDM:

If the Company does not file for new base delivery rates to take effect within fifteen days after the expiration of RY3, the RDM will be implemented as follows. Prior to the start of RY3, the Company will provide, along with the RY3 annual RPC targets, the monthly RPC targets associated with the RY3 annual RPC targets. To the extent the stay-out period beyond RY3 is less than 12 months, these monthly RPC targets will be used to implement the RDM in the stay-out period. The provisions of the calculation of the

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[2] The Company will provide to interested parties, upon request, a copy of any such work papers after the filing is made.

annual true-up on a full-year basis would also apply to any partial year, that is, the monthly RPC targets for the months of the partial year period would be summed, and then multiplied by the average monthly number of Bills for the partial year period to derive the partial year period Allowed Delivery Revenue. This Allowed Delivery Revenue would be compared to the Actual Delivery Revenue for the partial year period to determine any excess or shortfall. During the term of the Gas Rate Plan, the Company will continue to provide to the Director of the Office of Electric, Gas and Water monthly data on actual bills and revenues unless and until changed by Commission order.

Consolidated Edison Company of New York, Inc.
Case 13-S-0032
Steam Revenue Forecast
$ 000's

	Calendar Years				
Steam Operating Revenues	2014	RY2 Update	2015	RY3 Update	2016
Sales Revenues (Includes Fuel)	$ 643,994	$ 6,921	$ 650,915	$ 12,683	$ 663,598
Less: Revenue Taxes	17,646	213	17,859	331	18,190
Gross Margin	626,348	6,708	633,056	12,352	645,408
Cost of Sales					
Fuel and Purchased Steam Costs	169,057	4,898	173,955	12,730	186,685
Other Fuel Charges	1,989	79	2,068	192	2,260
Water	18,843	2,188	21,031	792	21,823
Water Chemicals	4,781	553	5,334	201	5,535
Sewer Charges	708	36	744	-	744
Electric and Gas Used	10,433	219	10,652	224	10,876
Cost of Sales	205,811	7,973	213,784	14,139	227,923
Net Revenue Contribution	$ 420,537	$ (1,265)	$ 419,272	$ (1,787)	$ 417,485

Steam Sales (MMlbs)	2014	RY2 Update	2015	RY3 Update	2016
SC 1	519	(9)	510	(8)	502
SC 2	2,488	5	2,493	(5)	2,488
SC 2 Demand	11,645	(101)	11,544	(148)	11,396
SC 3	2,713	(21)	2,692	(13)	2,679
SC 3 Demand	3,608	164	3,772	50	3,822
SC 4	483	(0)	483	3	485
SC 5	15	(15)	-	-	-
SC 5 Demand	220	(131)	89	(51)	38
Total	**21,690**	**(107)**	**21,583**	**(173)**	**21,410**

* **Note: includes fuel**

Consolidated Edison Company of New York, Inc.
Steam Case 13-S-0032
Steam Revenue Forecast
$ 000's

	Calendar Years				
Steam Sales Revenues	2014	RY2 Update	2015	RY3 Update	2016
SC 1	$ 27,213	$ (450)	$ 26,763	$ (402)	$ 26,361
SC 2	100,904	22	100,926	(240)	100,686
SC 2 Demand	328,489	(1,685)	326,804	(2,519)	324,285
SC 3	86,215	(665)	85,550	(319)	85,231
SC 3 Demand	93,468	4,889	98,357	1,480	99,837
SC 4	15,904	8	15,912	46	15,958
SC 5	458	(458)	-	-	-
SC 5 Demand	5,938	(3,626)	2,312	(1,096)	1,216
Fuel Rider Revenues	(32,207)	8,673	(23,534)	15,402	(8,132)
GRT	17,612	213	17,825	331	18,156
Total	$ 643,994	$ 6,921	$ 650,915	$ 12,683	$ 663,598

Consolidated Edison Company of New York, Inc.
Steam Case 13-S-0032
Other Operating Revenues
($000's)

		RY1 12 months ending 12/31/2014	RY 2 Adjustments	RY2 12 months ending 12/31/2015	RY3 Adjustments	RY3 12 months ending 12/31/2016
1	Interdepartmental Rents: ERRP Rents	$ 75,835	$ (553)	$ 75,282	$ 1,936	$ 77,218
2	Revenue Offset Re: 74th/59th Streets Transfer from Electric	5,000	-	5,000	-	5,000
3	Interdepartmental Rents: Hudson Avenue Tunnel	2,335	234	2,569	217	2,786
4	Special Services Repair Program	671	14	685	14	699
5	Late Payment Charges *	507	16	523	16	539
6	Real Estate Rents	78	2	80	2	81
		$ 84,426	$ (287)	$ 84,138	$ 2,185	$ 86,323

Consolidated Edison Company of New York, Inc.
Case 13-E-0030
Electric True Up Targets
$ 000's

	Twelve Months Ending December 31,		
Revenue True-ups	2014	RY2 Change	2015
Proceeds from Sales of TCCs	$ 90,000	$ -	$ 90,000
Transmission Service Charges	7,000	-	7,000
Transmission of Energy	8,765	-	8,765
Environmental Allowances (SO2)*	-	-	-
Expense True-ups			
Municipal Infrastructure Support			
Interference - excl. Company labor (80/20 True up)	84,794	1,781	86,575
Property Tax Expense (90/10 True up)			
New York City	$ 1,067,144	63,450	$ 1,130,594
Upstate and Westchester	115,555	5,539	121,094
Total Property Taxes	1,182,699	68,989	1,251,688
Employee Pensions	364,355	(72,938)	291,417
Other Post Employment Benefits	19,220	(12,287)	6,933
Pension / OPEB Expense Before SRIP Adjustment	383,575	(85,225)	298,350
SRIP Adjustment	(4,647)	332	(4,315)
Net Pension / OPEB Expense Rate Allowance	378,928	(84,893)	294,035
Storm Reserve	21,427	-	21,427
Management Variable Pay (Net of Capitalized)	23,549	-	24,119
ERRP - Major Maintenance	7,159	-	7,159
NEIL Insurance*	-	-	-
Interest True-Ups (page 2)			
Average Variable Rate	0.38%	0.73%	1.11%
Variable Rate Debt Cost	7,184,590	6,075,630	13,260,220
Corporate Income Tax			
Brownfield Tax Credits*	-	-	-

Note

* The Company will defer for the benefit of customers all SO_2 allowances, NEIL Dividends, and Brownfield Tax Credits received during the term of the plan.

Consolidated Company of New York, Inc.
Cases 13-E-0030 / 13-G-0031 / 13-S-0032
Variable Rate Debt

			RY1		RY2		RY3	
Bond	Maturity Date	Amount Outstanding	Effective Cost of Money	Effective Annual Cost	Effective Cost of Money	Effective Annual Cost	Effective Cost of Money	Effective Annual Cost
1999 Series A	05/01/34	292,700,000	0.46%	1,346,420	1.35%	3,951,450	2.94%	8,605,380
2010 Series A	06/01/36	224,600,000	0.26%	583,960	0.77%	1,729,420	1.68%	3,773,280
2001 Series B	10/01/36	98,000,000	0.46%	450,800	1.35%	1,323,000	2.94%	2,881,200
2004 Series A	01/01/39	98,325,000	0.46%	452,295	1.35%	1,327,388	2.94%	2,890,755
2004 Series B1	05/01/32	127,225,000	0.46%	585,235	1.35%	1,717,538	2.94%	3,740,415
2004 Series B2	10/01/35	19,750,000	0.46%	90,850	1.35%	266,625	2.94%	580,650
2004 Series C	11/01/39	99,000,000	0.26%	257,400	0.77%	762,300	1.68%	1,663,200
2005 Series A	05/01/39	126,300,000	0.26%	328,380	0.77%	972,510	1.68%	2,121,840
		1,085,900,000	0.38%	4,095,340	1.11%	12,050,230	2.42%	26,256,720
		Credit support costs		5,333,335		5,445,335		5,559,687
		Total costs		**$ 9,428,675**		**$ 17,495,565**		**$ 31,816,407**
		Allocation to Electric*		76.2%		75.8%		75.1%
		Electric Target		**$ 7,184,590**		**$ 13,260,220**		**$ 23,883,340**
		Allocation to Gas*		16.7%		17.4%		18.4%
		Gas Target		**$ 1,576,610**		**$ 3,052,420**		**$ 5,857,410**
		Allocation to Steam*		7.1%		6.8%		6.5%
		Steam Target		**$ 667,480**		**$ 1,182,930**		**$ 2,075,660**

* Interest costs will be allocated monthly based on the ratio of actual electric, gas, and steam plant to total plant.

	RY1	RY2	RY3
Net Utility Plant (Electric)	$ 19,080,872	$ 19,859,565	$ 20,624,652
Net Utility Plant (Gas)	4,187,168	4,571,542	5,058,211
Net Utility Plant (Steam)	1,772,699	1,771,644	1,792,456
	$ 25,040,739	$ 26,202,751	$ 27,475,319
Elec Allocation	76.2%	75.8%	75.1%
Gas Allocation	16.7%	17.4%	18.4%
Steam Allocation	7.1%	6.8%	6.5%
	100.0%	100.0%	100.0%

Consolidated Edison Company of New York, Inc.
Case 13-E-0030
Electric True Up Targets
$ 000's

Average Plant In Service Balances — **Target**

Rate Year 1	BOOK COST OF PLANT	ACCRUED DEPRECIATION	DEPRECIATION REMOVAL COST	AVERAGE NET PLANT EXCLUDING REMOVAL COST
Other (Production and Shared Services)	2,649,634	(607,288)	(7,978)	2,034,368
T&D - Interference (Additions/Removal only)	29,751	(69)	(3,650)	26,031
- Reliability (Additions/Removal only)	312,905	(722)	(13,937)	298,246
- All other	21,510,591	(4,904,284)	(62,181)	16,544,127
Storm Hardening (Additions/Removal only)	90,563	(209)	(1,443)	88,911
Total	24,593,444	(5,512,572)	(89,189)	18,991,683

Rate Year 2	BOOK COST OF PLANT	ACCRUED DEPRECIATION	DEPRECIATION REMOVAL COST	NET PLANT EXCLUDING REMOVAL COST
Other (Production and Shared Services)	2,828,902	(708,763)	(18,423)	2,101,715
T&D - Interference	87,860	(203)	(7,345)	49,242
- Reliability	588,140	(1,357)	(26,795)	559,987
- All other	22,153,585	(5,267,433)	(124,846)	16,792,375
Storm Hardening	179,249	(414)	(2,175)	176,660
Total	25,837,735	(5,978,170)	(179,585)	19,679,980

Consolidated Edison Company of New York, Inc.
Case 13-E-0030
Carrying Charge Rates

RY 1

	T&D and Interference Plant	Production Plant	General Plant
Pre Tax Overall Rate of Return	9.940%	9.940%	9.940%
Composite Book Depreciation Rate	2.810%	4.760%	7.200%
Total Carrying Charge Rate	12.750%	14.700%	17.140%

RY 2

	T&D and Interference Plant	Production Plant	General Plant
Pre Tax Overall Rate of Return	9.980%	9.980%	9.980%
Composite Book Depreciation Rate	2.810%	4.760%	7.200%
Total Carrying Charge Rate	12.790%	14.740%	17.180%

Consolidated Edison Company of New York, Inc.
Case 13-E-0030
Electric Net Plant True Up Examples

T&D Reliability Spending Target = 100

Storm Hardening Spending Target = 100

Total Target = 200

T&D Reliability Spending / (Deficiency)	Storm Hardening Spending / (Deficiency)	Total (Deficiency)	Total (Deficiency)
84 (16)	84 (16)	168 (32)	16 deferral for T&D Reliability 16 deferral for Storm Hardening
86 (14)	84 (16)	170 (30)	14 deferral for T&D Reliability 16 deferral for Storm Hardening
86 (14)	86 (14)	172 (28)	14 deferral for T&D Reliability 14 deferral for Storm Hardening
132 (0)	70 (30)	202 (0)	30 deferral for Storm Hardening
128 (0)	84 (16)	212 (0)	16 deferral for Storm Hardening
115 (0)	86 (14)	201 (0)	0 deferral
113 (0)	86 (14)	199 (1)	1 deferral for Storm Hardening
104 (0)	86 (14)	190 (10)	10 deferral for Storm Hardening
99 (1)	90 (10)	189 (11)	1 deferral for T&D Reliability 10 deferral for Storm Hardening

Consolidated Edison Company of New York, Inc.
Case 13-G-0031
Gas True Up Targets
$ 000's

	Twelve Months Ending December 31,				
	2014	RY2 Change	2015	RY3 Change	2016
Expense True-ups					
Municipal Infrastructure Support					
Interference - excl. Company labor (80/20 True up)	19,076	401	19,477	389	19,866
Property Tax Expense (90/10 True up)					
New York City	$145,280	16,730	$162,010	20,431	$182,441
Upstate and Westchester	47,825	2,282	50,107	2,390	52,497
Total Property Taxes	193,105	19,012	212,117	22,821	234,938
Employee Pensions	53,594	(10,578)	43,016	(9,978)	33,038
Other Post Employment Benefits	2,845	(1,819)	1,026	(813)	213
Pension / OPEB Expense Before SRIP Adjustment	56,440	(12,397)	44,043	(10,791)	33,251
SRIP Adjustment	(629)	(14,216)	(580)	(11,605)	(527)
Net Pension / OPEB Expense Rate Allowance	55,810	(26,614)	43,462	(22,396)	32,724
Management Variable Pay (Net of Capitalized)	4,481	108	4,590	111	4,701
Pipeline Integrity Costs	583	12	595	12	607
Research and Development (Downward only)	1,232	5	1,237	-	1,237
Interest True-Ups (page 2)					
Average Variable Rate	0.38%	0.73%	1.11%	1.31%	2.42%
Variable Rate Debt Cost	1,576,610	1,475,810	3,052,420	2,804,990	5,857,410

Consolidated Company of New York, Inc.
Cases 13-E-0030 / 13-G-0031 / 13-S-0032
Variable Rate Debt

			RY1		RY2		RY3	
Bond	Maturity Date	Amount Outstanding	Effective Cost of Money	Effective Annual Cost	Effective Cost of Money	Effective Annual Cost	Effective Cost of Money	Effective Annual Cost
1999 Series A	05/01/34	292,700,000	0.46%	1,346,420	1.35%	3,951,450	2.94%	8,605,380
2010 Series A	06/01/36	224,600,000	0.26%	583,960	0.77%	1,729,420	1.68%	3,773,280
2001 Series B	10/01/36	98,000,000	0.46%	450,800	1.35%	1,323,000	2.94%	2,881,200
2004 Series A	01/01/39	98,325,000	0.46%	452,295	1.35%	1,327,388	2.94%	2,890,755
2004 Series B1	05/01/32	127,225,000	0.46%	585,235	1.35%	1,717,538	2.94%	3,740,415
2004 Series B2	10/01/35	19,750,000	0.46%	90,850	1.35%	266,625	2.94%	580,650
2004 Series C	11/01/39	99,000,000	0.26%	257,400	0.77%	762,300	1.68%	1,663,200
2005 Series A	05/01/39	126,300,000	0.26%	328,380	0.77%	972,510	1.68%	2,121,840
		1,085,900,000	0.38%	4,095,340	1.11%	12,050,230	2.42%	26,256,720
		Credit support costs		5,333,335		5,445,335		5,559,687
		Total costs		**$ 9,428,675**		**$ 17,495,565**		**$ 31,816,407**
		Allocation to Electric*		76.2%		75.8%		75.1%
		Electric Target		**$ 7,184,590**		**$ 13,260,220**		**$ 23,883,340**
		Allocation to Gas*		16.7%		17.4%		18.4%
		Gas Target		**$ 1,576,610**		**$ 3,052,420**		**$ 5,857,410**
		Allocation to Steam*		7.1%		6.8%		6.5%
		Steam Target		**$ 667,480**		**$ 1,182,930**		**$ 2,075,660**

* Interest costs will be allocated monthly based on the ratio of actual electric, gas, and steam plant to total plant.

	RY1	RY2	RY3
Net Utility Plant (Electric)	$ 19,080,872	$ 19,859,565	$ 20,624,652
Net Utility Plant (Gas)	4,187,168	4,571,542	5,058,211
Net Utility Plant (Steam)	1,772,699	1,771,644	1,792,456
	$ 25,040,739	$ 26,202,751	$ 27,475,319
Elec Allocation	76.2%	75.8%	75.1%
Gas Allocation	16.7%	17.4%	18.4%
Steam Allocation	7.1%	6.8%	6.5%
	100.0%	100.0%	100.0%

Consolidated Edison Company of New York, Inc.
Case 13-G-0031
Gas True Up Targets
$ 000's

Average Plant In Service Balances — **Target**

Rate Year 1	BOOK COST OF PLANT	ACCRUED DEPRECIATION	DEPRECIATION REMOVAL COST	AVERAGE NET PLANT EXCLUDING REMOVAL COST
Delivery - All Other	$5,054,702	($1,227,691)	($2,845)	$3,824,166
- Interference (Additions/Removal only)	32,750	(55)	-	32,695
- Oil to Gas Conversion (Additions/Removal only)	42,143	(71)	-	42,072
Storm Hardening (Additions/Removal only)	3,449	(6)	-	3,443
Total	5,133,044	(1,227,824)	(2,845)	3,902,376

Rate Year 2	BOOK COST OF PLANT	ACCRUED DEPRECIATION	DEPRECIATION REMOVAL COST	AVERAGE NET PLANT EXCLUDING REMOVAL COST
Delivery - All Other	5,386,375	(1,318,138)	(5,595)	4,062,642
- Interference	97,457	(165)	-	97,292
- Oil to Gas Conversion	98,386	(166)	-	98,219
Storm Hardening	8,071	(14)	-	8,057
Total	5,590,288	(1,318,483)	(5,595)	4,266,210

Rate Year 3	BOOK COST OF PLANT	ACCRUED DEPRECIATION	DEPRECIATION REMOVAL COST	AVERAGE NET PLANT EXCLUDING REMOVAL COST
Delivery - All Other	5,798,251	(1,419,883)	(9,229)	4,369,139
- Interference	158,410	(268)	-	158,141
- Oil to Gas Conversion	171,637	(290)	-	171,347
Storm Hardening	29,899	(51)	-	29,849
Total	$6,158,196	($1,420,492)	($9,229)	$4,728,476

Consolidated Edison Company of New York, Inc.
Case 13-G-0031
Carrying Charge Rates

RY 1

	T&D Plant
Pre Tax Overall Rate of Return	10.020%
Composite Book Depreciation Rate	2.030%
Total Carrying Charge Rate	12.050%

RY 2

	T&D Plant
Pre Tax Overall Rate of Return	10.060%
Composite Book Depreciation Rate	2.030%
Total Carrying Charge Rate	12.090%

RY 3

	T&D Plant
Pre Tax Overall Rate of Return	10.140%
Composite Book Depreciation Rate	2.030%
Total Carrying Charge Rate	12.170%

Consolidated Edison Company of New York, Inc.
Case 13-S-0032
Steam True Up Targets
$ 000's

	Twelve Months Ending December 31,				
	2014	RY2 Change	2015	RY3 Change	2016
Revenue True-ups					
Environmental Allowances (SO2)*	-	-	-	-	-
Expense True-ups					
Municipal Infrastructure Support					
Interference - excl. Company labor (80/20 True up)	5,573	(21)	5,552	(93)	5,459
Property Tax Expense (90/10 True up)	107,735	8,622	116,357	10,831	127,188
Employee Pensions	25,972	(5,111)	20,861	(4,819)	16,041
Other Post Employment Benefits	1,375	(878)	497	(395)	102
Pension / OPEB Expense Before SRIP Adjustment	27,347	(5,989)	21,358	(5,214)	16,144
SRIP Adjustment	(339)	24	(316)	26	(290)
Net Pension / OPEB Expense Rate Allowance	27,008	(5,965)	21,042	(5,189)	15,854
Management Variable Pay (Net of Capitalized)	3,294	80	3,374	82	3,455
Research and Development (Downward only)	917	14	931	20	951
Interest True-Ups (page 2)					
Average Variable Rate	0.38%	0.73%	1.11%	1.31%	2.42%
Variable Rate Debt Cost	667,480	515,450	1,182,930	892,730	2,075,660

Note
* The Company will defer for the benefit of customers all SO_2 allowances received during the term of the plan.

Consolidated Company of New York, Inc.
Cases 13-E-0030 / 13-G-0031 / 13-S-0032
Variable Rate Debt

			RY1		RY2		RY3	
Bond	Maturity Date	Amount Outstanding	Effective Cost of Money	Effective Annual Cost	Effective Cost of Money	Effective Annual Cost	Effective Cost of Money	Effective Annual Cost
1999 Series A	05/01/34	292,700,000	0.46%	1,346,420	1.35%	3,951,450	2.94%	8,605,380
2010 Series A	06/01/36	224,600,000	0.26%	583,960	0.77%	1,729,420	1.68%	3,773,280
2001 Series B	10/01/36	98,000,000	0.46%	450,800	1.35%	1,323,000	2.94%	2,881,200
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2004 Series B1	05/01/32	127,225,000	0.46%	585,235	1.35%	1,717,538	2.94%	3,740,415
2004 Series B2	10/01/35	19,750,000	0.46%	90,850	1.35%	266,625	2.94%	580,650
2004 Series C	11/01/39	99,000,000	0.26%	257,400	0.77%	762,300	1.68%	1,663,200
2005 Series A	05/01/39	126,300,000	0.26%	328,380	0.77%	972,510	1.68%	2,121,840
		1,085,900,000	0.38%	4,095,340	1.11%	12,050,230	2.42%	26,256,720
		Credit support costs		5,333,335		5,445,335		5,559,687
		Total costs		**$ 9,428,675**		**$ 17,495,565**		**$ 31,816,407**
		Allocation to Electric*		76.2%		75.8%		75.1%
		Electric Target		**$ 7,184,590**		**$ 13,260,220**		**$ 23,883,340**
		Allocation to Gas*		16.7%		17.4%		18.4%
		Gas Target		**$ 1,576,610**		**$ 3,052,420**		**$ 5,857,410**
		Allocation to Steam*		7.1%		6.8%		6.5%
		Steam Target		**$ 667,480**		**$ 1,182,930**		**$ 2,075,660**

* Interest costs will be allocated monthly based on the ratio of actual electric, gas, and steam plant to total plant.

	RY1	RY2	RY3
Net Utility Plant (Electric)	$ 19,080,872	$ 19,859,565	$ 20,624,652
Net Utility Plant (Gas)	4,187,168	4,571,542	5,058,211
Net Utility Plant (Steam)	1,772,699	1,771,644	1,792,456
	$ 25,040,739	$ 26,202,751	$ 27,475,319
Elec Allocation	76.2%	75.8%	75.1%
Gas Allocation	16.7%	17.4%	18.4%
Steam Allocation	7.1%	6.8%	6.5%
	100.0%	100.0%	100.0%

Consolidated Edison Company of New York, Inc.
Case 13-S-0032
Steam True Up Targets
$ 000's

Average Plant In Service Balances — **Target**

Rate Year 1	BOOK COST OF PLANT	ACCRUED DEPRECIATION	DEPRECIATION REMOVAL COST	AVERAGE NET PLANT EXCLUDING REMOVAL COST
Production & Distribution	2,221,562	(456,198)	(12,559)	1,752,805
Storm Hardening (Additions/Removal only)	5,688	(20)	-	5,666
Total	$ 2,227,249	$ (456,219)	$ (12,559)	$ 1,758,471

Rate Year 2	BOOK COST OF PLANT	ACCRUED DEPRECIATION	DEPRECIATION REMOVAL COST	AVERAGE NET PLANT EXCLUDING REMOVAL COST
Production & Distribution	2,269,645	(511,014)	(26,971)	1,731,660
Storm Hardening	11,385	(41)	-	11,344
Total	$ 2,281,030	$ (511,055)	$ (26,971)	$ 1,743,004

Rate Year 3	BOOK COST OF PLANT	ACCRUED DEPRECIATION	DEPRECIATION REMOVAL COST	AVERAGE NET PLANT EXCLUDING REMOVAL COST
Production & Distribution	2,336,084	(569,832)	(45,747)	1,720,505
Storm Hardening	24,623	(88)	-	24,535
Total	$ 2,360,707	$ (569,920)	$ (45,747)	$ 1,745,040

Consolidated Edison Company of New York, Inc.
Case 13-S-0032
Carrying Charge Rates

RY 1

	Production Plant	Distribution Plant
Pre Tax Overall Rate of Return	10.020%	10.020%
Composite Book Depreciation Rate	4.050%	2.500%
Total Carrying Charge Rate	14.070%	12.520%

RY 2

	Production Plant	Distribution Plant
Pre Tax Overall Rate of Return	10.060%	10.060%
Composite Book Depreciation Rate	4.050%	2.500%
Total Carrying Charge Rate	14.110%	12.560%

RY 3

	Production Plant	Distribution Plant
Pre Tax Overall Rate of Return	10.140%	10.140%
Composite Book Depreciation Rate	4.050%	2.500%
Total Carrying Charge Rate	14.190%	12.640%

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
BOOK DEPRECIATION RATES

CO. ACCT. NO.	ACCOUNT TITLE	LIFE TABLE	AVERAGE SERVICE LIFE (Years)	NET SALVAGE (%)	DEPR. RATE (%)
	ELECTRIC PLANT				
	STEAM PRODUCTION				
310000	LAND AND LAND RIGHTS	-	-	-	-
311000	STRUCTURES AND IMPROVEMENTS	h 0.50	50	(50)	3.00
312000	BOILER PLANT EQUIPMENT	h 0.75	25	(55)	6.20
314000	TURBOGENERATOR UNITS	h 1.75	35	(40)	4.00
315000	ACCESSORY ELECTRIC EQUIPMENT	h 0.25	30	(40)	4.67
316000	MISC. POWER PLANT EQUIPMENT	h 0.50	35	(25)	3.57
	OTHER PRODUCTION				
340100	LAND AND LAND RIGHTS	-	-	-	-
341000	STRUCTURES AND IMPROVEMENTS	h 3.00	30	(20)	4.00
342000	FUEL HOLDERS, PROD. & ACCESSORIES	h 3.00	30	(20)	4.00
344000	GENERATORS	h 3.00	30	(20)	4.00
345000	ACCESSORY ELECTRIC EQUIPMENT	h 3.00	30	(20)	4.00
	TRANSMISSION PLANT				
350100	LAND AND LAND RIGHTS	-	-	-	-
352000	STRUCTURES AND IMPROVEMENTS	h 2.25	75	(35)	1.80
353000	STATION EQUIPMENT	h 1.75	50	(25)	2.50
354000	TOWERS AND FIXTURES	h 3.00	55	(40)	2.55
356000	OVERHEAD CONDUCTORS AND DEVICES	h 2.25	45	(35)	3.00
303090	CAPITALIZED SOFTWARE - TRANS. PLT	Amort	5	-	20.00
357100	UNDERGROUND CONDUIT - CAP LEASES	-	-	-	-
357000	UNDERGROUND CONDUIT	h 3.25	65	(20)	1.85
357200	UNDERGROUND CONDUIT - MAN & BRONX	h 3.25	65	(20)	1.85
358000	UNDERGROUND CONDUCTORS & DEVICES	h 2.75	60	(15)	1.92
	DISTRIBUTION PLANT				
360100	LAND AND LAND RIGHTS	-	-	-	-
360000	LAND AND LAND RIGHTS - LEASEHOLDS	Amort	50	-	2.00
361000	STRUCTURES AND IMPROVEMENTS	h 1.75	50	(50)	3.00
362000	STATION EQUIPMENT	h 2.00	50	(25)	2.50
364000	POLES, TOWERS AND FIXTURES	h 0.25	60	(100)	3.33
303010	CAPITALIZED SOFTWARE	Amort	5	-	20.00
303015	CAPITALIZED SOFTWARE (WMS)	Amort	15	-	6.67
365000	OVERHEAD CONDUCTORS AND DEVICES	h 0.25	70	(55)	2.21
366000	UNDERGROUND CONDUIT	h 1.25	85	(40)	1.65
366100	UNDERGROUND CONDUIT - MAN. & BRONX	h 1.25	85	(40)	1.65
367000	UNDERGROUND CONDUCTORS & DEVICES	h 0.75	50	(70)	3.40
368000	OVERHEAD TRANSFORMERS	h 1.00	35	(20)	3.43
368100	UNDERGROUND TRANSFORMERS	h 1.50	35	(20)	3.43
369100	SERVICES - OVERHEAD	h 0.50	70	(175)	3.93
369200	SERVICES - UNDERGROUND	h 0.75	80	(150)	3.13
370100	METERS - ELECTRO MECHANICAL	h 0.75	35	(5)	3.00
370110	METERS - SOLID STATE	h 0.75	20	(5)	5.25
370200	METER INSTALLS - ELECTRO MECHANICAL	(A)	35	-	2.86
370210	METER INSTALLS - SOLID STATE	(A)	20	-	5.00
371000	INSTALL. ON CUSTOMERS' PREMISES	h 0.50	70	-	1.43
373100	O.H. STREET LIGHTING & SIGNAL SYS.	h 0.00	55	(100)	3.64
373200	U.G. STREET LIGHTING & SIGNAL SYS.	h 0.50	80	(90)	2.38

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
BOOK DEPRECIATION RATES

CO. ACCT. NO.	ACCOUNT TITLE	LIFE TABLE	AVERAGE SERVICE LIFE (Years)	NET SALVAGE (%)	DEPR. RATE (%)
	GAS PLANT IN SERVICE				
	LNG. STORAGE PLANT				
360000	LAND & LAND RIGHTS - LIQ. ST.	-	-	-	-
361000	ST. & IMPROVE.-LIQ. STORAGE	h 2.50	40	(25)	3.13
362100	GAS HOLDERS-LIQ. STORAGE	h 4.00	30	(15)	3.83
363000	PURIFICATION EQUIPMENT	h 3.00	30	(15)	3.83
363100	LIQUEFACTION EQUIPMENT	h 3.00	30	(15)	3.83
363200	VAPORIZING EQUIPMENT	h 3.00	30	(15)	3.83
363300	COMPRESSOR EQUIP.-LIQ. ST.	h 3.00	30	(15)	3.83
363400	MEAS. & REG. EQUIP. - LIQ. ST.	h 3.00	30	(15)	3.83
363500	OTHER EQUIPMENT-LIQUEFIED ST.	h 3.00	30	(15)	3.83
	TRANSMISSION PLANT				
365100	LAND AND LAND RIGHTS	-	-	-	-
366000	STRUCTURES & IMPROVEMENTS	h 2.00	40	(50)	3.75
367100	STEEL MAINS AND OTHER	h 2.25	85	(60)	1.88
367200	CAST IRON MAINS	h 0.50	75	(100)	2.67
367300	TUNNELS	h 5.00	85	(80)	2.12
367400	STEEL MAINS - INTERRUPT PLANT	-	-	-	-
368000	COMPRESSOR STATION EQUIP	h 3.00	15	(5)	7.00
369000	MEAS. & REG. STATION EQ.	h 0.50	65	(35)	2.08
	DISTRIBUTION PLANT				
376120	STEEL MAINS AND OTHER	h 2.25	85	(60)	1.88
376130	STEEL MAINS - INTERRUPT PLANT	-	-	-	-
376110	CAST IRON MAINS	h 0.50	75	(100)	2.67
376140	CAST IRON MAINS - INTERRUPT PLANT	-	-	-	-
380100	SERVICES	h 0.75	65	(30)	2.00
380200	SERVICES - INTERRUPT PLANT	-	-	-	-
381000	METERS	h 1.50	40	(10)	2.75
382000	METER INSTALLATIONS	(B)	40	-	2.50
383000	HOUSE REGULATORS	h 2.25	35	(20)	3.43
384000	HOUSE REG. INSTALLATIONS	(C)	30	(5)	3.50
303020	CAPITALIZED SOFTWARE 5 YR	Amort	5	-	20.00

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
BOOK DEPRECIATION RATES

CO. ACCT. NO.	ACCOUNT TITLE	LIFE TABLE	AVERAGE SERVICE LIFE (Years)	NET SALVAGE (%)	DEPR. RATE (%)
	STEAM PLANT				
	PRODUCTION PLANT				
	LAND AND LAND RIGHTS				
310020	FULLY RECOVERED	-	-	-	-
310010	ALL OTHER	-	-	-	-
	LAND & LAND RIGHTS - LEASEHOLDS				
310400	FULLY RECOVERED	Amort	-	-	-
310200	59th STREET	Amort	-	-	-
310300	74th STEET	Amort	-	-	-
	STRUCTURES AND IMPROVEMENTS				
311200	74th STREET (FULLY RECOVERED)	(D)	-	-	1.25%
311300	ERRP	h 0.00	35	(60)	4.57%
311100	ALL OTHER	h 0.00	35	(60)	4.57%
	BOILER PLANT EQUIPMENT				
312200	74th STREET (FULLY RECOVERED)	(D)	-	-	1.43%
312300	ERRP	h 2.50	30	(30)	4.33%
312100	ALL OTHER	h 0.25	30	(30)	4.33%
	ACCESSORY POWER EQUIPMENT				
315200	74th STREET (FULLY RECOVERED)	(D)	-	-	0.71%
315300	ERRP	h 0.25	35	(25)	3.57%
315100	ALL OTHER	h 0.25	35	(25)	3.57%
	MISC. STATION EQUIPMENT				
316200	74th STREET (FULLY RECOVERED)	(D)	-	-	0.22%
316300	ERRP	h 1.50	40	(10)	2.75%
316100	ALL OTHER	h 1.50	40	(10)	2.75%
	DISTRIBUTION PLANT				
351000	STRUCTURES AND IMPROVEMENTS	h 5.00	50	-	2.00%
303040	CAPITALIZED SOFTWARE	Amort	5	-	20.00%
353010	MAINS - ALL OTHER	h 0.25	80	(75)	2.19%
353020	MAINS - ERRP	h 0.25	80	(75)	2.19%
353110	DESUPER. EQ. - ALL OTHER	h 1.25	45	(45)	3.22%
353120	DESUPERHEATING EQ. - ERRP	h 1.25	45	(45)	3.22%
359000	SERVICES	h 0.00	60	(50)	2.50%
360000	METERS	h 1.75	35	(5)	3.00%
361000	ACCESS. EQ. ON CUST. PREMISES	h 0.50	60	(15)	1.92%
362000	INST. OF METERS & ACCESS. EQ.	h 0.75	60	(20)	2.00%

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
BOOK DEPRECIATION RATES

CO. ACCT. NO.	ACCOUNT TITLE	LIFE TABLE	AVERAGE SERVICE LIFE (Years)	NET SALVAGE (%)	DEPR. RATE (%)
	COMMON UTILITY PLANT IN SERVICE				
	MISC. INTANGIBLE PLANT				
	CAPITALIZED SOFTWARE				
303060	5 YEAR AMORTIZABLE	Amort	5	-	20.00%
303070	10 YEAR AMORTIZABLE	Amort	10	-	10.00%
303080	15 YEAR AMORTIZABLE	Amort	15	-	6.67%
	BUILDINGS AND YARDS				
389000	LAND AND LAND RIGHTS	-	-	-	-
390000	STRUCTURES AND IMPROVEMENTS	h 0.75	55	(75)	3.18
390400	STRUCT. AND IMPROV. - CAP LEASES	-	-	-	-
	GENERAL PLANT				
391700	ELECTRONIC DATA PROCESSING EQ.	Amort	8	5	11.88
391110	OTHER OFFICE FURNITURE AND EQ.	Amort	18	-	5.56
392500	TRANSPORTATION EQUIPMENT	Amort	8	10	11.25
393000	STORES EQUIPMENT	Amort	20	5	4.75
394000	TOOLS, SHOP AND GARAGE EQUIP.	Amort	18	5	5.28
395000	LABORATORY EQUIPMENT	Amort	20	-	5.00
396000	POWER OPERATED EQUIPMENT	Amort	12	10	7.50
397000	COMMUNICATION EQUIPMENT	Amort	15	-	6.67
398000	MISCELLANEOUS EQUIPMENT	Amort	20	-	5.00

(A) Computed reserved based on the reserve ratio of Electric Meters without salvage
(B) Computed reserved based on the reserve ratio of Gas Meters without salvage
(C) Computed reserved based on the reserve ratio of House Regulators without salvage
(D) Rate applicable to net salvage recovery only

Consolidated Edison Company of New York, Inc.
Sale of John Street Property
Summary of Net Gain

		Calculation of Net Gain on Sale
Sales Price of Land		$ 9,200,000
Less:	Cost of Land (Purchased 1963 - 1965)	242,800
	Demolition Cost - Dock (1971)	124,800
	- Structure (1990)	186,800
	Deferred Appraisal Expenses	24,300
	Title Fee	450
	Cost of Sale	579,150
	Net Gain Before Taxes	**$ 8,620,850**
Less:	NYS Transfer Tax (0.4%) Selling Price	N/A
	NYC Transfer Tax (2.0%) Selling Price	N/A
	NYC Gross Receipts Tax (2.35%) Net Gain	200,000
	Total other taxes	**200,000**
	Net Gain Before Income Taxes	**$ 8,420,850**
Income Taxes		
New York State income tax @ 8.63%		726,700
Federal income tax @ 35%		2,693,000
	Total Income Taxes	**3,419,700**
	Net Gain After Income Taxes	**$ 5,001,150**
	Sharing Proposal Customer / Company	
	Customer Share (Before Income Tax)	**$ 4,935,000**
	Company Share (Before Income Tax)	**3,485,850**
	Net Gain Before Income Taxes	**$ 8,420,850**

Consolidated Edison Company of New York, Inc.
Sale of John Street
Proposed Journal Entries - Sale

No.	PSC Account	Description	Debit	Credit
1	131	Cash	$ 9,200,000	
	253	Other Deferred Credits - Deferred Gain from Sale		$ 9,200,000
		To record net cash proceeds from the sale of John Street		
2	253	Other Deferred Credits - Deferred Gain from Sale	$ 554,400	
	121	Non-Utility Plant		$ 554,400
		To transfer to the book cost of land against the net proceeds from the sale		
3	253	Other Deferred Credits - Deferred Gain from Sale	$ 24,300	
	253	Other Deferred Credits - Deferred Gain from Sale	450	
	186	Other Deferred Debits - Deferred Selling Expenses		$ 24,300
	131	Cash		450
		To record miscellaneous selling expenses associated with sale		
4	253	Other Deferred Credits - Deferred Gain from Sale	$ 200,000	
	131	Cash		$ 200,000
		To record NYS transfer and NYC gross receipts tax on the sales		
5	253	Other Deferred Credits - Deferred Gain from Sale	$ 8,420,850	
	421.2	Gain on Disposition of Property		$ 8,420,850
		To record gain on sale before income taxes		
6	409.2	Income Taxes, Other Income and Deductions	$ 726,700	
	236	Taxes Accrued		$ 726,700
		To record the New York State income tax effect.		
6	409.2	Income Taxes, Other Income and Deductions	$ 2,693,000	
	236	Taxes Accrued		$ 2,693,000
		To record the Federal income tax effect.		
7	190	Deferred State Income Tax Asset	$ 425,900	
	190	Deferred Federal Income Tax Asset	$ 1,578,200	
	411	Deferred State Income Tax Expense		$ 425,900
	411	Deferred Federal Income Tax Expense		$ 1,578,200
		To defer New York State & Federal Income tax effect on Customer Share		
7	421.2	Gain on Disposition of Property	$ 4,935,000	
	254	Regulatory Liability - Customer Share of John Street Sale		$ 4,935,000
		To establish liability for proceeds to be passed back to customers		

Consolidated Edison Company of New York, Inc.
Electric Case 13-E-0030
Earnings Sharing Partial Year
During Stub Period Starting January 1, 2016
(000's)

Assumption: CECONY Delays Filing for New Rates for Six Months

Month / Year	Electric Net Income	
January 31, 2016	$ 97,000	
February 28, 2016	95,000	
March 31, 2016	91,000	
April 30, 2016	90,000	
May 31, 2016	91,000	
June 30, 2016	116,000	
Total		$ 580,000

	Electric Rate Base	
Rate Base as of December 31, 2015	$ 18,112,641	
Rate Base as of June 30, 2016	18,500,000	
Total	36,612,641	
Divided by Two	2	
Average Rate Base During Stub Period	$ 18,306,320	
x Ratio of billed sales during stub period to annual sales forecast	44.8%	
Rate Base Subject to Earnings Test		$ 8,207,000
Overall Rate of Return		
($ 580,000 / $ 8,207,000)		7.07%
Return on Equity (Page 2)	9.01%	
Earnings Sharing Threshold	9.80%	
Earnings Above / (Under) Threshold	-0.79%	
Equity Earnings Base		
($ 8,207,000 x 48.00%)	$ 3,939,360	
Equity Earnings Above / (Under) Target		
($ 3,939,360 x -0.79%)	$ (30,940)	

Consolidated Edison Company of New York, Inc.
Electric Case 13-E-0030
Capital Structure & Cost of Money
During Stub Period Starting January 1, 2016

	Capital Structure %	Cost Rate %	Cost of Capital %
Long Term Debt	50.56%	5.39%	2.72%
Customer Deposits	1.44%	1.25%	0.02%
Total Debt	52.00%		2.74%
Common Equity	48.00%	9.01%	4.33%
Total	100.00%		7.07%

Consolidated Edison Company of New York, Inc.
Gas Case 13-G-0031
Earnings Sharing Partial Year
During Stub Period Starting January 1, 2017
(000's)

Assumption: CECONY Delays Filing for New Rates for Six Months

Month / Year	Gas Net Income	
January 31, 2017	$ 52,000	
February 28, 2017	52,000	
March 31, 2017	45,000	
April 30, 2017	29,000	
May 31, 2017	18,000	
June 30, 2017	14,000	
Total		$ 210,000

	Gas Rate Base	
Rate Base as of December 31, 2016	$ 4,272,460	
Rate Base as of June 30, 2017	4,500,000	
Total	8,772,460	
Divided by Two	2	
Average Rate Base During Stub Period	$ 4,386,230	
x Ratio of billed sales during stub period to annual sales forecast	65.6%	
Rate Base Subject to Earnings Test		$ 2,878,000
Overall Rate of Return		
($ 210,000 / $ 2,878,000)		7.30%
Return on Equity (Page 2)	9.49%	
Earnings Sharing Threshold	9.90%	
Earnings Above / (Under) Threshold	-0.41%	
Equity Earnings Base		
($ 2,878,000 x 48.00%)	$ 1,381,440	
Equity Earnings Above / (Under) Target		
($ 1,381,440 x -0.41%)	$ (5,640)	

Consolidated Edison Company of New York, Inc.
Gas Case 13-G-0031
Capital Structure & Cost of Money
During Stub Period Starting January 1, 2017

	Capital Structure %	Cost Rate %	Cost of Capital %
Long Term Debt	50.58%	5.39%	2.73%
Customer Deposits	1.42%	1.25%	0.02%
Total Debt	52.00%		2.74%
Common Equity	48.00%	9.49%	4.56%
Total	100.00%		7.30%

Consolidated Edison Company of New York, Inc.
Steam Case 13-S-0032
Earnings Sharing Partial Year
During Stub Period Starting January 1, 2017
(000's)

Assumption: CECONY Delays Filing for New Rates for Six Months

Month / Year	Steam Net Income	
January 31, 2017	$ 18,000	
February 28, 2017	18,000	
March 31, 2017	16,000	
April 30, 2017	9,000	
May 31, 2017	5,000	
June 30, 2017	4,000	
Total		$ 70,000

	Steam Rate Base	
Rate Base as of December 31, 2016	$ 1,604,346	
Rate Base as of June 30, 2017	1,600,000	
Total	3,204,346	
Divided by Two	2	
Average Rate Base During Stub Period	$ 1,602,173	
x Ratio of billed sales during stub period to annual sales forecast	63.3%	
Rate Base Subject to Earnings Test		$ 1,014,000
Overall Rate of Return ($ 70,000 / $ 1,014,000)		6.90%
Return on Equity (Page 2)	8.66%	
Earnings Sharing Threshold	9.90%	
Earnings Above / (Under) Threshold	-1.24%	
Equity Earnings Base ($ 1,014,000 x 48.00%)	$ 486,720	
Equity Earnings Above / (Under) Target ($ 486,720 x -1.24%)	$ (6,040)	

Consolidated Edison Company of New York, Inc.
Steam Case 13-G-0032
Capital Structure & Cost of Money
During Stub Period Starting January 1, 2017

	Capital Structure %	Cost Rate %	Cost of Capital %
Long Term Debt	50.58%	5.39%	2.73%
Customer Deposits	1.42%	1.25%	0.02%
Total Debt	52.00%		2.74%
Common Equity	48.00%	8.66%	4.16%
Total	100.00%		6.90%

<u>Consolidated Edison Company of New York, Inc.</u>
Case 13-S-0032
Steam Earnings Calculation

For purposes of calculating a weather related earnings adjustment due to colder or warmer than normal weather the net revenue effect of steam sales will be calculated as follows:

1. The normal weather period will be defined as the winter billing months of November – April, inclusive.

2. Normal weather for all three rate years will be defined as the average conditions over the 10 years ended December 31, 2012 measured in terms of Heating Degree Days (HDDs). HDDs on a daily basis are defined as the number of degrees that the average 24-hour dry-bulb temperature differs from a 56 degrees Fahrenheit reference when the average 24-hour dry-bulb temperature is less than 56 degrees. When the average 24-hour dry-bulb temperature equals or exceeds 56 degrees there will be no HDDs. For example, if the 24-hr average dry bulb temperature for a day during the winter billing period is 40 degrees, there would be 16 HDDs for that day.

3. For each billing cycle in each of the aforementioned billing months, a unit ($/Mlb) weather normalization adjustment charge or credit will be determined separately for each service classification. (<u>i.e.</u>, SC 1, SC 2, and SC 3) based upon the formula noted below. A billing cycle refers to the number of days between meter readings.

   The weather normalization adjustment formula is:

$$\frac{(NHDD - AHDD) * MLBHDD * PBR}{(BLMLB * BC) + (MLBHDD * AHDD)}$$

   Where:

NHDD -	Normal Heating Degree Days
AHDD -	Actual Heating Degree Days
MLBHDD -	Thousands of Pounds per Heating Degree Days*
PBR -	Penultimate Base Rate (exclusive of base fuel)
BLMLB -	Base Load, Thousands of Pounds per Day*
BC -	Number of Days in the Billing Cycle

<u>Consolidated Edison Company of New York, Inc.</u>
Case 13-S-0032
Steam Earnings Calculation

* The MLBHDD and BLMLB factors on a service classification basis will be determined by regression analysis of actual monthly service classification sales divided by the average number of billing days in the month and by the associated number of customer billing in the month vs. the number of heating degree days per average number of billing days in each month over the most recent full winter season (i.e., the November - April billing months).

4. The determined unit charge/credit for each billing trip will be multiplied by the associated actual sales for that billing cycle. The net revenue effect of the credits and charges for each service classification will be netted at the end of the winter period as defined above. The net revenue impact (i.e., base revenue less base fuel per service classification) will be summarized to determine the system net revenue impact.

Consolidated Edison Company of New York, Inc.
Common Allocation Factors

	Electric	Gas	Steam
Administrative & General Expenses			
A&G - Labor Related	78.70%	16.20%	5.10%
A&G - Other than Labor	81.14%	13.21%	5.65%
Pensions/OPEBs and Health Ins. Capitalized	72.67%	23.63%	3.70%
A&G Transferred - Other	76.55%	17.80%	5.65%
Customer Accounting Expenses			
Uncollectible Accounts	86.00%	14.00%	0.00%
Other Customer Accounts	82.00%	18.00%	0.00%
Energy Services	89.00%	11.00%	0.00%
Promotional Advertising	82.00%	18.00%	0.00%
Taxes Other than FIT			
Sales & Use	77.75%	15.50%	6.75%
Vehicle/Gasoline	81.00%	16.50%	2.50%
Payroll Taxes	78.75%	16.25%	5.00%
Payroll Taxes Transferred to Construction	72.50%	23.75%	3.75%
Other	81.25%	13.25%	5.50%
Plant			
Common Plant	83.00%	17.00%	0.00%
Common M&S	77.00%	17.00%	6.00%

Consolidated Edison Company of New York, Inc.
Case 13-E-0030, 13-G-0031, 13-S-0032
<u>Electric Service Reliability Performance Mechanism</u>

<u>Operation of Mechanism</u>

This Electric Service Reliability Performance Mechanism (“reliability mechanism”) will go into effect for Consolidated Edison Company of New York, Inc. (Con Edison or the Company) on January 1, 2014 and will remain in effect until reset by the Commission. The measurement periods for the reliability mechanism metrics are stated in the description of each metric below.

This reliability mechanism establishes eight performance metrics:

(a) threshold standards, consisting of system-wide performance targets;

(b) a major outage metric;

(c) a remote monitoring system metric;

(d) a restoration performance metric;

(e) a program standard for repairs to damaged poles;

(f) a program standard for the removal of temporary shunts;

(g) a program standard for the repair of "no current" street lights, and traffic signals; and

(h) a program standard for the installation of intrusion detection systems.

All revenue adjustments related to this reliability mechanism will come from shareholder funds and will be deferred for the benefit of ratepayers.

Summary of Mechanism

		Requirement for Revenue Adjustment	Annual Revenue Adjustment Exposure (millions)
Threshold Standards			
	Network Outage Duration	Con Ed Performance > 4.70	$5.0
	CAIDI[1] (radial)	Con Ed Performance > 2.04	$5.0
	Network Outages per 1000 customers	Con Ed Performance > 2.5[2]	$4.0
	Summer Open Automatics (network)	Con Ed Performance > 330	$1.0
	SAIFI[3] (radial)	Con Ed Performance > 0.495	$5.0
Major Outages			
	Network	The interruption of service to 15 percent or more of the customers in any network for a period of three hours or more.	$5.0 to $15.0/event
	Radial	One event that results in the sustained interruption of service to 70,000 customers for three hours or more.	$10.0/event
	Maximum Exposure		$30.0

[1] CAIDI – Customer Average Interruption Duration Index. The average interruption duration time (customers-hours interrupted) for those customers that experience an interruption during the year.

[2] The customer count as of December 31 of the preceding year was used in calculating historical performance that formed the basis of this target and will be used in measuring the Company's actual performance during each calendar year.

[3] SAIFI – System Average Interruption Frequency Index. It is the average number of times that a customer is interrupted per 1,000 customers served during the year.

Remote Monitoring System Reporting			
	Network	Failure by the Company to achieve 90 percent reporting rate for the Remote Monitoring System in each network during the last month of each quarter.	$10.0/network
	Maximum Exposure		$50.0
Restoration Performance			
	Restoration Radial	Restoration of service that does not meet the following target. Overhead Events Emergency Level — Restoration Targets 1-Upgraded — 1 Day 2-Serious — 2 Days 3A-Serious — 3 Days 3B-Full Scale (Tropical storm) — 4 Days 3B-Full Scale (Hurricane Category 1-2) — 7 Days 3B-Full Scale (Hurricane Category 3-5) — ≤ 3 weeks	$0.0 (trial basis and terminated when Outage Scorecard becomes effective)
Program Standards			
	Pole Repair		
		For all “Damaged Poles” and “Double Damaged Poles” that come into existence on or after 1/1/14, repairs not made within 30 days from the date the Company became aware of the “Damaged Pole” or “Double Damaged Pole” for at least 90% of these new “Damaged Poles” and “Double Damaged Poles”.	$3.0
	Shunt Removal		
		For all shunts that come into existence on or after 1/1/14, permanent repairs not made for at least 90% of these new cases within 90 days during the winter months, which are defined for purposes of this	Winter: $1.5 Summer: $1.5

			metric as January, February, March, April, November, and December, and at least 90% of these cases within 60 days during the remaining six months, May through October that is defined as the summer months.	
	No Current Street Lights and Traffic Signals			
			For all no currents that come into existence on or after 1/1/14, permanent repairs not made for at least 90% of these new cases within 90 days during the winter months, which are defined for purposes of this metric as January, February, March, April, November, and December, and at least 80% of these new cases within 45 days during the remaining six months, May through October that is defined as the summer months.	Winter: $1.5 Summer: $1.5
Over-Duty Circuit Breakers				
			If Con Edison does not replace at least 50 over-duty circuit breakers during the calendar year and at least 120 over a two year cycle.	$0.1 Per Breaker
		Maximum Exposure	Revenue adjustment capped at $1.5 million for not meeting annual target. At the end of the two-year cycle, there will be an additional revenue adjustment of $0.1 million per breaker, capped at $3.0 million, if the cumulative two-year cycle target is not met.	$6.0 Per two-year cycle
	Intrusion Detection System			
			For each Bulk Power System substation that is not equipped with an operational Intrusion Detection System by April 30, 2015	$2/substation
		Maximum Exposure		$24
			Total Revenue Adjustment Exposure:	**$136 for RY1 $139 for RY2**

<u>Exclusions</u>

The following exclusions will be applicable to operating performance under this reliability mechanism.

(a) Any outages resulting from a major storm, as defined in 16 NYCRR Part 97 (for at least 10% of the customers interrupted within an operating area or customers out of service for at least 24 hours), except as otherwise noted; this includes secondary underground network interruptions that occur in an operating area during winter snow/ice events that meet the 16 NYCRR Part 97 definition (10%/24 hour rule) and includes interruptions to customers in secondary network areas who are supplied via overhead lines connected to an underground network system.

(b) Heat-related outages are not a major storm. However, the Company may petition the Commission for an exemption for an outage if the Company can prove that such outage, whether heat-related or not, was beyond the Company's control, taking into account all facts and circumstances.

(c) Any incident resulting from a strike or a catastrophic event beyond the control of the Company, including but not limited to plane crash, water main break, or natural disasters (*e.g.*, hurricanes, floods, earthquakes).

(d) Any incident where problems beyond the Company's control involving generation or the bulk transmission system is the key factor in the outage, including, but not limited to, NYISO mandated load shedding. This criterion is not intended to exclude incidents that occur as a result of unsatisfactory performance by the Company.

<u>Reporting</u>

The Company will prepare an annual report(s) on its performance under this reliability mechanism. The annual report(s) will be filed by March 31st of each Rate

Year with the Secretary to the Commission, Director of the Office of Electric, Gas, and Water, Chief of Electric Distribution Systems, and the Chief of Utility Security. Copies of the annual report(s) will be simultaneously provided to the New York City Department of Transportation ("NYCDOT") Deputy Commissioner of Traffic Operations, the NYCDOT Director of Street Lighting, the Westchester County First Deputy Commissioner of Public Works, and the President of the Utility Workers Union of America, Local 1-2.

The reports will state the:

(a) Company's annual system-wide performance under the Threshold Standards and identify whether a revenue adjustment is applicable and, if so, the amount of the revenue adjustment;

(b) Company's performance under the Major Outage metric and identify whether a revenue adjustment is applicable and, if so, the amount of the revenue adjustment;

(c) Company's performance under the Remote Monitoring System metric and identify whether a revenue adjustment is applicable and, if so, the amount of the revenue adjustment;

(d) Company's performance under the Restoration metric

(e) Company's performance under the Program Standards applicable during the period and identify whether a revenue adjustment is applicable and, if so, the amount of the revenue adjustment; and

(f) provide adequate support for all exclusions.

Within 45 days of any event that meets the Major Outage criteria, the Company will file an interim report on the event, containing, among other things, information pertinent to determining whether a revenue adjustment for the event is applicable. Any requests for exclusion must be made in the interim report.

<u>Threshold Standards</u>

In Cases 90-E-1119, 95-E-0165, 96-E-0979, and 02-E-1240, the Commission adopted standards establishing minimum performance for frequency and duration of service interruption for network and radial systems. Under these standards, the frequency of service interruptions is measured by the System Average Interruption Frequency Index (“SAIFI”), and the duration of service interruptions is measured by the Customer Average Interruption Duration Index (“CAIDI”).

The system-wide performance targets used for purposes of the threshold standards metric are as set forth below. The measurement periods for the threshold standards are successive 12-month periods ending December 31 of each year. During each annual measurement period, Con Edison's year-end SAIFI index for its entire radial system will be measured against the respective SAIFI system-wide performance target. During each annual measurement period, Con Edison's year-end weighted average CAIDI index for its entire radial system will be measured against the respective CAIDI system-wide performance target.

The network duration target will be a temporary replacement for network CAIDI. The measurement period for network duration are successive 12-month periods ending December 31 of each year. During each annual measurement period, Con Edison's year-end duration for its entire network system will be measured against the respective duration target.

The network interruption and summer feeder open-auto targets will be a temporary replacement for network SAIFI. The measurement period for network interruption are successive 12-month periods ending December 31 of each year. During each annual measurement period, Con Edison's year-end number of interruptions for its entire network system will be measured against the respective interruption target. The measurement period for summer feeder open-auto includes the months of June, July, and August of each year. During each annual measurement period, Con Edison's summer-end feeder open-auto rate for its network system will be measured against the respective feeder open-auto target.

The Company’s annual performance in maintaining reliability must meet or be better than the SAIFI and CAIDI system-wide performance, Network Duration, Network Interruption, and Summer Feeder Open-Auto targets. A total of $20 million is at risk for performance not meeting these targets.

(a) Radial – CAIDI

A total of $5 million per year is at risk for customer interruption duration performance, as follows:

	Threshold Target (hours)	Revenue Adjustment (millions)
Radial CAIDI	2.04	$5

(b) Network Outage Duration

A total of $5 million per year is at risk for network outage duration performance, as follows:

	Threshold Target (hours)	Revenue Adjustment (millions)
Network outage duration	4.7	$5

(c) Radial – SAIFI

A total of $5 million per year is at risk for customer interruption frequency performance, as follows:

	Threshold Target	Revenue Adjustment (millions)
Radial SAIFI	0.495	$5

(c) Network Outage

A total of $4 million per year is at risk for network outage performance, as follows:

	Threshold Target	Revenue Adjustment (millions)
Network Outages per 1000 customers	2.5	$ 4

(d) Summer Feeder Open-Auto Target

A total of $1 million per year is at risk for summer network feeder open-auto performance, as follows:

	Threshold Target	Revenue Adjustment (millions)
Summer Network Feeder Open-Auto	330	$ 1

Major Outages

For purposes of this metric, a "major outage" event in a network system is defined as the interruption of service to 15 percent or more of the customers in any network for a period of three hours or more. If the Company creates any new second contingency networks during the Electric Rate Plan, those networks will be covered by this metric. A radial system interruption event is defined as one event that results in the sustained interruption of service to 70,000 customers for three hours or more.

Any single occurrence that results in multiple network or radial system interruption events will result in only one revenue adjustment being assessed. An example is the loss of an area substation that shuts down two or more networks or a combination of network and radial system load.

This single occurrence exception will not apply if each Major Outage that takes place during any single occurrence results from separate and distinct causes. For example, if there are two network shutdowns during a single heat wave, and each network shutdown results from failures on that particular network that were not beyond the Company's control, the single occurrence exception would not apply and two network shutdowns will be considered to have occurred.

In addition, Con Edison shall not be subject to a revenue adjustment when the 15% threshold is met due to an outage that is confined to one building within a network. The Company can petition the Commission for exemption on a case-by-case basis, of outages affecting more than one building that are, nevertheless, small scale and do not warrant classification as a Major Outage.

To avoid multiple revenue adjustments for the same operating performance problem or occurrence, interruptions and customer hours of interruption associated with Major Outage revenue adjustments will be excluded from the appropriate year-end system-wide performance calculations, except as noted.

The Company will be subject to a revenue adjustment based on the outage duration. Con Edison will be subject to a maximum revenue adjustment of $30 million. After the $30 million cap has been reached, the effect of the major outage will be included in the system-wide performance measurements. The revenue adjustment structure is as follows:

(a) Network Major Outage

Network Outage Duration	15% or More of Network Customers
3 to 6 hours	$5 million
> 6 hours to 12 hours	$10 million
> 12 hours	$15 million

(b) Radial Major Outage

A revenue adjustment of $10 million is at risk for each radial major outage.

<u>Remote Monitoring System</u>

For each network, except upon the occurrence of extraordinary system conditions, the Company will have 90% of its Remote Monitoring System units reporting properly in each network. Failure by the Company to achieve the target level for the Remote Monitoring System will result in a revenue adjustment of $10 million per network per measurement interval with an annual cap of $50 million.

Where the Company can demonstrate that extraordinary circumstances prevented it from achieving the target level, those circumstances will be factored in measuring the Company's compliance with the above requirement. The determination of whether extraordinary circumstances exist will be made on a case-by-case basis and will be based on the particular facts and circumstances presented.

The Company will be required to submit on a quarterly basis, the RMS reporting rate per network during the last month of each quarter that commenced June 30, 2008. This mechanism is an interim standard, with the intent of adopting a target level of 95% for each network when such a standard is found to be reasonable.

Restoration

In order to advance the process of developing an optimal restoration mechanism, without placing an undue burden on the Company, this metric will be on a trial basis with the proviso that there will be no negative rate adjustment when the Company does not meet the standard. Under this metric, the Company is liable for restoration times for all outage events affecting its radial systems. The restoration targets are measured from the end of the storm. In the Company's past emergency plan, Upgraded to Full Scale emergency events had an estimated restoration time for overhead events. This format has been used to set the restoration targets.

Overhead Events	
Emergency Level	Restoration Targets
1-Upgraded	1 Day
2-Serious	2 Days
3A-Serious	3 Days
3B-Fulll Scale (Tropical storm)	4 Days
3B-Full Scale (Hurricane Category 1-2)	7 Days
3B-Full Scale (Hurricane Category 3-5)	≤ 3 weeks

The Company will file a compliance report with the Commission within 30 days following any restoration period for which the restoration mechanism applies, detailing its performance relative to the restoration mechanism, and noting any exceptions that would apply. Program Standards

(a) Pole Repair

i) Definitions

1. “Damaged Poles” are poles damaged by storm conditions, vehicle contact, or other circumstances, and that support existing equipment with temporary external bracing while not posing an immediate threat to the safety of the public or the distribution system.

2. “Double Damaged Poles” are poles damaged by storm conditions, vehicle contact, or other circumstances, and that are not capable of supporting existing equipment. In each of these cases, a new pole is installed next to the damaged pole and is braced to the damaged pole to safely support the damaged pole until the Company transfers equipment to the new pole.

3. “Repair,” for purposes of this program standard, means transferring Company facilities to a new pole, and removing or “topping” the “damaged” pole.

ii) Performance Requirements

The Company will strive to repair all “Damaged Poles” and “Double Damaged Poles” in a timely manner. For all “Damaged Poles” and “Double Damaged Poles” that are in existence as of December 31, 2013, Con Edison will make permanent repairs and is subject to the revenue adjustment as required by the prior reliability mechanism. For all “Damaged Poles” and “Double Damaged Poles” that come into existence on or after January 1, 2014, Con Edison will make repairs within 30 days from the date the Company became aware of the “Damaged Pole” or “Double Damaged Pole” for at least 90% of these new “Damaged Poles” and “Double Damaged Poles”. In the event the Company does not achieve the 90% within 30 days threshold for “Damaged Poles” and

“Double Damaged Poles” that come into existence during or after the 2014 calendar year, it will incur a revenue adjustment of $3 million for such year.

Con Edison will make repairs to all “Damaged Poles” and “Double Damaged Poles” that come into existence on or after January 1, 2014 within six months of the dates the Company became aware of the damaged poles.

iii) Storm Exclusion

In an effort to permit the Company to utilize labor resources most effectively and facilitate the restoration of customers, the Company may utilize up to 60 days to make repairs on 90% of poles that become “Damaged Poles” and “Double Damaged Poles” during qualifying major storm events as defined in 16 NYCRR Part 97. Where the Company does not immediately make repairs on its poles, the Company shall ensure that each “Damaged Pole” and “Double Damaged Pole” is safe for public and vehicle access.

iv) Extraordinary Circumstances Exception

Where the Company can demonstrate that extraordinary circumstances prevent a repair within the 30-day, 60-day, or six month time frames, as appropriate, that non-repair will not be considered in measuring the Company's compliance with these requirements. The determination of whether extraordinary circumstances exist will be made on a case-by-case basis and will be based on the particular facts and circumstances presented.

v) Reporting

The Company’s annual report will: (i) report on "Damaged Poles" and "Double Damaged Poles" that come into existence from January 1 through December 31 of the prior year; (ii) provide the status of "Damaged Poles" and "Double Damaged Poles" that existed before January 1 of the prior year; (iii) identify the “Damaged Poles” and “Double Damaged Poles” that were not repaired; and, (iv) describe the extraordinary circumstances, if any, that prevented the repairs from being made. For (i) and (ii), the report(s) will include, at a minimum, a listing of the damaged pole locations, the date the Company became aware of the problem at that location, and the date of the repair.

(b) Shunt Removal

It is not the purpose of this metric to require Con Edison to eliminate the use of temporary shunts; to the contrary, temporary shunts may be needed to restore electric service pending permanent repairs. In cases where temporary shunts are used, the Company will strive to remove them and make permanent repairs in a timely manner. It is Con Edison's responsibility to identify all shunts installed by the Company.

i) Definitions

1. "Temporary Shunts" are cables installed by the Company to temporarily maintain service continuity to a customer pending the permanent repair of a Company facility.

2. "Publicly Accessible Shunts" include street/sidewalk shunts and overhead to underground service shunts, including shunts to street lights, installed by the Company. Shunts installed within individual customer facilities, typically behind the customer's meter (called a "meter pan bridge") or inside the customer's end line box (called a "service bridge"), that are not accessible to the general public are not covered by this metric.

3. "Permanent Repair" means that the condition necessitating the shunt has been fully remediated and service has been restored by the Company to the customer's facility before the shunt is removed.

ii) Performance Requirements

The Company will not remove any shunt that will have the effect of leaving a streetlight or traffic signal without power, except for exigent safety reasons,[4] until the condition giving rise to the need for the shunt has been completely repaired. Furthermore, it is Con Edison's responsibility to repair the conditions on its system that required the use of the temporary shunts. For all shunts that are in existence as of December 31, 2013, Con Edison will make permanent repairs as required by the prior reliability mechanism. For all shunts that come into existence on or after January 1, 2014, Con Edison will make permanent repairs for at least 90% of these new cases within 90 days during the winter months, which are defined for purposes of this metric as January, February, March, April, November, and December, and at least 90% of these cases within 60 days during the remaining six months, May through October. Failure to reach the 90% threshold will result in the follow revenue adjustments:

Adjustment Level
Winter Months $1,500,000
May – October $1,500,000

Con Edison will make permanent repairs in all cases in which temporary shunts are installed on or after January 1, 2014 within six months of the dates the shunts are installed.

The 60-day, 90-day and six month periods for making permanent repairs may be tolled in the event that, and for the period corresponding to, a third party (such as the municipal customer) must perform service at the site prior to, and as a precondition to, Con Edison's completion of work. The Company will be responsible for providing notice to the third party that its work is a precondition to the Company's work and for demonstrating the applicability of the tolling period.

[4] In such situations, and as appropriate, the Company either will replace its temporary shunt or effect the permanent repair.

iii) Extraordinary Circumstances Exception

Where the Company can demonstrate that extraordinary circumstances prevented a shunt repair within the 60-day, 90-day, or six month time frames, as appropriate, that non-repair will not be considered in measuring the Company's compliance with the above requirements. The determination of whether extraordinary circumstances exist will be made on a case-by-case basis and will be based on the particular facts and circumstances presented (*e.g.*, documentation demonstrating delays of more than 30 days in receiving street-opening permits from NYCDOT).

iv) Reporting

The Company's annual report will: (i) report on shunts installed from January 1 through December 31 of the prior year; (ii) provide the status of shunts installed before January 1 of the prior year; (iii) identify the shunt locations that were not permanently repaired within the 60-day, 90-day, and six month periods described above; and, (iv) describe the extraordinary circumstances, if any, that prevented the permanent repair of the shunts. For (i) and (ii), the report(s) will include, at a minimum, a listing of the shunt locations, the date the Company became aware of the problem at each such location, the date the shunt was installed, the date of the permanent repair, and the date the shunt was removed.

(c) No Current Street Lights and Traffic Signals

i) Definitions

1. A "no current" is a location where Con Edison's electric service supplying power to municipal street lights or traffic signals is not working due to a failure of Con Edison's service to the customer facility point, and the date that a "no current" comes into existence is the date of the "stop tag" notifying Con Edison of the "no current" condition.

2. "Permanent repair" means that service has been permanently restored by the Company to the customer's facility point.

ii) Performance Requirements

The Company will strive to make permanent repairs to all no currents (including both street lights and traffic signals) in a timely manner.

For all no currents that are in existence as of December 31, 2013, Con Edison will make permanent repairs as required by the prior reliability mechanism. An exception will be made in situations in which the Company can demonstrate that it could not complete its repair due to work required to be undertaken by third parties. For all no currents that come into existence on or after January 1, 2014, Con Edison will make permanent repairs for at least 90% of these new cases within 90 days during the winter months, which are defined for purposes of this metric as January, February, March, April, November, and December, and at least 80% of these new cases within 45 days during the remaining six months, May through October. The Company's maximum exposure each year under this metric will be $3 million, as follows:

Adjustment Level
Winter Months $1,500,000
May – October $1,500,000

The Company will make permanent repairs to all no currents that come into existence on or after January 1, 2014 within six months of the dates they come into existence.

The 45-day, 90-day, and six month periods for making permanent repairs may be tolled in the event that, and for the period corresponding to, a third party (such as the municipal customer) must perform service at the site prior to, and as a precondition to, Con Edison's completion of work. The Company will be responsible for providing notice to the third party that its work is a precondition to the Company's work and for demonstrating the applicability of the tolling period.

iii) Extraordinary Circumstances Exception

Where the Company can demonstrate that extraordinary circumstances prevented a "no current" from being permanently repaired within the 45-day, 90-day, or six month time frames, as appropriate, that non-repair will not be considered in measuring the Company's compliance with the above requirements. The determination of whether extraordinary circumstances exist will be made on a case-by-case basis and will be based on the particular facts and circumstances presented (*e.g.*, documentation demonstrating delays of more than 30 days in receiving street opening permits from NYCDOT).

iv) Reporting

The Company's annual report will: (i) report on "no currents" that came into existence from January 1 through December 31 of the prior year; (ii) provide the status of "no currents" that existed before January 1 of the prior year; (iii) identify the "no current" locations that were not repaired within the 45-day, 90-day, and six month periods; and, (iv) describe the extraordinary circumstances, if any, that prevented the permanent repair of the "no currents." For (i) and (ii), the report(s) will include, at a minimum, a listing of the "no current" locations, the date the Company became aware of the problem at each location, and the date of the permanent repair at each location.

(d). **Over-Duty Circuit Breakers**

Many of the Company's substations' circuit breakers are at or over their fault current capacity requiring customers with synchronous distributed generators sited in those networks to install customer side fault current mitigation where possible.[5] Elimination of over-duty circuit breakers and taking other reasonable steps necessary to enable the installation of synchronous generators is a priority because of the significant interest in the use of DG to address a variety of concerns.

[5] For the discussion of the costs of purchasing and installing fault current mitigation technology, please refer to Sec. I.5 (Distributed Generation).

i) Performance Requirements

For 13 kV and 27 kV over-duty circuit breakers, except upon the occurrence of extraordinary system conditions, the Company will replace a target of at least 50 over-duty circuit breakers during the calendar year (the "annual target level") and at least 120 over-duty circuit breakers during each two-year period (the "biannual target level").

There will be revenue adjustment applicable for the annual and for the biannual performance. If the Company does not achieve the annual target level for over-duty circuit breaker replacements, the Company will be subject to a $100,000 per breaker revenue adjustment with a maximum revenue adjustment of $1.5 million. If the Company does not achieve the biannual target level for over-duty circuit breaker replacements, the Company will be subject to an additional $100,000 per breaker revenue adjustment with a maximum revenue adjustment of $3 million.

ii) Selection and Prioritization of Replacements

The Company will, to the extent practicable, seek to include over-duty circuit breaker replacements in situations where maximum fault currents are between 100 and 103 percent of the breaker rating. The Company will determine the prioritization of breaker replacements. The Company will have at least one meeting of all interested DG parties annually to review implementation of the effort and to address prioritization of where to replace over-duty circuit breakers. This annual meeting should be done in conjunction with efforts to improve communications with the DG community.

iii) Extraordinary Circumstances Exception

Where the Company can demonstrate that extraordinary circumstances prevented it from achieving the target levels for the rate year, those circumstances will be factored in measuring the Company's compliance with the above requirements. The determination of whether extraordinary circumstances exist will be made on a case-by-case basis and will be based on the particular facts and circumstances presented.

iv) Reporting

The Company's annual report will: (i) report on the number of over-duty breakers in existence from January 1 through December 31 of the prior year; (ii) provide the status of the Company's efforts on replacing the over-duty breakers; (iii) identify all over-duty breakers that were replaced over the course of the prior calendar year; and (iv) describe the extraordinary circumstances, if any, that prevented the Company from achieving the target level for replacements.

(d) Intrusion Detection System Installation

i) Definitions

1 "Intrusion Detection System" A culmination of physical and electronic security devices installed at a site's perimeter for the purpose of detection, location and identification of an unauthorized individual or object through sound, vibration, motion, and/or light beams.

2 "Bulk Power System" as defined by the Northeast Power Coordinating Council Inc.(" NPCC") as, "the interconnected electrical systems within northeastern North America comprised of system elements on which faults or disturbances can have a significant adverse impact outside of the local area."

3 "Operational" for purposes of this program standard, means the annunciation of an activated Intrusion Detection System alarm at a manned twenty-four hour monitoring station.

ii) Performance Requirements

The Company will install an "Intrusion Detection System" that will encompass the perimeter of the twelve "Bulk Power System" substations identified in Exhibit 748. Con Edison will seek to make "Operational" each Intrusion Detection System no later than December 31, 2014. In the event that each installed Intrusion Detection System is not "Operational" by April 30, 2015, Con Edison will incur a revenue adjustment of

$2.00 million for each Bulk Power System substation where the installation of an operational Intrusion Detection System has not been completed. The revenue adjustment will continue on an annual basis, until the installation of an operational Intrusion Detection System at each Bulk Power Station is complete.

iii) Extraordinary Circumstances Exception

Where the Company can demonstrate that extraordinary circumstances prevented it from achieving the target completion date for the rate year, those circumstances will be factored in measuring the Company's compliance with the above requirements. The determination of whether extraordinary circumstances exist will be made on a case-by-case basis and will be based on the particular facts and circumstances presented.

iv) Reporting

The Company’s annual report will: (*i*) identify each previously identified Bulk Power System Substation that is not equipped with an operational Intrusion Detection System from January 1 through December 31 of the prior year; (*ii*) provide a status of the Company's efforts on installing an Intrusion Detection System at the previously identified Bulk Power System substations; (*iii*) identify all Bulk Power System substations that have an operational Intrusion Detection System and (iv) describe the extraordinary circumstances, if any, that prevented the Company from achieving the target date for Intrusion Detection System installation.

Consolidated Edison Company of New York, Inc.
Cases 13-E-0030, 13-G-0031, 13-S-0032

Gas Safety Performance Metrics

The gas safety performance measures described herein will be in effect for the term of the Gas Rate Plan. All gas safety measures and targets (and associated revenue adjustments)[1] for calendar year 2016 remain in effect thereafter unless and until changed by the Commission.[2]

1. **Leak Management/Emergency Response/Damages**

a. Leak Management - Year-End Total Backlog

If the year-end total leak backlog (types 1,2, 2A, 2M and 3)[3] exceeds the targets set forth below in calendar year 2014, 2015 and 2016, the following negative rate adjustment will be accrued on the Company's books for the benefit of firm customers for each calendar year that the performance measures noted below are not attained, as directed by the Commission.

2014

950 or less	No adjustment
greater than 950	12 basis points[4]

[1] Negative revenue adjustments relating to the Gas Safety Performance metrics in this section shall not exceed 150 basis points in any calendar year, unless and until changed by the Commission.

[2] The 195 mile replacement target established below, for the three-year period 2014 to 2016, does not remain in effect beyond 2016. However, the seventy (70) miles of main removal per year will remain in effect beyond 2016, unless and until changed by the Commission.

[3] These are defined in Company specification G-11809.

[4] The basis point negative revenue adjustment associated with each measure is stated on a pre-tax basis. The revenue requirement equivalent of a basis point on common equity capital per the gas revenue requirements under this Proposal is estimated to be $290,000 in RY1, $320,000 in RY2 and $360,000 in RY3.

2015	
850 or less	No adjustment
greater than 850	12 basis points
2016	
750 or less	No adjustment
greater than 750	12 basis points

b. Emergency Response - 30 Minute Response Time

If Con Edison does not respond to gas leak or odor calls within 30 minutes for at least 75 percent of the calls for calendar years 2014, 2015 and 2016 a negative rate adjustment of 6 basis points will be accrued on the Company's books for the benefit of firm customers for each calendar year that the performance measures are not attained, as directed by the Commission.

Gas leak and odor calls resulting from mass area odor complaints, major weather related occurrences, and major equipment failure are excluded from the calculations for the 30-minute response time.

c. Emergency Response - 45 Minute Response Time

If Con Edison does not respond to gas leak or odor calls within 45 minutes for at least 90 percent of the calls for calendar years 2014, 2015 and 2016, a negative rate adjustment of 4 basis points will be accrued on the Company's books for the benefit of firm customers for each calendar year that the performance measures are not attained, as directed by the Commission.

Gas leak and odor calls resulting from mass area odor complaints, major weather related occurrences, and major equipment failure are excluded from the calculations for the 45-minute response time.

d. Emergency Response - 60 Minute Response Time

If Con Edison does not respond to gas leak or odor calls within 60 minutes for at least 95 percent of the calls for calendar years 2014, 2015 and 2016, a negative rate adjustment of 2 basis points will be accrued on the Company's books for the benefit of firm customers for each calendar year that the performance measures are not attained, as directed by the Commission.

Gas leak and odor calls resulting from mass area odor complaints, major weather related occurrences, and major equipment failure are excluded from the calculations for the 60-minute response time.

e. Damage Prevention

All damages will be tracked, measured and counted following the guidelines for the data reported for the Annual Gas Safety Performance Measures report.

i) Damages to Gas Facilities Resulting from Mismarks

If the total number of damages to Company gas facilities resulting from mismarks made by the Company and its contractors with respect to the location of Company gas facilities exceeds the targets set forth below per 1,000 one-call tickets[5] in calendar year 2014, 2015 and 2016, the negative rate adjustment associated with such target will be accrued on the Company's

[5]For the purposes of this section, one-call tickets are defined as locate requests involving a work area in the Company's Bronx, Queens, Manhattan and Westchester service territory only.

books for the benefit of firm customers for each calendar year that the performance measure noted below is not attained, as directed by the Commission.

0.40 or less	No adjustment
greater than 0.40	10 basis points

ii) Damages by Company Employees and Company Contractors

If the total number of damages to Company gas facilities made by Company employees and Company contractors exceeds the targets set forth below per 1,000 one-call tickets in calendar year 2014, 2015 and 2016, the negative rate adjustment associated with such target will be accrued on the Company's books for the benefit of firm customers for each calendar year that the performance measure noted below is not attained, as directed by the Commission.

2014

0.22 or less	No adjustment
greater than 0.22	4 basis points

2015

0.18 or less	No adjustment
greater than 0.18	4 basis points

2016

0.15 or less	No adjustment
greater than 0.15	4 basis points

iii) Total Damages

If the number of total damages to Company gas facilities made by any party exceeds the targets set forth below per 1,000 one-call tickets in calendar year 2014, 2015 and 2016, the negative rate adjustment associated with such target will be accrued on the Company's books for the benefit of firm customers for each calendar year that the performance measure noted below is not attained, as directed by the Commission.

1.60 or less	No adjustment
greater than 1.60	4 basis points

2. **Gas Main Replacement**

The Company will remove from service 195 miles of leak-prone gas main during the three calendar year period 2014 to 2016. The Company will remove a minimum of 60 miles in 2014, 65 miles in 2015 and 70 miles in 2016. The Company will remove from service segments identified under its Main Replacement Program ("MRP") model of at least: 45 miles in 2014, 50 miles in 2015 and 55 miles in 2016.

For each calendar year:

- a minimum of 30 miles of main removed from service will be cast iron/wrought iron main;
- a minimum of 20 miles of main removed from service will be bare/unprotected steel main;
- no more than 15 miles of leak-prone gas main removed from service from other programs (e.g., oil-to-gas conversions) will be counted towards the annual performance target.
- of the 15 miles of leak-prone gas main removed from service from other programs:
  - no more than five miles of abandoned/retired leak-prone gas main removed from service will be counted towards the annual performance target; and
  - no more than ten miles of leak-prone gas main removed from service resulting from public improvement/interference replacement projects will be counted towards the annual performance target.

If the Company does not meet the annual target for removal of leak-prone gas main, including the annual MRP minimums and the minimums of 30 miles of cast iron and 20 miles of bare/unprotected steel main replacement, in 2014, 2015 or 2016, the Company will accrue on the Company's books of account a negative revenue adjustment equivalent to 8 basis points for such calendar year(s), which will be applied to the benefit of firm customers, as directed by the Commission.

If the Company does not remove from service a total of 195 miles of leak prone pipe over the three-year period, including removing 90 miles of cast iron main and 60 miles of bare/unprotected steel main, a negative rate adjustment equivalent to 24 basis points will be accrued on the Company's books for the benefit of firm service customers; provided, however, if the Company incurs a negative revenue adjustment in any calendar year, the 24 basis point negative rate adjustment will be reduced by the negative revenue adjustment already incurred.

3. **Gas Regulations Performance Measure**

This metric applies to instances of noncompliance (violations) with the gas safety regulations set forth below that are identified during Staff field and records audits. The categorization of violations hereunder as “High” or “Other” Risk is for administrative purposes of this metric only and do not constitute an admission by the Company as to the level of risk associated with any such regulation or the violation thereunder or that there is any risk associated with a violation.

Only violations identified and included in Staff field and record audit letters may be counted for purposes of this metric. At the conclusion of each audit, Staff and the Company will have a compliance meeting where Staff will present its findings to the Company, including which violation(s), if any, that Staff recommends be subject to this metric. The Company will have five business days from the date of the compliance meeting to cure any identified document deficiency. Only official Company records, as defined in the Company’s Operating and Maintenance plan, will be considered by Staff as a cure to a document deficiency. Violations that encompass more than one code section shall only count as one occurrence for this metric.[6]

A baseline of 67 High Risk and 96 Other Risk violations was established using the last five-year (2009 through 2013) average of Staff's field and records audit results. Annual thresholds for negative revenue adjustments that assume future Staff field and record audits consistent with the five-year period are set at a 25% reduction to the baseline for RY1, 50% reduction to the baseline for RY2 and 75% reduction to the baseline for RY3. Negative revenue adjustments, if any, would begin only after an applicable threshold is exceeded, as set forth in the following chart:

High Risk	Other Risk
Baseline – 67 Occurrences Threshold - 50 RY1, 33 RY2, 17 RY3 RY1 – 51 – 101 (1/2 BP); 102+ (1 BP) RY2 – 34 – 69 (1/2 BP); 70+ (1 BP) RY3 – 18 – 38 (1/2 BP); 39+ (1 BP)	Baseline – 96 Occurrences Threshold - 72 RY1, 48 RY2, 24 RY3 RY1 – 73 – 123 (1/9 BP); 124+ (1/3 BP) RY2 – 49 – 84 (1/9 BP); 85+ (1/3 BP) RY3 – 25 – 45 (1/9 BP); 46+ (1/3 BP)

Any negative revenue adjustments assessed under this metric shall not exceed 50 basis points for 2014, 75 basis points for 2015 and 100 basis points for 2016 and subsequent calendar years until changed by the Commission.

This metric will be effective as of January 1, 2014, and will be measured on a calendar year basis. With respect to violations, only documentation or actions performed,

[6] However, this is without prejudice to a penalty action under the Public Service Law for any violation not counted under this metric.

or required to be documented or performed, on or after the date of the Commission's approval of the Joint Proposal will constitute an occurrence under the metric. Violations that initially occur in 2013 but continue in to 2014 will be subject to this measure.

Staff will submit its final audit reports to the Secretary under Case 13-G-0031. If the Company disputes any of Staff's final audit results, or elects to seek exclusions based on extenuating circumstances, the Company may appeal Staff's finding to the Commission. If the Company elects to dispute any of Staff's findings, the Company will not incur a negative revenue adjustment on those Staff findings until such time as the Commission has issued a final decision on the Company's appeal. Upon Company request, the Commission may in its discretion, provide the Company with an evidentiary hearing prior to any final determination. The Company does not waive its right to seek judicial appeal of any Commission determination regarding a violation or penalty under applicable law.

During the term of the Gas Rate Plan, the Company shall not be precluded from seeking Commission approval to implement positive incentives associated with gas safety performance as an offset to negative revenues adjustments associated with these gas safety performance metrics based on Commission action implementing positive incentive for another utility and/or indicating a willingness to consider positive incentives.

4. **General Provisions**

The Company will report its annual performance in each of the areas set forth in this Appendix to the Secretary no later than sixty (60) days following the end of each calendar year. If a performance metric is not met, the associated negative revenue adjustment will be excused when the Company can demonstrate to the Commission extenuating circumstances that prevented the Company from meeting such performance metric. The determination of whether such circumstances exist will be made on a case-by-case basis by the Commission.

5. **Customer Satisfaction**

The levels of the Company's customers' satisfaction will be determined by surveys performed semi-annually by an outside vendor selected by the Company. The surveys, which will be the same surveys used in the current gas rate plan, will measure customers' satisfaction with the handling of calls to the Gas Emergency Response Center relating to gas service. Should the average of the two system-wide satisfaction survey indices for any Rate Year fall below 88.1 percent, Con Edison will provide a credit to customers, as directed by the Commission. The gross amount of the credit will be calculated proportionately from zero at a satisfaction level of 88.1 percent or above, up to a maximum of $3.3 million at a satisfaction level of 87.5 percent or below. System-wide emergencies will not be included in the surveys conducted under this provision.

Con Edison will submit reports on its performance of the customer satisfaction surveys twice a year following performance of each survey. The second report will also provide information for the annual period and, if applicable, any credit due customers.

HIGH RISK SECTIONS PART 255

ACTIVITY TITLE	CODE SECTION	RISK FACTOR
Material - General	255.53(a),(b),(c)	HIGH
Transportation of Pipe	255.65	HIGH
Pipe Design - General	255.103	HIGH
Design of Components - General Requirements	255.143	HIGH
Design of Components - Flexibility	255.159	HIGH
Design of Components - Supports and anchors	255.161	HIGH
Compressor Stations: Emergency shutdown	255.167	HIGH
Compressor Stations: Pressure limiting devices	255.169	HIGH
Compressor Stations: Ventilation	255.173	HIGH
Valves on pipelines to operate at 125 psig or more	255.179	HIGH
Distribution line valves	255.181	HIGH
Vaults: Structural Design requirements	255.183	HIGH
Vaults: Drainage and waterproofing	255.189	HIGH
Protection against accidental overpressuring	255.195	HIGH
Control of the pressure of gas delivered from high pressure distribution systems	255.197	HIGH
Requirements for design of pressure relief and limiting devices	255.199	HIGH
Required capacity of pressure relieving and limiting stations	255.201	HIGH
Qualification of welding procedures	255.225	HIGH
Qualification of Welders	255.227	HIGH
Protection from weather	255.231	HIGH
Miter Joints	255.233	HIGH
Preparation for welding	255.235	HIGH
Inspection and test of welds	255.241(a),(b)	HIGH
Nondestructive testing-Pipeline to operate at 125 PSIG or more	255.243(a)-(e)	HIGH
Welding inspector	255.244(a),(b),(c)	HIGH
Repair or removal of defects	255.245	HIGH
Joining Of Materials Other Than By Welding - General	255.273	HIGH
Joining Of Materials Other Than By Welding - Copper Pipe	255.279	HIGH
Joining Of Materials Other Than By Welding - Plastic Pipe	255.281	HIGH
Plastic pipe: Qualifying persons to make joints	255.285(a),(b),(d)	HIGH
Notification requirements	255.302	HIGH
Compliance with construction standards	255.303	HIGH
Inspection: General	255.305	HIGH
Inspection of materials	255.307	HIGH
Repair of steel pipe	255.309	HIGH
Repair of plastic pipe	255.311	HIGH
Bends and elbows	255.313(a),(b),(c)	HIGH
Wrinkle bends in steel pipe	255.315	HIGH
Installation of plastic pipe	255.321	HIGH
Underground clearance	255.325	HIGH
Customer meters and service regulators: Installation	255.357(d)	HIGH
Service lines: Installation	255.361(e),(f),(g),(h),(i)	HIGH
Service lines: Location of valves	255.365(b)	HIGH
External corrosion control: Buried or submerged pipelines installed after July 31, 1971	255.455(d),(e)	HIGH
External corrosion control: Buried or submerged pipelines installed before August 1, 1971	255.457	HIGH
External corrosion control: Protective coating	255.461(c)	HIGH
External corrosion control: Cathodic protection	255.463	HIGH
External corrosion control: Monitoring	255.465(a),(e)	HIGH
Internal corrosion control: Design and construction of transmission line	255.476(a),(c)	HIGH
Remedial measures: General	255.483	HIGH
Remedial measures: transmission lines	255.485(a),(b)	HIGH
Strength test requirements for steel pipelines to operate at 125 PSIG or more	255.505(a),(b),(c),(d)	HIGH
General requirements (UPGRADES)	255.553 (a),(b),(c),(f)	HIGH
Upgrading to a pressure of 125 PSIG or more in steel pipelines	255.555	HIGH
Upgrading to a pressure less than 125 PSIG	255.557	HIGH
Conversion to service subject to this Part	255.559(a)	HIGH
General provisions	255.603	HIGH
Operator Qualification	255.604	HIGH
Essentials of operating and maintenance plan	255.605	HIGH
Change in class location: Required study	255.609	HIGH
Damage prevention program	255.614	HIGH
Emergency Plans	255.615	HIGH
Customer education and information program	255.616	HIGH
Maximum allowable operating pressure: Steel or plastic pipelines	255.619	HIGH
Maximum allowable operating pressure: High pressure distribution systems	255.621	HIGH
Maximum and minimum allowable operating pressure: Low pressure distribution systems	255.623	HIGH
Odorization of gas	255.625(a),(b)	HIGH

Tapping pipelines under pressure	255.627	HIGH
Purging of pipelines	255.629	HIGH
Control Room Management	255.631(a)	HIGH
Transmission lines: Patrolling	255.705	HIGH
Leakage Surveys - Transmission	255.706	HIGH
Transmission lines: General requirements for repair procedures	255.711	HIGH
Transmission lines: Permanent field repair of imperfections and damages	255.713	HIGH
Transmission lines: Permanent field repair of welds	255.715	HIGH
Transmission lines: Permanent field repair of leaks	255.717	HIGH
Transmission lines: Testing of repairs	255.719	HIGH
Distribution systems: Leak surveys and procedures	255.723	HIGH
Compressor stations: procedures	255.729	HIGH
Compressor stations: Inspection and testing relief devices	255.731	HIGH
Compressor stations: Additional inspections	255.732	HIGH
Compressor stations: Gas detection	255.736	HIGH
Pressure limiting and regulating stations: Inspection and testing	255.739(a),(b)	HIGH
Regulator Station Overpressure Protection	255.743(a),(b)	HIGH
Transmission Line Valves	255.745	HIGH
Prevention of accidental ignition	255.751	HIGH
Protecting cast iron pipelines	255.755	HIGH
Replacement of exposed or undermined cast iron piping	255.756	HIGH
Replacement of cast iron mains paralleling excavations	255.757	HIGH
Leaks: Records	255.807(d)	HIGH
Leaks: Instrument sensitivity verification	255.809	HIGH
Leaks: Type 1	255.811(b),(c),(d),(e)	HIGH
Leaks: Type 2A	255.813(b),(c),(d)	HIGH
Leaks: Type 2	255.815	HIGH
Leak Follow-up	255.819(a)	HIGH
High Consequence Areas	255.905	HIGH
Required Elements (IMP)	255.911	HIGH
Knowledge and Training (IMP)	255.915	HIGH
Identification of Potential Threats to Pipeline Integrity and Use of the Threat Identification in an Integrity Program (IMP)	255.917	HIGH
Baseline Assessment Plan(IMP)	255.919	HIGH
Conducting a Baseline Assessment (IMP)	255.921	HIGH
Direct Assessment (IMP)	255.923	HIGH
External Corrosion Direct Assessment (ECDA) (IMP)	255.925	HIGH
Internal Corrosion Direct Assessment (ICDA) (IMP)	255.927	HIGH
Confirmatory Direct Assessment (CDA) (IMP)	255.931	HIGH
Addressing Integrity Issues (IMP)	255.933	HIGH
Preventive and Mitigative Measures to Protect the High Consequence Areas (IMP)	255.935	HIGH
Continual Process of Evaluation and Assessment (IMP)	255.937	HIGH
Reassessment Intervals (IMP)	255.939	HIGH
General requirements of a GDPIM plan	255.1003	HIGH
Implementation requirements of a GDPIM plan.	255.1005	HIGH
Required elements of a GDPIM plan.	255.1007	HIGH
Required report when compression couplings fail.	255.1009	HIGH
Requirements a small liquefied petroleum gas (LPG) operator must satisfy to implement a GDPIM plan	255.1015	HIGH

HIGH RISK SECTIONS PART 261		
Operation and maintenance plan	261.15	HIGH
Leakage Survey	261.17(a),(c)	HIGH
Carbon monoxide prevention	261.21	HIGH
Warning tag procedures	261.51	HIGH
HEFPA Liaison	261.53	HIGH
Warning Tag Inspection	261.55	HIGH
Warning tag: Class A condition	261.57	HIGH
Warning tag: Class B condition	261.59	HIGH

OTHER RISK SECTIONS PART 255

ACTIVITY TITLE	CODE SECTION	RISK FACTOR
Preservation of records	255.17	OTH
Compressor station: Design and construction	255.163	OTH
Compressor station: Liquid removal	255.165	OTH
Compressor stations: Additional safety equipment	255.171	OTH
Vaults: Accessibility	255.185	OTH
Vaults: Sealing, venting, and ventilation	255.187	OTH
Calorimeter or calorimeter structures	255.190	OTH
Design pressure of plastic fittings	255.191	OTH
Valve installtion in plastic pipe	255.193	OTH
Instrument, control, and sampling piping and components	255.203	OTH
Limitations On Welders	255.229	OTH
Quality assurance program	255.230	OTH
Preheating	255.237	OTH
Stress relieving	255.239	OTH
Inspection and test of welds	255.241(c)	OTH
Nondestructive testing-Pipeline to operate at 125 PSIG or more	255.243(f)	OTH
Plastic pipe: Qualifying joining procedures	255.283	OTH
Plastic pipe: Qualifying persons to make joints	255.285(c),(e)	OTH
Plastic pipe: Inspection of joints	255.287	OTH
Bends and elbows	255.313(d)	OTH
Protection from hazards	255.317	OTH
Installation of pipe in a ditch	255.319	OTH
Casing	255.323	OTH
Cover	255.327	OTH
Customer meters and regulators: Location	255.353	OTH
Customer meters and regulators: Protection from damage	255.355	OTH
Customer meters and service regulators: Installation	255.357(a),(b),(c)	OTH
Customer meter installations: Operating pressure	255.359	OTH
Service lines: Installation	255.361(a),(b),(c),(d)	OTH
Service lines: valve requirements	255.363	OTH
Service lines: Location of valves	255.365(a),(c)	OTH
Service lines: General requirements for connections to main piping	255.367	OTH
Service lines: Connections to cast iron or ductile iron mains	255.369	OTH
Service lines: Steel	255.371	OTH
Service lines: Cast iron and ductile iron	255.373	OTH
Service lines: Plastic	255.375	OTH
Service lines: Copper	255.377	OTH
New service lines not in use	255.379	OTH
Service lines: excess flow valve performance standards	255.381	OTH
External corrosion control: Buried or submerged pipelines installed after July 31, 1971	255.455(a)	OTH
External corrosion control: Examination of buried pipeline when exposed	255.459	OTH
External corrosion control: Protective coating	255.461(a),(b),(d),(e),(f),(g)	OTH
Rectifier Inspection	255.465 (b),(c),(f)	OTH
External corrosion control: Electrical isolation	255.467	OTH
External corrosion control: Test stations	255.469	OTH
External corrosion control: Test lead	255.471	OTH
External corrosion control: Interference currents	255.473	OTH
Internal corrosion control: General	255.475(a),(b)	OTH
Atmospheric corrosion control: General	255.479	OTH
Atmospheric corrosion control: Monitoring	255.481	OTH
Remedial measures: transmission lines	255.485(c)	OTH
Remedial measures: Pipelines lines other than cast iron or ductile iron lines	255.487	OTH
Remedial measures: Cast iron and ductile iron pipelines	255.489	OTH
Direct Assessment	255.490	OTH
Corrosion control records	255.491	OTH
General requirements (TESTING)	255.503	OTH
Strength test requirements for steel pipelines to operate at 125 PSIG or more	255.505(e),(h),(i)	OTH

Test requirements for pipelines to operate at less than 125 PSIG	255.507	OTH
Test requirements for service lines	255.511	OTH
Environmental protection and safety requirements	255.515	OTH
Records (TESTING)	255.517	OTH
Notification requirements (UPGRADES)	255.552	OTH
General requirements (UPGRADES)	255.553(d),(e)	OTH
Conversion to service subject to this Part	255.559(b)	OTH
Change in class location: Confirmation or revision of maximum allowable operating pressure	255.611(a),(d)	OTH
Continuing surveillance	255.613	OTH
Odorization	255.625(e),(f)	OTH
Pipeline Markers	255.707(a),(c),(d),(e)	OTH
Transmission lines: Record keeping	255.709	OTH
Distribution systems: Patrolling	255.721(b)	OTH
Test requirements for reinstating service lines	255.725	OTH
Inactive Services	255.726	OTH
Abandonment or inactivation of facilities	255.727(b)-(g)	OTH
Compressor stations: storage of combustible materials	255.735	OTH
Pressure limiting and regulating stations: Inspection and testing	255.739(c),(d)	OTH
Pressure limiting and regulating stations: Telemetering or recording gauges	255.741	OTH
Regulator Station MAOP	255.743 (c)	OTH
Service Regulator - Min.& Oper. Load	255.744 (d),(e)	OTH
Distribution Line Valves	255.747	OTH
Valve maintenance: Service line valves	255.748	OTH
Regulator Station Vaults	255.749	OTH
Caulked bell and spigot joints	255.753	OTH
Reports of accidents	255.801	OTH
Emergency lists of operator personnel	255.803	OTH
Leaks General	255.805(a),(b),(e),(g),(h)	OTH
Leaks: Records	255.807(a),(b),(c)	OTH
Type 2	255.815(b),(c),(d)	OTH
Type 3	255.817	OTH
Interruptions of service	255.823(a),(b)	OTH
Logging and analysis of gas emergency reports	255.825	OTH
Annual Report	255.829	OTH
Reporting safety-related conditions	255.831	OTH
General (IMP)	255.907	OTH
Changes to an Integrity Management Program (IMP)	255.909	OTH
Low Stress Reassessment (IMP)	255.941	OTH
Measuring Program Effectiveness (IMP)	255.945	OTH
Records (IMP)	255.947	OTH
Records an operator must keep	255.1011	OTH

OTHER RISK SECTIONS PART 261		
High Pressure Piping - Annual Notice	261.19	OTH
Warning tag: Class C condition	261.61	OTH
Warning tag: Action and follow-up	261.63(a)-(h)	OTH
Warning Tag Records	261.65	OTH

Consolidated Edison Company of New York, Inc.
Cases 13-E-0030, 13-G-0031, 13-S-0032
Steam Performance Metrics

The steam safety performance measures described herein will be in effect for the term of the Steam Rate Plan. The response time and steam leak backlog performance measures for calendar year 2016 will remain in effect thereafter unless and until changed by the Commission.

a. Emergency Response – 45-Minute Response Time

If a Con Edison Qualified Responder does not respond to steam leak/vapor calls from third parties within 45 minutes at the percentages set forth below for RY1, RY2 and RY3, the following negative revenue adjustment will be applied to the benefit of customers for each calendar year that the performance measure is not attained, as directed by the Commission.

Response Percentage	Negative Adjustment
90% or more	No adjustment
More than 88% but less than 90%	1.5 basis points[1]
88% or less	3.0 basis points

b. Emergency Response – 60-Minute Response Time

If a Con Edison Qualified Responder does not respond to steam leak/vapor calls from third parties within 60 minutes at the percentages set forth below for RY1, RY2 and RY3, the following negative rate adjustment will be applied to the benefit of customers

[1] The basis point negative revenue adjustment associated with each measure is stated on a pre-tax basis. The revenue requirement equivalent of a basis point on common equity capital per the steam revenue requirements under this Proposal is estimated to be $150,000.

for each calendar year that the performance measure is not attained, as directed by the Commission.

Response Percentage	Negative Adjustment
95% or more	No adjustment
More than 93% but less than 95%	1.5 basis points
93% or less	3.0 basis points

c. Emergency Response – Exceptions

Steam leak/vapor calls resulting from major weather-related occurrences, and other circumstances outside of the Company's control will be excluded from the calculations for the 45- and 60-minute response times.

If a performance metric is not met, the associated negative revenue adjustment will be excused when the Company can demonstrate to the Commission extenuating circumstances that prevented it from meeting such performance metric. The determination of whether such circumstances exist will be made on a case-by-case basis by the Commission.

d. Emergency Response – Definition

A Qualified Responder shall be any person trained in the appropriate Company procedures to recognize abnormal operating conditions, identify any threats to public safety resulting from Steam system conditions, and take proper actions to make situations safe. This includes, but is not limited to, Steam Distribution crews, supervisors and field planners.

e. Steam Leak Backlog

For RY1, RY2 and RY3, separate negative rate adjustments of 3.0 basis points will be applied to the benefit of customers if the average month-end steam leak backlog of the 12-month period ending December 31 exceeds 22.

f. Steam Leak Backlog - Exceptions

Con Edison shall have the right to petition the Commission with any extenuating circumstances or additional information for consideration before determination of any negative rate adjustments. If a performance metric is not met, the associated negative revenue adjustment will be excused if the Company can demonstrate to the Commission extenuating circumstances that prevented it from meeting such performance metric. The determination of whether such circumstances exist (*e.g*., extreme weather, Department of Transportation work embargos) will be made on a case-by-case basis by the Commission.

g. Reporting

Con Edison shall report to the Secretary no later than 60 days following the end of the calendar year regarding the Company's performance for each of the three measures noted above.

2. **Customer Satisfaction**

To assess the satisfaction level of steam customers, the Company will conduct two surveys per year.

i. Con Edison will perform two surveys per year of a representative sample of the steam customers who have contacted the Company. The representative sample is defined as a valid statistical sample of customers who have contacted the Company developed in consultation with an independent professional survey vendor.

ii. The Company will continue to use the same survey instrument that it used as part of the 2006 Steam Rate Plan. The surveys will be conducted within one month of the end of each six-month period.

iii. Con Edison will prepare an annual report that compiles, summarizes, and identifies key issues associated with the two surveys conducted during the previous Rate Year. This report will be completed within 90 days of the end of each Rate Year and submitted to the Secretary, with copies provided to interested parties who request them.

iv. Con Edison will be subject to a $50,000 revenue adjustment each Rate Year if it fails to conduct the two surveys and submit the report described above.

Consolidated Edison Company of New York, Inc.
Cases 13-E-0030, 13-G-0031, 13-S-0032

Customer Service Performance Mechanism

The Customer Service Performance Mechanism ("CSPM") described herein will be in effect for the term of the Electric Rate Plan and thereafter unless and until changed by the Commission.

a. Operation of Mechanism

The CSPM establishes threshold performance levels for designated aspects of customer service. The threshold performance levels are detailed on page 6 of Appendix 19. Failure by the Company to achieve the specified targets will result in a revenue adjustment of up to $40 million annually. All revenue adjustments related to the CSPM will be deferred for the benefit of customers.

b. Exclusions

Abnormal operating conditions are deemed to occur during any period of emergency, catastrophe, strike, natural disaster, major storm, or other unusual event not in the Company's control affecting more than 10 percent of the customers in an operating area during any month. A major storm will have the same definition as set forth in 16 NYCRR Part 97.

i) In the event abnormal operating conditions in one (1), two (2) or three (3) of the Company's six operating areas affect the Company's ability to perform any activity that is part of this CSPM, the data for the operating area(s) experiencing the abnormal operating conditions will be omitted from the calculation and the Company's results for any activity that is part of the CSPM that is affected by such abnormal operating conditions will be measured only by the data from the other operating area(s) for the period of the abnormal operating conditions.

ii) If abnormal operating conditions occur in more than three operating areas so that monthly results cannot be measured for a given activity, the month will be eliminated in the calculation of the actual annual average performance for that activity.

iii) In the event that abnormal operating conditions affecting the Company's ability to perform a given activity occur in more than three operating areas for an entire Rate Year, the activity will be inapplicable in that Rate Year and the associated revenue adjustment amount for that activity will also be inapplicable in that Rate Year.

iv) If changes in Company operations render it impractical to continue to measure performance in any activity, the measurement method and/or threshold standard will be revised or an alternative method or activity selected for the remainder of the period during which this CSPM is operative. Any such modifications must be mutually agreed to by Staff and the Company in writing. In the event Staff and the Company cannot agree to a modification, the revenue adjustment amount associated with the activity that can no longer be measured will be reallocated among the other activities for the remainder of the period during which this CSPM is operative.

c. Reporting

The Company will prepare an annual report on its performance that will be filed with the Secretary by March 1 following each Rate Year.[1] Each report will state: (i) any changes anticipated to be implemented in the following measurement period in any activity reflected in this Proposal, (ii) a summary of the effect of any of the exclusions described herein and/or any significant changes in operations which led to the reported performance level during the measurement period; and (iii) whether a revenue adjustment is applicable, and if so, the amount of the revenue adjustment. The Company will maintain sufficient records to support such reports.

d. Threshold Standards

The Company's threshold performance will be measured based on the Company's cumulative monthly performance for each Rate Year for the following four activities, except as otherwise noted.

i) Commission Complaints

Con Edison's Commission complaint performance measure will be the 12-month complaint rate per 100,000 customers as reported by the Office of Consumer Services each year for the 12-month period ending in December, based on the number of complaints received. A complaint is a contact by a customer, applicant, or customer's or applicant's agent that follows a contact with the Company about the issue of concern as to which the Company, having been given a reasonable opportunity to address the matter, has not satisfied the customer. The issue of concern must be one within the Company's responsibility and control, including an action, practice or conduct of the Company or its

[1] Due to the commencements of a new Rate Plan on January 1, 2014, the Company will file its final report under the existing Rate Plan for the period April 1, 2013 through December 31, 2013. The Report will be filed by March 1, 2014.

employees, not matters within the responsibility or control of an alternative service provider. Complaints resulting from the price of electric energy and capacity or the operation of the Company's MSC and that do not otherwise present just cause for charging a complaint against the Company will not be counted as complaints for the purposes of the CSPM. One or more contacts by a rate consultant raising the same issue as to more than one account, whether such contacts are made at the same time or different times, will not be counted as more than one complaint if the issue is under consideration by the Department or the Commission and no Company deficiency is found. Contacts by customers about the Shared Meter Law will not be complaints if the contact is about the requirements of the Shared Meter Law and no Company deficiency is found. The annual report filed by the Company shall provide an accounting, without identifying specific customer information (*e.g.*, by listing complaints by reference number, without providing customer names), of any complaints that the Company believes should not be counted due to the provisions of this paragraph, and state the resulting adjusted Commission Complaint rate.

ii) Call Answer Rate

"Call Answer Rate" is the percentage of calls answered by a Company representative within thirty (30) seconds of the customer's request to speak to a representative between the hours of 9:00 AM and 5:00 PM Monday through Friday (excluding holidays). The performance rate is the sum of the system-wide number of calls answered by a representative within thirty (30) seconds divided by the sum of the system-wide number of calls answered by representatives.

iii) Satisfaction of Callers, Visitors, and Emergency Contacts

The average of the satisfaction index ratings on the semi-annual surveys (conducted during the second and fourth quarters) of emergency callers (electric only), Call Center callers (non-emergency), and Service Center and Walk-in Center visitors, separately conducted by Communication Research Associates or another professional survey organization during each Rate Year. The Company shall notify Staff of any process instituted by the Company to change its survey contractor. The Company shall notify Staff at least six (6) months prior to making any material change to its survey questionnaire or survey methodologies.

iv) Outage Notification

The specific activities for communicating with customers, the public, and other external interests during defined electric service outage events remain as described by the Commission in Case 00-M-0095.[2] For each activity noted in that Order, performance that fails to meet the applicable threshold performance standard will result in a revenue adjustment at twice the level set forth in that Order (e.g, for each failure to complete a communication activity within the required time, the negative adjustment would be increased from $150,000 to $300,000). The overall amount at risk for Outage Notification ($8 million, established in Case 07-E-0523) shall remain unchanged.

2 Case 00-M-0095, Joint Petition of Consolidated Edison, Inc. and Northeast Utilities for Approval of a Certificate of Merger, with All Assets Being Owned by a Single Holding Company, Order Approving Outage Notification Incentive Mechanism (issued April 23, 2002).

Customer Service Performance Mechanism
Incentive Targets

Indicator	Maximum Revenue Adjustment	Threshold Level	Revenue Adjustment
Commission Complaints	$ 9 million	</ = 2.3 >2.3-</=2.6 >2.6-</=2.9 >2.9	N/A $2,000,000 $5,000,000 $9,000,000
Customer Satisfaction Surveys	$18 million		
Customer Survey of Emergency Calls (electric only)	$6 million	>/=79.0 <79.0->/=76.0 <76.0->/=73.0 <73.0	N/A $1,500,000 $3,000,000 $6,000,000
Customer Satisfaction Survey of Phone Center Callers (non emergency)	$6 million	>/=82.0 <82.0->/=80.0 <80.0->/=78.0 <78.0	N/A $1,500,000 $3,000,000 $6,000,000
Customer Satisfaction Survey of Service Center Visitors	$6 million	>/=84.0 <84.0->/=82.0 <82.0->/=80.0 <80.0	N/A $1,500,000 $3,000,000 $6,000,000
Outage Notification	$ 8 million	Communication Timeliness Communication Content	$300,000 per communication activity
Call Answer Rate	$ 5 million	>/=63.0% <63%->/=62.0% <62.0%->/=61.0% <61.0%->/=60.0% <60.0%	N/A $1,000,000 $2,000,000 $4,000,000 $5,000,000

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Case 13-E-0030

Revenue Allocation and Rate Design

Revenue Allocation

Based on a two-year rate plan, the delivery revenue change for each Rate Year will include (1) changes in T&D related revenues; (2) an increase in the MAC revenue requirement (RY1 only); (3) an increase in the purchased power working capital component of the Merchant Function Charge (MFC); (4) an increase in the T&D-related revenue to offset the reduction in the TCC imputation; and (5) recovery of incremental costs associated with the Low-Income Program. The T&D related delivery revenue change, including incremental Low-Income Program costs, will be allocated to Con Edison customers and NYPA delivery service. The increase in the MAC revenue requirement for RY1 will be allocated to Con Edison full service and retail access customers. The change to the purchased power working capital is allocable only to Con Edison full service customers. The increase in the T&D delivery revenues related to the TCC imputation change is allocable only to Con Edison full service and retail access customers. The revenue allocation for each Rate Year is shown in Table 2 of this Appendix.

The Rate Year T&D delivery revenue change, less gross receipts taxes, for each Rate Year will be allocated among the classes in four steps:

Step 1: Revenue Realignment

Con Edison T&D Delivery Revenues at the current rate level will be realigned in each Rate Year to address a portion of the revenue adjustments resulting from the 2010 Embedded Cost of Service ("ECOS") study. NYPA T&D Delivery Revenues at the current rate level will be realigned in each Rate Year based on the settlement in this proceeding. The specific revenue adjustments are set forth in Table 1 to this Appendix.

Specifically, in RY1, the NYPA class will be assigned an additional $9,000,000 above the otherwise applicable rate change. The surpluses/deficiencies for all other classes, except SC 12, as shown in Table 1 will be phased in over the two Rate Years. Surplus classes are SC 5 Rate II, SC 9 Rate I, SC 9 Rate II and SC 13. Deficient classes are SC 2, SC5 Rate I, SC 8 Rates I and II, and SC 12 Rates I and II. Average classes (i.e., neither surplus nor deficient) include SC 1 and SC 6. In order to mitigate the bill impacts on SC 12 customers, one half of the SC 12 deficiency will be phased in over two Rate Years. The net system deficiency remaining in RY1 will then be allocated to the surplus classes on an across-the-board basis.

In RY2, the NYPA class will receive an additional $9,000,000 adjustment above the otherwise applicable rate change. The net system deficiency remaining will be handled in the same fashion as was done for RY1.

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Case 13-E-0300

The impact of these revenue adjustments on all the customer classes, as shown on Table 1 and in Column (2) of Table 2 of this Appendix will then be added to the bundled T&D revenue before the revenue change to become the re-aligned bundled T&D revenue (Column (3) of Table 2).

Step 2: Allocation of T&D Rate Change
The RY T&D related delivery revenue change will be computed by deducting the change in the MAC revenue requirement and the change in purchased power working capital from the total rate change, excluding GRT. The resultant RY T&D related delivery revenue change net of the revenue increase associated with the TCC imputation change, plus incremental costs associated with the Low-Income Program, will then be apportioned as a uniform percentage increase to Con Edison and NYPA classes in proportion to their respective re-aligned bundled T&D revenues (Column (4) of Table 2), with a final adjustment made to each class's T&D related delivery revenue change to reflect the ECOS revenue adjustments from Step 1. The revenue increase associated with the TCC imputation change is allocable solely to Con Edison full service and retail access customers as shown in Column 4a of Table 2 (RY1 only). The resultant total T&D changes are shown in Column 5 of Table 2.

For RY1, the incremental costs associated with the Low-Income Program as explained in the Proposal that will be reflected in the revenue allocation will be set at $9.25 million and will include recovery of the estimated annual rate reductions in excess of the amount reflected in current April 2013 base rates (i.e., $47.5 million less $38.25 million). The cost of the low-income reconnection fee waivers remains at the current level (i.e., $500,000).

Step 3: Allocation of MAC Increase and Changes to Purchased Power Working Capital and C&C related POR Costs

The impacts of the changes to the MAC revenue requirement (RY1 only) and Purchased Power Working Capital component of the MFC are shown in Columns (7a) and (7b), respectively, of Table 2. The per kWh increase in the MAC revenue requirement and the per kWh change in the Purchased Power Working Capital component of the MFC do not vary by customer class. The MAC increase is applicable to full service and retail access customers and the Purchased Power Working Capital component is applicable to full service customers only.

Step 4: Total Class Change

The total revenue changes in RY1 and RY2 for each class will be the sum of each item described in Steps 2 and 3, i.e., Column (8) in Table 2.

The RY T&D delivery revenue changes for each class will then be restated for the historic period, i.e., the twelve months ended December 31, 2010, the period for which detailed billing data was available. Specifically, revenue ratios will be developed for each class by dividing the applicable RY T&D pure base revenues at the current rate level by the corresponding pure base revenues for the historical period. For NYPA, the RY T&D change will be divided by the applicable revenue ratio to determine the rate change applicable for the historical period. For Con Edison customers, the delivery revenue changes assigned to each class for the historic period will be determined in three steps. First, the T&D delivery revenue change for each RY will be allocated between non-competitive, reactive power demand charges and competitive revenues. The RY "non-competitive delivery revenue change" for each class will be determined by adjusting the total RY T&D related delivery revenue change allocated to each class by the change in competitive service and reactive power revenues for each class. Second, revenue ratios will be developed for each class by dividing the RY non-competitive T&D revenues for each class by the historic period non-competitive revenues for each class at the current rate level. Third, the revenue ratio for each class will be applied to the RY "non-competitive delivery revenue change" for each class to determine each class's "non-competitive delivery revenue change" for the historic period.

Rate Design

Design of Con Edison Delivery Rates

Before adjusting delivery rates to reflect the rate changes allocated to each class during RY1, delivery rates will reflect revenue neutral changes for SC 2 Rate I and SC 9 Rate I rate classes pursuant to Case 09-E-0428. These revenue neutral changes effectuate the elimination of declining block rates in these classes that was phased in over a 5-year period.

Design of Rates to Collect Change in Revenue Requirement

A. Non-Competitive Con Edison T&D Delivery Rates

1. In RYs 1 and 2, the customer charges for all existing classes, with the exception of SC 2 Rate II, will remain at the current levels. The SC 2 Rate II customer charge will be set equal to the customer charge of SC 2 Rate I.

2. After taking into consideration the revenue associated with customer charges, the per kWh charges in SC 1 Residential and Religious (Rate I) and SC 2 General Small (Rate I) and the per kWh charges in SC 6 will be changed to recover the balance of the revenue requirement assigned to each respective class.

3. Voluntary TOD rates for SC 1 Rate II will be designed to recover the combined class' overall non-competitive delivery revenue requirement. Such rates will be designed to be revenue neutral, i.e., the rates will yield the same level of service class revenues that the Company would receive under the proposed conventional rates. As explained in the Rate Design section of the Joint Proposal, the customer

charge will remain at its current level. The off-peak Domestic Hot Water Storage rate (Special Provision D) for SC1 Rate II will be set equal to the SC 1 Rate II off-peak energy delivery rates.

4. Similar to SC 1 Rate II, the rates for the new Voluntary TOD residential class (i.e., SC 1 Rate III) will be designed to recover the combined class' overall non-competitive delivery revenue requirement on a revenue-neutral basis. The customer charge for SC 1 Rate III will be set equal to the SC 1 Rate I customer charge. The off-peak energy delivery rates will be set to the off-peak energy delivery rates for SC 1 Rate II resulting from the design of rates that sets the customer charge equal to SC 1 Rate I.

5. Consistent with past practice, voluntary TOD rates for SC 2 Rate II will be designed to recover the class's overall non-competitive T&D related delivery revenue requirement. The rates will be designed to be revenue neutral, i.e., the rates yield the same level of service class revenues that the Company would receive under the proposed conventional rates.

6. The demand charges and per kWh charges in Rate I of SC 5, SC 8, SC 12 and SC 9 will be adjusted by the overall non-competitive T&D rate percentage change applicable to each class. The minimum charges for SC 5, 8 and 12 Rate I demand rates will be increased by 5 percent before the application of the non-competitive T&D rate percentage.

7. As described in the Rate Design section of the Joint Proposal, the SC 9 maximum rate will be increased by 33% in RY 1 and 67% in RY 2.

8. For SC 12 conventional customers billed for energy only (i.e., SC 12 Rate I), the per kWh charges and the minimum charge will be increased by the non-competitive T&D rate percentage change applicable to SC 12 (Rate I) customers. For SC 12 Rate III, rates are set equal to SC 2 Rate II.

9. The mandatory TOD rates for SC 5, 8, and 9, 12, and 13 and the voluntary TOD rates for SC 8, 9, and 12, will collect the revised revenue requirement applicable to these classes. The per kWh rates will be set equal across classes. The per kWh rates will be determined by revising current per kWh rates by the ratio of the proposed non-competitive kWh revenue requirement for these classes to the current level of non-competitive revenue collected from the per kWh charges in these classes. The demand rates in each of these classes will then be adjusted to recover the residual non-competitive revenue requirement for each of these classes. Voluntary TOD rates will be designed to recover the applicable class revenue requirement of all customers not billed under mandatory TOD rates.

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10. There will be no change in the relative relationships between high tension and low tension rates.

11. Standby rates will be developed consistent with the Commission's Opinion 01-04, Opinion and Order Approving Guidelines for the Design of Standby Service Rates, issued and effective October 26, 2001 ("Standby Rates Order") in Case 99-M-1470. In accordance with the standby rate guidelines, rates will be developed for each standby class to be revenue neutral at the revised revenue level. The Standby Rates Order (p. 7) defines revenue neutral to mean that "the full service class (not any individual customer) would contribute the same revenues if the full class was priced under either the standard service class rates or the standby rates (given the historic usage patterns of the customers in that class)." The standby rates for SC 9 customers that are eligible for station-use rates (e.g., wholesale generators) taking service through the Company's distribution system will be determined by removing the transmission component from the matrix contained in Appendix A of the PSC's Order of July 29, 2003, in Case 02-E-0781.

12. The rates under Rider I – Experimental Rate Program for Multiple Dwellings will be updated to recognize the SC 8 standby rates on which these rates are based.

13. The customer charges and distribution contract demand charges in SC 11 Buy-Back Service will be set equal to the customer charges and contract demand charges of the standby rates for the respective class. In addition, the SC 11 and other classes' reactive power charges applicable to induction generators will be increased to the same level ($1.41 per billable kVar).

B. Design of NYPA Delivery Rates

Rate I and Rate II charges under the P.S.C. No. 12 delivery service rate schedule will be changed by the overall T&D delivery revenue percentage change applicable to NYPA. Reactive power charges including those applicable to induction generators will be increased to $1.41, the same as the rate set for Con Edison customers. Consistent with the standby rate guidelines, Rate III and IV rates will be developed for each class within the NYPA tariff to be revenue neutral at the proposed revenue level, i.e., Rates III and IV will be developed to produce the same delivery revenues as the equivalent non-standby rates. There will be no change in the relative relationships between high tension and low tension rates.

C. Competitive Delivery Rates

Competitive delivery rates for Con Edison customers, i.e., the MFC and competitive metering charges, including the credit and collection related component of the Purchase of Receivables Discount Rate, will be set in each Rate

Year to reflect the revenue requirement for each Rate Year. Competitive metering credits applicable to NYPA will also be adjusted to reflect the revenue requirement for each RY. The MFC for Con Edison customers will consist of two components: a supply-related component, including a purchased power working capital component, and a credit and collection ("C&C") related component. There will be separate MFCs calculated for (1) SCs 1 customers, (2) SC 2 customers, and (3) all other customers.

i. The RY revenue requirement for the supply-related component (excluding purchased power working capital) will be developed by multiplying the total Con Edison T&D RY revenue requirement by the percentage represented by these costs for each group as compared to total Con Edison T&D delivery revenues at current rates. The resulting revenue requirement will then be divided by the RY sales of full service customers in each group to determine the $/kWh supply-related portion of the MFC for each full service class.

ii. The Rate Year revenue requirement for the C&C related component of the MFC will be developed by multiplying the total Con Edison T&D Rate Year revenue requirement by the percentage represented by credit and collection related costs for each group, inclusive of C&C costs attributable to the Purchase of Receivable ("POR") Discount Rate. The total Rate Year C&C related revenue requirement will be split between full service and POR customers based on the respective split of full service and POR forecasted Rate Year kWh sales. The C&C related rate component to be recovered through the MFC from full service customers will then be determined by dividing their share of the C&C related Rate Year revenue requirement for each group by the corresponding forecasted Rate Year kWh sales.

iii. The C&C related rate component to be recovered through the POR discount rate will be set in each Rate Year to reflect the calculated portion of total C&C costs attributable to POR customers, the estimated Rate Year POR kWh sales, and the forecasted level of POR supply costs in the Rate Year.

iv. The proposed rate associated with the purchased power working capital component of the MFC will be computed by dividing the purchased power working capital requirement for each Rate Year by forecasted Rate Year full-service customers' sales to derive a per kWh charge that will be added to the applicable competitive supply related MFC component for each service group.

v. Competitive metering services will recognize separate costing functions consisting of meter ownership, meter data service provider and combined meter service provider and meter installation costs. The Rate Year revenue requirements for the charges for meter ownership, meter services, and meter data services in each class eligible for competitive metering (i.e., SCs 5, 8, 9, 12 and 13 conventional and time-of-day billed accounts) will be developed similar to the Rate Year revenue requirement for the MFC components with the exception for the meter data service provider charge applicable to Rate II of SC 5, 8, 9 and Rate I of SC 13. The meter data service provider charge applicable to Rate II of SC 5, 8, 9 and Rate I of SC 13 will be changed by the overall Con Edison T&D average percent change. To calculate the $ per bill charges, the revenue requirements determined for each Rate Year will be divided by each eligible class's annual number of bills. In RY1 and RY2, the metering charges for Rider M – Day Ahead Hourly Pricing customers will be changed by the overall Con Edison T&D average percentage rate change in RY1 and RY2.

vi. The billing and payment processing charge applicable to Con Edison customers will be increased from $1.04 per bill to $1.20 per bill. For customers with a combined electric and gas account, the portion of the charge applicable to electric service will be $1.20 less the amount applicable to gas service. Likewise, ESCOs will pay $1.20 per bill per account, unless a customer has two separate ESCOs. In that case, the charge to the electric ESCO will be $1.20 less the charge applicable to the gas ESCO.

Appendix 20
Table 1

CASE 13-E-0030
Consolidated Edison Company of New York, Inc.
Embedded Cost-of-Service Study Results
For the Year 2010
Table 1A

Service Classification	**Initial Surplus/Deficiency[(1)(2)(3)] ($000)**	**RY1 Phase-In Surplus/Deficiency[(1)] ($000)**	**RY1 Adjustment[(4)] ($000)**	**RY1 Adjusted Surplus/Deficiency[(1)] ($000)**	**RY2 Phase-In Surplus/Deficiency[(1)] ($000)**	**RY2 Adjustment[(4)] ($000)**	**RY2 Adjusted Surplus/Deficiency[(1)] ($000)**
(1)	(2)	(3) = (2)/2	(4)	(5) = (3) + (4)	(6) = (2) - (5)	(7)	(8) = (6) + (7)
TOTAL CECONY	-			-			-
TOTAL NYPA	(18,000)	(9,000)		(9,000)	(9,000)		(9,000)
TOTAL SYSTEM	-			-			-
Individual CECONY Classes							
SC 1 Residential	-			-	-		-
SC 2 General Small	(13,355)	(6,678)		(6,678)	(6,678)		(6,678)
SC 5 Traction	(28)	(14)		(14)	(14)		(14)
SC 5 TOD	929	465	8	473	457	15	472
SC 6 Street Lighting	-			-	-		-
SC 8 Apt. House	(6,966)	(3,483)		(3,483)	(3,483)		(3,483)
SC 8 TOD	(301)	(151)		(151)	(151)		(151)
SC 9 General Large	17,107	8,554	2,496	11,050	6,058	4,992	11,050
SC 9 TOD	16,119	8,060	1,027	9,087	7,033	2,054	9,087
SC 12 Apt. House Htg.	(1,403)	(702)		(702)	(702)		(702)
SC 12 TOD	(1,460)	(730)		(731)	(730)		(730)
SC 13 Co-op City - TOD	289	145	4	149	141	8	149
Total Surplus	34,444	17,222			13,687		
Total Deficiency	(41,513)	(20,757)			(20,756)		
Grand Total	(7,069)	(3,535)	3,535	0	(7,069)	7,069	0
			3,535	0		7,069	0

(1) Deficiencies shown as negative.
(2) NYPA deficiency is result of settlement negotiations.
(3) SC12 deficiency has been reduced by one half to mitigate bill impacts.
(4) Applied to surplus classes only.

Case No. 13-E-0030
Consolidated Edison Company of New York, Inc.
Estimated T&D Revenues for Rate Year Ending December 31, 2014

	RY Ending 12/31/2014 Bundled T&D Revenue at 4/1/12 Rate Level (a)	RY JP Deficiency /(Surplus)	Re-Aligned Bundled T&D Revenue at 4/1/12 Rate Level	Proposed RY Rate Increase Allocated to All Customers	TCC Imputation	RY Total T&D Increase Including Deficiency /(Surplus) (b)	RY Total T&D % Rate Increase RY1 vs. Current	RY Target Bundled T&D Revenue at 1/1/2014 Rate Level (c)	Proposed RY MAC Increase Applicable to CECONY Customers	Proposed RY PPWC Change Applicable to CECONY Full Service Customers	Proposed RY Low Income Program Impact	RY Total Rate Increase Excl GRT
	(1)	(2)	(3)=(1)+(2)	(4)=(3)* - 1.06352845%	(4a)	(5)=(2)+(4)+(4a)	(5a)=(5)/(1)	(6)=(1)+(5)	(7a)	(7b)	(7c)	(8)=(5)+ Σ[(7a)~(7c)]
Proposed Rate Increase in Bundled Delivery Rev Requirement for RY - Incl. GRT (b)				$0								
Proposed Rate Increase in Bundled Delivery Rev Requirement for RY - Excl. GRT				$0								
Less: MAC Change				$22,820,000								
Less: Purchase Power Working Capital Change				$11,013,708								
Add: Reconnection Fees Waiver for Low Income Program				$0								
Add: Additional Discount for Low Income Program				$9,250,000								
Add: TCC Imputation				-$30,000,000								
T&D Related Delivery Revenue Increase				-$54,583,708								
Proposed % Rate Increase				-1.06352845%								
NYPA	$567,187,000	$9,000,000	$576,187,000	-$6,127,913	$0	$2,872,087	0.506374%	$570,059,087				$2,872,087
CECONY	$4,565,135,307	-$9,000,000	$4,556,135,307	-$48,455,795	$30,000,001	-$27,455,794	-0.601423%	$4,537,679,513	$22,820,000	$11,013,708	-$9,250,000	-$2,872,086
Total	$5,132,322,307	$0	$5,132,322,307	-$54,583,708	$30,000,001	-$24,583,707	-0.478998%	$5,107,738,600	$22,820,000	$11,013,708	-$9,250,000	$1
SC1	$1,983,510,025	$0	$1,983,510,025	-$21,095,193	$13,060,477	-$8,034,716	-0.405076%	$1,975,475,309	$6,993,449	$5,609,694	-$9,250,000	-$4,681,573
SC2	$318,432,240	$6,677,500	$325,109,740	-$3,457,635	$2,140,694	$5,360,559	1.683422%	$323,792,799	$1,033,340	$694,312	$0	$7,088,211
SC5 Rate I	$58,057	$14,000	$72,057	-$766	$474	$13,708	23.611279%	$71,765	$478	$581	$0	$14,767
SC5 Rate II	$4,518,000	-$472,500	$4,045,500	-$43,025	$26,638	-$488,887	-10.820872%	$4,029,113	$56,877	$0	$0	-$432,010
SC6	$2,231,570	$0	$2,231,570	-$23,733	$14,694	-$9,039	-0.405051%	$2,222,531	$4,780	$5,810	$0	$1,551
SC8 Rate I&III	$136,034,500	$3,483,000	$139,517,500	-$1,483,808	$918,657	$2,917,849	2.144933%	$138,952,349	$903,336	$290,507	$0	$4,111,692
SC8 Rate II	$7,245,000	$150,500	$7,395,500	-$78,653	$48,696	$120,543	1.663810%	$7,365,543	$54,965	$0	$0	$175,508
SC9 Rate I&III	$1,537,934,627	-$11,049,500	$1,526,885,127	-$16,238,858	$10,053,819	-$17,234,539	-1.120629%	$1,520,700,088	$9,197,304	$4,073,492	$0	-$3,963,743
SC9 Rate II	$550,255,961	-$9,086,500	$541,169,461	-$5,755,491	$3,563,345	-$11,278,646	-2.049709%	$538,977,315	$4,362,781	$274,820	$0	-$6,641,045
SC12 Rate I&III	$11,256,104	$701,500	$11,957,604	-$127,173	$78,735	$653,062	5.801848%	$11,909,166	$105,150	$41,833	$0	$800,045
SC12 Rate II	$11,319,653	$730,500	$12,050,153	-$128,157	$79,345	$681,688	6.022163%	$12,001,341	$102,760	$16,849	$0	$801,297
SC13	$2,339,570	-$148,500	$2,191,070	-$23,303	$14,427	-$157,376	-6.726706%	$2,182,194	$4,780	$5,810	$0	-$146,786
CECONY	$4,565,135,307	-$9,000,000	$4,556,135,307	-$48,455,795	$30,000,001	-$27,455,794	-0.601423%	$4,537,679,513	$22,820,000	$11,013,708	-$9,250,000	-$2,872,086

Notes: (a) Excludes current Low Income Program credits of $38.75 million (i.e., $38.25 million of low income rate reductions and $500,000 of waived reconnection fees) for SC1 and PPWC.
(b) Excludes the proposed incremental Low Income Program credits of $9,250,000
(c) Excludes the proposed Low Income Program credits of $48.0 million for SC1 (i.e., $47.5 million of low income rate reductions and $500,000 of waived reconnection fees).

Case No. 13-E-0030
Consolidated Edison Company of New York, Inc.
Estimated T&D Revenues for Rate Year 2 Ending December 31, 2015

	RY2 Ending 12/31/2015 Bundled T&D Revenue at 4/1/12 Rate Level (a)	Proposed Total T&D % Rate Increase Effective 1/1/2014	RY2 Ending 12/31/2015 Bundled T&D Revenue at 1/1/14 Rate Level (b)	RY JP Deficiency /(Surplus)	Re-Aligned Bundled T&D Revenue at 1/1/14 Rate Level	Proposed RY Rate Increase Allocated to All Customers	RY2 Total T&D Increase Including Deficiency /(Surplus)	RY2 Total T&D % Rate Increase RY2 vs. RY1	RY2 Target Bundled T&D Revenue at 1/1/2015 Rate Level (b)	Proposed RY2 MAC Increase Applicable to CECONY Customers	Proposed RY2 PPWC Change Applicable to CECONY Full Service Customers	Proposed RY2 Low Income Program Impact	RY2 Total Rate Increase Excl GRT
	(1)	(1a)	(1b)=(1)*(1a)	(2)	(3)=(1b)+(2)	(4)=(3)* 0.00000000%	(5)=(2)+(4)	(5a)=(5)/(1b)	(6)=(1b)+(5)	(7a)	(7b)	(7c)	(8)=(5)+ Σ[(7a)~(7c)]
Proposed Rate Increase in Bundled Delivery Rev Requirement for RY2 - Incl. GRT						$0							
Proposed Rate Increase in Bundled Delivery Rev Requirement for RY2 - Excl. GRT						$0							
Less: MAC Change						$0							
Less: Purchase Power Working Capital Change						$0							
Add: Reconnection Fees Waiver for Low Income Program						$0							
Add: Additional Discount for Low Income Program						$0							
T&D Related Delivery Revenue Increase						$0							
Proposed % Rate Increase						0.00000000%							
NYPA	$572,893,000	0.506374%	$575,793,981	$9,000,000	$584,793,981	$0	$9,000,000	1.563059%	$584,793,981				$9,000,000
CECONY	$4,584,880,719		$4,557,389,143	-$9,000,000	$4,548,389,143	$0	-$9,000,000	-0.197481%	$4,548,389,143	$0	$0	$0	-$9,000,000
Total	$5,157,773,719		$5,133,183,124	$0	$5,133,183,124	$0	$0	0.000000%	$5,133,183,124	$0	$0	$0	$0
SC1	$2,008,226,715	-0.405076%	$2,000,091,871	$0	$2,000,091,871	$0	$0	0.000000%	$2,000,091,871	$0	$0	$0	$0
SC2	$316,410,000	1.683422%	$321,736,516	$6,677,500	$328,414,016	$0	$6,677,500	2.075456%	$328,414,016	$0	$0	$0	$6,677,500
SC5 Rate I	$58,057	23.611279%	$71,765	$14,000	$85,765	$0	$14,000	19.508117%	$85,765	$0	$0	$0	$14,000
SC5 Rate II	$4,499,000	-10.820872%	$4,012,169	-$471,500	$3,540,669	$0	-$471,500	-11.751748%	$3,540,669	$0	$0	$0	-$471,500
SC6	$2,231,570	-0.405051%	$2,222,531	$0	$2,222,531	$0	$0	0.000000%	$2,222,531	$0	$0	$0	$0
SC8 Rate I&III	$134,751,510	2.144933%	$137,641,840	$3,483,000	$141,124,840	$0	$3,483,000	2.530481%	$141,124,840	$0	$0	$0	$3,483,000
SC8 Rate II	$7,201,000	1.663810%	$7,320,811	$150,500	$7,471,311	$0	$150,500	2.055783%	$7,471,311	$0	$0	$0	$150,500
SC9 Rate I&III	$1,548,031,175	-1.120629%	$1,530,683,489	-$11,049,500	$1,519,633,989	$0	-$11,049,500	-0.721867%	$1,519,633,989	$0	$0	$0	-$11,049,500
SC9 Rate II	$538,583,479	-2.049709%	$527,544,085	-$9,086,500	$518,457,585	$0	-$9,086,500	-1.722415%	$518,457,585	$0	$0	$0	-$9,086,500
SC12 Rate I&III	$11,204,990	5.801848%	$11,855,086	$701,500	$12,556,586	$0	$701,500	5.917292%	$12,556,586	$0	$0	$0	$701,500
SC12 Rate II	$11,343,653	6.022163%	$12,026,786	$729,500	$12,756,286	$0	$729,500	6.065627%	$12,756,286	$0	$0	$0	$729,500
SC13	$2,339,570	-6.726706%	$2,182,194	-$148,500	$2,033,694	$0	-$148,500	-6.805078%	$2,033,694	$0	$0	$0	-$148,500
CECONY	$4,584,880,719		$4,557,389,143	-$9,000,000	$4,548,389,143	$0	-$9,000,000	-0.197481%	$4,548,389,143	$0	$0	$0	-$9,000,000

(a) Excludes current Low Income Program credits of $38.75 million (i.e., $38.25 million of low income rate reductions and $500,000 of waived reconnection fees) for SC1 and PPWC.
(b) Excludes the proposed Low Income Program credits of $48.0 million for SC1 (i.e., $47.5 million of low income rate reductions and $500,000 of waived reconnection fees).

Case No 13-E-0030
Consolidated Edison Company of New York, Inc.
Factor Used to Allocate PJM OATT Costs Between NYPA and Con Edison Classes

	RY Ending 03/31/2013 Bundled T&D Revenue at Current (4/1/12) Rate Level Incl. Low Income Discount and PPWC *	RY Ending 12/31/2014 Bundled T&D Revenue at Current (1/1/14) Rate Level Incl. Low Income Discount and PPWC	RY Ending 12/31/2015 Bundled T&D Revenue at Current (1/1/15) Rate Level Incl. Low Income Discount and PPWC
	2013	RY1 (1/1/2014)	RY2 (1/1/2015)
NYPA	$ 575,812,912	$ 570,059,087	$ 584,793,981
Coned	$ 4,392,285,044	$ 4,507,460,513	$ 4,518,170,143
Total	$ 4,968,097,956	$ 5,077,519,600	$ 5,102,964,124
% NYPA	11.59%	11.23%	11.46%
% Coned	88.41%	88.77%	88.54%
Total	100.00%	100.00%	100.00%

* Based on Revenue Allocation of Rate Year 12 Months Ending 3/31/2013 in Case 09-E-0428.

GAS RATE DESIGN

1. Rate Design Targets

Table 1 provides the rate design targets for the Supply-Related and Credit and Collections/Theft ("C&C") components of the Merchant Function Charge ("MFC") including the C&C component of the Purchase of Receivables ("POR") discount rate and the Billing and Payment Processing ("BPP") charges for RY1, RY2 and RY 3, and non-competitive delivery charges for RY1, RY2 and RY3.

2. Allocation of Increased Revenue Requirement

For the first Rate Year, the net change, net of gross receipts taxes, in the Company's revenue requirement of $0, was allocated to firm sales and firm transportation customers in SC 1, 2, 3, 9 and 13 in the following manner: (a) Class Revenues from unbundled service and non-competitive delivery service at current rates for RY1 were estimated, including an adjustment among the classes for Low Income discounts**;** (b) Revenue deficiencies/surpluses as indicated in Table 2, were assigned to the SC 1, SC 2 Non-Heating, SC 2 Non-Heating DG, SC 2 Heating and SC 3 classes; (c) The average percentage rate change of zero was reflected in each of the resulting class revenues, as shown in column 5 of Table 2; (d) Low Income discounts were adjusted among the classes based upon each class's contribution to the adjusted total delivery revenue at current rates; (e) Class revenues from unbundled service at proposed rates were subtracted to determine the non-competitive delivery service revenue at proposed rates; (f) The total non-competitive delivery rate change is the difference between the non-competitive delivery revenue at current rates and the non-competitive delivery revenue requirement at proposed rates, as indicated in Table 2; and (g) The RY 1 overall percentage rate change for each class was determined by dividing the total RY 1 delivery rate change by the total delivery revenue at current rates.

For the second Rate Year, the non-competitive delivery rate change was determined by subtracting the non-competitive delivery revenue at current rates (i.e., RY 2 forecasted sales and transportation volumes priced at RY 1 non-competitive delivery rates) from the RY 2 (non-competitive) delivery revenue requirement, as adjusted for changes in unbundled revenues from RY 1 to RY 2. The total RY 2 delivery rate change was divided by the RY 2 total delivery revenues at current (RY 1) rates to determine the overall average delivery rate percentage change for RY 2.

The overall average delivery rate change and delivery rate percentage change for RY3 were determined in a similar manner.

3. Unbundled Charges

Con Edison will continue to unbundle the following charges:

A. **Merchant Function Charge**

1. The Merchant Function Charge ("MFC"), which is applicable to firm full service customers, consists of the following components:

- Supply-Related Component – This component will change each Rate Year in accordance with the rate design targets shown in Table 1.
- C&C Component – This component changes each Rate Year based upon the rate design targets shown in Table 1 for total C&C costs. Any C&C charges related to gas transportation customers whose ESCOs participate in the Company's Purchase of Receivables program ("POR"), will be included in the POR discount rate, based upon the rate design target given in Table 1 for total C&C costs. The allocation of the C&C rate design target between the MFC and the POR discount rate will be determined prior to Rate Years 1, 2 and 3 based upon the most recent information available.
- Uncollectible Accounts Expense ("UBs") associated with supply – This component changes each month in the manner described below.
- Gas in Storage Working Capital – This component will change each Rate Year.

2. Separate MFC charges will continue to be established for SC 1, SC 2 Heating, SC 2 Non-Heating SC 3, and SC 13. For the Supply-Related component and for the C&C component, different unit costs will be set for residential and for non-residential classes. At the end of each Rate Year, the supply-related and C&C components of the MFC will be trued up to the Rate Year design targets and any reconciliation amount will be included in the subsequent year's calculation of the MFC. The charge for UBs associated with supply will continue to be based upon actual supply costs for each month included in the Company's monthly Gas Cost Factor ("GCF"). The UBs associated with supply costs will be included in the MFC. Separate UB factors will be calculated for each of the three GCF groupings and will reflect the overall uncollectible rate of 0.81%, with uncollectible rates of 1.32% for residential customers and 0.45% for non-residential customers. Gas in Storage Working Capital costs will continue to be recovered through two components, a supply-related component assessed on firm full service customers through the MFC and a reliability/balancing-related component assessed on all firm customers through the MRA. The allocation between full service and all customers will be such that the volumetric rate, in cents per therm, for the supply-related component will be the same as the volumetric rate for the reliability/balancing-related component. Both components will be based on known actual costs during the 12 month period from January through December and an estimate of costs not yet incurred during that period. At

the end of each Rate Year, the Gas in Storage Working Capital included in the MFC and MRA will be trued-up to actual costs incurred for the rate year.

B. **Billing and Payment Processing Charge**

The BPP Charge for gas will be set at $1.20 for single service gas customers who purchase both their commodity and delivery from the Company and for retail access customers receiving separate bills from the Company and the ESCO. Dual service customers will pay no more than $0.60 for gas BPP. Table 1 provides the rate design targets for BPP for each Rate Year.

C. **Transition Adjustment for Competitive Services**

The Transition Adjustment for Competitive Services ("TACS") reconciles (1) actual revenues received through the C&C component of the POR discount rate with the amount reflected in the discount rate, and (2) any BPP lost revenue attributable to customers migrating to retail access and being billed for their gas use through an ESCO consolidated bill. The reconciliation in (1) above will be based on an allocation of the total C&C costs from Table 2 for Rate Years 1, 2 and 3.

The TACS applies to firm full service customers and to firm transportation customers and will continue to be assessed through the MRA. The TACS will be recovered at the same cents per therm rate from all firm customers.

4. **<u>Rate Design Within The Service Classes</u>**

A summary of the proposed rate design methodology is described below.

A. The minimum charges (the charge for the delivery of the first three therms or less) in all three Rate Years for SC 1, SC 2 Heating, SC 2 Non-Heating, and SC 3, SC 13 and for the corresponding SC 9 rates, will remain at the current levels.

B. For SC 1 and the corresponding SC 9 rates, the revenue change assigned to that class in all three Rate Years was assigned to the over 3 therm block.

C. For SC 2 Heating and Non-Heating, SC 3, SC 13 and the corresponding SC 9 rates, the remaining revenue change assigned to those classes in all three Rate Years was assigned to the remaining blocks on an equal percentage basis, except as described in D through G, below.

D. The air-conditioning rates within SC 2 and SC 3 were set equal to the proposed block rates in SC 13 consistent with past practice.

E. The rates for Riders G and I are being set using the same relationship that exists between SC 2 delivery rates and Riders G and I rates today.

F. No change was allocated to SC 14, and bypass customers taking firm service under contract rates. However distributed generation rates under Riders H and J are being changed by the average rate change allowed for their applicable non-distributed generation classes for each Rate Year.

G. New low income rates were set for eligible low income customers in SC 1 and SC 3. SC 1 low income customers will receive a reduction of $1.50 off the full SC 1 minimum charge consistent with the current discount. SC 3 low income customers will receive a reduction of $0.4880 per therm in their 4-90 therm block as well as a reduction of $7.25 off the full SC 3 minimum charge. Rates were increased to all other customers in the SC 1, SC 2 Heat, SC 2 Non-Heat, SC 3 and SC 13 classes to account for the rate reductions.

Consolidated Edison Company of New York Inc.
Case 13-G-0031
Rate Design Targets

	Supply MFC	C&C MFC	C&C POR	C&C Total *	BPP	Non-Competitive
Rate Year 1	$ 2,812,413	TBD	TBD	$ 6,249,061	$ 7,868,300	$ 930,382,677
Rate Year 2	$ 2,881,320	TBD	TBD	$ 6,402,168	$ 7,897,545	$ 952,242,227
Rate Year 3	$ 2,948,321	TBD	TBD	$ 6,551,043	$ 7,926,319	$ 974,540,325

* The allocation of the C&C Total for each Rate Year between the C&C MFC and C&C POR will be reflected in the compliance filing for each Rate Year.

Consolidated Edison Company of New York Inc.
Case 13-G-0031
Rate Design Revenue Allocation

DETERMINATION OF RATE INCREASE FOR THE PERIOD JANUARY 1, 2014 TO DECEMBER 31, 2014													
Service Class	RY 1 @ Current Rates	Deficiency/ (Surplus)	Realigned RY1 at Current Rates	Low Income Adjustment RY1	RY 1 Change	Total	MFC and POR C&C	BPP	Non-Competitive Delivery Revenue	Non-Competitive Delivery Change	Competitive Increase/ (Decrease)	Total Delivery Change	Percent Change Delivery
	(1)	(2)	(3)=(1)+(2)	(4)	(5)= (3) x % Change[1]	(6)=(3)+(4)+(5)	(7)	(8)	(9)=(6)-(7)-(8)	(10)	(11)	(12)=(10)+(11)	(13)
SC 1	$ 177,543,604	$ 942,637	$ 178,486,241	$ (412,579)	$ -	$ 178,073,662	$ 576,072	$ 4,799,814	$ 172,697,776	$ 610,528	$ (80,469)	$ 530,058	0.30%
SC 2 R1 - Non Heat	$ 100,828,702	$ 532,920	$ 101,361,623	$ 1,159,660	$ -	$ 102,521,283	$ 603,818	$ 450,493	$ 101,466,971	$ 2,921,113	$ (1,228,533)	$ 1,692,580	1.68%
SC 2 R1 - NH DG	$ 4,558,022	$ 23,119	$ 4,581,141	$ 52,412	$ -	$ 4,633,553	$ 87,313	$ 515	$ 4,545,724	$ 270,724	$ (195,194)	$ 75,530	1.66%
SC 2 R2 - Heat	$ 173,734,736	$ (3,945,562)	$ 169,789,174	$ 1,942,151	$ -	$ 171,731,324	$ 1,116,686	$ 463,085	$ 170,151,554	$ 530,641	$ (2,534,053)	$ (2,003,411)	-1.15%
SC 3	$ 488,279,867	$ 2,446,886	$ 490,726,753	$ (2,745,225)	$ -	$ 487,981,528	$ 6,673,638	$ 2,151,595	$ 479,156,296	$ 7,695,555	$ (7,993,894)	$ (298,339)	-0.06%
SC 13	$ 313,008	$ -	$ 313,008	$ 3,581	$ -	$ 316,589	$ 3,948	$ 2,799	$ 309,842	$ 12,857	$ (9,276)	$ 3,581	1.14%
Subtotal	$ 945,257,938	$ 0	$ 945,257,938	$ 0	$ -	$ 945,257,938	$ 9,061,474	$ 7,868,300	$ 928,328,163	$ 12,041,419	$ (12,041,419)	$ 0	0.00%
SC 14	$ 328,651	$ -	$ 328,651	$ -	$ -	$ 328,651	$ -	$ -	$ 328,651	$ -	$ -	$ -	0.00%
Firm Bypass	$ 653,000	$ -	$ 653,000	$ -	$ -	$ 653,000	$ -	$ -	$ 653,000	$ -	$ -	$ -	0.00%
Total	$ 946,239,589	$ 0	$ 946,239,589	$ 0	$ -	$ 946,239,589	$ 9,061,474	$ 7,868,300	$ 929,309,814	$ 12,041,419	$ (12,041,419)	$ 0	0.00%

DETERMINATION OF RATE INCREASE FOR THE PERIOD JANUARY 1, 2015 TO DECEMBER 31, 2015													
Service Class	RY 2 @ RY1 Rates	Deficiency/ (Surplus)	Realigned RY2 at Current Rates	Low Income Adjustment RY2	RY 2 Change	Total	MFC and POR C&C	BPP	Non-Competitive Delivery Revenue	Non-Competitive Delivery Change	Competitive Increase/ (Decrease)	Total Delivery Change	Percent Change Delivery
	(1)	(2)	(3)=(1)+(2)	(4)	(5)= (3) x % Change[2]	(6)=(3)+(4)+(5)	(7)	(8)	(9)=(6)-(7)-(8)	(10)	(11)	(12)=(10)+(11)	(13)
SC 1	$ 176,678,402	$ 942,637	$ 177,621,039	$ (478,353)	$ -	$ 177,142,686	$ 544,331	$ 4,772,498	$ 171,825,857	$ 451,266	$ 13,018	$ 464,284	0.26%
SC 2 R1 - Non Heat	$ 103,433,999	$ 523,083	$ 103,957,081	$ 1,157,099	$ -	$ 105,114,180	$ 619,564	$ 455,417	$ 104,039,200	$ 1,665,365	$ 14,817	$ 1,680,182	1.62%
SC 2 R1 - NH DG	$ 6,568,954	$ 32,956	$ 6,601,911	$ 73,483	$ -	$ 6,675,393	$ 121,312	$ 543	$ 6,553,538	$ 103,538	$ 2,901	$ 106,439	1.62%
SC 2 R2 - Heat	$ 173,137,897	$ (3,945,562)	$ 169,192,335	$ 1,882,602	$ -	$ 171,074,937	$ 1,111,199	$ 466,579	$ 169,497,158	$ (2,089,534)	$ 26,574	$ (2,062,960)	-1.19%
SC 3	$ 508,305,736	$ 2,446,886	$ 510,752,622	$ (2,638,355)	$ -	$ 508,114,267	$ 6,883,003	$ 2,199,709	$ 499,031,555	$ (356,075)	$ 164,606	$ (191,469)	-0.04%
SC 13	$ 316,622	$ -	$ 316,622	$ 3,524	$ -	$ 320,146	$ 4,079	$ 2,799	$ 313,268	$ 3,426	$ 98	$ 3,524	1.11%
Subtotal	$ 968,441,609	$ 0	$ 968,441,609	$ 0	$ -	$ 968,441,609	$ 9,283,488	$ 7,897,545	$ 951,260,576	$ (222,014)	$ 222,014	$ 0	0.00%
SC 14	$ 328,651	$ -	$ 328,651	$ -	$ -	$ 328,651	$ -	$ -	$ 328,651	$ -	$ -	$ -	0.00%
Firm Bypass	$ 653,000	$ -	$ 653,000	$ -	$ -	$ 653,000	$ -	$ -	$ 653,000	$ -	$ -	$ -	0.00%
Total	$ 969,423,260	$ 0	$ 969,423,260	$ 0	$ -	$ 969,423,260	$ 9,283,488	$ 7,897,545	$ 952,242,227	$ (222,014)	$ 222,014	$ 0	0.00%

DETERMINATION OF RATE INCREASE FOR THE PERIOD JANUARY 1, 2016 TO DECEMBER 31, 2016													
Service Class	RY 3 @ RY2 Rates	Deficiency/ (Surplus)	Realigned RY3 at Current Rates	Low Income Adjustment RY3	RY 3 Change	Total	MFC and POR C&C	BPP	Non-Competitive Delivery Revenue	Non-Competitive Delivery Change	Competitive Increase/ (Decrease)	Total Delivery Change	Percent Change Delivery
	(1)	(2)	(3)=(1)+(2)	(4)	(5)= (3) x % Change[3]	(6)=(3)+(4)+(5)	(7)	(8)	(9)=(6)-(7)-(8)	(10)	(11)	(12)=(10)+(11)	(13)
SC 1	$ 175,725,420	$ 942,637	$ 176,668,057	$ (533,829)	$ -	$ 176,134,227	$ 517,021	$ 4,744,140	$ 170,873,067	$ 397,058	$ 11,749	$ 408,808	0.23%
SC 2 R1 - Non Heat	$ 106,080,807	$ 519,657	$ 106,600,464	$ 1,159,821	$ -	$ 107,760,285	$ 637,574	$ 460,206	$ 106,662,505	$ 1,664,989	$ 14,489	$ 1,679,478	1.58%
SC 2 R1 - NH DG	$ 7,482,046	$ 36,382	$ 7,518,427	$ 81,801	$ -	$ 7,600,228	$ 133,516	$ 564	$ 7,466,149	$ 115,149	$ 3,034	$ 118,183	1.58%
SC 2 R2 - Heat	$ 172,866,853	$ (3,945,562)	$ 168,921,291	$ 1,837,305	$ -	$ 170,758,596	$ 1,123,941	$ 469,705	$ 169,164,950	$ (2,133,799)	$ 25,542	$ (2,108,257)	-1.22%
SC 3	$ 528,508,983	$ 2,446,886	$ 530,955,869	$ (2,548,582)	$ -	$ 528,407,288	$ 7,083,026	$ 2,248,905	$ 519,075,357	$ (262,660)	$ 160,964	$ (101,696)	-0.02%
SC 13	$ 320,248	$ -	$ 320,248	$ 3,484	$ -	$ 323,732	$ 4,286	$ 2,799	$ 316,647	$ 3,387	$ 97	$ 3,484	1.09%
Subtotal	$ 990,984,357	$ 0	$ 990,984,357	$ 0	$ -	$ 990,984,357	$ 9,499,364	$ 7,926,319	$ 973,558,674	$ (215,876)	$ 215,876	$ 0	0.00%
SC 14	$ 328,651	$ -	$ 328,651	$ -	$ -	$ 328,651	$ -	$ -	$ 328,651	$ -	$ -	$ -	0.00%
Firm Bypass	$ 653,000	$ -	$ 653,000	$ -	$ -	$ 653,000	$ -	$ -	$ 653,000	$ -	$ -	$ -	0.00%
Total	$ 991,966,008	$ 0	$ 991,966,008	$ 0	$ -	$ 991,966,008	$ 9,499,364	$ 7,926,319	$ 974,540,325	$ (215,876)	$ 215,876	$ 0	0.00%

Notes:
1 For RY1 Percent change is 0.00%
2 For RY2 Percent change is 0.00%
3 For RY3 Percent change is 0.00%

Consolidated Edison Company of New York, Inc.

Case 13-S-0032

Steam Revenue Allocation and Rate Design

With a zero increase and no realignment of costs, there are no bill impacts to estimate.

Appendix 23

Consolidated Edison Company of New York, Inc.
Cases 13-E-0030, 13-G-0031, 13-S-0032

Electric, Gas and Steam Reporting Requirements

The following are the Capital Reporting Requirements noted in Section D for Electric, Gas and Steam

A. Electric

By January 15, 2014, the Company will, for informational purposes, file with the Secretary its most recent projected 2014 and 2015 capital projects and programs list with associated expenditures for electric transmission, substations and distribution operations, electric production, electric storm hardening, municipal infrastructure, and shared services allocable to electric ("Project/Program List"). The Company has the flexibility over the term of the Electric Rate Plan to modify the list, priority, nature and scope of its electric capital projects identified in the Project/Program List, subject to the reporting provisions set forth below.

The Company will, for informational purposes, file with the Secretary and submit to the parties in this proceeding, subject to confidentiality concerns, by February 28, 2015 and 2016:

- a report on its project and/or program expenditures during the prior calendar year for electric transmission, substations and distribution operations, electric production, electric storm hardening, municipal infrastructure, and shared services allocable to electric ("Report").

- A five-year capital budget for electric transmission, substations and distribution operations, electric production, electric storm hardening, municipal infrastructure, and shared services allocable to electric.

The Report will provide (1) a list of all projects and/or programs reflected on the Project/Program List and in the Company's annual capital budgets that were eliminated, with supporting explanation; (2) a list of all new projects and/or programs that were added, with supporting explanation; (3) for all projects and/or programs, including new and eliminated projects and/or programs, the actual amount spent as compared to the forecasted budget amounts. To the extent the amount spent on a project or program varies from the forecasted amount by more than 15 percent, for projects or programs with a forecasted cost greater than $5 million but less than $25 million, or by more than 10 percent for projects or programs with a forecasted cost of $25 million or more, the Company shall provide an explanation of the reasons for the variance.

Quarterly budget meetings with Staff will continue, at which, among other issues, the Company will report on its current expectations in meeting the annual electric capital budget and Net Plant Targets.

The annual reporting requirements established in Cases 09-E-0428, 99-E-0930 and 06-E-0894 are discontinued.

B. **Gas**

The Company will, for informational purposes, file a Gas Capital Expenditures Report with the Secretary and submit it to the parties in this proceeding, subject to confidentiality concerns. The reports will be filed every six (6) months:

annual reports (covering the preceding calendar year) will be filed on February 28, 2015, 2016 and 2017; mid-year reports[1] (covering the first six (6) months of the applicable calendar year) will be filed on August 31, 2014, 2015 and 2016. The Company has the flexibility over the term of the Gas Rate Plan to modify the list, priority, nature and scope of its gas capital projects identified in the 2014-2016 Gas Capital Program (listed below), subject to the reporting provisions set forth below. The reports will include:

- Summary of Capital Expenditures - broken down by programs and projects, including Storm Hardening programs and projects as separate category.

- Summary of Capital Additions - broken down by programs and projects, including Storm Hardening programs and projects as separate category.

- For all programs and projects, a comparison of calendar year forecast of expenditures set forth in the 2014-2016 Gas Capital Program vs. calendar year actual expenditures.

- For multi-year programs and projects, a comparison of total expenditures set forth in the 2014-2016 Gas Capital Program vs. actual expenditures, broken down by calendar year (as part of the fourth quarter report).

- Narrative explanation of the reason(s) for any variance in excess of ten (10) percent between the expenditures set forth in the 2014-2016 Gas Capital Program and actual expenditures for any program or project.

- Narrative explanation of the reason and purpose for any new projects or programs exceeding $1 million that were or are going to be undertaken during the current calendar year that were not included in the expenditures set forth in the 2014-2016 Gas Capital Program for that calendar year.

- Summary of expenditures set forth in and the 2014-2016 Gas Capital Program actual capital expenditures for Interference related to:

[1] The Company's mid-year reports will recognize the fact that this Proposal reflects agreement on the annual forecasts in the 2014-2016 Gas Capital Program, rather than monthly expenditures.

- Municipal storm hardening projects.
- DEP Combined Sewer Overflow projects.

• Summary of capital expenditures related to No. 4/No. 6 oil-to-gas conversions. To the extent necessary, Company will report annually on higher than anticipated capital expenditures, as set forth in Section D.2.d of the Joint Proposal.

- For Main Replacement programs:
  - For the LPP identified and removed under the risk prioritization model:
    - Number of miles removed or abandoned by material.
    - The specific location of each section of main removed or abandoned.
  - For the LPP removed under all Other capital expenditure programs and in Flood Zone Reliability Program:
    - Number of miles removed or abandoned by material.
    - The specific location of each section of main removed or abandoned.
  - Annual ranking of Total Population LPP by Main Replacement Prioritization Model with segment ID only:
    - Rank of segments expected to be removed in current rate year with segment ID and location.
    - As part of year-end report, identify actual segments removed as compared to expected.
  - Actual cost of removal by material, by region.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
2014-2016 GAS CAPITAL PROGRAM

$(000)				
	2014	2015	2016	14-16 Total
Operating Areas				
Traditional New Business	$42,600	$44,073	$44,090	$130,763
Traditional New Business Regulators	$0	$3,000	$3,000	$6,000
New Business - #4/#6 Oil-to-Gas Conversions	$53,836	$69,044	$56,122	$179,002
New Business - #4/#6 Oil-to-Gas Regulators	$30,000	$25,000	$25,000	$80,000
System Reinforcement	$42,500	$42,502	$42,501	$127,503
System Reinforcement #4/#6 Oil-to-Gas Conversion	$2,496	$2,507	$2,501	$7,504
Meters Installation	$17,022	$16,895	$16,789	$50,705
Meters Installation - #4/#6 Oil-to-Gas Conversions	$734	$791	$566	$2,091
Total GD-1	**$189,188**	**$203,812**	**$190,569**	**$583,568**
GD-3 Leaking Services	$25,607	$24,999	$24,993	$75,599
GD-4 Corroded Steel Mains	$33,172	$33,080	$34,972	$101,224
GD-5 Cathodic Protection	$396	$397	$396	$1,189
GD-11 Small Diameter LPCI Replacement Program	$41,806	$43,089	$42,928	$127,823
GD-29 Steel Main Replacement For 2" Coupling Elimination	$6,797	$6,797	$6,797	$20,391
Additional Main Replacement	$34,400	$51,500	$68,800	$154,700
Total Operating Areas	**$331,366**	**$363,674**	**$369,455**	**$1,064,494**
Technical Operations				
Measurement - Meter Purchase	$7,132	$7,142	$7,140	$21,414
Measurement - #4/#6 Oil-toGas Conversions	$2,979	$1,555	$754	$5,288
Tunnels	$2,325	$2,341	$2,304	$6,970
LNG	$1,400	$1,750	$2,300	$5,450
Total Technical Operations	**$13,836**	**$12,788**	**$12,498**	**$39,122**
Pressure Control	**$2,790**	**$2,806**	**$2,803**	**$8,399**
Supply Mains				
12" Medium Pressure Cast Iron Main Replacement Program	$2,700	$2,700	$3,000	$8,400
Replace Saw Mill Elmsford Main	$1,100	$1,100	$500	$2,700
Replace Saw Mill Greenburgh Main	$1,100	$1,100	$1,500	$3,700
Second Supply Main to City Island	$0	$1,500	$700	$2,200
City Island Bridge	$1,500	$0	$0	$1,500
Westside Manhattan Loop	$250	$250	$250	$750
Westchester Large Valve Repl	$500	$500	$500	$1,500
Replace Corroded Union Tpke Mains	$600	$600	$500	$1,700
Annual Repl. of Supply Mains from Hawthorne to Peekskill (Albany)	$1,100	$1,000	$1,000	$3,100

Annual Repl. of Supply Mains from Greenburgh to Hawthorne	$0	$500	$500	$1,000
Annual Replacement of Supply Mains from Hawthorne to Katonah	$600	$1,000	$1,000	$2,600
Fort Washington HP Main	$0	$1,100	$1,100	$2,200
Replacement of the Astoria- Flushing Main	$0	$500	$1,000	$1,500
Small Main Ties Program	$500	$500	$0	$1,000
Yorktown Upgrade	$1,000	$1,000	$1,000	$3,000
Scarsdale HP Main	$500	$500	$600	$1,600
East Bronx HP Loop Ties	$0	$1,000	$1,000	$2,000
Cortlandt/ Peekskill Tie	$1,000	$1,000	$1,000	$3,000
Roosevelt Island Shaft	$0	$1,000	$1,000	$2,000
Westchester Creek MP Main Replacement	$0	$0	$500	$500
Second Supply to Roosevelt Island	$0	$0	$1,000	$1,000
Purchase/Armonk HP Tie	$0	$0	$1,000	$1,000
Sunnyside Yards	$1,100	$0	$0	$1,100
Hudson RR Yards	$1,100	$0	$2,100	$3,200
White Plains Regulator	$0	$1,600	$2,100	$3,700
E72nd St & York Ave Regulator Upgrade.	$0	$2,400	$0	$2,400
Mid-Town Manhattan HP Loop Reinforcement	$0	$0	$1,600	$1,600
Bayside Regulator	$0	$0	$1,600	$1,600
Portchester Medium Pressure Replacement	$0	$0	$1,100	$1,100
Pelham to Saw Mill	$0	$0	$550	$550
Pelham to Rye	$0	$0	$550	$550
W76 and Columbus Ave Regulator	$0	$0	$2,200	$2,200
Waterbury & Hobart Reg	$0	$0	$1,800	$1,800
Westchester Ave Main Replacement	$2,100	$500	$0	$2,600
Ferris Avenue Main Tie	$800	$800	$0	$1,600
Install HP Reg vent float check valves	$4,800	$0	$0	$4,800
Pipe Repalcement in Flood Prone Areas	$0	$16,600	$16,700	$33,300
Additional Flood Prone Main Replacement	$18,000	$26,000	$35,000	$79,000
Storm Hardening Tunnel Head Houses	$0	$25,000	$35,000	$60,000
Total Supply Mains	**$40,350**	**$89,750**	**$118,950**	**$249,050**
Transmission & Generation Projects				
Remotely Operating Valves (ROV's)	$1,500	$1,500	$1,500	$4,500
Transmission Pipeline Integrity Main Replacement Program	$1,000	$1,000	$1,000	$3,000
Westchester/Bronx Border to White Plains	$25,000	$25,000	$25,000	$75,000
St. Ann's Tee to Hunts Point Downgrade	$3,000	$0	$0	$3,000
Hunts Point Regulator Refurbishment	$2,500	$0	$0	$2,500
Greenburgh Yard Refurbishment	$200	$800	$0	$1,000
Critical Components - Hunts Point to Bronx Border	$6,000	$6,000	$6,000	$18,000
Total Transmission & Generation Projects	**$39,200**	**$34,300**	**$33,500**	**$107,000**
Information Technology Projects				
Gas Work Management System	$2,600	$17,600	$18,000	$38,200
Gas Data Warehouse	$750	$0	$0	$750
Vision/Netmap Implementation (Mapping Upgrade)	$3,000	$1,500	$0	$4,500
Gas Outage Management System Phase 0	$0	$250	$250	$500

Viryanet G4 Migration	$345	$0	$0	$345
NICE Recorder System	$0	$0	$0	$0
GIS Transmission Drip and Encroachments	$400	$0	$0	$400
Total Information Technology Projects	**$7,095**	**$19,350**	**$18,250**	**$44,695**
Total Gas Operations Less PI / Interference	**$434,637**	**$522,668**	**$555,456**	**$1,512,760**
Public Improvement / Interference	**$65,500**	**$63,913**	**$57,993**	**$187,406**
Total Gas Operations	**$500,137**	**$586,581**	**$613,449**	**$1,700,166**

C. Steam

By January 15, 2014, the Company will file with the Secretary its most recent projected expenditures by project and/or program for Steam Distribution, Steam Production, Municipal Infrastructure Support and Storm Hardening for calendar years 2014, 2015, 2016 and 2017 ("Program/Project List"). By December 15, 2014, the Company will provide to Staff and interested parties its Program/Project List for calendar years 2015, 2016, and 2017. By December 15, 2015, the Company will provide to Staff and interested parties its Program/Project List for calendar years 2016 and 2017.

On or before February 28 of each year during the term of the Steam Rate Plan, the Company will file with the Secretary, and provide copies to Staff and all interested parties, a report containing the following information:

(i) for steam distribution and storm hardening capital expenditures during the prior calendar year:

a) for each completed project, the date it was commenced and completed, and its total cost.
b) for each ongoing project, the project's status, date of commencement, estimated date of completion, costs expended to date, and projected total project cost.
c) for each project and program where the Company's expenditures have varied by more than fifteen (15) percent from the estimates contained in the Project/Program List, a detailed explanation and justification for such variation.
d) for each new project (*i.e.*, a project not previously identified in the Company's filings in this steam rate case), a detailed project description, justification of the need for the project, cash flow requirements from inception through completion, an explanation of how the cost figures were derived, and supporting work papers and/or other back up material.

(ii) for steam production, a report comparable to the report provided for electric production, as noted in the electric section of this Appendix, as it is applied to the steam production category.

(iii) for steam plant availability and performance statistics, plant availability and performance statistics for each steam production unit for the winter and summer periods.

(iv) for steam production and distribution O&M expenditures,

a) the Company's plans regarding major maintenance for the current calendar year, including a description of the anticipated major activities and total planned expenditures using the Company's currently effective O&M functional categories for production and distribution;
b) where the Company's actual O&M expenditures for the previous calendar year vary by more than fifteen (15) percent from the previous year's estimates by major maintenance O&M functional category; the report will also provide an explanation for any such variations.

Appendix 24

Consolidated Edison company of New York, Inc.
Cases 13-E-0030, 13-G-0031, 13-S-0032
Balancing Services and Charges for Power Generation Customers:

Variable Balancing Charge:

The customer shall pay a monthly Variable Balancing Charge on all volumes recorded as delivered and burned. The monthly Variable Balancing Charge shall be determined based on the allocated costs of assets used to balance Power Generator customers taking service pursuant to the tariff. By November 1st of each year, the Company will calculate the demand charges associated with its Storage and Firm Transportation contracts. A unit demand cost for the 2% balancing band will be calculated based on the annual demand cost of the Storage and FT deliverability dollars per dekatherm. This unit cost will then be applied as a Variable Balancing Charge to all generator volumes subject to the tariff service. This cost will be the ratio of dollars associated with Generator contribution divided by prior calendar total usage of the generators. For the initial period ending 10/31/2014, the Variable Balancing Charge is calculated to be 1.2 cents per dekatherm (dt).

The monthly Variable Balancing Charge shall be published in the Company's "Statement of Balancing Service Charges Applicable to Service Classification Nos. 9 and 20".

Monthly Cashout Credit on the Net Surplus Imbalance:

The Customer shall receive a Monthly Cashout Credit on the amount by which the aggregate Daily Delivery Quantities are less than the aggregate Daily Transportation

Quantities ("Net Surplus Imbalance") for those days in which this difference is no more than 2%. A Net Surplus Imbalance shall be considered gas purchased by the Company from the Customer. The Monthly Cashout Credit on the Net Surplus Imbalance Quantity shall be equal to the lower of the monthly average of daily Transco Z6-NY Midpoint prices or the Transco Z6-NY First-of-Month Low Range Price as published in Platt's Gas Daily.

Daily Cashout Credit on the Net Surplus Imbalance:

The Customer shall receive a Daily Cashout Credit on the amount by which the Daily Delivery Quantity is less than the Daily Transportation Quantity ("Net Surplus Imbalance") for those days in which this difference exceeds 2%. The Daily Cashout Credit on the Net Surplus Imbalance shall be equal to the product of the cost of gas and the applicable percentage, as shown below.

Net Surplus Imbalance	Charge Per Therm
(1) greater than 2% but less than or equal to 5%	90% of cost of gas
(2) greater than 5% but less than or equal to 10%	80% of cost of gas
(3) greater than 10%	70% of cost of gas

The cost of gas used in calculating the Daily Cashout Credit shall be the Transco Z6-NY Midpoint price as published in Platt's Gas Daily on the day in which the imbalance occurs.

Appendix 24

Monthly Cashout Charge on the Net Deficiency Imbalance:

The Customer shall pay a Monthly Cashout Charge on the amount by which the aggregate Daily Delivery Quantities are greater than the aggregate Daily Transportation Quantities ("Net Deficiency Imbalance") for those days in which this difference is no more than 2%. A Net Deficiency Imbalance shall be considered gas purchased by the Customer from the Company. The Monthly Cashout Charge on the Net Deficiency Imbalance Quantity shall be equal to the higher of the monthly average of daily Transco Z6-NY Midpoint prices or the Transco Z6-NY First-of-Month High Range Price as published in Platt's Gas Daily.

Daily Cashout Charge on the Net Deficiency Imbalance:

The Customer shall pay a Daily Cashout Charge on the amount by which the Daily Delivery Quantity is greater than the Daily Transportation Quantity ("Net Deficiency Imbalance") for those days in which this difference exceeds 2%. The Daily Cashout Charge on the Net Deficiency Imbalance shall be equal to the product of the cost of gas and the applicable percentage, as shown below.

Net Deficiency Imbalance	**Charge Per Therm**
(1) greater than 2% but less than or equal to 5%	110% of cost of gas
(2) greater than 5% but less than or equal to 10%	120% of cost of gas
(3) greater than 10%	130% of cost of gas

Appendix 24

The cost of gas used in calculating the Daily Cashout Charge shall be the Transco Z6-NY Midpoint price as published in Platt's Gas Daily on the day in which the imbalance occurs.

Consolidated Edison Company of New York, Inc.
Cases 13-E-0030, 13-G-0031, 00-S-0032
Lost and Unaccounted For Gas

Calculation of five-year average Line Loss Factor, Factor of Adjustment, and incentive/penalty bands
Based on 5 Year Period: TME Aug 09 to TME Aug 13

		Aug-13	Aug-12	Aug-11	Aug-10	Aug-09
	Citygate Receipts					
1.	Total Pipeline Receipts	353,025,876	330,946,295	342,972,760	332,275,136	340,139,839
2.	LNG Withdrawals	64,064	104,271	99,052	91,937	111,333
3.	Total Receipts from NY Facilities	10,249,629	5,128,958	3,271,542	2,567,607	2,176,945
4.	**Total Receipts (Sum of Lines 1-3)**	363,339,569	336,179,524	346,343,354	334,934,680	342,428,117
	Deliveries to Customers					
5.	Retail Sales and Transportation Deliveries	153,245,546	132,737,852	149,664,074	138,827,162	141,235,745
6.	Deliveries to Generation	170,834,882	165,278,604	150,306,718	149,447,735	150,283,656
7.	Gas Used for Company Purposes & CNG	161,513	165,463	136,113	121,212	147,597
8.	LNG Injections	273,800	13,066	162,480	318,165	259,956
9.	Total Heater & Compressor Consumption	405,119	370,097	357,530	336,346	356,421
10.	Total Deliveries to NY Facilities	34,253,075	34,006,479	40,384,365	41,193,909	45,130,723
11.	**Total Deliveries (Sum of Lines 5-10)**	359,173,935	332,571,561	341,011,279	330,244,529	337,414,098
12.	**Losses (Line 4 - Line 11)**	4,165,634	3,607,963	5,332,075	4,690,151	5,014,019
13.	**Contribution to system line loss from Generation at 0.5% (Line 6 * 0.005)**	854,174	826,393	751,534	747,239	751,418
14.	**Adjusted Line Loss (Line 12 - Line 13)**	3,311,459	2,781,570	4,580,541	3,942,913	4,262,601
15.	**Citygate Receipts adjusted for Generation (Line 4 - Line 6 - Line 13)**	191,650,513	170,074,527	195,285,102	184,739,706	191,393,043
16.	***Annual Line Loss Factor (LLF) (Line 14 / Line 15)***	1.7279%	1.6355%	2.3456%	2.1343%	2.2271%

5-Year Statistics (Aug 09 - Aug 13)

17.	**Five-Year average Line Loss Factor (LLF) (Average of Line 16)**	**2.014%**
18.	**Standard Deviation (SD) of Line 17**	**0.314%**
19.	**Upper Deadband Limit (Line 16 + (2* Line 17))**	**2.643%**
20.	**Lower Deadband Limit (Line 16 - (2* Line 17))**	**1.386%**
21.	**Factor of Adjustment 1/(1-Line 17)**	**1.0206**

Consolidated Edison Company of New York, Inc.
Cases 13-E-0030, 13-G-0031, 00-S-0032
Lost and Unaccounted For Gas

		Losses Below lower deadband limit	Losses within deadband of +/- two std deviations	Losses Above upper deadband limit
1.	Total Receipts	361,339,569	363,339,569	365,339,569
2.	Total Deliveries	359,173,935	359,173,935	359,173,935
3.	Line Loss (Line 1 - Line 2)	2,165,634	4,165,634	6,165,634
4.	Deliveries to Generators	170,834,882	170,834,882	170,834,882
5.	Contributions from Generators (Line 4 * 0.005)	854,174	854,174	854,174
6.	Adjusted Line Loss (Line 3 - Line 5)	1,311,459	3,311,459	5,311,459
7.	Receipts Adjusted for Generators (Line 1 - Line 4 - Line 5)	189,650,513	191,650,513	193,650,513
8.	Adjusted Line Loss Factor (Line 6 / Line 7)	0.692%	1.728%	2.743%
9.	Annual Factor of Adjustment (1/1-Line 8)	1.0070	1.0176	1.0282
10.	**Target 5 yr Avg Line Loss Factor (Appendix 25 Page 1)**	**2.014%**	**2.014%**	**2.014%**
11.	**Factor of Adjustment (FOA) (1/1-Line 10)**	**1.0206**	**1.0206**	**1.0206**
12.	Net Commodity Cost of Gas	450,000,000	450,000,000	450,000,000
13.	Upper Limit of Deadband (LLF) (Appendix K Line 19)	2.643%	2.643%	2.643%
14.	Upper Limit of Deadband (FOA)(1/1-Line 13)	1.0271	1.0271	1.0271
15.	Lower Limit of Deadband (LLF) (Appendix K Line 20)	1.386%	1.386%	1.386%
16.	Lower Limit of Deadband (FOA)(1/1-Line 15)	1.0141	1.0141	1.0141
17.	Company Benefit/(Cost)*	3,189,351		(476,479)

*** A cost is subtracted from the gas costs to be recovered from gas sales customers and a benefit is added to the gas costs to be recovered from gas sales customers.**

If the actual LLF is less than the Upper Limit of Deadband (LLF) and greater than Lower Limit of Deadband (LLF) then there is no benefit or cost

If the actual LLF is greater than the Upper Limit of Deadband (LLF) then the cost is Line 12 * (Line 16- Line 9)

If the actual LLF is less than the Lower Limit of Deadband (LLF) then the benefit is Line 12 * (Line 14 - Line 9)

Consolidated Edison Company of New York, Inc.
Cases 13-E-0030, 13-G-0031, 00-S-0032
Non-Affiliate Use of the Con Edison Corporate Name

Standards of Competitive Conduct
The following standards of competitive conduct shall govern the RegCo's relationship with any energy supply and energy service affiliates:

(I)(a) There are no restrictions on affiliates using the same name, trade names, trademarks, service name, service mark or a derivative of a name, of the HoldCo or the RegCo, or in identifying itself as being affiliated with the HoldCo or the RegCo. However, no non-affiliate, whether or not engaged in the energy supply and/or energy service business, will be allowed to use the same name, trade names, trademarks, service names, service marks, logos or a derivative of a name of RegCo except in the following limited circumstances:

(1) In the event an affiliate business, or the assets of that business, is sold or otherwise is no longer an affiliate, such non-affiliated company will be allowed to use the name, trade names, trademarks, service names, service marks or a derivative of a name of HoldCo or RegCo in New York State for a period not exceeding 6 months, provided that such use is restricted to (i) use of the HoldCo or RegCo logo during the pendency of the transition to new ownership (*e.g.*, vehicle and facility signage) and (ii) educating customers about the sales transaction and the impacts on customers. During that 6 month period, DPS Staff will be given the opportunity to preview any communication using HoldCo or RegCo’s name or logo that is to be sent from a non-affiliate to RegCo’s utility customers in New York. RegCo shall supply a copy of any such communication to DPS Staff in advance of its actual use. DPS Staff may reject any customer communication it deems not in compliance with this section by providing RegCo with written notice of its specific

objections. A communication will be deemed acceptable unless DPS Staff objects in a writing received by the RegCo within five business days of Staff's receipt of such communication from RegCo.

DPS Staff and the RegCo will work collaboratively to resolve any disagreement as to the content of the communication.

(2) RegCo and/or HoldCo may continue to license, in the same manner as has RegCo and/or HoldCo have done, the RegCo and/or HoldCo name, trade names, trademarks, service names, service marks, logos or a derivative of a name of RegCo for use in movie and/or television productions.

(3) RegCo and/or HoldCo may allow industry organizations of which RegCo, HoldCo, or their affiliates are members to use the RegCo name, trade names, trademarks, service names, service marks, logos or a derivative of a name of RegCo.

(4) RegCo and/or HoldCo may license the use of the RegCo name, trade names, trademarks, service names, service marks, logos or a derivative of a name of RegCo, to a non-affiliate to assist with the marketing of Commission approved energy efficiency programs.

(b) The RegCo will not provide sales leads for customers in its service territory to any affiliate, including the ESCO, and will refrain from giving any appearance that the RegCo speaks on behalf of an affiliate or that an affiliate speaks on behalf of the RegCo. If a customer requests information about securing any service or product offered within the service territory by an affiliate, the RegCo may provide a list of all companies known to RegCo operating in the service territory who provide the service or product, which may include an affiliate, but the RegCo will not promote its affiliate. The RegCo must process all similar requests for distribution services in the same manner and within the same period of time.

Consolidated Edison Company of New York, Inc.
Case 13-E-0030
Electric Capital Expenditures
$ 000's

Category	Rate Year 1	Rate Year 2
Other (Production and Shared Services)	$ 246,157	$ 241,973
T&D - Interference	59,501	56,718
- Reliability	456,732	531,596
- All other	544,404	599,067
Storm Hardening	179,929	278,311
Total	$ 1,486,722	$ 1,707,665

Consolidated Edison Company of New York, Inc.
Case 13-G-0031
Gas Capital Expenditures
$ 000's

Category	Rate Year 1	Rate Year 2	Rate Year 3
Delivery - All Other	**$358,992**	**$376,363**	**$418,522**
- Interference	**65,500**	**63,913**	**57,993**
- Storm Hardening	**5,021**	**36,459**	**56,942**
- Oil to Gas Conversions	**53,800**	**69,000**	**56,100**
Shared Services	**40,845**	**40,240**	**37,457**
Total	**$524,158**	**$585,975**	**$627,014**

Consolidated Edison Company of New York, Inc.
Case 13-S-0032
Steam Capital Expenditures
$ 000's

Category	Rate Year 1	Rate Year 2	Rate Year 3
Production & Distribution	**$ 55,221**	**$ 63,386**	**$ 63,380**
Storm Hardening	**26,500**	**30,500**	**35,000**
Total	**$ 81,721**	**$ 93,886**	**$ 98,380**

Consolidated Edison Company of New York, Inc.
Cases 13-E-0030 / 13-G-0031 / 13-S-0032
Company Labor Expense Reflected In Revenue Requirement
$ 000's

		Electric	Gas	Steam	Total
Twelve Months Ended June 30, 2012		$ 565,471	$ 109,385	$ 58,765	$ 733,621
Normalizations-Capital/Expense Mix		2,904	361	114	3,379
-AMR Savings		(409)	(90)	-	(499)
Program Changes-Staffing Request		8,889	1,381	423	10,693
-AMR Savings		(838)	(184)	-	(1,022)
Wage Escalations (July 2012 - December 2014, 30 months)		50,354	9,708	5,186	65,248
1% Productivity Imputation (July 2012-December 2014)	(a)	(13,332)	(2,572)	(1,378)	(17,281)
Twelve Months Ending Dec. 31, 2014 (RY1)		$ 613,039	$ 117,990	$ 63,110	$ 794,139
Staff's Adjustments					
Reductions to reflect June 30, 2013 actual headcount	(b)	(9,439)	(1,826)	(981)	(12,246)
Other Labor Adjustments		(7,001)	(1,123)	(351)	(8,475)
Labor Expense-Twelve Months Ending Dec. 31, 2014 (RY1)		$ 596,599	$ 115,041	$ 61,778	$ 773,418
Rate Year 2 Adjustments					
Program Changes		2,464	91	51	2,606
Wage Escalations		20,921	4,022	2,155	27,098
1% Productivity Imputation		(6,333)	(1,218)	(652)	(8,203)
Labor Expense-Twelve Months Ending Dec. 31, 2015 (RY2)		$ 613,650	$ 117,936	$ 63,331	$ 794,918
Rate Year 3 Adjustments					
Wage Escalations		-	4,120	2,207	6,327
1% Productivity Imputation		-	(1,259)	(675)	(1,934)
Labor Expense-Twelve Months Ending Dec. 31, 2016 (RY3)		$ -	$ 120,797	$ 64,864	$ 185,661

Note:
(a) Reflects 1% productivity imputation for Company labor. The amounts above excludes productivity imputation for AMR savings and associated payroll taxes.

(b) Adjustment to reflect Company's June 2013 staffing level of 13,400 as of that date (composed of 8,215 Union employees, 5,076 management personal, 109 "other" or "temporary" employees).