STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 19-E-0065 – 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 19-G-0066 – 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.

JOINT PROPOSAL

October 16, 2019

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JOINT PROPOSAL

THIS JOINT PROPOSAL ("Proposal" or "JP") is made as of the 16th day of October 2019, by and among Consolidated Edison Company of New York, Inc. ("Con Edison" or "Company"), New York State Department of Public Service Staff ("Staff"), the City of New York ("NYC"), Association for Energy Affordability ("AEA"), Blueprint Power, CALSTART, ChargePoint, Inc., Consumer Power Advocates ("CPA"), Direct Energy Services ("DES"), Environmental Defense Fund ("EDF")(Case 19-E-0065 only), Metropolitan Transportation Authority ("MTA"), Natural Resources Defense Council ("NRDC") (Case 19-E-0065 only), New York Energy Consumers Council ("NYECC"), New York Geothermal Energy Organization ("NYGEO"), New York State Office of General Services ("OGS"), New York Power Authority ("NYPA"), New York Retail Choice Coalition ("NYRCC"), the Sabin Center for Climate Change Law at Columbia Law School, Bob Wyman, 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 operating under an *Order Approving Electric and Gas Rate Plans* ("2017 Rate Order"),[1] that established the terms of an electric and gas rate plan which adopted, with modifications, the Joint Proposal submitted by parties to those proceedings on September 20, 2016 ("2016 Joint Proposal"). The 2017 Rate Order established, *inter alia*, electric and gas rates effective January 1, 2017 through December 31, 2019 ("2017 Electric and Gas Rate Plans") and adopted the 2016 Joint Proposal.

On January 31, 2019, Con Edison filed new tariff leaves to its Schedule for Electricity Service, P.S.C. No. 10 – Electricity (the "Electric Tariff"), Schedule for Power Authority of the State of New York ("PASNY") Delivery Service, P.S.C. No. 12 – Electricity (the "PASNY Tariff"), and Schedule for Gas Service, P.S.C. No. 9 – Gas (the "Gas Tariff"), and supporting testimony for new rates and charges for electric and gas service to become effective on January 1, 2020, for the 12-month period ending December 31, 2020. In that filing, the Company also included financial information for the two succeeding 12-month periods in order to facilitate development of multi-year rate plans through settlement discussions in the event parties elected to do so.

An administrative law judge ("ALJ") was appointed to preside over the rate proceedings. Parties engaged in discovery, with the Company responding to over 2,400 formal discovery requests on the filings. A procedural conference was held in New York

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[1] Cases 16-E-0060, 16-G-0061, 15-E-0050, and 16-E-0196, Consolidated Edison Company of New York, Inc. – Electric Rates, *Order Approving Electric and Gas Rate Plans* (issued and effective January 25, 2017).

City on March 13, 2019, which was immediately followed by a technical presentation by the Company on various aspects of the filing.

On March 20, 2019, the presiding ALJ issued a *Ruling on Schedule*, providing dates for certain activities in these cases, including the preliminary Company updates, Staff and intervenor testimony, rebuttal testimony and the start of evidentiary hearings.

On April 1, 2019, the Company filed its compliance plan to address the Commission's New Efficiency: New York ("NE:NY") Order.[2] On April 10, 2019, the Company provided the parties with preliminary revenue requirement updates and supporting exhibits, which included the costs associated with the Company's April 1 NE:NY filing.[3]

On May 24, 2019, twenty-five (25) parties filed testimony in response to the Company's filings.[4] On June 14, 2019, the Company filed update and rebuttal testimony, including the Company's formal revenue requirement update. Twelve (12) parties also

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[2] The Company's April 1 filing responded to two Commission orders: (1) Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative, *Order Adopting Accelerated Energy Efficiency Targets* (issued and effective December 13, 2018), and (2) Case 17-G-0606, Petition of Consolidated Edison Company of New York, Inc. for Approval of the Smart Solutions for Natural Gas Customers Program, *Order Approving with Modifications the Non-Pipeline Solutions Portfolio* (issued and effective February 7, 2019).

[3] The Company updated the April 1 filing on May 21 and July 1, 2019. The Company provided these updates to all parties in this proceeding.

[4] Parties filing initial testimony were Advanced Energy Economy Institute ("AEE"), Alliance for a Green Economy ("AGREE"), Bob Wyman, CALSTART, Citizen's Environmental Coalition ("CEC"), CityBridge LLC, County of Westchester ("Westchester"), CPA, DES, Department of Public Service Staff ("Staff"), EDF, MTA, Natural Resources Defense Council ("NRDC"), NYGEO, NYC, NYC Democratic Socialists of America, NYECC, NYPA, NYRCC, OGS, Pace Energy and Climate Center ("Pace"), Public Utility Law Project of NY ("PULP"), Sane Energy Project ("Sane"), The Alliance for Solar Choice ("TASC"), and the Utility Intervention Unit ("UIU") of the New York Department of State's Division of Consumer Protection.

filed rebuttal testimony on June 14, 2019.[5] In addition, four (4) parties filed sur-rebuttal testimony on August 19, 2019, pertaining to specific gas transmission projects in Manhattan and Queens that were introduced by the Company during the course of the proceedings.[6]

By notice dated June 17, 2019, Con Edison notified all parties of the commencement of settlement negotiations on June 27, 2019.[7] Settlement negotiations began on June 27, 2019, and continued on July 10,[8] 16-18, 22-25, and 29-31; August 1, 5-8, 12-15, 19-22, and 26-28; September 3-5, 10-12, 16-18, and 25; October 1, 8, 10, 11, and 15. These negotiations included "breakout" meetings on specific issues that were held with the consent of all parties.

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[5] Parties filing rebuttal testimony were AEE, Bob Wyman, ChargePoint, CPA, Staff, MTA, NYC, NYECC, NYRCC, Pace, PULP, and UIU.

[6] Parties filing sur-rebuttal testimony were AGREE, Bob Wyman, EDF, and Pace. The sur-rebuttal testimony was allowed by the ALJ's ruling in response to the motion to strike certain portions of Con Edison's testimony relating to the gas projects noted above that was filed by Pace and joined by AGREE, Bob Wyman, EDF, and CEC, on July 12, 2019. The motion also requested leave to file supplemental direct testimony to respond to those portions of testimony, and this request was granted.

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

[8] On July 8, 2019, the Company filed a letter with the Secretary agreeing to a one-month extension of the statutory suspension period in these 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 August 8, 2019, the Company agreed to a second one-month extension through February 29, 2020. 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 Company's agreement to a second extension, as set forth in the letter to the Secretary, was conditioned upon the Commission also waiving the limitations regarding selection of the historical test period in its *Statement of Policy on Test Periods in Major Rate Proceedings* and granting a "make-whole" provision for subsequent rate filings.

All negotiations were held either in person or via teleconference. 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 three-year rate plans for Con Edison's electric and gas services. These terms and conditions are set forth as noted in the table of contents and appendices listed above.

A. Term

The Signatory Parties recommend that the Commission adopt three-year electric and gas rate plans for Con Edison as set forth herein, effective as of January 1, 2020, and continuing through December 31, 2022 ("Electric Rate Plan" and "Gas Rate Plan," respectively, and collectively, both plans will be referred to as "Rate Plans").

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, 2020 and ending December 31, 2020; Rate Year 2 ("RY2") means the 12-month period starting January 1, 2021 and ending December 31, 2021; and Rate Year 3 ("RY3") means the 12-month period starting January 1, 2022 and ending December 31, 2022.

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 an additional $113.3 million in revenues on an annual basis starting in RY1, an additional $370.3 million increase in revenues on an annual basis starting in RY2, and an additional $326.4 million increase in revenues on an annual basis starting in RY3.[9]

The major components of the electric revenue requirements underlying this Proposal are set forth in Appendix 1.[10] These revenue requirements reflect the amortizations of various customer credits and debits on the Company's books of account that have previously been or are projected to be deferred by the Company. The list of deferred customer credits and debits to be applied during the Electric Rate Plan is attached as Appendix 3.

a. Supply and Supply-related Charges and Adjustments, Monthly Adjustment Clause and NYPA Surcharge

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

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[9] Nothing in this JP precludes or limits the Company from seeking recovery of incremental costs associated with: (i) the implementation of the New York State Climate Leadership and Community Protection Act; or (ii) transmission reinforcements necessary to maintain reliability that result from generation retirements due to new air emission regulations that may be adopted by the New York State Department of Environmental Conservation ("NYSDEC").

[10] These major components include planned capital spending of approximately $3.48 billion over the proposed three-year period for safety and reliability.

of retained generation through the Supply and Supply-related Charges and Adjustments[11] and the MAC mechanism, as currently set forth under General Rules 25 and 26.1 in the Electric Tariff, respectively. In addition, the Company will continue to collect certain charges from NYPA through the Statement of Other Charges and Adjustments ("NYPA OTH Statement"), as set forth under Additional Delivery Charges and Adjustments in Section H of the PASNY Tariff.[12]

The Company will modify General Rule 25.2.2(b), Adjustment Factor - MSC II (Leaf 333) of the Electric Tariff to include all costs associated with the procurement of energy and capacity hedges and supplies for Customers, including auction platform licensing fees, maintenance fees, customization fees and related costs.[13]

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[11] Costs recovered through the Supply and Supply-related Charges and Adjustments include the following costs: the Market Supply Charge ("MSC"); Adjustment Factors – MSC (except for Customers served under Rider M); the Merchant Function Charge; and the Clean Energy Standard Supply Surcharge. These costs include/will include the costs incurred by the Company as authorized by Commission orders in Cases 15-E-0302 and Case 15-E-0751 and Case 18-E-0071 for the procurement of Zero Emissions Credits ("ZECs"), Renewable Emissions Credits ("RECs"), Offshore Wind Zero Emissions Credits ("ORECs") and Alternative Compliance Payments ("ACPs").

[12] For costs, charges, and credits covered by the Supply and Supply-related Charges and Adjustments, the MAC mechanism, and NYPA OTH Statement, 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 mechanisms. Unless otherwise specified, the allocation of costs, revenues, incentives, and other adjustments between customers served under the Electric Tariff and customers served under the PASNY Tariff will be based on the PASNY allocation, as defined in Section H of the PASNY Tariff ("PASNY Allocation"). The PASNY Allocation is defined in Section H as the ratio of forecasted Rate Year Delivery Revenues under the PASNY Tariff to the total combined forecasted Rate Year Delivery Revenues under the PASNY and Electric Tariffs for the Rate Year in effect at the commencement of the collection period.

[13] Related costs are any additional costs associated with vendor support, supplier training, and hardware and software upgrades necessary to run the auction software that are not already included in licensing, maintenance, and customizations.

The following changes will be made to the MAC and NYPA OTH Statement, respectively as specified below:

i. Remove MAC Components 6 and 7 related to recovery of TCCs purchased through the New York Independent System Operator ("NYISO") auctions prior to May 1, 2008.

ii. Remove MAC Component 10 related to any incremental costs the Company incurred resulting from the divestiture of its electric generating facilities.

iii. Remove MAC Component 11 related to adjustments applicable to periods prior to May 1, 2000.

iv. Remove MAC Component 20 related to the restoration and operation of Hudson Avenue Unit 10/100.

v. Remove MAC Component 21 related to lost revenues associated with service rendered prior to April 1, 2008, for both targeted and system-wide demand management programs.

vi. Remove MAC Component 23 related to the Switching and Retention Incentive Payments approved in Case 04-E-0572.

vii. Remove MAC Component 36 related to the credit for the Constellation Settlement refund.

viii. Replace MAC Component 6 with a new component to recover any non-commodity related charges or credits not otherwise recovered through the MSC or Adjustment Factors-MSC related to Federal Energy Regulatory Commission ("FERC") approved or ordered NYISO or PJM rebills or recalculations of charges paid or credits received by NYISO or PJM customers.

ix. Revise the MAC Component 46, and NYPA OTH Statement related to the Company's Earning Adjustment Mechanisms ("EAMs"), to recover any positive incentives earned under EAMs, recover/credit any other incentives associated with Company incentive mechanisms,[14] and recover/credit revenue adjustments associated with Company performance metrics and mechanisms, as authorized by the Commission. This will be applicable to customers on a single cents per kWh basis. Paragraph (H)(6) of the Additional Delivery Charges and Adjustments section of the PASNY Tariff will be renamed

[14] For example, Brooklyn Queens Demand Management ("BQDM") and Non-Wires Alternatives ("NWAs") incentives.

"Contribution to Earning Adjustment Mechanisms ("EAMs") and Other Revenue Adjustments."

PASNY Customers will be allocated by the PASNY Allocation for the following four EAMs: Beneficial Electrification EAM, Distribution Energy Resource Utilization EAM, Electric Peak Reduction EAM and Locational System Relief Value ("LSRV") Load Factor EAM. The Share the Savings EAM and Deeper Energy Efficiency Lifetime Savings EAM will not be allocated to PASNY Customers.

x. Revise MAC Component 47 and NYPA OTH Statement related to climate change vulnerability studies to reflect recovery of costs in accordance with section K.1.d.

b. Revenue Decoupling Mechanism ("RDM")

The Company will amend the currently-effective RDM to reflect the modifications recommended in this Proposal as outlined in section G.7 and Appendix 4. The RDM, as modified, will continue unless and until changed by Commission order.

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, 2020, will become effective on the first day of the month in which they become effective, and (ii) any RDM deferrals will accrue interest as set forth in section F.2 below. The costs of the Low Income Program will be reconciled through the RDM as set forth in section N.

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 and earnings neutral to the Company.

c. PJM OATT Charges

Due to on-going litigation,[15] the Company may incur charges or receive refunds from PJM Interconnection L.L.C. related to its former 1000 MW firm transmission service agreement. In the event the Company does incur such charges/refunds, it may recover/credit that amount from its Con Edison customers through the MAC and from NYPA through the NYPA OTH Statement. The allocation of any such amount between Con Edison and NYPA customers will be based on the percentage allocation of T&D revenues to Con Edison and NYPA customers included in the revenue allocation for the rate year to which the charges relate.

NYPA's allocation will continue to be limited to $4.6 million in any rate year to which the charges relate. If PJM OATT rates and charges are incurred for less than a full rate year, then NYPA's allocation shall be limited to $4.6 million multiplied by the number of months in the partial year divided by twelve months. The Company will recover/credit any retroactive PJM billing adjustments through the MAC and, when not in excess of the applicable cap described above, through the NYPA OTH Statement.

Should the allocation to NYPA exceed the applicable limitation in any rate year, any excess in that year will instead be collected from Con Edison customers through the MAC.

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[15] Old Dominion Elec. Coop v. FERC, 898 F.3d 1254, reh'g denied, 905 F.3d 671 (D.C. Cir. 2018); PJM Interconnection, L.L.C., 168 FERC ¶ 61,133 (2019) (order on remand); see also See New Jersey Board of Public Utilities v. PJM et al., Order Denying Complaint, 163 FERC ¶ 61,139 (2018), reh'g petition pending.

d. 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, or EPA[16]) not already listed in or otherwise covered by the then-effective Supply and Supply-related Charges and Adjustments and the MAC tariff language, notwithstanding the Commission's adoption of this Proposal, the Company may make a tariff filing with the Commission providing for recovery of such charges/costs, or application of these credits, through the Supply and Supply-related Charges and Adjustments and the MAC mechanism and/or comparable adjustment mechanism, as appropriate. The proposed tariff amendment may include charges/costs/credits applicable to the period prior to the effective date of the tariff amendment.

e. Tax Cuts and Jobs Act of 2017 ("Tax Act")

On January 1, 2019, the Company implemented an electric sur-credit to pass back the realized 2019 savings from the Tax Act. The tax sur-credit will be set to zero as of January 1, 2020, subject to the Commission's Order on this Proposal.[17] The Company will amortize the net benefits realized from the Tax Act in 2018 over the three-year period of the Electric Rate Plan, amortize the protected excess deferred federal income

[16] FERC, NYISO, and the Environmental Protection Agency ("EPA").

[17] Residual TCJA balances associated with the 2019 over/under-collection of tax sur-credit, due to volumetric differences in forecasted and actual sales, will be deferred for disposition in the next electric base rate case. The Company will also modify its system benefit charge ("SBC"), effective January 1, 2020, to reflect the transfer of energy efficiency program cost recovery from the SBC to base rates, subject to the Commission's Order on this Proposal. *See* section G.7.f. Any residual energy efficiency program balances associated with the over/under-collection of the surcharge will be recovered/credited through the SBC surcharge in 2020.

tax ("EDFIT") balance resulting from the Tax Act over the average remaining life of the underlying assets, and beginning in RY1, amortize the unprotected EDFIT balance over five years.

f. Business Cost Optimization ("BCO") and Productivity

To account for the Company's BCO savings, operation and maintenance ("O&M") expense for electric operations is reduced by $80.4 million in RY1, an additional $46.0 million in RY2 and an additional $20.2 million in RY3 (these imputations have been included irrespective of whether they are realized). The electric revenue requirements also reflect a productivity adjustment of one percent, or $8.5 million in RY1, an additional one and a half percent, or $13.0 million in RY2, and an additional two percent, or $17.7 million in RY3.[18]

The Company will file quarterly reports on the status of its BCO Initiatives within thirty (30) days after the end of each calendar quarter.

g. Pension/Other Post Employment Benefits ("OPEBs")

In order to mitigate rate volatility, each Rate Year's electric revenue requirement reflects the three-year average of Pension/OPEB expense. A carrying charge at the cost of debt rate has been applied to account for the financing costs the Company will incur to accommodate this adjustment. This carrying charge will not be subject to reconciliation.

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[18] In its next base rate filing, the Company will account for savings that it has identified at the time of the filing that result from its implementation of Phases 1 & 2 of its Geographic Information System ("GIS") project.

2. **Gas**

The Signatory Parties propose that base rate changes be implemented on a levelized bill impact basis to provide rate stability over the term of the Gas Rate Plan. This Proposal recommends changes to the Company's retail gas sales and gas transportation service rates and charges, designed to produce a $47.2 million increase in revenues on an annual basis starting in RY1, an additional $176.3 million increase in revenues on an annual basis starting in RY2, and an additional $170.3 million increase in revenues on an annual basis starting in RY3.[19] Revenue changes by service class are shown in Appendix 21.

The annual levelized rate changes would result in higher 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. Accordingly, if the Company does not file for new rates to be effective January 1, 2023, the Company will make a compliance filing by December 1, 2022 to set rates effective January 1, 2023 at a level that is designed to produce non-competitive delivery base rate revenues on an annual basis that are lower by $20.89 million. The Revenue Decoupling Mechanism ("RDM") target for the Rate Year commencing January 1, 2023 will be reduced by $20.89 million.[20]

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[19] The levelized rate changes, proposed to levelize customer bill impacts, are inclusive of interest on the deferred rate increase calculated at the 2019 Other Customer-Provided Capital Rate of 4.2 percent.

[20] The Company will send to Staff and the parties the rates effective January 1, 2023 and RDM targets within thirty (30) days after the Commission order approving this Proposal.

The major components of the gas revenue requirements underlying this Proposal are set forth in Appendix 2.[21] These revenue requirements reflect the amortizations of various customer credits and debits on the Company's books of account that have previously been or are projected to be deferred by the Company. The list of deferred customer credits and debits to be applied during the Gas Rate Plan is attached as Appendix 3.

a. Revenue Decoupling Mechanism

The Company will amend the RDM to reflect the modifications recommended in this Proposal as outlined in section H.2.d and Appendix 5. The Company will move from a Revenue Per Customer model to a Revenue Per Class model whereby each customer group will have a target revenue level established in the gas tariff. In addition, SC 1 and its transportation equivalent under SC 9 will be included in the RDM and will be reflected as its own customer group. The RDM, as modified, will continue unless and until changed by Commission order.

b. Gas Cost Factor / Monthly Rate Adjustment

The Company will recover all supply and supply-related costs through the Monthly Rate Adjustment ("MRA"), Gas Cost Factor ("GCF"), and Daily Delivery Service ("DDS") mechanisms.[22]

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[21] These major components include planned capital spending of approximately $2.23 billion over the proposed three-year period for safety and reliability.

[22] The Company recovers various costs and charges, and provides certain credits, through the GCF, DDS, and MRA. For costs, charges, and credits covered by these 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 statements filed pursuant to these mechanisms.

i. **Changes to GCF**

(1) Under the GCF in General Information Section VII, fixed gas costs will be modified to include costs for capacity, including fees, purchased through third party Asset Management Agreements; and any fixed charges associated with Renewable Natural Gas ("RNG").

(2) Under the GCF in General Information Section VII, variable gas costs will be modified to include all costs associated with using online auction platforms including licensing, maintenance, customization fees and related costs;[23] and supply costs associated with RNG.[24]

ii. **Changes to MRA**

(1) **Advanced Metering Infrastructure ("AMI") EAM –** General Information IX.25 will be amended to rename the Earnings Adjustment Mechanism Related to AMI Customer Awareness ("AMI EAM") to "Earnings Adjustment Mechanisms ("EAMs") and Other Revenue Adjustments." It will further be modified to recover any positive incentives earned under EAMs, recover/credit any other incentives associated with Company incentive mechanisms, and recover/credit revenue adjustments associated with Company performance metrics and mechanisms, as authorized by the Commission. This will be applicable to firm customers on a single cents per therm basis. There will no longer be an Earnings Adjustment Mechanism attributed specifically to "AMI Customer Awareness."

(2) **Manhattan Project –** Under General Information Section IX, Special Adjustments, a new MRA component will be added to recover carrying charges of the Manhattan Gas Transmission Project,[25] if placed into service during the Gas Rate Plan, until such costs are reflected in base rates.

(3) **Interconnection Plant Surcharge –** Under General Information Section IX.27, the Interconnection Plant Surcharge will be expanded to recover carrying charges of plant necessary to interconnect

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[23] See definition of "related costs" in footnote 13.

[24] The Company will also make related changes to the DDS under Service Classification No. 20 set forth in the Company's tariff in order to recover associated RNG costs.

[25] *See* Section L.7 for a description of this project.

RNG supplies. In the next base rate case, the Company will file to incorporate these costs into base rates, as appropriate, using recovery periods consistent with the terms of the Company's contracts with its RNG suppliers.

(4) **Gas Service Line Surcharge –** Under General Information Section IX, Special Adjustments, a new MRA component will be added to recover Gas Service Line survey/inspection costs incurred above those included in base rates if the Commission does not grant in full the Company's petition to extend survey/inspection intervals.[26]

(5) **Oil to Gas Conversion Program Surcharge** - General Information Section IX.13 will be updated to discontinue the Oil to Gas Conversion Incentive Program effective January 1, 2020. The Oil to Gas Conversion Surcharge will continue to collect incentive payments provided to customers as authorized by Rate Plans in effect prior to January 1, 2020.

(6) **Pipeline Facilities Adjustment -** The Pipeline Facilities Adjustment, under General Information Section IX.18, will be amended to remove specific references to interstate pipeline companies, expenditure levels and Company rate plans.

(7) **New York Facilities Adjustment –** The Company's projection of New York Facilities operating revenues (i.e., net payments and receipts) is reflected in base rates. The use of the MRA solely for reconciliation of estimated and actual New York Facilities operating revenues will continue.[27] This will be applicable to firm customers on a single cents per therm basis.

(8) **Non-Pipeline Alternatives ("NPA")** - Under General Information Section IX, Special Adjustments, a new MRA component will be added to recover costs associated with NPAs, as described in Section D.2.c. below, until such costs are incorporated into base rates. Recovery of costs related to the District Energy Initiative pilot, as described in Section P.5, including costs related to consulting fees, will be recovered under this component.

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[26] The definition of a "Gas Service Line" was amended in Case 14-G-0357 to include piping up to the outlet of the meter for meters located indoors. The Company has filed a petition under Case 15-G-0244 to extend the required survey/inspection intervals. This petition is pending before the Commission. *See* Section E.28 of this Proposal for additional detail on this item.

[27] *See* Section E.25 for additional detail on this item.

(9) **Pipeline Safety Acts** - Under General Information Section IX, Special Adjustments, a new MRA component will be added to recover carrying charges associated with incremental capital incurred during this Rate Plan to comply with the Pipeline Safety Acts, as described in Section D.2.a. below, until such costs are incorporated into base rates.

(10) **Climate Change Vulnerability Study –** The Climate Change Vulnerability Study, under General Information Section IX.24, will be updated to reflect recovery of costs in accordance with Section K.1.d.

Nothing in this Gas Rate Plan precludes the Company from submitting a tariff filing to implement additional revenue neutral changes as between and among the GCF, DDS, and MRA during the term of the Gas Rate Plan.[28]

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" subject to sharing under this section.

1. Net base revenues[29] derived from

(i) Customers receiving interruptible service under SC 12 Rate 1 and SC 9 Rates B and D; and

(ii) Power generation customers[30] receiving interruptible or off-peak firm service, including off-peak firm service

[28] Such revenue neutral changes may include, for example, changes to the allocation of credits between and among full service customers, firm transportation customers and SC 20 marketers.

[29] 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.

under SC 9 Rate D(2) or special negotiated contracts; 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-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:[31] 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; and

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.[32]

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).

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[30] 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.

[31] 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 (iii) the Winter Bundled Sales Service ("WBSS").

[32] Gas balancing revenues will not include charges for DDS service.

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 and parties work papers underlying such surcharge or credit in order to afford Staff and parties an opportunity to raise with the Company any concerns that they may have with the size of the surcharge or credit. Any such surcharge or credit will be implemented over a 12-month period.

d. Lost and Unaccounted For Gas

The calculation for Lost and Unaccounted for Gas established by the 2010 Gas Rate Order, as modified effective January 1, 2014, continues for the term of this Gas Rate Plan, 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.[33]

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, 2020, 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 will be determined in October 2019, once the 12-month period ending August 2019 is completed and will be filed with the Secretary at that time. The LLF for the 12-month period ending August 31, 2020 will be compared to the target (*i.e.,* five-year average level as of August 2019). For RY2 and RY3, the target will be reset each year based on the average of the preceding five (5) years' LLFs.

[33] Adjusted Line Losses will also reflect the delivery in kind of an additional 0.5% of net deliveries at New York Facilities Receipt Points.

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 will be also be determined in October 2019 and will be included in the five-year average LLF filing with the Secretary.

Currently, metered gas for inactive accounts is considered to be Lost and Unaccounted For ("LAUF") gas. This Proposal recommends that metered gas for inactive accounts will be removed from the calculation of LAUF gas for those inactive accounts with an installed and operating AMI meter and for which the Company has been able to obtain relevant usage data other than through an installed and operating AMI meter. This change to the LAUF calculation will take effect beginning with the 12-month period ending August 2021.

Appendix 7 provides a sample LAUF calculation, which illustrates the potential benefit or cost to the Company.

e. Other Charges

The Signatory Parties agree that whenever the Company is or will be subject to FERC-approved charges, costs or credits not already listed in or otherwise covered by the then-effective tariff language for these adjustment mechanisms, notwithstanding the Commission's adoption of this Proposal, the Company may make a tariff filing with the Commission to provide for recovery of these costs or charges, or application of these credits, through the GCF, DDS, and/or MRA. 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 and Area Growth Conversion Programs Discontinued

The Company's program of providing financial incentives to residential and commercial customers to encourage their conversion from oil use to gas use shall be discontinued. The Company’s Area Growth programs in New York City and Westchester County shall also be discontinued.

g. Tax Cuts and Jobs Act of 2017

On January 1, 2019, the Company implemented a gas sur-credit to pass back the realized 2018 savings from the Tax Act over three years, the entirety of the realized 2019 savings, and an amortization of EDFIT balances over the average remaining life of the underlying assets. The tax sur-credit will be set to zero as of January 1, 2020, subject to the Commission’s order on this Proposal.[34] During the Gas Rate Plan, the Company will continue to amortize the net benefits realized in 2018 in RY1 and RY2 and continue to amortize the remaining protected EDFIT balance resulting from the Tax Act over the average remaining life of the underlying assets. Beginning in RY1, the Company will amortize the remaining unprotected EDFIT balance over five years.

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[34] Residual TCJA balances associated with the 2019 over/under-collection of tax sur-credit, due to volumetric differences in forecasted and actual sales, will be deferred for disposition in the next gas base rate case. The Company will also modify its SBC, effective January 1, 2020, to reflect the transfer of energy efficiency program cost recovery from the SBC to base rates, subject to the Commission’s Order on this Proposal. *See* section H.2.d.8. Any residual energy efficiency program balances associated with the over/under-collection of the surcharge will be recovered/credited through the SBC surcharge in 2020.

h. Business Cost Optimization and Productivity

To account for the Company's BCO savings, O&M expense for gas operations is reduced by $13.0 million in RY1, an additional $14.5 million in RY2 and an additional $4.9 million in RY3 (these imputations have been included irrespective of whether they are realized). The gas revenue requirements also reflect a productivity adjustment of one percent, or $2.0 million in RY1, an additional one and a half percent, or $3.1 million in RY2, and an additional two percent, or $4.3 million in RY3.

The Company will file quarterly reports on the status of its BCO Initiatives within thirty (30) days after the end of each calendar quarter.

i. Pension/OPEBs

In order to mitigate rate volatility, each Rate Year's gas revenue requirement reflects the three-year average of Pension/OPEB expense. A carrying charge at the cost of debt rate has been applied to account for the financing costs the Company will incur to accommodate this adjustment. This carrying charge will not be subject to reconciliation.

C. Computation and Disposition of Earnings

Following each of RY1, RY2 and RY3, Con Edison will compute, separately, the earned rate of return on common equity for its electric and gas businesses for the preceding Rate Year. The Company will file with the Secretary these computations of earnings no later than sixty (60) days after the end of each Rate Year.

1. Earnings Sharing Threshold

If the level of earned common equity return for any Rate Year exceeds 9.3 percent ("Earnings Sharing Threshold"), the amount in excess of the 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 9.3 percent but less than

9.8 percent will be deferred for the benefit of 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 9.8 percent but less than 10.3 percent will be deferred for the benefit of 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 10.3 percent will be deferred for the benefit of customers and the remaining ten (10) percent of any shared earnings will be retained by the Company.

2. Earnings Calculation Method

For each Rate Year, for purposes of determining whether the Company has earnings above the 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 performance-based revenue adjustments; (ii) other positive incentives (e.g., Brooklyn Queens Demand Management Response Program ("BQDM") and NWAs incentives); (iii) EAMs; (iv) the Company's share of property tax refunds earned during the applicable Rate Year; (v) any other Commission-approved ratemaking incentives and revenue adjustments in effect during the applicable Rate Year; and (vi) the amount of expense for awards under the Company's Executive Incentive Program.

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 base delivery rates to take effect within fifteen (15) days after the expiration of RY3, the Earnings Sharing Threshold and the other earnings sharing thresholds will continue until base delivery rates are reset by the Commission. Such calculation will be performed on an annual basis in the same manner as set forth above. Revenue targets and trued-up expenses contained in Appendices 4, 5, 8, 9 and 10 will be based on RY3 levels for electric and gas.

d. The actual average rate base for any stay-out period less than 12 months will be adjusted by an operating income ratio factor. This adjustment to rate base is intended to align operating income to the level of rate base that generated that income. This factor will be calculated as the ratio of operating income during the same partial year period in the previous Rate Year to the total operating income for that Rate Year. This methodology is illustrated in Appendix 12.

3. <u>Disposition of Shared Earnings</u>

For earnings above the related 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 earnings above the sharing threshold that would otherwise be deferred for the benefit of customers under this Proposal, to reduce under-collection of Site Investigation and Remediation costs ("SIR Costs") deferred in the Rate Year.[35]

In the event the amount of shared earnings available to reduce deferred under-collection of SIR Costs exceeds the amount of such deferred under-collection, the Company will apply the amount of the excess to reduce other interest-bearing deferred costs accumulated in the Rate Year (net change in the other regulatory asset and liability accounts). The Company's annual earnings report will include the amount, if any, of deferred under-collection 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.

D. Capital Expenditures and Net Plant Reconciliation

1. Electric

a. Net Plant Reconciliation

The electric revenue requirements for RY1, RY2 and RY3 reflect the average net electric plant balances set forth in Appendix 8. The average net electric plant balances include transmission and distribution ("T&D"), Municipal Infrastructure Support, Distributed System Implementation Plan ("DSIP"), [36] Electric Production and Shared Services allocable to Electric (collectively, "Average Electric Plant In Service

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[35] Under-collection of SIR costs is defined as the change in the net balance between the SIR regulatory asset account (excluding amortizations) and the SIR liability account.

[36] Planned DSIP capital costs are shown in Appendix 22.

Balances”). These balances do not reflect net plant balances for AMI or Customer Service System (“CSS”), which are addressed in sections D.3 and 4.

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, RY2 and RY3.[37]

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 20% above established capital expenditure targets incurred due to: (a) the Van Wyck Expressway project; and/or (b) the East Side Coastal Resiliency project, to the extent the Company’s capital expenditures related to those activities result in total actual average net plant in service (excluding removal costs) exceeding the Average Electric Plant In Service Balance in any or all Rate Years.

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

The reconciliations to Average Electric Plant In Service Balances for RY1, RY2 and RY3 will be cumulative; that is, a revenue requirement impact deferral will be required under this provision only if the cumulative revenue requirement impact of the Company's actual average net plant for the 36-month period covered by the Electric Rate Plan is below the amount included in the Average Electric Plant In Service Balances over such period as shown on Appendix 8.

b. Reporting Requirements

The Company will provide reports relating to capital expenditures in the manner set forth in Appendix 22.

c. Non-Wires Alternative ("NWA") Adjustment Mechanism

The costs incurred by the Company for implementation of new NWAs (ones that are not included in base rates) during the Electric Rate Plan, including the overall pre-tax rate of return on such costs, will be recovered over ten (10) years. Recovery of these NWA costs during this Electric Rate Plan will be through the MAC and NYPA OTH Statement. The Company shall file to incorporate unamortized NWA costs, including the return, into the Company's base rates when electric base delivery rates are next reset.

To the extent such new NWAs result in the Company displacing a capital project reflected in the Average Electric Plant In Service Balances, the balance(s) will be reduced to exclude the forecasted net plant associated with the displaced project. The carrying charge on the reduction of the Average Electric Plant In Service Balances that would otherwise be deferred for customer benefit will instead be applied as a credit against the recovery of the NWA in the MAC and the NYPA OTH Statement. In the event the carrying charge on the net plant of any displaced project is higher than the NWA recovery, the difference will be deferred for the benefit of customers.

The Company will earn incentives for NWA implementation on the same terms and conditions as established by the Commission for incentives under the TDM program.[38] Any earned incentives will be recovered through the MAC and NYPA OTH Statement.

Consistent with the Commission's TDM Order,[39] the Company will submit an implementation plan for all NWAs that includes at a minimum, detailed measurement and verification procedures, the portfolio of projects to be completed, a demonstration of whether the costs of NWA program expenditures are incremental to the Company's revenue requirement or will be displacing a project subject to the Net Plant Reconciliation mechanism, and a customer and community outreach plan. The Company will file updates to each implementation plan annually by January 31st of each year, or more frequently as necessary. The Company will also submit reports describing the expenditures and program activities, including all relevant details with respect to project costs, project in-service dates, incremental costs incurred, operational savings, and other benefits:

- Quarterly for active NWAs (e.g., NWAs that are being actively implemented with cost-effective portfolios with at least one contract with a third party provider(s) already negotiated) and
- Every six (6) months for NWA projects that are prior to development of a cost-effective portfolio or any negotiated contract with a third party provider.

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[38] *See* Case 15-E-0229, Targeted Demand Management Program, *Order Approving Shareholder Incentives* (issued January 25, 2017).

[39] Case 15-E-0229, Targeted Demand Management Program, Order Implementing with Modification the Targeted Demand Management Program, Cost Recovery, and Incentives (issued Dec. 17, 2015) ("TDM Order").

As the Company develops an NWA solution portfolio for a new NWA and has reasonable certainty regarding the costs for this new NWA, a Benefit Cost Analysis ("BCA") will be performed in consultation with Staff in accordance with the BCA Handbook and the Commission's BCA Order.[40] The Company will also develop a final BCA using actual NWA costs and quantities after the completion of the NWA.

2. Gas

a. Net Plant Reconciliation

The gas revenue requirements for RY1, RY2 and RY3 reflect the average net gas plant balances set forth in Appendix 9. The average net plant balances include Transmission and Delivery, Municipal Infrastructure Support and Shared Services allocable to gas (collectively, "Average Gas Plant In Service Balances"). These balances do not reflect net plant balances for AMI or CSS, which are addressed in sections D.3 and D.4.

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, 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

[40] Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, *Order Establishing Benefit Cost Analysis Framework* (issued January 21, 2016).

included in the Average Gas Plant In Service Balances (excluding removal costs), as set forth in Appendix 9, for RY1, RY2 and RY3.[41]

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;[42] (c) change in customary practice relating to interference (*e.g.*, responsibility for costs associated with New York City transit 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 average net

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

[42] 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, 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 2012, the DEC and DEP agreed to numerous modifications in an amendment to the CSO Consent Order, including integration of green infrastructure and substitution of more cost-effective grey infrastructure, and agreed to fixed dates for submittal of the Long-Term Control Plans, some of which dates were further revised in 2014, 2015, and 2018.

plant in service (excluding removal costs) exceeding the Average Gas Plant In Service Balance in any or all Rate Years.

Incremental capital costs to comply with the Pipeline Safety Act of 2011 and the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2019 will not be included in Average Gas Plant In Service Balances (see also Sections B.2.b and E.27).[43]

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

b. Reporting Requirements

The Company will provide reports relating to capital expenditures in the manner set forth in Appendix 22.

c. NPA Adjustment Mechanism

The Company will propose for Commission approval, within 180 days of the Commission Order adopting this Proposal, a new process for evaluating and implementing NPAs as substitutions for traditional gas infrastructure projects. The new process would be analogous to the DSIP screening process currently in place for electric. The filing will include, among other things, proposed project suitability criteria, a BCA

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[43] Carrying charges (including depreciation) associated with incremental capital to comply with the Pipeline Safety Act of 2011 and the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2019 incurred during the Gas Rate Plan will be recovered through the MRA until such costs are incorporated into base rates.

Handbook for NPAs that will be consistent with the Commission's BCA Order, an incentive proposal, and a plan for implementing the new process.

To the extent such new NPAs result in the Company displacing a capital project reflected in the Average Gas Plant In Service Balances, the balance(s) will be reduced to exclude the forecasted net plant associated with the displaced project. The carrying charge on the reduction of the Average Gas Plant In Service Balances that would otherwise be deferred for customer benefit will instead be applied as a credit against the recovery of the NPA in the MRA. In the event the carrying charge on the net plant of any displaced project is higher than the NPA recovery, the difference will be deferred for the benefit of customers.

The costs incurred by the Company for implementation of NPAs during the Gas Rate Plan, including the overall pre-tax rate of return on such costs, will be recovered as a regulatory asset (the Company will propose an amortization period with its implementation filing). Recovery of NPA costs and any applicable incentives during this Gas Rate Plan will be through the MRA. The Company shall file to incorporate unamortized NPA costs, including the return, into the Company's base rates when gas base delivery rates are next reset.

3. AMI

a. Net Plant Reconciliation

The AMI Order[44] authorized the Company to implement its AMI Business Plan subject to a $1.285 billion cap on capital expenditures.[45] Net plant reconciliation for AMI capital expenditures will be implemented for a single category of AMI capital expenditures that includes amounts allocated to both electric and gas customers. The electric and gas revenue requirements reflect the Average AMI Plant In Service Balances (excluding removal costs) set forth in Appendix 10 for the Company's installation of AMI during RY1, RY2 and RY3.

At the end of RY3, the Company will defer for the benefit of customers or the Company (subject to the cap described in this section), the revenue requirement impact (*i.e*., carrying costs, including depreciation, as identified in Appendix 10) of the amount by which the Company's actual capital expenditures for AMI results in average net plant (excluding removal costs) that is different from the amount included in the Average AMI Plant In Service Balances (excluding removal costs), as set forth in Appendix 10, for RY1, RY2 and RY3 for the AMI program. See Appendix 10 for examples of how this reconciliation mechanism will operate in situations where, during the multi-year period during which meters are being installed, actual expenditures in a year(s) result in actual

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[44] Cases15-E-0050, 13-E-0030, 13-G-0031, Con Edison Rates, *Order Approving Advanced Metering Infrastructure Business Plan Subject to Conditions* (issued March 17, 2016).

[45] Nothing in these Rate Plans is intended to affect in any manner the Company's rights under the AMI Order to petition the Commission in the event that AMI capital expenditures exceed $1.285 billion.

net plant that are either more or less than amounts reflected in the revenue requirement(s) for such year(s).

b. Reporting Requirements

The Company will include capital expenditures for AMI in the annual reports for electric and gas capital expenditures as set forth in Appendix 22.

4. New Customer Service System ("CSS")

a. Net Plant Reconciliation

The Company's implementation of CSS is subject to a $421 million cap on capital expenditures.[46] Net plant reconciliation for CSS capital expenditures will include amounts allocated to both electric and gas.

The Company's revenue requirement in these Rate Plans do not reflect any carrying costs associated with CSS. If a portion of CSS is placed into service and closes to plant, the Company will defer (subject to the cap described in this section) the associated revenue requirement impact (*i.e.*, carrying costs, including depreciation) in a manner similar to the AMI program example set forth in Appendix 10.

b. Stakeholder Meetings

The Company will schedule two stakeholder meetings during 2020 to discuss stakeholder requests regarding CSS technical features and requirements.

c. Reporting Requirements

The Company will include capital expenditures for CSS in the annual reports for electric and gas capital expenditures as set forth in Appendix 22.[47]

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[46] If the Company exceeds the CSS cost cap, it may petition for additional cost recovery.

5. **Additional Common Capital Reporting**

The Company will include common capital expenditures in the annual reports for capital expenditures as set forth in Appendix 22.

E. **Other Deferral Accounting and Reconciliation Mechanisms**

The Company will defer/reconcile costs and related items as detailed in this section. Reconciliations will be to the levels provided in rates, as set forth in Appendices 8 and 9. 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.3 above.

1. **Property Taxes (Electric and Gas)**

If the level of actual electric or gas 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 and 9, 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 in Rate Year 1, seven and half (7.5) basis points on common equity in Rate Year 2, and five (5) basis points on common equity in Rate Year 3. The Company will defer on its books of account, for recovery

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[47] Additional CSS reporting requirements are included in Appendix 26.

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 RY3) if its extraordinary efforts result in fundamental taxation changes and produce substantial net benefits to customers.

2. Pensions/OPEBs (Electric and Gas)

Pursuant to the Commission's Pension/OPEB Policy Statement,[48] the Company will reconcile its actual pensions/Other Post-Employment Benefits ("OPEBs") expenses to the level allowed in electric and gas rates as set forth in Appendices 8 and 9.

The Pension/OPEB Policy Statement provides that companies may seek prospective interest accruals or rate base treatment for amounts funded above the cost recoveries included in rates.[49] 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

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[48] 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/OPEB Policy Statement").

[49] *See* Pension/OPEB Policy Statement, Appendix A, page 16, footnote 3.

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 (incremental to the carrying charges authorized in section B.1.g and B.2.i); 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.[50]

3. Environmental Remediation (Electric and Gas)

Actual expenditures for site investigation and remediation allocated to Con Edison's electric and/or gas businesses,[51] including expenditures associated with former manufactured gas plant sites ("MGP"), Superfund and 1994 DEC Consent Order Appendix B sites (also referred to as SIR Costs), will be deferred on the Company's books of account and amortized as shown on Appendix 3. 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 and 2). The amortization period for SIR costs will continue to be five (5) years.

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[50] For this provision, the Company will not be subject to the Commission's general materiality threshold for deferral treatment purposes of five percent of net income available for common shareholders.

[51] 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.

4. **<u>Non-Officer Management Variable Pay (Electric and Gas)</u>**

The electric and gas revenue requirements reflect expense for the Company's Non-Officer Management Variable Pay Program. 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 and 9 for that service for that Rate Year.

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 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.

5. **<u>Adjustments for Competitive Services (Electric and Gas)</u>**

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 Purchase of Receivables ("POR") discount rate and the Billing and Payment Processing Charge.

6. **<u>East River Major Maintenance Cost Reserve (Electric)</u>**

Any residual East River Repowering Project ("East River") deferred balances on the Company's books of account as of December 31, 2019 may be used for East River during the Electric Rate Plan. In addition, the Company's electric base rates reflect an annual amount for East River Major Maintenance Costs of $8.798 million for each of

RY1, RY2 and RY3. To the extent that over the term of the Electric Rate Plan, the Company incurs cumulative East River Major Maintenance Costs more or less than the sum of the amounts provided in rates plus any residual deferred balance, the Company will defer any variation on its books of account for future recovery from or for credit to customers.

7. East River Interdepartmental Rent (Electric)

The level of the East River interdepartmental rent expense for electric customers in the Electric Rate Plan differs from the level set in steam rates. The Company has not filed to reset steam rates, therefore, the Company will continue to defer the impact of the change in expense to steam until steam base rates are reset, whether positive or negative, to continue the "earnings neutral" nature of these revenues to the Company.

8. Other Transmission Revenues (Electric)

The Company's revenue requirements include annual revenue targets for Transmission Congestion Contracts ("TCC") of $75 million; Transmission Service Charges ("TSC") of $5 million; and grandfathered transmission wheeling contracts ("GTWC") of $7 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.

9. 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.

10. <u>Brownfield Tax Credits (Electric)</u>

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.

11. <u>Proceeds from the Sales of SO_2 Allowances (Electric)</u>

The Company's electric revenue requirements do not reflect any proceeds that might be received from the sale of SO_2 allowances. With the exception of any proceeds received from the sale SO_2 allowances pursuant to the EPA's final rule on interstate transport of fine particulate matter and ozone (the "Transport Rule"), any proceeds from the sale of SO_2 allowances 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. Proceeds from the sale of Transport Rule SO_2 allowances and costs incurred to purchase emission allowances will be recovered/credited through the MAC.[52]

12. <u>BQDM Program and REV Demo Project Costs (Electric)</u>

The Company's electric base rates reflect amounts for the BQDM program and REV Demo projects, amortized over 10 years for spending as incurred in these

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[52] *See* Case 14-E-0272, Tariff filing by Consolidated Edison Company of New York, Inc. to make revisions related to the purchase and sale of SO2 and NOx emissions allowances through the MAC/MSC mechanisms contained in P.S.C. No. 10 – Electricity, *Order Approving Tariff Provision*, December 16, 2014.

programs), as set forth in Appendix 8.[53] The Company will defer annually the revenue requirement associated with program expenditures above or below the target levels reflected in base electric rates, subject to the overall cap on expenditures established by the Commission for these programs.[54] Any deferred balance will be addressed in the Company's next rate filing.

13. <u>Municipal Infrastructure Support (Other Than Company Labor) (Electric and Gas)</u>

If actual non-Company labor Municipal Infrastructure Support expenses (*e.g.*, contractor costs) vary from the level provided in electric and/or gas rates for any Rate Year, which levels are set forth in Appendices 8 and 9, 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 fifteen (15) percent[55] will be deferred on the Company's books of account and recovered from customers. Expenditures above the target plus fifteen (15) percent are not recoverable from customers except as follows: if actual electric and/or gas non-Company labor Municipal Infrastructure Support expenses (*e.g.*, contractors costs) vary from the

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[53] The Company's quarterly reports on REV demonstration projects in Case 14-M-0101 will include actual expenditures in the prior quarter and in the calendar year. The actual expenditures will be presented in aggregate for all REV demonstration projects and for each REV demonstration project.

[54] Case 14-E-0302, Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn Queens Demand Management Program, *Order Establishing Brooklyn/Queens Demand Management Program* (issued Dec. 12, 2014); Case 14-M-0101, Reforming the Energy Vision, *Order Adopting Regulatory Policy Framework and Implementation Plan* (issued February 26, 2015).

[55] E.g., for RY1 the maximum electric deferral is calculated as $136.315 million x 80 percent x 15 percent = $16.358 million.

respective level provided in rates above the target plus fifteen (15) percent, and such increased expenses are due to any public works or municipal infrastructure project with a projected total cost in excess of $100 million, eighty (80) percent of the variation above the target plus fifteen (15) percent, will be deferred on the Company's books of account for future recovery from electric and/or gas customers as applicable.

In addition, if there is a change in law, rules or customary practice relating to interference the Company will have the right to defer such incremental costs pursuant to section Q.2.

14. Long Term Debt Cost Rate (Electric and Gas)

As set forth in Appendices 1 and 2, the weighted average cost of long-term debt during the term of the Rate Plans is 4.63 percent for each RY1, RY2 and RY3. As set forth in Appendices 8 and 9, included in those weighted average cost rates is 3.02 percent in each RY1, RY2 and RY3 for Variable Rate Debt (*i.e.*, the Company's entire portfolio of floating-rate debt, including tax-exempt and taxable debt). 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 and 9. In the event the Variable Rate Debt[56] is refinanced with tax-exempt or taxable debt (which may include retiring the Variable Rate Debt) prior to January 1, 2023 (including under circumstances not contemplated by the Commission's *Order Authorizing Issuance of Securities*, issued April 19, 2019, in Case 19-M-0012, and therefore requiring

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

Commission authorization), the Company will include its costs associated with the refinancing of the Variable Rate Debt in the amounts to be reconciled.

15. <u>Energy Efficiency ("EE") (Electric and Gas)</u>

The Company's electric base rates reflect program costs to be incurred during the rate period as regulatory assets, amortized over ten years, for a Low-Moderate Income ("LMI") Energy Efficiency Program and a Non-Low-Moderate Income ("Non-LMI") Energy Efficiency Program, as set forth in Appendices 8 and 9. The amounts are based on the Company's April 1, 2019 filing in the NE:NY proceeding. If the Commission changes the amounts but does not adjust the Company's revenue requirements to reflect the final regulatory asset levels associated with approved program costs, net of the application of unspent funds, in the NE:NY proceeding, the Company will defer the revenue requirement impact of the three-year cumulative difference between the final amounts in the NE:NY proceeding and the level established for future credit/recovery from electric and gas customers as applicable.

The Company will reconcile the revenue requirement effect of the actual level of costs incurred for the LMI EE Program to the three-year cumulative (combined electric and gas) reconciliation targets and defer any cumulative over-collection over the term of the Rate Plans for future credit to customers.

The Company will reconcile the revenue requirement effect of the actual level of costs incurred for the Non-LMI EE Program to the three-year cumulative (combined electric and gas) reconciliation targets and defer any cumulative over-collection over the term of the Rate Plans for future credit to customers. There will also be contingent flexibility across commodities for the Non-LMI EE Program. Contingent flexibility in this provision shall mean that the Company can (i) shift any remaining funds from electric to gas when electric EE NE:NY derived lifetime savings targets have been met in any Rate Year and (ii) shift any remaining funds from gas to electric when gas EE NE:NY derived lifetime savings targets have been met in any Rate Year.[57]

16. <u>CSS O&M (Electric and Gas)</u>

The Company's electric and gas revenue requirements include forecasted O&M amounts for CSS, as set forth in Appendices 8 and 9. The Company will reconcile the actual level of O&M costs incurred for CSS over the term of the Rate Plans to the three-year cumulative (combined electric and gas) targets and defer any over-collection. Any deferral amounts at the end of the Rate Plans shall be used over the remaining CSS implementation period as authorized in future electric and/or gas rate plans. Any deferral amount at the end of CSS implementation will be credited to customers in the manner thereafter determined by the Commission.

17. <u>Sales and Use Tax Refunds 2019 (Electric and Gas)</u>

The Company's electric and gas revenue requirements reflect estimated sales and use tax refunds related to the June 1, 2015 through May 31, 2018 audit period of $19.2 million ($17.3 million to electric and $1.9 million to gas). The Company will defer refunds received above or below the levels reflected in base electric, gas, and steam rates. Any deferred balances will be addressed in the Company's next base rates filings.[58]

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[57] Electric and gas derived lifetime savings targets are those identified in the Company's System Energy Efficiency Plan ("SEEP") filings in Cases 15-M-0252 and the NE:NY proceeding.

[58] Sales and use tax refunds received in 2018 will be offset against electric and gas plant in service and amortized over 24 years as shown in Appendix 27 (steam allocation to be deferred until the next steam base rate case).

18. <u>Taxes on Health Insurance (Electric and Gas)</u>

The Company's electric and gas revenue requirements for RY3 reflect an estimate of excise taxes scheduled to become effective in 2022 under the Affordable Care Act as set forth in Appendices 8 and 9. If actual taxes are above or below the target levels reflected in base electric and gas rates, the Company will defer those differences on its books of account for future recovery from or credit to customers.

19. <u>Congestion Tolling Program (Electric and Gas)</u>

The Company's electric and gas revenue requirements do not reflect incremental congestion charges under the NY State Congestion Tolling Program. To the extent that the Company incurs such incremental congestion charges during the term of the Rate Plans, the Company will defer these costs on its books of account for future recovery from customers.

20. <u>Prevailing Wage Law (Electric and Gas)</u>

The Company's electric and gas base rates reflect amounts for Janitorial, Guard Service and Landscaping wages and benefits as set forth in Appendices 8 and 9. The Company will defer annually the revenue requirement associated with incremental expenditures required to comply with any new State Prevailing Wage Law for future recovery from customers.

21. <u>NYC Local Law 97 (Electric and Gas)</u>

The Company's electric and gas revenue requirements do not reflect incremental costs to be incurred for the Company buildings to comply with NYC Local Law 97. The Company will review its Local Law 97 audit with Staff prior to commencing Local Law 97-related work to determine what costs may be deferred under this provision. To the extent that the Company incurs such incremental costs during the term of the Rate Plans, the Company will defer these costs on its books of account for future recovery from customers. Penalties incurred under Local Law 97 shall not be deferred under this provision and cannot be recovered from customers.

22. <u>NWA (Electric)</u>

The Company's electric base rates reflect a regulatory asset amount for the Plymouth/Water Street and Columbus NWAs, amortized over 10 years, as set forth in Appendix 8. The Company will defer annually the revenue requirement associated with project expenditures above or below the target levels reflected in base electric rates. Any deferred balance will be addressed in the Company's next base rate filing.

23. <u>Major Storm Cost Reserve (Electric)</u>

a. Major Storm Reserve Funding

Any residual major storm deferral balance on the Company's books of account as of December 31, 2019 may be used during the Electric Rate Plan. In addition, the Company's annual electric revenue requirements provide funding for the major storm reserve of an annual amount of $22.5 million in RY1, $23.0 million in RY2 and $23.5 million in RY3.[59] 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

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[59] 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. This definition of major storm will be applied to weather events affecting the Company's overhead system. For the Company's underground network system, major storms are defined as weather event(s) that result in at least 5,000 customer outages and 800 jobs as recorded in the Company's outage management system. This includes one storm event that satisfies these criteria and multiple storm events that are up to two days apart and, in aggregate, satisfy these criteria.

major storm damage costs in excess of the amounts collected during the Electric Rate Plan plus any residual deferral balance, the Company will defer on its books of account expenses in excess of the balance of the major storm reserve for future recovery from customers. To the extent that the Company incurs major storm damage expenses less than the amounts collected during the Electric Rate Plan plus any residual deferral balance, the Company will defer any variation for the benefit of customers. All major storm expenses are subject to Staff review.

b. 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. These current practices include not charging stores handling, engineering, and other overheads costs to the major storm reserve.

The Company will be allowed to charge to the major storm reserve for costs incurred to obtain the assistance of contractors and/or utility companies providing mutual assistance, incremental employee labor, transportation, meals, lodging, and travel time (collectively, "Pre-Staging and Mobilization Costs") it incurs in reasonable anticipation that a storm will affect its electric operations to the degree meeting the definition of a major storm in 16 NYCRR Part 97, but which ultimately does not do so. Pre-Staging and Mobilization Costs up to $500,000 per event will not be chargeable to the major storm reserve. The Company will be allowed to charge to the major storm reserve Pre-Staging and Mobilization Costs between $500,000 and $2.5 million per event. For Pre-Staging and Mobilization Costs in excess of $2.5 million, per event, the Company will be allowed to charge 85% of such costs to the major storm reserve, and the Company will expense 15% of such costs in the year incurred. The Company may file a petition to defer the

15% of Pre-Staging and Mobilization Costs in excess of $2.5 million, per event. Each such petition will be subject to the Commission's three-part test traditionally applied to petitions requesting deferral accounting treatment.

The Company will exclude 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. The two (2) percent deductible does not apply to Pre-Staging and Mobilization Costs for major storms that do not materialize, as defined above.

The Company will be able to charge costs against the major storm reserve for a period up to thirty (30) days following the date on which the Company is able to serve all customers.

Following a major storm 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 30-day period following the date on which the Company is able to serve all customers will not be subject to the Commission's materiality requirement for deferrals.[60] Upon completion of the work necessary to restore the system to normal operation, 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. Actual costs will be used except where 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 ninety (90) days), the Company will include with its cost filing, 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).

24. <u>SmartCharge Program (Electric)</u>

The Company's electric base rates reflect regulatory asset amounts for the SmartCharge Program (the Company's off-peak EV charging program), amortized over 10 years, as set forth in Appendix 8. The Company will reconcile the revenue requirement associated with the actual level of costs incurred for the SmartCharge

[60] As noted in footnote 50.

Program over the term of the Rate Plan to the three-year cumulative targets and defer any over-collection for future credit to customers.

25. <u>NY Facilities Agreement (Gas)</u>

Forecasted costs and revenues under the Amended NY Facilities Agreement are reflected in the gas revenue requirements as set forth in Appendix 9. The Company will defer annually the revenue requirement associated with actual costs/revenues above or below those targets for surcharge or sur-credit to customers through the MRA.

26. <u>Research and Development Expense (Gas)</u>

Research and Development ("R&D") expenses reflected in the revenue requirements are set forth in Appendix 9 In the event the Company's actual R&D expenses for gas, excluding administrative costs, are less than the three-year cumulative target level in Appendix 9, the Company will defer on its books of account the amount of such under spending for future credit to customers.

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

27. <u>Pipeline Safety Acts (Gas)</u>

The Company's gas revenue requirements do not reflect O&M expenses to comply with new regulations associated with the Pipeline Safety Act of 2011 or the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2019. To the extent that the Company incurs any incremental O&M expenses to comply with the new regulations during the Gas Rate Plan, the Company will defer these O&M expenses on its books of account for future recovery from customers.

28. <u>Gas Service Lines (Gas)</u>

If the Commission does not approve the Company's petition in Case 15-G-0244 to extend survey/inspection intervals or if the Commission makes any modifications to the relief requested in that petition which cause the Company to incur additional costs above those reflected in the revenue requirement, such actual costs would be recovered through the MRA. Recovery of these additional costs will be capped at $99.79 million (cumulative over RY1 - RY3). The Company will submit semi-annual reports to Staff on costs associated with this program. MRA cost recovery under this program will be subject to Staff audit. Any new revenues generated by the survey/inspection process (*e.g.*, collection of $100 no-access fee) will be credited to customers through the MRA.

29. <u>White Plains Gate Station (Gas)</u>

The Company may recover up to $11 million through the Pipeline Facilities Adjustment component of the MRA for costs incurred after July 1, 2019 to build the White Plains Gate Station. To the extent the Company incurs amounts above that $11 million, the Company will defer that amount for recovery in the next gas base rate proceeding.

30. <u>Additional Reconciliation/Deferral Provisions</u>

In addition to the foregoing reconciliation provisions (*i.e.*, sections E.1 through E.29), 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 discontinuation. 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, SBC, Demand Side Management ("DSM") costs, MTA taxes, New York Public Service Law §18-a regulatory assessment, the Supply and Supply-related Charges and Adjustments and the MAC, and MRA/GCF mechanisms, as well as the cost of the Low Income customer charge discount (discussed below) as they may be applicable to electric and/or gas operations.

31. Discontinued Deferrals/Reconciliations

a. World Trade Center (Electric and Gas)

The Company will terminate its World Trade Center reconciliation as no further claims are anticipated.

b. System Peak Reduction (Electric)

The Company will terminate its System Peak Reduction reconciliation as the program has been discontinued.

c. Energy Efficiency (Electric and Gas)

The Company will terminate the reconciliation associated with the Energy Efficiency Program authorized in the 2017 Rate Order as it is being replaced with a LMI EE Program and a Non-LMI EE Program in these proceedings.[61]

d. Electric Vehicles - O&M (Electric)

The Company will terminate the O&M reconciliation associated with its EV Program in the 2017 Rate Order.

[61] Any unspent EEPS and ETIP funds from prior authorizations are being used to fund the LMI EE Program and Non-LMI EE Program in these proceedings.

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

The Company will terminate reconciliations associated with its original New York Facilities Agreement as the agreement has been amended (see section E.25 above).

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

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

a. Depreciation Rates (Electric and Gas)

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

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

b. Reserve Deficiency (Electric and Gas)

In addition to the depreciation produced by the application of the rates summarized in Appendix 11, an additional amount of depreciation expense will be realized, beginning in RY1, in connection with the recovery of a portion of the electric and gas depreciation reserve deficiency. The recovery will equal $71.3 million annually for electric and $8.0 million annually for gas and reflects the reserve deficiency identified in excess of the ten (10) percent tolerance band amortized over 20 years. The Company will also continue the amortizations established in the prior rate plan of $11.6 million for the book to theoretical electric reserve deficiency amortization and the $3.8 million electric amortization of the costs for the Hudson Avenue Station.

2. **Interest on Deferred Costs**

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. **Prospective Property Tax Refunds and Credits**

Property tax refunds allocated to electric and/or gas 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 credits 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.

4. **Prospective Sales and Use Tax Refunds/Assessments**

Sales and Use Tax refunds and/or assessments allocated to electric and/or gas that are not reflected in the respective Rate Plans will be deferred for future disposition or collection. The Company agrees to defer Sales and Use Tax refunds and/or assessments allocated to steam until the Company's next steam base rate case. Additionally, the Company is not relieved of the requirements of 16 NYCRR §89.3 with respect to any refunds it receives, except that refunds resulting from triennial true-ups (as opposed to those resulting from litigation or the New York State Department of Taxation and Finance's conciliation process) are "ordinary operating refunds" that are not reportable under 16 NYCRR §89.3.

5. **Income Taxes and Cost of Removal Audit**

On January 11, 2018, the Commission issued an order commencing a focused operations audit to investigate the income tax accounting of Con Edison and other New York State utilities in Case 18-M-0013 ("COR Audit").[62] Specifically, the COR Audit focuses on determining whether an error in income tax accounting occurred with respect to cost of removal ("COR") as alleged and whether Con Edison ratepayers received the benefit of the lower income tax expenses in rates as a result of the claimed errors. The COR Audit is currently being performed by an independent auditor selected by the

[62] Case 18-M-0013, In the Matter of a Focused Operations Audit to Investigate the Income Tax Accounting of Certain New York State Utilities, *Order Approving and Issuing the Request for Proposals Seeking a Third-Party Consultant to Perform Audits to Investigate the Income Tax Accounting of Certain New York State Utilities* (issued January 11, 2018).

Commission on April 23, 2018.[63] The Signatory Parties reserve all of their administrative and judicial rights to take and pursue their respective positions with respect to all issues, rulings and decisions in Case 18-M-0013.

6. 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 and/or gas revenue requirement calculations, as shown in Appendix 13. 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.

7. Allocation of Intercompany Shared Services Expense

Common expenses incurred by Consolidated Edison, Inc. ("CEI"), which are not directly charged services, are allocated under a three-factor formula to its subsidiaries. During the Rate Plans, the Company will allocate expenses for these intercompany shared services for each Rate Year under a three-factor allocation using forecasted operating revenue, segment payroll, and assets for each CEI subsidiary. If a CEI subsidiary has equity method investments, the revenue factor for that subsidiary will include a proportionate share of its equity method investments' revenues.

[63] Case 18-M-0013, supra, "Order Directing Utilities to Enter into Contract with Selected Independent Auditor" (issued April 23, 2018).

G. Electric Revenue Allocation/Rate Design and Tariff Changes

1. Revenue Allocation

The allocation of the delivery revenue change for each Rate Year is explained in Appendix 20. The revenue allocation reflects one-third of the revenue surplus/deficiency indications, as applicable, in each Rate Year based on the Company's Embedded Cost of Service ("ECOS") Study (see Table 1 of Appendix 20).

In its next electric base rate filing, the Company will make reasonable efforts to develop the proposed base electric delivery rates using an ECOS study premised upon 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 2022, the proposed rates will be premised upon a 2020 ECOS study year).

2. Rate Design

This Proposal establishes new competitive and non-competitive electric delivery service rates, including changes to provisions of the MAC and NYPA OTH Statement.[64] The rates implementing this Proposal will be developed as set forth in Appendix 20.

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[64] If, based on the make whole extension letters referred to in footnote 8, the Commission does not issue an order on this Proposal until after December 31, 2019, the Company will recover shortfalls and refund over-collections that result from the extension of the suspension period in this proceeding through a "make-whole" provision, as detailed in the Company's July 8, 2019 and August 8, 2019 letters. The revenue differences will be recovered or credited, with interest, over the remaining months of 2020. The Company will work with Staff to identify and calculate these revenue differences. The Company will update the Electric and PASNY Tariffs accordingly in the event that there is a make-whole provision from this rate plan, or delete, as necessary, obsolete provisions from the make-whole provision from Case 16-E-0060.

3. Customer Charges and Billing and Payment Processing

Customer charges will be changed as follows:

a. SC 1 customer charges will be changed as follows: Rate I increased to $16.00, $16.50, and $17.00 in RYs 1, 2, and 3, respectively; Rate II decreased from $24.30 to $21.46; and Rate III increased from $19.87 to $21.46 per month.

b. SC 2 customer charges will be increased as follows: Rate I increased from $26.01 to $28.10, Rate I (unmetered) from $21.60 to $23.69, and Rate II from $30.12 to $32.56 per month.

c. SC 6 customer charges will be increased from $33.89 to $36.60 per month.

d. Customer charges under standby service rates will be based on the customer costs (less billing and payment processing related costs) per the ECOS Study, which result in increases or decreases from current levels.

The billing and payment processing charge will be increased from $1.20 to $1.28.

4. Competitive Metering

Competitive metering charges, which consist of meter data service provider, meter service provider, and Meter Ownership component charges, have been eliminated and recovery of metering costs will be moved to base rates.

5. High Tension / Low Tension Differentials

The threshold for adjusting high tension/low tension differentials in Rate I and Rate II of SCs 5, 8, 9, and 12, and the NYPA Rate I and Rate II classes shall be set at a 5 percentage point difference between high tension/low tension cost ratios and high tension/low tension rate ratios as further explained in Appendix 20.

6. Optional Demand-Based Rate

The Company will establish an optional demand-based rate, which will be available with no cap to (a) existing residential geothermal customers and (b) new residential geothermal customers that meet the Company's requirements for its heat pump program to be launched during 2020. This rate will also be available to up to 5,000 other residential customers, including residential geothermal customers that do not meet the requirements. This rate will be based on the rate structure of Rider Z, Rate IV, and include a $27.00 customer charge, which reflects the full customer cost set forth in the 2017 ECOS study. The supply component of this rate will assess time-of-use supply for full service customers. In addition, this Optional Demand-Based Rate will be subject to review in the Company's next electric base rate case.

The Company agrees to track the accounts that sign on to this Optional Demand-Based Rate by adding a billing indicator in its existing Customer Service System. The Company will provide the following data points in an annual report filed with the Commission on March 1 of each Rate Year: (1) the number of customers participating in the rate, (2) the location of participating customers by county, (3) monthly on and off peak kW and kWh, and (4) monthly bill impacts. Reporting of the items specified above shall be provided separately for participants using geothermal technologies and participants without such technologies.

7. <u>Tariff Changes</u>

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.

(a) Changes to Rider J – Business Incentive Rate ("BIR"):

(i) The term of BIR rate reductions will be limited to 10 years for qualified new customers. Except as specified below, all new customers will receive a full discount for the first 5 years and a phased-out discount over the remaining 5 years (i.e., a decrease in the discount by 20 percent for each of the five years).

(ii) New customers that qualify under the Biomedical Research Program will receive a full discount for 10 years.

(iii) New customers participating in the Electric Vehicle ("EV") Quick Charging Station Program[65] as well as Business Incubator Graduates will be subject to the existing term limits. As previously established, rate reductions are available until December 31, 2025 for the EV Quick Charging Station Program and for five-year terms for Business Incubator Graduates.

(b) Add provisions to General Rule 5.2.4 – Excess Distribution Facilities to provide separate electric facilities to a premises for the purpose of providing publicly accessible EV fast charging to customers that meet the requirements of the EV Quick Charging Station Program under Rider J and fleet vehicles, as necessary to effectuate the changes described in this Proposal.

(c) Increase the amount of compensation payable for losses due to power failures under General Rule 21.1 (Leaf 171). The compensation limits for residential customers for food spoilage with and without proof of loss will be $540 and $235, respectively, and for commercial customers will be $10,700 with proof of loss.

(d) Amend General Rule 26.9 - Tax Sur-credit (Leaf 359) in the Electric Tariff and the Additional Delivery Charges and Adjustments section (Leaf 23) in the PASNY Tariff to indicate that Tax Sur-credits will no longer be provided after this Electric Rate Plan takes effect through the Tax Sur-credit mechanism.

(e) Update General Rule 28, Transition Adjustment for Competitive Services (Leaf 360), to specifically state the competitive services revenue targets used in the determination of the Transition Adjustment.

(f) Changes related to the transfer of energy efficiency costs from the Systems Benefit Charge ("SBC") to base delivery rates:

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[65] The EV Quick Charging Station program was implemented pursuant to Case 17-E-0814, Tariff Filing by Consolidated Edison Company of New York, Inc. to Modify its Electric Tariff Schedule, P.S.C. No. 10, to Expand to Scope of its Economic Development Business Incentive Rate to Include an Electric Vehicle Quick Charging Station Program, *Order Approving Tariff Amendments*, (issued April 24, 2018). The BIR Business Incubator program was established in Case 09-E-0428 et al, 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, *Order Establishing Three-Year Electric Rate Plan* (issued March 26, 2010).

(i) Revise General Rule 26.4 – SBC (Leaf 355) to exclude, from recovery through the Energy Efficiency Tracker Surcharge Rate, costs associated with programs funded through base delivery rates.

(ii) Provide credits related to energy efficiency costs to Recharge New York (“RNY”) customers under Special Provision G of SC 9 (Leaf 459.0.1).

(g) Changes as a result of the implementation of AMI:

(i) Add the phrase "Or a remote reading" to the definition for an Actual Reading in General Rule 2, Definitions and Abbreviations of Terms Used in this Rate Schedule, on Leaf 12.

(ii) Add the definition of "Interval Meter" in General Rule 2, Definitions and Abbreviations of Terms Used in this Rate Schedule on Leaf 15, to mean a meter with communications capability that records electric usage in time increments of 15 minutes or less and includes AMI meters. This new definition will include the legacy interval meters as well as AMI meters. The Company will also add a definition for “Interval Metering” to mean the measurement of customer electricity usage by means of an Interval Meter.

(iii) Modify leaves throughout the tariff to change "interval meter" and "interval metering" to "Interval Meter" and "Interval Metering."

(iv) Amend General Rule 6.5, Meters with Communications Capabilities (Leaf 61), to indicate that the Company will provide and maintain the communications service for customers served by Interval Meters installed under the Company's AMI program. General Rule 6.5 of the Electric Tariff will also be revised to indicate that Standby Multi-party Offset customers no longer need to provide and maintain the communications service once they have received an AMI meter. The Company will also revise General Rule 20.2.1(B)(8)(e) of the Electric Tariff (Leaf 157.4) to exempt AMI customers from the monthly communications service credit for Multi-party offset customers. Corresponding changes will be made in the Meters with Communications Capabilities section (Leaf 13) and the General Provisions - Metering Service section (Leaf 14) of the PASNY Tariff.

(v) Specify customer installation requirements in General Rule 7.1, Customer Wiring and Equipment (Leaf 64), to better enable AMI communications and to refer to the Company specifications for such installations.

(vi) Amend General Rule 10.11, Reactive Power Demand Charge (Leaf 95), to change "telecommunications service by the telecommunications carrier" to "communications service."

(vii) Amend General Rule 15.2, Reconnection Charge (Leaf 119), to waive the reconnection charge for electric customers with remote connect/disconnect capable meters whose service was shut off for non-payment or tampering-related reasons, if the customer's service is able to be restored remotely.

(viii) Add to General Rule 16.1, Charge for Replacing a Damaged Meter (Leaf 121), a new charge of $282 to replace a damaged AMI meter.

(h) Changes related to customers with distributed generation ("DG"):

(i) Modify SC 11 and General Rule 8.3 to allow inverter-based, synchronous and induction based Distributed Energy Resources ("DERs") for exports onto the secondary network. Such DERs will be subject to the safety and reliability considerations that the Company will evaluate as a part of the interconnection process, which may require the installation of mitigation technologies (e.g., fault limiting capability) at a cost to the Customer.

(ii) Revise General Rule 8.2 - Emergency Generating Facilities Used for Self-Supply (Leaf 78) to allow Customers with Electric Energy Storage systems to be connected to the grid, as long as they do not discharge, to be considered an emergency generating facility. This exempts such Customers from the Standby Service and Standby Service rate provision under General Rule 20.

(iii) Specify that a Customer may not deliver to the Company's distribution system while it is receiving electric energy delivered by the Company at the same service point in General Rule 8.3 - Generating Facilities Used Under Special Circumstances for Export (Leaf 79).

(iv) Update the dollar amount of the Monthly Communications Service Credit applicable to Standby Offset Customers under General Rule 20.2.1(B)(8)(e) of the Electric Tariff (Leaf 157.4) and the General Provisions – Metering Service section of the PASNY Tariff (Leaf 14).

(v) Replace references to the Standard Interconnection Requirements ("SIR") in General Rule 20.3.3, Customers With Targeted Exemptions, on Leaves 162.1 and 162.2, to refer to General Rule 20.2 - Interconnection and Operation.

(vi) Specify communication failure requirements of Output Meters as required for Customers with Designated Technologies who use Efficient CHP in General Rule 20.3, Customers Exempt from Standby Service Rates (Leaf 162.2), to mean two or more instances of Customer caused failed communications service in any calendar year.

(vii) Clarify in General Rule 20.5.4 to indicate that the Reliability Adjustment will only be used for the purposes of determining the Standby Reliability Credit (Leaf 167.1).

(viii) Clarify Rider J – BIR (Leaf 201) to indicate that the rate reduction applicable to energy delivery charges is applied only to the net kilowatt hours delivered by the Company to Grandfathered Net Metering and Phase One Net Metering Customers under Rider R. For Customers served under the Value Stack Tariff under Rider R, the rate reduction applicable to energy delivery charges will apply to the net hourly consumption.

(ix) Specify that Customers participating under Rider Q – Standby Rate Pilot are required to have an interval meter (Leaf 240).

(i) Modify Form G – Application for Rider R or Standby Service and/or Buy-back Service to conform to the provisions in the tariff and housekeeping changes. The housekeeping changes will include a clarifying change that if customers have selected Standby Service and does not make an election under Section 5, they would be billed under Standby Service rates. Section 5 will also be revised to clarify that they can leave Section 5.D blank if they plan to purchase supply from the Company or through and Energy Service Company ("ESCO"). For Customers that elect to purchase supply through a specific ESCO, that ESCO will make arrangements with the Company at the time of service.

(j) Update the percentages used for handling costs to 11%, and for corporate overheads to 15% for engineering and drafting, 19% for construction management, and 1% for administration, in the definition of costs associated with Special Services in General Rule 17.3 (Leaf 126) to reflect current costs.

(k) Update the residential and commercial Uncollectible Bill ("UB") factors related to the UB expense associated with MSC and Adjustment Factors-MSC charges based on a UB factor of 0.0046 or ($0.46 per $100). Update in General Rule 25.3(d) of the Electric Tariff (Leaf 336) to reflect UB factors of 0.0072 for residential customers and 0.0028 for all other customers.

(l) Update the UB factor related to the UB expense associated with MAC and Adjustment Factors-MAC charges in General Rule 26.1.2(b) of the Electric Tariff (Leaf 344) to reflect the system UB factor of 0.0046.

(m) Add a new provision to General Rule 4.6 - High Tension Service (Leaf 31) specifying requirements for high tension customers in the event of a primary feeder failure during a high electric load period. Provisions will include:

(i) A “high electric load period” occurs when the forecasted temperature variable is expected to be greater than or equal to 82.

(ii) When a primary feeder that supplies a High Tension customer is out of service during a high electric load period, the Company will notify the High Tension customer that it must isolate its facilities as soon as possible, but no later than within six hours of receiving notice. The Company will send the six-hour notification when one of the following conditions is met: (i) a voltage reduction of at least five percent has been ordered, or (ii) the next contingency can result in a Condition Yellow, or (iii) the forecasted load for the day is at least 90 percent of the forecasted summer system peak.

(iii) A High Tension customer must isolate its high tension equipment as soon as possible, but no later than six hours after receiving notification from the Company that it must isolate it high tension facilities.

(iv) If the High Tension customer is not able to isolate its high tension equipment within six hours, the Company will dispatch a contractor qualified to operate on 13 kV, 27 kV, and 33 kV switchgears to isolate the equipment and the customer will reimburse the Company for the contractor costs.

(v) The Company will inform High Tension customers of a forecasted “high electric load period” at least 24 hours prior to the beginning of the “high electric load period.”

(vi) The Company will provide an annual notification to High Tension customers by May 1st of the need to expedite the isolation of their equipment during a feeder outage and a reminder of the tariff requirements.

(n) Update the re-inspection charge in General Rule 16.3, Charges for Re-inspection (Leaf 121), and charges for certain special services provided at stipulated rates (i.e., hi-pot, Megger, and dielectric fluid tests) in General Rule 17.1, Special Services at Stipulated Rates (Leaf 122) to reflect current costs.

(o) Revise in General Rule 15.2, Reconnection Charge, of the Electric Tariff (Leaf 119), regarding waivers of the reconnection charge for customers enrolled in the Company’s Low Income Program under Rider S, as described in this JP. Also revise Rider S with Low Income Discount amounts, as described in this JP.

(p) Revise the RDM sections in the Electric Tariff (Leaf 352) and the PASNY Tariff (Leaf 22) to reset the annual level of low income program costs included in rates to $70.9 million (Low Income Discount and Reconnection Fee Waivers) for each rate year that the low-income program is in effect, and to indicate that the low-income program will continue beyond December 31, 2022, contingent on the continuation of full cost recovery in rates with reconciliation through the RDM Adjustment or an equivalent mechanism.

(q) Amend General Rule 17.5, Request for Aggregated Company Records, (Leaf 128) to indicate that Building-level Data will be provided in accordance with the applicable aggregation privacy standard.

(r) Eliminate Rider O and all references to Rider O.

(s) The Company will submit a proposed tariff filing in Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources, to allow NYPA and non-NYPA customers to participate in common Community Distribution Generation projects. Such filing will be made within ten days of the effective date of the tariff provisions currently pending before the Commission in Case 19-E-0464 filed June 18, 2019.

(t) Housekeeping changes:

(i) Add a heading on Leaf 104 in General Rule 12, Payments.

(ii) Correct “Nox” to “MWH” on Leaf 162 and delete the extra comma on Leaf 162.2 in General Rule 20.3.2, Customers With Designated Technologies.

(iii) Correct a typographical error from "ESCP" to "ECSP" in Rider J – Business Incentive Rate on Leaves 194 and 199.

(iv) Eliminate SC 1 – Special Provision G (Leaf 395), which describes how low income credits were applied to low income customers’ March 2017 bills.

(v) Correct a typographical error from “Clasification” to “Classification” in SC 12 on Leaf 478.

(vi) Eliminate Rider I and all references to Rider I since NYSERDA’s Multi-Family Pilots for Time Sensitive Prices, Demand Response and Load Management Program have ended.

(vii) Correct a typographical error, from Rider U to Rider T, under Charge for Demand Management Programs on Leaf 26 of the PASNY tariff.

(viii) Clarify under Rider Q – Standby Rate Pilot that customers will revert back to their “otherwise applicable rate,” rather than their “prior rate,” if they terminate their service under Rider Q. Certain Standby Service customers such as customers that were previously billed under the Targeted Exemption provisions prior to being billed under Rider Q cannot revert back to the Targeted Exemption provisions. They would be billed Standby Service rates if they terminate their service under Rider Q.

(ix) Add in SCs 5, 8, 9, 12, and 13, where it states that Retail Access Customers are not subject to General Rule 25, that they are also not subject to Rider M - Day-Ahead Hourly Pricing. Provisions under Rider M specify that customers can elect retail access service.

(x) Clarify in General Rule 26.9, Tax Sur-credit, that the criteria listed for demand-billed Customers exclude Standby Service rates. The criteria for Standby Service rates are listed in the sentence that follows.

(u) Modify, as appropriate, other tariff provisions that are now expiring or obsolete or being made for housekeeping purposes.

H. Gas Revenue Allocation/Rate Design and Tariff Changes

1. Revenue Allocation

The allocation of the delivery revenue change for firm customers for each Rate Year is explained in Appendix 21. The revenue allocation reflects one-third of the revenue surplus/deficiency indications, resulting from the Company's Gas Embedded Cost of Service Study, in a revenue neutral manner in each Rate Year. The surplus/deficiency revenue adjustments allocable to each of the Con Edison classes in each Rate Year are shown in Table 1 in Appendix 21.

2. Rate Design

This Proposal establishes new competitive and non-competitive gas delivery service rates.[66] The rates implementing this Proposal will be developed as set forth in Appendix 21, and reflect the following:

a. Firm Delivery Rates:

(i) Minimum Monthly Charges

The minimum monthly charges for the full service firm service classes and their SC 9 transportation equivalents will be increased as follows:

[66] If, based on the make whole extension letters referred to in footnote 8, the Commission does not issue an order on this Proposal until after December 31, 2019, the Company will recover shortfalls and refund over-collections that result from the extension of the suspension period in this proceeding through a "make-whole" provision, as detailed in the July 8, 2019 and August 8, 2019 letters. The revenue differences will be recovered or credited, with interest, over the remaining months of 2020. The Company will work with Staff to identify and calculate these revenue differences. The Company will update the Gas Tariff accordingly in the event that there is a make-whole provision from this rate plan, or delete, as necessary, obsolete provisions from the make-whole provision from Case 16-G-0061.

- The SC 1 minimum charge will be increased to $24.00, $26.00 and $27.70 in Rate Years 1, 2, and 3 respectively

- The SC 2 Rate I and SC 2 Rate II minimum charge will be increased to $31.00, $32.90 and $34.80 for Rate Years 1, 2 and 3, respectively.

- The SC 3 minimum charge will be increased to $21.50, $22.60 and $23.80 for Rate Years 1, 2 and 3, respectively.

- The SC 13 minimum charge will be increased to $53.14, $56.40, and $59.66 in Rate Years 1, 2, and 3, respectively.

- The Rider H, Distributed Generation, minimum charges will be increased by the same percentage increase as the SC 2 Rate I minimum charge, and will be set as follows:

DG Capacity	RY1	RY2	RY3
<= 0.25 MW	165.73	175.89	186.10
> 0.25 MW and <= 1 MW	226.52	240.41	254.30
> 1 MW and <= 3 MW	450.66	478.29	505.90
> 3 MW and < 5 MW	600.67	637.49	674.30
>= 5 MW and < 50 MW	90.98	96.56	102.10

- The Rider J, Residential Distributed Generation Rate, minimum charges will be increased as follows:

  -The minimum charge for Rider J Rate I, applicable to SC 1 customers, will be increased by the same percentage increase as the SC 1 minimum charge, and will be $ 24.30, $26.30, and $28.00, in Rate Years 1, 2 and 3, respectively.

  -The minimum charge for Rider J Rate II, applicable to SC 3 customers in buildings with four or less dwelling units, will be increased by the same percentage increase as the SC 3 minimum charge and will be $39.00, $41.00 and $43.20 in Rate Years 1, 2, and 3, respectively.

(ii) Billing and Payment Processing

The Billing and Payment Processing charge will be increased from $1.20 to $1.28.

b. Interruptible Service:

(i) SC12 Rate 1/SC9 Rate B:

Means of Interruption:

Effective November 1, 2020, interruption by means of temperature control device will be eliminated and all customers will be required to be notification customers.

Delivery Rates:

The monthly minimum charge will remain at its current level of $100 for the first 3 therms or less. The Rate 1 volumetric block rate structure will be changed to align with the SC 2 and SC 3 firm volumetric block rate structure, i.e., 4-90 therms, 91-3000 therms and > 3,000 therms. Separate volumetric rates will be maintained for non-residential and residential customers and the Company will eliminate the non-residential delivery rate for customers fully exempt from the petroleum business tax. The rates for the Rate 1 volumetric rate blocks will be set at 70% of each of the SC 2 Rate 2 volumetric block rates for non-residential customers and 70% of each of the SC 3 volumetric block rates for residential customers.

The minimum volumetric rate of one cent per therm for each rate block will be eliminated. The annual interruptible reconciliation will also be eliminated and a final reconciliation will be performed for the period June 1, 2019 through the month prior to the date that rates go into effect under this Rate Plan. Any overcharged amount will be reconciled by means of a credit applied to the Customer's future monthly bill.

(ii) SC12 Rate 2/SC9 Rate C:

There will be no change to the Rate 2 delivery rates during the term of this Gas Rate Plan.

c. Gas Balancing

The Company will make operational modifications to the Daily Balancing and Monthly Balancing programs applicable to interruptible and off-peak firm customers, as set forth in Appendix 25. These modifications will be incorporated into the Company's tariff and/or Gas Sales Transportation and Operating Procedures ("GTOP"), as applicable.

d. Tariff Changes

In addition to the tariff changes under Section B (2) related to the GCF and MRA, and those 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 UB factor related to the MRA, under General Information Section IX.11, will be updated to reflect the system UB factor of 0.0046 ($0.46 per $100 or 0.4600%).

2. The UB factor related to the MFC, under General Information Section IX.8., will be updated to reflect $0.7200 per $100 of commodity costs for residential customers and $0.2800 per $100 of commodity costs for non-residential customers.

3. The Billing and Payment Processing Charge will be updated to $1.28.

4. The percentages under 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. The percentage related to handling costs will be updated to 11% and the percentages related to corporate overheads will be updated to 7% for engineering and drafting, 13% for construction management, and 1% for administration.

5. The Low Income Reconciliation Adjustment will be updated, under General Information Section IX.10, to reflect the increase in the low income funding level from $10.9 million to $24.6 million.

6. Revise General Information Section III (8) (V), Reconnection Charges, regarding waivers of the reconnection charge for customers enrolled in the Company's Low Income Program under Rider E, as described in this JP. Also revise Rider E with Low Income Discount amounts, as described in this JP.

7. General Information IV.3. (c), regarding requests for Aggregated Company Records, will be updated to indicate that Building-Level Data will be provided in accordance with applicable aggregation privacy standards.

8. The System Benefits Charge provision, under General Information IX.16 and under Rates (J) (9) under SC 9, will be amended to exclude from recovery, through the Energy Efficiency Tracker Surcharge Rate, costs associated with programs funded through base delivery rates.

9. The following changes to the tariff will be made as a result of the implementation of AMI:

(a) A definition for “AMI Meter” will be added to General Information Section II.

(b) The definition for “Actual Reading” will be modified in General Information Section II (3) to reflect that a remote meter reading is considered an actual reading.

(c) Add a definition for “Interval Metering” in the General Information Section II to mean the measurement of customer gas usage by means of an Interval Meter. The Company will also add a definition for “Interval Meter” to mean a meter with communications capability that records gas usage in time increments of 60 minutes or less and to includes AMI meters as well as legacy interval meters.

(d) General Information Section III.5.(B) will be amended to add “as applicable” to language related to equipment costs.

(e) Miscellaneous Provisions Section F (2) under SC 9 will be amended to add “as applicable” to specify that firm transportation customers with annual requirements of at least 35,000 therms will not be responsible for metering and communications installation costs if AMI is available.

(f) Miscellaneous Provisions Section O under SC 9 will be amended to exempt SC 9 customers with an AMI meter from the on-site meter reading charge.

(g) Miscellaneous Provisions Sections E and F under SC 12 will be amended to exempt SC 12 customers with an AMI meter from installing and maintaining a dedicated customer phone line.

10. The New York City and Westchester Area Growth Programs, under General Information Section III (J) and (K), and references to these programs throughout the tariff, will be eliminated to reflect the discontinuance of these programs.

11. General Information Section IX.14 will be modified to reflect the inclusion of SC No. 1, and its transportation equivalent under SC9, in the RDM and a change in the RDM methodology from a revenue per customer to a revenue per class methodology. Customers taking service under Rider J, Residential Distributed Generation Rate, will continue to be excluded from the RDM, including Rider J

customers eligible to receive service under SC1 (and its transportation equivalent under SC9).

12. Daily and Monthly Balancing tariff provisions applicable to Interruptible and Off Peak Firm customers will be amended to reflect program modifications as described in section H.2.c. above.

13. Various tariff sections will be amended to reflect the emergency generator provisions described in section L.4 below.

14. The applicability Section under Rider J, under General Information Section VI., will be expanded to require customers to indicate if the request for gas service is for an emergency generator when they submit a Rider J application.

15. Discounts for customers under Rider D, the Excelsior Jobs Program ("EJP"), will be updated for customers who commence service under this Rider on or after January 1, 2020. Changes will be made to specify the EJP discounts under Rider D applicable to customers based on their rate class and the date on which they commence service.

16. The factor of adjustment ("FOA") and line loss factor, under General Information VII. (A)1.(d), will be updated to reflect the factors effective January 1, 2020, as discussed in section B.2.d above. This section will also be amended to delete language that is no longer applicable related to the line loss and factor of adjustment.

17. If not approved in the pending interruptible filing made by the Company on March 14, 2019 in Cases 18-G-0565/19-G-0191, the following provisions will be added to the tariff section regarding Interruptible Service Rate 1 and Rate 2, under Service Classification Nos. 9 and 12, Interruptible Service:

> (a) If a second failure to interrupt occurs within 48 hours of an initial strike, the second failure will not be considered a second "strike."
>
> (b) If a customer's failure to interrupt is due to failure of Company-owned equipment that is not attributable to the customer, the failure to interrupt will not be considered a "strike."

18. Interruptible service provisions will be revised to reflect the elimination of interruption by means of temperature control device, effective November 1, 2020. All Interruptible Rate 1 customers will be required to become notification customers by November 1, 2020, as described in Section H.2.b.

19. The factor used to estimate a customer's winter peak day gas usage under Rider H will be updated from 1.3 to 1.4 in order to reflect more recent actual customer usage data consistent with the data used in the ECOS study for this case.

20. General Information Section III.5.(C) will be amended to reflect the provisions for the relocation of meters from inside a customer's premises to outside, when performing any planned service line replacements, service line repairs, or new service installations, as described in Section L.2 below.

21. General Information Section IX.17 will be amended to indicate that Tax Sur-credits will no longer be provided through the Tax Sur-credit mechanism once this Rate Plan takes effect since the benefits associated with the Tax Cuts and Jobs Act of 2017 will be reflected in base rates.

23. The definition of the minimum charge under Service Classifications 1, 2, 3 and 13 will be modified to refer to the rate for the first 3 therms of gas rather than quoting the specific numerical rate.

24. The following obsolete tariff provisions will be deleted:

> (a) Language regarding the reconciliation of New York State taxes prior to October 1, 2004.
>
> (b) The RDM, under General Information Section IX.14, will be modified to eliminate the low income adjustment to actual delivery revenue for the Rate Year commencing January 1, 2017, since this is no longer applicable.

25. On leaf 183.4 the reference to the following leaf will be corrected from 184 to 183.5.

26. Tariff language regarding the Safety and Reliability Surcharge Mechanism, under General Information IX.23, will be amended to eliminate, in the tariff, detail that is set forth in Appendix 6 to the JP.

27. The table of contents will be amended to reflect additions and modifications to tariff provisions.

28. Modify, as appropriate, any other tariff provisions that are now expiring or obsolete or being made for housekeeping purposes.

I. Performance Metrics

Performance metrics designed to measure various activities that are applicable to the Company's Electric,[67] Gas, and Customer Service Operations,[68] and assess negative and/or positive revenue adjustments where performance targets are not met or are exceeded, respectively, are set forth in Appendices 14, 15, 17 and 18. Any positive or negative revenue adjustments during the Rate Plans will be recovered from or credited to customers through the MAC, NYPA OTH Statement, and MRA.

J. Customer Energy Solutions Provisions

1. EE Programs

The Company's budgets and targets for its EE programs – general electric EE programs including a heat pump program, kicker incentive, gas EE programs as well as electric and gas EE programs targeted to LMI customers – during this Rate Plan will be as set by the Commission's NE:NY order on the Company's compliance filing. Any differences in budgets and targets between the amount included in this Joint Proposal and as determined by the Commission in the NE:NY order will be reconciled as noted in Section E.15.

[67] Performance metrics for Electric Safety Standards were established by the Commission in Case 04-M-0159. The Company was authorized in Case 16-E-0060 to increase the inspection cycle for underground equipment (excluding underground residential distribution ("URD") equipment) from five years to eight years. The Company is authorized to continue this pilot in this rate plan as described in Appendix 15.

[68] See Section M.12 for the Uncollectible/Residential Service Termination positive incentive.

a. **EE Stakeholder Forums**

The Company will host one annual stakeholder forum each May to solicit and receive feedback from stakeholders regarding the Company's LMI and non-LMI EE programs.

b. **Coordination with New York City Retrofit Accelerator ("RA") Program**

The Company will appoint a single point of contact to coordinate EE activities with the New York City RA Program. This coordination will include a quarterly meeting between the Company and RA to discuss projects, best practices, and the coordination of messaging, marketing and outreach between the two programs.

c. **Interruptible Gas Customers**

Effective January 1, 2020, Rate 1 and Rate 2 Interruptible gas customers will be eligible to participate in the Company's EE programs with no additional costs or surcharges above the level in base rates.

d. **LMI Customers**

i. **LMI Program**

During the term of the rate plan, the Company will coordinate with NYSERDA on enhancements to the Company's LMI program to target two- to four- family homes. The Company will provide outreach services and develop targeted informational materials for all LMI customers. If applicable, the Company will encourage LMI customers in two-to four-family homes to enroll in the Company's LMI EE programs in addition to their participation in NYSERDA's LMI programs.

ii. Funding Commitments for LMI Customers

The Company will assist LMI customers by funding studies for EE projects proposed by owners/developers of LMI projects, not to exceed $30,000 per project, to support project scope of work development, pre-engineering, and other initial activities.

Any funding amount that will be provided for the study prior to project implementation will be considered part of the customer incentive for that project. The owner/developer would not need to refund the study costs if it opts not to pursue the project because cost-effective improvements are not identified. If, however, the owner/developer opts out for any other reason, including not meeting the incentive commitments described below, it would be required to reimburse the Company for the study costs.

Upon approval of the study's scope of work and completion of any pre-engineering site inspection, Con Edison will provide to the owner/developer a time-limited binding commitment, generally around 90 days but can be project specific, to provide incentives of a specified amount upon completion of the project, to aid the owner/developer in seeking financing. The Company's incentive commitment will be based on: (a) the study described above and (b) discussions between the Company and the owner/developer. The owner/developer will have to meet three conditions or the Company's commitment to provide an incentive will terminate:

(i) Place a purchase order or enter into a binding energy efficiency service agreement within 90 days, or another mutually agreed upon timeframe, as stated in the Company's commitment communication;

(ii) Complete the project within the agreed-upon time limit; and

(iii) Substantially complete the approved scope of work as provided in the commitment.

e. Measurement and Verification ("M&V") Efforts

As part of the Company's AMI deployment process, the Company will evaluate the use of data analytics for the data obtained from AMI to streamline and, if possible, reduce the costs associated with M&V efforts for its EE programs. If this evaluation provides feasible and practical suggestions, the Company will modify its M&V protocols.

f. Heat Pump Demand Pilot

The Company agrees to develop a Heat Pump Demand Pilot for interested heat pump customers on demand rates to allow them to adjust operation of their heat pumps in response to near real-time usage information, allowing them to better manage whole-home demand. The Company will file its Heat Pump Demand Pilot Implementation Plan under Case 19-E-0065 by July 1, 2020.

g. Smart Kids

The Company will include a segment in its Smart Kids curriculum for fifth grade students explaining the fundamental concepts related to air source and ground source heat pumps assuming the addition is in compliance with the New York State Department of Education's science curriculum for 5th grade students.

2. **Earnings Adjustment Mechanisms ("EAMs")**

During the terms of the rate plans, the Company will have the following seven EAMs.[69] These EAMs are more fully described in Appendix 23. The chart below contains the EAMs and their values.

[69] If the Company does not file for new rates to become effective January 1, 2023, the Company will make a filing for Commission approval by July 15, 2022 proposing budgets, targets and incentives for EAMs during the period following the end of RY3, subject to Commission orders in Case 18-M-0084 or any other applicable case. Prior to the filing, the Company will meet with Staff and parties to explain the proposal and solicit input.

Post filing, the Company will meet with parties to receive any additional comments the parties have. Parties will also be permitted to file comments on this filing.

EAM	Description			2020	2021	2022
				(EAMs in $ million)		
Deeper EE Lifetime Savings	Based on deeper lifetime energy efficiency savings, including LMI EE savings, over three years*	Electric	Min	$2.904	$3.818	$4.811
			Mid	n/a	n/a	n/a
			Max	$15.970	$18.326 + 2020 carryover	$20.849 + 2021 carryover
		Gas	Min	$0.963	$1.328	$1.737
			Mid	n/a	n/a	n/a
			Max	$5.298	$6.375 + 2020 carryover	$7.528 + 2021 carryover
Share the Savings	Based on lifetime MMBtu savings' unit cost reductions.	Elec. & Gas	Min	30% of $ / Lifetime MMBtu Savings applied to acquired non-LMI EE savings**		
			Mid			
			Max			
Beneficial Electrification	Based on GHG reductions provided by EVs and Heat Pumps.	Electric	Min	$2.904	$3.054	$3.208
			Mid	$7.259	$7.636	$8.019
			Max	$14.518	$15.272	$16.038
DER Utilization	Based on Solar PV, Storage and Wind adoption rate by customers (in MWh).	Electric	Min	$4.356	$4.581	$4.811
			Mid	$7.259	$7.636	$8.019
			Max	$14.518	$15.272	$16.038
Electric System Peak	Based on electric peak reduction below adjusted NYISO ICAP forecast for Company service territory.	Electric	Min	$4.356	$4.581	$4.811
			Mid	$7.259	$7.636	$8.019
			Max	$11.615	$12.217	$12.830
LSRV (Locational System Relief Value) Load Factor	Based on maintaining or improving the load factor of a certain number of LSRV networks or load areas.	Electric	Min	$1.452	$1.527	$1.604
			Mid	$4.356	$4.581	$4.811
			Max	$7.259	$7.636	$8.019
Gas System Peak	Based on gas peak day per heating degree day reduction.	Gas	Min	$1.445	$1.594	$1.737
			Mid	$2.408	$2.656	$2.895
			Max	$3.853	$4.250	$4.632

** As described in more detail in Appendix 23, the allocation of the basis points associated with the Deeper EE EAM in RY2 and RY3 can change if targets are shifted from year to year. Appendix 23 includes the basis points associated with each EAM and footnote 81 provides information on basis point calculations.*

*** Share the Savings incentives are not included in the total amounts.*

a. EAM Reporting Requirements

On each of March 31, 2021, 2022 and 2023, Con Edison will make a compliance filing to the Commission showing the calculation of incentives earned under each EAM for the rate year preceding the filing, except for the Gas System Peak EAM, which Con Edison will file on June 30, 2021, 2022, and 2023. The Company may begin collecting the calculated amount of incentives forty-five days after the compliance filing, through the MAC or MRA, as applicable, subject to adjustment if the Commission determines that the Company's incentive calculations should be corrected.

3. <u>Electric Vehicles</u>

The Company will continue to facilitate electric vehicles in New York through the SmartCharge New York and Make Ready Infrastructure programs described in detail below.

a. Smart Charge New York

The Company will continue its existing off-bill SmartCharge New York ("SCNY") Program, which provides incentives to enrolled vehicles charging within the Con Edison service territory at off peak times. SCNY will be modified to be a three-category program. The existing non-tariffed SCNY program structure will remain for

SC1 Rate I customers,[70] and the Company will implement new incentive structures for: (1) SC1 Rate III customers, and (2) for medium-duty / heavy-duty vehicles, including buses ("MHVs").

The SCNY Incentive Structure for SC1 Rate III will be modified to provide: (1) a $0.0166 per kWh incentive for vehicles charging off-peak (equal to the off-peak delivery charge), (2) a $5 per month bonus for vehicles installing, activating and plugging in a charging device that records charging information, for example, where, when and how much energy was used to charge the vehicle, (3) a $20 per month payment to the customer during the months of June through September if the customer does not charge during the on-peak hours, and (4) a $10 per month incentive during the months of October through May if the customer does not charge during the on-peak hours.

The SCNY Incentive Structure for MHVs is modified to provide: (1) a $0.0221 per kWh incentive for MHVs charging off-peak and (2) a $250 per month incentive during the months of June through September to MHVs that do not charge during the four-hour weekday Commercial System Relief Program ("CSRP") period in the network where the MHVs charge.

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[70] SC1 Rate I SmartCharge customers receive: (1) a $150 bonus for installing, activating and plugging in a charging device that records charging information, for example, where, when and how much energy was used to charge the vehicle, (2) $0.1000/kWh charged off peak, (3) a $5 per month bonus for vehicles using a charging device , and (4) a $20 per month payment to the customer during the months of June through September if the customer does not charge during the on-peak hours. Participating non customer EVs also receive the SC1 Rate I incentives when they charge in the Company's service territory.

b. Make Ready Infrastructure

The Company will implement two Make-Ready Infrastructure programs to incent direct current fast chargers ("DCFC") to be installed in the Company's service territory. The programs are: (1) Publicly-Accessible DCFC and (2) Fleet DCFC, to offset expected Company interconnection construction and excess distribution facility ("EXDF") costs for which the customer/developer would normally be responsible. The cumulative limit on the incentives to be provided during the rate plan will be $39 million with an initial annual allocation of $10 million to the Publicly-Accessible program and $3 million to the Fleet program. The Company will adjust total rate plan funding allocation between the two programs, as appropriate, based on program participation.

The Publicly-Accessible DCFC Make-Ready program will provide $10 million for each Rate Year to assist charging station developers by offsetting up to $1.2 million per site for expected Company interconnection and EXDF costs for which the customer/developer would normally be responsible, subject to a decreasing share of the Company's contribution in each Rate Year as follows:

- RY1: up to 92.5 % of construction and EXDF costs
- RY2: up to 87.5 % of construction and EXDF costs
- RY3: up to 85 % of construction and EXDF costs

The Fleet DCFC Make-Ready program incents owners of private and public vehicle fleets to invest in electrifying their fleets. The Company will provide $3 million per year for each Rate Year to offset up to $1.2 million per participant for the Company interconnection and EXDF costs that would normally be the fleet owner's responsibility.

This program will have a per participant cap of $1.2 million and the Company contribution will be as follows in each Rate Year:

- RY1: up to 92.5 % of construction and EXDF costs
- RY2: up to 87.5 % of construction and EXDF costs
- RY3: up to 85 % of construction and EXDF costs

In addition, for the Fleet DCFC Make Ready program, each participant is permitted one incentive during the rate plan. If, however, the Company determines in July 2021 that participation has not met expected levels, the Company will advise prior fleet incentive recipients that they could be eligible for additional incentive(s) at another location if they can complete the site by the end of the rate plan.

c. Other EV Items

In addition to the above, the Company will also promote EVs through the following actions:

- Develop network (by year end 2019) and non-network (by July 1, 2020) capacity maps that will show loading data on a feeder by feeder basis to the extent such information can be disclosed. The maps will help identify where interconnection costs for EV charging load may be greater or lesser than other areas
- Identify a point of contact for EVs in the Energy Services Department ("ESD") by December 31, 2019 and:
    - Develop an electric vehicle request form in Power Clerk to streamline the existing EV application process by July 1, 2020
    - After developing the form in Power Clerk, the Company will provide an EV user guide by September 30, 2020
- Enhance Customer Service Representative ("CSR") training for EVs
- Enhance the Company's EV communication channels, including its website, which will include an interconnect guide for EV charging
- Provide a presentation to interested parties on its Vehicle to Grid (V2G) REV Demonstration project in the 1st quarter of 2022[71]

[71] Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming Energy Vision ("REV Proceeding") - Demonstration Project Implementation Plan for Electric School Bus V2G (issued November 13, 2018).

4. <u>Energy Storage</u>

During the term of the Electric Rate Plan, the Company will implement two energy storage projects as described below.

a. Fox Hills Project

The Company will implement one in front of the meter energy storage project at its Fox Hills substation. The current plan is for the project to include a battery that will discharge over a peak period of four hours at an output of 7.5 MW/30 MWh to provide relief during system contingencies during high load days.

b. Nevins Street Projects – Battery Storage and Electric Vehicle Charging

The Company will implement two projects at its Nevins Street location in Brooklyn -- Battery Storage and DCFC Charging. Pursuant to the Battery Storage project, the Company will make the site ready for a battery installation and lease the property to a third party(ies) to own and operate a battery facility(ies) on the site. The Company will file a Public Service Law Section 70 petition for approval of this lease.

In addition, the Company will propose as a REV demonstration project that it will contract with a third party to own and operate a DCFC facility, which will be supported by the battery energy storage project to mitigate the effects of DCFC load during peak periods.

5. <u>Distributed Energy Resource Management System ("DERMS") and Interconnection Assistance</u>

a. DERMS System

Before June 30, 2020, the Company will hold one focus group session to explain the DERMS system, its current and projected status, and allow third parties to provide feedback on the Company's DERMS.

b. Interconnection Assistance

To assist parties wishing to interconnect their distributed generation to the Company's system, the Company will complete the following by year end 2019:

- Modify the system to address the current developer/customers requirement associated with resubmitting an application to update or correct their initial application in Power Clerk;
- Issue a guidance document explaining the Company's costs associated with a Coordinated Electric System Interconnection Review ("CESIR"), to assist developers in determining typical Company costs for these studies, by October 1, 2019;
- Develop a standard template and language in Permission to Operate letters (which advise developers that they have been granted approval/permission to operate their distributed generation equipment);
- Standardize invoices sent to developers interconnecting with the Company; and
- Accept electronic payments for invoices.

6. <u>Innovation Hub</u>

The Company's Innovation Hub is a corporate-wide initiative to implement transformative innovation projects. This group will meet with Staff twice each rate year, in February and August, to review the group's existing portfolio, provide updates to existing projects and discuss the Company's then-current strategy for the group. The Company will also meet annually with interested parties to discuss the Innovation Hub's activities.

7. Advanced Metering Infrastructure

a. AMI Scorecard

The AMI Order required the Company to develop a set of metrics for AMI "that can be used by the Commission to monitor the success of this AMI project based on Con Edison's purported benefits related to system operation, outage management, and billing errors."[72] Appendix 19 identifies each metric that the Company will track as well as the specific reporting requirements related to each metric.

b. AMI Platform Service Revenues

To the extent the Company identifies an opportunity to generate platform service revenues from the AMI system, the Company shall propose that 80% of the revenues generated should be provided to customers and 20% of the revenues retained by the Company so long as the platform service revenues derive from the Company's monopoly function as per the REV Track Two Order.

8. Scorecards

During the terms of the rate plans, the Company will provide:

- Energy Intensity scorecard; and
- Green House Gas ("GHG") emissions scorecard, providing New York City's most current GHG inventory as part of the Company's EAM reporting each March, currently on the City's website at https://nyc-ghg-inventory.cusp.nyu.edu/, and any other data sources if information is available for the County of Westchester.

[72] AMI Order, p. 47.

K. Additional Electric Provisions[73]

1. Actions to Address Climate Change

a. Weather Data Sensor and River Temperature Sensor Pilot Program

The Company will implement the Weather Data Sensor and River Temperature Sensor Installation Programs, as described in Appendix 16. The Company will evaluate the results of the Installation Programs as part of the Climate Change Vulnerability Study Implementation Plan required herein.

b. Climate Change Vulnerability Study Implementation Plan

By December 31, 2020, the Company will develop and file with the Commission's Secretary a detailed plan for implementation of the recommendations from the Climate Change Vulnerability Study ("Implementation Plan"). At a minimum, the Implementation Plan will include a plan for or discussion on the items described in Appendix 16.

c. Development of the Implementation Plan

In the first quarter of 2020, the Company will hold a meeting to receive Staff and stakeholder input on the scope of matters to be covered in the Implementation Plan. In the second, third, and fourth quarters of 2020, the Company will hold stakeholder meetings either in person or by telephone to provide updates on the status of the Implementation Plan and receive additional Staff and stakeholder feedback.

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[73] The Company and the City will enter into Memorandums of Understanding to explore mutual process improvements concerning new Department of Transportation streetlight connection requests and repairs to existing streetlights and tree removal practices in the municipal right of way (the new tree removal practices or specifications established as a result of this initiative will also be applied in Westchester County).

d. Spending and Cost Recovery for the Implementation Plan

The Company is authorized to spend up to $1.5 million to complete the Implementation Plan, including hiring a consultant(s). Costs for this study will be allocated between electric and gas based on the common cost allocation for Customer Accounting Expenses in Appendix 13 (84%/16%). The allocated costs for electric will be collected through the MAC and NYPA OTH Statement and for gas through the MRA, as incurred.

e. Updates on Implementation Plan Progress

The Company will convene two meetings in Rate Year 2 and two in Rate Year 3 to update Staff and stakeholders on the Company's progress in executing the Implementation Plan. These meetings may be in person or by telephone.

2. <u>Electric Overhead Line Workforce – 2018 Storm Investigation Report Implementation</u>

The Company will hire 20 additional overhead construction full-time employees pursuant to Recommendation 14 of Staff's 2018 Winter and Spring Storms Investigation Report in Case 19-M-0285 and the Company's Implementation Plan compliance filing in Case 19-E-0107.[74] Based on forecasted staffing needs, the Company currently plans to assign the 20 additional overhead construction full-time employees to the following regions: Bronx/Westchester – 12; Brooklyn/Queens – 4; Staten Island – 4.

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[74] This recommendation requires the Company to add at least 30 new overhead line workers. As the Company provided in its Implementation Plan, the Company has hired 12 additional employees into the overhead line worker career path since the 2018 storms. Based on current staffing needs, the 12 new overhead line workers have been assigned to the Company's Bronx/Westchester Region.

L. Additional Gas Provisions

1. Plumber Incentive Associated With Gas Service Line Surveys/Inspections

The Company will submit for Staff review a plan to offer plumbers incentives to perform survey/inspection work in tenant living spaces on behalf of the Company or, alternatively, a report that explains why such a plan would not be feasible and/or cost-effective. The Company plan or report will be submitted within 90 days of the Commission's Order adopting this Proposal.

2. Relocating Inside Gas Meters

The Company will relocate gas meters that are located inside a customer's premises and install them outside when performing any planned service line replacements (whether by insertion or direct bury), service line repairs, or new service installations, for no greater than a two unit dwelling premises that offers the customer and the Company the opportunity to relocate meters outside (*e.g.*, major renovation projects), and where work can feasibly be performed. The Company may also consider whether and where to relocate meters if the premise is located in a flood plain (*e.g.*, elevating the gas meter to a higher location). The following exceptions will apply to the meter relocations: (i) where the customer refuses to provide consent to such relocation; (ii) where local building codes or regulations preclude outside meters; (iii) for safety considerations; (iv) where space constraints or physical barriers preclude relocation; and/or (v) when the work involved is an emergency service line repair/replacement. Customers who already have services installed, and who have no greater than two dwelling units, will be moved to a list of customers for meter relocation at a later date. The Company will also make reasonable efforts to relocate meters for premises that are greater than two dwelling units where none of the above indicated exceptions apply.

Customers that refuse to move meters outside: 1) will be asked to sign a form explaining the reason(s) for refusal and stating that they are aware of the benefits of having their meters outside; and 2) will be subject to charges for costs related to survey/inspection of inside piping in accordance with Company tariff provisions.

In instances where one or more of the above exceptions apply, the Company will track and document each customer meter it does not relocate outside, as well as the reason(s) the relocation was not performed. The Company will also track the incremental costs associated with moving meters outside, and such costs will be deferred for future recovery from customers.

The Company will file with the Secretary an annual report beginning in 2021 that includes: 1) the number of meters relocated outside; 2) the number of meters left inside; and 3) of the meters left inside, the number that involved service replacements by installation of a new service line in premises for 1-2 family homes.

3. Emergency Generators

Customers who desire to install service lines for the purpose of supplying an emergency generator, and are residential customers with a maximum of four dwelling units being served by such a generator, and are located in an area that is subject to a moratorium on new gas connections, will be permitted to do so under the following conditions:

- The customer agrees to be served as an interruptible customer and must be able to shut down the emergency generator upon request from the Company. Customer will not be eligible for any service line or main extension entitlements and will be responsible for all associated costs;

- Given the limited nature of this service, these customers will not be required to submit an annual affidavit and they will not be required to have a back-up energy source for this limited service;
- An AMI meter must be installed – customers may not opt out of this metering technology;
- The customer will be served by a service line sized to handle the load for the emergency generator exclusively. Any gas usage through this service line for any other purpose will result in the termination of service on that line; and
- Con Edison will implement enhanced communication protocols, both during initial application process and during subsequently called interruptions, for vulnerable customers (*e.g.*, Elderly, Blind or Disabled customers and customers relying on life-sustaining equipment).

4. <u>Fire Department Gas Emergency Training</u>

The Company will work with Staff, the local fire departments, and emergency management organizations to adopt the principles of Pipeline Emergency Responders Initiative ("PERI").[75] Additionally, Con Edison will also continue to enhance its training regarding the appropriate response to gas-related emergencies offered to local fire department first responders and municipalities throughout its service territory. These enhancements will include more hands-on training, improvements to the training curriculum and an increased frequency of drills and other training targeted at improving the awareness of and response to natural gas leak emergencies. Con Edison will report to Staff on these efforts within 60 days of the end of each Rate Year. The report will identify participating fire departments and include at a minimum the number of drills and training sessions conducted in the previous rate year and the status of adopting the principles of PERI.

[75] For a description of PERI, see https://www.phmsa.dot.gov/pipeline/peri/peri-faqs.

5. Renewable Natural Gas

The Company will develop and implement a standard interconnection agreement for operators and developers of renewable natural gas ("RNG") that sets forth standards for gas conditioning and delivery into the Company's distribution system. The Company will develop standard interconnection agreements and will incorporate the standard agreement into the Company's "GTOP" Manual within one year of the Commission's order adopting this Proposal. In consultation with Staff, the Company will consider the provisions of the interconnection agreements already developed by other New York natural gas utilities and the Northeast Gas Association.

The Signatory Parties recognize that the Company is authorized to contract for and purchase RNG from providers within the Company's service territory. The Signatory Parties further acknowledge that such purchases may be more costly than conventional gas supplies. Recovery of supply costs are addressed in section B.2.b. The Company will initially recover the costs of plant necessary to interconnect local RNG supplies through the MRA and the Company will file to incorporate these costs into base rates in the Company's next gas rate filing, using recovery periods consistent with the term(s) of the Company's contracts with RNG suppliers.

6. Liquefied Natural Gas Facility

The Company will provide Staff with a confidential analysis to address the engineering concerns raised related to the Company's liquefied natural gas facility located in Astoria, Queens. The analysis will be conducted by a third party, updates on the status will be provided to Staff every six months and the Company will target the analysis to be complete prior to the submission of the Company's winter preparedness plan in 2021.

7. Manhattan Gas Transmission Project

The Company proposed a gas transmission project in Manhattan that would postpone the possible need to implement a gas moratorium on new firm gas customers in areas of New York City. If the Company determines to commence construction of the Manhattan project during the rate plan, the Company will review the need for the Manhattan Project with Staff and the parties to the case based on its most recent gas peak demand forecast. Any Manhattan project costs incurred will be subject to review and approval in the Company's next gas base rate proceeding before being included in base rates.

8. Mountain Valley Pipeline ("MVP") and Gas Moratorium

The Signatory Parties agree not to litigate in this proceeding any claims regarding Con Edison's temporary gas moratorium in certain areas of Westchester or any claims regarding Con Edison's gas transportation arrangement with MVP, and that such claims should not be adjudicated in this proceeding. Nothing in this Joint Proposal, however, limits any Signatory Party's right to raise or litigate any claims regarding Con Edison's temporary gas moratorium in certain areas of Westchester or Con Edison's gas transportation arrangement with MVP in a different proceeding. Any claims related to the moratorium may be adjudicated in separate proceedings before the Commission, including, but not limited to, any proceeding resulting from the Commission investigation in Case 19-G-0080. The foregoing shall not limit in any way the consideration of the gas moratorium in any other agency or court of competent jurisdiction.

Con Edison will continuously monitor gas needs in Westchester and consider market solicitations or innovative mechanisms to procure additional resources that help address peak day gas needs in Westchester. The Company will seek Commission authorization to conduct such solicitations by July 1, 2020. The solicitations will consider (i) new and emerging technologies that customers in Westchester are likely to adopt; and (ii) RNG, including projects that would add storage so that it can alleviate peak load needs on the coldest days.

9. Gas Planning

Con Edison will convene a meeting with parties in 2021 to discuss the Company's plans for addressing gas supply and gas infrastructure related issues in the Company's next gas rate case filing.

M. Customer Operations Provisions

1. Next Generation Customer Experience "Next Gen CX" Initiative

The Company will implement the Next Gen CX Initiative, a portfolio of investments to continue to meet rising customer expectations, facilitate policy goals, and drive operational efficiencies. The Company agrees to:

- File reports no later than 60 days after the end of each calendar quarter to the Secretary of the Commission on the Next Gen CX initiative, including the status of the initiative, recent activities, costs, BCO savings achieved, non-financial benefits achieved and projected activities. These quarterly reports will begin 60 days after the end of the second quarter of 2020 and continue until the end of the Rate Plans.
- Beginning 60 days after the end of the second quarter of 2020, incorporate the existing quarterly reports on the Digital Customer Experience ("DCX") into the Company's Next Gen CX reporting, with the addition of the following DCX-specific items: launch status of new customer tools and updates on website and mobile site performance and

traffic, customer transactions and completion rates, customer satisfaction, and other new customer-related functionalities. The Company will report on DCX activities through the end of the first quarter 2020 by filing a report using the existing format no later than April 30, 2020.

- File evaluation reports annually by March 1 with the Secretary on the Bill Redesign Program. The reports will include the number of customers adopting ebills, reduced costs for printing and postage, and customer use of the digital platform. The Company will also submit to the Secretary the results of its Phase Two analysis and prototype bill redesign recommendations for review with Staff prior to implementation.

- Create the following online forms in My Account for customers: Enrollment applications for Life Supporting Equipment ("LSE"), medical emergency, elderly/blind/disabled ("EBD") and the low income discount programs. Customers will be able to submit these forms online and track their application status in My Account. The Company will also evaluate and implement, if feasible, National Grid's protocol that allows medical professionals to upload LSE and EBD related forms on the Company's website directly without customer intervention.

- Make Financial Statement Forms ("FSF") available to customers in My Account.

2. <u>Customer Experience Center ("CEC") Disaster Hardening</u>

As part of its CEC Disaster Hardening program, the Company will implement technology solutions to harden its Internet Protocol ("IP") telephony system in order to maintain operational reliability if outage events occur at both of the Company's dedicated server farms that support the IP telephony system. By the end of 2019, the Company will file with the Secretary a report containing a comprehensive analysis of potential technology solutions, including an assessment to transition from the existing on-premises server farms to a cloud-based system.

3. Credit and Debit Card Fee Elimination

Within 90 days of the issuance of a Commission Order adopting this Proposal, the Company will file with the Secretary an Implementation Plan, including a customer education component, to eliminate credit and debit card payment fees charged to residential and small commercial customers. The Company will make a filing with the Secretary if the Company determines that it is necessary to reverse the no-fee policy based on emerging developments in the payment processing industry.

4. Outreach and Education

The Company will continue to develop and provide outreach and education activities, programs and materials to educate the Company's customers regarding their rights, responsibilities and options as utility customers. Additionally, the Company agrees to implement the two new initiatives: (1) targeted outreach and education for low-income and at-risk customers to facilitate participation in Next Gen CX and REV programs, and (2) targeted outreach plans by borough and Westchester County. The Company will file plans for these new initiatives with the Secretary by April 1, 2020 and will thereafter incorporate the new initiatives into the Company's annual outreach and education plans and report filed by September 30, which will continue through these Rate Plans.

5. Billing and Customer Data Issues

The Company commits that key account representatives will work with large customers and their representatives to resolve delayed billing issues and identify future billing problem resolution practices. The Company will also work with NYC and the MTA to address their unique billing and data access concerns.

The Company anticipates that billing issues specific to the BIR, Gross Receipts Tax ("GRT"), Standby Reliability Credit, ReCharge NY billing, Standby Offset billing, Distributed Generation Gas Load Factor Validation, Standby Multi-party Offset billing and Rider Q billing will be automated in the new CSS upon implementation.

6. Suspension of Residential Service Terminations During Certain Heat Events

The Company agrees to suspend service terminations for non-payment ("TONP") for residential customers during certain heat events as follows:

- On days where the heat index is forecasted by the National Weather Service to reach 93 degrees or higher.
- One calendar day before days where the heat index is forecasted by the National Weather Service to reach 93 degrees or higher.
- If the actual heat index reaches 93 degrees or higher on a given day, the Company will suspend residential TONPs on the following two calendar days.

7. Deferred Payment Agreements

Customers experiencing financial difficulty paying their utility bills are entitled under the Home Energy Fair Practices Act and its implementing regulations, specifically 16 NYCRR §11.10 Deferred Payment Agreements, to a deferred payment agreement

("DPA") that is fair to both customers and the Company. The Company commits to clarifying its training and reference materials to more clearly reflect the following current practices:

- Depending on the customer's circumstances, the Company may offer a DPA to residential customers without the need for a down payment and with installments that may be as low as $10 per billing cycle.
- DPAs can be modified if the customer's ability to pay changes for reasons they cannot control.
- If a residential customer indicates that they face a financial hardship that limits their ability to meet the terms of a DPA, the Company will work with the customer to come to mutually agreed upon agreement terms, including providing the opportunity to fill out an FSF where necessary.

8. <u>Balance Transfer Procedural Improvements</u>

The Company commits to make the following improvements to its procedures for handling situations where balances are transferred to customer accounts, specifically: (1) where arrears that were suspended while NYC Human Resource Administration ("HRA") or Westchester Department of Social Services (together, the social services agencies) took responsibility for payment of customer bills are reinstated to a customer's account, (2) where a final account balance is transferred to an active account based on the Company's final account matching process, and (3) where a bill that was promised to be paid by a social services agency goes unpaid for three or more months and is reinstated on a customer's account.

- Provide customers with additional time to pay balances transferred to their account.
    - The Company will provide customers 30 days' notice before putting unpaid social services agency balances back on a customer's account.
    - The Company will give customers 60 days before issuing a disconnect notice following reinstatement of arrears that were suspended while social services agencies were responsible for payment of customer bills.
- Enhanced communications: the Company will clarify letters, bill messages, postcards, and CSR reference materials related to these circumstances in order to make customers aware of balance transfers, the source/reason for the transfer, the amount of time the customer has to take action and/or dispute the charges and provide documentation, and the customer's right to file a complaint with the Commission.
- Escalation path: CSRs will escalate, as appropriate, customers' concerns to a group with specialized knowledge of the issue if they or their supervisors are not able to address the customer's balance transfer inquiry via routine account investigation.

9. Collection Activity Report ("CAR")

The Company will add an appendix to the CAR that will include new data fields showing a breakdown of the CAR residential data points between low income and non-low income customers. The Company will also add data regarding customer completion of the Financial Statement Form and clarify the assumptions behind the data fields on the CAR.

10. Web Service Between Company and HRA

The Company and HRA will continue to collaborate on a web service designed to streamline all transactions between the Company and HRA affecting residential customer accounts, including Home Energy Assistance Program ("HEAP"), One-Shot, Utility Guarantee ("UG") and Direct Vendor ("DV)" transactions.

HRA will make reasonable efforts to begin piloting the first phase of this web service by October 31, 2019. The pilot results will be evaluated over time and HRA will discuss with the Company whether to more comprehensively use the web service.

11. Green Button Connect ("GBC")

The Company will submit semi-annual scorecard report regarding its implementation of the Green Button Connect My Data standard that will include tracking the number of third-party vendors that apply with the Company to receive customer information via GBC (or Share My Data as branded by the Company), and the progress of those third-party vendors through the various stages of the on-boarding process, including technical testing. This scorecard will be submitted with the Company's semi-annual AMI scorecard.

12. Uncollectible/Residential Service Termination/Arrears Positive Incentive

For each Rate Year, the Company will earn a positive revenue adjustment for achieving the following targets for residential service terminations, bad debt write-offs, and arrears:

- A positive revenue adjustment of $6 million if the Company achieves the following targets:

Terminations < or = 30,302
Bad debt write-offs < or = $31,062,538
Arrears < or = $235,008,866

- A positive revenue adjustment of $4 million if the Company achieves one of the following sets of targets:

  (i) Terminations < or = 30,302
  Bad debt write-offs < or = $31,062,538
  Arrears < or = $249,039,027

  OR

  (ii) Terminations < or = 45,533
  Bad debt write-offs < or = $36,467,907
  Arrears < or = $235,008,866

- A positive revenue adjustment of $2 million if the Company achieves one of the following sets of targets:

  (i) Terminations < or = 37,918
  Bad debt write-offs < or = $33,765,222
  Arrears < or = $249,039,027

  OR

  (ii) Terminations < or = 45,533
  Bad debt write-offs < or = $36,467,907
  Arrears < or = $242,023,946

The Company will file an annual report with the Secretary by March 1 following each Rate Year indicating whether any of the above targets were achieved. Any positive revenue adjustment earned will be allocated between electric and gas based on the common cost allocation for Customer Accounting Expenses in Appendix 13 (84%/16%).

13. Customer Operations Quarterly Reporting

The Company will continue to submit the following quarterly reports outlined in the 2016 Joint Proposal that were adopted by the Commission in the 2017 Rate Order: the Payment and Meter Access Report as defined in Appendix 20 of the 2016 Joint Proposal, and the Same-day Electric Service Reconnect Report as required by Section L(11) of the

2016 Joint Proposal. These quarterly reports will continue to be submitted 30 days after the end of each reporting period.

N. Electric and Gas Low Income Programs

The Company's Electric and Gas Low Income Programs consist of two components. First, during the terms of the Rate Plans, and continuing thereafter unless and until changed by the Commission, the Company will provide a discount, depending on the program, to eligible and enrolled low income residential customers. Second, during the terms of the Rate Plans, the Company will waive reconnection fees for low income customers.

The Electric and Gas Low Income Programs have been designed to recover $70.2 million of discounts for electric and $24.6 million of discounts for gas in each Rate Year. The programs have also been designed to recover up to $701,627 in electric reconnection fee waiver costs per year and up to $75,000 in gas reconnection fee waiver costs per year.

1. Customer Enrollment

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

First, the Company will continue its existing enrollment procedure for UG and DV customers by HRA or the Westchester County Department of Social Services ("DSS") (the "Agencies"). The Agencies can use 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(s).

Second, the Company will continue its existing enrollment procedure for 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(s).

Finally, on January 1, April 1, July 1 and October 1, the Company will initiate a quarterly 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(s).[76] By each March 1, June 1, September 1 and December 1 during the 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 take

[76] The quarterly reconciliation process will begin April 1, 2020 and continue as described in this section until the end of the Rate Plan.

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. The Company will not be liable for discounts that are, or are not, applied to customers' accounts if Agency data is not received on schedule.

If the Company concludes at any time that the quarterly 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 Company will notify the parties of this circumstance. The Company, Staff, 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.

The Company will contribute up to $100,000 in each of the calendar years 2020, 2021 and 2022 towards the Agencies' mailing costs, not recovered in rates, to facilitate the quarterly reconciliations. 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 $100,000 provided herein.

2. Electric and Gas Customer Qualification

To qualify for the Electric or Gas Low Income Program ("Qualifying Customers"), an Electric Rate I SC1 customer or Gas SC 1 or SC 3 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, 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 Low Income Programs at the time these Rate Plans become effective will not be required to re-enroll in the Low Income Programs described herein.

In addition, the Company will formalize an escalation process for customers who have been removed from the Low Income Program(s) and would like to discuss or dispute their removal. The Company will provide refresher training for its CSRs regarding this escalation process.

3. <u>Electric and Gas Low Income Discount Program</u>

This Proposal is designed to implement the requirements of the Orders[77] issued in Case 14-M-0565, except where noted below.

Effective January 1, 2020, the Company will implement the Tiered discount levels identified in the table below. Tier 1 will include customers enrolled in the Electric and Gas Low Income Programs by virtue of receiving benefits under any of the following governmental assistance programs: SSI, Temporary Assistance to Needy Persons/Families, Safety Net Assistance, Medicaid, Supplemental Nutrition Assistance Program; or have received a standard HEAP grant in the preceding twelve (12) months. Tier 2 will include customers that have received a standard HEAP grant in the preceding twelve (12) months with one adder. Tier 3 will include customers that have received a standard HEAP grant in the preceding twelve (12) months with two adders. Tier 4

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[77] Case 14-M-0565, *Proceeding on Motion of the Commission to Examine Programs to Address Energy Affordability for Low Income Utility Customers,* Order Adopting Low Income Program Modifications and Directing Utility Filings (issued May 20, 2016); Order Approving Implementation Plans With Modifications (issued February 17, 2017); and Order Granting in Part and Denying in Part Requests for Reconsideration and Petitions for Rehearing (issued February 17, 2017) (collectively, the "Generic Affordability Proceeding" and "Low Income Orders").

customers are customers enrolled in the Electric and Gas Low Income Programs by virtue of being enrolled in a DV or UG Program.

The discount levels in the table below incorporate a one-time increase designed to offset the estimated Rate Year 1 total bill impact for electric and gas services as documented in this Joint Proposal. In Rate Years 2 and 3, the Company will only adjust the discount levels to reflect the required annual recalculation of the tiered discount levels[78] as directed by the Commission in the Generic Affordability Proceeding. The one-time adjustment noted above will remain but will not modified to reflect any additional rate plan increases associated with Rate Years 2 and 3.

Income Level	Electric Heating	Electric Non-heating	Gas Heating	Gas Non-heating
Tier 1	$16.00	$13.00	$60.00	$7.00
Tier 2	$16.00	$13.00	$66.00	$7.00
Tier 3	$42.00	$34.00	$87.00	$7.00
Tier 4	$22.00	$19.00	$73.00	$7.00

The target cost of the discount component of the Electric Low Income Program is $70.2 million per Rate Year. The target cost of the discount component of the Gas Low Income Program is $24.6 million per Rate Year.

The Signatory Parties recommend that if the Commission orders any changes to the Low Income Program(s) in this Proposal in the General Affordability Proceeding that

[78] See Section O.8 below for a description of how the annual recalculation of the tiered discount levels will be documented and filed with the Secretary.

such changes be implemented on a prospective-only basis. The Signatory Parties reserve all of their administrative and judicial rights in connection with the Generic Affordability Proceeding.

4. 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 target costs. All Electric and Gas Qualifying Customers, without limit, will be accepted into the program.

5. Reconnection Fee Waivers

Effective January 1, 2020, the Company will waive its electric and gas service reconnection fees for low income customers on a first come, first serve basis up to a target cost of $701,627 for each year of the Electric Rate Plan and $75,000 for each year of the Gas Rate Plan.[79]

The Company's tariff leaves will state that each fee waiver program will end once the cost of these programs equals the target cost for each of the Rate Years. The Company will notify the parties if it projects that the electric and/or gas target cost will be reached during any Rate Year.

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[79] 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 $701,627 and $75,000, respectively.

6. Budget Billing

Consistent with the Low Income Orders, the Company will continue automatically enrolling customers participating in the Low Income Program(s) into the Company's budget billing program (also referred to as the "levelized payment plan") on an opt-out basis. Customers enrolled in the Company's Low Income Program(s) that are in arrears or in Tier 4 will receive an opt-out budget billing notice when their arrears balance is paid in full, or if they enter into a DPA with the Company, provided that they are still enrolled in the Low Income Program(s) at that time. Once enrolled in the budget billing program, customers can end their participation at any time.

7. Cost Recovery

The programs described in this section will be implemented in a manner that is revenue and earnings neutral to the Company.

a. Electric

All under- and over-recoveries associated with the actual cost of low income discounts and the waiver of reconnection fees will be passed through the RDM to 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 recovery of the low income customer charges/discounts and waiver of reconnection fees.

b. 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 $24.6 million per year 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. If the Gas Low Income Program continues beyond the term of the Gas Rate Plan, but the MRA 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 recovery of the low income customer charges/discounts, and reconnection fee waivers.

8. Reporting Requirements

a. Annual Low Income Program Report

On October 1 of 2020 through 2023 the Company will file an Annual Low Income Program Report with the Secretary, with copies by email to parties to Case 19-E-0065, 19-G-0066 and 14-M-0565. This report will contain information consistent with the requirements in the Low Income Orders, including but not limited to the results of the annual recalculation of the tiered discount levels that will become effective in the following Rate Year.

b. Quarterly Low Income Program Report

The Company will continue to file a report on the Electric and Gas Low Income Programs for each calendar quarter. The quarterly report will be filed with the Secretary in Cases 19-E-0065, 19-G-0066 and 14-M-0565, within thirty (30) days after the end of each calendar quarter. The reporting template is attached hereto as Appendix 24.

O. Retail Access Issues

1. Improving Communications and Transparency

The Company will create a centralized process for regular updates to energy service companies ("ESCOs") via the Retail Access newsletter that is emailed to all ESCOs and posted on the Company's website. Day-to-day communications with ESCOs will continue outside of the newsletter process. The Company will endeavor to respond to simple inquiries – *i.e.*, inquiries that do not require investigation or detailed review – that are made to retailaccess@coned.com within three business days. If the Company requires additional time to respond to inquiries, the Company will notify the ESCO that additional time is necessary. Further discussion on the types of inquiries and response expectations to be addressed at first annual meeting referenced in Section 21 below.

2. Gas Marketer Collaborative Meetings

a. Structure of Regular Collaborative Meetings

Regular Meetings will be held at least twice each rate year (though Collaborative Members may collectively decide to hold additional meetings). Meeting notices and proposed agenda items shall be circulated via email to the email distribution and made available on the Company's ESCO website for the Gas Marketer Collaborative at least one week prior to scheduled meetings. Individuals that wish to be added to the email distribution list for the Gas Marketer Collaborative will be informed that they should contact the Company at the following email: tcis@coned.com. Any Collaborative Member may propose to add items to the proposed meeting agendas.

b. Structure of Special Collaborative Meetings

The Company agrees to convene a Special Collaborative that will be limited in duration to six months, beginning within 90 days of the Commission's Order adopting this Proposal. During that time, Special Collaborative Meetings will be held at least once during each of the first two months and then every other month thereafter. By consensus, the Collaborative members may agree to schedule additional meetings and/or teleconferences. The Special Collaborative will discuss the following issues:

- Intraday Nomination Flexibility for Virtual Storage;
    - How Virtual Storage Inventory Costs are Computed;
    - Intraday City Gate Allocations;
- Baseload peaking basis costs;
- Timely Cash Out Invoices;
- Alternative method to satisfy credit and security requirements related to imbalances;
- POR Disbursements Adjustments;
- An informational presentation on the components of the MRA;
- Details of how Con Ed will notify ESCOs of changes proposed by upstream pipelines that will affect rates;
- A presentation on how gas operations handles nominations for excess city gate capacity; and
- No harm-no foul rule for non-firm daily balancing.

Within 60 days of the last Special Collaborative Meeting, the Company will submit a report to the Secretary describing the Special Collaborative discussions.

Any issues considered in either the Regular Collaborative or the Special Collaborative will be resolved in a manner that is revenue and earnings neutral to the Company.

3. Annual Electric Marketer Meeting

Starting in 2020, the Company will hold an annual meeting each year with ESCOs and other third parties to answer questions on the electric retail choice program. Four weeks before the meeting, the Company will solicit comments, suggestions on topics to be covered and questions from ESCOs using the Company's distribution lists for gas and electric ESCOs. The Company will provide a summary of the agenda items discussed at the annual meeting in its Newsletter.

4. Updated Reference Materials for CSRs

The Company agrees to provide annual updated reference materials for call center representatives to update them on retail access developments including changes in rates charged ESCO customers and changes in UBP rules. The Company agrees to provide communications to remind CSRs of the procedure to follow when ESCO customers call with questions about their bill. ESCOs can at any time reach out to the Company via established channels to provide suggestions for materials or information that should be available to utility call center representatives.

5. Changes to Transportation Customer Information System

The Company will make changes to its Transportation Customer Information System ("TCIS") that reject nominations from approved gas marketers that over-nominate at City gates for firm supply under the Company's DDS program. The Company will complete these changes to TCIS by December 31, 2021.

6. General

The parties agree that no party supporting this Joint Proposal has waived its right to file a petition with the Commission to address, on a generic basis, issues related to the methodology used to compute the MFC and Credit and Collection Costs and Billing Back Out Credit.

P. Studies and Initiatives

1. Study on Depreciation and Climate Change

The Company will file a study with the Commission approximately 15 months after the Commission Order adopting the Joint Proposal on the potential depreciation impacts of climate change policies and laws on its gas, electric, steam, and common assets. The study will include an examination of the potential impacts of climate change policies and laws on average service lives, reserve deficiency/surplus, salvage value, cost of removal, depreciation rates and customer bills and an assessment of the appropriate survivor curve (e.g., h-curves or Iowa curves) to use in the Company's next base rate filing.

No later than 60 days after the Commission Order adopting the Joint Proposal, the Company will hold a meeting with interested parties to discuss the scope of the study and specific study requests. The Company shall notify all parties in these proceedings of the meeting date at least two weeks prior to the meeting. The Company will also circulate to all parties in these proceedings a proposed scope of study at least two weeks prior to the meeting. The Company will not finalize a scope of study for at least two weeks following the meeting in order to allow for interested parties to provide feedback.

The Company will hold a meeting with interested parties no sooner than two weeks, and within 60 days, of filing the study to discuss, among other things, the findings of the study and possible next steps. The Company shall notify all parties in these proceedings of the meeting date at least two weeks prior to the meeting.

The study will include an Appendix with a visual and statistical analysis of the curve fitting for both h-curves and Iowa-curves for the five highest-valued plant accounts for gas, electric, steam, and common assets.

2. NYPA Billable Demand Forecasting

The Company agrees to develop an econometric, statistical-based forecasting model for NYPA billable demand for use in the Company's next electric base rate case. No later than 90 days after the Commission Order adopting the Joint Proposal, the Company will hold a meeting to discuss potential approaches with interested parties.

3. Seasonal Rate Study

The Company will study the cost basis for seasonal differentials in both the Con Edison and NYPA tariffs. No later than 90 days after the Commission Order adopting the Proposal, the Company will hold a meeting with interested parties for input on study approach. The study is to be completed within one year of the Commission Order adopting the Proposal and circulated to all parties in Case 19-E-0065. The Company will schedule a meeting with parties within 60 days of completing the study to discuss the results.

4. **NYPA Classes For Embedded Cost of Service ("ECOS") Study**

The Company will expand its 2017 electric ECOS study to provide results for three NYPA classes (Rate I Demand, Rate I Non-demand, and Rate II). The study is to be completed within one year of the Commission Order adopting the Proposal and circulated to all parties in Case 19-E-0065. The Company will schedule a meeting with parties within 60 days of completing the study to discuss the results.

5. **District Energy Initiative**

The Company will implement a multi-phased District Energy Initiative, as described below:

Phase 1 (Detailed Assessment) **–** The Company will retain a consultant, with experience in geothermal district energy systems and heat pump heating and cooling solutions, to assist in developing a study to examine the feasibility of deploying geothermal district energy systems in the Company's service territory as an alternative to replacing leak prone pipe. The Company will benchmark with other utilities and district energy system installers and will seek to leverage analyses performed by other entities, including:

- HEET Study in Massachusetts and Central Hudson Study; and
- New York City studies, *e.g.*, Geothermal Webtool, Buildings Technical Working Group, and 80X50 community energy analysis, and NYSERDA studies.

Internal and external stakeholder engagement will commence early on in this phase and will include customer outreach/education. During this phase, the Company will also determine selection criteria for potential participants. The objective will be to obtain a diverse customer profile. The Company will conduct a detailed assessment of 10-15 potential sites for deployment. The Company will seek to develop a diverse portfolio of potential sites. The assessment will include local site characteristics, detailed load data, customer interest, financial feasibility, and opportunities to enhance feasibility (*e.g.*, energy efficiency investments). Con Edison will seek to select sites that maximize potential for success and replicability and test different use cases, giving preference to LMI communities, all else being equal. Cost estimates and projected tax implications also will be evaluated. All customer identities and personally identifiable information will remain confidential.

Phase 2 (Pilot) – Subject to the results of Phase 1, a pilot program will be initiated during RY2. Con Edison will seek to implement the pilot program to include at least two locations (at least one in NYC and one in Westchester). The Commission's approval of the Joint Proposal shall constitute approval of the pilot program at the first location only. Con Edison shall be authorized to proceed with the pilot program following submission of the Compliance filing described below.

For the first location, the Company will, in consultation with Staff, the City, and other parties, develop a compliance filing, which will include an implementation plan and estimated costs and will meet the following additional minimum requirements:

- The district energy system proposed for the first location will be designed and is intended to displace the need for installation of new main to replace bare steel/cast iron main; and
- On a capital expenditure basis, the cost of the district energy system for the first location is less than what it would otherwise cost the Company to install new mains in that location.

The cost of the pilot program for the first location will be recovered as a regulatory asset over a ten-year period through the MRA.

For the second location contemplated under the pilot program, or for any expansion of the pilot program, the Company will file a petition with the Commission seeking approval. The petition will describe the proposed second location or program expansion, as applicable, include an implementation plan, estimated costs, and proposed cost recovery mechanism. The second location will also meet the minimum requirements described for the first location above.

Phase 3 (Scalability Assessment) – Based on the results of any projects implemented during Phase 2, the Company will assess the feasibility of expanding the Pilot to additional locations. In particular, the Company should identify whether regulatory changes can lead to greater adoption of district systems and the projected benefits and costs of increasing the number of projects. The Pilot should include recommendations for the establishment of a viable regulatory, ownership and governance structure. A thorough financial analysis will evaluate future business-models and calculate the cost of expansion. The final report will also include an analysis and comparison of customer energy costs for those participating in geothermal district project compared to those remaining on the Company's gas system over a 1-year, 5-year, and 10-year period.

Reporting – Company to submit bi-annual reports on the status of this initiative. The reports will quantify energy savings, system benefits and carbon emission reductions.

Cost recovery (consulting fees) – Costs related to consulting fees for studies and reports will be capped at $1.5 million, to be deferred and recovered through the MRA.

Q. Miscellaneous Provisions

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

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

Nothing herein precludes Con Edison from filing a new general electric rate case or a new general gas rate case prior to January 1, 2023, for rates to be effective on or after January 1, 2023.

Changes to the Company's base delivery service rates during the term of the Electric or Gas 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 and Gas Rate Plans, 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 and/or gas 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 and/or gas rates unreasonable or insufficient for the provision of safe and adequate service or just and reasonable rates.

d. Nothing herein will preclude any Signatory Party 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, which are not contrary to the agreed upon terms and conditions set forth herein. All changes will be implemented on a revenue neutral and earnings neutral basis.

e. The Signatory Parties reserve the right to oppose any filings made 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[80] in an annual amount, calculated and applied separately for electric and gas, equating to ten (10) basis points of return on common equity or more,[81] 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.[82]

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

[81] For electric, such amounts are estimated to be $14.5 million in RY1, $15.2 million in RY2 and $16.0 million in RY3. For gas, such amounts are estimated to be $4.8 million in RY1, $5.3 million in RY2 and $5.8 million in RY3.

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

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 or gas 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 and gas, equating to ten (10) basis points of return on common equity or more,[83] Con Edison will defer on its books of account the full change in expense, with any such deferrals as credits or debits 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. Financial Protections

Annually, the Company will provide Staff with the five-year earnings forecast for CEI and each direct subsidiary of CEI (e.g., Con Edison Company of New York, Orange and Rockland Utilities, Inc., Con Edison Transmission, Inc. and Con Edison Clean Energy Businesses, Inc.). The forecast will include the income statement, balance sheet and cash flow statements for CEI and each above-listed entity. The Company will submit

[83] 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.

the forecast to Staff no later than thirty (30) calendar days after it is reviewed by the Finance Committee of CEI's Board of Directors. The Company will update Staff when there are material changes to the five-year forecast.

After the completion of the Company's annual audit by its external auditors, the Company will provide Staff with actual financial statements (*i.e.*, income statement, balance sheet, cash flow statement and consolidating adjustments) for CEI and each direct subsidiary of CEI for the previous year. The Company will submit these statements to Staff no later than thirty (30) calendar days after the completion of the annual audit by its external auditors.

The five-year earnings forecast and actual financial statements will be provided to Staff by filing with the Records Access Officer pursuant to the Commission's trade secret process.

No additional ring-fencing measures will be implemented at this time. The Company will evaluate two metrics at the end of each semi-annual period ending June 30 and December 31. The first metric will calculate whether investments in CEI's non-utility businesses exceed 15 percent of CEI's total consolidated operations as measured by revenues, assets, or cash flow. The second metric will calculate if the ratio of holding company debt (which will measure only direct debt obligations of Consolidated Edison, Inc. and exclude non-recourse financing by non-utility entities) as a percentage of total consolidated debt exceeds 20 percent. The Company will notify Commission no later than 60 days after the end of a semi-annual period if any of the financial protection metric thresholds are exceeded. Within 60 days of such a notification, the Company will submit a filing providing a ring-fencing plan to insulate the Company, or, in the alternative, demonstrating why additional ring-fencing measures are not necessary at that time.

4. <u>Trade Secret Protection</u>

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.

5. <u>Provisions Not Separable</u>

The Signatory Parties intend this Proposal to be a complete resolution of all the issues in Cases 19-E-0065 and 19-G-0066. It is understood that each provision of this Proposal is in consideration and support of all the other provisions, and expressly conditioned upon acceptance by the Commission. Except as set forth herein, none of the Signatory Parties is deemed to have approved, agreed to or consented to any principle, methodology or interpretation of law underlying or supposed to underlie any provision herein. If the Commission fails to adopt this Proposal according to its terms, then the Signatory Parties to the Proposal will be free to pursue their respective positions in this proceeding without prejudice.

6. <u>Provisions Not Precedent</u>

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 and gas issues do not preclude those parties from addressing such issues in future rate proceedings or in other proceedings.

7. 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, subject to any reservations expressed by any individual Signatory Party on its signature page. 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.

8. 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.

9. 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.

10. Scope of Provisions

No term or provision of this Proposal that relates specifically to one or more but not all of electric and gas 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.

11. 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: 10/17/2019

By Robert Hoglund
Robert Hoglund

NEW YORK STATE DEPARTMENT OF
PUBLIC SERVICE

Dated: 10/16/19

By: ______________________
STEVEN J. KRAMER
STAFF COUNSEL

THE CITY OF NEW YORK

Dated: October 17, 2019 By: ____________________________

Mark Chambers, RA
Director
New York City Mayor's Office of Sustainability

The City of New York is a Signatory Party to the Joint Proposal, but advances the following concerns:

- The magnitude of the increases to the electric and gas revenue requirements and the impacts the higher rates will have on many residential customers.

- The reliability of the electric system in New York City. As demonstrated by the outages that occurred in July 2019, it is of paramount importance that Con Edison focus its investments on preserving and increasing electric system reliability and resiliency.

- The magnitude of the energy efficiency-related shareholder incentives in Section J.2.

The City of New York is agreeing to support the Joint Proposal because of provisions that are expected to benefit New York City residents, and especially low-income residents. The City has been a staunch advocate for the inclusion of these important provisions. The nature of the City's concerns, and the balancing of the concerns with the attributes of the Joint Proposal, will be discussed in the City's Statement on the Joint Proposal.

Due to the above-stated concerns, the City of New York will remain engaged directly with Con Edison to monitor the Company's performance and capital spending each year. In the event the Company deviates from the commitments and agreements it made in this Joint Proposal, and/or it is not making investments needed to preserve system reliability, the City reserves and will exercise its right to challenge the Company's conduct before the Public Service Commission, including requesting that an investigation into the prudence of the Company's actions be commenced. The City of New York expects that the Public Service Commission would act promptly in response to any such petition to protect the Company's customers and ensure that they continue to receive statutorily-mandated safe and adequate service.

THE NEW YORK POWER AUTHORITY*

Dated: 10/16/19

By: ______________________

Keith Hayes
Senior Vice President
Clean Energy Solutions

* New York Power Authority signs this Joint Proposal with respect to the electric service provisions (Case 19-E-0065) and takes no position on the gas service provisions (Case 19-G-0066).

THE NEW YORK STATE OFFICE OF
GENERAL SERVICES

Dated: 10/17/19

By: [signature]

Tyler W. Wolcott
Counsel to the New York State Office of
General Services

THE METROPOLITAN
TRANSPORTATION AUTHORITY

Dated: 10/17/19

By: ______________________

Tyler W. Wolcott
Counsel to the Metropolitan Transportation Authority

THE NEW YORK RETAIL CHOICE COALITION

Dated: 10/18/19

By: Natara Feller

Natara Feller, Esq.

Managing Partner

Feller Law Group, PLLC

THE SABIN CENTER FOR CLIMATE CHANGE
LAW AT COLUMBIA LAW SCHOOL

Dated: Oct. 16, 2019

By: ______________________
Michael B. Gerrard, Esq.

CHARGEPOINT, INC.

Dated: October 17, 2019

By: ______________________

Kevin George Miller
Director, Public Policy

CASE 19-E-0065

The Natural Resources Defense Council (NRDC) participated in the negotiations of this Joint Proposal only with regard to the customer energy solutions provisions, including energy efficiency, and actions to address climate change, set forth in sections K. and J. of the Joint Proposal. NRDC is therefore agreeing to only those portions of the Joint Proposal pertaining to those provisions (i.e. Sections J. and K.). NRDC takes no position regarding the remaining portions of the Joint Proposal.

NATURAL RESOURCES DEFENSE COUNCIL

Dated: 10/17/19

By: ______________________________

BOB WYMAN

Dated: 17 October 2019 By: [signature]

CALSTART, INC.

Dated: 10/17/2019

By: Meredith 2. Alexander

NY GEOTHERMAL ENERGY
ORGANIZATION

Dated: October 18, 2019

By: Bill Nowak

Bill Nowak
Executive Director

The Association for Energy Affordability (AEA) participated in the rate case discussions of Customer Energy Solutions, specifically energy efficiency and earnings adjustment mechanisms. AEA agrees with and supports the earnings adjustment mechanisms and energy efficiency provisions and associated reconciliations in the Joint Proposal.

October 15, 2019

David Hepinstall

CONSUMER POWER ADVOCATES

Dated: 10/16/2019

By: [signature]

BLUEPRINT POWER

Dated: 10/16/2019 By: ______________________

ENVIRONMENTAL DEFENSE FUND[84]

Dated: 17 October 2019

By: ______________________

Elizabeth B. Stein
Senior Manager and Senior Attorney, Energy

[84] EDF is to be considered a signatory for Electric Case 19-E-0065 only.

NEW YORK ENERGY CONSUMERS COUNCIL

Dated: 10/15/2019 | 4:09 PM EDT

By: DocuSigned by:

Daniel Egan Co-President

Dated: 10/15/2019 | 8:07 PM EDT

By: DocuSigned by:

Phil Skalaski

Philip Skalaski Co-President

DIRECT ENERGY SERVICES, LLC

Dated: 10/18/19

By: Angela Schon

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-E-0065
Electric Revenue Requirement
For The Twelve Months Ending December 31, 2020
($ 000's)

	Rate Year 1 Forecast	Rate Change	Rate Year 1 With Rate Change
Operating revenues			
Sales revenues	$ 7,350,676	$ 113,251	$ 7,463,927
Other operating revenues	210,428	545	210,972
Total operating revenues	7,561,104	113,796	7,674,900
Operating expenses			
Purchased power	1,346,009		1,346,009
Operations & maintenance expense	1,690,743	612	1,691,354
Depreciation	1,220,892		1,220,892
Regulatory amortization	(61,141)		(61,141)
Other (carrying cost on pension levelization)	2,341		2,341
Taxes other than income taxes	1,885,971	3,386	1,889,357
Total operating expenses	6,084,815	3,998	6,088,813
Operating income before income taxes	1,476,289	109,798	1,586,087
New York State income taxes	62,317	7,137	69,454
Federal income taxes	63,159	21,559	84,717
Utility operating income	$ 1,350,813	$ 81,102	$ 1,431,915
Rate Base	$ 21,659,543		$ 21,659,543
Rate of Return	6.24%		6.61%

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-E-0065
Electric Revenue Requirement
For The Twelve Months Ending December 31, 2020 and December 31, 2021
($ 000's)

	Rate Year 1 With Rate Change	Rate Year 2 Revenue/Expense Rate Base Changes	Rate Change	Rate Year 2 With Rate Change
Operating revenues				
Sales revenues	$ 7,463,927	$ (2,461)	$ 370,319	$ 7,831,786
Other operating revenues	210,972	(1,029)	1,778	211,721
Total operating revenues	7,674,900	(3,489)	372,096	8,043,507
Operating expenses				
Purchased power	1,346,009	59,765		1,405,774
Operations & maintenance expense	1,691,354	15,077	1,999	1,708,430
Depreciation	1,220,892	73,905		1,294,797
Regulatory amortization	(61,141)	(752)		(61,893)
Other (carrying cost on pension levelization)	2,341	2,951		5,292
Taxes other than income taxes	1,889,357	108,894	11,073	2,009,324
Total operating expenses	6,088,813	259,840	13,072	6,361,725
Operating income before income taxes	1,586,087	(263,330)	359,024	1,681,782
New York State income taxes	69,454	(18,970)	23,337	73,821
Federal income taxes	84,717	(53,460)	70,494	101,752
Utility operating income	$ 1,431,915	$ (190,900)	$ 265,193	$ 1,506,209
Rate Base	$ 21,659,543	$ 1,123,709		$ 22,783,253
Rate of Return	6.61%			6.61%

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-E-0065
Electric Revenue Requirement
For The Twelve Months Ending December 31, 2021 and December 31, 2022
($ 000's)

	Rate Year 2 With Rate Change	Rate Year 3 Revenue/Expense Rate Base Changes	Rate Change	Rate Year 3 With Rate Change
Operating revenues				
Sales revenues	$ 7,831,786	$ 17,818	$ 326,432	$ 8,176,035
Other operating revenues	211,721	(1,052)	1,567	212,235
Total operating revenues	8,043,507	16,765	327,999	8,388,271
Operating expenses				
Purchased power	1,405,774	48,100		1,453,874
Operations & maintenance expense	1,708,430	13,947	1,763	1,724,140
Depreciation	1,294,797	68,609		1,363,406
Regulatory amortization	(61,893)			(61,893)
Other (carrying cost on pension levelization)	5,292	(2,342)		2,950
Taxes other than income taxes	2,009,324	115,332	9,760	2,134,416
Total operating expenses	6,361,725	243,645	11,523	6,616,893
Operating income before income taxes	1,681,782	(226,880)	316,476	1,771,378
New York State income taxes	73,821	(16,508)	20,571	77,884
Federal income taxes	101,752	(52,153)	62,140	111,739
Utility operating income	$ 1,506,209	$ (158,219)	$ 233,765	$ 1,581,755
Rate Base	$ 22,783,253	$ 1,142,744		$ 23,925,997
Rate of Return	6.61%			6.61%

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-E-0065
Electric Other Operating Revenues
For The Twelve Months Ending December 31, 2020, December 31, 2021, and December 31, 2022
($ 000's)

	Rate Year 1	Rate Year 2 Changes	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Miscellaneous Service & Other Revenues					
Miscellaneous Service Revenues - 4510	$ 20,176		$ 20,176		$ 20,176
Transmission of Energy	7,000		7,000		7,000
Transmission Service Charges (4571)	5,000		5,000		5,000
Maintenance of Interconnection Facilities	1,088		1,088		1,088
Excess Distribution Facilities	3,557		3,557		3,557
Late Payment Charges	35,462	1,766	37,228	1,652	38,880
NYSERDA on-bill recovery financing program	19		19		19
The Learning Center Services	703		703		703
Proceeds from Sales of TCCs	75,000		75,000		75,000
POR Discount (Revenues from ESCO)	26,717		26,717		26,717
Substation Operation Services	49		49		49
Electric Reconnection Fee	448		448		448
Reconnection Fee Waiver	(702)		(702)		(702)
Miscellaneous	27		27		27
Total Miscellaneous Service & Other Revenues	174,544	1,766	176,310	1,652	177,962
Rents					
Joint Operating Rents	17,105	(917)	16,188	(1,039)	15,149
Pole Attachment and Parity Billings	16,111	26	16,137	27	16,164
Total Rents	33,215	(890)	32,325	(1,012)	31,313
Revenue imputation - Cases 09-M-0114 and 09-M-0243	625	(26)	599	(26)	573
Revenue imputation - 2004-2007 Capital Overspend	2,587	(100)	2,487	(100)	2,387
Total	3,212	(126)	3,086	(126)	2,960
Total Other Operating Revenue	$ 210,972	$ 749	$ 211,721	$ 514	$ 212,235

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-E-0065
Electric Operations & Maintenance Expenses
For The Twelve Months Ending December 31, 2020, December 31, 2021, and December 31, 2022
($ 000's)

	Rate Year 1	Rate Year 2 Changes	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Fuel and Purchased Power	$ 1,346,009	$ 59,765	$ 1,405,774	$ 48,100	$ 1,453,874
A&G, Health Ins. Cap.	(15,000)	(503)	(15,503)	(520)	(16,022)
Advanced Metering Infrastructure	32,745	1,348	34,093	(4,276)	29,817
Bargaining Unit Contract Cost	194	4	198	4	202
Bond Administration & Bank Fees	10,078	222	10,300	226	10,526
Company Labor - Advanced Metering Infrastructure	8,454	3,132	11,585	1,079	12,664
Company Labor - Central Engineering	5,945	199	6,144	206	6,349
Company Labor - Construction Management	6,027	202	6,229	208	6,437
Company Labor - Corporate & Shared Services	193,577	5,078	198,655	5,050	203,705
Company Labor - Customer Energy Solutions	15,552	1,740	17,292	1,261	18,554
Company Labor - Customer Information System	929	671	1,600	6,374	7,973
Company Labor - Customer Operations	110,863	(6,840)	104,023	(2,852)	101,170
Company Labor - Electric Operations	173,914	4,754	178,668	3,347	182,014
Company Labor - Gas Operations	785	26	812	27	839
Company Labor - Production	24,216	810	25,027	838	25,864
Company Labor - Substation Operations (SSO)	69,077	2,312	71,389	2,389	73,778
Company Labor - System & Transmission Operations (STO)	33,433	1,119	34,552	1,156	35,709
Corporate & Shared Services	26,525	1,186	27,712	609	28,321
Corporate Fiscal Expense	3,920	86	4,007	88	4,095
Customer Energy Solutions	7,976	651	8,626	1,293	9,919
Customer Information System	2,885	(1,637)	1,247	(3,397)	(2,150)
Duplicate Misc. Charges	(11,564)	-	(11,564)	-	(11,564)
Employee Welfare Expense	149,256	3,281	152,537	3,355	155,891
Environmental Affairs	6,029	134	6,162	135	6,297
ERRP Major Maintenance	8,798	-	8,798	-	8,798
External Audit Services	3,273	73	3,345	74	3,419
Facilities & Field Services	6,527	143	6,671	147	6,817
Finance & Accounting Operations	18,023	527	18,550	408	18,958
Information Technology	34,715	3,062	37,778	4,451	42,229
Informational Advertising	6,139	415	6,554	407	6,961
Injuries & Damages / Workers Compensation	50,254	1,105	51,359	1,130	52,488
Institutional Dues & Subscription	1,841	40	1,882	41	1,923
Insurance Premium	40,995	902	41,897	921	42,818
Intercompany Shared Services	(7,749)	(170)	(7,919)	(174)	(8,093)
Load Dispatching and PJM Wheeling	(3,367)	-	(3,367)	-	(3,367)
Ops - Central Engineering	1,873	41	1,914	42	1,956
Ops - Construction Management	1,315	29	1,343	30	1,373
Ops - Customer Operations	56,645	3,193	59,838	2,192	62,030
Ops - Electric Operations	139,280	7,171	146,451	(4,345)	142,106
Ops - Gas Operations	888	20	908	19	927
Ops - Interference	136,315	13,626	149,940	9,584	159,525
Ops - Production	21,492	46	21,537	442	21,979
Ops - Substation Operations (SSO)	38,343	(725)	37,618	(10,631)	26,987
Ops - System & Transmission Operations (STO)	25,541	357	25,898	569	26,468
Other Compensation (Long-Term Equity)	5,073	80	5,153	113	5,266
Outside Legal Services	634	14	648	14	662
Pension and OPEB Costs	56,072	(0)	56,072	(0)	56,072
RCA - Amort of MGP/Superfund	7,256	6,418	13,674	4,840	18,515
RCA - Amort. of Energy Efficiency Programs	31,248	17,676	48,924	22,950	71,874
Regulatory Commission Expense - All Other	1,374	30	1,404	31	1,435
Regulatory Commission Expense - General and R&D	36,655	807	37,461	823	38,285
Rents - ERRP	68,244	2,128	70,371	149	70,521
Rents - General	51,065	1,122	52,187	1,148	53,335
Rents - Interdepartmental	13,942	1,130	15,072	941	16,013
Research & Development	8,162	179	8,341	183	8,525
Security	1,019	22	1,041	23	1,064
Storm Reserve	22,463	494	22,957	505	23,462
Uncollectible Reserve - Customer	39,701	1,644	41,344	1,545	42,890
Uncollectible Reserve - Sundry	3,249	-	3,249	-	3,249
Worker's Comp NYS Assessment	2,769	61	2,830	62	2,892
All Other	(58)	(1)	(59)	(1)	(60)
Business Cost Optimization - Labor	(25,054)	(13,043)	(38,097)	(8,312)	(46,409)
Business Cost Optimization - Non-Labor	(55,323)	(32,945)	(88,268)	(11,869)	(100,138)
Company Labor - Fringe Benefit Adjustment	(5,614)	(3,598)	(9,211)	(1,604)	(10,815)
Business Cost Optimization - Productivity	(8,481)	(12,969)	(21,450)	(17,740)	(39,190)
Total Operation & Maintenance Expenses	$ 3,037,363	$ 76,841	$ 3,114,204	$ 63,810	$ 3,178,014

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-E-0065
Electric Taxes Other Than Income Taxes
For The Twelve Months Ending December 31, 2020, December 31, 2021, and December 31, 2022
($000's)

	Rate Year 1	Rate Year 2 Changes	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Property Taxes					
New York City	$ 1,455,736	$ 101,283	$ 1,557,019	$ 95,119	$ 1,652,138
Upstate & Westchester	153,179	9,339	162,518	9,909	172,427
Total Property Taxes	1,608,915	110,622	1,719,537	105,028	1,824,565
Payroll Taxes	54,177	15	54,192	1,007	55,199
Revenue Taxes	223,364	9,266	232,630	8,882	241,512
Other Taxes					
Sales and Use Tax	2,318	51	2,369	52	2,421
Taxes on Health Insurance	-	-	-	10,111	10,111
Other Taxes	583	13	596	13	609
Total Other Taxes	2,901	64	2,965	10,176	13,141
Total Taxes Other than Income Taxes	$ 1,889,357	$ 119,967	$ 2,009,324	$ 125,092	$ 2,134,416

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-E-0065
Electric New York State Income Taxes
For The Twelve Months Ending December 31, 2020, December 31, 2021, and December 31, 2022
($ 000's)

	Rate Year 1	Rate Year 2 Changes	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Operating Income Before Income Taxes	$ 1,586,087	$ 95,695	$ 1,681,782	$ 89,596	$ 1,771,378
Interest Expense	(525,930)	(28,693)	(554,623)	(27,292)	(581,915)
Book Income Before State Income Taxes	1,060,157	67,002	1,127,159	62,304	1,189,463
Tax Computation					
Current State Income Taxes	9,984	5,556	15,540	2,275	17,815
Deferred State Income Taxes	59,470	(1,189)	58,281	1,788	60,069
NYS Income Tax Expense	$ 69,454	$ 4,367	$ 73,821	$ 4,063	$ 77,884

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-E-0065
Electric Federal Income Taxes
For The Twelve Months Ending December 31, 2020, December 31, 2021, and December 31, 2022
($ 000's)

	Rate Year 1	Rate Year 2 Changes	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Operating Income Before Income Taxes	$ 1,586,087	$ 95,695	$ 1,681,782	$ 89,596	$ 1,771,378
Interest Expense	(525,930)	(28,693)	(554,623)	(27,292)	(581,915)
Book Income Before Income Taxes	1,060,157	67,002	1,127,159	62,304	1,189,463
Tax Computation					
Current Federal Income Tax	137,573	11,901	149,474	19,707	169,180
Deferred Federal Income Tax	103,133	6,291	109,424	(8,263)	101,161
Excess Deferred Federal Income Tax - Protected	(35,898)	(1,394)	(37,292)	(1,793)	(39,085)
Excess Deferred Federal Income Tax - Unprotected	(97)	(11)	(108)	(1)	(109)
Excess Deferred Federal Income Tax - Unprotected - Accelerated	(97,260)		(97,260)		(97,260)
Excess Deferred Federal Income Tax - Non-Plant	(18,544)		(18,544)		(18,544)
Amortization of Deferred ITC	(1,665)		(1,417)		(1,080)
R&D Tax Credit	(2,525)		(2,525)		(2,525)
Federal Income Tax Expense	$ 84,717	$ 17,035	$ 101,752	$ 9,987	$ 111,739

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-E-0065
Rate Base - Electric
Average Twelve Months Ending December 31, 2020 and December 31, 2021
($000's)

	RY1	RY2 Changes	RY2
Utility Plant			
Electric Plant In Service	$ 30,657,139	$ 1,692,378	$ 32,349,517
Electric Plant Held For Future Use	67,279		67,279
Common Utility Plant (Electric Allocation)	2,691,659	63,865	2,755,524
Total	33,416,077	1,756,243	35,172,320
Utility Plant Reserves:			
Accumulated Reserve for Depreciation - Plant in Service	(7,407,269)	(693,032)	(8,100,302)
Accumulated Reserve for Depreciation - Common Plant (Electric Allocation)	(848,521)	(101,061)	(949,582)
Total	(8,255,790)	(794,094)	(9,049,884)
Net Plant	25,160,287	962,149	26,122,436
Non-Interest Bearing CWIP	863,085	10,301	873,386
Working Capital - Materials/Supplies, Prepayment and Cash Working Capital	853,053	33,045	886,098
Unamortized Premium & Discount	126,814	(1,437)	125,377
Unamortized Preferred Stock Expense	16,735	(771)	15,964
Customer Advance Construction	(13,530)		(13,530)
Net Deferrals / Credits from Reconciliation Mechanisms	271,717	130,529	402,246
Accumulated Deferred Income Taxes	-	-	-
Accumulated Deferred Federal Income Taxes	(4,649,782)	46,608	(4,603,174)
Accumulated Deferred State Income Taxes	(808,848)	(58,816)	(867,663)
Total	(5,458,630)	(12,208)	(5,470,836)
Average Rate Base	21,819,531	1,121,608	22,941,141
Earnings Base Capitalization Adjustment to Rate Base	26,132		26,132
Pension/OPEB Reduction	(141,980)		(141,980)
Former Employees/Contractor Proceeding Rate Base Reduction	(18,730)	786	(17,944)
2018 Sales and Use Tax Refund	(25,411)	1,315	(24,096)
Total Average Rate Base	$ 21,659,543	$ 1,123,709	$ 22,783,253

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-E-0065
Rate Base - Electric
Average Twelve Months Ending December 31, 2021 and December 31, 2022
($000's)

	RY2	RY3 Changes	RY3
Utility Plant			
Electric Plant In Service	$ 32,349,517	$ 1,617,408	$ 33,966,925
Electric Plant Held For Future Use	67,279		67,279
Common Utility Plant (Electric Allocation)	2,755,524	63,068	2,818,592
Total	35,172,320	1,680,476	36,852,796
Utility Plant Reserves:			
Accumulated Reserve for Depreciation - Plant in Service	(8,100,302)	(729,284)	(8,829,586)
Accumulated Reserve for Depreciation - Common Plant (Electric Allocation)	(949,582)	(52,282)	(1,001,864)
Total	(9,049,884)	(781,566)	(9,831,450)
Net Plant	26,122,436	898,910	27,021,346
Non-Interest Bearing CWIP	873,386	59,209	932,595
Working Capital - Materials/Supplies, Prepayment and Cash Working Capital	886,098	25,949	912,047
Unamortized Premium & Discount	125,377	(2,789)	122,588
Unamortized Preferred Stock Expense	15,964	(771)	15,193
Customer Advance Construction	(13,530)		(13,530)
Net Deferrals / Credits from Reconciliation Mechanisms	402,246	170,637	572,883
Accumulated Deferred Income Taxes			
Accumulated Deferred Federal Income Taxes	(4,603,174)	48,650	(4,554,524)
Accumulated Deferred State Income Taxes	(867,663)	(59,114)	(926,778)
Total	(5,470,836)	(10,464)	(5,481,302)
Average Rate Base	22,941,141	1,140,681	24,081,821
Earnings Base Capitalization Adjustment to Rate Base	26,132		26,132
Pension/OPEB Reduction	(141,980)		(141,980)
Former Employees/Contractor Proceeding Rate Base Reduction	(17,944)	786	(17,158)
2018 Sales and Use Tax Refund	(24,096)	1,277	(22,819)
Total Average Rate Base	$ 22,783,253	$ 1,142,744	$ 23,925,996

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-E-0065
Average Capital Structure & Cost of Money
For the Twelve Months Ending December 31, 2020, December 31, 2021 and December 31, 2022

RY 1

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre Tax Cost %
Long term debt	50.91%	4.63%	2.36%	2.36%
Customer deposits	1.09%	2.45%	0.03%	0.03%
Subtotal	52.00%		2.39%	2.39%
Common Equity	48.00%	8.80%	4.22%	5.71%
Total	100.00%		6.61%	8.10%

RY 2

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre Tax Cost %
Long term debt	50.98%	4.63%	2.36%	2.36%
Customer deposits	1.02%	2.45%	0.03%	0.03%
Subtotal	52.00%		2.39%	2.39%
Common Equity	48.00%	8.80%	4.22%	5.71%
Total	100.00%		6.61%	8.10%

RY 3

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre Tax Cost %
Long term debt	51.03%	4.63%	2.36%	2.36%
Customer deposits	0.97%	2.45%	0.03%	0.03%
Subtotal	52.00%		2.39%	2.39%
Common Equity	48.00%	8.80%	4.22%	5.71%
Total	100.00%		6.61%	8.10%

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

Case 19-E-0065

Long Term Debt

Forecast - Rate Year Ending December 31, 2020

						a	b	c	d	e = b + c + d	f = g / a	g
CECONY			Rate	Issue Date	Maturity Date	Amount Outstanding	Original Issue Amount	Premium or Discount	Expense of Issuance	Net Proceeds	Cost of Debt	Effective Annual Cost
Debentures:												
	2003	Series A	5.875%	4/7/03	04/01/33	$ 175,000,000	$ 175,000,000	$ (1,022,000)	$ (1,662,326)	$ 172,315,674	5.93%	$ 10,370,728
	2003	Series C	5.100%	6/10/03	06/15/33	200,000,000	200,000,000	(336,000)	(1,866,135)	197,797,865	5.14%	10,273,404
	2004	Series B	5.700%	2/9/04	02/01/34	200,000,000	200,000,000	(538,000)	(1,864,406)	197,597,594	5.74%	11,480,080
	2005	Series A	5.300%	3/7/05	03/01/35	350,000,000	350,000,000	(1,193,500)	(3,541,534)	345,264,966	5.35%	18,707,834
	2005	Series B	5.250%	6/20/05	07/01/35	125,000,000	125,000,000	(731,250)	(1,142,914)	123,125,836	5.30%	6,624,972
	2006	Series A	5.850%	3/6/06	03/15/36	400,000,000	400,000,000	(60,000)	(3,616,500)	396,323,500	5.88%	23,522,550
	2006	Series B	6.200%	6/13/06	06/15/36	400,000,000	400,000,000	(756,000)	(3,669,000)	395,575,000	6.24%	24,947,500
	2006	Series E	5.700%	11/28/06	12/01/36	250,000,000	250,000,000	(712,500)	(2,262,500)	247,025,000	5.74%	14,349,167
	2007	Series A	6.300%	8/23/07	08/15/37	525,000,000	525,000,000	(2,924,250)	(4,751,250)	517,324,500	6.35%	33,330,850
	2008	Series B	6.750%	4/1/08	04/01/38	600,000,000	600,000,000	(1,758,000)	(5,449,750)	592,792,250	6.79%	40,740,258
	2009	Series C	5.500%	12/2/09	12/01/39	600,000,000	600,000,000	(2,268,000)	(5,673,813)	592,058,187	5.54%	33,264,727
*	**2010**	Series A	4.450%	6/2/10	05/01/20	116,666,667	350,000,000	(759,500)	(2,518,935)	346,721,565	4.54%	5,300,948
	2010	Series B	5.700%	6/2/10	05/01/40	350,000,000	350,000,000	(1,701,000)	(3,306,369)	344,992,631	5.75%	20,116,912
	2012	Series A	4.200%	3/13/12	03/15/42	400,000,000	400,000,000	(1,424,000)	(4,228,381)	394,347,619	4.25%	16,988,413
	2013	Series A	3.950%	2/28/13	03/01/43	700,000,000	700,000,000	(4,872,000)	(6,866,027)	688,261,973	4.01%	28,041,268
	2014	Series A	4.450%	3/6/14	03/15/44	850,000,000	850,000,000	(714,000)	(8,804,659)	840,481,341	4.49%	38,142,289
	2014	Series B	3.300%	11/24/14	12/01/24	250,000,000	250,000,000	(867,500)	(2,042,196)	247,090,304	3.42%	8,540,970
	2014	Series C	4.625%	11/24/14	12/01/54	750,000,000	750,000,000	(1,912,500)	(7,814,167)	740,273,333	4.66%	34,930,667
	2015	Series A	4.500%	11/17/15	12/01/45	650,000,000	650,000,000	(650,000)	(6,906,434)	642,443,566	4.54%	29,501,881
	2016	Series A	3.850%	6/17/16	06/15/46	550,000,000	550,000,000	(775,500)	(5,899,245)	543,325,255	3.89%	21,397,492
	2016	Series B	2.900%	11/16/16	12/01/26	250,000,000	250,000,000	(1,017,500)	(2,112,299)	246,870,201	2.94%	7,354,327
	2016	Series C	4.300%	11/16/16	12/01/56	500,000,000	500,000,000	(4,355,000)	(5,350,674)	490,294,326	4.49%	22,470,567
	2017	Series A	3.875%	6/8/17	06/15/47	500,000,000	500,000,000	(1,850,000)	(5,417,927)	492,732,073	3.91%	19,556,698
	2017	Series B	3.125%	11/16/17	11/15/27	350,000,000	350,000,000	(91,000)	(2,864,898)	347,044,102	3.15%	11,036,030
	2017	Series C	4.000%	11/15/17	11/15/57	350,000,000	350,000,000	(1,386,000)	(3,652,237)	344,961,763	4.14%	14,503,824
	2018	Series A	3.800%	5/10/18	05/15/28	300,000,000	300,000,000	(51,000)	(2,548,347)	297,400,653	3.82%	11,464,984
	2018	Series B	4.500%	5/10/18	05/15/58	700,000,000	700,000,000	(3,227,000)	(7,515,512)	689,257,488	4.65%	32,574,251
	2018	Series C	3mL + 0.40%	6/26/18	06/25/21	640,000,000	640,000,000		(3,554,657)	636,445,343	3.24%	20,704,886
	2018	Series D	4.0000%	11/30/18	11/01/28	500,000,000	500,000,000	(370,000)	(4,247,094)	495,382,906	4.09%	20,461,709
	2018	Series E	4.6500%	11/30/18	11/01/48	600,000,000	600,000,000	(2,310,000)	(6,446,287)	591,243,713	4.70%	28,191,876
	2019	Series A	4.125%	5/7/19	05/15/49	700,000,000	700,000,000	(245,000)	(7,663,567)	692,091,433	4.16%	29,138,619
	2019	Series B	4.125%	11/1/19	11/01/49	400,000,000	400,000,000		(4,260,000)	395,740,000	4.16%	16,642,000
*	**2020**	Series A	3.930%	5/1/20	05/01/50	666,666,667	1,000,000,000		(10,650,000)	989,350,000	3.97%	26,436,667
*	**2020**	Series B	3.930%	9/1/20	09/01/50	216,666,667	650,000,000		(6,922,500)	643,077,500	3.97%	8,591,917
						$ 15,115,000,000	$ 16,115,000,000	$ (40,878,000)	$ (157,092,539)	$ 15,917,029,461	4.63%	$ 699,701,263
Tax Exempt Debt Issue through New York State												
	2004	Series C	VAR	11/5/04	11/01/39	$ 99,000,000	$ 99,000,000		$ (1,834,951)	$ 97,165,049	2.71%	$ 2,680,269
	2005	Series A	VAR	5/19/05	05/01/39	126,300,000	126,300,000		(1,842,329)	124,457,671	2.69%	3,401,177
	2010	Series A	VAR	11/9/10	06/01/36	224,600,000	224,600,000		(4,906,341)	219,693,659	2.73%	6,127,240
						$ 449,900,000	$ 449,900,000	$ -	$ (8,583,622)	$ 441,316,378	2.71%	$ 12,208,687
Subtotals						$ 15,564,900,000	$ 16,564,900,000	$ (40,878,000)	$ (165,676,160)	$ 16,358,345,840	4.57%	$ 711,909,950
Redemption of Preferred Stock												993,442
Unamortized Loss on Reacquired Debt Expense												7,505,489
Total CECONY						$ 15,564,900,000				**	4.63%	$ 720,408,880

Notes:

* Debt outstanding balances and annual costs are prorated for the months outstanding during the period.

** RY1 Long term debt rate also applied to RY2 and RY3

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-G-0066
Gas Revenue Requirement
For The Twelve Months Ending December 31, 2020
($ 000's)

	Rate Year 1 Forecast	Rate Change	Rate Year 1 With Rate Change
Operating revenues			
Sales revenues	$ 2,315,642	$ 83,923	$ 2,399,565
Other operating revenues	40,411	302	40,714
Total operating revenues	2,356,053	84,225	2,440,279
Operating expenses			
Purchased gas costs	760,859		760,859
Operations & maintenance expenses	397,924	453	398,377
Depreciation	300,806		300,806
Regulatory amortizations	(9,732)		(9,732)
Other (carrying cost on pension levelization)	481		481
Taxes other than income taxes	429,803	2,568	432,371
Total operating expenses	1,880,140	3,021	1,883,162
Operating income before income taxes	475,913	81,204	557,117
New York State income taxes	19,663	5,278	24,941
Federal income taxes	42,245	15,944	58,189
Utility operating income	$ 414,005	$ 59,981	$ 473,987
Rate Base	$ 7,170,725		$ 7,170,725
Rate of Return	5.77%		6.61%

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-G-0066
Gas Revenue Requirement
For The Twelve Months Ending December 31, 2020 and December 31, 2021
($ 000's)

Operating revenues	Rate Year 1 With Rate Change	Rate Year 2 Revenue/Expense Rate Base Changes	Rate Change	Rate Year 2 With Rate Change
Sales revenues	$ 2,399,565	$ 19,657	$ 122,011	$ 2,541,233
Other operating revenues	40,714	738	439	41,891
Total operating revenues	2,440,279	20,395	122,450	2,583,124
Operating expenses				
Purchased gas costs	760,859	3,492		764,351
Operations & maintenance expenses	398,377	(8,931)	659	390,105
Depreciation	300,806	32,352		333,158
Regulatory amortizations	(9,732)	2,079		(7,653)
Other (carrying cost on pension levelization)	481	607		1,088
Taxes other than income taxes	432,371	46,228	3,734	482,332
Total operating expenses	1,883,162	75,827	4,392	1,963,381
Operating income before income taxes	557,117	(55,432)	118,058	619,742
New York State income taxes	24,941	(4,797)	7,674	27,818
Federal income taxes	58,189	(12,344)	23,181	69,026
Utility operating income	$ 473,987	$ (38,291)	$ 87,203	$ 522,899
Rate Base	$ 7,170,725	$ 739,970		$ 7,910,695
Rate of Return	6.61%			6.61%

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

Case 19-G-0066
Gas Revenue Requirement
For The Twelve Months Ending December 31, 2021 and December 31, 2022
($ 000's)

	Rate Year 2 With Rate Change	Rate Year 3 Revenue/Expense Rate Base Changes	Rate Change	Rate Year 3 With Rate Change
Operating revenues				
Sales revenues	$ 2,541,233	$ 4,002	$ 167,055	$ 2,712,290
Other operating revenues	41,891	1,132	601	43,624
Total operating revenues	2,583,124	5,134	167,656	2,755,914
Operating expenses				
Purchased gas costs	764,351	(5,029)		759,322
Operations & maintenance expenses	390,105	5,905	902	396,912
Depreciation	333,158	28,570		361,728
Regulatory Amortizations	(7,653)	31,560		23,907
Other (carrying cost on pension levelization)	1,088	(482)		606
Taxes other than income taxes	482,332	44,424	5,112	531,868
Total operating expenses	1,963,381	104,948	6,014	2,074,343
Operating income before income taxes	619,742	(99,813)	161,642	681,572
New York State income taxes	27,818	(7,614)	10,507	30,710
Federal income taxes	69,026	(19,814)	31,738	80,950
Utility operating income	$ 522,899	$ (72,385)	$ 119,397	$ 569,911
Rate Base	$ 7,910,695	$ 711,223		$ 8,621,918
Rate of Return	6.61%			6.61%

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-G-0066
Gas Other Operating Revenues
For The Twelve Months Ending December 31, 2020, December 31, 2021, and December 31, 2022
($ 000's)

	Rate Year 1	Rate Year 2 Changes	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Miscellaneous Service & Other Revenues					
Miscellaneous Service Revenues	$ 2,362		$ 2,362		$ 2,362
Reconnection Fee Waiver	(75)		(75)		(75)
Late Payment Charges	8,500	510	9,010	616	9,626
Learning Center Revenues	106		106		106
POR Discount	8,642		8,642		8,642
Reimbursement To KeySpan - Governor's Island	(39)		(39)		(39)
Total Miscellaneous Service & Other Revenues	19,496	510	20,006	616	20,622
Rents					
Interdepartmental Rents	8,440	810	9,250	1,245	10,495
New York Facilities	6,936		6,936		6,936
Real Estate Rents	540	(137)	403	(121)	282
Total Rents	15,916	673	16,589	1,124	17,713
Transmission System Reinforcement Recoveries					
NYPA Variable and Maintenance	1,033		1,033		1,033
Steam Department - ERRP Incremental Charges	1,215		1,215		1,215
Total	2,249	-	2,249	-	2,249
Research and Development True-Up and Surcharge	2,900		2,900		2,900
Revenue imputation - Cases 09-M-0114 and 09-M-0243	153	(6)	147	(6)	141
Total Other Operating Revenues	$ 40,714	$ 1,177	$ 41,891	$ 1,734	$ 43,625

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-G-0066
Gas Operations & Maintenance Expenses
For The Twelve Months Ending December 31, 2020, December 31, 2021, and December 31, 2022
($ 000's)

	Rate Year 1	Rate Year 2 Changes	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Fuel and Purchased Power	$ 760,859	$ 3,492	$ 764,351	$ (5,029)	$ 759,322
A&G, Health Ins. Cap.	(3,083)	(103)	(3,186)	(107)	(3,293)
Advanced Metering Infrastructure	5,704	462	6,166	(668)	5,498
Bargaining Unit Contract Costs	41	1	42	1	43
Bond Administration & Bank Fees	1,784	39	1,823	41	1,863
Company Labor - Advanced Metering Infrastructure	1,325	648	1,973	257	2,230
Company Labor - Construction Management	7,011	235	7,246	242	7,488
Company Labor - Corporate & Shared Services	45,524	1,572	47,097	1,610	48,706
Company Labor - Customer Energy Solutions	4,524	173	4,696	179	4,875
Company Labor - Customer Information System	191	138	329	1,310	1,639
Company Labor - Customer Operations	26,147	(1,134)	25,013	(369)	24,644
Company Labor - Electric Operations	826	28	853	29	882
Company Labor - Gas Operations	75,599	2,040	77,639	2,078	79,717
Corporate & Shared Services	6,620	270	6,890	165	7,054
Corporate Fiscal Expense	838	19	857	19	876
Customer Energy Solutions	536	18	554	145	699
Customer Information System	593	(338)	256	(697)	(442)
Duplicate Misc. Charges	(875)		(875)		(875)
Employee Welfare Expense	30,679	673	31,353	689	32,042
Environmental Affairs	723	16	739	16	755
External Audit Services	673	15	688	15	703
Facilities & Field Services	1,185	26	1,211	27	1,238
Finance & Accounting Operations	4,606	128	4,734	104	4,838
Information Technology	8,561	768	9,329	1,116	10,445
Informational Advertising	1,448	146	1,594	172	1,766
Injuries & Damages/ Workers Compensation	10,329	227	10,556	233	10,788
Institutional Dues & Subscription	776	17	793	17	810
Insurance Premium	6,836	150	6,986	154	7,140
Intercompany Shared Services	(1,611)	(34)	(1,646)	(37)	(1,683)
New York Facilities	5,061	111	5,172	114	5,286
Ops - Construction Management	1,613	35	1,648	37	1,685
Ops - Customer Operations	11,220	618	11,837	427	12,264
Ops - Electric Operations	139	3	142	3	145
Ops - Gas Operations	82,149	(4,451)	77,698	1,308	79,006
Ops - Interference	29,638	1,685	31,323	1,581	32,904
Other Compensation (Long-Term Equity)	1,042	17	1,059	23	1,082
Outside Legal Services	130	3	133	3	136
Pension and OPEB Costs	11,525	(0)	11,525	0	11,525
RCA - Amort. of MGP/Superfund	2,305	1,319	3,624	995	4,619
RCA - Amort. of Energy Efficiency Programs	2,453	3,679	6,132	4,021	10,153
Regulatory Commission Expense - All Other	752	17	769	16	785
Regulatory Commission Expense - General and R&D	10,101	221	10,323	227	10,550
Rents - General	361	8	369	8	377
Rents - Interdepartmental	4		4		4
Research & Development	4,732	104	4,836	105	4,942
Security	209	5	214	4	218
Uncollectible Reserve - Customer	11,457	651	12,108	787	12,895
Uncollectible Reserve - Sundry	668		668		668
Worker's Comp NYS Assessment	569	13	582	12	594
All Other	267	6	273	6	279
Business Cost Optimization - Labor	(3,466)	(3,216)	(6,683)	(2,008)	(8,691)
Business Cost Optimization - Non-Labor	(9,485)	(11,289)	(20,773)	(2,930)	(23,703)
Company Labor - Fringe Benefit Adjustment	(543)	(892)	(1,435)	(395)	(1,829)
Business Cost Optimization - Productivity	(2,034)	(3,117)	(5,151)	(4,278)	(9,429)
Total Operation & Maintenance Expenses	$ 1,159,235	$ (4,780)	$ 1,154,455	$ 1,778	$ 1,156,233

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-G-0066
Gas Taxes Other Than Income Taxes
For The Twelve Months Ending December 31, 2020, 2021, and 2022
($000s)

	Rate Year 1	Rate Year 2 Changes	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Property Taxes					
New York City	$ 284,930	$ 43,228	$ 328,158	$ 42,690	$ 370,848
Upstate & Westchester	61,440	2,302	63,742	2,422	66,164
Total Property Taxes	346,370	45,530	391,900	45,112	437,012
Payroll Taxes	11,640	45	11,685	311	11,996
Revenue Taxes	73,526	4,368	77,894	2,015	79,909
Other Taxes					
Sales and Use Tax	709	16	725	16	741
Taxes on Health Insurance				2,078	2,078
Other Taxes	126	3	129	3	132
Total Other Taxes	836	19	854	2,097	2,952
Total Taxes Other than Income Taxes	432,371	49,962	482,332	49,536	531,868

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-G-0066
Gas New York State Income Taxes
For The Twelve Months Ending December 31, 2020, December 31, 2021, and December 31, 2022
($ 000's)

	Rate Year 1	Rate Year 2 Changes	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Operating Income Before Income Taxes	$ 557,117	$ 62,626	$ 619,742	$ 61,829	$ 681,572
Interest Expense	(175,021)	(18,407)	(193,429)	(17,364)	(210,793)
Book Income Before Income Taxes	382,095	44,218	426,314	44,465	470,779
Tax Computation					
Current State Income Taxes	4,773	2,027	6,800	2,921	9,721
Deferred State Income Taxes	20,168	850	21,018	(28)	20,989
NYS Income Tax Expense	$ 24,941	$ 2,877	$ 27,818	$ 2,893	$ 30,710

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-G-0066
Gas Federal Income Taxes
For The Twelve Months Ending December 31, 2020, December 31, 2021, and December 31, 2022
($ 000's)

	Rate Year 1	Rate Year 2 Changes	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Operating Income Before Income Taxes	$ 557,117	$ 62,626	$ 619,742	$ 61,829	$ 681,572
Interest Expense	(175,021)	(18,407)	(193,429)	(17,364)	(210,793)
Book Income Before Income Taxes	382,095	44,218	426,314	44,465	470,779
Tax Computation					
Current Federal Income Tax	50,349	4,282	54,631	7,994	62,625
Deferred Federal Income Tax	35,051	6,508	41,559	2,940	44,499
Excess Deferred Federal Income Tax - Protected	(10,065)	44	(10,021)	972	(9,049)
Excess Deferred Federal Income Tax - Unprotected	30	4	34	5	39
Excess Deferred Federal Income Tax - Unprotected Accelerated	(12,071)		(12,071)		(12,071)
Excess Deferred Federal Income Tax - Non-Plant	(3,780)		(3,780)		(3,780)
Amortization of Investment Tax Credit	(757)	(1)	(758)	13	(745)
R&D Tax Credit	(568)		(568)		(568)
Federal Income Tax Expense	$ 58,189	$ 10,837	$ 69,026	$ 11,924	$ 80,950

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-G-0066
Rate Base - Gas
Average Twelve Months Ending December 31, 2020 and December 31, 2021
($000's)

	RY1	RY2 Changes	RY2
Utility Plant			
Gas Plant In Service	$ 9,585,787	$ 974,261	$ 10,560,048
Common Utility Plant (Gas Allocation)	551,304	13,081	564,384
Total	10,137,091	987,342	11,124,433
Utility Plant Reserves:			
Accumulated Reserve for Depreciation - Plant in Service	(1,695,529)	(187,823)	(1,883,352)
Accumulated Reserve for Depreciation - Common Plant (Gas Allocation)	(173,794)	(20,699)	(194,493)
Total	(1,869,323)	(208,522)	(2,077,845)
Net Plant	8,267,768	778,819	9,046,588
Non-Interest Bearing CWIP	440,192	(42,187)	398,005
Working Capital - Materials/Supplies, Prepayment and Cash Working Capital	142,993	8,133	151,125
Unamortized Premium & Discount	33,370	(378)	32,992
Unamortized Preferred Stock Expense	3,170	(146)	3,024
Customer Advance Construction	(1,970)		(1,970)
Gas Stored Underground - Non Current	1,239		1,239
Accrual for Unbilled Revenues	43,594		43,594
Net Deferrals / Credits from Reconciliation Mechanisms	70,688	28,140	98,828
Accumulated Deferred Income Taxes			
Accumulated Deferred Federal Income Taxes	(1,616,298)	(12,159)	(1,628,457)
Accumulated Deferred State Income Taxes	(197,677)	(20,586)	(218,263)
Total	(1,813,974)	(32,745)	(1,846,720)
Average Rate Base	7,187,069	739,635	7,926,705
Earnings Base Capitalization Adjustment to Rate Base	7,199		7,199
Pension/OPEB Reduction	(16,201)		(16,201)
Former Employees/Contractor Proceeding Rate Base Reduction	(4,598)	193	(4,405)
2018 Sales and Use Tax Refund	(2,745)	142	(2,603)
Total Average Rate Base	$ 7,170,725	$ 739,970	$ 7,910,695

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-G-0066
Rate Base - Gas
Average Twelve Months Ending December 31, 2021 and December 31, 2022
($000's)

	RY2	RY 3 Changes	RY3
Utility Plant			
Gas Plant In Service	$ 10,560,048	$ 983,673	$ 11,543,721
Common Utility Plant (Gas Allocation)	564,384	12,917	577,302
Total	11,124,433	996,590	12,121,023
Utility Plant Reserves:			
Accumulated Reserve for Depreciation - Plant in Service	(1,883,352)	(218,532)	(2,101,885)
Accumulated Reserve for Depreciation - Common Plant (Gas Allocation)	(194,493)	(10,708)	(205,201)
Total	(2,077,845)	(229,241)	(2,307,086)
Net Plant	9,046,588	767,350	9,813,937
Non-Interest Bearing CWIP	398,005	(44,513)	353,492
Working Capital - Materials/Supplies, Prepayment and Cash Working Capital	151,125	9,908	161,034
Unamortized Premium & Discount	32,992	(734)	32,258
Unamortized Preferred Stock Expense	3,024	(146)	2,878
Customer Advance Construction	(1,970)		(1,970)
Gas Stored Underground - Non Current	1,239		1,239
Accrual for Unbilled Revenues	43,594		43,594
Net Deferrals / Credits from Reconciliation Mechanisms	98,828	17,513	116,340
Accumulated Deferred Income Taxes			
Accumulated Deferred Federal Income Taxes	(1,628,457)	(17,489)	(1,645,945)
Accumulated Deferred State Income Taxes	(218,263)	(20,997)	(239,260)
Total	(1,846,720)	(38,485)	(1,885,205)
Average Rate Base	7,926,705	710,892	8,637,597
Earnings Base Capitalization Adjustment to Rate Base	7,199		7,199
Pension/OPEB Reduction	(16,201)		(16,201)
Former Employees/Contractor Proceeding Rate Base Reduction	(4,405)	193	(4,212)
2018 Sales and Use Tax Refund	(2,603)	138	(2,465)
Total Average Rate Base	$ 7,910,695	$ 711,223	$ 8,621,918

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

Case 19-G-0066

Average Capital Structure & Cost of Money

For the Twelve Months Ending December 31, 2020, December 31, 2021 and December 31, 2022

RY 1

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre Tax Cost %
Long term debt	50.91%	4.63%	2.36%	2.36%
Customer deposits	1.09%	2.45%	0.03%	0.03%
Subtotal	52.00%		2.39%	2.39%
Common Equity	48.00%	8.80%	4.22%	5.71%
Total	100.00%		6.61%	8.10%

RY 2

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre Tax Cost %
Long term debt	50.98%	4.63%	2.36%	2.36%
Customer deposits	1.02%	2.45%	0.03%	0.03%
Subtotal	52.00%		2.39%	2.39%
Common Equity	48.00%	8.80%	4.22%	5.71%
Total	100.00%		6.61%	8.10%

RY 3

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre Tax Cost %
Long term debt	51.03%	4.63%	2.36%	2.36%
Customer deposits	0.97%	2.45%	0.03%	0.03%
Subtotal	52.00%		2.39%	2.39%
Common Equity	48.00%	8.80%	4.22%	5.71%
Total	100.00%		6.61%	8.10%

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

Case 19-G-0066

Long Term Debt

Forecast - Rate Year Ended December 31, 2020

						a	b	c	d	e = b + c + d	f = g / a	g
CECONY			Rate	Issue Date	Maturity Date	Amount Outstanding	Original Issue Amount	Premium or Discount	Expense of Issuance	Net Proceeds	Cost of Debt	Effective Annual Cost
Debentures:												
	2003	Series A	5.875%	4/7/03	04/01/33	$ 175,000,000	$ 175,000,000	$ (1,022,000)	$ (1,662,326)	$ 172,315,674	5.93%	$ 10,370,728
	2003	Series C	5.100%	6/10/03	06/15/33	200,000,000	200,000,000	(336,000)	(1,866,135)	197,797,865	5.14%	10,273,404
	2004	Series B	5.700%	2/9/04	02/01/34	200,000,000	200,000,000	(538,000)	(1,864,406)	197,597,594	5.74%	11,480,080
	2005	Series A	5.300%	3/7/05	03/01/35	350,000,000	350,000,000	(1,193,500)	(3,541,534)	345,264,966	5.35%	18,707,834
	2005	Series B	5.250%	6/20/05	07/01/35	125,000,000	125,000,000	(731,250)	(1,142,914)	123,125,836	5.30%	6,624,972
	2006	Series A	5.850%	3/6/06	03/15/36	400,000,000	400,000,000	(60,000)	(3,616,500)	396,323,500	5.88%	23,522,550
	2006	Series B	6.200%	6/13/06	06/15/36	400,000,000	400,000,000	(756,000)	(3,669,000)	395,575,000	6.24%	24,947,500
	2006	Series E	5.700%	11/28/06	12/01/36	250,000,000	250,000,000	(712,500)	(2,262,500)	247,025,000	5.74%	14,349,167
	2007	Series A	6.300%	8/23/07	08/15/37	525,000,000	525,000,000	(2,924,250)	(4,751,250)	517,324,500	6.35%	33,330,850
	2008	Series B	6.750%	4/1/08	04/01/38	600,000,000	600,000,000	(1,758,000)	(5,449,750)	592,792,250	6.79%	40,740,258
	2009	Series C	5.500%	12/2/09	12/01/39	600,000,000	600,000,000	(2,268,000)	(5,673,813)	592,058,187	5.54%	33,264,727
*	**2010**	Series A	4.450%	6/2/10	05/01/20	116,666,667	350,000,000	(759,500)	(2,518,935)	346,721,565	4.54%	5,300,948
	2010	Series B	5.700%	6/2/10	05/01/40	350,000,000	350,000,000	(1,701,000)	(3,306,369)	344,992,631	5.75%	20,116,912
	2012	Series A	4.200%	3/13/12	03/15/42	400,000,000	400,000,000	(1,424,000)	(4,228,381)	394,347,619	4.25%	16,988,413
	2013	Series A	3.950%	2/28/13	03/01/43	700,000,000	700,000,000	(4,872,000)	(6,866,027)	688,261,973	4.01%	28,041,268
	2014	Series A	4.450%	3/6/14	03/15/44	850,000,000	850,000,000	(714,000)	(8,804,659)	840,481,341	4.49%	38,142,289
	2014	Series B	3.300%	11/24/14	12/01/24	250,000,000	250,000,000	(867,500)	(2,042,196)	247,090,304	3.42%	8,540,970
	2014	Series C	4.625%	11/24/14	12/01/54	750,000,000	750,000,000	(1,912,500)	(7,814,167)	740,273,333	4.66%	34,930,667
	2015	Series A	4.500%	11/17/15	12/01/45	650,000,000	650,000,000	(650,000)	(6,906,434)	642,443,566	4.54%	29,501,881
	2016	Series A	3.850%	6/17/16	06/15/46	550,000,000	550,000,000	(775,500)	(5,899,245)	543,325,255	3.89%	21,397,492
	2016	Series B	2.900%	11/16/16	12/01/26	250,000,000	250,000,000	(1,017,500)	(2,112,299)	246,870,201	2.94%	7,354,327
	2016	Series C	4.300%	11/16/16	12/01/56	500,000,000	500,000,000	(4,355,000)	(5,350,674)	490,294,326	4.49%	22,470,567
	2017	Series A	3.875%	6/8/17	06/15/47	500,000,000	500,000,000	(1,850,000)	(5,417,927)	492,732,073	3.91%	19,556,698
	2017	Series B	3.125%	11/16/17	11/15/27	350,000,000	350,000,000	(91,000)	(2,864,898)	347,044,102	3.15%	11,036,030
	2017	Series C	4.000%	11/15/17	11/15/57	350,000,000	350,000,000	(1,386,000)	(3,652,237)	344,961,763	4.14%	14,503,824
	2018	Series A	3.800%	5/10/18	05/15/28	300,000,000	300,000,000	(51,000)	(2,548,347)	297,400,653	3.82%	11,464,984
	2018	Series B	4.500%	5/10/18	05/15/58	700,000,000	700,000,000	(3,227,000)	(7,515,512)	689,257,488	4.65%	32,574,251
	2018	Series C	3mL + 0.40%	6/26/18	06/25/21	640,000,000	640,000,000	0	(3,554,657)	636,445,343	3.24%	20,704,886
	2018	Series D	4.0000%	11/30/18	11/01/28	500,000,000	500,000,000	(370,000)	(4,247,094)	495,382,906	4.09%	20,461,709
	2018	Series E	4.6500%	11/30/18	11/01/48	600,000,000	600,000,000	(2,310,000)	(6,446,287)	591,243,713	4.70%	28,191,876
	2019	Series A	4.125%	5/7/19	05/15/49	700,000,000	700,000,000	(245,000)	(7,663,567)	692,091,433	4.16%	29,138,619
	2019	Series B	4.125%	11/1/19	11/01/49	400,000,000	400,000,000	0	(4,260,000)	395,740,000	4.16%	16,642,000
*	**2020**	Series A	3.930%	5/1/20	05/01/50	666,666,667	1,000,000,000	0	(10,650,000)	989,350,000	3.97%	26,436,667
*	**2020**	Series B	3.930%	9/1/20	09/01/50	216,666,667	650,000,000	0	(6,922,500)	643,077,500	3.97%	8,591,917
						$ 15,115,000,000	$ 16,115,000,000	$ (40,878,000)	$ (157,092,539)	$ 15,917,029,461	4.63%	$ 699,701,263
Tax Exempt Debt Issue through New York State												
	2004	Series C	VAR	11/5/04	11/01/39	$ 99,000,000	$ 99,000,000		$ (1,834,951)	$ 97,165,049	2.71%	$ 2,680,269
	2005	Series A	VAR	5/19/05	05/01/39	126,300,000	126,300,000		(1,842,329)	124,457,671	2.69%	3,401,177
	2010	Series A	VAR	11/9/10	06/01/36	224,600,000	224,600,000		(4,906,341)	219,693,659	2.73%	6,127,240
						$ 449,900,000	$ 449,900,000	$ -	$ (8,583,622)	$ 441,316,378	2.71%	$ 12,208,687
Subtotals						$ 15,564,900,000	$ 16,564,900,000	$ (40,878,000)	$ (165,676,160)	$ 16,358,345,840	4.57%	$ 711,909,950
Redemption of Preferred Stock												993,442
Unamortized Loss on Reacquired Debt Expense												7,505,489
Total CECONY						$ 15,564,900,000				**	4.63%	$ 720,408,880

Notes:

* Debt outstanding balances and annual costs are prorated for the months outstanding during the period.

** RY1 long term debt rate also applied to RY2 and RY3

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-G-0066
Calculation of Phased Rate Increase
For the Twelve Months Ending December 31, 2020, December 31, 2021 and December 31, 2022
($ 000's)

Rate Increase	Twelve Months Ending December 31, 2020	2021	2022	Cumulative Total
RY - 1	$ 83,923	$ 83,923	$ 83,923	$ 251,769
RY - 2		122,011	122,011	244,022
RY - 3			167,055	167,055
Total	$ 83,923	$ 205,934	$ 372,989	$ 662,846

Phased rate increase without interest				
RY - 1	$ 46,923	$ 46,923	$ 46,923	$ 140,769
RY - 2		176,011	176,011	352,022
RY - 3			170,055	170,055
Total	$ 46,923	$ 222,934	$ 392,989	$ 662,846
Variation	$ 37,000	$ (17,000)	$ (20,000)	$ -
Interest at 4.20%	$ 574	$ 884	$ 311	$ 1,769

Phased rate increase with interest				
RY - 1	$ 47,218	$ 47,218	$ 47,218	$ 141,654
RY - 2		176,306	176,306	352,612
RY - 3			170,350	170,350
Total	$ 47,218	$ 223,524	$ 393,874	$ 664,615

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-E-0065
Amortization of Electric Regulatory Deferrals (Credits & Debits)
($ 000's)

Electric	Amortization Period	Twelve Months Ending December 31, 2020	2021	2022	Total
Regulatory Assets (Debits)					
MTA work	5	$ 47,580	$ 47,580	$ 47,580	$ 142,740
Property Tax Deferrals	5	29,177	29,177	29,177	87,531
Pensions/OPEBs	5	16,454	16,454	16,454	49,362
Interference	5	13,988	13,988	13,988	41,964
Carrying Charges (Net Plant Reconciliation)	5	1,759	1,759	1,759	5,276
Interest on Deferrals	5	856	856	856	2,568
Positive Incentive Revenue Adjustments	3	3,360	3,360	3,360	10,080
Interest Rate True-Up (Auction Rate / LT Debt)	1	15,216			15,216
NYSIT Rate Change	1	5,766			5,766
Customer Cash Flow Benefits - Bonus Depreciation	1	832			832
Deferred Workers Compensation Recoveries	1	425			425
WTC Incident System Restoration Interest Accrued	1	69			69
Verizon Joint Use Settlement	1	46			46
Electric Service Reliability Rate Adjustment (CAIDI SAIFI)	1	8			8
Smart Grid Demonstration Grant	1	3			3
Total Regulatory Assets (a)		$ 135,539	$ 113,174	$ 113,174	$ 361,886
Regulatory Liabilities (Credits)					
Sale of Property - Gain on North 1st street	5	$26,087	$26,087	$26,087	$78,261
Sale of Property - Gain on Kent Avenue	5	8,161	8,161	8,161	24,483
BQDM & REV Demo Carrying Charge Deferral	5	4,987	4,987	4,987	14,961
2019 Sales and Use Tax Refund	5	3,448	3,448	3,448	10,344
DSM Liquidated	5	1,492	1,492	1,492	4,476
AMI Customer Engagement	5	654	654	654	1,962
Rate Case EE and DM Programs Carrying Charge Deferral	5	444	444	444	1,332
Carrying Cost - SIR Deferred Balances	5	402	402	402	1,206
Additional 18A Assessment	5	378	378	378	1,134
Electric Vehicle Rate Incentive Expense True Up	5	350	350	350	1,050
Federal Tax Reform Transition Period	3	125,784	125,784	125,784	377,352
Negative Revenue Adjustment - Major Network Outage	3	1,667	1,667	1,667	5,000
ERRP Rent	3	1,213	1,213	1,213	3,640
Property Tax Settlement - 74th Street (86% customer portion)	1	9,814			9,814
Management Variable Pay	1	5,057			5,057
Property Tax Settlement - 59th Street (86% customer portion)	1	3,005			3,005
Sale of Property - Verplanck Quarry	1	1,201			1,201
Prop Tax Refund Town	1	1,123			1,123
Former Employees/Contractor Proceeding	1	1,105			1,105
Sale of Property - 708 1st Ave - insurance proceeds	1	211			211
Sale of Property Liability	1	52			52
Interest on Headroom Capacity	1	33			33
Sale of Property - Windmill Road - North Castle	1	9			9
Deferral of NYS Brownfield Credit	1	2			2
Total Regulatory Liabilities (b)		$ 196,679	$ 175,067	$ 175,067	$ 546,813
Net Debit / (Net Credit) (a - b)		$ (61,140)	$ (61,893)	$ (61,893)	$ (184,927)
Regulatory Assets to be amortized in O&M					
Energy Efficiency	10	$ 8,620	$ 21,475	$ 42,419	$ 72,514
Non Wire Alternative Projects (NWS)	10	3,923	6,547	6,731	17,202
System Peak Reduction	10	3,706	3,706	3,706	11,119
SmartCharge	10	446	827	1,481	2,754
REV - Demonstration Projects	9	8,607	9,549	10,340	28,496
Brooklyn Queens Demand Management Program (BQDM)	8	5,945	6,820	7,195	19,961
Site Investigation and Remediation (SIR) Program Costs	5	7,256	13,674	18,515	39,445

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-G-0066
Amortization of Gas Regulatory Deferrals (Credits & Debits)
($ 000's)

Gas	Amortization Period	Twelve Months Ending December 31, 2020	2021	2022	Total
Regulatory Assets (Debits)					
Meadowlands Heaters	12	$ 2,844	$ 2,844	$ 2,844	$ 8,532
Property Tax Deferrals	5	7,088	7,088	7,088	21,264
Gas Service Line	5	6,374	6,374	6,374	19,122
Inside Gas Meters	5	4,147	4,147	4,147	12,441
Interference	5	2,281	2,281	2,281	6,843
Interest Rate True-Up (Auction Rate / LT Debt)	5	921	921	921	2,763
Carrying Charges (Net Plant Reconciliation)	5	135	135	135	406
Positive Incentive Revenue Adjustments	3	4,464	4,464	4,464	13,392
Building Meter Conversion Study	3	98	98	98	294
NYSIT Rate Change	1	728			728
Interruptible Gas Collaborative	1	96			96
Deferred Workers Compensation Recoveries	1	91			91
Gas Peak Demand Reduction Collaborative	1	50			50
Interest on deferred POR	1	14			14
Total Regulatory Assets (a)		$ 29,331	$ 28,352	$ 28,352	$ 86,036
Regulatory Liabilities (Credits)					
Sales and Use Tax Refund	5	$ 387	$ 387	$ 387	$ 1,160
Penalties on Off-peak / interruptible customers	5	283	283	283	849
Interest on Deferrals	5	258	258	258	774
Pensions/OPEBs	5	184	184	184	552
Pipeline Integrity	5	123	123	123	369
Carrying Cost - SIR Deferred Balances	5	32	32	32	96
Negative revenue adjustments	3	3,178	3,178	3,178	9,534
Federal Tax Reform Transition Period	2	31,560	31,560		63,120
Additional 18A Assessment	1	1,237			1,237
Management Variable Pay	1	1,022			1,022
Former Employees/Contractor Proceeding	1	259			259
Customer Cash Flow Benefits - Bonus Depreciation	1	172			172
R and D Recon	1	118			118
Unauthorized Use Charge - Divested Stations	1	84			84
Prop Tax Refund Town	1	83			83
Sale of Property - 708 1st Ave - insurance proceeds	1	18			18
WTC Incident System Restoration Interest Accrued	1	64			64
Oil to Gas Conversion	1	1			1
Total Regulatory Liabilities (b)		$ 39,063	$ 36,005	$ 4,445	$ 79,512
Net Debit / (Net Credit) (a - b)		$ (9,731)	$ (7,652)	$ 23,908	$ 6,524
Regulatory Assets to be amortized in O&M					
Energy Efficiency	10	$ 2,453	$ 6,132	$ 10,153	$ 18,738
Site Investigation and Remediation (SIR) Program Costs	5	2,304	3,623	4,618	10,546

Consolidated Edison Company of New York
Case 19-E-0065
Electric Delivery Volume and Delivery Revenue
Twelve Months ending December 31, 2020, December 31, 2021, and December 31, 2022

Delivery Volume - GWHs
Twelve Months ending December 31st

	2020	2021	2022
Con Edison Customers	44,574	43,828	43,272
New York Power Authority	9,694	9,533	9,371
Recharge New York	718	718	718
Total Delivery Volumes	54,986	54,079	53,361

Delivery Revenues ($ '000)
Twelve Months ending December 31st

	2020			2021			2022		
	At Current (Jan 2019) Rates	Revenue Targets at RY1 Rates	Revenue Change for RY1	At Current (Jan 2019) Rates	Revenue Targets at RY2 Rates	Revenue Change for RY2	At Current (Jan 2019) Rates	Revenue Targets at RY3 Rates	Revenue Change for RY3
Non Competitive - Subject to RDM									
Con Edison Customers*	$4,731,924	$4,868,353	$136,429	$4,681,580	$5,126,866	$445,286	$4,656,122	$5,378,188	$722,066
New York Power Authority	602,032	617,038	15,006	594,010	646,470	52,460	590,903	674,610	83,707
Total Non-Competitive Revenues - RDM Customers	$5,333,956	$5,485,391	$151,435	$5,275,590	$5,773,336	$497,746	$5,247,025	$6,052,798	$805,773
Non Competitive - Non - RDM									
Con Edison Customers	$43,805	$47,245	$3,440	$45,222	$50,746	$5,524	$44,715	$52,164	$7,449
Recharge New York	36,204	37,061	857	36,204	39,342	3,138	36,204	41,431	5,227
Total Non-Competitive Revenues - Non-RDM Customers	$80,009	$84,306	$4,297	$81,426	$90,088	$8,662	$80,919	$93,595	$12,676
Competitive									
Billing & Payment Processing	$42,131	$45,893	$3,762	$42,403	$46,196	$3,793	$42,715	$46,525	$3,810
Metering	15,091	0	(15,091)	15,075	0	(15,075)	15,145	0	(15,145)
Merchant Function Charge	60,146	49,088	(11,058)	58,263	51,811	(6,452)	57,070	54,015	(3,055)
Total Competitive Revenues	$117,368	$94,981	($22,387)	$115,741	$98,007	($17,734)	$114,930	$100,540	($14,390)
Total Delivery Revenues	$5,531,333	$5,664,678	$133,345	$5,472,757	$5,961,431	$488,674	$5,442,874	$6,246,933	$804,059

*SC 1 revenues are at full customer charge for all customers.

Consolidated Edison Company of New York, Inc.
Case 19-E-0065
Monthly Electric Revenue Targets

Revenue Targets for Rate Year ending December 2020 (Thousand $)

	SC 1	SC 2 & 6	SC 8	SC 5 & 9	SC 12	CECONY	NYPA	TOTAL
Jan-20	171,959	37,749	10,416	148,639	2,907	371,670	47,417	419,087
Feb-20	168,288	39,049	10,197	147,874	2,792	368,200	39,551	407,751
Mar-20	154,973	36,346	9,580	143,168	2,525	346,592	42,961	389,553
Apr-20	140,866	33,415	8,490	137,849	1,849	322,469	43,294	365,763
May-20	141,476	32,003	9,772	146,948	1,265	331,464	44,105	375,570
Jun-20	174,755	36,297	15,136	192,530	1,521	420,238	54,537	474,775
Jul-20	231,736	41,822	19,662	238,048	2,188	533,456	70,708	604,165
Aug-20	240,245	41,852	19,697	237,209	2,221	541,224	68,887	610,111
Sep-20	212,974	40,935	19,372	234,779	2,094	510,154	61,757	571,911
Oct-20	168,247	35,289	14,783	191,527	1,370	411,216	53,359	464,575
Nov-20	148,787	32,441	9,742	147,741	1,454	340,165	43,103	383,268
Dec-20	170,344	37,008	9,818	152,285	2,050	371,505	47,357	418,862
Rate Year 2020	2,124,650	444,206	156,665	2,118,595	24,238	4,868,353	617,038	5,485,391

Notes:
(1) SC 1 revenues are at full customer charge for all customers.
(2) SC 9 reflects the exclusion of BIR delivery revenues.
(3) SCs 5, 8, 9, 12, and NYPA reflect the inclusion of Reactive Power revenues.

Consolidated Edison Company of New York, Inc.
Case 19-E-0065
Monthly Electric Revenue Targets

Revenue Targets for Rate Year ending December 2021 (Thousand $)

	SC 1	SC 2 & 6	SC 8	SC 5 & 9	SC 12	CECONY	NYPA	TOTAL
Jan-21	186,896	41,918	11,144	160,718	3,134	403,810	47,629	451,439
Feb-21	176,186	41,911	10,589	154,395	2,962	386,043	43,840	429,883
Mar-21	162,665	39,012	9,988	149,692	2,643	364,000	45,295	409,295
Apr-21	144,869	35,343	8,810	141,240	1,888	332,150	41,816	373,966
May-21	143,730	33,430	10,005	150,059	1,276	338,500	44,723	383,224
Jun-21	185,091	39,492	16,137	204,377	1,624	446,720	59,260	505,980
Jul-21	245,537	45,362	20,795	251,409	2,344	565,447	74,688	640,136
Aug-21	254,609	45,429	20,760	250,356	2,332	573,486	72,736	646,222
Sep-21	224,937	44,070	20,597	247,372	2,243	539,219	65,203	604,422
Oct-21	177,731	38,124	15,431	201,336	1,419	434,041	59,192	493,233
Nov-21	157,722	35,042	10,241	156,118	1,550	360,673	43,390	404,063
Dec-21	175,202	38,824	10,089	156,459	2,203	382,777	48,696	431,473
Rate Year 2021	2,235,175	477,957	164,586	2,223,529	25,620	5,126,866	646,470	5,773,336

Notes:
(1) SC 1 revenues are at full customer charge for all customers.
(2) SC 9 reflects the exclusion of BIR delivery revenues.
(3) SCs 5, 8, 9, 12, and NYPA reflect the inclusion of Reactive Power revenues.

Consolidated Edison Company of New York, Inc.
Case 19-E-0065
Monthly Electric Revenue Targets

Revenue Targets for Rate Year ending December 2022 (Thousand $)

	SC 1	SC 2 & 6	SC 8	SC 5 & 9	SC 12	CECONY	NYPA	TOTAL
Jan-22	191,937	43,896	11,431	164,252	3,185	414,701	49,320	464,021
Feb-22	182,802	44,484	10,979	159,306	3,129	400,700	45,684	446,384
Mar-22	172,282	42,322	10,525	157,926	2,756	385,811	47,210	433,021
Apr-22	155,361	38,559	9,325	150,898	2,079	356,222	44,731	400,953
May-22	154,188	36,339	10,589	159,803	1,360	362,279	46,877	409,157
Jun-22	194,123	42,216	16,983	213,921	1,725	468,967	65,513	534,480
Jul-22	259,317	48,738	21,801	263,537	2,487	595,880	73,698	669,579
Aug-22	266,329	48,393	21,637	260,498	2,520	599,377	75,628	675,005
Sep-22	236,537	47,145	21,380	258,406	2,528	565,996	72,047	638,043
Oct-22	186,260	40,507	16,032	208,455	1,493	452,747	58,196	510,943
Nov-22	165,843	37,386	10,709	162,745	1,554	378,237	50,335	428,572
Dec-22	182,556	41,004	10,422	160,944	2,345	397,271	45,369	442,640
Rate Year 2022	2,347,535	510,989	171,813	2,320,689	27,163	5,378,188	674,610	6,052,798

Notes:
(1) SC 1 revenues are at full customer charge for all customers.
(2) SC 9 reflects the exclusion of BIR delivery revenues.
(3) SCs 5, 8, 9, 12, and NYPA reflect the inclusion of Reactive Power revenues.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Gas Case 19-G-0066
Sales Revenues
($ 000's)

Base Revenues (excl GRT)	Twelve Months Ending December 31, 2020	RY2 Sales Gain/(Loss)	Twelve Months Ending December 31, 2021	RY 3 Sales Gain/(Loss)	Twelve Months Ending December 31, 2022
Service Classification 1	220,358	17,467	237,825	15,570	253,395
Service Classification 2 - Non-Heating	129,988	12,666	142,654	11,561	154,215
Service Classification 2 - Heating	225,255	28,949	254,204	28,791	282,995
Service Classification 2 - DG	11,649	5,058	16,707	1,887	18,594
Service Classification 2 - Contract	2,095	-	2,095	-	2,095
Service Classification 3	865,565	121,692	987,257	120,382	1,107,639
Service Classification 3 - DG	19	3	22	2	24
Service Classification 13	463	77	540	66	606
Service Classification 14	467	-	467	-	467
Service Classification 12 R2	14,501	142	14,643	49	14,692
Total	**1,470,360**	**186,054**	**1,656,414**	**178,308**	**1,834,722**

Volumes (Therms)	2020	RY2 Sales Gain/(Loss)	2021	RY 3 Sales Gain/(Loss)	2022
Service Classification 1	40,430,000	(710,000)	39,720,000	(530,000)	39,190,000
Service Classification 2 - Non-Heating	225,350,000	(600,000)	224,750,000	(990,000)	223,760,000
Service Classification 2 - Heating	352,410,000	3,510,000	355,920,000	4,310,000	360,230,000
Service Classification 2 - DG	60,110,000	-	78,110,000	-	81,220,000
Service Classification 2 - Contract	26,880,000	-	26,880,000	-	26,880,000
Service Classification 3	1,063,040,000	13,510,000	1,076,550,000	13,060,000	1,089,610,000
Service Classification 3 - DG	10,000		10,000		10,000
Service Classification 13	860,000	30,000	890,000	-	890,000
Service Classification 14	270,000	-	270,000	-	270,000
Service Classification 12 R2	175,890,000		175,890,000	-	175,890,000
	1,945,250,000	**15,740,000**	**1,978,990,000**	**15,850,000**	**1,997,950,000**

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-G-0066
Monthly Gas Revenue Targets
($ 000's)

Revenue Targets for Rate Year ending December 2020

	SC 1	SC 2 R1	SC 2 R2	SC 3 1-4 Dwelling Units	SC 3 more than 4 Dwelling Units	TOTAL
Jan-20	19,918	11,338	34,578	59,746	73,426	199,006
Feb-20	19,937	11,482	38,202	62,372	76,669	208,662
Mar-20	19,624	10,918	32,348	52,444	64,213	179,547
Apr-20	18,527	10,145	24,846	37,611	52,354	143,483
May-20	17,969	9,362	14,392	23,633	31,963	97,319
Jun-20	18,222	11,165	8,420	16,051	18,572	72,430
Jul-20	17,401	10,927	7,160	13,465	16,572	65,525
Aug-20	16,347	10,491	5,964	11,805	14,808	59,415
Sep-20	17,185	10,584	6,210	12,544	14,303	60,826
Oct-20	17,283	10,303	8,378	16,031	19,646	71,641
Nov-20	17,823	10,669	15,377	27,779	36,184	107,832
Dec-20	20,123	12,604	29,380	49,460	63,914	175,481
Rate Year 2020	220,359	129,988	225,255	382,941	482,624	1,441,167

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-G-0066
Monthly Gas Revenue Targets
($ 000's)

Revenue Targets for Rate Year ending December 2021

	SC 1	SC 2 R1	SC 2 R2	SC 3 1-4 Dwelling Units	SC 3 more than 4 Dwelling Units	TOTAL
Jan-21	21,614	12,615	40,436	69,555	87,453	231,673
Feb-21	21,499	12,439	43,241	70,309	88,634	236,122
Mar-21	21,224	11,950	36,436	58,749	74,080	202,439
Apr-21	19,969	10,974	27,392	40,996	59,367	158,698
May-21	19,330	10,074	15,825	25,813	36,092	107,134
Jun-21	19,719	12,465	9,492	17,880	21,744	81,300
Jul-21	18,790	12,158	8,086	14,912	19,411	73,357
Aug-21	17,646	11,664	6,723	13,015	17,326	66,374
Sep-21	18,547	11,741	6,972	13,827	16,693	67,780
Oct-21	18,663	11,418	9,499	17,927	23,061	80,568
Nov-21	19,250	11,793	17,582	31,515	42,479	122,619
Dec-21	21,575	13,362	32,519	54,441	71,977	193,874
Rate Year 2021	237,826	142,653	254,203	428,939	558,317	1,621,938

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-G-0066
Monthly Gas Revenue Targets
($ 000's)

Revenue Targets for Rate Year ending December 2022

	SC 1	SC 2 R1	SC 2 R2	SC 3 1-4 Dwelling Units	SC 3 more than 4 Dwelling Units	TOTAL
Jan-22	22,870	13,110	44,112	75,354	96,471	251,917
Feb-22	22,870	13,182	47,956	77,607	99,663	261,278
Mar-22	22,718	13,019	41,330	66,608	85,531	229,206
Apr-22	21,436	12,206	31,290	46,901	69,205	181,038
May-22	20,717	11,216	17,876	28,958	41,900	120,667
Jun-22	21,011	13,550	10,439	19,524	24,634	89,158
Jul-22	20,012	13,283	8,945	16,287	22,151	80,678
Aug-22	18,747	12,622	7,353	14,092	19,587	72,401
Sep-22	19,730	12,764	7,668	15,025	18,937	74,124
Oct-22	19,872	12,382	10,530	19,677	26,234	88,695
Nov-22	20,506	12,762	19,652	35,005	48,386	136,311
Dec-22	22,907	14,120	35,843	59,726	80,177	212,773
Rate Year 2022	253,396	154,216	282,994	474,764	632,876	1,798,246

Appendix 6 -- Safety and Reliability Surcharge Mechanism

Consolidated Edison Company of New York, Inc.
Case 19-G-0066
Safety and Reliability Surcharge Mechanism (SRSM)

The Safety and Reliability Surcharge Mechanism ("SRSM") allows Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company") to: 1.) recover the carrying costs on incremental capital expenditures and O&M expenses associated with the replacement of Leak Prone Pipe ("LPP") above the levels established under the Gas Rate Plan; and 2.) recover incremental O&M expenses associated with lowering the Company's leak backlog.

A. LPP Replacement

The SRSM allows Con Edison to recover the carrying costs on incremental capital expenditures and O&M expenses associated with the replacement of LPP above the levels established under the Gas Rate Plan, subject to the conditions set forth below:

1.) Both the actual costs of LPP replacement incurred by the Company in total across all regions and the actual LPP footage replaced by the Company under the Main Replacement Program[1] as of the end of the applicable Rate Year must exceed the targets[2] shown below in Table 1:

Table 1	2020 (RY1)	2021 (RY2)	2022 (RY3)
Miles of Main Replaced	85	85	85
Capital Spending (000's)	$425,427	$435,607	$449,365

2.) Incremental actual costs are recoverable up to the capital and O&M caps set forth below in Table 2:

Table 2			
Capital Cost Cap Per Mile by Area	**2020 (RY1)**	**2021 (RY2)**	**2022 (RY3)**
Manhattan	$11,069,714	$11,372,182	$11,591,545
Queens	$5,970,563	$6,125,361	$6,246,704
Bronx	$4,267,136	$4,348,426	$4,437,013
Westchester	$3,327,158	$3,401,209	$3,466,934
O&M Cost Cap Per Mile by Area	**2020 (RY1)**	**2021 (RY2)**	**2022 (RY3)**
Manhattan	$267,476	$265,646	$264,501
Queens	$115,843	$115,028	$114,522
Bronx	$55,715	$55,336	$55,099
Westchester	$49,241	$48,910	$48,705

[1] This covers the following programs listed under Exhibit GIOP-1: Replace Corroded Steel Mains, Replace Cast Iron Mains and Services Associated with Main Work.

[2] The Company must also meet the overall targets in each rate year (*i.e.*, 85 in RY1, 85 in RY2 and 85 in RY3 and a cumulative three year target of 270) to be eligible for recovery under this mechanism.

3.) Recovery of the incremental costs is to begin no earlier than March 1st of each year following the end of the applicable Rate Year (*e.g.*, recovery of incremental O&M costs incurred in RY1 will begin on March 1, 2021 and be recovered over a 12 month period through February 2022 while the carrying charges associated with the incremental capital costs will be recovered until base rates are reset in the next rate case). Carrying charges on incremental capital associated with the new mains will be calculated based on a book life of 85 years, a tax life of 20 years, and an estimated property tax factor of 3%.

Page 3 of this Appendix provides several examples that demonstrate how the LPP portion of the SRSM will work under various potential scenarios. Page 4 of this appendix provides an example of the capital carrying costs calculation.

B. Leak Backlog

The SRSM will also allow the Company to recover incremental O&M expenses associated with lowering the Company's leak backlog, subject to the conditions set forth below:

1.) The actual leak backlog level the Company achieves is below the applicable Rate Year target (as described in the Gas Performance Measures Appendix 17) and the Company exceeds the annual rate allowance for leak repairs as set forth in Table 3:

Table 3	2020 (RY1)	2021 (RY2)	2022 (RY3)
O&M Spending (000's)	$51,634	$49,987	$49,092

2.) Recovery will be capped at the lesser of the total incremental cost or $5,100 per actual leak repaired below the applicable target.

Recovery of the incremental costs is to begin no earlier than March 1st, of each year following the end of the applicable Rate Year (*e.g.,* recovery of incremental O&M costs incurred in RY1 will begin on March 1, 2021 and be recovered over a 12 month period through February 2022).

Consolidated Edison Company of New York, Inc.
Gas Case 19-G-0066
Safety and Reliability Surcharge Mechanism Incremental Cost Example
($000's)

LLP Example for 2020 (RY1)

Targets	**Manhattan**	**Queens**	**Bronx**	**Westchester**	**Total**
Target Mileage	11	14	18	42	85
Target Capital	$ 127,034,594	$ 83,797,466	$ 74,929,893	$ 139,665,281	$ 425,427,235
$Capital/Mile Cap	$ 11,069,714	$ 5,970,563	$ 4,267,136	$ 3,327,307	
Target O&M	$ 3,069,651	$ 1,625,947	$ 978,386	$ 2,067,016	$ 7,741,000
$O&M/M Cap	$ 267,487	$ 115,849	$ 55,717	$ 49,243	
LPP MAC Factor	2%	2%	1%	1%	

Scenario 1	**Manhattan**	**Queens**	**Bronx**	**Westchester**	**Total**
Actual Mileage	10	13	16	45	84
Actual Capital	$ 133,000,000	$ 77,000,000	$ 76,000,000	$ 143,000,000	$ 429,000,000
Actual Capital/Mile	$ 12,695,843	$ 5,907,126	$ 4,884,394	$ 3,179,510	
Recoverable Capital	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Scenario 1 Result: No additional recovery, total target miles not exceeded.

Scenario 2	**Manhattan**	**Queens**	**Bronx**	**Westchester**	**Total**
Actual Mileage	11	16	19	42	88
Actual Capital	$ 129,000,000	$ 82,000,000	$ 73,000,000	$ 139,000,000	$ 423,000,000
Actual Capital/Mile	$ 11,240,978	$ 5,113,781	$ 3,933,240	$ 3,311,457	
Recoverable Capital	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Scenario 2 Result: No additional recovery, total target capital costs not exceeded.

Scenario 3	**Manhattan**	**Queens**	**Bronx**	**Westchester**	**Total**
Actual Mileage	11	12	19	47	89
Actual Capital	$ 125,000,000	$ 80,000,000	$ 78,000,000	$ 144,000,000	$ 427,000,000
Actual Capital/Mile	$ 10,892,421	$ 6,647,222	$ 4,202,640	$ 3,065,429	
Incremental Miles			1	5	4
Incremental Cost Spent over Target Capital (A)			**3,070,107**	**4,334,719**	**1,572,765**
Incremental Cost/Mile			3,070,107	866,944	
Lessor of Actual or Cap Cost/Mile			3,070,107	866,944	
Incremental Cost at Cost/Mile Cap (B)			**3,070,107**	**4,334,719**	**7,404,826**
Recoverable O&M (capital x O&M factor)			40,087	64,153	104,240
Recoverable Capital (the lesser of A or B total)					**$ 1,572,765**

Scenario 3 Result: Company recovers carrying costs on $1.573M of incremental capital plus $104K of incremental O&M.

Scenario 4	**Manhattan**	**Queens**	**Bronx**	**Westchester**	**Total**
Actual Mileage	11	15	20	44	90
Actual Capital	$ 125,000,000	$ 90,800,000	$ 82,500,000	$ 145,000,000	$ 443,300,000
Actual Capital/Mile	$ 10,892,421	$ 6,039,200	$ 4,217,843	$ 3,297,292	
Incremental Miles	0	1	2	2	5
Incremental Cost Spent over Target Capital (A)		7,002,534	7,570,107	5,334,719	17,872,765
Incremental Cost/Mile		7,002,534	3,785,053	2,667,359	
Lessor of Actual or Cap Cost/Mile		5,970,563	3,785,053	2,667,359	
Incremental Cost at Cost/Mile Cap (B)		**5,970,563**	**7,570,107**	**5,334,719**	**18,875,388**
Recoverable O&M (capital x O&M factor)		115,849	98,846	78,953	293,647
Recoverable Capital (the lesser of A or B)		**$ 5,970,563**	**$ 7,570,107**	**$ 5,334,719**	**$ 18,875,388**

Scenario 4 Result: Company recovers carrying costs on $18.875M of incremental capital plus $294K of incremental O&M.

Consolidated Edison Company of New York, Inc.

Gas Case 19-G-0066

Example of Revenue Requirement Calculation for Safety and Reliability Surcharge Mechanism

	2020	2021	2022
Assumed incremental capital amount spent in RY1, meets all requirements for recovery.		$ 12,904,826	
Plant in Service			
Beginning of Period	$ -	$ 12,764,421	$ 12,483,612
Addition	12,904,826	-	-
Depreciation	(140,405)	(280,809)	(280,809)
End of Period	12,764,421	12,483,612	12,202,803
Average Net Plant in Service	6,382,211	12,624,017	12,343,208
Average Deferred FIT and SIT Balance*	(22,832)	(152,883)	(357,931)
Average Net Rate Base	6,359,378	12,471,133	11,985,276
Pre Tax Rate of Return	8.10%	8.10%	8.10%
Earnings Base	517,159	1,022,940	1,000,186
Earnings - Expenses			
Income Tax - Removal Cost	18,335	36,670	36,670
Book Depreciation**	140,405	280,809	280,809
Property Taxes***	193,572	387,145	387,145
Total Earnings Effects	869,471	1,727,564	1,704,810
Gross-Up Factor	0.97	0.97	0.97
Revenue Requirement	$ 842,604	$ 1,674,182	$ 1,652,131
Depreciation - Tax	241,965	1,173,565	2,035,220
Depreciation - Book Excluding COR	75,913	227,738	377,911
Deferred Tax - FIT	34,871	198,624	348,035
Deferred Tax - SIT	10,793	61,479	107,725
Average Deferred Taxes	22,832	152,883	357,931

2020+2021 to be recovered March 2021 to February 2022 1/12th per month	$ 2,516,786	
2022 to be recovered March 2022 to February 2023**** 1/12 per month		$ 1,652,131

Notes:

*Assumed tax life of 20 years

**Assumed book life of 85 years

***Assumed estimated property tax factor of 3%

****Surcharge recovery will end in December 2022 if new rates go into effect January 2023.

Consolidated Edison Company of New York, Inc
Calculation of Five-Year Average Line Loss Factor, Factor of Adjustment, and Incentive/Penalty bands
Based on 5 Year Period: TME August 2015 to TME August 2019

		Aug-19	Aug-18	Aug-17	Aug-16	Aug-15
	Citygate Receipts					
1.	Total Pipeline Receipts	358,491,090	364,725,887	372,064,693	379,071,541	391,451,202
2.	LNG Withdrawals	123,717	277,614	69,916	297,617	490,659
3.	Total Receipts from NY Facilities	13,870,174	7,789,058	4,337,458	4,489,819	3,664,374
4.	**Total Receipts (Sum of Lines 1-3)**	372,484,981	372,792,559	376,472,067	383,858,977	395,606,235
	Deliveries to Customers					
5.	Retail Sales and Transportation Deliveries	195,407,558	191,602,913	178,112,686	163,365,941	180,059,780
5.1	Inactive Accounts	TBD				
6.	Deliveries to Generation	145,129,669	148,880,771	159,859,973	181,928,065	168,653,886
7.	Gas Used for Company Purposes & CNG	102,087	163,893	131,376	117,469	138,392
8.	LNG Injections	490,860	389,287	506,981	325,065	1,154,060
9.	Total Heater & Compressor Consumption	331,517	354,831	346,921	330,074	477,636
10.	Total Deliveries to NY Facilities	24,610,410	25,027,660	31,992,256	33,369,660	37,960,412
11.	**Total Deliveries (Sum of Lines 5-10)**	366,072,100	366,419,355	370,950,193	379,436,274	388,444,166
12.	**Losses (Line 4 - Line 11)**	6,412,881	6,373,204	5,521,874	4,422,703	7,162,069
	Contribution to system line loss from Generation at 0.5%					
13.	**(Line 6 * 0.005)**	725,648	744,404	799,300	909,640	843,269
13.1	**NYF Exchange 0.5%**	53,735	50,442			
14.	**Adjusted Line Loss (Line 12 - Line 13 - Line 13.1)**	5,633,497	5,578,358	4,722,574	3,513,062	6,318,800
15.	**Citygate Receipts adjusted for Generation (Line 4 - Line 6 - Line 13)**	226,629,663	223,167,384	215,812,794	201,021,272	226,109,080
16.	***Annual Line Loss Factor (LLF) (Line 14 / Line 15)***	2.4858%	2.4996%	2.1883%	1.7476%	2.7946%

5-Year Statistics (Aug 15 - Aug 19)

17.	**Five-Year average Line Loss Factor (LLF) (Average of Line 16)**	**2.343%**
	Std Deviation	**0.396%**
	2 Std Deviations	**0.792%**
18.	**Standard Deviation (SD) of Line 16**	**0.396%**
	LLF% Target	**2.343%**
19.	**Upper Deadband Limit (Line 17 + (2* Line 18))**	**3.135%**
20.	**Lower Deadband Limit (Line 17 - (2* Line 18))**	**1.551%**
21.	**Factor of Adjustment 1/(1-Line 17)**	**1.0240**
22	**Maximuxm Upper Limit (Line 17 + (4* Line 18))**	**3.927%**
23	**Maximum Lower Limit (Line 17 - (4* Line 18))**	**0.7592%**
24	**Total Receipts W/O Gen (Line 4 - Line 6 - Line 13)**	**226,629,663**
25	**Total Deliveries W/O Gen (Line 11 - Line 6)**	**220,942,431**

DETERMINE LLF% TARGET & DEAD BAND
Basis: Target & Dead Band are calculated from 5 years of historical data
Dead Band is equal to +/- 2 standard deviations

Upper Deadband FOA 1/(1-Line 19)	**1.0324**
Lower Deadband FOA 1/(1-Line 20)	**1.0158**
Maximum Factor of Adjustment 1/(1-Line 22)	**1.0409**
Minimum Factor of Adjustment 1/(1-Line 23)	**1.0076**

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-E-0065
Electric True Up Targets
($ 000's)

	Twelve Months Ending December 31,				
Revenue True-ups	2020	RY2 Change	2021	RY3 Change	2022
Proceeds from Sales of TCCs	$ 75,000	$ -	$ 75,000	$ -	$ 75,000
Transmission Service Charges	5,000	-	5,000	-	5,000
Transmission of Energy	7,000	-	7,000	-	7,000
Environmental Allowances (SO2)*	-	-	-	-	-
Expense True-ups					
Municipal Infrastructure Support					
Interference - excl. Company labor (80/20 True up)	136,315	13,626	149,940	9,584	159,525
Property Tax Expense (90/10 True up)					
Total Property Taxes	1,608,915	110,622	1,719,537	105,028	1,824,565
Employee Pensions	60,291	-	60,291	-	60,291
Other Post Employment Benefits	(4,219)	-	(4,219)	-	(4,219)
Pension / OPEB Expense	56,072	-	56,072	-	56,072
Storm Reserve	22,463	494	22,957	505	23,462
Management Variable Pay (Net of Capitalized)	28,982	971	29,953	1,003	30,956
ERRP - Major Maintenance	8,798	-	8,798	-	8,798
NEIL Dividends, Congestion Tolling, and NYC Local Law 97*	-	-	-	-	-
Prevailing Wage Law*	16,934	373	17,307	380	17,687
Customer Service System ("CSS")	3,814	(967)	2,847	2,977	5,824
Taxes on Health Insurance	-	-	-	10,111	10,111
Rate Base True-ups					
BQDM	27,618	3,189	30,807	(1,483)	29,324
REV Demo Projects	46,196	4,268	50,464	(1,584)	48,880
Energy Efficiency - unamortized from prior case	60,488	(6,367)	54,121	(6,367)	47,754
Energy Efficiency: Non-LMI	-	36,713	36,713	94,607	131,320
Energy Efficiency: LMI	-	6,015	6,015	12,990	19,005
SmartCharge (off-peak EV charging)	2,223	1,842	4,066	2,971	7,037
Non-Wire Alternatives (Plymouth/Water St. and Columbus)	17,840	15,515	33,355	5,466	38,821
Site Investigation and Remediation	13,743	14,498	28,241	8,903	37,143
Interest True-ups (page 2)					
Average Variable Rate	3.02%	0.00%	3.02%	0.00%	3.02%
Variable Rate Debt Cost	23,512	(251)	23,262	(237)	23,024
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. The Company will defer for future recovery incremental costs associated with Congestion Tolling, NYC Local Law 97, and Prevailing Wage Law. For the Prevailing Wage Law, this appendix shows amounts currently reflected in base rates for Janitorial, Guard Service, and Landscaping wages and benefits.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

Cases 19-E-0065 / 19-G-0066

For The Twelve Months Ending December 31, 2020, December 31, 2021, and December 31, 2022

Variable Rate Debt

Bond	Maturity Date	Amount Outstanding	RY1 Effective Cost of Money	RY1 Effective Annual Cost	RY2 Effective Cost of Money	RY2 Effective Annual Cost	RY3 Effective Cost of Money	RY3 Effective Annual Cost
2004 Series C	11/01/39	$ 99,000,000	2.71%	$ 2,680,269	2.71%	$ 2,680,269	2.71%	$ 2,680,269
2005 Series A	05/01/39	126,300,000	2.69%	3,401,177	2.69%	3,401,177	2.69%	3,401,177
2010 Series A	06/01/36	224,600,000	2.73%	6,127,240	2.73%	6,127,240	2.73%	6,127,240
2018 Series C / 2021 Series [B]*	6/25/21 / 7/01/24	640,000,000	3.24%	20,704,886	3.24%	20,704,886	3.24%	20,704,886
		$ 1,089,900,000	3.02%	$ 32,913,572	3.02%	$ 32,913,572	3.02%	$ 32,913,572

	RY1	RY2	RY3
Total costs	**$ 32,913,572**	**$ 32,913,572**	**$ 32,913,572**
Allocation to Electric*	71.4%	70.7%	70.0%
Electric Target	**$ 23,512,290**	**$ 23,261,590**	**$ 23,024,100**
Allocation to Gas*	23.5%	24.5%	25.4%
Gas Target	**$ 7,726,230**	**$ 8,055,830**	**$ 8,362,170**
Allocation to Steam*	5.1%	4.8%	4.6%
Steam Target	**$ 1,675,050**	**$ 1,596,150**	**$ 1,527,300**

* Actual series designation to be determined at a later date

** 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)	$ 25,160,287	$ 26,122,436	$ 27,021,346
Net Utility Plant (Gas)	8,267,768	9,046,588	9,813,937
Net Utility Plant (Steam)	1,792,456	1,792,456	1,792,456
	$ 35,220,511	$ 36,961,480	$ 38,627,739
Elec Allocation	71.4%	70.7%	70.0%
Gas Allocation	23.5%	24.5%	25.4%
Steam Allocation	5.1%	4.8%	4.6%
	100.0%	100.0%	100.0%

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-E-0065
Electric Average Net Plant Target Excluding AMI
Average Twelve Months Ending December 31, 2020, December 31, 2021, and December 31, 2022
($ 000's)

Target

	Book Cost of Plant	Accumulated Depreciation	Depreciation Removal Cost	Average Net Plant Excluding Removal Cost
RY1	$ 32,778,043	$ (8,189,515)	$ (16,040)	$ 24,572,488
RY2	34,313,553	(8,930,885)	(16,992)	25,365,677
RY3	35,864,791	(9,649,258)	(18,194)	26,197,340

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-E-0065
Electric - Planned Capital Expenditure
($ 000's)

	Rate Year 1	Rate Year 2	Rate Year 3
Electric*	$ 1,821,576	$ 1,875,660	$ 1,802,426
AMI	250,568	178,150	15,428
CSS	63,343	83,498	99,227
Total	$ 2,135,487	$ 2,137,308	$ 1,917,081

Notes:
Provided for informational purposes only.

* The Company 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.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-E-0065
Carrying Charge Rates
For The Twelve Months Ending December 31, 2020, December 31, 2021, and December 31, 2022

RY 1

	Electric Plant	AMI Plant
Pre Tax Overall Rate of Return	8.100%	8.100%
Composite Book Depreciation Rate	3.382%	7.281%
Total Carrying Charge Rate	11.482%	15.381%

RY 2

	Electric Plant	AMI Plant
Pre Tax Overall Rate of Return	8.100%	8.100%
Composite Book Depreciation Rate	3.400%	6.917%
Total Carrying Charge Rate	11.500%	15.017%

RY 3

	Electric Plant	AMI Plant
Pre Tax Overall Rate of Return	8.100%	8.100%
Composite Book Depreciation Rate	3.402%	6.697%
Total Carrying Charge Rate	11.502%	14.797%

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-G-0066
Gas True Up Targets
For The Twelve Months Ending December 31, 2020, December 31, 2021, and December 31, 2022
($ 000's)

	Twelve Months Ending December 31,				
	2020	RY2 Change	2021	RY3 Change	2022
Revenue True-Ups					
New York Facilities - Revenues	$ 6,936	$ -	$ 6,936	$ -	$ 6,936
New York Facilities - Expenses	5,061	111	5,172	114	5,286
New York Facilities - Revenues net of Expenses	1,875	(111)	1,764	(114)	1,650
Expense True-ups					
Municipal Infrastructure Support					
Interference - excl. Company labor (80/20 True up)	29,638	1,685	31,323	1,581	32,904
Property Tax Expense (90/10 True up)	346,370	45,530	391,900	45,112	437,012
Employee Pensions	12,392	-	12,392	-	12,392
Other Post Employment Benefits	(867)	-	(867)	-	(867)
Pension / OPEB Expense	11,525	-	11,525	-	11,525
Management Variable Pay (Net of Capitalized)	7,224	242	7,466	250	7,716
Congestion Tolling, NYC Local Law 97, and Pipeline Safety Act of 2011/Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2019 *	-	-	-	-	-
Prevailing Wage Law*	2,555	56	2,611	58	2,669
Gas Service Lines **	7,234	(6,515)	718	-	718
Customer Service System ("CSS")	784	(199)	585	612	1,197
Research and Development (Internal Programs)	1,563	34	1,597	35	1,633
Taxes on Health Insurance	-	-	-	2,078	2,078
Rate Base True-ups					
Energy Efficiency: Non-LMI	8,154	18,734	26,888	20,983	47,872
Energy Efficiency: LMI	-	741	741	1,440	2,181
Site Investigation and Remediation	5,526	2,379	7,905	1,229	9,135
Interest True-ups (page 2)					
Average Variable Rate	3.02%	0.00%	3.02%	0.00%	3.02%
Variable Rate Debt Cost	7,726	330	8,056	306	8,362

Note
* The Company will defer for future recovery incremental costs associated with Congestion Tolling, NYC Local Law 97, Pipeline Safety Act of 2011/Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2019, and Prevailing Wage Law. For the Prevailing Wage Law, this appendix shows amounts currently reflected in base rates for Janitorial, Guard Service, and Landscaping wages and benefits.

** If the Company incurs additional costs above these included in rates as a result of the Commission not approving the Company's petition in Case 15-G-0244, such actual costs would be recovered through the MRA. Recovered costs for base O&M cost plus MRA recovery will be capped at $108.46 million cumulative total over RY1-RY3 (i.e. base rate total of $8.67 million plus MRA cap of $99.79 million).

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

Cases 19-E-0065 / 19-G-0066

For The Twelve Months Ending December 31, 2020, December 31, 2021, and December 31, 2022

Variable Rate Debt

Bond	Maturity Date	Amount Outstanding	RY1 Effective Cost of Money	RY1 Effective Annual Cost	RY2 Effective Cost of Money	RY2 Effective Annual Cost	RY3 Effective Cost of Money	RY3 Effective Annual Cost
2004 Series C	11/01/39	$ 99,000,000	2.71%	$ 2,680,269	2.71%	$ 2,680,269	2.71%	$ 2,680,269
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2010 Series A	06/01/36	224,600,000	2.73%	6,127,240	2.73%	6,127,240	2.73%	6,127,240
2018 Series C / 2021 Series [B]*	6/25/21 / 7/01/24	640,000,000	3.24%	20,704,886	3.24%	20,704,886	3.24%	20,704,886
		$ 1,089,900,000	3.02%	$ 32,913,572	3.02%	$ 32,913,572	3.02%	$ 32,913,572

	RY1	RY2	RY3
Total costs	**$ 32,913,572**	**$ 32,913,572**	**$ 32,913,572**
Allocation to Electric*	71.4%	70.7%	70.0%
Electric Target	**$ 23,512,290**	**$ 23,261,590**	**$ 23,024,100**
Allocation to Gas*	23.5%	24.5%	25.4%
Gas Target	**$ 7,726,230**	**$ 8,055,830**	**$ 8,362,170**
Allocation to Steam*	5.1%	4.8%	4.6%
Steam Target	**$ 1,675,050**	**$ 1,596,150**	**$ 1,527,300**

* Actual series designation to be determined at a later date

** 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)	$ 25,160,287	$ 26,122,436	$ 27,021,346
Net Utility Plant (Gas)	8,267,768	9,046,588	9,813,937
Net Utility Plant (Steam)	1,792,456	1,792,456	1,792,456
	$ 35,220,511	$ 36,961,480	$ 38,627,739
Elec Allocation	71.4%	70.7%	70.0%
Gas Allocation	23.5%	24.5%	25.4%
Steam Allocation	5.1%	4.8%	4.6%
	100.0%	100.0%	100.0%

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-G-0066
Gas Average Net Plant Target Excluding AMI
Average Twelve Months Ending December 31, 2020, December 31, 2021, and December 31, 2022
($ 000's)

Target

	Book Cost of Plant	Accumulated Depreciation	Depreciation Removal Cost	Average Net Plant Excluding Removal Cost
RY1	$ 9,982,308	$ (1,856,163)	$ (3,073)	$ 8,123,072
RY2	10,916,310	(2,052,380)	(3,166)	8,860,764
RY3	11,869,603	(2,266,820)	(3,034)	9,599,749

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-G-0066
Gas - Planned Capital Expenditure
($ 000's)

	Rate Year 1	Rate Year 2	Rate Year 3
Gas*	$ 989,522	$ 985,386	$ 964,536
AMI	70,896	52,720	4,457
CSS	12,974	17,102	20,324
Total	$ 1,073,392	$ 1,055,208	$ 989,317

Notes:
Provided for informational purposes only.

* The Company has the flexibility over the term of the Gas Rate Plan to modify the list, priority, nature and scope of its capital programs and projects.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-G-0066
Carrying Charge Rates
For The Twelve Months Ending December 31, 2020, December 31, 2021, and December 31, 2022

RY 1

	Gas Plant	AMI Plant
Pre Tax Overall Rate of Return	8.100%	8.100%
Composite Book Depreciation Rate	2.867%	6.931%
Total Carrying Charge Rate	10.967%	15.031%

RY 2

	Gas Plant	AMI Plant
Pre Tax Overall Rate of Return	8.100%	8.100%
Composite Book Depreciation Rate	2.887%	6.616%
Total Carrying Charge Rate	10.987%	14.716%

RY 3

	Gas Plant	AMI Plant
Pre Tax Overall Rate of Return	8.100%	8.100%
Composite Book Depreciation Rate	2.868%	6.315%
Total Carrying Charge Rate	10.968%	14.415%

Consolidated Edison Company of New York, Inc.
Case 19-E-0065
Electric Average AMI Net Plant Target
$ 000's

	Target			
	BOOK COST OF PLANT	**ACCUMULATED DEPRECIATION**	**DEPRECIATION REMOVAL COST**	**AVERAGE NET PLANT EXCLUDING REMOVAL COST**
RY1	$ 638,033	$ (66,274)	$ -	$ 571,759
RY2	858,767	(118,999)	-	739,768
RY3	988,004	(182,192)	-	805,812

Consolidated Edison Company of New York, Inc.
Case 19-G-0066
Gas Average AMI Net Plant Target
$ 000's

	Target			
	BOOK COST OF PLANT	**ACCRUED DEPRECIATION**	**DEPRECIATION REMOVAL COST**	**AVERAGE NET PLANT EXCLUDING REMOVAL COST**
RY1	$ 154,783	$ (13,160)	$ -	$ 141,623
RY2	208,122	(25,465)	-	182,657
RY3	251,420	(40,265)	-	211,154

Consolidated Edison Company of New York, Inc.
Case 19-E-0065 & Case 19-E-0066
Carrying Charge Rates

RY 1

	Electric AMI Plant	Gas AMI Plant
Pre Tax Overall Rate of Return	8.100%	8.100%
Composite Book Depreciation Rate	7.281%	6.931%
Total Carrying Charge Rate	15.381%	15.031%

RY 2

	Electric AMI Plant	Gas AMI Plant
Pre Tax Overall Rate of Return	8.100%	8.100%
Composite Book Depreciation Rate	6.917%	6.616%
Total Carrying Charge Rate	15.017%	14.716%

RY 3

	Electric AMI Plant	Gas AMI Plant
Pre Tax Overall Rate of Return	8.100%	8.100%
Composite Book Depreciation Rate	6.697%	6.315%
Total Carrying Charge Rate	14.797%	14.415%

Consolidated Edison Company of New York, Inc.
Case 19-E-0065 & Case 19-G-0066
Examples Of Electric and Gas AMI Single Category Net Plant In Service Reconciliation
$ 000's

RY1	Net Plant In Service - Actual			Cap Tracking	
	Electric	Gas	Total	Cap @ $1.285B	Under/(Over) Cap
Beg Balance	$ 501,494	$ 128,735	$ 630,229	$ 1,285,000	$ 654,771
Jan-20	501,657	128,769	630,425	1,285,000	654,575
Feb-20	501,819	128,802	630,621	1,285,000	654,379
Mar-20	614,416	161,056	775,472	1,285,000	509,528
Apr-20	614,579	161,090	775,668	1,285,000	509,332
May-20	614,741	161,123	775,865	1,285,000	509,135
Jun-20	614,904	161,157	776,061	1,285,000	508,939
Jul-20	615,067	161,190	776,257	1,285,000	508,743
Aug-20	615,229	161,223	776,453	1,285,000	508,547
Sep-20	740,717	196,704	937,422	1,285,000	347,578
Oct-20	740,880	196,738	937,618	1,285,000	347,382
Nov-20	741,043	196,771	937,814	1,285,000	347,186
Dec-20	741,205	196,804	938,010	1,285,000	346,990
Average	628,033	164,783	792,816		

RY2	Net Plant In Service - Actual			Cap Tracking	
	Electric	Gas	Total	Cap @ $1.285B	Under/(Over) Cap
Dec-20	$ 741,205	$ 196,804	$ 938,010	$ 1,285,000	$ 346,990
Jan-21	761,368	184,838	946,206	1,285,000	338,794
Feb-21	761,531	184,871	946,402	1,285,000	338,598
Mar-21	865,759	207,782	1,073,541	1,285,000	211,459
Apr-21	865,922	207,816	1,073,737	1,285,000	211,263
May-21	866,084	207,849	1,073,933	1,285,000	211,067
Jun-21	866,247	207,883	1,074,130	1,285,000	210,870
Jul-21	866,410	207,916	1,074,326	1,285,000	210,674
Aug-21	866,572	207,949	1,074,522	1,285,000	210,478
Sep-21	949,706	218,289	1,167,996	1,285,000	117,004
Oct-21	949,869	218,322	1,168,192	1,285,000	116,808
Nov-21	950,032	218,356	1,168,388	1,285,000	116,612
Dec-21	950,194	218,389	1,168,584	1,285,000	116,416
Average	867,933	206,622	1,074,556		

RY3	Net Plant In Service - Actual			Cap Tracking	
	Electric	Gas	Total	Cap @ $1.285B	Under/(Over) Cap
Dec-21	$ 950,194	$ 218,389	$ 1,168,584	$ 1,285,000	$ 116,416
Jan-22	965,194	217,389	1,182,584	1,285,000	102,416
Feb-22	965,194	217,389	1,182,584	1,285,000	102,416
Mar-22	1,022,744	255,764	1,278,508	1,285,000	6,492
Apr-22	1,022,744	255,764	1,278,508	1,285,000	6,492
May-22	1,022,744	255,764	1,278,508	1,285,000	6,492
Jun-22	1,022,744	255,764	1,278,508	1,285,000	6,492
Jul-22	1,022,744	255,764	1,278,508	1,285,000	6,492
Aug-22	1,022,744	255,764	1,278,508	1,285,000	6,492
Sep-22	1,030,458	257,993	1,288,451	1,285,000	(3,451)
Oct-22	1,030,458	257,993	1,288,451	1,285,000	(3,451)
Nov-22	1,030,458	257,993	1,288,451	1,285,000	(3,451)
Dec-22	1,030,458	257,993	1,288,451	1,285,000	(3,451)
Average	1,012,379	248,461	1,260,841		

Consolidated Edison Company of New York, Inc.
Case 19-E-0065
Examples Of Electric AMI Net Plant Overspend and Underspend Scenarios
(Thousands of Dollars Except Carrying Charges)

RY1	Book Cost			Depreciation Reserve			Net Plant			Carrying Charge Computed 15.38%
	Actual	PSC/Rates	Variation	Actual	PSC/Rates	Variation	Actual	PSC/Rates	Variation	
Beg Balance	$ 501,494	$ 511,494	$ (10,000)	$ 44,059	$ 44,787	$ (728)	$ 457,435	$ 466,707	$ (9,272)	
Jan-20	501,657	511,657	(10,000)	47,272	48,000	(728)	454,385	463,656	(9,272)	(118,840)
Feb-20	501,819	511,819	(10,000)	50,486	51,214	(728)	451,333	460,605	(9,272)	(118,840)
Mar-20	614,416	624,416	(10,000)	53,702	54,430	(728)	560,714	569,986	(9,272)	(118,840)
Apr-20	614,579	624,579	(10,000)	57,494	58,222	(728)	557,084	566,356	(9,272)	(118,840)
May-20	614,741	624,741	(10,000)	61,288	62,016	(728)	553,454	562,725	(9,272)	(118,840)
Jun-20	614,904	624,904	(10,000)	65,083	65,811	(728)	549,821	559,093	(9,272)	(118,840)
Jul-20	615,067	625,067	(10,000)	68,879	69,607	(728)	546,187	555,459	(9,272)	(118,840)
Aug-20	615,229	625,229	(10,000)	72,677	73,405	(728)	542,552	551,824	(9,272)	(118,840)
Sep-20	740,717	750,717	(10,000)	76,476	77,204	(728)	664,241	673,513	(9,272)	(118,840)
Oct-20	740,880	750,880	(10,000)	80,915	81,643	(728)	659,965	669,237	(9,272)	(118,840)
Nov-20	741,043	751,043	(10,000)	85,355	86,083	(728)	655,688	664,960	(9,272)	(118,840)
Dec-20	741,205	751,205	(10,000)	89,796	90,525	(728)	651,409	660,681	(9,272)	(118,840)
Average	628,033	638,033	(10,000)	65,546	66,274	(728)	562,487	571,759	(9,272)	

RY2	Book Cost			Depreciation Reserve			Net Plant			Carrying Charge Computed 15.02%
	Actual	PSC/Rates	Variation	Actual	PSC/Rates	Variation	Actual	PSC/Rates	Variation	
Dec-20	$ 741,205	$ 751,205	$ (10,000)	$ 89,796	$ 90,525	$ (728)	$ 651,409	$ 660,681	$ (9,272)	
Jan-21	761,368	751,368	10,000	95,659	94,967	692	665,709	656,401	9,308	116,485
Feb-21	761,531	751,531	10,000	100,103	99,412	692	661,427	652,119	9,308	116,485
Mar-21	865,759	855,759	10,000	104,549	103,858	692	761,210	751,901	9,308	116,485
Apr-21	865,922	855,922	10,000	109,487	108,796	692	756,434	747,126	9,308	116,485
May-21	866,084	856,084	10,000	114,427	113,736	692	751,657	742,349	9,308	116,485
Jun-21	866,247	856,247	10,000	119,368	118,677	692	746,879	737,570	9,308	116,485
Jul-21	866,410	856,410	10,000	124,311	123,619	692	742,099	732,790	9,308	116,485
Aug-21	866,572	856,572	10,000	129,255	128,563	692	737,317	728,009	9,308	116,485
Sep-21	949,706	939,706	10,000	134,200	133,509	692	815,506	806,198	9,308	116,485
Oct-21	949,869	939,869	10,000	139,493	138,801	692	810,376	801,068	9,308	116,485
Nov-21	950,032	940,032	10,000	144,787	144,095	692	805,245	795,937	9,308	116,485
Dec-21	950,194	940,194	10,000	150,082	149,391	692	800,112	790,804	9,308	116,485
Average	867,933	858,767	9,167	119,632	118,999	633	748,302	739,768	8,534	

RY3	Book Cost			Depreciation Reserve			Net Plant			Carrying Charge Computed 14.80%
	Actual	PSC/Rates	Variation	Actual	PSC/Rates	Variation	Actual	PSC/Rates	Variation	
Dec-21	$ 950,194	$ 940,194	$ 10,000	$ 150,082	$ 149,391	$ 692	$ 800,112	$ 790,804	$ 9,308	
Jan-22	965,194	940,194	25,000	156,362	154,687	1,674	808,833	785,507	23,326	287,625
Feb-22	965,194	940,194	25,000	161,658	159,984	1,674	803,536	780,210	23,326	287,625
Mar-22	1,022,744	997,744	25,000	166,955	165,281	1,674	855,789	832,463	23,326	287,625
Apr-22	1,022,744	997,744	25,000	172,550	170,876	1,674	850,194	826,868	23,326	287,625
May-22	1,022,744	997,744	25,000	178,146	176,471	1,674	844,598	821,273	23,326	287,625
Jun-22	1,022,744	997,744	25,000	183,741	182,067	1,674	839,003	815,677	23,326	287,625
Jul-22	1,022,744	997,744	25,000	189,336	187,662	1,674	833,408	810,082	23,326	287,625
Aug-22	1,022,744	997,744	25,000	194,931	193,257	1,674	827,813	804,487	23,326	287,625
Sep-22	1,030,458	1,005,458	25,000	200,526	198,852	1,674	829,932	806,606	23,326	-
Oct-22	1,030,458	1,005,458	25,000	206,159	204,485	1,674	824,299	800,973	23,326	-
Nov-22	1,030,458	1,005,458	25,000	211,792	210,117	1,674	818,666	795,341	23,326	-
Dec-22	1,030,458	1,005,458	25,000	217,424	215,750	1,674	813,034	789,708	23,326	-
Average	1,012,379	988,004	24,375	183,826	182,192	1,633	828,554	805,812	22,742	

Cumulative Carrying Charges 2,272,737

Note:

Any credit due electric and/or gas customers or debit due the Company will be determined upon project completion, after computing net plant associated with actual aggregate expenditures for both electric and gas to the net plant associated with the overall project cap of $1.285 billions. If at the completion of the project the actual net plant amount for a service is above/below the net plant target for that service, the Company will be able to defer carrying charges associated with the net plant overage/shortage for that service to the extent the capital expenditures associated with the AMI Deployment do not exceed the overall project capital cap of $1.285 billions.

Consolidated Edison Company of New York, Inc.
Case 19-G-0066
Examples Of Gas AMI Net Plant Overspend and Underspend Scenarios
(Thousands of Dollars Except Carrying Charges)

RY1	Book Cost			Depreciation Reserve			Net Plant			Carrying Charge
	Actual	PSC/Rates	Variation	Actual	PSC/Rates	Variation	Actual	PSC/Rates	Variation	Computed 15.03%
Beg Balance	$ 128,735	$ 118,735	$ -	$ 8,265	$ 8,265	$ -	$ 120,470	$ 110,470	$ 10,000	
Jan-20	128,769	118,769	10,000	9,674	8,981	693	119,094	109,787	9,307	116,574
Feb-20	128,802	118,802	10,000	10,391	9,698	693	118,411	109,104	9,307	116,574
Mar-20	161,056	151,056	10,000	11,108	10,415	693	149,949	140,642	9,307	116,574
Apr-20	161,090	151,090	10,000	11,981	11,288	693	149,109	139,802	9,307	116,574
May-20	161,123	151,123	10,000	12,854	12,161	693	148,269	138,962	9,307	116,574
Jun-20	161,157	151,157	10,000	13,728	13,035	693	147,428	138,121	9,307	116,574
Jul-20	161,190	151,190	10,000	14,602	13,909	693	146,588	137,281	9,307	116,574
Aug-20	161,223	151,223	10,000	15,477	14,784	693	145,747	136,440	9,307	116,574
Sep-20	196,704	186,704	10,000	16,351	15,658	693	180,353	171,046	9,307	116,574
Oct-20	196,738	186,738	10,000	17,398	16,705	693	179,340	170,033	9,307	116,574
Nov-20	196,771	186,771	10,000	18,444	17,751	693	178,327	169,020	9,307	116,574
Dec-20	196,804	186,804	10,000	19,491	18,798	693	177,313	168,006	9,307	116,574
Average	164,783	154,783	9,583	13,824	13,160	664	150,959	141,623	9,336	

RY2	Book Cost			Depreciation Reserve			Net Plant			Carrying Charge
	Actual	PSC/Rates	Variation	Actual	PSC/Rates	Variation	Actual	PSC/Rates	Variation	Computed 14.72%
Dec-20	$ 196,804	$ 186,804	$ 10,000	$ 19,491	$ 18,798	$ 693	$ 177,313	$ 168,006	$ 9,307	
Jan-21	184,838	186,838	(2,000)	19,713	19,845	(132)	165,125	166,992	(1,868)	(22,904)
Feb-21	184,871	186,871	(2,000)	20,761	20,893	(132)	164,111	165,978	(1,868)	(22,904)
Mar-21	207,782	209,782	(2,000)	21,808	21,941	(132)	185,974	187,842	(1,868)	(22,904)
Apr-21	207,816	209,816	(2,000)	22,964	23,096	(132)	184,852	186,720	(1,868)	(22,904)
May-21	207,849	209,849	(2,000)	24,119	24,251	(132)	183,730	185,598	(1,868)	(22,904)
Jun-21	207,883	209,883	(2,000)	25,275	25,407	(132)	182,608	184,475	(1,868)	(22,904)
Jul-21	207,916	209,916	(2,000)	26,431	26,563	(132)	181,485	183,353	(1,868)	(22,904)
Aug-21	207,949	209,949	(2,000)	27,587	27,720	(132)	180,362	182,230	(1,868)	(22,904)
Sep-21	218,289	220,289	(2,000)	28,744	28,876	(132)	189,545	191,413	(1,868)	(22,904)
Oct-21	218,322	220,322	(2,000)	29,944	30,076	(132)	188,379	190,246	(1,868)	(22,904)
Nov-21	218,356	220,356	(2,000)	31,144	31,276	(132)	187,212	189,080	(1,868)	(22,904)
Dec-21	218,389	220,389	(2,000)	32,345	32,477	(132)	186,045	187,912	(1,868)	(22,904)
Average	206,622	208,122	(1,500)	25,367	25,465	(98)	181,255	182,657	(1,402)	

RY3	Book Cost			Depreciation Reserve			Net Plant			Carrying Charge
	Actual	PSC/Rates	Variation	Actual	PSC/Rates	Variation	Actual	PSC/Rates	Variation	Computed 14.42%
Dec-21	$ 218,389	$ 220,389	$ (2,000)	$ 32,345	$ 32,477	$ (132)	$ 186,045	$ 187,912	$ (1,868)	
Jan-22	217,389	220,389	(3,000)	33,488	33,678	(189)	183,901	186,712	(2,811)	(33,763)
Feb-22	217,389	220,389	(3,000)	34,689	34,878	(189)	182,700	185,511	(2,811)	(33,763)
Mar-22	255,764	258,764	(3,000)	35,890	36,079	(189)	219,875	222,685	(2,811)	(33,763)
Apr-22	255,764	258,764	(3,000)	37,262	37,452	(189)	218,502	221,313	(2,811)	(33,763)
May-22	255,764	258,764	(3,000)	38,635	38,824	(189)	217,129	219,940	(2,811)	(33,763)
Jun-22	255,764	258,764	(3,000)	40,008	40,197	(189)	215,757	218,567	(2,811)	(33,763)
Jul-22	255,764	258,764	(3,000)	41,380	41,570	(189)	214,384	217,195	(2,811)	(33,763)
Aug-22	255,764	258,764	(3,000)	42,753	42,942	(189)	213,011	215,822	(2,811)	(33,763)
Sep-22	257,993	260,993	(3,000)	44,126	44,315	(189)	213,867	216,678	(2,811)	-
Oct-22	257,993	260,993	(3,000)	45,509	45,698	(189)	212,484	215,295	(2,811)	-
Nov-22	257,993	260,993	(3,000)	46,892	47,081	(189)	211,101	213,912	(2,811)	-
Dec-22	257,993	260,993	(3,000)	48,275	48,464	(189)	209,718	212,529	(2,811)	-
Average	248,461	251,420	(2,958)	40,078	40,265	(187)	208,383	211,154	(2,771)	(270,101)
									Cumulative Carrying Charges	853,943

Note:

Any credit due electric and/or gas customers or debit due the Company will be determined upon project completion, after computing net plant associated with actual aggregate expenditures for both electric and gas to the net plant associated with the overall project cap of $1.285 billions. If at the completion of the project the actual net plant amount for a service is above/below the net plant target for that service, the Company will be able to defer carrying charges associated with the net plant overage/shortage for that service to the extent the capital expenditures associated with the AMI Deployment do not exceed the overall project capital cap of $1.285 billions.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

Average Service Lives, Net Salvage,
Annual Depreciation Rates and Life Tables
(Effective 1/1/2020)

PSC Acct	Company Account	Life Table No.	Average Service Life In Years	Net Salvage %	Annual Rate %	
	Electric Plant in Service					
	Production Plant - Steam Production					
311	311000 E Structures & Improvements	L0.5	90	(25)	3.23	(D)
312	312000 E Boiler Plant Equipment	L0.5	60	(25)	3.67	(D)
314	314000 E Turbogenerator	L0	40	(25)	4.10	(D)
315	315000 E Accessory Electric Eq	S0.5	45	(25)	3.84	(D)
316	316000 E Misc Power Plant Equipment	S1	50	(25)	3.46	(D)
	Production Plant - Other Production					
341	341000 E Structures & Improvements	R1	95	(10)	4.06	(D)
342	342000 E Fuel Holders	L0.5	70	(10)	3.92	(D)
344	344000 E Generators	S1	55	(10)	5.37	(D)
344	344100 E Solar Generators	h 3.50	20		5.00	(D)
345	345000 E Accessory Electric Eq	R1.5	60	(10)	5.10	(D)
348	348000 E Storage Equipment	h 4.00	15	0	6.67	(D)
	Transmission Plant					
303	303090 E Cap Sftw for Electric Tran	SQ	5	-	20.00	(B)
351	351000 E Storage Equipment	h 4.00	15	0	6.67	
352	352000 E Structures & Improvements	R2	75	(45)	1.93	
353	353000 E Station Equipment	S0	50	(35)	2.70	
354	354000 E Towers & Fixtures	R4	65	(30)	2.00	
356	356000 E O/H Conductors & Devices	R2	55	(30)	2.36	
357	Underground Conduit					
	357000 E UG Conduit	S4	70	(15)	1.64	
	357200 E U/G Conduit - Manhattan/Br	S4	70	(15)	1.64	
358	358000 E U/G Conductors & Devices	R2.5	60	(25)	2.08	

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

Average Service Lives, Net Salvage,
Annual Depreciation Rates and Life Tables
(Effective 1/1/2020)

PSC Acct	Company Account	Life Table No.	Average Service Life In Years	Net Salvage %	Annual Rate %	
	Electric Plant in Service					
	Distribution Plant					
360	360000 E Land & LR - Easements/Lshl	SQ	50	-	2.00	
361	361000 E Structures & Improvements	R2	55	(50)	2.73	
362	362000 E Station Equipment	R1.5	50	(40)	2.80	
	362010 E Station Equipment BQDM DC Link	SQ	10		10.00	
363	363000 E Energy Storage Equipment	h 4.00	15		6.67	
	363010 E Energy Storage Equipment BQDM Brownsville Proj.	SQ	10		10.00	
364	364000 E Poles, Towers and Fixtures	R1	65	(110)	3.23	
303	Capitalized Software					
	303010 E Cap Sftw for Electric Dist	SQ	5	-	20.00	(B)
	303015 E Cap Sftw for Electric Dist (WMS)	SQ	15	-	6.67	(B)
365	365000 E O/H Conductors & Devices	R0.5	70	(70)	2.43	
366	Underground Conduit					
	366000 E U/G Conduit	R2	85	(50)	1.76	
	366100 E U/G Conduit - Manhattan/Br	R2	85	(50)	1.76	
	366010 E U/G Conduit -BQDM	SQ	10	0	10.00	
367	367000 E U/G Conductors & Devices	R0.5	50	(80)	3.60	
	367010 E U/G Conductors & Devices BQDM DC link	SQ	10	0	10.00	
368	Line Transformers					
	368000 E Line Trnsf O/H	R0.5	33	(20)	3.64	
	368100 E Line Trnsf U/G	S0	33	(20)	3.64	
	368110 E Transformers BQDM	SQ	10	0	10.00	
369	Services					
	369100 E Services - O/H	R0.5	70	(180)	4.00	
	369200 E Services - U/G	R1	75	(150)	3.33	
370	Meters					
	370100 E Meters - Purchases (Electro-Mechanical)	R0.5	35	(5)	3.00	
	370110 E Meters - Purchases (Solid-State)	S1	20	(5)	5.25	
	370120 E Meters - Purchases AMI	S2	20	0	5.00	
	370150 E Meters - Unrecovered EM Purchases	R0.5	35	(5)	3.00	
	370160 E Meters - Unrecovered SS Purchases	S1	20	(5)	5.25	
370	Meters Installations					
	370200 E Meters - Install (Electro-Mechanical)		35	-	2.86	
	370210 E Meters - Install (Solid-State)		20	-	5.00	
	370310 E Meters - Install (AMI)	S2	20	-	5.00	
	370250 E Meters - Unrecovered EM Install		35	-	2.86	
	370260 E Meters - Unrecovered SS Install		20	-	5.00	
371	371000 E Inst on Cust Prem	R1	65	(5)	1.62	
373	Street Lighting and Signal Systems					
	373100 E St Lt & Sig Sys - O/H	R0.5	50	(115)	4.30	
	373200 E St Lt & Sig Sys - U/G	R0.5	70	(110)	3.00	
	General Plant					
392	392100 E Truck Automobile	SQ	8	10	11.25	
	392200 E Light Truck Automobile	SQ	8	10	11.25	
397	397000 E Communication Equipment	SQ	15		6.67	
	Electric Plant Held for Future Use					
	Transmission Plant					
357	357300 E UG Conduit Fu		-		-	

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

Average Service Lives, Net Salvage,
Annual Depreciation Rates and Life Tables
(Effective 1/1/2020)

PSC Acct	Company Account	Life Table No.	Average Service Life In Years	Net Salvage %	Annual Rate %	
	Gas Plant in Service					
	Natural Gas Storage Plant					
	Other Storage Plant					
361	361000 G Str & Impr - Liquefied Sto	S0.5	80	(15)	4.38	(D)
362	362100 G Gas Holders - Liq Stg	S2.5	80	(15)	2.57	(D)
363	363000 G Purification Equipment	R2.5	70	(15)	4.83	(D)
363.1	363100 G Liquefaction Equipment	R4	70	(15)	5.00	(D)
363.2	363200 G Vaporizing Equipment	S2.5	40	(15)	5.32	(D)
363.3	363300 G Compr Eq - Liq Stg	R2.5	60	(15)	4.19	(D)
363.4	363400 G Meas & Reg Eq.- Liq Stg	S1	30	(15)	4.85	(D)
363.5	363500 G Other Eq - Liq Stg	S0	60	(15)	5.43	(D)
	Transmission Plant					
366	366000 G Structures & Improvements	S0.5	45	(45)	3.22	
367	Mains					
	367100 G Gas Mains- All Other	R2	85	(85)	2.18	(A)
	367200 G Gas Mains - Cast Iron	R1.5	70	(110)	3.00	
	367300 G Gas Mains - Tunnel	S4	90	(85)	2.06	
368	368000 G Compressor Station Eq	R3	35	(20)	3.43	
369	369000 G Meas & Reg Stn Eq	S0	50	(30)	2.60	
	Distribution Plant					
376	Mains					
	376120 G Gas Mains - All Other	R2	85	(85)	2.18	(A)
	376110 G Gas Mains - Cast Iron	R1.5	70	(110)	3.00	(A)
380	380100 G Gas Services - All Other	R1	60	(55)	2.58	(A)
381	381000 G Meters - Purchases	R0.5	35	(10)	3.14	
	381100 G Meters - AMI Purchases	S2	20	0	5.00	
	381150 G Meters - Unrecovered Meter Purchases	R0.5	35	(10)	3.14	
382	382000 G Meters - Installations	R0.5	35	-	2.86	
	382100 AMI G Meters - Installations	S2	20	-	5.00	
	382150 G Meters - Unrecovered Meter Install	R0.5	35	-	2.86	
383	383000 G House Reg - Pch	R2	45	(10.00)	2.44	
384	384000 G House Reg - Inst	R2	45	-	2.22	
303	303020 G Cap Sftw for Gas 5 yr	SQ	5	-	20.00	(B)
	General Plant					
392	392100 G Truck Automobile	SQ	8	10	11.25	
397	397000 G Communication Equipment	SQ	15		6.67	

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

Average Service Lives, Net Salvage,
Annual Depreciation Rates and Life Tables
(Effective 1/1/2020)

PSC Acct	Company Account	Life Table No.	Average Service Life In Years	Net Salvage %	Annual Rate %	
	Common Utility Plant in Service					
	Intangible Plant					
303	**Miscellaneous Intangible Plant**					
	303060 C Cap Sftw for C Plant 5 yr	SQ	5	-	20.00	(B)
	303070 C Cap Sftw for C Plant 10 yr	SQ	10	-	10.00	(B)
	303080 C Cap Sftw for C Plant 15 yr					
	HR Payroll	SQ	15	-	6.67	(B)
	Project One	SQ	15	-	6.67	(B)
	PowerPlant	SQ	15	-	6.67	(B)
	303090 C AMI software	SQ	20		5.00	(B)
	303400 C Oracle Strategic Agreement	SQ	15	-	6.67	(B)
	General Plant					
390	**Structures and Improvements**					
	390100 C Struct & Improv TRC A	S0	55	(40)	2.55	
	390200 C Struct & Improv TRC B	S0	55	(40)	2.55	
	390300 C Struct & Improv TRC C	S0	55	(40)	2.55	
391	**Office Furniture and Equipement**					
	Electronic Data Processing Equipment					
	391700 C OFE. - EDP Eq	SQ	8	5	11.88	(C)
	391720 C OFE. - EDP Eq - ERRP	SQ	8	5	11.88	(C)
	Other Office Furniture and Equipment					
	391100 C OFE. - Furniture	SQ	18	-	5.56	(C)
	391200 C OFE. - Office Machines	SQ	18	-	5.56	(C)
392	**Transportation Equipment**					
	392100 C Tr. Eq. - Automobiles	SQ	8	10	11.25	(C)
	392200 C Tr. Eq. - Light Trucks	SQ	8	10	11.25	(C)
	392300 C Tr. Eq. - Heavy Trucks	SQ	8	10	11.25	(C)
	392400 C Tr. Eq. - Tr. & Mtd.Equip.	SQ	8	10	11.25	(C)
	392500 C Tr. Eq. - Buses	SQ	8	10	11.25	(C)
	392600 C Tr. Eq. - Tractors	SQ	8	10	11.25	(C)
393	393000 C Stores Equipment	SQ	20	5	4.75	(C)
394	394000 C Tools, Shop & Garage Eq	SQ	18	5	5.28	(C)
395	395000 C Laboratory Equipment	SQ	20	-	5.00	(C)
396	396000 C Power Operated Equipment	SQ	12	10	7.50	(C)
397	397000 C Comm. Eqment	SQ	15	-	6.67	(C)
397	397100 C AMI Comm. Eqment	SQ	15	-	6.67	(C)
397	397200 C Light Tower Lease					(E)
398	398000 C Misc. Equip.	SQ	20	-	5.00	(C)

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

Average Service Lives, Net Salvage,
Annual Depreciation Rates and Life Tables
(Effective 1/1/2020)

Nonutility Property
Plant in Service

121	**304700 NU Nonutility Telecom**	SQ	**10**	**0**	**10.00**

NOTES

(A) Gas Plant in Service other than Interruptible Gas Plant.
(B) Amortization in accordance with the Software Accounting Guideline.
(C) Effective 1/1/95, investment in account is being amortized in accordance with the method specified in Case No. 93-M-1098.
(D) Life span method is used. Curve shown is interim survivor curve.
(E) Light Tower Lease is amortized by Accounting Research and Procedures

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

Cases 19-E-0065 and 19-G-0066

Earnings Sharing Partial Year

During Stub Period Starting January 1, 2023

(000's)

Assumption: Con Ed Files for New Gas Rates Effective January 2023,
but Delays Filing for New Electric Rates for Six Months

Month / Year	Electric Net Income	
January 31, 2023	$ 116,000	
February 28, 2023	118,000	
March 31, 2023	97,000	
April 30, 2023	107,000	
May 31, 2023	148,000	
June 30, 2023	213,000	
Total		$ 799,000

	Electric Rate Base	
Rate Base as of December 31, 2022	$ 22,783,253	
Rate Base as of June 30, 2023	23,925,996	
Total	46,709,249	
Divided by Two	2	
Average Rate Base During Stub Period	$ 23,354,625	
x Ratio of operating income for the six months ended June 2022 to operating income for the 12 months ended December 2022	46.85%	
Rate Base Subject to Earnings Test		$ 10,942,000
Overall Rate of Return ($ 799,000 / $ 10,942,000)		7.30%
Return on Equity (Page 2)	10.24%	
Earnings Sharing Threshold	9.30%	
Earnings Above / (Under) Threshold	0.94%	
Equity Earnings Base ($10,942,000 x 48.00%)	$ 5,252,160	
Equity Earnings Above / (Under) Target ($ 5,252,160 x 0.94%)	$ 49,480	

Note: the approach illustrated above would also apply to a delay in filing a gas case.
All amounts are hypothetical.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

Cases 19-E-0065 and 19-G-0066

Capital Structure & Cost of Money

During Stub Period Starting January 1, 2023

	Capital Structure %	Cost Rate %	Cost of Capital %
Long Term Debt	50.91%	4.63%	2.36%
Customer Deposits	1.09%	2.45%	0.03%
Total Debt	52.00%		2.38%
Common Equity	48.00%	10.24%	4.92%
Total	100.00%		7.30%

Note : Amounts are hypothetical.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

Cases 19-E-0065, 19-G-0066

Common Allocation Factors

	Electric	Gas	Steam
Administrative & General Expenses (FERCs 9200 - 9350)	77.60%	15.95%	6.45%
Customer Accounting Expenses (FERCs 9010 - 9160)	84.00%	16.00%	-
Taxes Other than Income Taxes/Property Taxes	77.60%	15.95%	6.45%
Common Plant (including Property Taxes on Common Plant)	83.00%	17.00%	-
Common M&S	77.00%	17.00%	6.00%

Appendix 14 -- Electric Service Reliability Performance Mechanism

Consolidated Edison Company of New York, Inc.
Case 19-E-0065
Electric Service Reliability Performance Mechanism

Operation of Mechanism

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, 2020 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 nine performance metrics:

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

(b) a major outage metric;

(c) a remote monitoring system metric;

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

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

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

(g) a program standard for over-duty circuit breakers;

(h) a program standard for Level II deficiency repairs; and

(i) a program standard for the Non-Network Reliability program in Westchester County.

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 CAIDI	Con Ed Performance > 6.89	$5.0
Radial CAIDI[1]	Con Ed Performance > 2.04	$5.0
Network SAIFI	Con Ed Performance > 0.0176	$5.0
Radial SAIFI[2]	Con Ed Performance > 0.495	$5.0
	Maximum Annual Exposure	$20.0
Major Outages		
Network	Each area substation with the interruption of service to 15 percent or more of the customers in a network for a period of three hours or more. If more than one network served by a single area substation has 15 percent or more customer outages, the outages will be considered a single network major outage event for purposes of determining the revenue adjustment. In addition, if a major outage event occurs at a double-area substation,[3] it will be considered a single event for purposes of determining the revenue adjustment if the total peak load of the double-area substation is less than 500 MW.	Initial Major Outage Event: 3 hrs to 6 hrs = $10.0 >6 hrs to 12 hrs = $15.0 >12 hrs = $25.0 Each additional Major Outage Event: 3 hrs to 6 hrs = $7.5 >6 hrs to 12 hrs = $10.0 >12 hrs = $15.0
Radial	One event that results in the sustained interruption of service to at least 12,500 radial customers for 180,000 or more customer hours.	$10.0/event
Maximum Annual Exposure		$110.0

[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] 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.

[3] Double-area substations are area substations located at the same geographic location in the same building or adjacent buildings that are served by the same sub-transmission feeders.

	Requirement for Revenue Adjustment	Annual Revenue Adjustment Exposure (millions)
Remote Monitoring System Reporting		
Network	Failure by the Company to achieve 90 percent reporting rate in the second quarter and 85 percent reporting rate in the first, third and fourth quarters of the calendar year for the Remote Monitoring System in each network during the last month of each quarter.	$10.0/network
Maximum Annual Exposure		$50.0
Program Standards		
Pole Repair	For all "Damaged Poles" and "Double Damaged Poles" that come into existence on or after 1/1/20, 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 1/1/20, 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 90% of these cases within 60 days during the remaining six months, May through October that is defined as the summer months.	Winter: $1.5 Summer: $1.5
No Current Street Lights and Traffic Signals	For all no currents that come into existence on or after 1/1/20, 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 in each calendar year and at least 180 over the three-year cycle. Revenue adjustment capped at $1.5 million per year for not meeting annual target. At the end of the three-year cycle, there will be an additional revenue adjustment of $0.1 million per breaker, capped at $3.0 million, if the cumulative three-year cycle target is not met.	$0.1 per breaker $1.5 annually $3.0 cumulative per three-year cycle

	Requirement for Revenue Adjustment	Annual Revenue Adjustment Exposure (millions)
Level II Deficiency Repair	For all Level II Deficiencies that come into existence on or after January 1, 2020, permanent repairs not made by Con Edison for at least 85% of these new Level II Deficiencies within 365 days from the date the Company became aware of these deficiencies.	$2.0
Non-Network Reliability for Westchester County	For each Rate Year, of Rate Years 1-3, that Con Edison does not spend 90% of its annual Non-Network Reliability Program's budget allocated for Westchester County. The annual budget is $25 million plus or minus any shortfalls for not spending or excess spending in the prior Rate Year.	$5.0
	Maximum Rate Year 1 & 2 Annual Exposure Maximum Rate Year 3 Exposure	$17.5 $20.5
	Total Annual Revenue Adjustment Exposure:	**$197.5 for RY1 $197.5 for RY2 $200.5 for RY3**

Exclusions

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. Heat-related outages are not a major storm.

(b) 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).

(c) 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.

(d) The Company may petition the Commission for exemption from the requirements and/or revenue adjustment associated with the RPM metrics, on a case-by-case basis.

<u>Reporting</u>

The Company will prepare an annual report on its performance under this reliability mechanism. The annual report 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; and Chief of Electric Distribution Systems. Copies of the annual report 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 Program Standards applicable during the period and identify whether a revenue adjustment is applicable and, if so, the amount of the revenue adjustment; and

(e) 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.

Threshold Standards

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 network 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 network system will be measured against the respective CAIDI system-wide performance target. 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 Company's annual performance in maintaining reliability must meet or be better than the Network and Radial SAIFI and CAIDI system-wide performance 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 radial customer interruption duration performance, as follows:

	Threshold Target (hours)	Revenue Adjustment (millions)
Radial CAIDI	2.04	$5.0

(b) Network CAIDI

A total of $5 million per year is at risk for network customer outage duration performance, as follows:

	Threshold Target (hours)	Revenue Adjustment (millions)
Network CAIDI	6.89	$5.0

(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	$5.0

(d) Network SAIFI

A total of $5 million per year is at risk for network outage performance, as follows:

	Threshold Target	Revenue Adjustment (millions)
Network SAIFI	0.0176	$ 5.0

<u>Major Outages</u>

For purposes of this metric, a "major outage" event in a network system is defined as each area substation with the interruption of service to 15 percent or more of the customers in a network for a period of three hours or more. If more than one network served by a single area substation has 15 percent or more network customer outages, the outages will be considered a single network major outage event for purposes of determining the revenue adjustment. In addition, if a major outage event occurs at a double-area substation, it will be considered a single event for purposes of determining the revenue adjustment if the total peak load of the double-area substation is less than 500 MW. If the Company creates any new second contingency networks and area substations that supply second contingency networks during the term of the Electric Rate Plan, those networks and area substations will be covered by this metric. Con Edison shall not be subject to a revenue adjustment when the 15 percent threshold is met due to an outage that is confined to one building within a network.

A major outage event in a radial system is defined as one event that results in the sustained interruption of service to at least 12,500 radial customers for 180,000 or more customer hours. When the shutdown of a network causes connected radial customer outages, only the network major outage metric shall apply. A radial system served by an area substation that is supplied by two feeders and two transformer banks ("Two-bank station") is excluded from the radial major outage metric.

The Company will be subject to an annual maximum revenue adjustment of $110 million. To avoid multiple revenue adjustments for the same operating performance problem or occurrence, interruptions and customer hours of interruption associated with major outage metric revenue adjustments will be excluded from the appropriate year-end system-wide performance calculations until the maximum annual $110 million cap has been reached. After the $110 million annual 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

Initial Major Outage Event	
Network Outage Duration	**Area Substation with 15% or More Customer Outages in a Network**
3 to 6 hours	$10 million
> 6 hours to 12 hours	$15 million
> 12 hours	$25 million
Additional Major Outage Event(s)	
Network Outage Duration	**Additional Area Substation(s) with 15% or More Customer Outages in a Network**
3 to 6 hours	$7.5 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 event.

<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 during the second quarter and 85% of its Remote Monitoring System units reporting properly in each network during the first, third and fourth quarters in a calendar year. 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.

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, 2019, 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, 2020, 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 2020 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, 2020 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 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, 2019, 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, 2020, Con Edison will make permanent repairs for at least 90% of these new cases within 90 days during the winter

[4] In such situations, and as appropriate, the Company either will replace its temporary shunt or make the permanent repair.

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, 2020 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.

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 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, 2019, 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, 2020, 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, 2020 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 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. 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.

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 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.

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 180 over-duty circuit breakers during each three-year period (the "triannual target level").

There will be revenue adjustment applicable for the annual and for the triannual 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 triannual 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.

(e). Level II Deficiency Repairs

i) Definitions

1. A "Level II Deficiency" is a deficiency that is likely to fail prior to the next inspection cycle and represents a threat to safety and/or reliability should a failure occur prior to repair as defined in the Commission's Electric Safety Standards (current version in Order dated January 13, 2015 in Case 04-M-0159)

ii) Performance Requirements

For all Level II Deficiencies that come into existence on or after January 1, 2020, Con Edison will strive to make repairs to all within 365 days from the date the Company became aware of the Level II Deficiencies. In the year Con Edison does not repair 85% of these Level II Deficiencies within the 365-day threshold, the Company will incur a revenue adjustment of $2 million.

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 will report its performance as part of the comprehensive report filed by February 15 each year in Case 04-M-0159 and as part of its annual RPM filing. The Company's annual RPM report will: (i) report on the number of Level II Deficiencies discovered from January 1 through December 31 of the prior year; (ii) provide the status of the Company's efforts on repairing the Level II Deficiencies; (iii) identify any Level II Deficiencies that have been reclassified as another deficiency level during the prior calendar year, reason for such reclassification, and the amount of deficiencies that have been reclassified; (iv) identify any deficiencies that have been reclassified as a Level II Deficiencies during the prior calendar year, reason for such reclassification, and the amount of deficiencies that have been reclassified; and (v) describe the extraordinary circumstances, if any, that prevented the Company from achieving the target level for repairs.

(f). Non-Network Reliability for Westchester County

i) Performance Requirements

The Company will spend at least 90% of its annual Non-Network Reliability capital program budget for Westchester County ($25 million) in RY1. For RY2 and RY3, the Company will spend at least 90% of its annual Non-Network Reliability capital program budget for Westchester County ($25 million) plus or minus any funds above or below the annual Non-Network Reliability capital program budget for Westchester County that were spent or not spent in the prior Rate Year.

ii) 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 exposure to a negative revenue adjustment. 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. Petitions filed requesting an exception shall not seek to reduce the total amount of reliability related investment required in Westchester County.

iii) Reporting

The Company’s annual report will include: (i) the total amount spent from January 1 through December 31 of the prior Rate Year; (ii) the current annual Non-Network Reliability capital program budget for Westchester County, including any unspent funds from the prior rate year, if applicable; (iii) a description of which storm hardening measures were addressed by categories, including but not limited to, Poles, Open Wire Conversion, Breakaway Service Connectors, Undergrounding, Smart Switches, Manual Isolation Switches, Underground Residential Developments -Automatic Transfer Switch, Paper Insulated Lead Covered/Okonite Cable Replacement, and Other; and (iv) a description of circumstances, if any, that prevented the Company from achieving the target level of spending.

Appendix 15 -- Safety Standards Pilot Program

Consolidated Edison Company of New York, Inc.
Case 19-E-0065
Electric Safety Standards

Continuation of Eight-Year Underground Inspection Cycle Pilot[1]

The eight-year underground inspection cycle is effective as of January 1, 2015. The annual performance target for inspections shall be as follows in order to comply with the eight-year inspection cycle:

Underground Inspection Annual Goal	Percentage	Cumulative Minimum
First year inspection goal: 85% of annual target	85% of 12.5% in year one	10.625%
Second year inspection goal: 90% of annual target	90% of 12.5% in year two	21.875%
Third year inspection goal: 95% of annual target	95% of 12.5% in year three	33.75%
Fourth year inspection goal: 95% of annual target	95% of 12.5% in year four	45.625%
Fifth year inspection goal: 95% of annual target	95% of 12.5% in year five	57.5%
Sixth year inspection goal: 95% of annual target	95% of 12.5% in year six	69.375%
Seventh year inspection goal: 95% of annual target	95% of 12.5% in year seven	81.25%
Eighth year inspection goal: 100% of all facilities to be inspected	100% of 100% in year eight	100%

In all other respects, during the term of the Rate Plan, this program will be subject to the Commission's orders in the Electric Safety Standards proceeding (Case 04-M-0159) and related proceedings, including but not limited to any reporting requirements, exceptions, exclusions and the negative revenue adjustments specified in the Electric Safety Standards, as those requirements may be amended by the Commission. For example, if the Commission takes action to replace negative revenue adjustments with a scorecard or otherwise modifies the negative revenue adjustments, as proposed in Case 16-E-0323, such modification will be applicable to the eight-year program established in this Eight-Year Underground Inspection Cycle.

[1] Approved by the Commission in Case 16-E-0060, et al, *Order Approving Electric and Gas Rate Plans* issued January 25, 2017.

If Company and/or Staff believe that the inspection cycle and/or inspection activities should be changed, the Company may submit a petition: (a) for a change in the underground inspection program; (b) for recovery of costs associated with the modified underground inspection program, along with consideration of the other safety related programs; and (c) premised on a reasonable transition that recognizes the time needed to acquire, train and mobilize the additional resources to meet any revision to the underground inspection program. If the Company files such a petition it will not be subject to a materiality threshold.

Appendix 16 – Actions to Address Climate Change

Consolidated Edison Company of New York, Inc.
Case 19-E-0065
Actions to Address Climate Change

Sensor Installations

The Company will undertake the following installation programs:

1. Weather Data and Ground Temperature Sensors

a. Install weather data sensors (including precipitation) at selected company facilities by April 30, 2020

i. Install weather data sensors at all eight (8) locations identified in the Climate Change Vulnerability Study as having projected average ambient temperature differentials, relative to Central Park, of 0.3 degrees or greater. Approximate locations (subject to design): (1) four in Queens; (2) two in Brooklyn; (3) two in Manhattan.

ii. Install, as a pilot program, data sensors at five (5) locations identified in the Climate Change Vulnerability Study as having projected maximum temperature differentials, relative to Central Park, and not at the same location as the projected average differential. Approximate locations (subject to design): (1) two in Queens; (2) one each in Brooklyn, Staten Island, and the Bronx

iii. Install one (1) soil temperature sensor in Brooklyn and one (1) in Staten Island to complement Con Edison's existing four (4) sensors in Westchester, Manhattan, Queens and the Bronx.

iv. Analyze the weather data information to better understand the relationship between local climatic conditions and equipment performance and to inform system designs and operations.

v. Provide public access upon request to the data collected in a format that addresses any Company confidentiality concerns to assist researchers with efforts to monitor temperatures locally.

vi. Investigate weather data collection efforts outside of the Company and determine the value to Con Edison, and accessibility for Con Edison use.

2. River Temperature Sensors

a. Install river temperature sensors and recording equipment by April 30, 2020. The Company has two facilities that take in river water for cooling: the East River station and the 59th St. station. Intake water temperature is already recorded and archived at the East River station.

i. Install a sensor and associated equipment to record and archive the temperature of Hudson River intake water at the Company's 59th Street station.

ii. Analyze the river temperature data to better understand the relationship between local climatic conditions and equipment performance and to inform system designs and operations.

iii. Provide public access upon request to the data collected in a format that addresses any Company confidentiality concerns to assist researchers with efforts to monitor temperatures locally.

iv. Investigate river temperature data collection efforts outside of the Company and determine the value to Con Edison, and accessibility for Con Edison use.

<u>Climate Change Implementation Plan (CCIP)</u>

By December 31, 2020: Con Edison will develop a detailed plan for implementation of the recommendations from the Climate Change Vulnerability Study including:

1. Climate Projections

a. Review climate science for comprehensive updates to major climate model sets (e.g., the latest reports from the National Climate Assessment and the New York City Panel on Climate Change, and the "Global Warming of 1.5C" report from the Intergovernmental Panel on Climate Change) and update, if necessary, climate data prior to selection of a projected pathway for the climate variables relevant to Con Edison's planning and operations including temperature, temperature variable, sea level, precipitation and storm surge and include underlying assumptions, emissions pathway, and statistical percentile.

b. Update the selected climate projections with new climate science at least every five years including evaluation of the Company's flood protection planning standard (currently FEMA 100+3). Stakeholders may at any time submit new climate science information for consideration by the Company.

2) Load Forecasting

a. The Company produces an annual 10-year load forecast to plan investments to meet growing demand and an annual 20-year load forecast as part of its strategic planning activity. This forecasting process considers drivers of demand including economic activity and population growth and incorporates the most recent historical weather experienced in our service territory and uses temperature variable as an indicator metric for peak demand.

b. The CCIP will incorporate the selected climate projections, as applicable, into the annual 10-year and 20-year load forecasting processes.

c. The plan will include a process to review temperature variable ratings and adjust them as appropriate.

3) Load Relief

a. The Company develops an annual 10-year load relief plan that identifies capital investments to meet growth in electric demand. The Company also develops an annual 20-year load relief plan as part of its strategic planning activity. Comparing forecasted load to system capacity, these processes identify future projected overloads on the Company's sub-transmission and distribution systems along with actions to resolve them including non-wires solutions, load transfers, expansion of substation capability (adding cooling or new equipment), or construction of new substations.

b. The CCIP will incorporate the selected climate projections, as applicable, into the annual 10-year and 20-year load relief processes, including the consideration of an asset's expected useful life and the relevant timeframe of climate projections.

4) Reliability Planning for the Sub-Transmission and Distribution Systems

a. The Company develops an annual five-year sub-transmission and one-year distribution system reliability plan that includes an assessment of the reliability of its sub-transmission, network, and non-network systems, on an individual basis, using reliability metrics including NRI and TPRA and identifies capital investments necessary to meet system reliability standards.

b. The CCIP will incorporate the selected climate projections, as applicable, into the annual reliability planning process to identify and prioritize future infrastructure investments needed to maintain reliability and resiliency.

5) Asset Management

a. Con Edison's planning processes include evaluations of the condition and performance of the Company's extensive asset base, including, for example, evaluating the performance of overhead lines and ranking the performance of substation and transmission assets based on failure rates.

b. The CCIP will incorporate the selected climate projections into the asset management process, as applicable, to consider any potential impacts of climate change on expected future performance of assets and will incorporate an asset's expected useful life in planning considerations.

6) Facility Energy System Planning (HVAC and Cooling towers)

a. The Company operates various facilities that use heating, ventilation, and air conditioning systems (HVAC) for space cooling. These systems require periodic evaluation of operating performance and replacement as they reach the end of their useful lives. The Company also installs HVAC systems in newly constructed facilities as necessary.

b. The CCIP will incorporate the selected climate projections and an asset's expected useful life, as applicable, into the process for the periodic replacement and new installation of HVAC systems.

7) Emergency Response Activations

a. The Company maintains a Corporate Emergency Response Plan (CERP) that outlines preparation, training and the actual response to emergencies. The plan includes various thresholds for activation of the Company's Corporate Emergency Response Center. A number of these thresholds include weather as a criterion.

b. The CCIP will incorporate the selected climate projections, as applicable, into the CERP activation thresholds and periodic review process for those thresholds.

8) Examination of Worker Safety Protocols

a. Con Edison employees work to provide reliable energy delivery to our customers 24 hours a day in virtually all types of weather conditions. The Company's health and safety protocols include a process to evaluate the appropriate procedures and equipment to safely conduct operations.

b. The CCIP will incorporate the selected climate projections, as applicable, into the Company's worker safety protocols, and make the necessary changes and/or investments to continue to safely and reliably conduct operations.

9) **Climate Risk Governance**

a. The CCIP will indicate how the management of climate risk will be integrated into the Company's organizational governance structure including the roles and responsibilities of management.

Appendix 17 -- Gas Performance Mechanism

Consolidated Edison Company of New York, Inc.
Cases 19-G-0066
Gas Safety Performance Metrics

The gas safety performance measures described herein will be in effect for the term of the Gas Rate Plan. Unless otherwise indicated, all gas safety measures and targets (and associated revenue adjustments)[1] for calendar year 2022 remain in effect thereafter unless and until changed by the Commission.[2]

Negative Revenue Adjustments

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 for Rate Years 2020, 2021 and 2022, the following negative revenue adjustments will be accrued on the Company's books for the benefit of firm customers for each Rate Year that the performance measures noted below are not attained, as directed by the Commission. Backlog must be at or below target between December 21 and December 31.[4]

2020	
300 or less	No adjustment
greater than 300	15 basis points[5]

[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 270-mile replacement target established below, for the three-year period 2020 to 2022, does not remain in effect beyond 2022. However, the miles of main removal per year will remain at 90 miles, unless and until changed by the Commission.

[3] These are defined in Company specification G-11809.

[4] Only "successful elimination" of a leak will be considered a valid leak repair.

[5] 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 $480,000 in RY1, $530,000 in RY2 and $580,000 in RY3.

2021

250 or less	No adjustment
greater than 250	15 basis points

2022

200 or less	No adjustment
greater than 200	15 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 Rate Years 2020, 2021 and 2022, a negative revenue adjustment of 12 basis points will be accrued on the Company's books for the benefit of firm customers for each Rate Year that the performance measures are not attained, as directed by the Commission.

The Company may seek the following exclusion to operating performance under this measure:

> Gas leak and odor calls resulting from mass area odor complaints, major weather-related occurrences, and major equipment failure.

Con Edison shall provide notification to safety@dps.ny.gov within seven (7) days of such event that the Company is seeking Staff's consent to the exclusion. Staff will respond within ninety (90) days stating whether it concurs or does not concur to the requested exclusion.[6]

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 Rate Years 2020, 2021 and 2022, a negative revenue adjustment of 8 basis points will be accrued on the

[6] This exclusion, as well as the right to petition the Commission pursuant to the General Provisions section below, also applies to the 45-Minute Response Time and 60-Minute Response Time measures.

Company's books for the benefit of firm customers for each Rate Year that the performance measures are not attained, as directed by the Commission.

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 Rate Year 2020, 2021 and 2022, a negative revenue adjustment of 5 basis points will be accrued on the Company's books for the benefit of firm customers for each Rate Year that the performance measures are not attained, as directed by the Commission.

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. Con Edison will exclude refreshes from "New York 811" because "New York 811" can exclude these types of tickets. Con Edison will not exclude refreshes[7] from "Dig Safely New York" because "Dig Safely New York" (Westchester) cannot currently exclude refresh tickets. Con Edison will report to Staff when "Dig Safely New York" can exclude refresh tickets.

f. 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 Rate Years 2020, 2021 and 2022, the negative revenue adjustment associated with such target will be accrued on the Company's books for the benefit of firm

[7] Refreshes are defined in the guidelines as any one-call ticket which has the same requesting party and location of the proposed scope of work.

customers for each Rate Year that the performance measure noted below is not attained, as directed by the Commission.

Greater than 1.50 but less than or equal to 2.00	No adjustment
Greater than 2.00 but less than or equal to 2.25	5 basis points
Greater than 2.25 but less than or equal to 2.50	10 basis points
Greater than 2.50	20 basis points

2. **Gas Main Replacement**

The Company will remove from service 270 miles of 12-inch and under cast iron and unprotected steel gas main during the three-year Rate Year period, 2020 to 2022.[8] The Company will remove a minimum of 85 miles in 2020 and 85 miles in 2021. [9]

If the Company does not meet the annual target for removal of leak-prone gas main in 2020 or 2021, the Company will accrue on the Company's books of account a negative revenue adjustment equivalent to 15 basis points for such Rate 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 270 miles of leak prone pipe over the three-year period 2020 through 2022, a negative revenue adjustment equivalent to 15 basis points will be accrued on the Company's books for the benefit of firm service customers.

3. **Gas Regulations Performance Measure**

This metric applies to instances of noncompliance (violations) with the gas safety regulations set forth below that are identified in Staff field and records audits. The

[8] 12 inch and under cast iron and unprotected steel gas main that is abandoned in place will count towards this metric.

[9] Con Edison will remove/replace at least 12 miles of flood prone pipe over the three-year Gas Rate Plan, of which at least six miles will be in New York City and at least six miles will be in Westchester County.

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 ten (10) calendar 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.[10]

Negative revenue adjustments, if any, would be applied as set forth in the following chart:

High Risk	**Other Risk**
Field Audits - 1-20 (1/2 BP) 21+ (1 BP) Records Audits – 6 to 20 (1/2 BP) 21+ (1 BP)	Field Audits - >0 (1/4 BP) Records Audits - >15 (1/4 BP)

In the event the Company does not make a base rate filing for new rates to go into effect on January 1, 2023, the above targets will be applied beginning on January 1, 2023, and remain in effect until changed by the Commission:

[10] However, this is without prejudice to a penalty action under the Public Service Law for any violation not counted under this metric.

Any negative revenue adjustments assessed under this metric shall not exceed 75 basis points for 2020, 2021 and 2022 and subsequent years unless and until changed by the Commission. For any code section, the number of violations will be capped at ten for the negative revenue adjustment determination with the requirement that violations in excess of ten be addressed by a corrective action plan formally submitted to Staff by the Company to achieve compliance going forward. If the Company fails to submit a corrective action plan, or fails to comply with the corrective action plan, where applicable, the negative revenue adjustment associated with the violations may be applied. The corrective action plan will be provided in the Company's response to the audit letter. In addition, if the Company is found to be in violation of its work procedure, but the work procedure exceeds Code 255 or 261, and the Company is not in violation of the Code requirement, the violation will not be subject to a negative revenue adjustment under this Safety Violation metric.

Audits of liquefied natural gas ("LNG") facilities under Part 193 shall be included under this performance measure. The "High Risk" and "Other Risk" classifications of Subparts of 193 that are applicable to the Company's operations are included in Table 2. This metric will be effective as of January 1, 2020 and will be measured on a calendar year basis. Violations/occurrences shall count in the year that the subject activity took place. With respect to violations, only documentation or actions performed, 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 before 2020, but continue into 2020, will be subject to this measure; for example, if a leak repair is performed in December 2019 and a follow-up inspection is required by December 28, 2019, but is not performed until January 2020, that would be a continuing violation that could count towards the 2020 performance measure.

Staff will submit its final audit reports to the Secretary under Case 19-G-0066. If the Company disputes any of Staff's final audit results, the Company may appeal Staff's findings 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.

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 circumstance 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.

Positive Rate Adjustments

1. **Leak Management/Emergency Response/Damage Prevention**

a. Leak Management - Year-End Total Backlog

The Company shall receive a positive revenue adjustment, up to an annual maximum of 4 basis points, for reducing the leak backlog below the associated annual targets as detailed below.

<u>2020</u>

176 to 200	1 BP
126 to 175	2 BP
<=125	4 BP

<u>2021</u>

126 to 150	1 BP
76 to 125	2 BP
<=75	4 BP

<u>2022</u>

76 to 100	1 BP
26 to 75	2 BP
<=25	4 BP

To be eligible for the full positive revenue adjustments set forth above, 85% of leaks in each Rate Year must be repaired within 60 days, and Con Edison will file an annual report on any leaks not repaired within one year. If the Company fails in any Rate Year to meet the 85% target or to file an annual report, the positive revenue adjustments the Company will be eligible to receive in that Rate Year will be reduced by one basis point. Con Edison will report its performance in repairing 85% of leaks in 60 days and any leaks not repaired within one year in its annual filing to the Secretary on its performance in each of the areas set forth in this Appendix.

b. <u>Emergency Response</u>

If Con Edison responds to gas leak or odor calls within 30 minutes for at least 95 percent of the calls for calendar years 2020, 2021 and 2022, the Company shall receive for the applicable year(s) a positive revenue adjustment of 2, 4, or 6 basis points. The basis points available for response time performance in each of Rate Year 2020, Rate Year 2021 and Rate Year 2022 is set forth below:

Response within 30 minutes 95% to 95.99%	2 BP
Response within 30 minutes 96% to 97.99%	4 BP
Response within 30 minutes =>98%	6 BP

c. Damage Prevention

If the Company successfully reduces the number of total damages to Company gas facilities made by any party, Con Edison shall receive for the applicable year(s) a positive revenue adjustment. The basis points available for damage prevention performance (per 1,000 one-call tickets) for each of Rate Year 2020, Rate Year 2021 and Rate Year 2022 is shown below:

1.26 to 1.50	5 BP
<=1.25	10 BP

Appendix 17, Table 1

Cases 19-G-0066 - Con Edison - Pipeline Safety Measures

Pipeline Safety Measures	Criteria	Unit	NRA (BPs)	PRA (BPs)	CY 2020 Target	NRA (BPs)	PRA (BPs)	CY 2021 Target	NRA (BPs)	PRA (BPs)	CY 2022 Target	NRA (BPs)	PRA (BPs)	Beyond 2022 Target
Leak Backlog/Management	Total: Type 1, 2A, 2, and 3	Leaks	15	-	> 300	15	-	> 250	15	-	> 200	15	-	> 200
	Total: Type 1, 2A, 2, and 3	Leaks	-	1	176 to 200	-	1	126 to 150	-	1	76 to 100	-	1	76 to 100
	Total: Type 1, 2A, 2, and 3	Leaks	-	2	126 to 175	-	2	76 to 125	-	2	26 to 75	-	2	25 to 75
	Total: Type 1, 2A, 2, and 3	Leaks	-	4	<=125	-	4	<=75	-	4	<=25	-	4	<=25
	(1) Con Edison will be recognized as having met the leak backlog targets if they are achieved between December 21 and December 31.													
	(2) Leaks that fail re-check must be added back into the backlog.													
	(3) 85% of leaks repaired within 60 days, annual report on leaks not repaired within 1 year													
Leak Prone Pipe (LPP)	Removal Target	Miles	15	-	<85	15	-	<85	15	-	<270	15	-	<90
	(4) Con Edison will target at least 12 miles of flood prone pipe removal/replacement over the three-year agreement, of which at least 6 miles will be in New York City and 6 miles in Westchester County.													
	(5) Cumulative three-year target of 270 miles.													
Emergency Response	Respond within 30 minutes	%	12	-	75	12	-	75	12	-	75	12	-	75
	Respond within 45 minutes	%	8	-	90	8	-	90	8	-	90	8	-	90
	Respond within 60 minutes	%	5	-	95	5	-	95	5	-	95	5	-	95
	Respond within 30 minutes	%	-	2	95 to 95.99	-	2	95 to 95.99	-	2	95 to 95.99	-	2	95 to 95.99
	Respond within 30 minutes	%	-	4	96 to 97.99	-	4	96 to 97.99	-	4	96 to 97.99	-	4	96 to 97.99
	Respond within 30 minutes	%	-	6	≥ 98	-	6	≥ 98	-	6	≥ 98	-	6	≥ 98
	(6) Any reports resulting from mass area odor complaints, major weather related occurrences, and major equipment failure may be excluded from these counts pending prior Staff approval.													
	(7) Exclusions are considered on a case-by-case basis, must be made via email or in writing, and shall be requested within seven days of such an occurrence. The Company may proceed with filing its request for an exclusion if it has not received a response from Staff within 90 days.													
Violations or Non-Compliances	Record Audits: High Risk	Per	1	-	> 20	1	-	> 20	1	-	> 20	1	-	> 20
	Record Audits: High Risk	Per	1/2	-	6 to 20	1/2	-	6 to 20	1/2	-	6 to 20	1/2	-	6 to 20
	Record Audits: Other Risk	Per	1/4	-	> 15	1/4	-	> 15	1/4	-	> 15	1/4	-	> 15
	Field Audits: High Risk	Per	1	-	> 20	1	-	> 20	1	-	> 20	1	-	> 20
	Field Audits: High Risk	Per	1/2	-	1 to 20	1/2	-	1 to 20	1/2	-	1 to 20	1/2	-	1 to 20
	Field Audits: Other Risk	Per	1/4	-	>0	1/4	-	>0	1/4	-	>0	1/4	-	>0
	(8) Violations will be capped at 10 with remediation plans required for violations in excess of 10.													
	(9) Con Edison will have 10 calendar days from the date of the compliance meeting to cure any identified document deficiency.													
	(10) Reduced negative revenue adjustment exposure from 100 to 75 points.													
Damage Prevention (per 1,000 one-call tickets)	Total: No Calls, Excavator Error, Company and Company Contractor Error, and Mismarks	Rate	20	-	>2.50	20	-	>2.50	20	-	>2.50	20	-	>2.50
		Rate	10	-	2.26 – 2.50	10	-	2.26 – 2.50	10	-	2.26 – 2.50	10	-	2.26 – 2.50
		Rate	5	-	2.01 – 2.25	5	-	2.01 – 2.25	5	-	2.01 – 2.25	5	-	2.01 – 2.25
		Rate	-	-	1.51 – 2.00	-	-	1.51 – 2.00	-	-	1.51 – 2.00	-	-	1.51 – 2.00
		Rate	-	5	1.26 – 1.50	-	5	1.26 – 1.50	-	5	1.26 – 1.50	-	5	1.26 – 1.50
		Rate	-	10	≤1.25	-	10	≤1.25	-	10	≤1.25	-	10	≤1.25
	(11) Con Edison will not exclude refresh because “Dig Safely New York” (Westchester) cannot currently exclude these.													
	(12) Damages will be tracked, measured and counted following the guidelines for the data reported for the annual performance measures report.													
	(13) Con Edison will report to Staff when these numbers are available, and Staff/parties can use the numbers to inform the next rate case exposure.													
Total Exposure			150	20		150	20		150	20		150	20	

Title	Chapter	Subchapter	Part	Section	Subdivision	Description	Risk
16	III	C	255	17	All	Preservation of Records	Other
16	III	C	255	53	All	Materials - General	High
16	III	C	255	65	All	Materials - Transportation of Pipe	High
16	III	C	255	103	All	Pipe Design - General	High
16	III	C	255	143	All	Design of Pipeline Components - General Requirements	High
16	III	C	255	159	All	Design of Pipeline Components - Flexibility	High
16	III	C	255	161	All	Design of Pipeline Components - Supports and Anchors	High
16	III	C	255	163	All	Compressor Stations - Design and Construction	Other
16	III	C	255	165	All	Compressor Stations - Liquid Removal	Other
16	III	C	255	167	All	Compressor Stations - Emergency Shutdown	High
16	III	C	255	169	All	Compressor Stations - Pressure Limiting Devices	High
16	III	C	255	171	All	Compressor Stations - Additional Safety Equipment	Other
16	III	C	255	173	All	Compressor Stations - Ventilation	High
16	III	C	255	179	All	Valves on Pipelines to Operate at 125 PSIG (862 kPa) or More	High
16	III	C	255	181	All	Distribution Line Valves	High
16	III	C	255	183	All	Vaults - Structural Design Requirements	High
16	III	C	255	185	All	Vaults - Accessibility	Other
16	III	C	255	187	All	Vaults - Sealing, Venting, and Ventilation	Other
16	III	C	255	189	All	Vaults - Drainage and Waterproofing	High
16	III	C	255	190	All	Calorimeter or Calorimixer Structures	Other
16	III	C	255	191	All	Design Pressure of Plastic Fittings	Other
16	III	C	255	193	All	Valve Installation in Plastic Pipe	Other
16	III	C	255	195	All	Protection Against Accidental Overpressuring	High
16	III	C	255	197	All	Control of the Pressure of Gas Delivered from High Pressure Distribution Systems	High
16	III	C	255	199	All	Requirements for Design of Pressure Relief and Limiting Devices	High
16	III	C	255	201	All	Required Capacity of Pressure Relieving and Limiting Stations	High
16	III	C	255	203	All	Instrument, Control, and Sampling Piping and Components	Other
16	III	C	255	225	All	Qualification of Welding Procedures	High
16	III	C	255	227	All	Qualification of Welders	High
16	III	C	255	229	All	Limitations On Welders	Other

16	III	C	255	230	All	Quality Assurance Program	Other
16	III	C	255	231	All	Welding - Protection from Weather	High
16	III	C	255	233	All	Welding - Miter Joints	High
16	III	C	255	235	All	Preparation for Welding	High
16	III	C	255	237	All	Welding - Preheating	Other
16	III	C	255	239	All	Welding - Stress Relieving	Other
16	III	C	255	241	(a),(b)	Inspection and Test of Welds	High
16	III	C	255	241	(c)	Inspection and Test of Welds	Other
16	III	C	255	243	(a),(b),(c),(d),(e)	Nondestructive Testing - Pipeline to Operate at 125 PSIG (862 kPa) or More	High
16	III	C	255	243	(f)	Nondestructive Testing - Pipeline to Operate at 125 PSIG (kPa) or More	Other
16	III	C	255	244	All	Welding Inspector	High
16	III	C	255	245	All	Welding - Repair or Removal of Defects	High
16	III	C	255	273	All	Joining of Materials other than by Welding - General	High
16	III	C	255	279	All	Joining of Materials other than by Welding - Copper Pipe	High
16	III	C	255	281	All	Joining of Materials other than by Welding - Plastic Pipe	High
16	III	C	255	283	All	Plastic Pipe - Qualifying Joining Procedures	Other
16	III	C	255	285	(a),(b),(d)	Plastic Pipe - Qualifying Persons to make Joints	High
16	III	C	255	285	(c)(e)	Plastic Pipe - Qualifying Persons to make Joints	Other
16	III	C	255	287	All	Plastic Pipe - Inspection of Joints	Other
16	III	C	255	302	All	Notification Requirements	High
16	III	C	255	303	All	Compliance with Construction Standards	High
16	III	C	255	305	All	Inspection - General	High
16	III	C	255	307	All	Inspection of Materials	High
16	III	C	255	309	All	Repair of Steel Pipe	High
16	III	C	255	311	All	Repair of Plastic Pipe	High
16	III	C	255	313	(a),(b),(c)	Bends and Elbows	High
16	III	C	255	313	(d)	Bends and Elbows	Other
16	III	C	255	315	All	Wrinkle Bends in Steel Pipe	High
16	III	C	255	317	All	Protection from Hazards	Other
16	III	C	255	319	All	Installation of Pipe in a Ditch	Other
16	III	C	255	321	All	Installation of Plastic Pipe	High

16	III	C	255	323	All	Casing	Other
16	III	C	255	325	All	Underground Clearance	High
16	III	C	255	327	All	Cover	Other
16	III	C	255	353	All	Customer Meters and Regulators - Location	Other
16	III	C	255	355	All	Customer Meters and Regulators - Protection from Damage	Other
16	III	C	255	357	(a),(b),(c)	Customer Meters and Service Regulators - Installation	Other
16	III	C	255	357	(d)	Customer Meters and Service Regulators - Installation	High
16	III	C	255	359	All	Customer Meter Installations - Operating Pressure	Other
16	III	C	255	361	(a),(b),(c),(d)	Service Lines - Installation	Other
16	III	C	255	361	(e),(f),(g),(h),(i)	Service Lines - Installation	High
16	III	C	255	363	All	Service Lines - Valve Requirements	Other
16	III	C	255	365	(a),(c)	Service Lines - Location of Valves	Other
16	III	C	255	365	(b)	Service Lines - Location of Valves	High
16	III	C	255	367	All	Service Lines - General Requirements for Connections	Other
16	III	C	255	369	All	Service Lines - Connections to Cast Iron or Ductile Iron Mains	Other
16	III	C	255	371	All	Service Lines - Steel	Other
16	III	C	255	373	All	Service Lines - Cast Iron and Ductile Iron	Other
16	III	C	255	375	All	Service Lines - Plastic	Other
16	III	C	255	377	All	Service Lines - Copper	Other
16	III	C	255	379	All	New Service Lines not in Use	Other
16	III	C	255	381	All	Service Lines - Excess Flow Valve Performance Standards	Other
16	III	C	255	455	(a)	External Corrosion Control - Buried or Submerged Pipelines Installed after July 31, 1971	Other
16	III	C	255	455	(d),(e)	External Corrosion Control - Buried or Submerged Pipelines Installed after July 31, 1971	High
16	III	C	255	457	All	External Corrosion Control - Buried or Submerged Pipelines Installed before July 31, 1971	High
16	III	C	255	459	All	External Corrosion Control - Examination of Buried Pipeline when Exposed	Other
16	III	C	255	461	(a),(b),(d),(e),(f),(g)	External Corrosion Control - Protective Coating	Other
16	III	C	255	461	(c)	External Corrosion Control - Protective Coating	High
16	III	C	255	463	All	External Corrosion Control - Cathodic Protection	High
16	III	C	255	465	(a),(e)	External Corrosion Control - Monitoring	High

16	III	C	255	465	(b),(c),(d),(f)	External Corrosion Control - Monitoring	Other
16	III	C	255	467	All	External Corrosion Control - Electrical Isolation	Other
16	III	C	255	469	All	External Corrosion Control - Test Stations	Other
16	III	C	255	471	All	External Corrosion Control - Test Leads	Other
16	III	C	255	473	All	External Corrosion Control - Interference Currents	Other
16	III	C	255	475	All	Internal Corrosion Control - General	Other
16	III	C	255	476	(a),(c)	Internal Corrosion Control - Design and Construction of Transmission Line	High
16	III	C	255	476	(d)	Internal Corrosion Control - Design and Construction of Transmission Line	Other
16	III	C	255	479	All	Atmospheric Corrosion Control - General	Other
16	III	C	255	481	All	Atmospheric Corrosion Control - Monitoring	Other
16	III	C	255	483	All	Remedial Measures - General	High
16	III	C	255	485	(a),(b)	Remedial Measures - Transmission Lines	High
16	III	C	255	485	(c)	Remedial Measures - Transmission Lines	Other
16	III	C	255	487	All	Remedial Measures - Distribution Lines other than Cast Iron or Ductile Iron Lines	Other
16	III	C	255	489	All	Remedial Measures - Cast Iron and Ductile Iron Pipelines	Other
16	III	C	255	490	All	Direct Assessment	Other
16	III	C	255	491	All	Corrosion Control Records	Other
16	III	C	255	503	All	Test Requirements - General	Other
16	III	C	255	505	(a),(b),(c),(d)	Strength Test Requirements for Steel Pipelines to Operate at 125 PSIG (862 kPa) or More	High
16	III	C	255	505	(e),(h),(i)	Strength Test Requirements for Steel Pipelines to Operate at 125 PSIG (862 kPa) or More	Other
16	III	C	255	507	All	Test Requirements for Pipelines to Operate at less than 125 PSIG (862 kPa)	Other
16	III	C	255	511	All	Test Requirements for Service Lines	Other
16	III	C	255	515	All	Environmental Protection and Safety Requirements	Other
16	III	C	255	517	All	Test Requirements - Records	Other
16	III	C	255	552	All	Upgrading / Conversion - Notification Requirements	Other
16	III	C	255	553	(a),(b),(c),(f)	Upgrading / Conversion - General Requirements	High
16	III	C	255	553	(d),(e)	Upgrading / Conversion - General Requirements	Other

16	III	C	255	555	All	Upgrading to a Pressure of 125 PSIG (862 kPa) or More in Steel Pipelines	High
16	III	C	255	557	All	Upgrading to a Pressure Less than 125 PSIG (862 kPa)	High
16	III	C	255	559	(a)	Conversion to Service Subject to this Part	High
16	III	C	255	559	(b)	Conversion to Service Subject to this Part	Other
16	III	C	255	603	All	Operations - General Provisions	High
16	III	C	255	604	All	Operator Qualification	High
16	III	C	255	605	All	Essentials of Operating and Maintenance Plan	High
16	III	C	255	609	All	Change in Class Location - Required Study	High
16	III	C	255	611	(a),(d)	Change in Class Location - Confirmation or Revision of Maximum Allowable Operating Pressure	Other
16	III	C	255	613	All	Continuing Surveillance	Other
16	III	C	255	614	All	Damage Prevention Program	High
16	III	C	255	615	All	Emergency Plans	High
16	III	C	255	616	All	Customer Education and Information Program	High
16	III	C	255	619	All	Maximum Allowable Operating Pressure - Steel or Plastic Pipelines	High
16	III	C	255	621	All	Maximum Allowable Operating Pressure - High Pressure Distribution Systems	High
16	III	C	255	623	All	Maximum and Minimum Allowable Operating Pressure - Low Pressure Distribution Systems	High
16	III	C	255	625	(a),(b)	Odorization of Gas	High
16	III	C	255	625	(e),(f)	Odorization of Gas	Other
16	III	C	255	627	All	Tapping Pipelines Under Pressure	High
16	III	C	255	629	All	Purging of Pipelines	High
16	III	C	255	631	All	Control Room Management	High
16	III	C	255	705	All	Transmission Lines - Patrolling	High
16	III	C	255	706	All	Transmission Lines - Leakage Surveys	High
16	III	C	255	707	(a),(c),(d),(e)	Line Markers for Mains and Transmission Lines	Other
16	III	C	255	709	All	Transmission Lines - Record Keeping	Other
16	III	C	255	711	All	Transmission Lines - General Requirements for Repair Procedures	High
16	III	C	255	713	All	Transmission Lines - Permanent Field Repair	High

						of Imperfections and Damages	
16	III	C	255	715	All	Transmission Lines - Permanent Field Repair of Welds	High
16	III	C	255	717	All	Transmission Lines - Permanent Field Repairs of Leaks	High
16	III	C	255	719	All	Transmission Lines - Testing of Repairs	High
16	III	C	255	721	(b)	Distribution Systems - Patrolling	Other
16	III	C	255	723	All	Distribution Systems -Leakage Surveys and Procedures	High
16	III	C	255	725	All	Test Requirements for Reinstating Service Lines	Other
16	III	C	255	726	All	Inactive Service Lines	Other
16	III	C	255	727	(b),(c),(d),(e),(f),(g)	Abandonment or Inactivation of Facilities	Other
16	III	C	255	729	All	Compressor Stations - Procedures for Gas Compressor Units	High
16	III	C	255	731	All	Compressor Stations - Inspection and Testing of Relief Devices	High
16	III	C	255	732	All	Compressor Stations - Additional Inspections	High
16	III	C	255	735	All	Compressor Stations - Storage of Combustible Materials	Other
16	III	C	255	736	All	Compressor Stations - Gas Detection	High
16	III	C	255	739	(a),(b)	Pressure Limiting and Regulating Stations - Inspection and Testing	High
16	III	C	255	739	(c),(d),(e),(f)	Pressure Limiting and Regulating Stations - Inspection and Testing	Other
16	III	C	255	741	All	Pressure Limiting and Regulating Stations - Telemetering or Recording Gauges	Other
16	III	C	255	743	(a),(b)	Pressure and Limiting and Regulating Stations - Testing of Relief Devices	High
16	III	C	255	743	(c)	Regulator Station MAOP	Other
16	III	C	255	744	(c),(d),(e)	Service Regulators and Vents - Inspection	Other
16	III	C	255	745	All	Transmission Line Valves	High
16	III	C	255	747	All	Valve Maintenance - Distribution Systems	Other
16	III	C	255	748	All	Valve Maintenance - Service Line Valves	Other
16	III	C	255	749	All	Vault Maintenance	Other
16	III	C	255	751	All	Prevention of Accidental Ignition	High
16	III	C	255	753	All	Caulked Bell and Spigot Joints	Other
16	III	C	255	755	All	Protecting Cast Iron Pipelines	High
16	III	C	255	756	All	Replacement of Exposed or Undermined Cast Iron Piping	High
16	III	C	255	757	All	Replacement of Cast Iron Mains Paralleling Excavations	High

16	III	C	255	801	All	Reports of accidents	Other
16	III	C	255	803	All	Emergency Lists of Operator Personnel	Other
16	III	C	255	805	(a),(b),(e),(g),(h)	Leaks - General	Other
16	III	C	255	807	(a),(b),(c)	Leaks - Records	Other
16	III	C	255	807	(d)	Leaks - Records	High
16	III	C	255	809	All	Leaks - Instrument Sensitivity Verification	High
16	III	C	255	811	(b),(c),(d),(e)	Leaks - Type 1 Classification	High
16	III	C	255	813	(b),(c),(d)	Leaks - Type 2A Classification	High
16	III	C	255	815	(b),(c),(d)	Leaks - Type 2 Classification	High
16	III	C	255	817	All	Leaks - Type 3 Classification	Other
16	III	C	255	819	(a)	Leaks - Follow-Up Inspection	High
16	III	C	255	821	All	Leaks - Nonreportable Reading	High
16	III	C	255	823	(a),(b)	Interruptions of Service	Other
16	III	C	255	825	All	Logging and Analysis of Gas Emergency Reports	Other
16	III	C	255	829	All	Annual Report	Other
16	III	C	255	831	All	Reporting Safety-Related Conditions	Other
16	III	C	255	905	All	High Consequence Areas	High
16	III	C	255	907	All	General (IMP)	Other
16	III	C	255	909	All	Changes to an Integrity Management Program (IMP)	Other
16	III	C	255	911	All	Required Elements (IMP)	High
16	III	C	255	915	All	Knowledge and Training (IMP)	High
16	III	C	255	917	All	Identification of Potential Threats to Pipeline Integrity and Use of the Threat Identification in an Integrity Program (IMP)	High
16	III	C	255	919	All	Baseline Assessment Plan (IMP)	High
16	III	C	255	921	All	Conducting a Baseline Assessment (IMP)	High
16	III	C	255	923	All	Direct Assessment (IMP)	High
16	III	C	255	925	All	External Corrosion Direct Assessment (ECDA)(IMP)	High
16	III	C	255	927	All	Internal Corrosion Direct Assessment (ICDA)(IMP)	High
16	III	C	255	931	All	Confirmatory Direct Assessment (CDA)(IMP)	High
16	III	C	255	933	All	Addressing Integrity Issues (IMP)	High
16	III	C	255	935	All	Preventive and Mitigative Measures to Protect the High Consequence Areas (IMP)	High
16	III	C	255	937	All	Continual Process of Evaluation and Assessment (IMP)	High

16	III	C	255	939	All	Reassessment Intervals (IMP)	High
16	III	C	255	941	All	Low Stress Reassessment (IMP)	Other
16	III	C	255	945	All	Measuring Program Effectiveness (IMP)	Other
16	III	C	255	947	All	Records (IMP)	Other
16	III	C	255	1003	All	General Requirements of a GDPIM Plan	High
16	III	C	255	1005	All	Implementation Requirements of a GDPIM Plan	High
16	III	C	255	1007	All	Required Elements of a GDPIM Plan	High
16	III	C	255	1009	All	Required Report when Compression Couplings Fail	High
16	III	C	255	1011	All	Records an Operator Must Keep (GDPIM)	Other
16	III	C	255	1015	All	GDPIM Plan Requirements for a Master Meter or a Small Liquefied Petroleum Gas (LPG) Operator	High
16	III	C	261	15	All	Operation and Maintenance Plan	High
16	III	C	261	17	(a),(c)	Leakage Survey	High
16	III	C	261	19	All	High Pressure Piping	Other
16	III	C	261	21	All	Carbon Monoxide Prevention	High
16	III	C	261	51	All	Warning Tag Procedures	High
16	III	C	261	53	All	HEFPA Liaison	High
16	III	C	261	55	All	Warning Tag Inspection	High
16	III	C	261	57	All	Warning Tag - Class A condition	High
16	III	C	261	59	All	Warning Tag - Class B condition	High
16	III	C	261	61	All	Warning Tag - Class C Condition	Other
16	III	C	261	63	All	Warning Tag - Action and Follow-Up	Other
16	III	C	261	65	All	Warning Tag Records	Other
49	I	D	193	2011	All	Reporting	Other
49	I	D	193	2017	All	Plans and Procedures	High
49	I	D	193	2019	All	Mobile and Temporary LNG Facilities	High
49	I	D	193	2057	All	Thermal Radiation Protection	High
49	I	D	193	2059	All	Flammable Vapor-Gas Dispersion Protection	High
49	I	D	193	2067	All	Wind Forces	High
49	I	D	193	2101	All	Design - Scope	High
49	I	D	193	2119	All	Design - Records	High
49	I	D	193	2155	All	Structural Requirements	High
49	I	D	193	2161	All	Design - Dikes	High

49	I	D	193	2167	All	Covered Systems	High
49	I	D	193	2173	All	Water Removal	High
49	I	D	193	2181	All	Impoundment Design and Capacity	High
49	I	D	193	2187	All	Nonmetallic Membrane Liner	High
49	I	D	193	2301	All	Construction - Scope	High
49	I	D	193	2303	All	Construction Acceptance	High
49	I	D	193	2304	All	Corrosion Control Overview	High
49	I	D	193	2321	All	Nondestructive Tests	High
49	I	D	193	2401	All	Equipment - Scope	High
49	I	D	193	2441	All	Equipment - Control Center	High
49	I	D	193	2445	All	Sources of Power	High
49	I	D	193	2501	All	Operations - Scope	High
49	I	D	193	2503	All	Operating Procedures	High
49	I	D	193	2505	All	Operations - Cooldown	High
49	I	D	193	2507	All	Monitoring Operations	High
49	I	D	193	2509	All	Emergency Procedures	High
49	I	D	193	2511	All	Personnel Safety	High
49	I	D	193	2513	All	Transfer Procedures	High
49	I	D	193	2515	All	Investigations of Failures	High
49	I	D	193	2517	All	Purging	High
49	I	D	193	2519	All	Communication Systems	High
49	I	D	193	2521	All	Operating Records	Other
49	I	D	193	2603	All	Maintenance - General	High
49	I	D	193	2605	All	Maintenance Procedures	High
49	I	D	193	2607	All	Foreign Material	Other
49	I	D	193	2609	All	Support Systems	High
49	I	D	193	2611	All	Fire Protection	High
49	I	D	193	2613	All	Auxiliary Power Sources	High
49	I	D	193	2615	All	Isolating and Purging	High
49	I	D	193	2617	All	Maintenance - Repairs	High
49	I	D	193	2619	All	Control Systems	High
49	I	D	193	2621	All	Testing Transfer Hoses	High
49	I	D	193	2623	All	Inspecting LNG Storage Tanks	High

49	I	D	193	2625	All	Corrosion Protection	High
49	I	D	193	2627	All	Atmospheric Corrosion Control	Other
49	I	D	193	2629	All	External Corrosion Control - Buried or Submerged Components	Other
49	I	D	193	2631	All	Internal Corrosion Control	Other
49	I	D	193	2633	All	Interference Currents	Other
49	I	D	193	2635	All	Monitoring Corrosion Control	High
49	I	D	193	2637	All	Remedial Measures	High
49	I	D	193	2639	All	Maintenance Records	Other
49	I	D	193	2703	All	Design and Fabrication	Other
49	I	D	193	2705	All	Construction, Installation, Inspection, and Testing	High
49	I	D	193	2707	All	Operations and Maintenance	High
49	I	D	193	2709	All	Security	High
49	I	D	193	2711	All	Personnel Health	Other
49	I	D	193	2713	All	Training - Operations and Maintenance	High
49	I	D	193	2715	All	Training - Security	High
49	I	D	193	2717	All	Training - Fire Protection	High
49	I	D	193	2719	All	Training - Records	Other
49	I	D	193	2801	All	Fire Protection	High
49	I	D	193	2903	All	Security Procedures	High
49	I	D	193	2905	All	Protective Enclosures	High
49	I	D	193	2907	All	Protective Enclosure Construction	High
49	I	D	193	2909	All	Security Communications	High
49	I	D	193	2911	All	Security Lighting	High
49	I	D	193	2913	All	Security Monitoring	High
49	I	D	193	2915	All	Alternative Power Sources	High
49	I	D	193	2917	All	Warning Signs	Other

Consolidated Edison Company of New York, Inc.
Cases 19-E-0065, 19-G-0066
Customer Service Performance Mechanism

The Customer Service Performance Mechanism ("CSPM") described herein will be in effect for the term of the 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 this Appendix. 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. 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 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. The net number of customers used to determine the complaint rate will include only metered account customers (i.e., will not include sub-metered or master-metered consumers). 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 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), Customer Experience Center (formerly referred to as 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. The Parties acknowledge that issues related to utility customer satisfaction surveys are being addressed in Case 15-M-0566, In the Matter of Revisions to Customer Service Performance Indicators Applicable to Gas and Electric Corporations.

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.[1] 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.

v) **<u>Customer Satisfaction – Gas Emergency Calls</u>**

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 89.0 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 89.0 percent or above, up to a maximum of $3.3 million at a satisfaction level of 88.4 percent or below. System-wide emergencies will not be included in the surveys conducted under this provision.

[1] 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).

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.

Customer Service Performance Mechanism
Incentive Targets

Indicator	Maximum Revenue Adjustment	Threshold Level	Revenue Adjustment
Commission Complaints	$9 million	</ = 2.0 > 2.0 - </= 2.2 > 2.2 - </= 2.4 > 2.4	N/A $2,000,000 $5,000,000 $9,000,000
Customer Satisfaction Surveys Emergency Calls (electric only)	$18 million		
	$6 million	>/= 85.2 < 85.2 - >/= 82.2 < 82.2 - >/= 79.2 < 79.2	N/A $1,500,000 $3,000,000 $6,000,000
Customer Satisfaction Survey of Phone Center Callers (non-emergency)	$6 million	>/= 88.5 < 88.5 - >/= 86.5 < 86.5 - >/= 84.5 < 84.5	N/A $1,500,000 $3,000,000 $6,000,000
Customer Satisfaction Survey of Service Center Visitors	$6 million	>/= 89.0 < 89.0 - >/= 87.0 < 87.0 - >/= 85.0 < 85.0	N/A $1,500,000 $3,000,000 $6,000,000
Outage Notification	$8 million	Communication Timeliness; Communication Content	$300,000 per communication activity
Gas Emergency Calls	$3.3 million	<=88.4% to <89.0%	$0 to $3.3 million
Call Answer Rate	$5 million	**Rate Year 1:** >/= 66.3 < 66.3 - >/= 64.5 < 64.5 - >/= 62.8 < 62.8 - >/= 61.0 < 61.0 **Rate Year 2:** >/= 66.6 < 66.6 - >/= 64.8 < 64.8 - >/= 63.1 < 63.1 - >/= 61.3 < 61.3 **Rate Year 3:** >/= 67.0 < 67.0 - >/= 65.2 < 65.2 - >/= 63.5 < 63.5 - >/= 61.7 < 61.7	 N/A $1,000,000 $2,000,000 $4,000,000 $5,000,000 N/A $1,000,000 $2,000,000 $4,000,000 $5,000,000 N/A $1,000,000 $2,000,000 $4,000,000 $5,000,000

Appendix 19 - Advanced Metering Infrastructure (AMI) Scorecard / Metrics

Category	Service/Function	Metric	Description	Target	Report Start Date	Update Frequency
Customer Engagement	Energy Savings Messages / Tools	Customers using the AMI Portal	Percentage of customers in each region with AMI meters that log on to usage/analytics page (available via web, mobile web, tablet or apps) at least once during the reporting period, broken down by service class and low income / non-low income. Baseline established based on data from at least the first 6 months of deployment in each region. Improvement measured against regional baselines each reporting period. Additional reporting (no targets established): Percentage of customers that logged on more than once during each reporting period.	To be set once-baseline has been established for each region, and following Staff review.	Underway	Semi annual
		Customers targeted with energy saving messaging	Percentage of customers with AMI meter at least 30 days that are targeted during the reporting period with messages regarding their energy savings tools, personalized usage and/or savings tips. Data broken out by low income and non-low income. Additional reporting (no targets established): If possible, Company will track and report for each reporting period the number of customers that use the online portal once they receive targeted messaging.	Percentage of customers that will be targeted will be established after Staff review and prior to initial report on 4/30/2018.	Underway	Semi annual
		Near-Real Time Data	Number of customers with an AMI meter that have access to near real-time data via the web, mobile web, tablet or apps.	Starting at end of 3Q2018, 99% of meters deployed will be presented with near real time data. Refer to roll-out plan for quantities on a quarterly basis.	Underway	Semi annual
	Awareness / Education	Customer Awareness of AMI*	Customer awareness of AMI technology, features and benefits, measured by surveys of customers in each region. Baseline established on a regional basis prior to roll-out of AMI in each area (March 2017 for Staten Island). Subsequent progress ("check-in surveys") measured semi-annually, beginning at least 6 months after the beginning of deployment, through the end of roll-out in each region. Check-in surveys will draw from customers with AMI meters only. In the post-deployment surveys, the Company will measure low-income awareness. See Note 3 below.	To be set for each region following baseline surveys that will be done three months prior to-the deployment. Staff will review.	Underway	Semi annual

Category	Service/Function	Metric	Description	Target	Report Start Date	Update Frequency
Customer Engagement	Awareness / Education	Targeted Energy Forum	Con Edison hosted forums where the Company will provide in-depth information on the AMI plan, features, and benefits.	2 per region. Staff will review.	Underway	Annual
	Green Button Connect My Data	Green Button Connect My Data	Number of customers who share their data via GBC in the reporting period plus number of customers that continue to share based on elections made in a prior period. Establish baseline using calendar year 2018 data.	To be set once baseline has been established, and following Staff review.	Underway	Semi annual
	TOU (Time of Use) and TVP (Time Variable Pricing) tariffs	Customer Adoption of Time-Variant Rates	Number of customers with AMI meters that adopt a TOU or TVP tariff, expressed as a number and percentage of each by rate (e.g., Electric SC1 Rate III, Electric SC2 Rate II, pilot rates, etc.). The Company will document the number of customers on existing TOU or TVP rates prior to the start of AMI roll-out, for comparison purposes.	Company will report this information for tracking purposes only.	Underway	Semi annual
	Community Outreach	Community Organization Events	Number of organizational events attended where information on AMI plan, features, and benefits would be presented.	20 presentations per year. With a minimum of 4 per region in each year until the conclusion of deployment in that region.	Underway	Semi annual
Billing	Billing	Estimated Bills	Percentage of bills that were estimated for accounts with AMI meters during the reporting period.	< 1.5 % of bills will be estimated for customers with AMI	Underway	Semi annual
Outage Management	Power Quality	Proactive power quality issue identification	Reduction in truck rolls due to power quality complaints.	500 per year after full deployment of AMI in 2022.	Underway	Annual
	False Outages	Number of false outages resolved through AMI	Number of false outages that were found through AMI that Company did not have to send a crew or call to confirm.	9000 per year once AMI is fully deployed in 2022.	Underway	Annual
	Meter Reading Costs	Reduction in manual meter operations costs	Track avoided meter operations O&M costs and report.	In accordance with O&M reductions filed in the 2016 Rate Case.	Underway	Annual
	Environmental benefits resulting from less vehicle usage	Reduction in vehicle fuel consumption and vehicle emissions	Reduction in vehicle fuel consumption and vehicle emissions due to reduction in manual meter reading costs, reduction in false outages and reduction in number of field visits during outages to confirm a customer has power.	This goal will be aligned with the information provided in the November 2015 Business Plan on tons of carbon avoided.	Underway	Annual

Category	Service/Function	Metric	Description	Target	Report Start Date	Update Frequency
System Operation and Environmental Benefits	Conservation Voltage Optimization (CVO)-Networks	Number of networks deployed with CVO	Number of networks with AMI deployed and have implemented CVO.	Substation voltage schedules will be updated to incorporate the AMI feedback loop within one year following the installation of all AMI meters associated with that station. Note that for this reason, kWH reductions noted below cannot be reported on until mid-2019.	Underway	Semi annual
	Conservation Voltage Optimization (CVO)-KWh savings	Quantify kWh savings attributed to CVO	Quantify kWh savings attributed to CVO.	Goal is 1.5% energy savings based on calculations verified using a similar measurement and verification process as used for Brooklyn/Queens Demand Management project, subject to future changes in load composition.	10/31/2019	Annual
	Conservation Voltage Optimization (CVO)-Environmental benefits	Environmental benefits due to CVO	Provide total fuel consumption savings and corresponding emissions reductions.	By the end of 2022, reduction in fossil fuel consumption resulting in CO2 emission reductions of 229,000 metric tons in the CECONY service area and 369,000 metric tons in all of New York State annually, subject to changes in generation fuel mix and imports/exports with neighboring pools.	10/31/2019	Annual
AMI Meter Deployment	Number of AMI meters installed	Number of AMI meters installed	Provide the number and percentage of AMI meters installed and working by borough and in Westchester. Information will be provided on a quarterly basis.	See Note 4 for target.	Underway	Semi annual

Note 1 : Twelve months after AMI installation has been completed in each region, the Company will perform a survey to examine the link, if any, between AMI deployment and Distributed Energy Resource adoption. Results of this study will be provided at the next scheduled reporting interval.

Note 2 : The Company will file two reports in each calendar year, six months apart, with the Secretary to the Commission. The reports will contain Con Edison's Scorecard information, including provide the results from the customer surveys. All reports will no longer be required following the last reporting interval after completion of the AMI deployment.
Note 3 : In the post-deployment survey performed for each region, the Company will measure low income customer awareness. Results will be provided at the next scheduled reporting interval.

Note 4 : AMI Rollout Plan from Con Edison's November 2015 Benefit Cost Analysis spreadsheet, with exception for Westchester which has been accelerated from what was proposed in November 2015 Benefit Cost Analysis spreadsheet.

Electric Revenue Allocation and Rate Design

Revenue Allocation

Based on a three-year rate plan, the delivery revenue change for each Rate Year includes: (1) changes in delivery related revenues, e.g., total T&D revenue, including certain items related to the Monthly Adjustment Clause ("MAC"), competitive and non-competitive amounts; (2) a decrease in the revenue requirement due to the retained generation component of the MAC (Rate Year 1 only); (3) a change in the purchased power working capital component of the Merchant Function Charge ("MFC"); (4) increases in delivery revenue associated with the transfer of energy efficiency costs from the System Benefits Charge ("SBC") to base delivery rates; and (5) an increase in delivery revenue to offset the projected decrease in revenue associated with the Low-Income Program and Reconnection Fee Waiver Program (Rate Year 1 only).

The decrease in the MAC revenue requirement for Rate Year 1 was 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 delivery revenue associated with energy efficiency cost recovery that was transferred to base rates was allocated to Con Edison full service and retail access customers. The Recharge New York ("RNY") customers will receive a bill credit to offset the delivery rate increase due to the transfer of energy efficiency cost recovery to base delivery rates, as they are currently exempt from the SBC. This will permit RNY customers to continue to receive an exemption from cost recovery associated with energy efficiency programs. The T&D delivery revenue change, including incremental Low Income costs and Reconnection Fee Waiver costs, was allocated to Con Edison customers and NYPA delivery service.

The Rate Year T&D delivery revenue change, less gross receipts taxes, for each Rate Year was allocated among the classes in four steps:

Step 1: Revenue Realignment

Con Edison and NYPA T&D delivery revenues were realigned in each Rate Year to address one-third of the revenue surpluses/deficiencies resulting from the Company's 2017 Embedded Cost of Service ("ECOS") study before applying the otherwise applicable revenue changes. The specific revenue adjustments are set forth in Table 1 to this Appendix.

Surplus classes are SC8, and SC 9 time of day (TOD). Deficient classes are SC 1, SC 2, SC 5, SC 6, SC 12 TOD, and NYPA. SC 8 TOD, SC 9, and SC 12 are average classes (i.e., neither surplus nor deficient).

The revenue surpluses/deficiencies from Table 1 applicable to each customer class are also shown on Table 2 of this Appendix. The revenue surpluses/deficiencies are shown on column B1 of Table 2 and were added to the bundled T&D revenue before the revenue change to establish the re-aligned bundled T&D revenue column B2 of Table 2.

Step 2: Allocation of T&D Revenue Change

The Rate Year T&D delivery revenue change was adjusted for changes to: (1) the MAC revenue requirement; (2) purchased power working capital; (3) incremental costs associated with the transfer of energy efficiency cost recovery to base delivery rates; and, (4) incremental costs associated with the Low Income Programs including the Reconnection Fee Waiver Program. The resultant Rate Year T&D related delivery revenue increase was then allocated as a uniform percentage increase to Con Edison and NYPA classes in proportion to their respective re-aligned bundled T&D revenues column B2 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 portion of the revenue increase associated with the transfer of energy efficiency cost recovery assigned to the Con Edison classes, is allocated to Con Edison full service and retail access customers, including RNY loads, based on their sales consumption and is reflected in column C1 of Table 2. The resultant total T&D delivery changes are shown in column C2 of Table 2.

For Rate Year 1, the $ 15.5 million increase in the level of Low Income Program discounts (i.e. $70.2 million less $54.7 million), as explained in the Joint Proposal, was allocated to Con Edison classes and NYPA based on each class's pro rata share of bundled T&D delivery revenues. The incremental cost associated with the low income reconnection fee waivers reflected in the revenue allocation is $0.154 million and includes recovery of the estimated annual reconnection fee waiver costs in excess of the costs at the current level (i.e., $701,627 less $547,000).

Step 3: Allocation of MAC Decrease, Changes to Purchased Power Working Capital, Energy Efficiency Credit to RNY Customers, and Changes to Low Income Discount Program with Reconnect Fee Waiver

The impacts of the changes to the MAC revenue requirement (Rate Year 1 only) and Purchased Power Working Capital component of the MFC are shown in columns D1 and D2, respectively, of Table 2 (for Rate Years 1, 2 and 3). The per kWh decrease 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 decrease is applicable to Con Edison full service and retail access customers and the Purchased Power Working Capital component is applicable only to Con Edison full service customers. Since the SBC does not apply to RNY loads, an SBC credit was developed for RNY loads. The SBC credit for RNY loads was developed by dividing the revenue requirement associated with energy efficiency costs transferred to base delivery rates by total sales and applying the resultant rate to the estimated RNY sales. This credit is reflected in column D3 of Table 2. The impact of the change of Low Income Discount and the costs associated with the Reconnect Fee Waiver is applicable to the SC1 customers and is shown on in column

D4 of Table 2.

Step 4: Total Class Revenue Change

The total revenue changes in Rate Years 1, 2 and 3 for each class are equal to the sum of each item described in Steps 2 and 3 (i.e., column D in Table 2).

For Con Edison customers, the delivery revenue changes assigned to each class were determined as follows. The T&D delivery revenue change for each Rate Year was allocated among non-competitive revenues, customer charge revenues, reactive power demand charge revenues and competitive revenues. Customer charges for SCs 1, 2 and 6 were changed as discussed in the Rate Design section of this Appendix.

The Rate Year "non-competitive delivery revenue change" for each class was determined by adjusting the total Rate Year T&D related delivery revenue change allocated to each class by the changes in competitive service revenues, customer charge revenues, and reactive power demand charge revenues for each class. Non-competitive T&D delivery revenue changes for each class were restated for the historic period (i.e., the twelve months ended December 31, 2017), the period for which detailed billing data were available. Revenue ratios were developed for each class by dividing the Rate Year non-competitive T&D revenues, less customer charge revenue, for each class by the historic period non-competitive T&D revenues, less customer charge revenue, for each class at the current rate level. For NYPA, the Rate Year T&D change was divided by the applicable revenue ratio to determine the rate change applicable for the historical period. The revenue ratio for each class was then applied to the Rate Year "non-competitive delivery revenue change" for each class to determine each class's "non-competitive delivery revenue change" for the historic period.

Summaries of revenue increases that show revenue impacts on delivery only and total bill basis for each of the Rate Years are shown on Table 2a.

Rate Design

Revenue Neutral Rate Changes at Current (1/1/2019) Rate Level

Prior to adjusting delivery rates to reflect the rate changes allocated to the service classes for each Rate Year, demand and energy charges were redesigned revenue neutral (i.e., producing the same level of revenue) to the January 1, 2019 rate level to better align revenues with costs for certain demand-billed classes as described below.

A. Shift of Five Percent of Usage Revenues into Demand Revenues
   Demand and energy rates were redesigned to reflect revenue neutral changes to shift five percent of usage revenues into demand revenues for Rate I of SCs 5, 8, 9 and 12.

B. Adjustment to High Tension/Low Tension Differentials
The high tension and low tension differential refers to the annualized high tension /low tension demand rates for demand billed customers compared with the high tension/low tension costs based on the 2017 ECOS study. The threshold for adjusting high tension/low tension differentials in Rate I of SCs 5, 8, 9, and 12, and NYPA classes was changed from a 10 percentage point difference to a 5 percentage point difference between high tension/low tension cost ratios and high tension/low tension rate ratios. Demand rates were redesigned, revenue neutral to the January 1, 2019 rate level, to adjust the high tension/low tension differentials for Rate I of SCs 8 and 9, and Rate II of SCs 5, 9 and NYPA.

A summary of the adjustments to the high tension and low tension differentials is shown on Table 3.

Design of Rates to Collect Change in Revenue Requirement

A. Non-Competitive Con Edison T&D Delivery Rates

1. The customer charges for SCs 1, 2 and 6, including voluntary time-of-day ("VTOD") rates, were changed to move them closer to the customer costs as indicated in the ECOS study. The monthly customer charges for SC 1 were increased over the three-year term from $15.76 to $16.00 in Rate Year 1, $16.50 in Rate Year 2, and $17.00 for Rate Year 3. For SC 2, the monthly customer charges for Rate I and unmetered service were increased from $26.01 to $28.10 and from $21.60 to $23.69, respectively. The customer charge for SC 6 was increased from $33.89 to $36.60 per month. The customer charges applicable to voluntary TOD rates for SC1 (Rate II and III) and SC2 (Rate II) have been set equal to the proposed customer charge of Rate I for SCs 1 and 2, respectively, plus incremental cost associated with a TOD meter. This results in a decrease in SC 1 Rate II from $24.30 to $20.46; an increase in SC 1 Rate III from $19.87 to $20.46; and an increase for SC 2 Rate II from $30.12 to $32.56 per month per month. For the TOD demand classes, a new customer charge was created to reflect the transfer of metering costs to base rates.

2. The per kWh charges in SC 1 Rate I, SC 2 Rate I and the per kWh charges in SC 6 were changed to recover the entire non-competitive T&D delivery revenue requirement net of customer charge revenue, assigned to each respective rate class.

3. Voluntary TOD rates for SC 1 Rate II were designed to recover the overall SC 1 non-competitive delivery revenue requirement. Such rates were 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. The off-peak Domestic Hot Water Storage rate (Special Provision D) for SC1 Rate II was set

equal to the SC 1 Rate II off-peak energy delivery rates.

4. Similar to SC 1 Rate II, Voluntary TOD rates for SC1 Rate III were designed to recover the overall SC 1 non-competitive delivery revenue requirement on a revenue-neutral basis.

5. The Company established a new optional demand-based rate under SC 1 Rate IV. This rate was based on the rate structure of Rider Z, Rate IV, and includes a $27.00 customer charge, which reflects the full customer cost set forth in the 2017 ECOS study.

6. Consistent with past practice, voluntary TOD rates for SC 2 Rate II were designed to recover the overall SC 2 non-competitive T&D related delivery revenue requirement. The rates were 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.

7. The revenue neutral redesigned demand charges of Rate I of SCs 5, 8, 9 and 12 (including the shift of usage revenue to demand revenue and any applicable adjustments to high tension/low tension differentials), were changed to recover the entire overall non-competitive T&D delivery revenue requirement applicable to each class. The minimum demand delivery rates were increased by the transfer of meter charges into base delivery rates as noted in the Competitive Delivery Rates section below. The per kWh charges for Rate I of SCs 5, 8, 9 and 12 were kept at the revenue neutral level (i.e., January 1, 2019 rate level) redesigned to reflect the shift of 5 percent of usage revenues into demand revenues.

8. For SC 12 conventional customers billed for energy only (i.e., SC 12 Rate I), the per kWh charges and the minimum charge were increased by the non- competitive T&D delivery rate percentage change applicable to SC 12 (Rate I) customers. For SC 12 Rate III energy only, rates are set equal to SC 2 Rate II rates.

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, were developed to collect the revised revenue requirement applicable to these classes through changes in demand charges. The meter costs which were transferred into base delivery rates are recovered in a new customer charge as further described in Competitive Delivery Rates section below. The per kWh rates were maintained at the current rate levels and set equal across classes for all three Rate Years. The demand rates of Rate II of SCs 5, 9 and 13 were set to recover the non-competitive revenue requirement for each of these classes. The redesigned demand rates of Rate II of SCs 8 and 12, adjusted to reflect the revenue neutral adjustment of the high tension/low tension differentials for each of the Rate Years, were changed to recover the entire non-competitive revenue requirement for each of these classes for each Rate Year. Voluntary TOD rates were designed to

recover the applicable class revenue requirement of all customers not billed under mandatory TOD rates. These Voluntary TOD rates also reflect the transfer of meter costs into base delivery rates through the introduction of a new customer charge as further described below.

10. Standby rates were 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 were 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 were 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. Standby rates for SC 13 (Rate II) were developed by increasing the current rates by the non-competitive T&D delivery revenue percentage increase applicable to SC 13 Rate I. Customer charges for standby rates were based upon full customer costs including metering costs.

11. The customer charges and distribution contract demand charges in SC 11 Buy- Back Service were 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 were increased to the same level ($2.14 per billable kVar).

12. Rates for the Company's Innovative Pricing Pilot under Rider Z and Rider AA, applicable to SC 1 and SC 2 customers, were increased by the same percentage increases as the SC 1 and SC 2 rates, respectively. Customer charges under Riders Z and AA were increased to the revised levels of the SC 1 Rate I and SC 2 Rate I customer charges, respectively.

13. Smart Home Rate ("SHR") - Rates for the Company's Smart Home Rate Demonstration Project under Rider AB, applicable to SC 1 customers, were increased by the same percentages as the SC 1 Rate I rate.

B. Design of NYPA Delivery Rates

After adjusting for any high tension and low tension differential on a revenue neutral basis as described above, Rate I and Rate II charges under the P.S.C. No. 12 delivery

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service rate schedule were changed by the overall T&D delivery revenue percentage change applicable to NYPA. Reactive power charges, including those applicable to induction generators, were increased to $2.14, the same as the rate set for Con Edison customers. Consistent with the standby rate guidelines, Rate III and IV rates were developed for each class within the NYPA tariff to be revenue neutral at the proposed revenue level, i.e., Rates III and IV were developed to produce the same delivery revenues as the equivalent non-standby rates.

C. Competitive Delivery Rates

Competitive delivery rates for Con Edison customers, i.e., the MFC including the credit and collection ("C&C") related component of the Purchase of Receivables Discount Rate, were set in each Rate Year to reflect the revenue requirement for each Rate Year. The MFC for Con Edison customers consists of two components: a supply-related component, including a purchased power working capital component, and a C&C related component. There were separate MFCs calculated for (1) SC 1 customers, (2) SC 2 customers, and (3) all other customers.

i. For each Rate Year, revised revenue levels for the MFC supply-related and C&C related components were based on percentages of delivery revenue as determined in the 2017 ECOS study. The resulting revenue requirement was then divided by the Rate Year full service customer sales in each group to determine the $/kWh supply-related portion of the MFC for each service class.

ii. The Rate Year revenue requirement for the C&C related component of the MFC was developed by multiplying the total Con Edison T&D Rate Year delivery revenue requirement by the percentage represented by C&C 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 was 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 was then 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 was 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 was 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 was added to the applicable competitive supply related MFC component for each service group.

v. Competitive metering charges, which consist of meter data service provider, meter service provider, and meter ownership component charges, have been eliminated and recovery of metering costs was transferred to base delivery rates at the current (2019) rate level. For Rate I of SCs 5, 8, 9, and 12, meter costs have been transferred to the minimum delivery demand charges at the current level of non–mandatory hourly pricing ("MHP") meter charges and the remaining meter costs (i.e. incremental meter costs associated with MHP customers) for these classes are recovered in the demand charges. The metering costs for the mandatory TOD rates of SC 5, 8, and 9, 12, and 13 were transferred to a newly created customer charge, initially set at the level of the current metering charges. The metering costs for customers served under voluntary TOD rates of SC 8, 9, and 12 were transferred into a new customer charge initially set at the weighted average of the current rate level for MHP and non-MHP customers. Standby rates also reflect the metering costs in the customer charges. With the elimination of competitive metering charges, the competitive metering credits applicable to NYPA were eliminated.

vi. The billing and payment processing charge applicable to Con Edison customers was increased from $1.20 to $1.28 per bill. For customers with a combined electric and gas account, the portion of the charge applicable to electric service is $1.28 less the amount applicable to gas service (e.g., $0.64). Likewise, ESCOs pay $1.28 per bill per account, unless a customer has two separate ESCOs. In that case, the charge to the electric ESCO is $1.28 less the charge applicable to the gas ESCO (e.g., $0.64).

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-E-0065 - Joint Proposal
Embedded Cost-of-Service Study Results
For the Year 2017
Table 1A

	Service Classification	Initial Adjusted Surplus/Deficiency* ($000)	RY 1 Phase-in Surplus/Deficiency* ($000)	RY 1 Adjusted Surplus/Deficiency* ($000)	RY 2 Phase-in Surplus/Deficiency* ($000)	RY 2 Adjusted Surplus/Deficiency* ($000)	RY 3 Phase-in Surplus/Deficiency* ($000)
		(1)	(2) = (1) / 3	(3) = (1) - (2)	(4) = (1) / 3	(5) = (3) - (4)	(6) = (1) / 3
	NYPA	($1,473,430)	($491,143)	($982,287)	($491,143)	($491,144)	($491,144)
	Individual CECONY Classes						
SC 1	Residential	($4,989,671)	($1,663,223)	($3,326,448)	($1,663,223)	($1,663,225)	($1,663,225)
SC 2	General Small	(937,679)	(312,560)	(625,119)	(312,560)	(312,559)	(312,559)
SC 5	Traction	(15,375)	(5,125)	(10,250)	(5,125)	(5,125)	(5,125)
SC 5	TOD	(7,868)	(2,623)	(5,245)	(2,623)	(2,622)	(2,622)
SC 6	Street Lighting	(391,887)	(130,629)	(261,258)	(130,629)	(130,629)	(130,629)
SC 8	Apt. House	2,504,118	834,706	1,669,412	834,706	834,706	834,706
SC 8	TOD	0	0	0	0	0	0
SC 9	General Large	0	0	0	0	0	0
SC 9	TOD	5,342,644	1,780,881	3,561,763	1,780,881	1,780,882	1,780,882
SC 12	Apt. House Htg.	0	0	0	0	0	0
SC 12	TOD	(30,852)	(10,284)	(20,568)	(10,284)	(10,284)	(10,284)
	TOTAL CECONY CLASSES	1,473,430	491,143	982,287	491,143	491,144	491,144
	TOTAL SYSTEM	$0	$0	$0	$0	$0	$0

* Deficiencies shown as negative

Appendix 20
Table 1

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-E-0065 - Joint Proposal
Estimated T&D Revenues for Rate Year Ending December 31, 2020

			Proposed RY1 Rate Increase Allocated to All Customers ($)	
Proposed Rate Increase in Bundled Delivery Rev Requirement for RY - Incl. GRT			113,251,000	(a)
Proposed Rate Increase in Bundled Delivery Rev Requirement for RY - Excl. GRT			109,865,000	(b)
Adjustment to Bundled Delivery Rev Requirement for RY - Excl. GRT		(kWhr)	RY1	
- MAC Change (Retained Generation)	(p)	45,292,000,000	3,566,000	(c)
- Purchase Power Working Capital Change	(q)	22,675,000,000	4,204,465	(d)
- Reconnection Fees Waiver for Low Income Program			154,627	(d1)
- Additional Discount for Low Income Program			15,462,668	(d2)
- SBC Transfer to Base Rate			-	(e)
- Total Adjustment			23,387,760	(f)= ∑(c:e)
T&D Related Delivery Revenue Increase			133,252,760	(g) = (b) + (f)
Proposed % Rate Increase			2.40912581%	(h)

	RY1 Ending 12/31/2020 Bundled T&D Revenue at Current 1/1/19 Rates Level **(a)**	RY1 Deficiency /(Surplus)	Re-Aligned Bundled T&D Revenue at Current 1/1/2019 Rates Level	RY1 Rate Increase Allocated to All Customers	SBC Allocable to CECONY w.RNY	RY1 Total T&D Increase Including Deficiency /(Surplus) **(b)**	RY1 Total T&D Rate Increase % (RY1 vs. Current)	RY1 Target Bundled T&D Revenue at 1/1/2020 Rate Level **(c)**	RY1 MAC Increase Applicable to CECONY Customers	RY1 PPWC Change Applicable to CECONY Full Service Customers	RY1 SBC Credit to RNY	Low Income Program Impact	RY1 Total Rate Increase Excl. GRT
	(A)	(B1)	(B2) = (A) + (B1)	(B3) = (B2) * (h)	(C1) = (E2)	(C2)=(B1)+(B3) +(C1)	(C3)=(C2)/(A)	(C4)=(A)+(C2)	(D1)= -((c)/(p))*kWh	(D2) = -((d)/(q))*kWh	(D3)	(D4)=(d1)+(d2)	(D)=(C2)+(D1)+(D2)+ (D3)+(D4)
SC1	$2,144,670,944	$1,663,224	$2,146,334,168	$51,707,890	$0	$53,371,114	2.488546%	$2,198,042,058	-$1,058,100	-$1,901,327	$0	-$15,617,295	$34,794,392
SC2	438,699,172	312,560	439,011,732	10,576,345	0	10,888,905	2.482089%	449,588,077	-195,417	-341,549	0		10,351,939
SC5 Rate I	81,000	5,125	86,125	2,075	0	7,200	8.888889%	88,200	-79	0	0		7,121
SC5 Rate II	3,418,000	2,623	3,420,623	82,407	0	85,030	2.487712%	3,503,030	-9,054	0	0		75,976
SC6	1,888,970	130,629	2,019,599	48,655	0	179,284	9.491098%	2,068,254	-787	-1,854	0		176,643
SC8 Rate I&III	145,257,580	-834,706	144,422,874	3,479,329	0	2,644,623	1.820644%	147,902,203	-130,855	-96,420	0		2,417,348
SC8 Rate II	9,819,923	0	9,819,923	236,574	0	236,574	2.409123%	10,056,497	-10,550	-2,781	0		223,243
SC9 Rate I&III	1,715,387,950	0	1,715,387,950	41,325,854	0	41,325,854	2.409126%	1,756,713,804	-1,549,555	-1,763,187	0		38,013,112
SC9 Rate II	444,042,997	-1,780,881	442,262,116	10,654,651	0	8,873,770	1.998403%	452,916,767	-584,754	-81,030	0		8,207,986
SC12 Rate I&III	12,623,512	0	12,623,512	304,116	0	304,116	2.409124%	12,927,628	-14,015	-13,350	0		276,751
SC12 Rate II	11,124,455	10,284	11,134,739	268,250	0	278,534	2.503799%	11,402,989	-12,125	-2,967	0		263,442
SC13	2,120,000		2,120,000	51,073	0	51,073	2.409104%	2,171,073	-709	0			50,364
CECONY	$4,929,134,503	-$491,142	$4,928,643,361	$118,737,219	$0	$118,246,077	2.398922%	$5,047,380,580	-$3,566,000	-$4,204,465	$0	-$15,617,295	$94,858,317
NYPA	602,032,000	491,142	602,523,142	14,515,541		15,006,683	2.492672%	617,038,683			0		15,006,683
Total	$ 5,531,166,503	$ -	5,531,166,503	$ 133,252,760	$ -	$ 133,252,760	2.409126%	$ 5,664,419,263	$ (3,566,000)	$ (4,204,465)	$ -	$ (15,617,295)	$ 109,865,000

Appendix 20, Table 2
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CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

Case 19-E-0065 - Joint Proposal

Estimated T&D Revenues for Rate Year Ending December 31, 2021

			Proposed RY2 Rate Increase Allocated to All Customers	
			($)	
Proposed Rate Increase in Bundled Delivery Rev Requirement for RY - Incl. GRT			370,319,000	(a)
Proposed Rate Increase in Bundled Delivery Rev Requirement for RY - Excl. GRT			359,247,000	(b)
Adjustment to Bundled Delivery Rev Requirement for RY - Excl. GRT		(kWh)	RY2	
- MAC Change (Retained Generation)	(p)	44,546,000,000	-	(c)
- Purchase Power Working Capital Change	(q)	22,260,000,000	(565,686)	(d)
- SBC Transfer to Base Rate			(16,830,633)	(e)
- Total Adjustment			(17,396,319)	(f)= (c)+(d)+(e)
T&D Related Delivery Revenue Increase			341,850,681	(g) = (b) + (f)
Proposed % Rate Increase			6.09925648%	(h)

	(A) RY2 Ending 12/31/2021 Bundled T&D Revenue at 1/1/2020 Rates Level **(a)**	(B1) RY2 Deficiency /(Surplus)	(B2) = (A) + (B1) Re-Aligned Bundled T&D Revenue at 2020 Rates Level	(B3) = (B2) * (h) RY2 Rate Increase Allocated to All Customers	(C1) = (E2) SBC Allocable to CECONY w.RNY	(C2)=(B1)+(B3)+(C1) RY2 Total T&D Increase Including Deficiency /(Surplus) **(b)**	(C3)=(C2)/(A) RY2 Total T&D Rate Increase % (RY2 vs. RY1)	(C4)=(A)+(C2) RY2 Target Bundled T&D Revenue at 1/1/2021 Rate Level **(c)**	(D1)= -((c)/(p))*kWh RY2 MAC Increase Applicable to CECONY Customers	(D2) = -((d)/(q))*kWh RY2 PPWC Change Applicable to CECONY Full Service Customers	(D3) RY2 SBC Credit to RNY	(D4)=(C2)+(D1)+(D2)+(D3) RY2 Total Rate Increase Excl. GRT
SC1	$2,173,315,400	$1,663,224	$2,174,978,624	$132,657,525	$5,080,141	$139,400,890	6.414204%	$2,312,716,290	$0	$254,635	$0	$139,655,525
SC2	454,871,835	312,560	455,184,395	27,762,864	961,191	29,036,615	6.383472%	483,908,450	0	47,522	0	29,084,137
SC5 Rate I	88,200	5,125	93,325	5,692	384	11,201	12.699546%	99,401	0	0	0	11,201
SC5 Rate II	3,506,105	2,623	3,508,728	214,006	44,162	260,791	7.438197%	3,766,896	0	0	0	260,791
SC6	2,048,546	130,629	2,179,175	132,913	3,840	267,382	13.052282%	2,315,928	0	254	0	267,636
SC8 Rate I&III	146,348,410	-834,706	145,513,704	8,875,254	627,865	8,668,413	5.923134%	155,016,823	0	12,706	0	8,681,119
SC8 Rate II	10,256,041	0	10,256,041	625,542	51,842	677,384	6.604732%	10,933,425	0	483	0	677,867
SC9 Rate I&III	1,734,574,994	0	1,734,574,994	105,796,178	7,414,956	113,211,134	6.526736%	1,847,786,128	0	236,973	-50,306	113,397,801
SC9 Rate II	444,692,676	-1,780,881	442,911,795	27,014,326	2,791,793	28,025,238	6.302159%	472,717,914	0	10,902	-225,417	27,810,723
SC12 Rate I&III	12,902,653	0	12,902,653	786,966	68,355	855,321	6.629032%	13,757,974	0	1,830	0	857,151
SC12 Rate II	11,206,182	10,284	11,216,466	684,121	58,370	752,775	6.717498%	11,958,957	0	381	0	753,156
SC13	2,164,928		2,164,928	132,045	3,456	135,501	6.258915%	2,300,429	0	0		135,501
CECONY	$4,995,975,970	-$491,142	$4,995,484,828	$304,687,432	$17,106,355	$321,302,645	6.431229%	$5,317,278,615	$0	$565,686	-$275,723	$321,592,608
NYPA	608,816,721	$491,142	$609,307,863	$37,163,249		$37,654,391	6.184848%	$646,471,112			-	$37,654,391
Total	$ 5,604,792,691	$ -	5,604,792,691	$ 341,850,681	$ 17,106,355	$ 358,957,036	6.404466%	$ 5,963,749,727	$ -	$ 565,686	$ (275,723)	$ 359,246,999

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-E-0065 - Joint Proposal
Estimated T&D Revenues for Rate Year Ending December 31, 2022

			Proposed RY3 Rate Increase Allocated to All Customers ($)	
Proposed Rate Increase in Bundled Delivery Rev Requirement for RY - Incl. GRT			326,432,000	(a)
Proposed Rate Increase in Bundled Delivery Rev Requirement for RY - Excl. GRT			316,672,000	(b)
Adjustment to Bundled Delivery Rev Requirement for RY - Excl. GRT		(kWh)	RY3	
- MAC Change (Retained Generation)	(p)	43,990,000,000	-	(c)
- Purchase Power Working Capital Change	(q)	22,034,000,000	(106,960)	(d)
- SBC Transfer to Base Rate			(30,596,719)	(e)
- Total Adjustment			(30,703,679)	(f)= (c)+(d)+(e)
T&D Related Delivery Revenue Increase			285,968,321	(g) = (b) + (f)
Proposed % Rate Increase			4.82123714%	(h)

	(A) RY3 Ending 12/31/2022 Bundled T&D Revenue at 1/1/2021 Rates Level **(a)**	(B1) RY3 Deficiency /(Surplus)	(B2) = (A) + (B1) Re-Aligned Bundled T&D Revenue at 2021 Rates Level	(B3) = (B2) * (h) RY3 Rate Increase Allocated to All Customers	(C1) = (E2) SBC Allocable to CECONY w.RNY	(C2)=(B1)+(B3)+(C1) RY3 Total T&D Increase Including Deficiency /(Surplus) **(b)**	(C3)=(C2)/(A) RY3 Total T&D Rate Increase % (RY3 vs. RY2)	(C4)=(A)+(C2) RY3 Target Bundled T&D Revenue at 1/1/2022 Rate Level **(c)**	(D1)= -((c)/(p))*kWh RY3 MAC Increase Applicable to CECONY Customers	(D2) = -((d)/(q))*kWh RY3 PPWC Change Applicable to CECONY Full Service Customers	(D3) RY3 SBC Credit to RNY	(D4)=(C2)+(D1)+(D2)+(D3) RY3 Total Rate Increase Excl. GRT
SC1	$2,304,116,790	$1,663,224	$2,305,780,014	$111,167,122	$9,284,653	$122,114,999	5.299862%	$2,426,231,789	$0	$48,009	$0	$122,163,008
SC2	490,980,261	312,560	491,292,821	23,686,392	1,788,910	25,787,862	5.252322%	516,768,123	0	9,228	0	25,797,090
SC5 Rate I	99,401	5,125	104,526	5,039	707	10,871	10.936510%	110,272	0	0	0	10,871
SC5 Rate II	3,779,008	2,623	3,781,631	182,321	81,314	266,258	7.045711%	4,045,266	0	0	0	266,258
SC6	2,315,928	130,629	2,446,557	117,954	7,071	255,654	11.038944%	2,571,582	0	49	0	255,703
SC8 Rate I&III	153,935,506	-834,706	153,100,800	7,381,353	1,149,003	7,695,650	4.999269%	161,631,156	0	2,403	0	7,698,053
SC8 Rate II	10,988,012	0	10,988,012	529,758	96,870	626,628	5.702833%	11,614,640	0	102	0	626,730
SC9 Rate I&III	1,831,002,508	0	1,831,002,508	88,276,973	13,432,378	101,709,351	5.554845%	1,932,711,859	0	44,674	-92,627	101,661,398
SC9 Rate II	463,043,481	-1,780,881	461,262,600	22,238,564	5,024,502	25,482,185	5.503195%	488,525,666	0	2,078	-415,055	25,069,208
SC12 Rate I&III	13,860,806	0	13,860,806	668,262	125,860	794,122	5.729263%	14,654,928	0	345	0	794,467
SC12 Rate II	11,918,483	10,284	11,928,767	575,114	106,769	692,167	5.807509%	12,610,650	0	73	0	692,240
SC13	2,300,429		2,300,429	110,909	6,364	117,273	5.097875%	2,417,702	0	0		117,273
CECONY	$5,288,340,613	-$491,142	$5,287,849,471	$254,939,761	$31,104,401	$285,553,020	5.399671%	$5,573,893,633	$0	$106,961	-$507,682	$285,152,299
NYPA	643,089,709	$491,142	$643,580,851	$31,028,559		$31,519,701	4.901291%	$674,609,410			-	$31,519,701
Total	$ 5,931,430,322	$ -	5,931,430,322	$ 285,968,320	$ 31,104,401	$ 317,072,721	5.345637%	$ 6,248,503,043	$ -	$ 106,961	$ (507,682)	$ 316,672,000

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-E-0065 - Joint Proposal
Summary of Revenue Increases
Rate Year (RY) 1

	Current Revenues at 1/1/19 Rates		RY1 Rate Change with GRT						RY1 Increase %	
	Rate Year Delivery Revenue Excl. Low Income Discount Including GRT [1]	Rate Year Total Bill Revenue Including GRT [2]	Rate Year T&D Increase	Incremental Low Income	Incremental Low Income Discount	SBC [3]	Tax Sur-Credit [4]	Total Rate Year T&D Increase	T&D % Increase Over RY1 Revenue at 1/1/19 Rate Level	Bill % Increase Over RY1 Revenue at 1/1/19 Rate Level
	(A)	(B)	(C1)	(C2)	(C3)	(C4)	(C5)	(C)=∑(C1:C5)	(D)=(C)/(A)	(E)=(C)/(B)
SC 1	$2,374,404,032	$3,168,080,717	$45,718,392	$6,246,965	-$16,098,614	-$26,833,378	$100,982,964	$110,016,329	4.6%	3.5%
SC 2	480,894,069	627,475,328	9,393,226	1,277,756		-4,955,759	20,142,190	25,857,413	5.4%	4.1%
SC 5 Rate I	97,269	156,327	7,090	251		-1,997	5,110	10,453	10.7%	6.7%
SC 5 Rate II	5,543,249	12,334,887	68,362	9,956		-229,618	151,586	285	0.0%	0.0%
SC 6	2,022,365	2,612,942	176,209	5,878		-19,967	124,234	286,355	14.2%	11.0%
SC 8 Rate I&III	174,066,053	272,219,982	2,071,503	420,347		-3,318,482	7,601,617	6,774,986	3.9%	2.5%
SC 8 Rate II	12,033,433	19,947,168	201,542	28,581		-267,555	635,278	597,846	5.0%	3.0%
SC 9 Rate I&III	2,069,526,289	3,231,841,256	34,191,978	4,992,684		-39,035,088	79,277,646	79,427,221	3.8%	2.5%
SC9 Rate II	567,889,771	1,006,511,449	7,173,737	1,287,216		-13,657,289	25,407,030	20,210,695	3.6%	2.0%
SC 12 Rate I&III	15,938,277	26,450,551	248,539	36,741		-355,409	511,605	441,476	2.8%	1.7%
SC 12 Rate II	13,868,451	22,963,339	239,153	32,408		-307,489	523,708	487,780	3.5%	2.1%
SC 13	2,136,829	2,668,348	45,746	6,170		-17,970	218,452	252,398	11.8%	9.5%
CECONY	$5,718,420,088	$8,393,262,294	$99,535,477	$14,344,954	-$16,098,614	-$89,000,000	$235,581,421	$244,363,238	4.3%	2.9%
NYPA	589,167,832	1,144,556,480	13,715,523	1,753,660		0	31,418,579	46,887,762	8.0%	4.1%
Total	$6,307,587,920	$9,537,818,774	$113,251,000	$16,098,614	-$16,098,614	-$89,000,000	$267,000,000	$291,251,000	**4.6%**	**3.1%**

Notes

(1) Delivery revenue is defined as total bill revenue less MSC and GRT associated with supply.

(2) Includes rate year delivery revenue in (1) plus an estimate for the MSC and GRT. Includes supply estimates for retail access customers and NYPA.

(3) Reflects the impact from the energy efficiency cost recovery transferred from the SBC to base delivery rates in RY1.

(4) Reflects the impact from the elimination of the tax sur-credit in the current year.

Appendix 20, Table 2A
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CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-E-0065 - Joint Proposal
Summary of Revenue Increases
Rate Year (RY) 2

	Current Revenues at 1/1/20 Rates		RY2 Rate Change with GRT			RY2 Increase %	
	Rate Year Delivery Revenue Incl. Low Income Discount Including GRT [1]	Rate Year Total Bill Revenue Including GRT [2]	Rate Year T&D Increase	EAMs [3]	Total Rate Year T&D Increase	T&D % Increase Over RY2 Revenue at 1/1/20 Rate Level	Bill % Increase Over RY2 Revenue at 1/1/20 Rate Level
	(A)	(B)	(C1)	(C2)	(C)=(C1)+(C2)	(D)=(C)/(A)	(E)=(C)/(B)
SC 1	$2,470,666,431	$3,251,943,456	$143,960,112	$6,457,226	$150,417,338	6.1%	4.6%
SC 2	512,457,510	660,279,446	29,980,594	1,100,058	31,080,652	6.1%	4.7%
SC 5 Rate I	107,723	166,781	11,546	0	11,546	10.7%	6.9%
SC 5 Rate II	5,546,690	12,338,349	268,829	51,007	319,837	5.8%	2.6%
SC 6	2,287,773	2,878,353	275,885	3,809	279,694	12.2%	9.7%
SC 8 Rate I&III	178,736,662	275,296,337	8,948,696	716,370	9,665,067	5.4%	3.5%
SC 8 Rate II	12,856,045	20,828,863	698,761	139,316	838,077	6.5%	4.0%
SC 9 Rate I&III	2,119,130,935	3,259,480,023	116,893,049	8,242,504	125,135,553	5.9%	3.8%
SC9 Rate II	576,950,238	1,006,301,208	28,667,930	3,806,417	32,474,346	5.6%	3.2%
SC 12 Rate I&III	16,349,441	26,861,748	883,571	54,813	938,384	5.7%	3.5%
SC 12 Rate II	14,117,933	23,094,734	776,370	59,381	835,751	5.9%	3.6%
SC 13	2,382,898	2,914,419	139,678	4,518	144,196	6.1%	4.9%
CECONY	$5,911,590,279	$8,542,383,717	$331,505,022	$20,635,419	$352,140,440	6.0%	4.1%
NYPA	627,582,212	1,173,746,848	38,815,008	2,402,098	41,217,107	6.6%	3.5%
Total	$6,539,172,491	$9,716,130,565	$370,320,030	$23,037,517	$393,357,547	**6.0%**	**4.0%**

Notes
[1] Delivery revenue is defined as total bill revenue less MSC and GRT associated with supply.
[2] Includes rate year delivery revenue in (1) plus an estimate for the MSC and GRT. Includes supply estimates for retail access customers and NYPA.
[3] Reflects the impact from the EAMs recoveries in RY2.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

Case 19-E-0065 - Joint Proposal
Summary of Revenue Increases
Rate Year (RY) 3

	Current Revenues at 1/1/21 Rates		RY3 Rate Change with GRT			RY3 Increase %	
	Rate Year Delivery Revenue Incl. Low Income Discount Including GRT (1)	Rate Year Total Bill Revenue Including GRT (2)	Rate Year T&D Increase	EAMs (3)	Total Rate Year T&D Increase	T&D % Increase Over RY3 Revenue at 1/1/21 Rate Level	Bill % Increase Over RY3 Revenue at 1/1/21 Rate Level
	(A)	(B)	(C1)	(C2)	(C)=(C1)+(C2)	(D)=(C)/(A)	(E)=(C)/(B)
SC 1	$2,606,726,782	$3,382,214,360	$125,928,137	$3,945,164	$129,873,301	5.0%	3.8%
SC 2	550,731,201	700,147,359	26,592,170	896,257	27,488,427	5.0%	3.9%
SC 5 Rate I	119,472	178,530	11,206	762	11,968	10.0%	6.7%
SC 5 Rate II	5,851,363	12,643,006	274,464	39,774	314,238	5.4%	2.5%
SC 6	2,565,743	3,156,321	263,584	4,046	267,630	10.4%	8.5%
SC 8 Rate I&III	186,731,183	282,700,060	7,935,311	447,032	8,382,343	4.5%	3.0%
SC 8 Rate II	13,674,277	21,765,191	646,046	92,572	738,618	5.4%	3.4%
SC 9 Rate I&III	2,217,373,253	3,339,293,709	104,794,657	5,556,937	110,351,594	5.0%	3.3%
SC9 Rate II	594,718,766	1,014,383,280	25,841,854	2,466,287	28,308,141	4.8%	2.8%
SC 12 Rate I&III	17,374,727	27,887,010	818,953	84,219	903,172	5.2%	3.2%
SC 12 Rate II	14,866,517	23,784,240	713,575	59,291	772,866	5.2%	3.2%
SC 13	2,524,399	3,055,919	120,887	2,654	123,541	4.9%	4.0%
CECONY	$6,213,257,682	$8,811,208,985	$293,940,845	$13,594,994	$307,535,839	4.9%	3.5%
NYPA	665,312,170	1,202,195,502	32,491,155	1,828,030	34,319,185	5.2%	2.9%
Total	$6,878,569,852	$10,013,404,487	$326,432,000	$15,423,024	$341,855,024	**5.0%**	**3.4%**

Notes

(1) Delivery revenue is defined as total bill revenue less MSC and GRT associated with supply.

(2) Includes rate year delivery revenue in (1) plus an estimate for the MSC and GRT. Includes supply estimates for retail access customers and NYPA.

(3) Reflects the impact from the EAMs recoveries in RY3.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

Case 19-E-0065 - Joint Proposal

Summary of Revenue Neutral Redesigned Rates to Reflect High Tension/Low Tension Differential Adjustments (Based on a 5 Percentage Point Difference)

SC 8 Rate I, SC 9 Rate I, SC5 Rate II, SC9 Rate II, and NYPA Rate II

At Current 1/1/2019 Rate Level

		SC 8 Rate I				SC 9 Rate I		
Demand	Block	Current Rate 1/1/2019	Redesigned to Reflect Shift of 5% of Rev. Recovered from Energy to Demand at 1/1/2019	Full HT/LT Differential Adjustment	Block	Current Rate 1/1/2019	Redesigned to Reflect Shift of 5% of Rev. Recovered from Energy to Demand at 1/1/2019	Full HT/LT Differential Adjustment
Summer								
LT	0-10 kW	$375.88	$380.53	$380.53	0-5 kW	$173.95	$176.77	$176.77
	> 10 kW	$33.90	$34.33	$34.32	> 5 kW	$25.41	$25.83	$25.83
HT	0-10 kW	$296.11	$299.77	$273.87	0-5 kW	$134.48	$136.66	$122.81
	> 10 kW	$26.70	$27.04	$24.69	> 5 kW	$19.27	$19.59	$18.03
Winter								
LT	0-10 kW	$290.57	$294.16	$294.16	0-5 kW	$138.95	$141.21	$141.21
	> 10 kW	$26.19	$26.52	$26.51	> 5 kW	$20.07	$20.40	$20.40
HT	0-10 kW	$210.79	$213.40	$187.50	0-5 kW	$99.53	$101.15	$87.30
	> 10 kW	$18.97	$19.21	$16.86	> 5 kW	$13.91	$14.14	$12.58
	Annualized Charges							
	HT	$28.76	$29.12	$29.11		$21.85	$22.21	$22.21
	LT	$21.55	$21.82	$19.47		$15.70	$15.96	$14.40
	% HT/LT	75%	75%	67%		72%	72%	65%
	HT/LT % Based on Costs [1]			67%				65%

		SC 5 Rate II		SC 9 Rate II		NYPA Rate II	
Demand	Time Period (Per kW)	Current Rate 1/1/2019	Full HT/LT Differential Adjustment	Current Rate 1/1/2019	Full HT/LT Differential Adjustment	Current Rate 1/1/2019	Full HT/LT Differential Adjustment
Summer							
LT	M-F, 8 AM - 6 PM	$4.60	$4.60	$8.33	$8.33	$7.40	$7.40
	M-F, 8 AM - 10 PM	$9.46	$9.35	$15.56	$16.79	$20.46	$21.77
	All Hours - All Days	$9.06	$9.98	$16.70	$15.17	$22.47	$20.09
		$23.12	$23.93	$40.59	$40.29	$50.33	$49.26
HT	M-F, 8 AM - 6 PM	$4.60	$4.60	$8.33	$8.33	$7.40	$7.40
	M-F, 8 AM - 10 PM	$9.46	$9.35	$15.56	$16.79	$20.46	$21.77
		$14.06	$13.95	$23.89	$25.12	$27.86	$29.17
Winter							
LT	M-F, 8 AM - 10 PM	$8.04	$7.93	$11.48	$12.71	$11.89	$13.20
	All Hours - All Days	$2.86	$3.78	$5.36	$3.83	$7.11	$4.73
		$10.90	$11.71	$16.84	$16.54	$19.00	$17.93
HT	M-F, 8 AM - 10 PM	$8.04	$7.93	$11.48	$12.71	$11.89	$13.20
	Annualized Charges						
	HT	$10.05	$9.94	$15.62	$16.85	$17.21	$18.52
	LT	$14.97	$15.78	$24.76	$24.46	$29.44	$28.37
	% HT/LT	67%	63%	63%	69%	58%	65%
	HT/LT % Based on Costs [1]		61%		69%		66%

[1] See Exhibit (ERP-1) Schedule 1

Appendix 20
Table 3

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

Case 19-E-0065 - Joint Proposal

Factor Used to Allocate Certain Costs Between NYPA and Con Edison Classes

PASNY Allocation

	Bundled T&D Revenues at 1/1/2020 Rate Level*	Bundled T&D Revenues at 1/1/2021 Rate Level*	Bundled T&D Revenues at 1/1/2022 Rate Level*
	RY1 (Effective 1/1/2020)	RY2 (Effective 1/1/2021)	RY3 (Effective 1/1/2022)
NYPA	$617,038,683	$646,471,112	$674,609,410
Coned	4,983,545,535	5,254,004,980	5,510,741,238
Total	$5,600,584,218	$5,900,476,092	$6,185,350,648
% NYPA	11.02%	10.96%	10.91%
% Coned	88.98%	89.04%	89.09%
Total	100.00%	100.00%	100.00%

*Includes Low Income Discount, Reconnect Fee Wavier, and Purchase Power Working Capital ("PPWC")

Appendix 20
Table 4

Consolidated Edison Company of New York, Inc.
Case 19-G-0066

Gas Revenue Allocation and Rate Design

1. Revenue Allocation

Table 1 provides the revenue allocation for each Rate Year, which is explained below.
For the first Rate Year, the $45,782,000 net increase in the Company's delivery revenue requirement ($47,218,000, less gross receipts tax of $1,436,000), was allocated to firm sales and firm transportation customers in SC 1, 2, 3, 9 and 13 in the following manner:

(a) The Rate Year total delivery revenues, including competitive and non-competitive revenues, at the current level for SC 1, SC 2 Rate 1, Rider H, SC 3 and Rider J Rate II were realigned in a revenue neutral manner to reduce interclass deficiencies and surpluses as indicated by the Company's embedded cost of service ("ECOS") study. For each Rate Year, deficiency and surplus indications have been reduced by one-third.
(b) The Rate Year net delivery revenue increase of $45,782,000 was adjusted to reflect the incremental low income program costs of $14,129,715 ($13,700,000 excluding gross receipts tax) for a total increase of $61,347,715 ($59,482,000 excluding gross receipts tax).
(c) This Rate Year adjusted delivery increase of $59,482,000 (excluding gross receipts tax) was then allocated to each class by applying the overall Rate Year percentage increase to each class' Adjusted Rate Year delivery revenue as realigned for ECOS surplus and deficiency indications.
(d) The total delivery revenue increase by class was determined by subtracting the Adjusted Delivery Revenue at the Rate Year Level from the Total Delivery Revenues at the current rate level.
(e) The Rate Year 1 overall percentage rate change for each class was determined by dividing the total Rate Year 1 delivery rate change by the total delivery revenue at current rates.

For the second and third Rate Years, the allocation of the total increase in the Company's revenue requirement, less gross receipts tax, was calculated in a similar fashion.

The overall percentage rate changes for each class for Rate Years 2 and 3 were also determined by dividing the total Rate Year delivery rate changes by the total Rate Year delivery revenues at current rates. The RY2 delivery revenues at current rates reflect the RY1 non-competitive base tariff rates as well as the RY1 billing and payment processing rates, RY1 Merchant Function Charge ("MFC") supply and Merchant Function Charge Credit and Collection ("C&C") targets. The RY3 total Rate Year delivery revenues at current rates reflect the RY2 non-competitive base tariff rates as well as the billing and processing rates, RY2 MFC supply and MFC C&C targets.

A summary of revenue impacts by class, on a delivery-only and total-bill basis for each of the

Rate Years, is shown on Table 1a.

2. Rate Design

The rate design process for each Rate Year consisted of the following steps:

- Determining the amount of the revenue increase applicable to competitive charges;
- Determining the amount of the revenue increase to be applied to non-competitive charges; and
- Designing rates for non-competitive charges.

Competitive Delivery Charges

The competitive delivery components include the Merchant Function Charge fixed components, that is, the MFC supply and credit and collections components; the purchase of receivables ("POR") credit and collections component and the billing and payment processing ("BPP") charge, as discussed in Section 3 below. For each Rate Year revised revenue levels for the MFC fixed components, POR credit and collections component were based on percentages of delivery revenue as determined in the Gas ECOS study.

The amount of the revenue increase attributable to the competitive service charges reflects the change in the MFC revenues and, for Rate Year 1, the change in the BPP revenues. There were no revenue changes associated with the BPP charge for Rate Years 2 and 3 since the BPP rate will remain at the level set in RY1 for the remaining two rate years. The change in the MFC revenues for each Rate Year was determined by taking the difference between the MFC target revenues calculated at the Rate Year level and the MFC targets revenues for the previous Rate Year. The change in the BPP revenues was determined by taking the difference between the BPP revenues calculated at the proposed BPP rate and the BPP revenues priced at the previous Rate Year's BPP rate.

Table 2 provides the MFC Supply and MFC C&C Targets for all three Rate Years.

Non-Competitive Delivery Revenues and Rates

The non-competitive delivery revenue increase by class was determined by subtracting the increase in the competitive delivery revenues from the total delivery revenue increase as shown on Table 1.

A summary of the proposed non-competitive rate design methodology, which was used for all three Rate Years, is described below.

The minimum charges (the charge for the delivery of the first three therms or less) for SC 1, SC 2 Rate I, SC 2 Rate II, SC 3, SC 13 and for the corresponding SC 9 rates, will increase in all three Rate Years, and are shown in Section H.2.a (i) of the Joint Proposal.

After considering the amount of the delivery revenue increase attributable to changes in the minimum charges, the remaining non-competitive delivery revenue increase within each class was allocated as follows:

A. For SC 1 and the corresponding SC 9 rate, the balance of the revenue increase was collected through the volumetric rate block (i.e., for all usage over 3 therms per month).

B. The charges for the first volumetric rate block (i.e., for usage from 4 to 90 therms) within SC 2 were set equal for Rate I and Rate II. The charges for the remaining two volumetric rate blocks within Rate I and Rate II (i.e., for usage from 91 to 3,000 therms and for usage greater than 3,000 therms) were increased, on a uniform percentage basis, based upon the remaining revenue increases for Rate I and Rate II after deducting the change in annual revenues attributable to the minimum charge, the first volumetric (4-90 therms) per therm charge and the air conditioning rates (described below).

C. The charges for the three volumetric rate blocks within SC 3 and the corresponding SC 9 rates (i.e., for usage from 4 to 90 therms, for usage from 91 to 3,000 therms and for usage greater than 3,000 therms) were increased, on a uniform percentage basis, based upon the remaining revenue increase for this class after deducting the changes in annual revenues attributable to the minimum charge and to the air conditioning rates (as explained below).

D. The two volumetric rate blocks within SC 13 and the corresponding SC 9 rates were increased, on a uniform percentage basis, based on the revenue increase for this class.

E. 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.

F. Rider G (Economic Development Zone) and Rider I (Gas Manufacturing Incentive) rates were set equal to the applicable SC 2 rates for the first 250 therms per month of usage. The delivery rates for usage from 251-3,000 therms (the "penultimate rate") and in excess of 3,000 therms (the "terminal rate") were increased at the same uniform percentage as their applicable SC 2 rates which maintains the relationship that exists today between the penultimate and terminal delivery rates for Riders G and I and SC 2 delivery rates.

G. Distributed generation rates under Riders H and J were changed as follows:

- The Rider H, Distributed Generation minimum charges were increased by the same percentage increase as the SC 2 Rate I minimum charge. The per therm rates and the contract demand rate were increased, on a uniform percentage basis, based upon the remaining revenue increase after deducting the changes in annual revenues attributable to the minimum charge.
- The Rider J Rate I minimum charge, applicable to SC 1 and equivalent SC 9 customers, was increased by the same percentage increase as the SC 1 minimum charge. The per therm delivery rate was increased by the same percentage increase as applied to the SC 1 per therm delivery rate.
- The Rider J Rate II minimum charge, applicable to SC 3 and equivalent SC 9 customers in buildings with four or less dwelling units, was increased by the same

percentage increase as the SC 3 minimum charge. The per therm rate was increased based upon the remaining revenue increase after deducting the change in annual revenues attributable to the minimum charge.

H. No change was allocated to SC 14, and bypass customers taking firm service under contract rates.

Rates in all three Rate Years in the SC 1, SC 2 Rate I, SC 2 Rate II, SC 3 and SC 13 classes reflect increases to account for the increase in the low income funding level from $10.9 million to $24.6 million.

3. Competitive Service Charges

Con Edison will continue to unbundle the following competitive service charges:

A. Merchant Function Charge

The Merchant Function Charge, 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 2.
- C&C Component – This component will change each Rate Year based upon the rate design targets shown in Table 2. 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 percentage, based upon the rate design targets shown in Table 2.
- Uncollectible Accounts Expense ("UBs") associated with supply – this component will change each month in the manner described below.

Separate MFC charges will continue to be established for SC 1, SC 2 Rate I, SC 2 Rate II, 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 be update to reflect the overall uncollectible rate of 0.46%, with uncollectible rates of 0.72% for residential customers and 0.28% for non-residential customers.

B. Billing and Payment Processing Charge

The BPP Charge for gas will increase to $1.28 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 $0.64 for gas BPP.

C. Transition Adjustment for Competitive Services

The Transition Adjustment for Competitive Services ("TACS") reconciles any BPP lost revenue attributable to customers migrating to retail access and being billed for their gas use through an ESCO consolidated bill. 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.

D. Purchase of Receivable Discount Percentage

As noted above, The POR discount percentage reflects the C&C charges related to gas transportation customers whose ESCOs participate in the Company's POR program based upon the rate design targets shown in Table 2. The POR Discount Percentage also reflects the reconciliation of prior periods credit and collection expenses and recoveries.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

Case 19-G-0066 - Joint Proposal

Allocation of Incremental Revenue Requirement Among Service Classes for Rate Year 1

Proposed Rate Increase in Bundled Delivery Rev Requirement - Incl. GRT	$47,218,000
Proposed Rate Increase in Bundled Delivery Rev Requirement - Excl. GRT	$45,782,000
Additional Discount for Low Income Program	$13,700,000
Total Delivery Revenue Increase	$59,482,000
Percentage Delivery Revenue Increase	4.213%

	(1)	(2)	(3)=(1)+(2)	(4)=(3)* %	(5)=(3)+(4)	(6)=(2)+(4)	(7) = (6)/(1)	(8)	9 = (6)+(8)
Service Class	Rate Year Bundled Total Delivery Rev. ($)	(Surplus)/ Deficiency (a) ($)	Adjusted Rate Year Del Revenue ($)	Rate Increase **4.213%** ($)	Adj Delivery Rev incl Rate Increase at RY Rate Level ($)	Delivery Rate Year Increase ($)	Rate Year Increase (%)	Low Income Program Impact ($)	Total Rate Year Increase ($)
SC No. 1	221,814,774	(5,654,469)	216,160,305	9,106,801	225,267,106	3,452,332	1.56%	(5,875,000)	(2,422,668)
SC No. 2 Rate I	128,551,332	(2,645,273)	125,906,059	5,304,404	131,210,462	2,659,130	2.07%		2,659,130
SC No. 2 Rate I, Rider H	11,684,994	(240,449)	11,444,545	482,157	11,926,702	241,708	2.07%		241,708
SC No. 2 Rate II	217,957,683	0	217,957,683	9,182,525	227,140,208	9,182,525	4.21%		9,182,525
SC No. 3	831,391,019	8,540,000	839,931,019	35,386,169	875,317,188	43,926,169	5.28%	(7,825,000)	36,101,169
SC No. 3, Rider J	18,663	191	18,854	794	19,648	986	5.28%		986
SC. No. 13	454,549	0	454,549	19,150	473,699	19,150	4.21%		19,150
Sub-Total	1,411,873,013	-	1,411,873,013	59,482,000	1,471,355,013	59,482,000	4.21%	(13,700,000)	45,782,000
SC No. 14	467,030								
Negotiated	2,095,000								
Total	1,414,435,044								

(a) Represents 1/3 of the (Surplus)/Deficiency Indications

Determination of Non-Competitive Delivery Rate Increase by Service Class for Rate Year 1

	(1)	(2)	(3)	(4)	(5)=(2)+(3)+(4)	(6)=(1)-(5)
		Incremental Competitive Service Revenues				
Service Class	Rate Year Increase ($)	Billing and Payment Processing ($)	MFC Fixed Supply Related ($)	Total MFC Credit & Collection Related ($)	Total ($)	Non-Competitive Rate Year Delivery Revenue Increase ($)
SC No. 1	3,452,332	280,393	(31,178)	(195,340)	53,875	3,398,457
SC No. 2 Rate I	2,659,130	31,371	(90,574)	(831,847)	(891,050)	3,550,180
SC No. 2 Rate I, Rider H	241,708	200	(75,310)	(190,689)	(265,799)	507,507
SC No. 2 Rate II	9,182,525	32,769	(260,433)	(1,311,381)	(1,539,045)	10,721,570
SC No. 3	43,926,169	147,299	(493,463)	(4,175,352)	(4,521,516)	48,447,685
SC No. 3, Rider J	986	3	(37)	(159)	(193)	1,178
SC. No. 13	19,150	401	(1,077)	(2,728)	(3,405)	22,555
Sub-Total	59,482,000	492,435	(952,072)	(6,707,496)	(7,167,133)	66,649,133
SC No. 14	0					
Negotiated	0					
Total	59,482,000					

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-G-0066 - Joint Proposal
Allocation of Incremental Revenue Requirement Among Service Classes for Rate Year 2

Proposed Rate Increase in Bundled Delivery Rev Requirement - Incl. GRT	$176,306,000
Proposed Rate Increase in Bundled Delivery Rev Requirement - Excl. GRT	$170,920,000
Additional Discount for Low Income Program	
Total Delivery Revenue Increase	$170,920,000
Percentage Delivery Revenue Increase	11.489%

	(1)	(2)	(3)=(1)+(2)	(4)=(3)* %	(5)=(3)+(4)	(6)=(2)+(4)	(7) = (6)/(1)
Service Class	Rate Year Bundled Total Delivery Rev. ($)	(Surplus)/ Deficiency (a) ($)	Adjusted Rate Year Del Revenue ($)	Rate Increase **11.489%** ($)	Adj Delivery Rev incl Rate Increase at RY Rate Level ($)	Delivery Rate Year Increase ($)	Rate Year % Increase
SC No. 1	223,387,353	(5,654,469)	217,732,884	25,015,554	242,748,437	19,361,084	8.67%
SC No. 2 Rate I	131,745,308	(2,645,273)	129,100,035	14,832,435	143,932,470	12,187,162	9.25%
SC No. 2 Rate I, Rider H	15,570,645	(240,449)	15,330,196	1,761,302	17,091,498	1,520,853	9.77%
SC No. 2 Rate II	229,819,258	0	229,819,258	26,404,169	256,223,427	26,404,169	11.49%
SC No. 3	886,634,361	8,540,000	895,174,361	102,847,497	998,021,859	111,387,498	12.56%
SC No. 3, Rider J	19,643	191	19,834	2,279	22,113	2,470	12.57%
SC. No. 13	494,068	0	494,068	56,764	550,832	56,764	11.49%
Sub-Total	1,487,670,635	-	1,487,670,635	170,920,000	1,658,590,635	170,920,000	11.49%
SC No. 14	467,030						
Negotiated	2,095,000						
Total	1,490,232,666						

(a) Represents 1/3 of the (Surplus)/Deficiency Indications

Determination of Non-Competitive Delivery Rate Increase by Service Class for Rate Year 2

	(1)	(2)	(3)	(4)	(5)=(2)+(3)+(4)	(6)=(1)-(5)
		Incremental Competitive Service Revenues				
Service Class	Rate Year Increase ($)	Billing and Payment Processing ($)	MFC Fixed Supply Related ($)	Total MFC Credit & Collection Related ($)	Total ($)	Non-Competitive Rate Year Delivery Revenue Increase ($)
SC No. 1	19,361,084	0	12,109	38,492	50,601	19,310,484
SC No. 2 Rate I	12,187,162	0	7,091	54,719	61,810	12,125,351
SC No. 2 Rate I, Rider H	1,520,853	0	7,688	16,472	24,160	1,496,693
SC No. 2 Rate II	26,404,169	0	20,670	87,562	108,233	26,295,937
SC No. 3	111,387,498	0	196,417	697,903	894,320	110,493,178
SC No. 3, Rider J	2,470	0	15	41	56	2,414
SC. No. 13	56,764	0	88	188	275	56,489
Sub-Total	170,920,000	0	244,078	895,378	1,139,455	169,780,545
SC No. 14	0					
Negotiated	0					
Total	170,920,000					

Appendix 21, Table 1
Page 2 of 3

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-G-0066 - Joint Proposal
Allocation of Incremental Revenue Requirement Among Service Classes for Rate Year 3

Proposed Rate Increase in Bundled Delivery Rev Requirement - Incl. GRT	$170,350,000
Proposed Rate Increase in Bundled Delivery Rev Requirement - Excl. GRT	$165,146,000
Additional Discount for Low Income Program	
Total Delivery Revenue Increase	$165,146,000
Percentage Delivery Revenue Increase	9.871%

Service Class	(1) Rate Year Bundled Total Delivery Rev. ($)	(2) (Surplus)/ Deficiency (a) ($)	(3)=(1)+(2) Adjusted Rate Year Del Revenue ($)	(4)=(3)* % Rate Increase 9.871% ($)	(5)=(3)+(4) Adj Delivery Rev incl Rate Increase at RY Rate Level ($)	(6)=(2)+(4) Delivery Rate Year Increase ($)	(7) = (6)/(1) Rate Year % Increase
SC No. 1	240,769,196	(5,654,469)	235,114,726	23,209,238	258,323,964	17,554,769	7.29%
SC No. 2 Rate I	144,246,492	(2,645,273)	141,601,219	13,978,097	155,579,316	11,332,823	7.86%
SC No. 2 Rate I, Rider H	17,561,406	(240,449)	17,320,957	1,709,830	19,030,787	1,469,381	8.37%
SC No. 2 Rate II	259,560,507	0	259,560,507	25,622,392	285,182,899	25,622,392	9.87%
SC No. 3	1,010,243,348	8,540,000	1,018,783,348	100,568,712	1,119,352,060	109,108,712	10.80%
SC No. 3, Rider J	22,115	191	22,307	2,202	24,509	2,393	10.82%
SC. No. 13	562,529	0	562,529	55,530	618,059	55,530	9.87%
Sub-Total	1,672,965,593	-	1,672,965,593	165,146,000	1,838,111,593	165,146,000	9.87%
SC No. 14	467,030						
Negotiated	2,095,000						
Total	1,675,527,624						

(a) Represents 1/3 of the (Surplus)/Deficiency Indications

Determination of Non-Competitive Delivery Rate Increase by Service Class for Rate Year 3

Service Class	(1) Rate Year Increase ($)	(2) Incremental Competitive Service Revenues: Billing and Payment Processing ($)	(3) MFC Fixed Supply Related ($)	(4) Total MFC Credit & Collection Related ($)	(5)=(2)+(3)+(4) Total ($)	(6)=(1)-(5) Non-Competitive Rate Year Delivery Revenue Increase ($)
SC No. 1	17,554,769	0	11,154	34,837	45,991	17,508,778
SC No. 2 Rate I	11,332,823	0	10,702	62,494	73,196	11,259,628
SC No. 2 Rate I, Rider H	1,469,381	0	12,123	24,525	36,648	1,432,734
SC No. 2 Rate II	25,622,392	0	31,706	109,633	141,339	25,481,052
SC No. 3	109,108,712	0	184,885	655,568	840,453	108,268,259
SC No. 3, Rider J	2,393	0	14	37	51	2,342
SC. No. 13	55,530	0	133	269	402	55,128
Sub-Total	165,146,000	0	250,716	887,363	1,138,078	164,007,922
SC No. 14	0					
Negotiated	0					
Total	165,146,000					

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-G-0066 - Joint Proposal
Summary of Revenue Increases

Rate Year 1

	Current Revenues at 1/1/19 Rates [1]		RY1 Rate Change with GRT						Percent Rate Change	
Service Class	Rate Year Total Delivery Revenue with GRT [2] (1)	Rate Year Total Bill Revenue with GRT [3] (2)	Delivery Rate Change (3)	Incremental Low Income Impact (4)	Incremental Low Income Discount (5)	SBC [4] (6)	Tax Sur-Credit [5] (7)	Total Rate Change (8)=(3)+(4)+(5)+(6)+(7)	Delivery Only (9)=(8)/(1)	Total Bill (10)=(8)/(2)
SC No. 1	$210,226,971	$229,517,693	$1,397,333	$2,163,285	($6,059,275)	($347,846)	$19,135,355	$16,288,852	7.7%	7.1%
SC No. 2 Rate I	124,395,457	231,918,688	1,482,496	1,260,040		(1,938,834)	11,085,657	11,889,360	9.6%	5.1%
SC No. 2 Rate I, Rider H	12,338,793	41,019,606	134,755	114,534		(517,166)	620,078	352,202	2.9%	0.9%
SC No. 2 Rate II	212,071,252	380,219,740	7,289,272	2,181,273		(3,032,014)	17,566,564	24,005,094	11.3%	6.3%
SC No. 3	803,850,159	1,311,087,088	36,898,942	8,406,034	($8,070,439)	(9,146,378)	67,971,775	96,059,933	11.9%	7.3%
SC. No. 13	434,443	844,783	15,202	4,549		(7,399)	47,345	59,697	13.7%	7.1%
Sub-Total	$1,363,317,076	$2,194,607,597	$47,218,000	$14,129,715	($14,129,715)	($14,989,636)	$116,426,774	$148,655,138	10.9%	6.8%
SC No. 14 + contracts	2,642,391	15,596,710								
Total	$1,365,959,467	$2,210,204,307	$47,218,000	$14,129,715	($14,129,715)	($14,989,636)	$116,426,774	$148,655,138	10.9%	6.7%

Notes:
[1] Current Revenues Include the tax sur-credit and the recovery of Company Energy Efficiency costs in the System Benefits Charge.
[2] Delivery Revenue is defined as total bill revenue less gas supply cost and GRT associated with the gas supply cost.
[3] Includes supply estimate for transportation customers.
[4] Reflects the impact from the energy efficiency cost recovery transferred from the SBC to base delivery rates in RY1.
[5] Reflects the impact from the elimination of the tax sur-credit in the current year.

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CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-G-0066 - Joint Proposal
Summary of Revenue Increases

Rate Year 2

	Current Revenues at 1/1/20 Rates		**RY2 Rate Change with GRT [3]**					**Percent Rate Change**	
Service Class	Rate Year Total Delivery Revenue with GRT [1] (1)	Rate Year Total Bill Revenue with GRT [2] (2)	Delivery Rate Change (3)	White Plains Gate Station (4)	EAMs (5)	Positive Revenue Adjustments (6)	Total Rate Change (7)=(3)+(4)+(5)+(6)	Delivery Only (8)=(7)/(1)	Total Bill (9)=(7)/(2)
SC No. 1	$230,664,819	$249,619,451	$19,971,187	$249,968	$65,103	$85,791	$20,372,050	8.8%	8.2%
SC No. 2 Rate I	136,853,037	244,105,141	12,571,201	1,414,409	443,051	510,972	14,939,632	10.9%	6.1%
SC No. 2 Rate I, Rider H	16,568,420	53,843,000	1,568,778	491,566	152,345	181,893	2,394,582	14.5%	4.4%
SC No. 2 Rate II	238,891,433	408,738,681	27,236,213	2,239,895	368,548	626,592	30,471,248	12.8%	7.5%
SC No. 3	919,839,653	1,433,595,333	114,900,068	6,775,257	1,248,983	1,953,051	124,877,358	13.6%	8.7%
SC. No. 13	515,415	940,129	58,553	5,601	2,325	2,454	68,932	13.4%	7.3%
Sub-Total	$1,543,332,776	$2,390,841,736	$176,306,000	$11,176,695	$2,280,355	$3,360,753	$193,123,803	12.5%	8.1%
SC No. 14 + contracts	2,642,765	15,598,914		169,163	51,349	61,752	282,264		
Total	$1,545,975,541	$2,406,440,650	$176,306,000	$11,345,858	$2,331,704	$3,422,505	$193,406,067	12.5%	8.0%

Notes:

[1] Delivery Revenue is defined as total bill revenue less gas supply cost and GRT associated with supply cost

[2] Includes supply estimate for transportation customers.

[3] Assumes recovery of $11 million related to White Plains Gate Station over the 12 month period beginning January 2021 (RY2). Assumes in service date of November 2020.
Includes recovery of EAMs earned in RY1 for seven months (effective June).
Includes recovery of positive revenue adjustments earned in RY1 for 10 months (effective March).

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-G-0066 - Joint Proposal
Summary of Revenue Increases

Rate Year 3

Service Class	Current Revenues at 1/1/21 Rates: Rate Year Total Delivery Revenue with GRT [1] (1)	Current Revenues at 1/1/21 Rates: Rate Year Total Bill Revenue with GRT [2] (2)	RY3 Rate Change with GRT [3]: Delivery Rate Change (3)	RY3 Rate Change with GRT [3]: White Plains Gate Station (4)	RY3 Rate Change with GRT [3]: EAMs (5)	RY3 Rate Change with GRT [3]: Positive Revenue Adjustments (6)	RY3 Rate Change with GRT [3]: Total Rate Change (7)=(3)+(4)+(5)+(6)	Percent Rate Change: Delivery Only (8)=(7)/(1)	Percent Rate Change: Total Bill (9)=(7)/(2)
SC No. 1	$248,992,047	$267,693,755	$18,107,946	($249,968)	$69,754	$29,796	$17,957,527	7.2%	6.7%
SC No. 2 Rate I	152,112,244	258,891,883	11,689,938	(1,414,408)	334,600	151,345	10,761,475	7.1%	4.2%
SC No. 2 Rate I, Rider H	19,467,904	58,226,584	1,515,684	(491,566)	129,427	58,523	1,212,067	6.2%	2.1%
SC No. 2 Rate II	272,826,608	444,730,564	26,429,792	(2,239,894)	848,809	423,091	25,461,798	9.3%	5.7%
SC No. 3	1,057,380,570	1,577,368,409	112,549,361	(6,775,255)	2,447,166	1,227,479	109,448,751	10.4%	6.9%
SC. No. 13	596,413	1,021,126	57,280	(5,601)	825	217	52,721	8.8%	5.2%
Sub-Total	$1,751,375,786	$2,607,932,321	$170,350,000	($11,176,692)	$3,830,581	$1,890,450	$164,894,339	9.4%	6.3%
SC No. 14 + contracts	2,925,028	15,881,174		(169,163)	41,886	17,814	(109,463)		
Total	$1,754,300,814	$2,623,813,495	$170,350,000	($11,345,855)	$3,872,467	$1,908,263	$164,784,876	9.4%	6.3%

Notes:
[1] Delivery Revenue is defined as total bill revenue less gas supply cost and GRT associated with supply cost
[2] Includes supply estimate for transportation customers.
[3] Assumes expiration of White Plains Gate Station cost recovery.
Includes recovery of EAMs earned in RY1 for five months (January through May) and recovery of EAMs earned in RY2 for seven months (effective June).
Includes recovery of positive revenue adjustments earned in RY1 for two months (January through February) and recovery of positive revenue adjustments earned in RY2 for ten months (effective March).

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CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

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Merchant Function Charge Targets

		Credit & Collections (C&C)		
	Supply MFC	C&C MFC	C&C POR	C&C Total
	$	$	$	$
Rate Year 1	2,238,645	5,812,929	2,140,103	7,953,032
Rate Year 2	2,523,521	6,576,214	2,388,872	8,965,086
Rate Year 3	2,796,660	7,285,887	2,649,554	9,935,441

Appendix 21, Table 2

Appendix 22 – Capital Reporting Requirements

Consolidated Edison Company of New York, Inc.
Cases 19-E-0065, 19-G-0066

Capital Reporting Requirements

The following are the Capital Reporting Requirements noted in Section D of the Proposal:

1. Electric and Common

The Company will, for informational purposes, file with the Secretary and submit to the parties in this proceeding, subject to confidentiality concerns, reports during the rate plan as follows: February 28 (“Annual Report”), May 15, August 15, and November 15 (“Quarterly Reports”). The reports will cover the Company’s capital projects and programs list with associated expenditures for electric transmission, substations and distribution operations,[1] electric production, Distributed System Implementation Plan (DSIP), municipal infrastructure, and common.

All Quarterly Reports will include:

- A list of capital expenditures against current year-to-date and annual budget targets for electric transmission, substations, distribution operations, electric production, DSIP, municipal infrastructure, and all common projects and programs.
- Highlight new projects and programs that incurred expenditures that were not in the annual budget and/or rate plans. Provide white papers for these projects.

The Annual Report will include:

- A list of the project and program expenditures in the categories noted above during the prior calendar year against year-end and annual budget targets for the prior calendar year.
- A list of all projects and programs that had been reflected in the Company’s

[1] Distribution operations quarterly and annual reports shall include the Company’s non-network reliabilty program and the $25 million annual non-network reliability budget for Westchester County. At minimum, these reports will provide data on the categories of information required by the Company’s report on its program standard for the Non-Network Reliability program in Westchester County as described in Appendix 14, Program Standards (f)(iii).

prior calendar year budget or rate plan and that had no expenditure in the prior calendar year, with supporting explanation.

- A list of all new projects and/or programs that were added, with supporting white paper.

- Narrative on cost variances exceeding 10% on projects greater than $5 million.

- The rate plan capital expenditures for the current calendar year for the projects and programs in the categories noted above.

- Five-year capital budget for the the projects and programs in the categories noted above.

- The actual capital expenditures, O&M expenses, and deferred amounts, if applicable, during the prior calendar year for AMI, CSS, and DSIP implementation. The actual expenditures will be presented in aggregate form, separately for capital and O&M expenditures, and for deferred amounts, if applicable, for each of the categories listed above (*i.e.*, AMI, CSS and DSIP implementation).

The program budget for the DSIP as set forth in the Company's rate filing is as follows (in $000):

Investment	**2020**	**2021**	**2022**	**Total**
VVO	$14,300	$14,300	$14,300	**$42,900**
Modernize Protective Relays	$12,600	$12,600	$12,600	**$37,800**
IOAP	$1,300	$1,300	$1,300	**$3,900**
DERMS	$0	$1,250	$2,500	**$3,750**
DMTS	$3,333	$3,333	$3,333	**$9,999**
DRMS	$1,300	$1,300	$1,300	**$3,900**
DMAP	$1,667	$1,667	$1,667	**$5,001**
Web Service Interface	$0	$0	$0	**$0**
Total	**$34,500**	**$35,750**	**$37,000**	**$107,250**

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.

2. 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, 2020, 2021 and 2022; mid-year reports[2] (covering the first six (6) months of the applicable calendar year) will be filed on August 31, 2020, 2021 and 2022. The reports will include:

- Summary of Capital Expenditures - formatted similar to the Company's presentation in Exhibit___(GIOSP-1); categorize projects into Transmission, Distribution, Technical Operations, Growth and Other; separately track AMI costs during the deployment period; separately identify AMI module costs, tin case meter replacements and the gas portion of allocated common costs; and continue all other current reporting requirements.
- Summary of Capital Additions - broken down by programs and projects.
- For all programs and projects, a comparison of calendar year forecast of expenditures set forth in the 2020-2022 Gas Capital Program vs. calendar year actual expenditures.
- For multi-year programs and projects, a comparison of total expenditures set forth in the 2020-2022 Gas Capital Program vs. actual expenditures, broken down by calendar year (as part of the annual reports only).
- Narrative explanation of the reason(s) for any variance in excess of ten (10) percent between the expenditures set forth in the 2020-2022 Gas Capital Program and actual expenditures for any program or project.

[2] The Company's mid-year reports will recognize the fact that this Proposal reflects agreement on the annual forecasts in the 2020-2022 Gas Capital Program, rather than monthly expenditures.

- 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 2020-2022 Gas Capital Program for that calendar year.

- Summary of expenditures set forth in and the 2020-2022 Gas Capital Program actual capital expenditures for Interference related to:

    - Municipal storm hardening projects.

    - DEP Combined Sewer Overflow projects.

- 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:
        - 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.
    - The amount of and calculation for any incremental costs the Company recovers through the Safety and Reliability Surcharge Mechanism.

- Rehabilitation of Large Diameter Gas Mains

    - For CISBOT (Cast Iron Joint Sealing Robot)
        - The number of joints rehabilitated
        - The specific location of each section of main that is rehabilitated.

        - Actual cost of CISBOT by region.
        - Results of integrity verification using an internal camera and an external pit at tie-in locations (including assessment for graphitization for cast iron mains) where rehabilitation work is planned
        - Any repairs completed on CISBOT joints
    - For CIPL (Cure in Place Liner)
        - Number of feet rehabilitated by material.
        - The specific location of each section of main rehabilitated.
        - Actual cost of CIPL by material, by region
        - Results of integrity verification using an internal camera and an external pit at tie-in locations where rehabilitation work is planned
        - Any repairs completed on lined mains

APPENDIX 23: EARNINGS ADJUSTMENT MECHANISMS

Beginning January 1, 2020, the Company will have seven Earnings Adjustment Mechanisms ("EAMs") associated with electric and/or gas during the rate plan. The EAMs will be measured on a calendar year basis for RY_1, RY_2, and RY_3.

The following is a summary of the EAMs; details regarding the EAMs, including metrics, associated achievement, and basis points are more fully described further below.

Cross-Commodity EAMs

	Level	2020	2021	2022
Share the Savings	Minimum	30% of $ / Lifetime MMBtu Savings applied to acquired non-LMI EE savings		
	Midpoint			
	Maximum			
Deeper Energy Efficiency	Minimum	2	2.5	3
	Maximum	11	12 + BP Carryover from 2020[1]	13 + BP Carryover from 2021[1]

Electric-Only EAMs

	Level	2020	2021	2022
Beneficial Electrification	Minimum	2	2	2
	Midpoint	5	5	5
	Maximum	10	10	10
DER Utilization	Minimum	3	3	3
	Midpoint	5	5	5
	Maximum	10	10	10
Electric Peak Reduction	Minimum	3	3	3
	Midpoint	5	5	5
	Maximum	8	8	8
LSRV Load Factor	Minimum	1	1	1
	Midpoint	3	3	3
	Maximum	5	5	5

Gas-Only EAMs

	Level	2020	2021	2022
Gas Peak Reduction	Minimum	3	3	3
	Midpoint	5	5	5
	Maximum	8	8	8

[1] The basis points carryover mechanism is defined later in this Appendix.

The table below provides a summary of the value of a basis point for each rate year for electric and gas.

Value of an EAM basis point	**Rate Year 1**	**Rate Year 2**	**Rate Year 3**
Electric ($ million) [RY_x $ BP Electric]	$1.45	$1.53	$1.60
Gas ($ million) [RY_x $ BP Gas]	$0.48	$0.53	$0.58

1.0 Cross-Commodity EAMs

1.1 Share-the-Savings ("STS") EAM

1.1.1 Description

The STS EAM is designed to reduce unit costs for the Company's combined electric and gas EE portfolio (excluding the LMI EE portfolio) by reducing the unit cost of lifetime energy savings (on a dollar per lifetime million British thermal units (MMBtu) basis)[2] below unit cost levels as approved or modified in an upcoming Commission Order in the NE:NY proceeding in Case 18-M-0084, while increasing the overall achievement level of energy savings. Under the STS EAM, the Company will be awarded 30% of unit cost savings realized from the Company's acquired non-LMI EE savings once the Company has met minimum non-LMI EE lifetime savings targets, as provided in the metric described below.

1.1.2 Metric

The EAM performance and associated Company incentive will be calculated by determining (i) the non-LMI EE unit cost savings relative to the baseline unit cost, (ii) applying that to the acquired non-LMI EE savings and (iii) applying a percent share to the result. Mathematically,

$$\begin{aligned}\text{STS EAM (\$)} \\ &= [\mathrm{RY_x}\ \text{Baseline LMMBtu Unit Cost} - \mathrm{RY_x}\ \text{Acquired LMMBtu Unit Cost}] \\ &\quad * \mathrm{RY_x}\ \text{Acquired LMMBtu} * \mathrm{S\%}\end{aligned}$$

Where,

X	Is equal to 1, 2 and 3 for RY_1, RY_2 and RY_3 respectively

[2] Throughout this Appendix, the terms LMMBtu will refer to lifetime MMBtu EE savings and AMMBtu will refer to annual MMBtu EE savings.

RY_x Baseline LMMBtu Unit Cost	Company's unit cost for non-LMI baseline lifetime EE savings calculated as: $$\frac{RY_x \text{ Baseline Budget}}{RY_x \text{ Baseline LMMBTU}}$$
RY_x Baseline Budget	The Company's total budget approved or modified in an upcoming Commission Order in the NENY proceeding for non-LMI EE in Rate Year x, *i.e.*, RY_x budget for the following: (i) non-LMI electric EE including heat pumps, (ii) kicker incentive and (iii) non-LMI gas EE budgets
RYx Baseline LMMBtu	Company's non-LMI lifetime baseline savings for RYx calculated as: $$RY_x \text{ Baseline AMMBtu} * RY_x \text{ TRM SEEP Portfolio EUL}$$
RY_x Baseline AMMBtu	The Company's annual energy savings targets as approved or modified in an upcoming Commission Order in the NENY proceeding for (i) non-LMI electric EE including heat pumps, (ii) kicker incentive and (iii) non-LMI gas EE budgets in MMBtu for Rate Year x
RY_x TRM SEEP Portfolio EUL	The weighted average portfolio Effective Useful Life ("EUL"), weighted by savings on a program basis, as determined by the applicable Technical Resource Manual ("TRM") for the non-LMI EE portfolio based on the Company's most recent system EE plan ("SEEP") issued prior to RY_x and filed in Case 18-M-0084
RYx Acquired LMMBtu Unit Cost	Company's unit cost for non-LMI acquired lifetime energy efficiency savings calculated as: $$\frac{RY_x \text{ Actual Expenditures}}{RY_x \text{ Acquired LMMBtu}}$$
RY_x Actual Expenditures	Company expenditures on (i) non-LMI electric EE including heat pumps, (ii) kicker incentive and (iii) non-LMI gas EE in Rate Year x
RY_x Acquired LMMBtu	Company's non-LMI lifetime verified gross savings acquired in RYx and calculated as: $$RY_x \text{ Acquired AMMBtu} * RY_x \text{ TRM EUL}$$
RY_x Acquired AMMBtu	Company acquired annual verified gross energy savings from (i) non-LMI EE including heat pumps, (ii) kicker incentive and (iii) non-LMI gas EE in Rate Year x as reported in Company's year-end scorecard after the end of Rate Year x

RY_x TRM Portfolio EUL	The weighted average portfolio EUL, weighted on a savings by measure basis, for the non-LMI EE portfolio as determined by the applicable TRM at the time the savings are acquired in Rate Year x

$$\text{RY}_\text{x}\ \text{TRM Portfolio EUL} = \frac{\sum(\text{RY}_\text{x}\ \text{TRM Measure EUL} * \text{RY}_\text{x}\ \text{Measure Acquired AMMBtu})}{\text{RY}_\text{x}\ \text{Acquired AMMBtu}}$$

RY_x TRM Measure EUL	The EUL of each measure as determined by the applicable TRM at the time the non-LMI EE portfolio savings are acquired in RYx
RY_x Measure Acquired AMMBtu	The total acquired annual verified gross savings in MMBtu achieved through the particular EE measure in Rate Year x
S %	Percent share of savings Company is permitted to retain and is set at – (i) 30% if RY_x Acquired LMMBtu is greater than or equal to RY_x Baseline LMMBtu and RYx Acquired LMMBtu Unit Cost is less than RYx Baseline LMMBtu Unit Cost, and (ii) 0 % otherwise

1.1.3 Measurement

The applicable TRM, at the time savings are acquired, will be used for each non-LMI EE measure in RY_x. The applicable full SEEP will be filed in Cases 15-M-0252 and 18-M-0084 based on the reporting schedule as defined in Clean Energy Guidance Document CE-02. The acquired savings will be based on Staff's verified gross savings guidance.[3]

1.1.4 Achievement

Achievement for this EAM is based on the formula detailed in section 1.1.2 which provides the Company incentive.

1.2 <u>Deeper Energy Efficiency Lifetime Savings ("DEEL") EAM</u>

1.2.1 Description

[3] Verified gross savings, as defined in this EAM appendix, will be reported in compliance with Staff Guidance CE-08 and in compliance with any future modifications to Staff Guidance or any related future Commission directives for the applicable future rate year(s).

The DEEL EAM drives achievement of EE savings from EE measures considered as "deep." Examples of deeper EE programs include building envelope measures and higher efficiency building heating, cooling, and ventilation systems. This EAM encourages the Company to provide EE measures, which are typically more technically challenging, require more lead time, have longer EULs, and/or are more expensive for customers to undertake and for utilities to implement, but have longer and greater payback, thus defined as "deeper."

The EAM is based on the ability of the Company to deliver deeper EE lifetime MMBtu savings above target levels and up to a maximum level as discussed in the metric below. Further, to encourage the Company to undertake multi-year deeper EE projects that straddle multiple rate years, the DEEL EAM will allow the Company to transfer any unachieved targets and basis points between the minimum and maximum levels in any given rate year to the following rate year(s) in this rate period.

1.2.2 Metric

The DEEL metric is based on lifetime energy savings provided by deeper EE measures in the Company's entire EE portfolio – LMI and non-LMI – expressed in LMMBtu. In other words, the Deeper LMMBtu acquired in a given year ("RY_x DEEL Acquired") is defined as:

RY_x DEEL Acquired =

$$[\sum RY_x \text{ Acquired Deeper AMMBtu}] * RY_x \text{ TRM Portfolio Deeper EUL}$$

Where,

X	Is equal to 1, 2 and 3 for RY_1, RY_2 and RY_3 respectively
RY_x Acquired Deeper AMMBtu	Company acquired annual verified gross energy savings (LMI and non-LMI electric EE, gas EE, and heat pumps) in Rate Year x, but excluding energy savings related to the following EE measures: (i) Lighting measures: Savings associated with LED lighting, lighting replacement, and non-networked lighting controls (ii) Energy kits: Savings associated with free EE kits distributed to customers (iii) Simple HVAC controls: Savings associated with (i) controls that do not intelligently or automatically optimize design settings (temperature, airflow, etc.) to adapt to changes in building occupancy, temperature, humidity or other relevant elements of building operation, or (ii) residential thermostats

(iv) Behavioral programs: Savings associated with programs commonly defined as behavioral EE programs where savings are predicated on electronic or mail messages sent to customers to influence and drive customer behavior

RY_x TRM Portfolio Deeper EUL	The weighted average portfolio EUL, weighted on a savings by measure basis, as determined by the applicable TRM at the time the deeper EE portion of the EE portfolio of energy savings are acquired in RY_x

$$\text{RY}_\text{x}\ \text{TRM Portfolio Deeper EUL} = \frac{\sum(\text{RY}_\text{x}\ \text{TRM Deeper Measure EUL} * \text{RY}_\text{x}\ \text{Deeper Measure Acquired AMMBtu})}{\sum \text{RY}_\text{x}\ \text{Acquired Deeper AMMBtu}}$$

RY_x TRM Deeper Measure EUL	The individual deeper EE measure EUL as determined by the applicable TRM at the time the deeper EE measure savings are acquired in Rate Year x
RY_x Deeper Measure Acquired AMMBtu	The acquired annual verified gross savings in MMBtu of the individual deeper EE measure in Rate Year x

1.2.3 Measurement

The RY_x DEEL Acquired and the associated variables - RY_x Acquired Deeper AMMBtu and RY_x TRM Portfolio Deeper EUL - will be reported in the Company's annual EAM report.

1.2.4 Targets

The DEEL EAM will allow the Company to transfer any unachieved target savings in any given rate year, between minimum and maximum levels, to the following rate year(s) in this rate period resulting in potential corresponding carryovers. Each rate year's targets ("RY_x DEEL Min" and "RY_x DEEL Max") are defined as below.

	Level	**2020**	**2021**	**2022**
DEEL LMMBtu	Minimum	RY_1 DEEL Min = 9,000,000[4]	RY_2 DEEL Min = 10,500,000[4]	RY_3 DEEL Min= 12,000,000[4]
	Maximum	RY_1 DEEL Max = 12,000,000[4]	RY_2 DEEL Max = 14,000,000[4] + Btu Carryover from 2020	RY_3 DEEL Max = 16,000,000[4] + Btu Carryover from 2021

Where,

Btu Carryover from 2020: Is equal to [12,000,000 LMMBtu - RY_1 DEEL Acquired] but not to exceed 3,000,000 LMMBtu (i.e., the difference of RY_1 DEEL Max and RY_1 DEEL Min). If RY_1 DEEL Acquired is greater than or equal to 12,000,000 LMMBtu, then the Btu Carryover from 2020 will be 0.

Btu Carryover from 2021: Is equal to [14,000,000 LMMBtu + Btu Carryover from 2020 – RY_2 DEEL Acquired] but not to exceed 6,500,000 LMMBtu (i.e., the maximum possible Btu Carryover from 2020 added to the difference of RY_1 DEEL Max and RY_1 DEEL Min). Also, if RY_2 DEEL Acquired is greater than or equal to [14,000,000 LMMBtu + Btu Carryover from 2020], then the Btu Carryover from 2021 will be 0.

The Company will make a compliance filing in the rate case proceeding adjusting DEEL EAM targets if the Commission, in its Order in the NENY proceeding in Case 18-M-0084, modifies the Company's final energy efficiency proposal. The Company will change DEEL EAM targets based on an average of Commission's modification to the total budget (authorized $ for the entire EE portfolio) and Commission's authorized unit cost (on a $ per AMMBtu basis). Mathematically:

$$\mathrm{RY_x\ DEEL\ M_{Adj}} = \mathrm{RY_x\ DEEL\ M} * \frac{1}{2}\left[\left\{\frac{\mathrm{RY_x\ Budget_i}}{\mathrm{RY_x\ Budget_o}}\right\} + \left\{\frac{\mathrm{RY_x\ Unit\ Cost_i}}{\mathrm{RY_x\ Unit\ Cost_o}}\right\}\right]$$

[4] As noted at the end of this section the Company will adjust targets for DEEL EAM if the Commission authorization in the NENY proceeding in Case 18-M-0084 is different from the Company's proposal in the proceeding.

Where,

X	Is 1, 2, and 3 for RY_1, RY_2 and RY_3 respectively
RY_x DEEL M_{adj}	The adjusted targets (applicable for both minimum and maximum targets) for the fixed, non-carryover portion in Rate Year x
RY_x DEEL M	The targets (both minimum and maximum targets) for the fixed, non-carryover portion in Rate Year x; e.g. for RY_2, the minimum non-carryover portion is 10,500,000 LMMBtu and the maximum non-carryover portion is 14,000,000 LMMBtu
RY_x $Budget_i$	The Commission approved total budget (LMI and non-LMI electric and gas EE, kicker incentive and heat pumps) in $ in the NENY proceeding
RY_x $Budget_o$	The Company filed total budget (LMI and non-LMI electric and gas EE, kicker incentive and heat pumps) in $ in the NENY proceeding
RY_x Unit $Cost_i$	The Commission approved unit cost (LMI and non-LMI electric and gas EE, kicker incentive and heat pumps) in $/AMMBtu in the NENY proceeding
RY_x Unit $Cost_o$	The Company filed unit cost (LMI and non-LMI electric and gas EE, kicker incentive and heat pumps) in $/AMMBtu in the NENY proceeding

1.2.5 Achievement

Achievement will be based on deeper EE LMMBtu savings acquired in Rate Year x as defined above. The Company will receive an EAM once the Company meets the RY_x DEEL Min savings level and will receive a linearly increasing incentive until maximum for the rate year. The Company will report achievement using the following 3 steps:

<u>Step 1:</u> RY_x DEEL Acquired, will be calculated as described above.

<u>Step 2</u>: The Company will calculate the Basis Points in a given rate year corresponding to its RY_x DEEL Acquired. This is "RY_x DEEL $BP_{awarded.}$"

The DEEL EAM will allow the Company to transfer any unachieved basis points in any given rate year, between minimum and maximum levels, to the following rate year(s) in this rate period resulting in potential corresponding carryovers. Annual achievable basis points inclusive of carryovers are defined below.

	Level	**2020**	**2021**	**2022**
DEEL Basis Points	Minimum	RY_1 DEEL $BP_{min} = 2$	RY_2 DEEL $BP_{min} = 2.5$	RY_3 DEEL $BP_{min} = 3$
	Maximum	RY_1 DEEL $BP_{max} = 11$	RY_2 DEEL $BP_{max} = 12 +$ BP Carryover from 2020	RY_3 DEEL $BP_{max} = 13 +$ BP Carryover from 2021

Where,

BP Carryover from 2020 — Is equal to [11 – RY_1 DEEL $BP_{awarded}$] but not to exceed 9 (i.e., the difference of RY_1 DEEL BP_{max} and RY_1 DEEL BP_{min}). If RY_1 DEEL Acquired is greater than or equal 12,000,000 LMMBtu, then the BP Carryover from 2020 will be 0.

BP Carryover from 2021 — Is equal to [12 + BP Carryover from 2020 – RY_2 DEEL $BP_{awarded}$] not to exceed [9.5 + BP Carryover from 2020]. If RY_2 DEEL Acquired is greater than or equal to [14,000,000 LMMBtu + Btu Carryover from 2020], then the BP Carryover from 2021 will be 0.

The Company's earned basis points will be calculated as follows:

a) If RY_x DEEL Acquired is less than RY_x DEEL Min then

RY_x DEEL $BP_{awarded} = 0$

b) If RY_x DEEL Acquired is between the RY_x DEEL Min and RY_x DEEL Max, then

$$RY_x \text{ DEEL } BP_{awarded} = RY_x \text{ DEEL } BP_{min} + RY_x \text{ DEEL BP Slope} * (RY_x \text{ DEEL}_{acheived} - RY_x \text{ DEEL}_{min})$$

$$RY_x \text{ DEEL Slope BP} = \frac{RY_x \text{ DEEL BP Max} - RY_x \text{ DEEL BP Min}}{RY_x \text{ DEEL Max} - RY_x \text{ DEEL Min}}$$

Where,

x — Is equal to 1, 2, and 3 for RY_1, RY_2 and RY_3 respectively

c) If RY_x DEEL Acquired is greater than or equal to the RY_x DEEL Max, then

RY_x DEEL $BP_{awarded}$ = RY_x DEEL BP_{max}

<u>Step 3</u>: The Company's basis points will be converted to a dollar incentive that will be calculated as follows:

RY_x DEEL EAM ($) = RY_x DEEL $BP_{awarded} * (RY_x\ \$\ BP\ Electric + RY_x\ \$\ BP\ Gas)$

Where,

RY_x DEEL EAM =	Company incentive in dollars for DEEL EAM achievement in Rate Year x
RY_x $ BP Electric =	$ per basis point in Rate Year x for Electric
RY_x $ BP Gas =	$ per basis point in Rate Year x for Gas

2.0 Electric-only EAMs

2.1 Beneficial Electrification ("BEEL") EAM

2.1.1 Description

The BEEL EAM encourages Company efforts that will result in adoption of beneficial electrification technologies, i.e., electric vehicles and heat pumps, which lead to a decrease in lifetime CO_{2e} (carbon dioxide or carbon dioxide equivalent) emissions on a marginal emissions basis. For the purposes of this EAM, the beneficial electrification technologies are:

Beneficial Electrification Technologies
Air-Source Heat Pump ("ASHP") and ASHP mini-split
Ground-Source Heat Pump ("GSHP") and GSHP mini-split
Battery Electric Vehicle ("BEV")
Plugin Hybrid Electric Vehicle ("PHEV")
Electric Transit Bus ("EV T Bus")
Medium- and Heavy-duty Electric Vehicles ("MD/HD EV")

These technologies are considered based on their associated annualized lifetime CO_{2e} emission reductions as further discussed below. To the extent that the amount of lifetime CO_{2e} emissions due to incremental adoption of such beneficial electrification technologies in a given rate year are reduced by an amount exceeding the minimum levels for the rate year as described below, the Company will receive an incentive under the BEEL EAM. The performance targets will be set such that the level of CO_{2e}

emission reductions from the beneficial electrification technologies will surpass what is currently projected.

2.1.2 Metric

The Beneficial Electrification metric will be the total lifetime CO_2 emissions reductions provided by annual incremental beneficial electrification technologies in any given rate year.

RY_x Lifetime CO_{2e} Reduction (metric tons) =
+ RY_x ASHP and ASHP mini-split lifetime CO_{2e} emissions reductions
+ RY_x GSHP and GSHP mini-split lifetime CO_{2e} emissions reductions
+ RY_x BEV lifetime CO_{2e} emissions reductions
+ RY_x PHEV lifetime CO_{2e} emissions reductions
+ RY_x EV T Bus lifetime CO_{2e} emissions reductions
+ RY_x MD/HD EV lifetime CO_{2e} emissions reductions

Where,

x Is equal to 1, 2 and 3 for RY_1, RY_2, and RY_3 respectively

2.1.3 Measurement

The total lifetime CO_{2e} emissions reductions will be measured in metric tons and be calculated by summing the lifetime CO_{2e} emissions reductions provided by each incremental beneficial electrification technology added in the applicable Rate Year. Emission reductions formulas for BEEL EAM in this Appendix are typically generalized for ease of explanation and tons in this section refer to metric tons. All detailed CO_{2e} emission reductions calculations can be found in Appendix 23 Attachment A.

ASHP and ASHP mini-splits
The ASHP and ASHP mini-split beneficial electrification measurement will consider all new ASHP and ASHP mini-split installations in the Company's service territory during each Rate Year. The rate year incremental units of ASHP and ASHP mini-splits will be tracked from reported Company EE program activity in its year-end EE scorecards and other available data sources providing information related to ASHP installations outside of those directly incentivized by Company programs.

The lifetime CO_{2e} emissions reductions from ASHP and ASHP mini-splits will be determined by calculating the lifetime cooling and heating emissions impact. The ASHP and ASHP mini-split calculations will be conducted separately using the below generalized formula, but with varying input values. The lifetime cooling emissions impact calculates the avoided MWhs of consumption and applies the marginal grid emission intensity to determine the CO_{2e} emissions avoided. The lifetime heating emissions impact calculates the avoided emissions from replacing a natural gas or fuel oil fired heating system while accounting for the increased emissions associated with the increased electricity consumption by the ASHP or ASHP mini-split.

$$RY_x\ ASHP\ CO_{2e}\ Reduction = RY_x\ Heat\ Pump * Avoided\ CO_{2e}\ per\ Heat\ Pump * RY_x\ TRM\ Heat\ Pump\ EUL$$

Where:

X	Is equal to 1, 2 and 3 for RY_1, RY_2 and RY_3 respectively
RY_x ASHP CO_{2e} Reduction	The lifetime CO_{2e} emissions reductions in tons associated with incremental air-source heat pumps and air-source heat pump mini-splits installed in Rate Year x
RY_x Heat Pump	The number of heat pumps (ASHPs and/or ASHP mini-splits) installed in the Company's service territory and added in Rate Year x
Avoided CO_{2e} per Heat Pump	The annual reduction in CO_{2e} emissions associated with the installation of an ASHP and/or ASHP mini-split
RY_x TRM Heat Pump EUL	The EUL for a ASHP and/or ASHP mini-split, as defined by the applicable TRM at the time the EE portfolio savings are acquired in Rate Year x for the heat pumps directly incentivized for the Company and as defined by the applicable TRM for the majority of Rate Year x for all other air-source heat pumps and/or air-source heat pump mini-splits

GSHP and GSHP mini-splits
The GSHP and GSHP mini-split beneficial electrification measurement will consider all new GSHP and GSHP mini-split installations in the Company's service territory during each Rate Year. The rate year incremental units of GSHP and GSHP mini-splits will be tracked from reported Company EE program activity in its year-end EE scorecards filed and other available data sources providing information related to GSHP installations outside of those directly incentivized by Company programs.

The lifetime CO_{2e} emissions reductions from GSHP and GSHP mini-splits will be determined by calculating the lifetime cooling and heating emissions impact. The GSHP and GSHP mini-split calculation will be conducted using the below generalized formula. The lifetime cooling emissions impact calculates the avoided MWhs of consumption and applies the marginal grid emission intensity to determine the CO_{2e} emissions avoided. The lifetime heating emissions impact calculates the avoided emissions from replacing a natural gas or fuel oil fired heating system while accounting for the increased emissions associated with the increased electricity consumption by the GSHP or GSHP mini-split.

$$RY_x\ GSHP\ CO_{2e}\ Reduction = RY_x\ GS\ Heat\ Pump * Avoided\ CO_{2e}\ per\ Heat\ Pump * RY_x\ TRM\ Heat\ Pump\ EUL$$

Where:

x	Is equal to 1, 2 and 3 for RY_1, RY_2 and RY_3 respectively
RY_x GSHP CO_{2e} Reduction	The lifetime CO_{2e} emissions reductions in tons associated with incremental ground-source heat pumps installed in Rate Year x
RY_x GS Heat Pump	The number of heat pumps (GSHPs and/or GSHP mini-splits) installed in the Company's service territory added in Rate Year x
Avoided CO_{2e} per Heat Pump	The total annual reduction in CO_{2e} emissions associated with the installation of a GSHP and/or GSHP mini-split
RY_x TRM Heat Pump EUL	The EUL for a GSHP and/or GSHP mini-split, as defined by the applicable TRM at the time the EE portfolio savings are acquired in Rate Year x for the heat pumps directly incentivized for the Company and as defined by the applicable TRM for the majority of Rate Year x for all other ground-source heat pumps and/or ground-source heat pump mini-splits

BEV

The BEV beneficial electrification measurement will consider all incremental light-duty BEV registrations in the Company's service territory during each Rate Year. The Company primarily tracks registrations in its service territory using EValuateNY, a NYSERDA funded tool that uses vehicle registration data from the New York State Department of Motor Vehicles, and any other available sources.

BEVs reduce CO_{2e} emissions because CO_{2e} emissions associated with the electricity used by BEVs are lower than CO_{2e} emissions resulting from a gasoline-based internal combustion engine. The generalized formula below calculates the lifetime avoided CO_{2e} emissions from replacing an internal combustion engine vehicle with a BEV.

RY_x BEV CO_{2e} Reduction

$$= (RY_x\ BEV\ ) * (Avg\ annual\ mile_{BEV}) * \left(\frac{Ton\ CO_{2e}}{mile_{ICE\ Vehicle}} - \frac{Ton\ CO_{2e}}{mile_{BEV}}\right) * BEV_{life}$$

Where:

x	Is equal to 1, 2 and 3 for RY_1, RY_2 and RY_3 respectively
RY_x BEV CO_{2e} Reduction	The lifetime CO_{2e} emissions reductions in tons associated with BEVs registered in Rate Year x
RY_x BEV	The number of BEVs registered in the Company's service territory and added in Rate Year x
Avg annual $mile_{BEV}$	The average number of miles travelled by a BEV annually
Ton CO_2e / $Mile_{ICE\ Vehicle}$	The CO_{2e} emissions associated with one mile travelled in a light-duty internal combustion engine vehicle.
Ton CO_2e / $Mile_{BEV}$	The CO_{2e} emissions associated with one mile travelled in a BEV.
BEV_{life}	The typical useful life of a registered BEV

PHEV

The PHEV beneficial electrification measurement will consider all new incremental light-duty PHEV registrations in the Company's service territory during each Rate Year. The Company primarily tracks registrations in its service territory using EValuateNY, a NYSERDA tool that uses vehicle registration data from the New York State Department of Motor Vehicles, and any other available sources.

PHEVs reduce CO_{2e} emissions because CO_{2e} emissions associated with the electricity used by PHEVs are lower than CO_{2e} emissions resulting from a gasoline-based internal combustion engine. The generalized formula below calculates the lifetime avoided CO_{2e} emissions from replacing an internal combustion engine vehicle with a PHEV.

RY_x PHEV CO_{2e} Reduction

$$= (RY_x\ PHEV) * (Avg\ annual\ mile_{PHEV}) * \left(\frac{Ton\ CO_{2e}}{mile_{ICE\ Vehicle}} - \frac{Ton\ CO_{2e}}{mile_{PHEV}}\right) * PHEV_{life}$$

Where:

x	Is equal to 1, 2 and 3 for RY_1, RY_2 and RY_3 respectively
RY_x PHEV CO_{2e} Reduction	The lifetime CO_{2e} emissions reductions in tons associated with PHEVs registered in Rate Year x
RY_x PHEV	The number of PHEVs registered in the Company's service territory added in Rate Year x
Avg annual $mile_{PHEV}$	The average number of miles travelled by a PHEV annually
Ton CO_2e / $Mile_{ICE\ Vehicle}$	The CO_{2e} emissions associated with one mile travelled in a light-duty internal combustion engine vehicle
Ton CO_2e / $Mile_{PHEV}$	The CO_{2e} emissions associated with one mile travelled in a PHEV
$PHEV_{life}$	The typical useful life of a registered PHEV

EV Transit Bus

The EV Transit Bus beneficial electrification measurement will consider all new incremental EV Transit Bus, including public buses, school buses, and other buses used for local or regional transportation, registrations in the Company's service territory during each Rate Year. The Company primarily tracks registrations in its service territory from New York Metropolitan Transit Authority ("MTA") and Port Authority data and will augment with other sources that provide information related to other EV Buses registered in the Company's service territory.

EV Transit Buses reduce CO_{2e} emissions because CO_{2e} emissions associated with the electricity used by EV Transit Buses are lower than CO_{2e} emissions resulting from a diesel fuel-based internal combustion engine. The formula below calculates the lifetime avoided metric tons CO_{2e} emissions from replacing a diesel bus with an EV Transit Bus.

$$\text{EV Transit Bus } CO_{2e} \text{ Reduction} = (RY_x\ EV\ Transit\ Bus) * (Avg\ annual\ mile_{EV\ Transit\ Bus}) * \left(\frac{Ton\ CO_{2e}}{mile_{Diesel\ Bus}} - \frac{Ton\ CO_{2e}}{mile_{EV\ Transit\ Bus}}\right) * EV\ Transit\ Bus_{life}$$

Where:

x	Is equal to 1, 2 and 3 for RY_1, RY_2 and RY_3 respectively
RY_x EV Transit Bus CO_{2e} Reduction	The lifetime CO_{2e} emissions reductions in tons associated with EV Transit Buses registered in Rate Year x
RY_x EV Transit Bus	The number of EV Transit Buses registered in the Company's service territory in Rate Year x
Avg annual $mile_{EV\ Transit\ Bus}$	The average number of miles traveled by an EV Transit Bus annually
Ton CO_2e / $Mile_{Diesel\ Bus}$	The CO_{2e} emissions associated with one mile travelled in an diesel internal combustion engine bus
Ton CO_2e / $Mile_{EV\ Transit\ Bus}$	The CO_{2e} emissions associated with one mile travelled in an EV Transit Bus
EV Transit Bus_{life}	The typical useful life of a EV Transit Bus

MD/HD EV

The MD/HD EV beneficial electrification measurement will consider all new incremental MD/HD EV registrations in the Company's service territory in each Rate Year. The Company primarily tracks registrations in its service territory using EValuateNY, a NYSERDA tool that uses vehicle registration data from the New York State Department of Motor Vehicles, and any other available sources.

MD/HD EVs reduce CO_{2e} emissions because CO_{2e} emissions associated with the electricity used by MD/HD EVs for New York City and Westchester are lower than CO_{2e} emissions resulting from a diesel fuel-based internal combustion engine. The MD EV and HD EV calculations will be determined separately using the below generalized formula. The formula calculates the lifetime avoided metric tons CO_{2e} emissions from replacing a diesel MD/HD vehicle with an MD/HD EV. The formula below calculates the lifetime avoided CO_{2e} emissions from replacing a diesel MD/HD vehicle with an MD/HD EV.

$$RY_x\ MD/HD\ CO_{2e}\ Reduction = (RY_x\ MD/HD\ EV) * (Avg\ annual\ mile_{MD/HD\ EV} * \left(\frac{Ton\ CO_{2e}}{mile_{Diesel\ MD/HD\ Vehicle}} - \frac{Ton\ CO_{2e}}{mile_{MD/HD\ EV}}\right) * MD/HD\ EV_{life}$$

Where:

x	Is equal to 1, 2 and 3 for RY_1, RY_2 and RY_3 respectively
RY_x MD/HD CO_{2e} Reduction	The lifetime CO_{2e} emissions reductions in tons associated with MD/HD EVs registered in Rate Year x
RY_x MD/HD EV	The number of MD/HD EVs registered in the Company's service territory added in Rate Year x
Avg annual $mile_{MD/HD\ EV}$	The CO_{2e} emissions associated with one mile travelled in an MD/HD EV
Ton CO_2e / $Mile_{Diesel\ MD/HD\ Vehicle}$	The CO_{2e} emissions associated with one mile travelled in a diesel internal combustion engine MD/HD vehicle
Ton CO_2e / $Mile_{MD/HD\ EV}$	The emissions associated with one mile travelled in an MD/HD EV
MD/HD EV_{life}	The typical useful life of a MD/HD EV

2.1.4 Target

See table below for a summary of targets.

	Level	**2020**	**2021**	**2022**
Beneficial Electrification (ton CO_{2e})	Minimum	RY_1 BEEL Min = 222,602[5]	RY_2 BEEL Min = 365,799[5]	RY_3 BEEL Min = 414,042[5]
	Midpoint	RY_1 BEEL Mid = 254,403[5]	RY_2 BEEL Mid = 417,767[5]	RY_3 BEEL Mid = 473,191[5]
	Maximum	RY_1 BEEL Max = 286,203[5]	RY_2 BEEL Max = 469,735[5]	RY_3 BEEL Max = 532,340[5]

If the Commission orders a change in the Company's proposal related to heat pumps in the New Efficiency New York proceeding in Case 18-M-0084, the Company will make a

[5] As noted further in this section the Company will adjust targets for BEEL EAM if the Commission authorization for heat pumps in the NENY proceeding in Case 18-M-0084 is different from the Company's proposal in the proceeding.

compliance filing in the rate case proceeding adjusting BEEL EAM targets. The Company will change BEEL EAM targets based on a new baseline for the heat pump portion of the metric. The Company will use an average of Commission's modification to the total heat pump budget (authorized $) and Commission's authorized heat pump unit cost (on a $ per AMMBtu basis). The Company will adjust targets based on the following two steps.

Step 1: Develop a new adjusted baseline for each rate year.

$$\mathrm{RY_x\ BEEL\ Baseline_{Adj}} = \mathrm{RY_x\ BEEL\ HP\ Baseline} * \left[\frac{1}{2}\left[\left\{\frac{\mathrm{RY_x\ HP\ Budget_i}}{\mathrm{RY_x\ HP\ Budget_o}}\right\} + \left\{\frac{\mathrm{RY_x\ HP\ Unit\ Cost_i}}{\mathrm{RY_x\ HP\ Unit\ Cost_o}}\right\}\right]\right] + \mathrm{RY_x\ BEEL\ EV\ Baseline}$$

Where,

x	Is 1, 2, and 3 for RY_1, RY_2 and RY_3 respectively
RY_x BEEL $Baseline_{Adj}$	The adjusted baseline (applicable for minimum, mid-point and maximum targets) for BEEL EAM for Rate Year x
RY_x BEEL HP Baseline	The heat pump portion of the baseline (including ASHP, ASHP mini-splits, GSHP, GSHP mini-splits) in tons of $CO2_e$ for BEEL EAM for Rate Year x; See table below

RYx BEEL HP Baseline	2020	2021	2022
Total HP Portion of Baseline	72,949	96,406	112,037

RY_x BEEL EV Baseline	The EV portion of the baseline (including BEV, PHEV, EV Transit Bus, and MD/HD EV) in tons of $CO2_e$ for BEEL EAM for Rate Year x; See table below

RYx BEEL EV Baseline	2020	2021	2022
Total EV portion of Baseline	139,053	252,070	282,289

RY_x HP $Budget_i$	The Commission approved budget for heat pumps in $ in the NENY proceeding
RY_x HP $Budget_o$	The Company filed final budget for heat pumps in $ in the NENY proceeding

RY_x HP Unit $Cost_i$	The Commission approved unit cost for heat pumps in $/AMMBtu in the NENY proceeding
RY_x HP Unit $Cost_o$	The Company filed final unit cost for heat pumps in $/AMMBtu in the NENY proceeding

Step 2: Determine adjusted targets for each rate year to set minimum, midpoint and maximum targets at 5%, 20% and 35% above the adjusted baseline as indicated in the table below.

	Level	**2020**	**2021**	**2022**
Beneficial Electrification (ton CO_{2e})	Minimum	RY_1 BEEL Min = RY_1 BEEL $Baseline_{adj}$ * 1.05	RY_2 BEEL Min = RY_2 BEEL $Baseline_{adj}$ * 1.05	RY_3 BEEL Min = RY_3 BEEL $Baseline_{adj}$ * 1.05
	Midpoint	RY_1 BEEL Mid = RY_1 BEEL $Baseline_{adj}$ * 1.2	RY_2 BEEL Mid = RY_2 BEEL $Baseline_{adj}$ * 1.2	RY_3 BEEL Mid = RY_3 BEEL $Baseline_{adj}$ * 1.2
	Maximum	RY_1 BEEL Max = RY_1 BEEL $Baseline_{adj}$ * 1.35	RY_2 BEEL Max = RY_2 BEEL $Baseline_{adj}$ * 1.35	RY_3 BEEL Max = RY_3 BEEL $Baseline_{adj}$ * 1.35

2.1.5 Achievement

Achievement of the Beneficial Electrification EAM will be based upon lifetime CO_2 emissions reductions provided by the incremental beneficial electrification technologies added in each Rate Year. The Company will determine the EAM based on the following 3 steps.

Step 1: The total CO_2 emissions reductions for each Rate Year will be calculated as follows:

RY_x Total Lifetime CO_2 Emissions Reduction (tons) =
+ RY_x ASHP and ASHP mini-split lifetime CO_2 emissions reductions
+ RY_x GSHP and GSHP mini-split lifetime CO_2 emissions reductions
+ RY_x BEV lifetime CO_2 emissions reductions
+ RY_x PHEV lifetime CO_2 emissions reductions
+ RY_x EV Transit Bus lifetime CO_2 emissions reductions
+ RY_x MD/HD EV lifetime CO_2 emissions reductions

Where,

x Is equal to 1, 2 and 3 for RY_1, RY_2, and RY_3 respectively

The emission reductions for each beneficial electrification technology will be calculated for each rate years using the formulas provided in section 2.1.3.

Step 2: The basis points allocated to the BEEL EAM are identified as provided in the table below.

	Level	**2020**	**2021**	**2022**
BEEL Basis Points	Minimum	RY_1 BEEL $BP_{min} = 2$	RY_2 BEEL $BP_{min} = 2$	RY_3 BEEL $BP_{min} = 2$
	Midpoint	RY_1 BEEL $BP_{mid} = 5$	RY_2 BEEL $BP_{mid} = 5$	RY_3 BEEL $BP_{mid} = 5$
	Maximum	RY_1 BEEL $BP_{max} = 10$	RY_2 BEEL $BP_{max} = 10$	RY_3 BEEL $BP_{max} = 10$

The Company earned basis points will be calculated as follows:

a) If RY_x Total Lifetime CO_2 Emissions Reduction is less than RY_x BEEL Min, then RY_x BEEL $BP_{awarded} = 0$

Where,

RY_x BEEL $BP_{awarded}$ Annual basis points, awarded to Company for BEEL EAM achievement

b) If RY_x Total Lifetime CO2 Emissions Reduction is between RY_x BEEL Min and up to RY_x BEEL Mid, then

RY_x BEEL $BP_{awarded}$ = RY_x BEEL BP_{min} + BEEL Min-Mid Slope * (RY_x Total Lifetime CO_2 Emissions Reduction – RY_x BEEL Min)

Where,

BEEL Min-Mid Slope Is equal to $\frac{RY_x \text{ BEEL } BP_{mid} - RY_x \text{ BEEL } BP_{min}}{RY_x \text{ BEEL Mid} - RY_x \text{ BEEL Min}}$

c) If RY_x Total Lifetime CO_2 Emissions Reduction is between the RY_x BEEL Mid and up to RY_x BEEL Max, then

RY_x BEEL $BP_{awarded}$ = RY_x BEEL BP_{mid} + BEEL Mid-Max Slope * (RY_x Total Lifetime CO2 Emissions Reduction – RY_x BEEL Mid)

Where,

BEEL Mid-Max Slope Is equal to $\frac{RY_x \text{ BEEL } BP_{max} - RY_x \text{ BEEL } BP_{mid}}{RY_x \text{ BEEL Max} - RY_x \text{ BEEL Mid}}$

d) If RY_x Total Lifetime CO_2 Emissions Reduction is greater than RY_x BEEL Max, then

RY_x BEEL $BP_{awarded}$ = RY_x BEEL BP_{max}

Step 3: The Company's basis points will be converted to a dollar incentive that will be calculated as follows:

RY_x BEEL EAM ($) = RY_x BEEL $BP_{awarded} * (RY_x$ $ BP Electric)

Where,

RY_x BEEL EAM	Company incentive in dollars for BEEL EAM achievement in Rate Year x
RY_x $ BP Electric	$ per basis point in Rate Year x for Electric

2.2 Distributed Energy Resource ("DER") Utilization ("DER U") EAM

2.2.1 Description

The DER U EAM encourages the Company to work with DER providers and expand the use of DER interconnected to the Company's grid in its service territory for the purposes of reducing customer reliance on grid-supplied electricity. For the DER U EAM, DERs are defined as rooftop photovoltaics (PV), community PV, battery storage, ice storage, and wind energy and will be considered based on their associated annualized MWh as further discussed below.

DER U Technologies
Rooftop PV
Community PV
Battery Storage
Ice Energy Storage
Wind Power

2.2.2 Metric

The DER U metric is the sum of the MWh produced, consumed, or discharged, as applicable to the aforementioned DER technology, and calculated as follows:

DER Utilization (MWh) =

Community Solar PV MWh annualized production
+ Rooftop Solar PV MWh annualized production
+ Battery storage MWh annualized discharge
+ Ice Energy storage MWh annualized consumption
+ Wind Power MWh annualized production

2.2.3 Measurement

DERs will be measured in terms of the annualized megawatt-hour ("MWh") produced or discharged from incremental (new to the Rate Year) DERs, or annualized MWh consumed in the case of ice energy storage. MWh would be treated as positive values with the sum of produced, discharged and consumed energy, and determining achievement against targets; that is, 1 MWh produced or discharged is equivalent to 1 MWh consumed for the purpose of the metric. Because not all DERs are individually metered or measured, MWh produced or consumed by incremental DERs will be determined on an annualized basis using assumptions, described below.

Rooftop Solar Photovoltaics
Annualized MWh produced by incremental rooftop solar PV installations in the Con Edison service territory during the rate years will be calculated as:

RY_x Rooftop Solar PV (MWh) = [RY_x Rooftop Solar MW] * [8760 hours per year] * [14.1% annual capacity factor][6]

Where:

x	Is equal to 1, 2, and 3 for RY_1, RY_2 and RY_3 respectively
RY_x Rooftop Solar PV (MWh)	The annualized produced MWh associated with incremental rooftop solar PV interconnected in Rate Year x
RY_x Rooftop Solar MW	RY_x incremental installed capacity in ac-MW of rooftop Solar PV that will be tracked from interconnected Solar PV submitted through the New York State Standardized Interconnection Requirements ("NYS SIR") process and as reported in the Company's SIR Inventory Report as of January 15th following Rate Year x

[6] Case 15-E-0751, *In the Matter of the Value of Distributed Energy Resources*, Copy of Solar Simulations for DPS (October 28, 2016).

Community Solar Photovoltaics
Annualized MWh produced by incremental community solar PV installations in the Con Edison service territory during the rate years will be calculated as:

RY_x Community Solar PV (MWh) = [RY_x Community Solar MW] * [8760 hours per year] * [15.5% annual capacity factor][7]

Where:

x	Is equal to 1, 2, and 3 for RY_1, RY_2 and RY_3 respectively
RY_x Community Solar PV (MWh)	The annualized produced MWh associated with incremental community solar PV interconnected in Rate Year x
RY_x Community Solar MW	RY_x incremental installed capacity in ac-MW of community Solar PV will be tracked from interconnected community solar PV submitted through the New York State Standardized Interconnection Requirements (“NYS SIR”) process and as reported in the Company’s SIR Inventory Report as of January 15th following Rate Year x

Batteries
Annualized MWh discharged by incremental behind-the-meter battery installations in the Con Edison service territory during the rate years will be calculated as:

RY_x Battery Storage (MWh) = [RY_x Total Battery (MW)] * [4 hours discharge] * [365 days per year][8]

Where:

x	Is equal to 1, 2, and 3 for RY_1, RY_2 and RY_3 respectively
RY_x Battery Storage (MWh)	The annualized discharged MWh associated with incremental battery storage interconnected in Rate Year x

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[7] Case 15-E-0751, *In the Matter of the Value of Distributed Energy Resources*, Copy of Solar Simulations for DPS (October 28, 2016).
[8] Refer to Appendix B, Page B-12 of DOE/EPRI Electricity Storage Handbook

RY_x Total Battery (MW)	RY_x incremental installed capacity in MW of new batteries based on their inverter ratings, tracked through the SIR process and as reported in the Company's SIR Inventory Report as of January 15th after RY_x less any batteries acquired through the Company's bulk storage solicitation conducted in compliance with the Commission's December 13, 2018 storage order in Case 18-E-0130

Ice Energy Storage
Annualized MWh consumed by incremental ice energy storage installations in the Con Edison service territory during the rate years will be calculated as:

RY_x Ice Storage (MWh) =

$$(RY_x\ Installed\ tons) * \left(\frac{0.55kW^{9}}{ton}\right) * \left(\frac{4\ hours}{charge}\right) * (110\ charges\ per\ year)^{10}$$

Where:

x	Is equal to 1, 2, and 3 for RY_1, RY_2 and RY_3 respectively
RY_x Ice Storage (MWh)	The annualized consumed MWh associated with incremental ice storage in Rate Year x
RY_x Installed tons	RY_x incremental ice storage installed in the Company's service territory

Wind Energy
Annualized MWh produced by incremental Wind Power installations in the Con Edison service territory during the rate years will be calculated as:

RY_x Wind Energy (MWh) = [RY_x Megawatts Wind] * [8760 hours per year] * [26% annual capacity factor] [11]

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[9] The 0.55 kW/ton figure represents the efficiency of a chiller as noted by American Society of Heating, Refrigerating and Air-Conditioning Engineers Standard 90.1.
[10] 110 charges per year based on number of weekdays in May through September.
[11] Wind Energy annual capacity factor based on the New York ISO's Power Trends 2019 report (See p. 28 in https://www.nyiso.com/documents/20142/2223020/2019-Power-Trends-Report.pdf/0e8d65ee-820c-a718-452c-6c59b2d4818b?t=1556800999122).

Where:

x	Is equal to 1, 2, and 3 for RY_1, RY_2 and RY_3 respectively
RY_x Wind Energy (MWh)	The annualized produced MWh associated with incremental wind capacity interconnected in Rate Year x
RY_x Megawatts Wind	RY_x incremental capacity of wind tracked through available data sources, or the SIR process and as reported in the Company's SIR Inventory Report as of January 15th after Rate Year x.

2.2.4 Targets

See table below for a summary of targets.

	Level	**2020**	**2021**	**2022**
DER Utilization (MWh)	Minimum	RY_1 DER U Min = 80,297	RY_2 DER U Min = 126,004	RY_3 DER U Min = 116,431
	Midpoint	RY_1 DER U Mid = 87,944	RY_2 DER U Mid = 134,479	RY_3 DER U Mid = 125,801
	Maximum	RY_1 DER U Max = 103,239	RY_2 DER U Max = 147,190	RY_3 DER U Max = 139,856

2.2.5 Achievement

To achieve the DER Utilization EAM, the Company must meet a targeted annualized megawatt-hour ("MWh") produced or discharged from incremental (new to the Rate Year) DERs, or annualized MWh consumed in the case of ice energy storage by new incremental DER Utilization technologies adopted in each Rate Year.

The Company will determine the EAM based on the following 3 steps.

<u>Step 1</u>: The total annualized MWh for each Rate Year will be calculated as follows:

RY_x DER Utilization =

+ RY_x Community Solar PV MWh annualized production
+ RY_x Rooftop Solar MWh annualized production
+ RY_x Battery storage MWh annualized discharge
+ RY_x Ice Energy storage MWh annualized consumption
+ RY_x Wind Power MWh annualized production

Where,

x   Is equal to 1, 2 and 3 for RY_1, RY_2, and RY_3 respectively

The annualized MWh for each DER U technology will be calculated for each rate year using the formulas provided in section 2.2.3.

Step 2: The basis points allocated to the DER U EAM are identified as provided in the table below.

	Level	**2020**	**2021**	**2022**
DER U Basis Points	Minimum	RY_1 DER U BP_{min} = 3	RY_2 DER U BP_{min} = 3	RY_3 DER U BP_{min} = 3
	Midpoint	RY_1 DER U BP_{mid} = 5	RY_2 DER U BP_{mid} = 5	RY_3 DER U BP_{mid} = 5
	Maximum	RY_1 DER U BP_{max} = 10	RY_2 DER U BP_{max} = 10	RY_3 DER U BP_{max} = 10

The Company's achieved basis points for the DER U EAM will be calculated as follows:

a) If RY_x DER Utilization is less than RY_x DER U Min, then
RY_x DER U $BP_{awarded}$ = 0

Where,

RY_x DER U $BP_{awarded}$ Annual basis points, awarded to Company for DER U EAM achievement for Rate Year x

b) If RY_x DER Utilization is between RY_x DER U Min and up to RY_x DER U Mid, then

RY_x DER U $BP_{awarded}$ = RY_x DER U BP_{min} + DER U Min-Mid Slope * (RY_x DER Utilization– RY_x DER U Min)

Where,

DER U Min-Mid Slope   Is equal to $\frac{RY_x \text{ DER U } BP_{mid} - RY_x \text{ DER U } BP_{min}}{RY_x \text{ DER U Mid} - RY_x \text{ DER U Min}}$

c) If RY_x DER Utilization is between the target midpoint and up to target maximum, then

$$RY_x \text{ DER U } BP_{awarded} = RY_x \text{ DER U } BP_{mid} + \text{DER U Mid-Max Slope} * (RY_x \text{ DER Utilization} - RY_x \text{ DER U Mid})$$

Where,

DER U Mid-Max Slope Is equal to $\frac{RY_x \text{ DER U } BP_{max} - RY_x \text{ DER U } BP_{mid}}{RY_x \text{ DER U Max} - RY_x \text{ DER U Mid}}$

d) If RY_x DER Utilization is greater than or equal to the target maximum, then

$$RY_x \text{ DER U } BP_{awarded} = RY_x \text{ DER U } BP_{max}$$

Step 3: The Company's basis points will be converted to a dollar incentive that will be calculated as follows:

$$RY_x \text{ DER U EAM (\$)} = RY_x \text{ DER U } BP_{awarded} * (RY_x \$ BP\ Electric)$$

Where,

RY_x DER U EAM	Company incentive in dollars for DER U EAM achievement in Rate Year x
RY_x \$ BP Electric	\$ per basis point in Rate Year x for Electric

2.3 Electric Peak Reduction ("EPR") EAM

2.3.1 Description

This EAM incentivizes Con Edison to deliver New York Control Area ("NYCA") coincident electric system peak reductions that provide additional system benefits and lower supply costs to customers. To the extent that there is a decline in the actual weather normalized NYCA coincident electric system peak below the rate year minimum level established for the EPR EAM, the Company will receive an incentive under the EPR EAM. The minimum, mid-point and maximum levels of achievement are set below the adjusted NYISO Installed Capacity ("ICAP") forecast Gold Book update issued in December prior to each rate year, with the adjustment being a downward revision of 0.9% to account for historic (median) forecasting error. The minimum, mid-point and maximum targets are developed based on forecasted load-modifiers in the Company's service territory derived from the NYISO ICAP forecast Gold Book issued in April prior to the rate year.

2.3.2 Metric

The EPR EAM metric will be based on the actual weather normalized NYCA coincident system peak for the Company's service territory for each rate year and measured in Megawatts (MW) as generally reported in the Load Forecasting Task Force in December prior to the rate year.

2.3.3 Measurement

The EPR EAM will use the NYISO reported weather-adjusted coincident peak for the Company's service territory.

RY_x Normalized Peak = NYISO reported peak in MW for the Company's service territory for Rate Year x.

Where:

x	Is equal to 1, 2, and 3 for RY_1, RY_2 and RY_3 respectively
RY_x Normalized Peak	Weather normalized peak in MW, generally published in the table "RY_x New York Control Area Peak Load Forecast" from the "RY_{x+1} Final ICAP Forecast" presentation in December of the Rate Year x, for Rate Year x

2.3.4 Targets

The rate year minimum, midpoint and maximum targets, in MW, are set based on the following formulas:

$$RY_x\ EPR\ Min = RY_x\ Annual\ Adjusted\ ICAP\ Forecast - 7.5\%\ of\ RY_x\ DER\ Baseline$$

$$RY_x\ EPR\ Mid = RY_x\ Annual\ Adjusted\ ICAP\ Forecast - 20\%\ of\ RY_x\ DER\ Baseline$$

$$RY_x\ EPR\ Max = RY_x\ Annual\ Adjusted\ ICAP\ Forecast - 35\%\ of\ RY_x\ DER\ Baseline$$

Where,

x	Is equal to 1, 2, and 3 for RY_1, RY_2 and RY_3 respectively
RY_x Annual Adjusted ICAP Forecast	NYISO reported peak for the Company's service territory generally published in the table "New York Control Area Peak Load Forecast" from the "RY_x Final ICAP Forecast" presentation multiplied by 0.991 (99.1%) to adjust for median forecasting error of -0.009 (-0.9%)
RY_x DER Baseline	The rate year DER baseline is the total, in MW, impact of forecasted load-modifiers used in the NYISO's RY_x Load and Capacity Data (Gold Book) released in April of RY_{x-1} on the Company's NYCA coincident system peak The RY_x DER baseline is a summation, in MW, of Zone I, Zone J and Zone H (prorated data for Zone H to account for the Company's service territory portion in Zone H) load-modifier data drawn from the following tables generally published in NYISO RY_x Load and Capacity Data ("Gold Book") issued in April of RY_{x-1} (For RY_1, the Company will use the tables noted below from the 2019 Gold Book, and for RY_2 and RY_3 the Company will use equivalent tables from the respective RY_2 and 3 Gold Books): • Table I-8b: Energy Efficiency and Codes & Standards Peak Impacts, "Reductions in Coincident Summer Peak Demand by Zone Relative to 2018 - MW" • Table I-9a: Solar PV Nameplate Capacity, "Behind-the-Meter Reductions in Coincident Summer Peak Demand by Zone - MW AC" • Table I-10a: Non-Solar Distributed Generation Nameplate Capacity, "Behind-the-Meter Reductions in Coincident Summer and Winter Peak Demand by Zone – MW" • Table I-11b: Electric Vehicle Peak Usage Forecast, "Total Increase in Coincident Summer Peak Demand by Zone – MW"

• Table I-12c: Energy Storage Peak Reductions, "Behind-the-Meter Reductions in Coincident Summer Peak Demand by Zone – MW"

	Level	2020	2021	2022
Electric Peak Reduction	Minimum	RY_1 EPR Min = RY_1 Annual Adjusted ICAP Forecast – 7.5% of RY_1 DER Baseline	RY_2 EPR Min = RY_2 Annual Adjusted ICAP Forecast – 7.5% of RY_2 DER Baseline	RY_3 EPR Min = RY_3 Annual Adjusted ICAP Forecast – 7.5% of RY_3 DER Baseline
	Midpoint	RY_1 EPR Mid = RY_1 Annual Adjusted ICAP Forecast - 20% of RY_1 DER Baseline	RY_2 EPR Mid = RY_2 Annual Adjusted ICAP Forecast - 20% of RY_2 DER Baseline	RY_3 EPR Mid = RY_3 Annual Adjusted ICAP Forecast - 20% of RY_3 DER Baseline
	Maximum	RY_1 EPR Max = RY_1 Annual Adjusted ICAP Forecast - 35% of RY_1 DER Baseline	RY_2 EPR Max = RY_2 Annual Adjusted ICAP Forecast - 35% of RY_2 DER Baseline	RY_3 EPR Max = RY_3 Annual Adjusted ICAP Forecast - 35% of RY_3 DER Baseline

2.3.5 Achievement

Achievement will be based on the Company reducing its electric peak below the targeted thresholds described above. The Company's achievement will result in eligible basis points if the metric meets or exceeds target thresholds, with linear scaling between minimum and midpoint, and between midpoint and maximum basis points as further discussed below.

Step 1: The weather normalized actual peak for each Rate Year will be identified as discussed above to obtain RY_x Normalized Peak.

Step 2: The basis points allocated to the EPR EAM are identified as provided in the table below.

	Level	2020	2021	2022
EPR Basis Points	Minimum	RY_1 EPR $BP_{min} = 3$	RY_2 EPR $BP_{min} = 3$	RY_3 EPR $BP_{min} = 3$
	Midpoint	RY_1 EPR $BP_{mid} = 5$	RY_2 EPR $BP_{mid} = 5$	RY_3 EPR $BP_{mid} = 5$
	Maximum	RY_1 EPR $BP_{max} = 8$	RY_2 EPR $BP_{max} = 8$	RY_3 EPR $BP_{max} = 8$

The achieved basis points for the EPR EAM will be calculated as follows:

a) If RYx Normalized Peak is greater than RYx EPR Min then,

RY_x EPR $BP_{awarded}$ = 0

Where,

RY_x EPR $BP_{awarded}$	Annual basis points, awarded to Company for EPR EAM achievement for Rate Year x

b) If RYx Normalized Peak is equal to RYx EPR Min then,

RY_x EPR $BP_{awarded}$ = RY_x EPR BP_{min}

c) If RY_x Normalized Peak is between the RY_x EPR Min and greater than or equal to RY_x EPR Mid, then

RY_x EPR $BP_{awarded}$ = RYx EPR BP_{min} + EPR Min-Mid Slope * (RY_x Normalized Peak – RY_x EPR Mid)

With EPR Min-Mid Slope $= \frac{\text{RY}_\text{x}\text{ EPR BP Mid} - \text{RY}_\text{x}\text{ EPR BP Min}}{ABS[\text{RY}_\text{x}\text{ EPR}_\text{mid} - \text{RY}_\text{x}\text{ EPR}_\text{min}]}$

Where,

x	Is equal to 1, 2 and 3 for RY_1, RY_2, and RY_3 respectively

d) If RY_x Normalized Peak is between the RY_x EPR Mid and greater than RY_x EPR Max, then

RY_x EPR $BP_{awarded}$ = RY_x EPR BP_{mid} + EPR Mid-Max Slope* (RY_x Normalized Peak – RY_x EPR Mid)

With EPR Mid-Max Slope = $\frac{\text{RY}_\text{x}\text{EPR BP Max} - \text{RY}_\text{x}\text{ EPR BP Mid}}{ABS[\text{RY}_\text{x}\text{ EPR}_\text{max} - \text{RY}_\text{x}\text{ EPR}_\text{mid}]}$

Where,

x	Is equal to 1, 2 and 3 for RY_1, RY_2, and RY_3 respectively

e) If RY_x Normalized Peak is less than or equal to RY_x EPR Max, then

RY_x EPR $BP_{awarded}$ = RY_x EPR BP_{max}

Step 3: The Company's basis points will be converted to an incentive that will be calculated as follows:

$$\text{RY}_\text{x}\ \text{EPR EAM}\ (\$) = \text{RY}_\text{x}\ \text{EPR BP}_\text{awarded} * \text{RY}_\text{x}\ \$\ \text{BP Electric}$$

Where,

RY_x EPR EAM	Company incentive in dollars for EPR EAM achievement in Rate Year x
RY_x \$ BP Electric	\$ per BP in RY_x for Electric

2.4 LSRV Load Factor ("LLF") EAM

2.4.1 Discussion

The LLF EAM is designed to improve the load factor of more constrained portions of the distribution system that are not current or likely Non-wires Alternatives ("NWS") areas. The LLF EAM will be based on load factor improvements in nine LSRV (Locational System Relief Value) areas identified in the Company's "Schedule for Electricity Service, P.S.C. No. 10 – Electricity, Statement of VDER Value Stack Credits"[12] because they are more system constrained than non-LSRV areas. The areas ("LLF Area") that will constitute the LLF EAM are:

- LLF $Area_1$: East 179th Street Substation
- LLF $Area_2$: Millwood West Substation
- LLF $Area_3$: Parkchester #1 Substation
- LLF $Area_4$: Parkchester #2 Substation
- LLF $Area_5$: Wainwright Substation
- LLF $Area_6$: West 42th Street #1 Substation
- LLF $Area_7$: West 65th Street #1 Substation
- LLF $Area_8$: Willowbrook Substation
- LLF $Area_9$: Yorkville

2.4.2 Metric

For each LLF Area, the load factor ("LF") will be calculated each year using the following formula, rounded to the nearest tenth of one percent:

[12] Case 15-E-0751, *In the Matter of the Value of Distributed Energy Resources* and Case 15-E-0082, *Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions For Implementing a Community Net Metering Program* (filed November 1, 2017).

$$RY_x \text{ LLF Area}_y \text{ LF} = \frac{\sum RY_x \, MW_{measured}}{RY_x \, MW_{peak} \times RY_x \, n_{hourly\ readings}}$$

Where,

x	Is equal to 1, 2, and 3 for RY_1, RY_2 and RY_3 respectively
y	Ranges from 1 to 9 for each of LLF Areas
RY_x $MW_{measured}$	MW readings measured every hour at a given LLF Area in Rate Year x
RY_x MW_{peak}	The peak MW measurement for a given LLF Area in Rate Year x
RY_x $n_{hourly\ readings}$	Number of hourly readings taken in Rate Year x

2.4.3 Measurement

Each year, the percent change of the substation LF will be calculated based on a baseline of the previous year's LF. A LLF Area will be counted towards achievement if the area shows no decline or an improvement in its LF as further shown formulaically below.

$$RY_x\ LLF\ Area_y = 1\ if\ \frac{LF_{RY_x} - LF_{RY_{x-1}}}{LF_{RY_{x-1}}} \geq 0; Else\ 0$$

Where:

X	Is equal to 1, 2, and 3 for RY_1, RY_2 and RY_3 respectively
Y	Ranges from 1 to 9 for each of LLF Areas

The LLF EAM will be based on the total number of LLF Areas that can maintain or improve its load factor in the rate year as compared to the previous year.

$$RY_x \text{ LLF Achieved} = \sum_{y=1}^{9} RY_x\ LLF\ Area_y$$

2.4.4 Target

The targets are summarized in the table below.

	Level	**2020**	**2021**	**2022**
LSRV Area $_{achieved}$ (# of Areas)	Minimum	RY_1 LLF Min = 5	RY_2 LLF Min = 5	RY_3 LLF Min = 5
	Midpoint	RY_1 LLF Mid = 7	RY_2 LLF Mid = 7	RY_3 LLF Mid = 7
	Maximum	RY_1 LLF Max = 9	RY_2 LLF Max = 9	RY_3 LLF Max = 9

2.4.5 Achievement

Achievement will be based on the number of LSRV areas that maintain or improve its LF each year. The Company's achievement will result in eligible basis points if the metric meets or exceeds target thresholds, with linear scaling between minimum and midpoint, and between midpoint and maximum basis points as further discussed below.

Step 1: The number of LLF Areas for each Rate Year that show no deterioration in load factors will be identified as discussed above to obtain RY_x LLF Achievement.

Step 2: The basis points allocated to the LLF EAM are identified as provided in the table below.

	Level	**2020**	**2021**	**2022**
LLF Basis Points	Minimum	RY_1 LLF BP_{min} = 1	RY_2 LLF BP_{min} = 1	RY_3 LLF BP_{min} = 1
	Midpoint	RY_1 LLF BP_{mid} = 3	RY_2 LLF BP_{mid} = 3	RY_3 LLF BP_{mid} = 3
	Maximum	RY_1 LLF BP_{max} = 5	RY_2 LLF BP_{max} = 5	RY_3 LLF BP_{max} = 5

The potential basis points for the LLF EAM will be calculated as follows:

a) If RY_x LLF Achieved is less than RY_x LLF Min then,

RY_x LLF $BP_{awarded} = 0$

Where,

RY_x LLF $BP_{awarded}$ — Annual basis points, awarded to Company for LLF EAM achievement for Rate Year x

b) If RY_x LLF Achieved = RY_x LLF Min then,

RY_x LLF $BP_{awarded}$ = RY_x LLF BP_{min}

c) If RY_x LLF Achieved is between the RY_x LLF Min and up to RY_x LLF Mid, then

$$RY_x \text{ LLF } BP_{awarded} = RY_x \text{ LLF } BP_{min} + \text{LLF Min-Mid Slope} * (RY_x \text{ LLF Achieved} - \text{LLF } RY_x \text{ Mid})$$

$$\text{With LLF Min-Mid Slope} = \frac{RY_x \text{ LLF BP Mid} - RY_x \text{ LLF BP Min}}{RY_x \text{ LLF}_{mid} - RY_x \text{ LLF}_{min}}$$

Where,

x Is equal to 1, 2 and 3 for RY_1, RY_2, and RY_3 respectively

d) If RY_x LLF Achieved is between the RY_x LLF Mid and up to RY_x LLF Max, then

$$RY_x \text{ LLF } BP_{awarded} = RY_x \text{ LLF } BP_{mid} + \text{LLF Mid-Max Slope} * (RY_x \text{ LLF Achieved} - \text{LLF } RY_x \text{ Mid})$$

$$\text{With LLF Mid-Max Slope} = \frac{\text{LLF } RY_x \text{ BP Max} - \text{LLF } RY_x \text{ BP Mid}}{\text{LLF } RY_{x\ max} - \text{LLF } RY_{x\ mid}}$$

Where,

x Is equal to 1, 2 and 3 for RY_1, RY_2, and RY_3 respectively

e) If RY_x LLF Achieved if greater than or equal to RY_x LLF Max, then

$$RY_x \text{ LLF } BP_{awarded} = RY_x \text{ LLF } BP_{max}$$

<u>Step 3</u>: The Company's basis points will be converted to an incentive that will be calculated as follows:

$$RY_x \text{ LLF EAM (\$)} = RY_x \text{ LLF } BP_{awarded} * RY_x \text{ \$ BP Electric}$$

Where,

RY_x LLF EAM	Company incentive in dollars for LLF EAM achievement in Rate Year x
RY_x \$ BP Electric	\$ per BP in RY_x for Electric

3.0 Gas-Only EAM

3.1 Gas Peak Reduction ("GPR") EAM

3.1.1 Discussion

The GPR EAM incentivizes the Company to deliver firm gas system peak reductions to reduce peak gas demand that reduces the Company's gas supply needs. The GPR EAM sets performance targets based on a regression of four-year historical gas peak demand data, with the historic data based on the prior four winter periods preceding the Rate Year, e.g., the RY1 winter will be considered the 2020-2021 winter and will measure usage against the prior four winters, 2016-2017, 2017-2018, 2018-2019, 2019-2020, as the baseline. The minimum, mid-point and maximum targets are based on the standard error from the regression trend. The GPR EAM achievement is based on the ability of the Company to meet the firm gas system peak reduction targets.

3.1.2 Metric

The GPR metric reflects a seasonally-adjusted gas demand peak, which is expressed in terms of thousands of dekatherms per day (MDt/day) per Heating Degree Day (HDD). See below for more detail.

$$\mathrm{RY_x\ GPR} = \frac{\mathrm{RY_x\ Winter\ Firm\ Peak\ Demand\ Day} - \mathrm{RY_x\ Maximum\ Summer\ Firm\ Peak\ Demand\ Day}}{\mathrm{RY_x\ Winter\ Firm\ Peak\ Day\ HDD}}$$

Where,

x	Is equal to 1, 2, and 3 for RY_1, RY_2 and RY_3 respectively
RY_x GPR	Peak day gas demand per HDD in Rate Year x
RY_x Winter Firm Peak Demand Day	The firm winter gas peak day in Rate Year x. Winter is defined as the period between November 1 of Rate Year x through March 31 of Rate Year x+1 (*i.e.*, winter of Rate Year 1 is the period from November 1, 2020 through March 31, 2021)
RY_x Maximum Summer Firm Peak Demand Day	The maximum firm gas peak day in the summer of Rate Year x. Summer is defined as the period between July 1 and September 30 of Rate Year x (*i.e.*, summer of Rate Year 1 is the period from July 1, 2020 through September 30, 2020)

RY_x Winter Firm Peak Demand Day HDD	A measure of the number of degrees that the peak gas day's 24-hour average dry bulb temperature is below 62º F for Rate Year x

Measurement

The GPR EAM will use gas meter readings in its service area and will source the data from the Company's Gas Day Operations ("GDO") system.

Winter Firm Peak Day Demand
The winter actual firm gas peak demand day, in MDt, will be comprised of the sum of all meters that register supply flowing into the Company's service territory and will include supplies from the Con Edison Liquefied Natural Gas ("LNG") plant, the Rye Compressed Natural Gas ("CNG") station, any additional supplies from trucked CNG, and will net out interchange of the bi-directional meters with National Grid that provide the entire consumption by National Grid customers, and will also net out interruptible gas consumption within the Company's service territory.

Maximum Summer Firm Peak Day Demand
The maximum summer actual firm gas peak demand day, in MDt, will be comprised of the sum of: (a) all meters that register supply flowing into the Company's service territory and will include supplies from the Con Edison Liquefied Natural Gas ("LNG") plant, the Rye Compressed Natural Gas ("CNG") station, any additional supplies from trucked CNG, and (b) will net out: (1) interchange of the bi-directional meters with National Grid that provide the entire consumption by National Grid customers, (2) interruptible gas consumption within the Company's service territory associated with electric and steam generation. The subsequent result [(a)-(b)] is multiplied by a 0.835 factor [13] to net out any interruptible gas consumption not associated with electric and steam generation.

Heating Degree Days
The HDD is a measure of the number of degrees that the peak gas day's 24-hour average dry bulb temperature is below 62 º F. For the purposes of the GPR EAM, HDD shall be based on measured dry bulb temperatures at the Central Park Weather Station for the actual winter firm gas peak day demand.

For each rate year, the Company will file the peak demand data, the RY_x GPR, the linear regression and baseline results, standard error of regression, and associated targets as well as any Company achievement in the gas EAM report that the Company will file with the Commission no later than the June 30th following the Rate Year.

3.1.3 Target

[13] The Company will use a 0.835 factor to net out interruptible gas consumption in the summer. The factor is equal to the average daily actual interruptible load (excluding steam and electric generators) for July 2019 divided by the average daily actual load for July 2019.

The rate year minimum, midpoint and maximum targets, in (MDt/day)/HDD, are set based on the following formulas (and use of Standard Error as commonly defined statistically):

$$RY_x\ GPR\ Min = RY_x\ GPR\ Forecast - 0.3\ Standard\ Error$$

$$RY_x\ GPR\ Mid = RY_x\ GPR\ Forecast - 1.0\ Standard\ Error$$

$$RY_x\ GPR\ Max = RY_x\ GPR\ Forecast - 1.75\ Standard\ Error$$

Where,

x	Is equal to 1, 2, and 3 for RY_1, RY_2 and RY_3 respectively
RY_x GPR Forecast	An analysis of the most recent four-year data to identify trend in peak gas demand, from which the Company will extrapolate a fifth year (*i.e.*, for Rate Year x) on the least squares curve line based on the foregoing four data points:

$$RY_x\ Result\ from\ Linear\ Regression\ for\ dependent\ variable: (GPR\ RY_{x-1}, GPR\ RY_{x-2}, GPR\ RY_{x-3}, GPR\ RY_{x-4})$$

3.1.4 Achievement

Achievement of the GPR EAM will be based upon the Company's ability to meet the target firm gas system peak level. The GPR EAM basis points will be based on the achievement of targets as described above, with linear scaling between minimum and mid, and between mid and maximum basis points.

Step 1: The weather-adjusted gas peak reduction for each Rate Year, $RY_x\ GPR$, will be calculated as described above.

Step 2: The basis points allocated to the GPR EAM are identified as provided in the table below.

	Level	**2020**	**2021**	**2022**
GPR Basis Points	Minimum	RY_1 GPR $BP_{min} = 3$	RY_2 GPR $BP_{min} = 3$	RY_3 GPR $BP_{min} = 3$
	Midpoint	RY_1 GPR $BP_{mid} = 5$	RY_2 GPR $BP_{mid} = 5$	RY_3 GPR $BP_{mid} = 5$
	Maximum	RY_1 GPR $BP_{max} = 8$	RY_2 GPR $BP_{max} = 8$	RY_3 GPR $BP_{max} = 8$

The Company's achieved basis points will be calculated as follows:

a) If RY_x GPR is less than RY_x GPR Min, then RY_x GPR $BP_{awarded} = 0$

Where,

RY_x GPR $BP_{awarded}$	Annual basis points awarded to Company for GPR EAM achievement

b) If RY_x GPR is between at RY_x GPR Min and up to RY_x GPR Mid, then

$$RY_x \text{ GPR } BP_{awarded} = RY_x \text{ GPR } BP_{min} + \text{GPR Min-Mid Slope} * (RY_x \text{ GPR} - RY_x \text{ GPR Min})$$

Where,

GPR Min-Mid Slope	Is equal to $\frac{RY_x \text{ GPR } BP_{mid} - RY_x \text{ GPR } BP_{min}}{ABS[RY_x \text{ GPR Mid} - RY_x \text{ GPR Min}]}$

c) If RY_x GPR is between RY_x GPR Mid and up to RY_x GPR Max, then

$$RY_x \text{ GPR } BP_{awarded} = RY_x \text{ GPR } BP_{mid} + \text{GPR Mid-Max Slope} * (RY_x \text{ GPR} - RY_x \text{ GPR Mid})$$

Where,

GPR Mid-Max Slope	Is equal to $\frac{RY_x \text{ GPR } BP_{max} - RY_x \text{ GPR } BP_{mid}}{ABS[RY_x \text{ GPR Max} - RY_x \text{ GPR Mid}]}$

d) If RY_x GPR is greater than RY_x GPR Max, then RY_x GPR $BP_{awarded} = RY_x$ GPR BP_{max}

<u>Step 3</u>: The Company's basis points will be converted to a dollar incentive that will be calculated as follows:

$$RY_x \text{ GPR EAM (\$)} = RY_x \text{ GPR } BP_{awarded} * (RY_x \text{ \$ BP Gas})$$

Where,

RY_x GPR EAM	Company incentive in dollars for GPR EAM achievement in Rate Year x
RY_x \$ BP Gas	\$ per basis point in Rate Year x for Gas

Technology	Annual ton CO2e avoided / unit
EVs - BEVs	3.13
EVs - PHEVs	2.87
EV Buses	96.77
MD EV	7.81
MD/HD EV	24.98
ASHP	0.47
GSHP	2.07

Air Source Heat Pump Heating Analysis

		Source
Units	1	
kBTU / Unit	12.84	TRM: kBTU/ (h*ton) of cooling capacity
HSPF_ee	9.2	TRM: Assume high efficiency model; COP 2.7
ELFH	526	TRM Input, Appendix G: Assume highrise pre 1979 NYC
kWh Consumed / unit heating	**734**	
kWh to btu	3412.14	
btu consumed	2,504,896.48	
btu required for heating	6,753,840	
Furnace efficiency	80%	
Btu consumed by equivalent furnace	8,442,300	
kWh consumed / furnace unit	**2,474.20**	

Emission Intensity of Fuels

	kg CO2 / MMBTu	kg CO2 / MWh	Tons / MMBtu	Average Heating System Efficiency	Tons per MMBtu Output	kg CO2 / MMBtu	kg CO2 / MWh	Table source
Oil	73.15	249.60	0.08	80%	0.1	90.72	309.54	Link
Natural Gas	53.06	181.05	0.058	80%	0.073	65.77	224.42	
Electric	76.31	260.39	0.084	270%	0.031	28.26	96.44	

kg to US ton
907.185

kg CO2e Avoided / MWh (Heating) Gas	224.42	157.0937	70% Gas fired conversion
kg CO2e Avoided / MWh (Heating) Oil	309.54	92.86327	30% Oil fired conversion

Cooling Analysis (replacing existing room AC with ASHP)

units	1		
tons / unit	1.07	Assume heat pump replaces similarly sized room AC(S)	
kBTU / hr	12.84	TRM: kBTU/ (h*ton) of cooling capacity	
SEERbase	9.8	Based on the kBTU / Range and assume louvered sides	
SEERee	18	TRM Input: High efficiency model	
EFLHcool	793	TRM Input: High efficiency model	
Annual kWh saved / unit replaced (RAC)	**473.32**	378.6548	80% Room Air Conditioner Conversion
kW savings			
Units	1		
EER_baseline	9.8	Based on the kBTU / Range and assume louvered sides	
EER_EE	12.8	TRM Input: Based on SEER 18	
Coincident Factor	0.8	TRM Input	
Tons / unit	1.07		
Delta kW / unit (RAC)	**0.246**	0.197	80% Room Air Conditioner Conversion

kG CO2e avoided / MW heat pump analysis

Units / MW	4519
Cooling MWh saved / unit	0.422
Cooling MWh saved / MW	1908
kg CO2 avoided for cooling / MW	907,795
heating MWh consumed / MW	3,317.60
NYISO Marginal Emission kg / MW	475.82
kg CO2 produced for heating / MW	1,578,576
heating MWh avoided (furnace) / MW	11,181.36
kg CO2 avoided for heating (furnace) / MW	2,794,858
Net kg CO2 avoided for heating / MW	1,216,283
Total kg CO2 avoided / MW	**2,124,078**
Total kg CO2 avoided / unit	**470**
Total ton CO2 avoided / unit	**0.470**

Cooling Analysis (replacing existing Central Air with efficient ASHP)

units	1		
tons / unit	1.07		
kBTU / hr	12.84	TRM: kBTU/ (h*ton) of cooling capacity	
SEERbase	13	TRM Input: normal replacement (assumes to be the same as an existing heat pump)	
SEERee	18	TRM Input: High efficiency model	
EFLHcool	793	TRM Input, Appendix G: Assume highrise pre 1979 NYC	
Annual kWh saved / unit replaced (CAC)	**217.57**	**43.51**	20% Central Air Conversion
kW savings			
Units	1		
EER_baseline	11.09	TRM Input: Normal replacement	
EER_EE	12.8	TRM Input: Based on SEER 18	
Coincident Factor	0.8	TRM Input	
Tons / unit	1.07		
Delta kW / unit (CAC)	**0.124**	**0.025**	20% Central Air Conversion
			20%

Annual kWh saved / unit replaced (RAC & CAC)	**422.17**
Delta kW / unit (RAC & CAC)	**0.221**

Ground Source Heat Pump Heating Analysis

		Source		
Units	1			
tons/unit	3.1	pg.59 of EIA study	Link (secondary)	
kBTU / Unit	37.2	Assumption		
HSPF_ee	12.28	Link (Table A-6)	Link	HSPF = (COP of 4.2)*(3.413)
ELFH	786	TRM Input, Appendix G: Assume NYC single family detached heating		
kWh Consumed / unit heating	**2,380**			
kWh to btu	3412.14			
btu consumed	8,122,000			
btu required for heating	29,239,200			
Furnace efficiency	80%			
Btu consumed by equivalent furnace	36,549,000			
kWh consumed by equivalent furnace	**10,711.46**			

Emission Intensity of Fuels

	kg CO2 / MMBTu	kg CO2 / MWh	Tons / MMBtu	Average Heating System Efficiency	Tons per MMBtu Output	kg CO2 / MMBtu	kg CO2 / MWh	Table source
Oil	73.15	249.60	0.08	80%	0.10	90.72	309.54	Link
Natural Gas	53.06	181.05	0.058	80%	0.073	65.77	224.42	
Electric	76.31	260.39	0.084	270%	0.031	28.26	96.44	
kg to US ton								
907.185								

kg CO2e Avoided / MWh (Heating) Gas	224.42	157.0937	70% Gas fired conversion
kg CO2e Avoided / MWh (Heating) Oil	309.54	92.86327	30% Oil fired conversion

Cooling Analysis (replacing room AC with GSHP)

units	1		
tons / unit	3.1	pg.59 of EIA	Link (secondary)
kBTU / hr	37.2	TRM: kBTU/ (h*ton) of cooling capacity	
EERBase	9.8	Based on the kBTU / Range and assume louvered sides	
EERee	19.75	Link	Table A-6; convert COP to SEER
EFLHcool	649	Assume same (i.e. room AC used to cool more than just room and therefore runs more hours than assumed in TRM)	
Annual kWh saved / unit replaced	**1241.13**	992.90461	80% Room Air Conditioner Conversion
kW savings			
Units	1		
EER_baseline	9.8	Based on the kBTU / Range and assume louvered sides	
EER_EE	17.1	Link (Table A-6)	
Coincident Factor	0.69	TRM Input: page 128	
Tons / unit	3.1		
Delta kW / unit	**1.12**	0.894505	80% Room Air Conditioner Conversion

kG CO2e avoided / MW heat pump analysis

Units / MW	923
Cooling MWh saved / unit	1.10
Cooling MWh saved / MW	1012
kg CO2 avoided for cooling / MW	481,506
heating MWh consumed / MW	2,197.63
NYISO marginal emission rate kg / MW	475.82
kg CO2 produced for heating / MW	1,045,672
heating MWh avoided (furnace) / MW	9,889.32
kg CO2 avoided for heating (furnace) / MW	2,471,904
Net kg CO2 avoided for heating / MW	1,426,231
Total kg CO2 avoided / MW	**1,907,737**
Total kg CO2 avoided / unit	**2,066**
Total ton CO2 avoided / unit	**2.07**

Cooling Analysis (replacing Central Air with GSHP)

units	1		
tons / unit	3.1		
kBTU / hr	37.2	TRM: kBTU/ (h*ton) of cooling capacity	
SEERbase	13	TRM Input: normal replacement (assumes to be the same as an existing heat pump)	
SEERee	18	TRM Input: High efficiency model	
EFLHcool	649	TRM Input, Appendix G: Assume NYC single family detached cooling	
Annual kWh saved / unit replaced (CAC)	**515.87**	**103.1744**	20% Central Air Conversion
kW savings			
Units	1		
EER_baseline	11.09	TRM Input	
EER_EE	17.1	Link (Table A-6)	
Coincident Factor	0.8	TRM Input	
Tons / unit	3.1		
Delta kW / unit (CAC)	**0.943**	**0.18863**	20% Central Air Conversion

Annual kWh saved / unit replaced (RAC & CAC)	**1096.08**
Delta kW / unit (RAC & CAC)	**1.083**

kg CO2e avoided / MWh Light Duty BEV Analysis

Item	Value	Source / Notes	
Btu / gallon gasoline	123,000	Link	Average of HHV Energy Content of Gasoline/E10
Btu / kWh	3,412		
kWh / gallon gasoline	36.05		
Gallons / MWh	27.74		
kg CO2e emissions / liter gasoline	2.425	Link	CO2e of Gasoline - light duty
kg CO2e emissions / gallon gasoline	9.18		Convert liters to gallons
kg CO2e emissions / MWh (gasoline fuel)	254.65		kgCO2e emissions / MWh of energy in gasoline
Passenger vehicle efficiency (miles per gallon gasoline)	22.00	Link	2015 weighted average economy of cars and light trucks
miles per MWh (gasoline car)	610.30		
kg CO2e / mile (gasoline car)	0.42		
Passenger BEV efficiency (kWh / mile)	0.32	Link	Average of PHEV kWh/mi & EV kWh/mi
NYISO Marginal Emission Rate (kg / kWh)	0.48		
kg CO2e/mile (electric car)	0.15		
kgCO2e savings/mile (gas-electric)	0.2650		
Miles traveled / vehicle / year	11,824	DoE	Average annual vehicle mileage (miles)
Net kg CO2e avoided / per EV per year	3,133		
Net ton CO2e avoided / per EV per year	**3.13**		

kg CO2e avoided / MWh Light Duty PHEV Analysis

Item	Value	Source / Notes	
Btu / gallon gasoline	123,000	Link	Average of HHV Energy Content of Gasoline/E10
Btu / kWh	3,412		
kWh / gallon gasoline	36.05		
Gallons / MWh	27.74		
kg CO2e emissions / liter gasoline	2.425	Link	CO2e of Gasoline - light duty
kg CO2e emissions / gallon gasoline	9.18		Convert liters to gallons
kg CO2e emissions / MWh (gasoline fuel)	254.65		kgCO2e emissions / MWh of energy in gasoline
Passenger vehicle efficiency (miles per gallon gasoline)	22.00	Link	2015 weighted average economy of cars and light trucks
miles per MWh (gasoline car)	610.30		
kg CO2e / mile (gasoline car)	0.42		
Passenger PHEV efficiency (kWh / mile)	0.37	Link	Average of PHEV kWh/mi & EV kWh/mi
NYISO Marginal Emission Rate (kg / kWh)	0.48		
kg CO2e/mile (electric car)	0.17		
kgCO2e savings/mile (gas-electric)	0.2426		
Miles traveled / vehicle / year	11,824	DoE	Average annual vehicle mileage (miles)
Net kg CO2e avoided / per EV per year	2,869		
Net ton CO2e avoided / per EV per year	**2.87**		

kg CO2e avoided / MWh Heavy Duty Electric Bus Analysis

Item	Value	Source / Notes	
Btu / gallon diesel	138,490	Link	
Btu / kWh	3,412		
kWh / gallon diesel	40.59		
Gallons / MWh	24.64		
kg CO2e emissions / liter diesel	2.685		
kg CO2e emissions / gallon diesel	10.16	Link	
kg CO2e emissions / MWh (diesel fuel)	250.42		kgCO2e emissions / MWh of energy in diesel
Diesel bus efficiency (miles per gallon diesel)	2.28	Link	Columbia report, page 9
miles per MWh (diesel bus)	56.18		Old MTA report
kg CO2e / mile (diesel bus)	4.46		
Bus EV efficiency (kWh / mile)	2.00	Link	MTA Data, page 12
NYISO Marginal Emission Rate (kg / kWh)	0.48		
kg CO2e / mile (electric bus)	0.95		
kgCO2e savings/mile (diesel-electric)	3.51		
Miles traveled / vehicle / year	27,600	Link	MTA Data
Net kg CO2e avoided / per electric bus per year	96,771		
Net ton CO2e avoided / per electric bus per year	**96.77**		

Availability	79%
MDBF-miles	5,369
kWh/mile	3.9
kWh/hour	19.2
miles/hour	4.9
miles	32,213
hours	6,526
kW-h	125,363

January 9 – June 30, 2018 Data (10 Standard 40-foot Electric Buses)

kg CO2e avoided / MWh Med Vehicle Analysis

Item	Value	Source / Notes	
Btu / gallon diesel	138,490	Link	
Btu / kWh	3,412		
kWh / gallon diesel	40.59		
Gallons / MWh	24.64		
kg CO2e emissions / liter diesel	2.685		
kg CO2e emissions / gallon diesel	10.16	Link	
kg CO2e emissions / MWh (diesel fuel)	250.42		kgCO2e emissions / MWh of energy in diesel
Diesel Med Vehicle mpg	7.63	link	https://afdc.energy.gov/files/u/publication/field_evaluation_md_elec_delivery_trucks.pdf
miles per MWh (diesel MD/HD vehicle)	187.99		
kg CO2e / mile (diesel MD/HD vehicle)	1.33		
Med/Heavy EV efficiency (kWh / mile)	1.30		https://facts.daimler.com/en/trucks/product-range/fuso/ecanter/
NYISO Marginal Emission Rate (kg / kWh)	0.48		
kg CO2e / mile (Med/Heavy EV)	0.62		
kgCO2e savings/mile (diesel-electric)	0.71		
Miles/vehicle-day	30.00		
Miles/vehicle-year	10,950.00		
Miles traveled / vehicle / year	10,950		
Net kg CO2e avoided / per MD/HD EV per year	7,813		
Net ton CO2e avoided / per MD/HD EV per year	**7.81**		

kg CO2e avoided / MWh Heavy Vehicle Analysis

Item	Value	Source / Notes	
Btu / gallon diesel	138,490	Link	
Btu / kWh	3,412		
kWh / gallon diesel	40.59		
Gallons / MWh	24.64		
kg CO2e emissions / liter diesel	2.685		
kg CO2e emissions / gallon diesel	10.16	Link	
kg CO2e emissions / MWh (diesel fuel)	250.42		kgCO2e emissions / MWh of energy in diesel
lbs/US ton	2000		
CI Diesel Engine Med/Heavy Avg Gallons fuel per 1000 ton-mile	21.95	Link	EPA fuel efficiency standards
CI Diesel Engine Med/Heavy Avg ton-mile per gallon (assume c	0.02195		
Avg Med/Heavy lbs	26000	Link	EPA Emissions Classifications, just taking the max for Med, min for Heavy
Avg Med/Heavy US tons	13		
Diesel Med/Heavy Vehicle mpg	3.50		
miles per MWh (diesel MD/HD vehicle)	86.34		
kg CO2e / mile (diesel MD/HD vehicle)	2.90		
Heavy EV efficiency (kWh / mile)	1.30		Proprietary HD EV usage data from BYD (EV manufacturer)
NYISO Marginal Emission Rate (kg / kWh)	0.48		
kg CO2e / mile (Med/Heavy EV)	0.62		
kgCO2e savings/mile (diesel-electric)	2.28		
Miles/vehicle-day	30.00		
Miles/vehicle-year	10,950		
Miles traveled / vehicle / year	10,950		
Net kg CO2e avoided / per MD/HD EV per year	24,984		
Net ton CO2e avoided / per MD/HD EV per year	**24.98**		

QUARTERLY LOW INCOME REPORT

[Company Name]

LOW INCOME PROGRAM QUARTER ENDING: 3/31/2019

ITEM DESCRIPTION	CUSTOMERS		
	Electric-only	Gas-only	Combination
1a. Rate discount participants -Total			
1b. Tier 1			
1b. Tier 2			
1c. Tier 3			
1d. Tier 4			
1e. New enrollments			
1f. Exited customers			
2a. Arrears forgiveness participants - Total			
2b. New enrollments			
2c. Exited customers			
2d. Completed			
2e. Defaulted			
2f. Cancelled (customer request)			
2g. Other			
4a. Energy efficiency program participant referrals - Total			
4b. EmPower-NY			
4c. Other			
3. Participant reconnnection fees waived - Total			

ITEM DESCRIPTION	DOLLARS	
	Electric	Gas
5a. Rate discounts - Amount expended		
5b. Over/undercollection		
6a. Arrears forgiveness - Amount expended		
6b. Over/undercollection		
7a. Reconnection fee waivers - Total		
7b. Remaining balance		
8. Average bill - Heating		
9. Average bill - Non-heating		
10a. Total Over/Under Collection		
10b. Regulatory Asset/(Liability) Balance-End of Qua		

ITEM DESCRIPTION	COLLECTION DATA	
	Customers	Dollars
11. Participant Arrears - Total		
12. Termination notices sent to participants		
13a. Participants terminated		
13b. Heat-related		
14a. Participants reconnected		
14b. Due to HEAP/DSS		
14c. Due to DPA		
15a. Active Participant DPAs - beginning of period		
15b. DPAs made		
15c. DPAs reinstated		
15d. DPAs defaulted		
15e. DPAs satisfied		
15f. Active Participant DPAs - End of Period		
15g. Participant DPAs in Arrears >60 days		
16. Participant Uncollectibles		
17. Budget Billing Participants		
17a. Credit Reconciliations (overcollection)		
17b. Debit Reconciliations (undercollection)		

Consolidated Edison Company of New York, Inc.
Cases 19-G-0066
Interruptible and Off-Peak Firm Balancing

The Company will revise its tariff and/or Gas Sales and Transportation Operating Agreement ("GTOP"), as applicable, to implement the operational changes described below. These changes will be implemented for winter 2020-2021.

Daily Balancing:

Customers will pay a Variable Balancing Charge of $0.0015 per therm on all usage.

A Daily Cashout Credit/Charge, to be billed to the energy services company ("ESCO"), will apply to daily net surplus/deficiency imbalances that exceed 5% as follows:

Net Surplus Imbalance	Credit per therm
(1) Greater than 5% but less than or equal to 10%	95% of cost of gas
(2) Greater than 10% but less than or equal to 15%	90% of cost of gas
(3) Greater than 15% but less than or equal to 20%	80% of cost of gas
(4) Greater than 20%	50% of cost of gas

Net Deficiency Imbalance	Charge per therm
(1) Greater than 5% but less than or equal to 10%	105% of cost of gas
(2) Greater than 10% but less than or equal to 1520%	110% of cost of gas
(3) Greater than 15% but less than or equal to 20%	120% of cost of gas
(4) Greater than 20%	150% of cost of gas

The cost of gas used in calculating the Daily Cashout Credit/Charge will be a weighted average price equal to the product of the percentage weightings, as defined in the GTOP, and the Transco Z6 NY, Tetco M3 and Iroquois Z2 midpoint price as published in Platt's Gas Daily on the day in which the imbalance occurs.

A Monthly Cashout Credit/Charge, to be billed to the ESCO, will apply to the aggregate daily surplus/deficiency imbalances that fall within 5% as follows:

Net Surplus Imbalance	Credit per therm
(1) Less than 5%	100% of cost of gas
(2) Greater than 5% but less than or equal to 10%	95% of cost of gas
(3) Greater than 10% but less than or equal to 15%	90% of cost of gas
(4) Greater than 15% but less than or equal to 20%	80% of cost of gas
(5) Greater than 20%	50% of cost of gas

Net Deficiency Imbalance	Charge per therm
(1) Less than 5%	100% of cost of gas
(2) Greater than 5% but less than or equal to 10%	105% of cost of gas

(3) Greater than 10% but less than or equal to 15%	110% of cost of gas
(4) Greater than 15% but less than or equal to 20%	120% of cost of gas
(5) Greater than 20%	150% of cost of gas

The cost of gas used in calculating the Monthly Cashout Credit will be a weighted average price equal to the product of the percentage weightings, as defined in the GTOP, and the lower of (i) the monthly average daily Transco Z6 NY, Tetco M3 or Iroquois Z2 prices (days of interruption excluded) or (ii) the Transco Z6 NY, Tetco M3 and Iroquois Z2 First of the Month Low Range Price as published in Platt's Gas Daily

The cost of gas used in calculating the Monthly Cashout Charge will be a weighted average price equal to the product of the percentage weightings, as defined in the GTOP, and the higher of (i) the monthly average daily Transco Z6 NY, Tetco M3 or Iroquois Z2 prices or (ii) the Transco Z6 NY, Tetco M3 and Iroquois Z2 First of the Month High Range Price as published in Platt's Gas Daily

Monthly Balancing:

Customers will pay a Variable Balancing Charge of $0.002 per therm on all usage.

Daily Delivery Quantity ("DDQ"):

Each month, the Company shall determine the Customer's Non-Firm DDQ and the ESCO shall be obligated to deliver this amount each day to the Company's City Gate unless otherwise notified by the Company.

a. To the extent practical the Company will utilize a methodology for determining the Non-Firm DDQ similar to that utilized to determine the firm DDQ under Daily Balancing Service. ESCOs and/or Customers can request a modification to the DDQ by providing documentation to the Company as to why the DDQ is inappropriate. Changes will be granted at the discretion of the Company but can't be unreasonably withheld.
b. The Company, upon 48 hours' notice, may modify the DDQ intra-month for the purpose of adjusting to temperature swings, customer usage and to minimize end of month cash out exposure.
c. The ESCO shall provide to the Company notice of the natural gas scheduled for delivery at the City Gate by pipeline transporters for each day of the succeeding month. The scheduled nomination must equal Customer's Non-Firm DDQ.

City Gate Balancing:
The ESCO shall nominate and schedule deliveries of gas to the Company's city gates in an aggregate amount equal to the Customer's Non-Firm DDQ within a tolerance of ± 2%.

a. The obligation to deliver the Non-Firm DDQ will be waived when service has been interrupted by the Company for a full day or when the Customer elects to burn an alternate fuel for a full day and notifies the Company of such.

b. In the event that the total quantity of gas delivered to the city gate is less than 98% of the Customer's Non-Firm DDQ, the ESCO shall pay a per therm amount equal to the Company's Daily Cashout Charge (at the less than 5% tier) plus a City Gate Balancing Penalty Charge of $25.00 per dekatherm (increased to $50 per dekatherm if the Company has issued an OFO) multiplied by the difference between:
   i. 98% of the Customer's Non- Firm DDQ for such day; and
   ii. the total quantity of gas delivered by ESCO to the Company on such day.

c. The Company is not obligated to accept any volumes that have been nominated by the ESCO to the extent that such nomination exceeds Customer's Non-Firm DDQ +2%. In the event that the total quantity of gas delivered to the citygate is more than 102% of the Customer's Non-Firm DDQ, and the Company at its discretion accepts the gas, the Company shall pay the ESCO a per therm amount equal to the Daily Cash Out Price (at the less than 5% tier) multiplied by the difference between:
   i. the quantity of gas delivered by Customer to the Company on such day; and
   ii. 102% of Customer's Non-Firm DDQ for such day.

d. In the event that the Company interrupts service for at least one gas day to a Customer and the Company accepts the Customer's gas deliveries to the city gate during that interruption, the Company shall purchase the Customer's gas at the Daily Cash Out Price.

A <u>Monthly Cashout Credit/Charge</u> will apply to the aggregate daily surplus/deficiency imbalance at 100% of the cost of gas

The cost of gas used in calculating the Monthly Cashout Credit will be a weighted average price equal to the product of the percentage weightings, as defined in the GTOP, and the lower of (i) the monthly average daily Transco Z6 NY, Tetco M3 or Iroquois Z2 prices (days of interruption excluded); or (ii) the Transco Z6 NY, Tetco M3 and Iroquois Z2 First of the Month Low Range Price as published in Platt's Gas Daily.

The cost of gas used in calculating the Monthly Cashout Charge will be a weighted average price equal to the product of the percentage weightings, as defined in the GTOP, and the higher of (i) the monthly average daily Transco Z6 NY, Tetco M3 or Iroquois Z2 prices (days of interruption excluded); or (ii) the Transco Z6 NY, Tetco M3 and Iroquois Z2 First of the Month High Range Price as published in Platt's Gas Daily.

Appendix 26 – CSS Project Reporting Requirements

Consolidated Edison Company of New York, Inc.
Case 19-E-0065, 19-G-0066
Reporting Requirements Associated with the CSS Project

The Company will provide three reports to Staff pertaining to the CSS implementation.

First, the Company will provide the below implementation status report to Staff pertaining to the CSS project bi-annually for 2020, providing reports by July 17, 2020, and January 15, 2021. As the CSS project ramps up, starting in 2021, the Company will provide quarterly reports on the 15th of January, April, July, October in 2021 and 2022.

Implementation Status Report

Metric Group	Metric	Description
Project Cost Performance	Project Cost Variance (budget vs. actual)	The completed work cost compared to the planned cost.
	Change Control Metrics (approved vs. rejected)	Manage and measure scope of work change requests (approved requests vs. rejected) to document requests and due diligence in the approval process, and that resources are used efficiently.
Project Schedule Performance	Schedule Adherence	The percentage to which the project is on schedule (project plan timeline and actual work completed as per the schedule).
	Project Milestones	Project milestones achieved on schedule.
Earned Value	Cost Performance Index	Measures the financial effectiveness and efficiency of a project, represents the amount of completed work for every unit of cost spent. This ratio is calculated by dividing the budgeted cost of work completed by the actual cost of the work performed.
	Schedule Performance Index	Measures how close the project is to being completed compared to the schedule. This ratio is calculated by dividing the budgeted cost of work performed by the planned value.
Organizational Change Management ("OCM")	OCM Strategy Document	Provide OCM strategy document to Staff that outlines communications with stakeholders, employee engagement initiatives with stakeholders, planned presentations, town hall events, staff meetings, webcasts, etc.

Second, the Company will provide an annual staffing, and training facilities implementation plans on December 15 of 2020, 2021 and 2022 for the upcoming rate year.

Third, the Company will file with the Commission a cost savings report one year after the completion of the CSS project discussing cost savings achieved in the prior calendar year as described below.

Con Edison Benefits Realization – Reductions

Function	Description	Cost Category	Expected Initial Reporting Period	Estimated Annual Cost Reduction ($k)	Benefits this Year ($)	Benefits to Date ($)	Benefits in Total ($)
CSS Sustainability	Reduction in the sustainability costs required to maintain legacy CSS	Capital	2024	$10,000			
Mainframe MIPS	Reduction in IBM mainframe processor MIPS to support the mainframe systems, retirement of Information Management System (“IMS”)	Capital	2024	$2,000			
IMS Retirement	IBM IMS legacy database subsystem retirement	Capital	2024	$700			
CECONY IT Support	Reduced FTE requirements to support ongoing IT organization	O&M	2024	$2,354			
CECONY Project Support	Cost reduction to be realized by not backfilling IT project resources while they support the new CSS project	O&M	2024	$2,891			
IT Contractor Spend	Reduction in the contractor support required for legacy CSS	O&M	2024	$2,000			
IMS Headcount	IMS systems workload reduction	O&M	2024	$275			
Reduced licenses for Customer Care and Billing (“CC&B”)	Reduction in the maintenance costs supporting Oracle CC&B	O&M	2024	$221			
Training Reduction	Reduction in training requirements for new employees	O&M	2024	$2,205			
Finance COA process	Elimination of Chart of Accounts (“COA”) table activity and associated FTE	O&M	2024	$42			
Specialized Activities	Reduction in headcount supporting specialized activities due to improved accuracy and processing capabilities in the new CSS	O&M	2024	$725			

<u>CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.</u>

Case 19-E-0065

2018 Sales and Use Tax Refund Amortzation - Electric

($000's)

		Book Depreciation *		Tax Depreciation		Difference between Tax and Book	Total Def Inc. Taxes				Net
Year	Plant	Annual	Cumulative	Annual	Cumulative	Depreciation	FIT	SIT	Total Annual	Cumulative	Rate Base
2020	$ (26,486)	$ 1,104	$ 1,104	$ 993	$ 993	$ 110	$ (22)	$ (7)	$ (29)	$ (29)	$ (25,411)
2021	(26,486)	1,104	2,207	1,912	2,905	(808)	159	53	211	182	(24,096)
2022	(26,486)	1,104	3,311	1,768	4,674	(665)	131	43	174	356	(22,819)
2023	(26,486)	1,104	4,414	1,636	6,310	(532)	105	35	139	495	(21,576)
2024	(26,486)	1,104	5,518	1,513	7,823	(410)	80	27	107	602	(20,365)
2025	(26,486)	1,104	6,621	1,400	9,223	(296)	58	19	77	680	(19,184)
2026	(26,486)	1,104	7,725	1,295	10,517	(191)	38	12	50	730	(18,031)
2027	(26,486)	1,104	8,829	1,198	11,715	(94)	18	6	25	754	(16,903)
2028	(26,486)	1,104	9,932	1,182	12,897	(78)	15	5	20	775	(15,779)
2029	(26,486)	1,104	11,036	1,182	14,078	(78)	15	5	20	795	(14,655)
2030	(26,486)	1,104	12,139	1,182	15,260	(78)	15	5	20	816	(13,531)
2031	(26,486)	1,104	13,243	1,182	16,442	(78)	15	5	20	836	(12,407)
2032	(26,486)	1,104	14,346	1,182	17,624	(78)	15	5	20	857	(11,283)
2033	(26,486)	1,104	15,450	1,182	18,806	(78)	15	5	20	877	(10,159)
2034	(26,486)	1,104	16,553	1,182	19,987	(78)	15	5	20	897	(9,035)
2035	(26,486)	1,104	17,657	1,182	21,169	(78)	15	5	20	918	(7,911)
2036	(26,486)	1,104	18,761	1,182	22,351	(78)	15	5	20	938	(6,787)
2037	(26,486)	1,104	19,864	1,182	23,533	(78)	15	5	20	959	(5,663)
2038	(26,486)	1,104	20,968	1,182	24,715	(78)	15	5	20	979	(4,539)
2039	(26,486)	1,104	22,071	1,182	25,896	(78)	15	5	20	1,000	(3,415)
2040	(26,486)	1,104	23,175	589	26,486	514	(101)	(33)	(134)	865	(2,445)
2041	(26,486)	1,104	24,278			1,104	(217)	(72)	(288)	577	(1,630)
2042	(26,486)	1,104	25,382			1,104	(217)	(72)	(288)	288	(815)
2043	(26,486)	1,104	26,486			1,104	(217)	(72)	(288)	0	(0)

* The Company's depreciation levels in this case reflect annual amortization of the sales and use tax refund. In future filings, the Company will include the impact of sales and use tax refund amortization within the depreciation section of its revenue requirement exhibits.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Case 19-G-0066
2018 Sales and Use Tax Refund Amortzation - Gas
($000's)

		Book Depreciation *		Tax Depreciation		Difference between Tax and Book Depreciation	Total Def Inc. Taxes				Net
Year	Plant	Annual	Cumulative	Annual	Cumulative		FIT	SIT	Total Annual	Cumulative	Rate Base
2020	$ (2,861)	$ 119	$ 119	$ 107	$ 107	$ 12	$ (2)	$ (1)	$ (3)	$ (3)	$ (2,745)
2021	(2,861)	119	238	207	314	(87)	17	6	23	20	(2,603)
2022	(2,861)	119	358	191	505	(72)	14	5	19	38	(2,465)
2023	(2,861)	119	477	177	682	(58)	11	4	15	54	(2,330)
2024	(2,861)	119	596	163	845	(44)	9	3	12	65	(2,200)
2025	(2,861)	119	715	151	996	(32)	6	2	8	73	(2,072)
2026	(2,861)	119	834	140	1,136	(21)	4	1	5	79	(1,948)
2027	(2,861)	119	954	129	1,265	(10)	2	1	3	81	(1,826)
2028	(2,861)	119	1,073	128	1,393	(8)	2	1	2	84	(1,704)
2029	(2,861)	119	1,192	128	1,521	(8)	2	1	2	86	(1,583)
2030	(2,861)	119	1,311	128	1,648	(8)	2	1	2	88	(1,461)
2031	(2,861)	119	1,430	128	1,776	(8)	2	1	2	90	(1,340)
2032	(2,861)	119	1,550	128	1,904	(8)	2	1	2	93	(1,219)
2033	(2,861)	119	1,669	128	2,031	(8)	2	1	2	95	(1,097)
2034	(2,861)	119	1,788	128	2,159	(8)	2	1	2	97	(976)
2035	(2,861)	119	1,907	128	2,287	(8)	2	1	2	99	(854)
2036	(2,861)	119	2,026	128	2,414	(8)	2	1	2	101	(733)
2037	(2,861)	119	2,146	128	2,542	(8)	2	1	2	104	(612)
2038	(2,861)	119	2,265	128	2,669	(8)	2	1	2	106	(490)
2039	(2,861)	119	2,384	128	2,797	(8)	2	1	2	108	(369)
2040	(2,861)	119	2,503	64	2,861	56	(11)	(4)	(15)	93	(264)
2041	(2,861)	119	2,622			119	(23)	(8)	(31)	62	(176)
2042	(2,861)	119	2,742			119	(23)	(8)	(31)	31	(88)
2043	(2,861)	119	2,861			119	(23)	(8)	(31)	0	0

* The Company's depreciation levels in this case reflect annual amortization of the sales and use tax refund. In future filings, the Company will include the impact of sales and use tax refund amortization within the depreciation section of its revenue requirement exhibits.