Attachment 7

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 19-E-0378 -	Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of New York State Electric & Gas Corporation for Electric Service.
CASE 19-G-0379 -	Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of New York State Electric & Gas Corporation for Gas Service.
CASE 19-E-0380 -	Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Rochester Gas and Electric Corporation for Electric Service.
CASE 19-G-0381 -	Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Rochester Gas and Electric Corporation for Gas Service.

ORDER APPROVING ELECTRIC AND GAS RATE PLANS IN ACCORD WITH JOINT PROPOSAL, WITH MODIFICATIONS

Issued and Effective: November 19, 2020

TABLE OF CONTENTS

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service Commission held in the City of Albany on November 19, 2020

COMMISSIONERS PRESENT:

John B. Rhodes, Chair
Diane X. Burman, dissenting
James S. Alesi
Tracey A. Edwards
John B. Howard

CASE 19-E-0378 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of New York State Electric & Gas Corporation for Electric Service.

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ORDER APPROVING ELECTRIC AND GAS RATE PLANS IN ACCORD WITH JOINT PROPOSAL

(Issued and Effective November 19, 2020)

BY THE COMMISSION:

I. INTRODUCTION

In this Order, the Commission approves electric and gas rate plans for New York State Electric & Gas Corporation (NYSEG) and Rochester Gas and Electric Corporation (RG&E)

(collectively, the Companies). The approved rate plans, established for the period beginning April 17, 2020, and ending on April 30, 2023, are generally in accord with the terms of a joint proposal (Joint Proposal) signed, in whole or in part, by 23 parties representing diverse interests, including the Companies, trial staff of the Department of Public Service (DPS Staff), environmental groups, a labor union, individual ratepayers, and large industrial, commercial and institutional energy consumers.[1] However, our approval is predicated on modifications to the Joint Proposal's electric rate plans, which will be discussed in the body of this Order.

The Joint Proposal was negotiated within the context of two significant events – the enactment into law of the Climate Leadership and Community Protection Act (CLCPA) and the coronavirus (COVID-19) pandemic. The former, signed by Governor Andrew Cuomo on July 18, 2019, sets forth New York's nation-leading policy goals in the ongoing fight against climate change, while the latter led to Governor Cuomo's March 7, 2020, state of emergency declaration that remains in effect today. As several provisions in the Joint Proposal further the objectives of the CLCPA and many others are directly responsive to the pandemic, we take this opportunity to commend all of the parties to these rate proceedings for their dedicated advocacy. Indeed, as more fully discussed throughout this Order, positions taken by every party, whether signatory parties to the Joint Proposal or not, have informed our adoption of the Joint Proposal with modifications and contributed to rate plans that balance

[1] Topics briefly discussed in this introduction are more comprehensively addressed throughout the body of this Order. This includes the identification of specific parties and the extent to which they have signed onto the electric and/or gas provisions of the Joint Proposal, as well as, where necessary, definitions of particular terms.

customer support mechanisms, governmental policies and revenue requirement levels, while at the same time ensuring the Companies' ability to provide reliable service at just and reasonable rates.

The rate plans in the Joint Proposal[2] contain notable increases for customers of the Companies' electric businesses. More specifically, after shaping/levelization, NYSEG Electric delivery rates would be increased by $45.7 million (6.1% of delivery revenues) in Rate Year (RY) 1, $84.8 million (10.6% of delivery revenues) in RY 2 and $88.6 million (9.9% of delivery revenues) in RY 3. For average residential customers, these proposed increases would result in monthly bill increases of approximately $2.49 (3.6%) in RY 1, $4.13 (5.7%) in RY 2 and $5.54 (7.2%) in RY 3.

While there are numerous ways to quantify changes in rates, the total change in the bills of residential customers captures most of the moving components of such bills, including commodity costs, the elimination of an energy efficiency surcharge, and the elimination of a sur-credit related to tax savings. Looking at the total bills of all NYSEG Electric customers over the three years of the Joint Proposal, including the fact that the Revenue Adjustment Mechanism (RAM) ends two months into RY 2, shows how large the increases are on customers' bills. For the known changes in the Joint Proposal, such increases would be 2.0% in RY 1, 4.4% in RY 2, and 5.0% in RY 3. The calculations of these amounts can be seen in Attachment 2.

For RG&E, electric delivery rate increases would be $15.2 million (3.4% of delivery revenues) in RY 1, $28.1 million (6.3% of delivery revenues) in RY 2 and $30.7 million (6.2% of

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2 The Joint Proposal and its appendices are attached to and incorporated into this Order as Attachment 1.

delivery revenues) in RY 3, with corresponding increases to average monthly residential bills of $0.37 (0.5%), $3.82 (5.0%) and $4.14 (5.2%), respectively. For total bill impacts for all electric customers, the delivery rate increases in the Joint Proposal would result in total bill increases of 0.8% in RY 1, 3.8% in RY 2, and 3.8% in RY 3. The calculations of these amounts can be seen in Attachment 2.

The signatory parties state that while they are aware that their proposed rate increases will have an impact on all electric customers, they point out that these additional revenues are necessary to ensure the Companies' continued reliability and compliance with statutory, regulatory, code and industry standard requirements. We agree that the proposed rate plans use the additional revenues in ways that will lead to important improvements within the Companies' service territories.

In particular, the Joint Proposal contemplates approximately $2.5 billion of investments in the Companies' electric systems to replace aging infrastructure ($1.6 billion at NYSEG and $871 million at RG&E), an increase in overall vegetation management spending from $30 million to $57 million for NYSEG's electric business, and the rightsizing of the Companies' labor forces through the addition of over 500 full-time employees, including 150 linemen and 55 apprentice linemen specifically intended to improve the Companies' storm recovery responses. Additionally, capital expenditures related to NYSEG's Bulk Electric System Program will facilitate its compliance with Federal Energy Regulation Commission requirements and enhance system performance. Also, the rate plans in the Joint Proposal contain large increases in the energy efficiency and heat pump budgets for the Companies in order to attempt to comply with the levels approved in Case 18-M-0084.[3]

Before turning to the proposals related to the Companies' gas businesses, a number of COVID-related relief measures in the Joint Proposal warrant mention. First, a $30 million emergency financial relief program is created that would grant up to $100 in bill credits to vulnerable residential and small business customers. For participants in the Companies' Low Income Programs – all of whom will be eligible – these credits should offset approximately 50 percent of the rate increases those customers would otherwise experience during the three years of the rate plans.[4] Next, small and large business customers may benefit from the Economic Development Grant Assistance Program, which is focused on economic recovery and retention projects necessitated by the pandemic – e.g., costs associated with transitioning to a remote work environment or cleaning and disinfection services. Additionally, while not directly related to COVID, the Companies' commitment to hire a number of additional workers will provide stable employment to up to 500 people in an uncertain economic climate.

Finally, it is notable that the Companies initially sought combined increases in RY 1 of $200.4 million, while DPS Staff proposed a total increase of $39 million, establishing what is essentially the minimum increase that might be required through a fully-litigated proceeding. Following settlement

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[3] Case 18-M-0084, Comprehensive Energy Efficiency Initiative, Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios through 2025 (issued January 16, 2020) (2020 Energy Efficiency Order), p. 65; See also, Case 15-M-0252, Utility Energy Efficiency Programs, Order Authorizing Utility-Administered Energy Efficiency Portfolio Budgets and Targets for 2019-2020 (issued March 15, 2018), pp. 21-22.

[4] In RY 3, most low income program participants will have monthly bills of approximately $25 (NYSEG) or $48 (RG&E).

discussions occurring after onset of the pandemic, the signatory parties agreed to RY 1 increases of just $20.7 million, almost $20 million less than DPS Staff's combined proposed RY 1 increases. While that combined $20.7 million RY 1 figure includes a $45.7 million increase at NYSEG Electric, the Companies originally requested a RY 1 increase at NYSEG Electric of $174.5 million. Thus, the RY 1 increase at NYSEG Electric reflected in the Joint Proposal represents a 75 percent reduction from the Companies' originally stated revenue requirement.

For the Companies' gas businesses, after shaping/levelization, under the Joint Proposal NYSEG's gas delivery rates would be decreased by $0.5 million (0.3% of delivery revenues) in RY 1, increased by $3.4 million (1.7% of delivery revenues) in RY 2 and increased by $5.3 million (2.5% of delivery revenues) in RY 3. For average residential customers, this would lead to a decrease in the average monthly bill of $0.02 (0.0%) in RY 1, an increase of $0.53 (0.6%) in RY 2 and an increase of $1.22 (1.4%) in RY 3. For total bill impacts for all gas customers, the delivery rate increases in the Joint Proposal would result in total bill changes of negative 0.4% in RY 1 followed by increases of 1.1% in RY 2 and 1.3% in RY 3. The calculations of these amounts can be seen in Attachment 2.

For RG&E, shaped/levelized gas delivery rates would result in a decrease of $1.1 million (0.6%) in RY 1, a $0.9 million (0.5%) increase in RY 2, and a $3.9 million (2.1%) increase in RY 3, with corresponding average monthly bill impacts of an $0.80 (0.1%) decrease, a $0.10 (0.1%) increase and an $0.81 (1.1%) increase, respectively. For total bill impacts for all gas customers, the delivery rate increases in the Joint Proposal would result in total bill changes of negative 0.6% in

RY 1 followed by increases of 0.5% in RY 2 and 1.0% in RY 3. The calculations of these amounts can be seen in Attachment 2.

In addition to the decreases and the subsequent lower percentage rate increases, the Joint Proposal's gas-related provisions implement forward-looking strategies that are designed to ensure the Companies' compliance with the CLCPA. Indeed, as reflected in the Joint Proposal, the Companies commit to achieving net-zero growth in gas sales throughout their service territories during the three-year rate period, discontinuing their promotion of natural gas services, incentivizing the expanded use of heat pumps and pursuing non-pipe alternatives. They also agree to conduct a number of worthwhile studies, including those related to geothermal district energy systems, natural gas system resiliency and the impacts of clean energy policies on the future of gas businesses. In sum, the gas-related provisions further New York's ambitious climate-related policy goals that can serve as a model for future rate cases.

The Joint Proposal is the product of many negotiation sessions noticed to, and attended by, representatives of a large number of participating parties, both before and after the onset of the COVID-19 crisis. It provides benefits to ratepayers by including an earnings-sharing mechanism, various downward-only reconciliation mechanisms, and negative revenue adjustments if the Companies miss established targets for certain customer service, electric reliability and gas safety performance metrics. In addition to the CLCPA, the Joint Proposal promotes various other State and Commission objectives, including the advancement of grid modernization efforts and distributed energy, continued economic development support and the enhancement of the Companies' low income programs. Moreover, the Joint Proposal addresses the economic impacts from the

COVID-19 crisis in ways that could not have been achieved in the context of litigation.

While we believe that the signatory parties in the electric rate plans have taken ample effort to minimize ratepayer impacts during the COVID-19 pandemic by focusing only on critical incremental spending needs and agreeing to cost recoveries in ways that have been successfully employed previously, this unique time in history requires an even bolder approach to minimizing customers' financial impacts.

While the RY 1 bill impacts are lower, the increases in RY 2 and RY 3 of nearly 4% to 5% are significant and a concern at this perilous time in New York. We share the concerns raised by several parties, the public through their many comments at the Public Statement Hearings as well as in writing and from telephone calls, and several elected representatives that every reasonable effort must be made at this time to minimize impacts on customers.

We believe that total impacts overall, including considering all underlying changes to surcharges and sur-credits, should be kept at or below 2% per year. To achieve this goal, we are approving the Joint Proposal with a limited number of modifications to both electric rate plans. Our modifications are made in a way that will ensure that they do not impact any aspect of the necessary and desirable goals supported by the Joint Proposal.

We emphasize that we do not make these modifications lightly. We fully understand that each Joint Proposal requires a balancing of multiple parties' interests, revenues for the Companies to provide safe and reliable service, and financial impacts on customers. By limiting our adjustments to financial ones designed to lessen collections from customers during the period covered by the Joint Proposal, we ensure that all planned spending and system improvements agreed to in the Joint Proposal remain unchanged.

Our modifications will necessarily result in complex recalculations of many of the specific amounts included in the appendices of the Joint Proposal. As Attachments to this Order, we will provide three revised Joint Proposal appendices (revised Appendices A, B, and D, included with this Order as Attachments 3, 4, and 5, respectively) and order the Companies to file additional updated appendices as needed within 30 days of the issuance of this Order.

For NYSEG Electric, the modifications contained in this Order result in the following changes. For RY 1, the delivery rate increase is reduced from $45.7 million to $45.3 million. This minor modification has little impact on the percentage increases and bill impacts. For RY 2, the shaped/levelized delivery rate increase is changed from $84.8 million to $45.6 million. This results in the percentage impacts on delivery revenues going from 10.6% to 5.9%, the typical monthly residential bill increase going from $4.13 (5.7% increase) to $1.84 (2.5% increase), and the total bill impact going from 4.4% to 2.0%. For RY 3, the shaped/levelized delivery rate increase is changed from $88.6 million to $36.0 million. This results in the percentage impact on delivery revenue going from 9.9% to 4.2%, the typical monthly residential bill increase going from $5.54 (7.2% increase) to $2.42 (3.3% increase), and the total bill impact going from 5.0% to 2.0%. These changes are summarized in Attachment 6, and the calculations for the modified total bill increases can be seen in Attachment 7.

For RG&E Electric, the modifications contained in this Order result in the following changes. For RY 1, in order to achieve 2.0% or lower increases each year, we must slightly increase the RY 1 amount while lowering the increases in RY 2 and RY 3. Our modification results in the RY 1 shaped/levelized delivery rate increase going from $15.2 million to $21.4 million. This results in the percentage impact on delivery bills going from 3.4% to 4.8%, the typical monthly residential bill increase going from $0.37 (0.5% increase) to $1.20 (1.6% increase), and the total bill impact going from 0.8% to 1.6%. For RY 2, the shaped/levelized delivery rate increase is changed from $28.1 million to $13.9 million. This results in the percentage impacts on delivery revenues going from 6.3% to 3.1%, the typical monthly residential bill increase going from $3.82 (5.0% increase) to $1.95 (2.5% increase), and the total bill impact going from 3.8% to 2.0%. For RY 3, the shaped/levelized delivery rate increase is changed from $30.7 million to $15.8 million. This results in the percentage impact on delivery revenue going from 6.2% to 3.3%, the typical monthly residential bill increase going from $4.14 (5.2% increase) to $2.26 (2.9% increase), and the total bill impact going from 3.8% to 2.0%. These changes are summarized in Attachment 6, and the calculations for the modified total bill increases can be seen in Attachment 7.

We find that there is a sufficient record basis for our decision to adopt the terms proposed by the signatory parties as set forth in the attached Joint Proposal, with the modifications contained in the body of this Order. The Statements in Support of the signatory parties and the record evidence on which those parties rely persuade us that the underlying aspects of the Joint Proposal should be approved, and that our modifications only reflect a necessary re-balancing due to our duty to protect customers at this critical time.

II. BACKGROUND OF THE PROCEEDING

The Commission issued its most recent electric and gas major rate order for NYSEG and RG&E on June 15, 2016. That order established three-year rate plans for both Companies and services through April 30, 2019.[5] Most provisions included in those rate plans remain in effect until the establishment of new rate plans. On May 20, 2019, the Companies filed tariff revisions to change their rates, charges, rules and regulations for electric and gas service that were proposed to go into effect for the Rate Year beginning April 1, 2020, and ending March 31, 2021. The Companies made supplemental filings, corrections, and updates to the rate filings on July 9, August 6, August 8, August 9, and October 11, 2019, and filed rebuttal testimony and exhibits on October 15, 2019. The Commission suspended the Companies' rate filings and initiated these proceedings to examine the merits of the Companies' proposals.[6]

In rebuttal testimony, the Companies proposed an increase of NYSEG’s electric delivery rates of approximately $162.7 million, a proposed 21.6 percent increase in delivery revenues.[7] NYSEG sought to increase its gas delivery rates by approximately $4.1 million, reflecting a delivery revenue increase of 2.0 percent.[8] RG&E proposed to increase its electric delivery rates by $38.7 million, an increase in delivery

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[5] Cases 15-E-0283, et al., New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation - Electric and Gas Rates, Order Approving Electric and Gas Rate Plans in Accord with Joint Proposal (issued June 15, 2016).

[6] Notice of Suspension of Effective Date of Major Rate Changes and Initiation of Proceeding (issued June 7, 2019).

[7] Ex. 92, Companies’ Policy Panel Rebuttal Testimony, p. 2.

[8] Id.

revenues of 8.6 percent.[9] For its gas business, RG&E sought a delivery rate decrease of $1.8 million, a decrease in delivery revenues of 1.0 percent.[10]

DPS Staff began its audit and investigation of the rate filings soon after they were submitted. The Administrative Law Judges (ALJs) held an initial conference with the parties on June 25, 2019, and set a schedule for the filing of testimony. Fossil Free Tompkins (FFT) filed testimony and exhibits on September 19, 2020. DPS Staff and various intervenor parties filed testimony and exhibits on September 20, 2019.[11] The New York Power Authority (NYPA) filed testimony and exhibits on September 23, 2019, which was accepted for filing without objection. The Companies, DPS Staff and various intervenors filed rebuttal testimony on October 15, 2019.[12]

The Companies filed a notice of impending settlement negotiations on October 11, 2019.[13] To facilitate such

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[9] Id.

[10] Id.

[11] The other intervenor parties that filed testimony were Concerned Citizens of Oneonta; County of Westchester; Richard Ford; Dennis Higgins; International Brotherhood of Electric Workers, Local Union 10 (Local Union 10); Multiple Intervenors (MI); Nucor Steel Auburn (Nucor Steel); the Public Utility Law Project of New York Inc. (PULP); Rochester People’s Climate Coalition (RPCC); Karl Seeley; the New York State Department of State, Division of Consumer Protection, Utility Intervention Unit (UIU); ChargePoint, Inc.; the New York Power Authority (NYPA); and Walmart, Inc.

[12] The other intervenor parties that filed rebuttal testimony were Dennis Higgins, MI, Nucor Steel, NYPA, PULP, Bob Wyman, and UIU.

[13] Pursuant to 16 NYCRR 3.9(a)(2), the ALJs informed us on October 15, 2019, that the notice of impending settlement negotiations complied with our rules and provided all interested persons with a reasonable opportunity to prepare for and participate in settlement discussions.

negotiations, the Companies consented to extensions of the suspension period in these proceedings through July 15, 2020.[14] On February 26, 2020, the Companies filed a letter stating that the Companies, DPS Staff and other parties had reached an agreement in principle.

On March 7, 2020, Governor Andrew Cuomo declared a state of emergency due to the unprecedented COVID-19 pandemic that was spreading rapidly throughout the State and country.[15] On March 23, 2020, PULP filed a motion pursuant to 16 NYCRR 3.6 requesting that the ALJs direct the Companies to provide new rate case data and supplemental testimony to address the economic impacts resulting from the COVID-19 pandemic, instruct DPS Staff to investigate such new supplemental filings and respond in a manner protecting the public interest, and allow DPS Staff and the intervening parties to conduct reasonable discovery and file comments or include such supplemental filings and discovery responses in briefs. AARP NY (AARP) filed papers in support of the motion.

The Companies, DPS Staff and MI opposed the motion and requested that settlement discussions be allowed to continue to address the potential impacts from the COVID-19 crisis. In addition, the Companies filed for approval to extend the maximum suspension period through September 13, 2020, to accommodate continued settlement negotiations, including discussions focused

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[14] See Companies' letters requesting extension of suspension periods dated October 16, 2019, and November 15, 2019. The Commission extended the suspension period through July 15, 2020. Order on Extension of Maximum Suspension Period of Major Rate Filings (issued March 19, 2020).

[15] Executive Order 202 (Cuomo) No. 202.8 (9 NYCRR 8.202.8).

on the impact of the COVID-19 pandemic.[16] The ALJs denied PULP’s motion in a ruling issued April 7, 2020, finding the arguments by the Companies, DPS Staff and MI that the economic impacts from the COVID-19 pandemic could be considered appropriately in further settlement discussions to be compelling.[17]

On June 22, 2020, the Companies filed the Joint Proposal with the Secretary. The Joint Proposal was signed by the Companies, the New York State Department of Public Service Staff; Alliance for a Green Economy (AGREE) (gas businesses only); Binghamton Regional Sustainability Coalition (gas businesses only); Bob Wyman; ChargePoint, Inc. (electric businesses only); Concerned Citizens of Oneonta (NYSEG gas and electric businesses only); Dennis Higgins (gas businesses only); Empire State Development Corporation (ESDC), the New York State Department of Economic Development; FFT (gas businesses only); HeatSmart, a program of Solar Tompkins Inc. (gas businesses only); Local Union 10 (NYSEG gas and electric businesses only); Keith Schue (gas businesses only); MI; New York Geothermal Energy Organization (NY Geo); NYPA (electric businesses only); Nucor Steel (NYSEG gas and electric businesses only); RCI (gas

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[16] See, Companies’ Letter dated March 26, 2020. The Commission extended the suspension period through September 13, 2020. Order on Extension of Maximum Suspension Period of Major Rate Filings (issued June 15, 2020). In a letter dated June 30, 2020, the Companies requested an extension of the suspension period through October 31, 2020. The Commission extended the suspension period through October 31, 2020. Order on Extension of Maximum Suspension Period of Major Rate Filings (issued August 14, 2020). Following receipt of the Companies’ letter dated October 13, 2020, the Commission extended the suspension period through November 30, 2020. Order on Extension of Maximum Suspension Period of Major Rate Filings (issued October 16, 2020).

[17] On April 22, 2020, PULP and AARP filed an interlocutory appeal from the April 7, 2020 ruling. We discuss this appeal later in this Order.

businesses only); Ratepayer and Community Intervenors (RPCC) (gas businesses only); Suzanne Winkler (NYSEG gas business only); and Walmart (electric businesses only).

The Secretary issued Notices Seeking Public Comment on the Joint Proposal on June 23 and June 30, 2020. On July 2, 2020, the ALJs issued a Ruling on Schedule to consider the Joint Proposal. Pursuant to the schedule, on or about July 15, 2020, various parties filed Statements in Support of, or Opposition to, the Joint Proposal. The Companies, DPS Staff, MI, and NY Geo filed Statements in Support of the Joint Proposal. NYPA and Walmart filed Statements in Support of the Joint Proposal with regard to the Companies' electric businesses only. Concerned Citizens of Oneonta and Nucor Steel filed Statements in Support of the Joint Proposal as it relates to NYSEG only. Dennis Higgins and Keith Schue, separately, and AGREE, FFT, RCI, RPCC and HeatSmart and the Binghamton Regional Sustainability Coalition (the Indicated Environmental Parties), jointly, filed Statements in Support of the Joint Proposal with regard to the Companies' gas businesses only. The Indicated Environmental parties also filed a Statement in Opposition to the Joint Proposal with regard to the Companies' electric businesses. PULP, AARP and Richard Ford filed Statements in Opposition to the Joint Proposal. The Utility Intervention Unit (UIU), a part of the Division of the Consumer Protection of the Department of State, filed a statement opposing the Joint Proposal provision regarding implementation of Advanced Metering Infrastructure (AMI). On July 29, 2020, the Companies, DPS Staff, MI and Nucor Steel filed Reply Statements in Support of the Joint Proposal; PULP and AARP filed a joint Statement in Opposition to the Joint Proposal; and RCI filed a Reply Statement in support of the Joint Proposal with regard to the Companies' gas businesses and in opposition to the Joint Proposal with regard to the Companies’ electric businesses.

On August 6, 2020, the ALJs conducted an evidentiary hearing on the Joint Proposal by telephone conference call. The Companies and DPS Staff produced witness panels that were cross examined by PULP, AARP, FFT and RCI. A total of 337 exhibits have been entered into the evidentiary record, including the Joint Proposal, the parties’ pre-filed testimony, certain interrogatory responses, and various other documents.

On August 11, 2020, the ALJs issued a schedule for the filing of post-hearing briefs. Pursuant to that schedule, the Companies and AARP filed post-hearing briefs on August 18, 2020. On August 25, 2020, the Companies filed a post-hearing reply letter in lieu of brief and DPS Staff filed a post-hearing reply brief.

Public Statement Hearings were held on the Companies’ underlying rate filings on August 6, 14 and 15 and September 5, 2019. The ALJs held public statement hearings on the Joint Proposal on August 26, 2020, and on the proposed closure of six customer service walk-in offices on August 27, 2020, via web conferencing.

III. NOTICE OF PROPOSED RULE MAKING AND PUBLIC COMMENTS

Pursuant to the State Administrative Procedure Act (SAPA) §202(1), Notices of Proposed Rulemaking were published in the State Register on August 21, 2019 [SAPA Nos. 19-E-0378SP1, 19-G-0379SP1, 19-E-0380SP1, 19-G-0381SP1]. Public Statement Hearings were held on the Companies’ underlying rate filings in the City of Rochester on August 6, 2019, in Keene Valley and the City of Ithaca on August 14, 2019, in Binghamton on August 15, 2019, and in Yorktown Heights on September 5, 2019. Additional public statement hearings were held on August 26, 2020, with respect to the Joint Proposal in general, and on August 27, 2020, specifically in connection to the proposed closure of six customer service walk-in offices. In addition, numerous written comments have been posted on the Commission’s website in these cases and over a thousand telephone comments have been received on the Commission’s opinion line. A brief summary of the public comments is set forth below.[18]

With respect to the Companies’ underlying rate filings, numerous commenters opposed the Companies’ requested rate increases as too high. Some commenters stated that the Commission should reduce the Companies’ rates of return to make rates more affordable and that the Companies should reduce employee bonuses or use profits to pay for or offset the costs of the programs for which the Companies seek rate increases. Commenters stated that the requested increases would make rental properties less affordable and have a negative financial impact on farmers and farmworkers. Commenters stated that the Companies have excessive outages, provide poor service, and they should not be allowed to charge ratepayers to catch up on repairs and routine maintenance, including vegetation management, that they should have been performing all along.

Commenters stated that the proposed increases would negatively impact low income households and seniors on fixed incomes. Some commenters opposed fixed customer charges for electric delivery services as excessive and argued that such charges should be substantially decreased or discontinued. Several commenters opposed the Companies’ proposal to install smart meters throughout their service territories.

Various commenters raised concerns about climate change and stated that the Companies need to transition from the

[18] A more comprehensive summary is set forth in Attachment 8 to this Order.

use of fossil fuels as quickly as possible, many of them citing the recently enacted CLCPA. Some commenters stated that the Companies should promote community-based solar programs, heat pumps, and other green energy and beneficial electrification projects, while discontinuing programs that promote the use of natural gas.

Regarding the Joint Proposal, many commenters spoke in favor of the gas provisions, but all commenters opposed the provisions regarding the Companies' electric businesses. Commenters stated that the requested increases for the electric businesses were too high and were particularly inappropriate given the economic situation resulting from the COVID-19 pandemic. Various commenters stated that the proposed return on equity (ROE) should be lowered and that spending should be reprioritized away from the implementation of AMI; rather, it should be focused on the implementation of a five-year tree-trimming cycle at NYSEG or improving the Companies' infrastructure, including substations. Commenters opposed AMI, asserting that it provides benefits for the Companies but not ratepayers. Several commenters opposed the proposed closure of customer service centers, expressing that face-to-face interactions are important, especially to the elderly and low income customers, many of whom, the commenters maintain, do not have access to the internet or cellular phone service.

IV. OVERVIEW OF POSITIONS ON THE JOINT PROPOSAL

The Companies and DPS Staff support the Joint Proposal in its entirety upon the grounds that it satisfies our settlement guidelines and is in the public interest. As described earlier, numerous other parties representing varied interests also intervened and participated in these proceedings. Both a brief description of those parties that support or oppose the Joint Proposal, in whole or part, and a brief overview of their respective positions on the Joint Proposal are set forth below.

MI is an unincorporated association of approximately 60 large industrial, commercial, and institutional energy consumers with manufacturing and other facilities located throughout New York State, including the Companies' service territories. MI supports the Joint Proposal in its entirety, stating that the Joint Proposal is in the public interest and should be adopted without modification to maintain the comprehensive, careful and equitable balancing of interests that the Joint Proposal contains. MI supports the term of the rate plans, the electric and gas delivery revenue requirements, the electric and gas revenue allocations, the electric and gas rate designs applicable to large non-residential service classes, and the proposed treatment of Earnings Adjustment Mechanisms (EAMs).

NY Geo states that it seeks "to support New York's greenhouse gas reduction and energy efficiency goals by advancing the transition of the heating sector from a fossil fuel base to a clean, renewable heating base." NY Geo supports the Joint Proposal in its entirety but specifically notes with favor the adoption of an Environmentally Beneficial Electrification EAM based on greenhouse gas reductions from the adoption of heat pumps and electric vehicles (EVs); the inclusion of a heat pump share-the-savings EAM; the commitment to study the feasibility of deploying geothermal district energy systems in the Companies' service territories; and the encouragement of customers to consult with community organizations to make more informed energy choices. NY Geo also highlights the various provisions regarding changes to the Companies' natural gas businesses to address climate change.

Bob Wyman is an individual who submitted testimony regarding depreciation as to gas infrastructure generally and to the DeRuyter Transmission Replacement Project originally proposed in these proceedings. Mr. Wyman signed the Joint Proposal in its entirety but did not submit a statement in support of the Joint Proposal.

The New York State Department of Economic Development, Empire State Development Corporation is focused on economic development in New York State. The ESDC signed the Joint Proposal in its entirety but did not file a statement in support of the Joint Proposal.

Local Union 10 provided testimony addressing NYSEG’s proposal to close customer service walk-in offices and signed the Joint Proposal with respect to the NYSEG businesses only. IBEW Local 10 did not file a statement in support of or opposition to the Joint Proposal.

Nucor Steel is a large scrap-based steel manufacturer and NYSEG customer. Nucor Steel signed the Joint Proposal as it relates to NYSEG and maintains that the change in overall delivery revenues, the proposed levelization of rate changes over the three year period, revenue allocation generally, and specific allocations proposed for energy efficiency costs, incremental heat pumps, AMI, and incremental vegetation management all reflect a delicate balancing of a variety of competing concerns. Nucor Steel states that, as a whole, the Joint Proposal is in the public interest.

Concerned Citizens of Oneonta is a local community group that is focused on climate change issues. Concerned Citizens signed the Joint Proposal with respect to the NYSEG businesses only and states that it supports the Joint Proposal in light of various commitments regarding the Companies’ natural gas business and related to climate change, which Concerned

Citizens consider to be useful steps in the right direction under the CLCPA.

ChargePoint, Inc. is an EV charging network that submitted testimony on the Companies' proposed EV charging programs. ChargePoint, Inc. signed the Joint Proposal as it relates to the Companies' electric businesses only and did not file a statement in support of or opposition to the Joint Proposal.

NYPA is a corporate municipal entity and political subdivision of the State and, among other things, is authorized to finance, develop and implement energy-related programs and services for public entities in New York State. NYPA supports the electric service provisions of the Joint Proposal as fair and reasonable and consistent with the public interest, and states that the Joint Proposal advances NYPA's policy goals in a manner that may not have been achievable in a litigated rate case. NYPA specifically notes support for provisions that address the sale of street lights to municipalities, accommodate municipalities seeking to install "Smart City" devices on their street light infrastructure,[19] that expand the Companies' EV programs, and that require the Companies to perform a study of their electric transmission systems to identify options and costs to alleviate congestion associated with planned renewable energy projects.

Walmart signed the Joint Proposal with respect to the Companies' electric businesses only. Walmart specifically notes with favor that the Joint Proposal contains a ROE and overall revenue requirement that are significantly reduced from the

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[19] Smart City devices are various smart street lighting technologies, including light dimming controls, cameras for safety and security, and sensors to collect data on traffic, weather and air quality, among other things.

Companies' initial requests. Walmart is satisfied that the resulting base rate impacts on Service Classification SC 7-1 for NYSEG and SC-8 for RG&E are reasonable and fair in comparison with the rate exposure presented in the Companies' rate filings. Walmart supports the Joint Proposal as a just, reasonable and fair resolution of the issues in the electric rate cases.

Dennis Higgins is an individual who signed in support of the Joint Proposal with respect to the Companies' gas businesses only. Mr. Higgins states his belief that the Companies made sincere efforts to address many concerns expressed by the parties with respect to gas matters and he raises various issues for consideration as the State implements the CLCPA. Mr. Higgins also states that the Joint Proposal for the electric businesses does not include major overhauls to the electric grid needed to support the expansion of beneficial electrification, such as long-range plans to upgrade 3-phase lines and substations to accommodate the integration of green energy projects. Mr. Higgins also offers suggestions to improve the rate case process to foster more effective and informed public participation.

Keith Schue is an individual who signed in support of the Joint Proposal with respect to the Companies' gas businesses only. Mr. Schue states that his support for the gas portion of the Joint Proposal is based on the Companies' commitments to those gas matters intended to address climate change and the CLCPA, which he views as necessary steps in the right direction. Mr. Schue states that while he does not formally oppose the terms of the Joint Proposal that deal with the Companies' electric businesses, he cannot support them because they do not address sufficiently the integration of distributed carbon-free electricity production with the transmission system and energy storage systems.

UIU is a division of a State agency and is authorized by Executive Law §94-a(4)(b)(ii) to represent the interests of New York consumers before federal, state and local administrative and regulatory agencies engaged in the regulation of energy services. UIU submitted a statement in opposition to the terms of the Joint Proposal regarding the Companies' implementation of AMI. UIU maintains that the AMI proposal is not supported by current State economic policies and should be rejected or, in the alternative, considered in a separate proceeding to allow for further stakeholder input and development of the Companies' AMI business plan.

PULP is a non-profit organization that promotes the rights and interests of low income and fixed-income utility consumers in matters affecting affordability and consumer protection of utility services. PULP opposes the Joint Proposal, stating that it is not in the public interest. PULP notes that the Commission has, in past times of economic uncertainty, required utilities to identify and include in rate plans austerity measures to provide rate relief to ratepayers.[20] PULP states that the Joint Proposal does not reflect a willingness by the signatory parties to reduce unnecessary expenses and to provide real rate relief during the current economic crisis. PULP states that the Joint Proposal inappropriately provides for double-digit increases, insufficient COVID-19 related proposals, limited customer service policies and actions, limited low income programs, the proposed closure of customer service offices, and a plan to implement a costly AMI program. PULP also states that a full-

[20] See, Case 09-M-0435, Proceeding on Motion of the Commission Regarding Development of Utility Austerity Programs, Notice Requiring the Filing of Utility Austerity Plans (issued May 15, 2009).

cycle vegetation management program for NYSEG should have been adopted.

AARP states that it has “tens of thousands” of members 50 years of age and older, many of whom have low-to-moderate incomes. Stressing the economic impacts from the COVID-19 pandemic, AARP argues that the Joint Proposal with respect to the Companies’ electric businesses should be rejected, that the information in these proceedings should have been updated to reflect current economic conditions, and that temporary rates should be established instead of multi-year rate plans. AARP asserts that the standard of review to determine whether a Joint Proposal is in the public interest is outdated and often misapplied. AARP maintains that the COVID-19 provisions in the Joint Proposal are insufficient and based on the assumption that the economy will recover by May 2021, and that more comprehensive austerity measures should be instituted. AARP further argues that the proposed return on equity is too high and that the Joint Proposal contains capital projects that lack appropriate justification, an AMI program that will cost more and provide less benefits than claimed, and a vegetation management program for NYSEG that does not include full-cycle vegetation management program. Both AARP and PULP maintain that support of the Joint Proposal with respect to the Companies’ electric businesses is “narrow and shallow” and that the Joint Proposal should be considered separately for the Companies’ electric businesses and gas businesses.

The Indicated Environmental Parties are organizations within the Companies’ service territories that address various issues affecting their communities, including concerns about environmental impacts resulting from the Companies’ rate plans. The Indicated Environmental Parties support the Joint Proposal with respect to the Companies’ gas businesses, stating that it contains numerous provisions that reflect meaningful compromise among normally adversarial parties and concessions to address environmental concerns. The Indicated Environmental Parties specifically cite Appendix M to the Joint Proposal, describing it as "a first of its kind agreement in New York between gas companies and ratepayer representatives" that begins to align the gas Companies' activities with the CLCPA. The Indicated Environmental Parties state that the proposed gas rate increases are minimal and that the Joint Proposal concerning the Companies' gas businesses satisfies the Commission's settlement guidelines and is in the public interest.

The Indicated Environmental Parties oppose the Joint Proposal with respect to the Companies' electric businesses, stating that it does not represent a meaningful compromise among adversarial parties and does not serve the public interest. The Indicated Environmental Parties note that advocates for consumers and, with one exception, advocates for the environment did not sign the Joint Proposal for the electric businesses. The Indicated Environmental Parties maintain that the Joint Proposal for the electric businesses contains "exorbitant rate increases" that are particularly inappropriate in light of current economic conditions. The Indicated Environmental Parties claim that proposed capital projects lack appropriate justification and fail to prioritize substation modernization. The organizations also take issue with the proposed ROE, vegetative management program for NYSEG, AMI program, and fixed customer charges. The Indicated Environmental Parties also make various proposals for improving participation by small public-interest intervenors in the rate case process.

RCI separately states that the Joint Proposal with respect to the Companies' gas businesses is in the public interest and should be adopted independent of the Joint Proposal as to the Companies' electric businesses. With respect to the Companies' gas businesses, RCI states that the Joint Proposal does not "move at quite the pace desired by parties," but serves at least as "a good start" in meeting the State's goals under the CLCPA. With respect to the Companies' electric business, RCI asserts that the Joint Proposal fails to address adequately the economic impacts from the COVID-19 crisis, fails to move NYSEG to a full-cycle vegetation management program, fails to provide sufficiently for substation upgrades, and proposes rate increases that are too high.

Richard Ford is an individual who opposes fixed customer charges. Mr. Ford submitted a statement in opposition to the Joint Proposal asserting that rates need to be reformed to remove disincentives for energy conservation and should not include high fixed customer charges.

Suzanne Winkler is an individual who signed the Joint Proposal as it relates to the Companies' gas businesses only. Ms. Winkler did not file a statement in support of or opposition to the Joint Proposal. On August 24, 2020, Ms. Winkler filed in these proceedings a copy of a statement she filed in Case 20-G-0131, in which she states that the Companies' filings in that case on August 17, 2020, do not reflect all the commitments made in the Joint Proposal with respect to the Companies' gas businesses.[21]

[21] Case 20-G-0131, Proceeding on Motion of the Commission in Regard to Gas Planning Procedures, Order Instituting Proceeding (issued March 19, 2020). To the extent that Ms. Winkler states that the filings in the generic gas planning proceeding should have contained different information to comport with the terms of the Joint Proposal, we note that any purported deficiencies in the Companies' filings in the generic proceeding were raised and are more appropriately addressed in that proceeding.

V. DISCUSSION

A. Standard of Review

The Commission will adopt the terms of a joint proposal where it finds that its terms, when viewed as a whole, produce a result that is in the public interest. Under the Commission's public interest standard, we evaluate a joint proposal to determine whether its terms fall within the range of reasonable results that would have likely arisen from a Commission decision in a litigated proceeding and, for rate cases, whether the rates proposed are just and reasonable and are in the public interest.[22] A joint proposal should balance the protection of consumers with fairness to investors and the long-term viability of the utility. These considerations are "themselves elements of the public interest standard."[23]

AARP argues that the public interest standard is sufficiently "amorphous and opaque to be malleable from case to case" and, in practice, minimizes the value of the positions and interests of residential intervenors.[24] PULP states that DPS Staff and the utilities are not "adverse parties" within the commonsense definition of the terms and share the same basic approach to regulation. AARP and the Indicated Environmental Parties assert that a power and resource imbalance exists between the utilities, DPS Staff and various business concerns on the one hand and residential customer intervenors on the other. The Indicated Environmental Parties also state that the rate case process is often confusing for individuals and small nonprofit groups and that it does not provide intervenor funding

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[22] Public Service Law §65(1).

[23] Cases 90-M-0255, et al., Procedures for Settlements and Stipulation Agreements, Opinion 92-2 (issued March 24, 1992) (Settlement Guidelines).

[24] AARP Statement in Opposition to the Joint Proposal, pp. 9-11.

for their participation. AARP argues that compromise is not appropriate in matters involving the public interest and that a party should not have to agree to a rate increase to have its position on an unrelated policy or program that would have a small or no revenue impact included in a joint proposal.

The rate case process is inherently complex. Our settlement guidelines have been in place since 1992 and have provided an appropriate framework for resolution of often highly contentious issues between parties with vastly different backgrounds and interests. The settlement guidelines allow flexibility for review of rate plans proposed in different cases and that address complex and interrelated rate plan provisions. The products of such negotiations may not satisfy all parties on all issues, especially when rate increases are proposed. Nevertheless, the Commission’s review process ensures that rate plans provide for safe and adequate service at just and reasonable rates and that a proposed rate plan, when viewed as a whole, is in the public interest.[25]

In any event, we agree with the Companies and DPS Staff that any challenges to our rate case settlement guidelines and rate case processes are beyond the purview of these proceedings and are more appropriately the subject of a generic proceeding where all interested parties may be heard. In this regard, we note that the Indicated Environmental Parties request that “DPS initiate a general proceeding that reviews the

[25] We also note that AARP, the Indicated Environmental Parties, and Dennis Higgins raise complaints about the manner in which the Companies and DPS Staff responded to discovery requests. Under our rules of practice, those issues are appropriately addressed to the Administrative Law Judges. 6 NYCRR 5.3(d), 5.4(d), 5.10. Our review of the record does not show that any parties sought to compel responses to any discovery requests.

settlement process and provides standardized recommendations for how this process will work across utility rate cases.”[26] While we do not foreclose the possibility of revisiting the Commission’s settlement guidelines and regulations at some future time, we do not see that there is a need to start any such proceeding now.

B. Term of Rate Plans

The Joint Proposal offers slightly longer than three-year rate plans for electric and gas services for both NYSEG and RG&E. All four rate plans are proposed to be effective beginning on April 17, 2020, and continue through April 30, 2023. For purposes of the Joint Proposal, RY 1 would consist of the 12-month period ending on April 30, 2021, RY 2 would consist of the twelve-month period ending April 30, 2022, and RY 3 would consist of the twelve-month period ending April 30, 2023. Unless specifically noted otherwise, the terms of the rate plans proposed by the Joint Proposal would continue after expiration of RY 3, until changed by order of the Commission.

The multi-year term of the rate plans provides the Companies with an adequate revenue requirement and the rate stability necessary to effectively pursue longer term projects and meet their obligation of providing safe, adequate and reliable electric and gas service. The rate plan is beneficial because it will allow the Companies to focus on managing their electric and gas businesses rather than filing annual rate cases. The rate plans also moderate the rate changes by incrementally increasing rates over the term and they create rate certainty, which benefits customers and the Company, as well as market participants seeking to provide new or enhanced

[26] Indicated Environmental Parties Statement in Opposition, p. 22.

products and services by allowing long-term planning efforts. The negotiated rate plans allow the signatory parties to address the economic impacts from the COVID-19 pandemic in ways that could not have been accomplished as part of a litigated outcome. Under all the circumstances, we conclude that the term of the rate plans is beneficial to all parties.

C. COVID-19

Joint Proposal

Health and economic crises attendant to the COVID-19 pandemic are still evolving. While recognizing that future developments may yet require broader ameliorative measures, the Joint Proposal includes several provisions intended to address the adverse conditions already resulting from the pandemic. These provisions seek to balance customer support mechanisms and reduce rate impacts and revenue requirement levels, while also ensuring the Companies' continued ability to provide reliable service at just and reasonable rates.

Beginning with customer relief provisions, the Companies suspended residential and non-residential disconnects for nonpayment in March 2020, contemplating that the suspension would remain in place until a date determined by the Companies in consultation with DPS Staff or the Commission.[27] The Companies also suspended collection of various customer charges, including reconnect fees, residential customer deposits, late

[27] Since the filing of the Joint Proposal, Governor Cuomo has signed chapter 108 of the Laws of 2020, which prohibits utility corporations from disconnecting services to residential customers for nonpayment of overdue charges until at least 180 days after the COVID-19 state of emergency declared in New York has been lifted. The law expires on March 31, 2021, at which time its provisions are deemed repealed. The Companies have indicated that they are aware of the new law and complying with its provisions.

payment charges and same day turn on fees; this policy too is to remain in place until a future date agreed upon by the Companies and the Commission. Although collection of such fees has been suspended, the revenues forecasted in each of the revenue requirements in the Joint Proposal assume that a pre-pandemic level of such collections will materialize. This has the effect of isolating customers from any revenue shortfall due to the collection suspension. The Joint Proposal acknowledges that modifications to this treatment may be determined in the generic COVID-19 proceeding.[28]

The Joint Proposal puts forth a “ratepayer helping ratepayer” fund to provide assistance to vulnerable residential and small commercial customers who may also be granted relief through one-time bill credits of up to a maximum of $100 that will occur over three phases. In phase one, residential customers on minimum payment agreements and low income program participants, as well as small commercial customers on payment agreements or in arrears, will be eligible.[29] Customers who do not qualify for credits in phase one may become eligible in phase two or three as their financial circumstances are negatively impacted by the pandemic.

The ratepayer-funded credits would be capped at $16.5 million for NYSEG ratepayers and at $13.5 million for RG&E ratepayers. When bill credits are provided, the Companies will create regulatory assets that will be recovered over five years beginning in July 2021. Here again, signatories to the Joint

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[28] Case 20-M-0266, Proceeding on Motion of the Commission Regarding the Effects of COVID-19 on Utility Service, Order Establishing Proceeding (issued June 11, 2020).

[29] As of April 2020, approximately 133,000 customers satisfied the criteria for these credits.

Proposal recognize that modifications to the Customer Bill Credit Program may arise out of the generic COVID-19 proceeding.

Next, the Companies would maintain an arrears forgiveness program within their Low Income Programs, and self-enrollment in such Low Income Programs would be expanded to include any customer who can provide a letter indicating that he or she is eligible to participate in the Home Energy Assistance Program (HEAP), even if that customer has been denied a HEAP grant.[30] The Companies would also institute more flexible deferred payment agreement (DPA) provisions, such as negotiating a DPA based on the customer’s ability to pay, regardless of the customer’s prior payment or DPA history; negotiating DPAs verbally and honoring the agreement even if it is not signed; continuing a process to implement electronic DPAs and, where documentation to support a DPA request is necessary, being flexible regarding the timeline and format of such proof.

Within 60 days of the Commission’s order approving the Joint Proposal, the Companies would file an updated Outreach Plan reflecting various additional means of informing customers about potential assistance available to help with their utility bills. These include outbound calling campaigns, bill messages, websites, emails, interactive voice response messages and EnergyLines Bill inserts. The Companies will similarly engage in additional customer advocate communications, including expanded community, agency and municipality outreach, all with

[30] This topic is addressed more fully in our “Low Income Program” discussion later in this Order.

the goal of ensuring that vulnerable populations are aware of payment options and assistance programs.[31]

An Economic Development Grant Assistance Program intended to assist challenged electric business customers is also included in the Joint Proposal. It would be comprised of a Small Business Customer Program (funding of up to $1 million per Company) and a Large Business Customer Program (funding of up to $2 million per Company) focused on economic recovery and retention projects necessitated by the pandemic – e.g., transitioning to a remote work environment or cleaning and disinfection services. There would be a $15,000 cap per small-business project and a $50,000 cap per large-business project; the Economic Development Grant Assistance Program would be discontinued at the end of the proposed rate plans.

For its COVID-related revenue requirement adjustments, the Joint Proposal reflects additional reductions, particularly in RY 1, that are in direct response to the pandemic's impact on the Companies' customers. Adjustments in RY 1 costs to operations and maintenance charges are as follows: a $5.7 million decrease at NYSEG Electric and a $3.0 million decrease at RG&E Electric in connection with the delayed implementation of the Grid Model Enhancement Project, now scheduled to begin in RY 2; a 25 percent decrease for collection-related costs at all four Companies; a 20 percent reduction in travel costs; and a reduction at the Gas businesses to reflect the delayed start of

[31] The proposed closure of certain customer walk-in offices is discussed more fully below. It is notable, however, that no such closures would occur until at least June 2021. Moreover, the Companies will provide DPS Staff with reports of customer traffic in each such office; in the event a particular office sees a material increase in traffic between now and then, it may be determined that closure is no longer appropriate.

the Damage Prevention Program. The Joint Proposal also contemplates increases in each year's O&M costs to maintain the Arrears Forgiveness Program at 2016 Rate Plan levels.

Under the Joint Proposal, the Companies would collect rates for Energy Efficiency and Heat Pump Programs during the rate plans that are lower than the budget levels approved in the 2020 Energy Efficiency Order.[32] For NYSEG Electric, the RY 1 level would be set at 80 percent of the budget level set forth in the 2020 Energy Efficiency Order; RY 2 would be set at 85 percent; and RY 3 would be set at 90 percent. For RG&E Electric, NYSEG Gas, and RG&E Gas, the RY 1 and 2 levels would be set at 85 percent of the levels set forth in the 2020 Energy Efficiency Order. Delivery rates would need to be adjusted in the years after the term of these Rate Plans to provide the Companies with the recovery of the Commission-approved budgets established in 2020 Energy Efficiency Order.

The Joint Proposal includes updated inflation information that reflects actual inflation through the first quarter of 2020 and the April 10, 2020 Blue Chip Forecast. This updated information resulted in an additional $10.9 million reduction in revenue requirements during the three Rate Years across all four businesses. The Companies' rate base has likewise been adjusted in response to the pandemic, with delayed implementation of AMI by one year and the delayed implementation of associated information technology requirements by 6- to 12-months. Over 30 other gas and electric projects have also been delayed, resulting in related delays in cash flows and in-service dates.

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[32] See, Case 18-M-0084, supra, Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios through 2025, p. 65; See also, Case 15-M-0252, supra, Order Authorizing Utility-Administered Energy Efficiency Portfolio Budgets and Targets for 2019-2020, pp. 21-22.

Due to the uncertainty in interest rates stemming from the pandemic, the signatories to the Joint Proposal agreed to reconciliation of the long-term debt issuances for both Companies, which will grant the Companies flexibility when negotiating in the debt market. Consideration of the pandemic's impacts also resulted in adjustments to the Energy Efficiency and Electric Heat Pump Program costs reflected in the revenue requirements. Finally, vegetation management costs related to the Companies' Danger Tree programs will be deferred and amortized over five years, which will result in revenue requirement reductions of more than $9 million in RY 1 and more than $20 million cumulatively over the three-year rate period.[33]

Added together, the foregoing pandemic-related revenue reductions are approximately $98.9 million during the three rate years.

Statements in Opposition (COVID-19)

In general, parties that filed statements in opposition to the Joint Proposal do not take issue with the COVID-related provisions described above.[34] Rather, these parties emphasize the "unprecedented economic devastation" wrought by the pandemic and argue that more comprehensive mitigation efforts are warranted. Indeed, each party cites action taken by the Commission following the Great Recession of 2008 and maintains that the instant relief measures pale in comparison.

[33] Vegetation management is more fully discussed later in this Order.

[34] PULP's assertions in connection with certain customer relief provisions are described at the end of this section.

PULP, for instance, "acknowledges that the Companies have negotiated a form of rate relief for residential and business customers...and have included specific COVID-19 provisions" in the Joint Proposal. It nonetheless claims that such provisions are inadequate and that the Companies should be directed to file austerity plans akin to those submitted by utilities in 2009.[35] AARP similarly observes that the Joint Proposal "contains several provisions that would provide a modicum of relief to victims of the pandemic," but also that the "Companies were much more generous during the last recession." Finally, according to RCI,[36] the "Companies' response to COVID-19, while appreciated, is stingy compared to actions [undertaken] in the 2009 recession."

More specifically, these parties recommend a variety of steps the Companies might take to reduce unnecessary expenses and provide "real rate relief/rate credits" for customers. These include reduced and deferred capital expenditures; temporarily ceasing the payment of dividends to the Companies' parent company; cutting back on advertising, printing, postage and periodical subscriptions; delayed payments to vendors; salary and hiring freezes; early retirement offerings; tax deferral strategies, and inter-company borrowing as opposed to external debt issuances. Adoption of such strategies would, according to PULP, AARP and RCI, more explicitly demonstrate the Companies' willingness to share the burden of the pandemic with

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[35] See Case 09-M-0435, Proceeding on Motion of the Commission Regarding the Development of Utility Austerity Programs.

[36] The Statement in Opposition submitted by RCI was also signed by the Alliance for a Green Economy, Binghamton Regional Sustainability Coalition, Fossil Free Tompkins, HeatSmart Tomkins and Rochester People's Climate Coalition.

customers, "especially since [the Companies] are in a better position to do so."[37]

In that regard, PULP and AARP both refer to PULP's March 23, 2020 motion requesting that the Companies be directed to file updated financial data that would, ostensibly, more accurately reflect the economic impacts of the pandemic and thus better inform decision-making and advocacy in this proceeding, particularly by DPS Staff. In other words, as set forth in AARP's and PULP's joint interlocutory appeal of the ALJ's ruling denying PULP's motion, if the Companies' original sales and expense forecasts have been rendered stale by the pandemic's impacts, the revenue requirements underlying the Joint Proposal are unrealistic and misleading.

Relatedly, AARP contends that the Commission's standard of review vis-à-vis joint proposals has been routinely misapplied, and the above-referenced ALJ ruling correspondingly reflects "a lack of awareness of consistent Commission practice of approving joint proposals without modification over the objections of advocate-intervenors participating on behalf of residential customers."[38] AARP requests that, in order to avoid such an outcome, particularly in light of existing economic turmoil and uncertainty, the Commission authorize temporary

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[37] As discussed earlier in this Order, the ALJs held four virtual public statement hearings on the Joint Proposal in August 2020; several commenters echoed this assertion at every hearing, maintaining that it would be inappropriate for the Companies to profit while the public suffers.

[38] In denying PULP's request, the ALJs observed that the then ongoing negotiations would be based on updated information and allow for input by PULP and AARP; the ensuing Joint Proposal, meanwhile, would have to be supported by relevant information and also be subject to opposition by intervening parties (see Ruling Denying Public Utility Law Project's Motion to Reopen the Record, p. 6 (issued April 7, 2020).

rates pursuant to Public Service Law §114 and, in any ensuing new rate proceeding, direct the Companies to file supporting data that is consistent with current financial reality. AARP adds that any new rate proceeding should also consider the outcome of the generic COVID-19 proceeding.

Finally, PULP opposes the bill credit program, arguing that any achieved short-term relief will be offset by higher customer payments in future rate years.[39] It reiterates its preference for austerity filings by the Companies and claims that, in any event, the bill credit program should be applicable to a broader pool of ratepayers. Moreover, PULP maintains that, because the financial consequences of COVID-19 will be felt by customers for many years, initiating the repayment process in July 2021 is ill-conceived.

In conclusion, PULP "believes that uniform COVID-19 procedures for additional low income relief and collections should be determined in the current [COVID-19] generic proceeding focused upon such issues and determinations, as is long-standing Commission and DPS practice."[40] PULP would thus have those customer relief provisions specifically identified in the Joint Proposal removed.

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[39] PULP Comments in Opposition. PULP is particularly concerned with a potential "hockey-stick" effect, where low rates rise drastically in later years of the rate case and beyond.

[40] It is notable that UIU also filed a statement in opposition (Ex. 219). While such opposition is focused primarily on the Companies' proposed AMI system, UIU is particularly concerned with implementation of that system during the COVID-19 pandemic. UIU, like PULP, AARP and RCI, suggests that austerity measures arising out of the COVID-19 generic proceeding would be appropriate.

Replies to Statements in Opposition (COVID-19)

DPS Staff, the Companies and MI (among others)[41] filed responses to the statements in opposition. In large part, these responses provide procedural arguments for rejecting the claims of PULP, AARP and RCI.

In connection with AARP’s motion for temporary rates, DPS Staff avers that the motion is premature, as it presumes the Commission will not adopt the Joint Proposal. The Companies cite to the language of Public Service Law §114, noting that temporary rates may be appropriate when the outcome of a rate proceeding is delayed and that no such delay is present here. MI, meanwhile, argues that AARP has not submitted any evidence suggesting temporary rates are presently warranted, the adoption of such rates is in any event not without risk to customers (e.g., if the Commission subsequently concluded that the Joint Proposal’s rates were just and reasonable, customers would be subject to an additional rate increase), and that the Commission has initiated the generic COVID-19 proceeding to address the pandemic’s impacts on a statewide basis.

In that regard, DPS Staff agrees with PULP’s contention that comprehensive relief measures are appropriately considered within the context of the generic proceeding; DPS Staff nonetheless notes that no definitive timetable in which such relief measures might arise out of that proceeding has been established. Accordingly, the customer relief provisions proposed here present “a framework of assistance that offers immediate, and perhaps more timely, crucial support during this transitional period”; DPS Staff thus maintains that those

[41] COVID-related sections of the various parties’ original statements in support are essentially reiterations of those provisions as they appear in the Joint Proposal; to avoid redundancy, they are not reproduced here.

provisions should be adopted rather than removed from the Joint Proposal.

With respect to PULP's specific assertion that the bill credit program should be expanded to include a greater number of customers, DPS Staff contends that doing so would potentially expose such customers to significantly higher long-term rates. According to DPS Staff, the $30 million budget for the bill credit proposal was agreed upon because it provides meaningful relief while limiting long-term adverse financial consequences.

Discussion

There can be no question that the full long-term financial ramifications of the COVID-19 pandemic are wide-ranging and as yet uncertain. We accordingly agree that the consideration of broader customer relief measures may be warranted; that consideration, however, is more appropriately undertaken in the generic COVID-19 proceeding rather than here. Indeed, there, the Commission is presently considering the submissions of myriad entities, including the Joint Utilities, water companies, PULP, AARP, UIU, MI, the City of New York, the National Resources Defense Council and the New York Association of Public Power, regarding the pandemic's impacts on rate-setting, rate design, utility financial strength, regulatory priorities and low income programs, among many other related subjects.[42]

During the pendency of the generic proceeding, the COVID-19 related customer relief provisions and revenue adjustments found in the Joint Proposal offer crucial immediate assistance to vulnerable customers, while also ensuring that the Companies maintain adequate resources to provide reliable services at just and reasonable rates. Moreover, as repeatedly acknowledged in the Joint Proposal, signatory parties are aware that these ameliorative measures may be augmented or modified as the result of the generic proceeding. We accordingly approve the COVID-19 related provisions in the Joint Proposal, as such provisions protect and further the public interest.

Turning to AARP's motion for temporary rates pursuant to Public Service Law §114, we agree with the Companies' assertion that such rates are not required absent delay in the resolution of a rate proceeding; no such delay exists and we thus deny the motion. With respect to AARP's interlocutory appeal and objection to the ALJs' ruling denying PULP's request to reopen the record and the associated interlocutory appeal, we find that the ALJs appropriately allowed settlement negotiations to continue. Indeed, each of the beneficial COVID-related measures we discuss throughout this Order is the direct,

[42] See Case 20-M-0266, Proceeding on Motion of the Commission Regarding the Effects of COVID-19 on Utility Service, Order Establishing Procedure issued June 11, 2020. The Joint Utilities are Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., KeySpan Gas East Corp. d/b/a National Grid, National Fuel Gas Distribution Corporation, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange and Rockland Utilities, Inc., Rochester Gas and Electric Corporation and the Brooklyn Union Gas Company d/b/a National Grid NY.

informed result of those negotiations. Accordingly, the interlocutory appeal is denied.[43]

D. Revenue Requirements

1. Annual Electric Revenue Increases

NYSEG

The Joint Proposal recommends that NYSEG be provided electric delivery rate increases of $45.684 million in RY 1, $99.200 million in RY 2, and $56.063 million in RY 3. As levelized/shaped, NYSEG’s delivery rates would be increased by $45.684 million or 6.1 percent in RY 1, $84.770 million or 10.6 percent in RY 2, and $88.565 million or 9.9 percent in RY 3. These levelized/shaped amounts include approximately $11.0 million in RY 1, $13.3 million in RY 2, and $9.1 million in RY 3 as a result of a largely revenue-neutral shift of energy efficiency costs from the System Benefits Charge (SBC) to base rates in accordance with Commission policy. For average residential customers, the proposed revenue increases would result in monthly bill increases of approximately $2.49 or 3.6 percent in RY 1, $4.13 or 5.7 percent in RY 2, and $5.54 or 7.2 percent in RY 3.[44]

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[43] We have previously indicated that PULP’s filings, as well as others related to the broader ramifications of COVID-19, have been incorporated into the generic COVID-19 proceeding (see Case 20-M-0266, Order Establishing Procedure issued June 11, 2020). Notably, “comment topics” expressly solicited in the appendix to that Order include “[w]hat has been the impact of COVID-19 on earnings, liquidity, cash flow and access to capital?,” and “[w]hat long-term impacts due to COVID-19 are forecasted at this time in relation to earnings, liquidity, cash flow, other credit quality metrics and access to capital?” As stated above, the Commission is currently considering submissions from several entities regarding just those subjects.

[44] The average residential customer refers to a non-heating electric customer using 600 kWh per month.

The proposed $45.7 million revenue requirement increase in RY 1 is approximately 72 percent less than the $162.7 million increase requested by NYSEG in rebuttal testimony and approximately 40 percent less than the $76.7 million electric base rate increase recommended by DPS Staff in pre-filed testimony. The Joint Proposal’s proposed increases reflect an overall reduction, as compared to the Companies’ filings, of $53.3 million resulting from the change from the 9.5 percent ROE and 50 percent common equity to 50 percent debt ratio sought by the Companies to the 8.8 percent ROE and 48 percent common equity to 52 percent debt ratio recommended in the Joint Proposal.[45]

The proposed revenue requirements also reflect reductions in allowed capital spending of over $500 million for projects that NYSEG delayed in implementing or excluded completely in entering into the Joint Proposal. These implementation changes and exclusions are reflected in the Joint Proposal to address the economic impacts from the COVID-19 pandemic. NYSEG represents that it has reduced its overall planned capital expenditures by $190 million for its Bulk Electric System Program (FERC Compliance), $227 million for its Resiliency Plan, $125 million for its Substation Modernization Program, $51 million for delayed implementation of AMI, and $30 million for its NERC Alert Priority 3 Program.[46] NYSEG also estimates that reductions to planned plant additions resulting from the Joint Proposal will lead to $27.5 million in lower revenue requirements over the course of the proposed rate plan.

The final revenue requirements also reflect an offset of the $9.0 million amount NYSEG agreed to pay to resolve Case

[45] Ex. 331, Companies’ Response to ALJ-1.

[46] Ex. 331, Companies’ Response to ALJ-2.

19-E-0105.[47] In addition, they reflect approximately $61 million in benefits from the Tax Cuts and Jobs Act of 2017 and approximately $8.7 million in imputed productivity savings.[48]

As an additional measure to address economic impacts from the COVID-19 crisis, the Joint Proposal provides for various adjustments to O&M expenses in RY 1, including a $5.7 million decrease to reflect the delayed start of NYSEG's Grid Model Enhancement Project, which will begin in RY 2. The roll-in of energy efficiency (EE)/Heat Pump targeted programs into base rates will be set at 80 percent of the levels set forth in the 2020 Energy Efficiency Order for RY 1, 85 percent for RY 2, and 90 percent for RY 3, with the difference allocated to the post-Rate Plan period. Other measures taken to moderate rate increases, such as deferred recovery of certain costs and modifications to amortization periods, are discussed in the COVID-19 section above.

NYSEG's electric rate increases are driven by several factors including capital investment, vegetation management, and increased staffing needed for the company to continue providing safe and reliable service. To offset a projected lower sales forecast, the revenue requirement would be increased by approximately $27.7 million in RY 1 and $27.8 million overall. As a result of the proposed capital projects, rate base will be increased significantly. Rates will be higher by $53.7 million

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[47] Cases 19-E-0105 et al., Proceeding on Motion of the Commission Investigating Utility Preparation and Response to Power Outages During the 2018 Winter and Spring Storms for New York State Electric & Gas Corporation, Order Adopting Terms of Joint Proposal (issued February 6, 2020).

[48] Under the Joint Proposal, the revenue requirements reflect productivity adjustments for the Companies of 1.25 percent in Rate 1 and 1.5 percent in RYs 2 and 3, which is greater than the typical 1.0 percent productivity adjustment.

in RY 1, $20.0 million in RY 2, and $26.1 million in RY 3 due to increases to rate base. Depreciation costs would be increased by $30.2 million in RY 1, $9.3 million in RY 2, and $16.3 million in RY 3.[49] A number of full-time equivalent employees are being added to NYSEG's workforce, resulting in increases to labor and benefits (excluding Pension and OPEBs) of $29.4 million in RY 1, $9.8 million in RY 2, and $8.0 million in RY 3. Over the course of the rate plan, increases to the number of outside contractors required to complete work would result in an overall increase of $15.5 million for this expense item. Finally, the Joint Proposal's expanded and more aggressive vegetation management programs would result in an increased yearly expenditure of $19.5 million in RY 1, $21.5 million in RY 2, and $23.5 million in RY 3.

RG&E

The Joint Proposal's revenue requirements support RG&E's electric delivery rates being decreased by $3.344 million in RY 1 and being increased by $53.159 million in RY 2 and $37.791 million in RY 3. As levelized/shaped, RG&E's electric delivery rates would be increased by $15.238 million or 3.4 percent in RY 1, $28.064 million or 6.3 percent in RY 2, and $30.721 million or 6.2 percent in RY 3. These amounts include approximately $4.5 million in RY 1, $5.1 million in RY 2, and $5.3 million in RY 3 as a result of the largely revenue-neutral shift of energy efficiency costs from the SBC to base rates. For average residential customers, the proposed revenue increases would result in monthly bill increases of

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[49] The additional rate base and depreciation account for approximately 75 percent of the increase for NYSEG Electric. During the three-year rate plan, approximately $1.6 billion would be invested in NYSEG's electric system, which represents an approximate 72 percent increase over 2016-2018 spending levels.

approximately $0.37 or 0.5 percent in RY 1, $3.82 or 5.0 percent in RY 2, and $4.14 or 5.2 percent in RY 3.

The proposed revenue requirement decrease of $3.344 million in RY 1 is significantly different from the $38.7 million increase requested by RG&E in rebuttal testimony and the $0.7 million electric rate base increase recommended by DPS Staff in pre-filed testimony. The Joint Proposal's electric revenue requirements for RG&E reflect an overall reduction of $34.0 million resulting from the change from the 9.5 percent ROE and 50 percent common equity to 50 percent debt ratio sought by the Companies to the 8.8 percent ROE and 48 percent common equity to 52 percent debt ratio recommended in the Joint Proposal.[50]

The proposed revenue requirements also reflect capital spending reductions of over $170 million for projects that RG&E delayed in implementing or excluded completely in entering into the Joint Proposal. RG&E states that it has reduced its overall planned capital expenditures by $37 million for its Bulk Electric System Program, $82 million for its Resiliency Plan, $22 million for delayed implementation of AMI, $17 million for Energy Storage Pilot Programs, and $12 million for its Circuit Breaker Replacement Program.[51] RG&E also estimates that reductions to planned plant additions resulting from the Joint Proposal will lead to $13.4 million in lower revenue requirements over the course of the proposed rate plan.

RG&E's final revenue requirements reflect an offset of the $1.5 million amount NYSEG agreed to pay to resolve Case 19-

[50] Ex. 331, Companies' Response to ALJ-1.

[51] Ex. 331, Companies' Response to ALJ-2.

E-0106.[52] The proposed revenue requirements also reflect approximately $31.0 million in benefits from the Tax Cuts and Jobs Act of 2017 and approximately $3.1 million in imputed productivity savings.

The COVID-19 provisions of the Joint Proposal provide for adjustments to O&M expenses in RY 1, including a $3.0 million decrease to reflect the delayed start of RG&E’s Grid Model Enhancement Project, which will begin in RY 2. The roll-in of EE/Heat Pump programs into base rates will be set at 85 percent of the levels set forth in the 2020 Energy Efficiency Order for RYs 1 and 2, with the difference allocated to the post-Rate Plan period. Other measures taken to moderate rate increases are discussed in the COVID-19 section above.

As with NYSEG, RG&E’s rate increases are driven by several factors including capital investments and increased staffing needed for the company to continue providing safe and reliable service. To offset a projected lower sales forecast, the revenue requirement would be increased by approximately $30.9 million in RY 1 and, due to offsets from projected increases in RYs 2 and 3, $30.8 million overall. As a result of the proposed capital projects, rate base will be increased significantly in RYs 2 and 3, leading to rates increasing by approximately $0.1 million in RY 1, $26.4 million in RY 2, and $15.5 million in RY 3. Depreciation costs would be increased by $13.6 million in RY 1, $8.6 million in RY 2, and $9.7 million in

[52] Cases 19-E-0106 et al., Proceeding on Motion of the Commission Investigating Utility Preparation and Response to Power Outages During the 2018 Winter and Spring Storms for Rochester Gas and Electric Corporation, Order Adopting Terms of Joint Proposal (issued February 6, 2020).

RY 3.[53] A number of full-time equivalent employees are being added to NYSEG's workforce, resulting in increases to labor and benefits (excluding Pension and OPEBs) of $7.9 million in RY 1, $2.4 million in RY 2, and $1.8 million in RY 3. Over the course of the rate plan, increases to the number of outside contractors required to complete work would result in an overall increase of $9.5 million during the rate plan. Costs for the Low Income Program are being increased in RY 1 by $10.0 million to properly reflect costs.

Discussion

Although the signatory parties have made significant efforts to moderate the proposed rate increases, PULP, AARP, and other parties, as well as numerous public commenters, assert that the proposed revenue requirement increases, particularly for NYSEG Electric, are too high. Those parties argue that rate increases are inappropriate given the economic impacts from the COVID-19 pandemic and that the proposed rate plans do not place sufficient focus on improving system reliability.

The Companies and DPS Staff state that the Joint Proposal strikes an appropriate balance between the interests of ratepayers and the Companies by providing customer relief in response to the current economic situation while seeking to improve system reliability, fund needed and mandatory infrastructure improvements, enhance vegetation management programs, and increase the Companies' workforce, among other things. The Companies maintain that the proposed capital investments and other costs are vital to their ability to continue to provide safe and reliable service. MI additionally

[53] The additional rate base and depreciation account for 82 percent of the increase for RG&E Electric. During the three-year rate plan, approximately $871 million would be invested in RG&E's electric system, an approximate 34 percent increase over 2016-2018 spending levels.

notes that the proposed electric rate increases reflect various Commission policies and initiatives, such as energy efficiency and low income assistance programs.

As stated above, the proposed rate increases for the Companies' electric businesses are driven by several factors, such as increased costs for distribution vegetation management, various capital expenditures, and additional full-time equivalent employees. All parties agree that increased costs for distribution vegetation management programs are necessary to reduce service outages caused by trees and branches and to improve system reliability. Enhanced electric distribution vegetation management programs also will benefit ratepayers by reducing storm restoration time and cost and improving public safety. NYSEG's distribution vegetation management budget under the Joint Proposal is almost double its current amount and includes necessary funding for new programs focusing on reclaiming identified circuits and areas that have reliability issues and have not been trimmed in over five years. The growing need to address increased outages due to tree interference with power lines in NYSEG's service territory and the continuing goal to move NYSEG to a full five-year trimming cycle provide ample justification for the proposed increases for distribution vegetation management programs, which are discussed in more detail later in this Order.

Similarly, the proposed increases for various capital projects are necessary for system reliability and resiliency.[54] Among other things, the proposed increases include "mandatory" capital expenditures for Bulk Electric System projects and upgrades necessary for FERC compliance and system reliability and performance; continuation of the Rochester Area Reliability

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[54] The Companies' AMI Program is discussed later in this Order.

Project, which improves the existing transmission system by building an additional bulk power station; and non-AMI DSIP Grid Automation projects to facilitate integration of clean energy resources and providing ratepayers with greater control over their energy usage. In addition, as stated by the Companies, "NYSEG and RG&E will spend $550 million and $309 million, respectively to replace aging equipment and improve reliability, and $107 million and $309 million, respectively, in projects to improve resiliency and reduce the frequency and duration of outages, and to create a more intelligent and automated system."[55]

Over the term of the rate plans, NYSEG Electric would add 195 full-time equivalent positions (FTEs) and RG&E Electric would add 36 FTEs. The additional FTEs include the 150 linemen DPS Staff recommended in its 2018 Winter and Spring Storms Report to bring NYSEG's overhead line workforce back to previous levels.[56] The addition of line workers and field personnel will improve the Companies' safety and reliability and storm response and restoration efforts. Other additions are needed to support infrastructure projects, vegetation management programs, and consumer service and Energy Efficiency initiatives and programs. These additions to the Companies' workforce should benefit the economy.

The signatory parties made significant efforts to keep the increases and their impacts down in light of the economic impacts from the COVID-19 crisis. Among other things, the Joint Proposal delays implementation or excludes various capital

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[55] Companies' Statement in Support of the Joint Proposal, p. 8.

[56] Case 19-M-0285, In the Matter of Utility Preparation and Response to Power Outages During the March 2018 Winter and Spring Storms, DPS Staff Report (filed April 18, 2019), p. 45.

projects, delays collection of costs and modifies amortization periods, applies regulatory liabilities to offset increases, and shapes and levelizes rates to ameliorate rate impacts. The proposed increases are in amounts agreed to among many parties after extensive negotiations resolving numerous issues in an attempt to moderate customer bill impacts while supporting the Companies' cash flow, credit metrics and service quality. In addition, the proposed rate plans protect ratepayers by including a downward-only Net Plant reconciliation for certain individual projects and the overall capital plan, as well as downward-only reconciliations for labor and electric vegetation management costs.

As we have stated, we are supportive of the carefully considered spending agreed to in the Joint Proposal. We find that the signatory parties have appropriately balanced the need for the Companies to maintain and improve the provision of safe and reliable electric service while not passing on excessive costs to customers. The spending will allow the Companies to replace aging infrastructure, modernize their systems, hire needed workers, and help the State meets its conservation and energy policy goals which are essential to combating climate change and maintaining public health. The proposed expenditures will address system safety, reliability and resiliency, and allow the Companies to meet legal obligations such as site investigation and remediation costs and property taxes. As the Companies' state, even after the proposed increases, their residential delivery rates will remain among the lowest in the State for investor-owned utilities.[57]

However, we also have clearly heard the many concerns regarding the size of the electric rate increases. While

[57] Companies' Statement in Support of the Joint Proposal, pp. 9-10.

increases are often necessary to support the extensive efforts that New York's utilities are tasked with carrying out, there are times when special consideration must be given. We therefore approve the Joint Proposal while modifying the electric rate increases for the Companies. For NYSEG, our modifications will lower the RY 1 increase from $45.684 million to $45.298 million. For RY 2, we lower the rate increase from $84.770 million to $45.640 million and for RY 3 we lower the increase from $88.565 million to $36.007 million. For RG&E, we raise the rate increase from $15.237 million to $21.352 million to be able to lower the RY 2 and RY 3 amounts even more. For RY 2, we lower the rate increase from $28.064 million to $13.898 million and for RY 3 we lower the increase from $30.721 million to $15.828 million.

To achieve these rate increases, we make the following modifications to the Joint Proposal. First, we will cap the collections for both NYSEG and RG&E's electric energy efficiency and heat pump programs during the rate plans at the level proposed in the Joint Proposal for RY 1. Next, we will require that the Grid Model Enhancement Project (GMEP) be capitalized instead of being expensed as proposed in the Joint Proposal.

We will modify the amortization period of the Danger Tree Program to be ten years for each rate year's expense, as opposed to the five years proposed in the Joint Proposal. Similarly, for NYSEG Electric, we modify the Joint Proposal so that the Reclamation Program related to additional vegetation management is amortized over ten years in the same manner as the Danger Tree Program costs, as opposed to being expensed as the Joint Proposal calls for. Also for NYSEG Electric, we will use additional Excess Depreciation Reserve (EDR) in RY 2 and RY 3 to further offset the rate increases. Finally, for RG&E Electric, we will modify the "shaping/levelization" employed so that the outcome of the rate increases equal the amounts that we have stated.

Regarding the energy efficiency and heat pump collections, the Joint Proposal included program budgets which were then offset by unspent funds, to arrive at a net collection level. For NYSEG Electric, the Joint Proposal called for program budgets of $18.715 million in RY 1, $31.759 million in RY 2, and $40.750 million in RY 3. A total of $7.893 million each year of unspent funds was used to offset the costs, with resulting net collections of $10.822 million in RY 1, $23.866 million in RY 2, and $32.857 million in RY 3. For RG&E Electric, the Joint Proposal called for program budgets of $9.332 million in RY 1, $14.363 million in RY 2, and $19.584 million in RY 3. A total of $4.892 million each year of unspent funds was used to offset the costs, with resulting net collections of $4.440 million in RY 1, $9.471 million in RY 2, and $14.692 million in RY 3.

While we are fully supportive of the Companies' spending at these levels (and more, up to the amounts provided for in the 2020 Energy Efficiency Order), we believe that collections can be capped at the RY 1 level. This is, in part, due to the likelihood of the COVID-19 pandemic limiting the Companies' ability to ramp up their spending for such programs as quickly as has been proposed. However, to maintain our commitment to the important public policy goals of these programs, any expenditures above the RY 1 level (after first allocating the annual unspent funds to the amount) can be deferred for future recovery, subject to the caps contained in Appendix T of the Joint Proposal. In addition, this reconciled item will now be eligible to be recovered through the Revenue

Adjustment Mechanism.[58] These modifications will provide for substantial rate relief while giving the Companies every incentive to continue to vigorously pursue the programs.

The Grid Model Enhancement Project is a multi-year project which provides inventory of all distribution system endpoints in support of the Distributed System Implementation Plan (DSIP) efforts of the Companies. While the Joint Proposal calls for the GMEP to be expensed, we believe that this project needs to be capitalized because it provides benefits over an extended period of time, similar to the DSIP investments that it is related to.

The Danger Tree Program being proposed in the Joint Proposal for both NYSEG Electric and RG&E Electric is an effort to proactively address danger trees, including those being negatively impacted by the emerald ash borer beetle. This work is of limited duration, as opposed to traditional vegetation management, and the benefit from the program will be experienced by customers for a substantial amount of time. While the Joint Proposal proposed to amortize each rate year’s expense over five years, we modify the amortization period to ten years. We find that the longer time period more accurately matches the long-term benefits provided by the program.

NYSEG Electric’s Reclamation Program is also a limited duration vegetation management effort. It is designed to allow NYSEG to “catch up” on its vegetation management, as a significant portion of its circuits have become overgrown. Similar to the Danger Tree Program, we find that such expenses are best considered over a ten-year period to better match the

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[58] Should energy efficiency and heat pump costs be deferred and later recovered through the RAM, the collections for such costs should follow the rate design currently prescribed in Appendix BB of the Joint Proposal.

collections from customers with the benefits the program provides. We note that both NYSEG and PULP had proposed a longer recovery period for such costs in their direct testimony.[59]

NYSEG Electric has an estimated $424.8 million of EDR based on the agreed upon depreciation rates. This is the amount the book depreciation reserve exceeds calculated accrued depreciation. Essentially, it is estimated that customers have contributed that amount more than what is necessary, given current depreciation studies. Typically, such amounts are used as moderators to help reduce rate increases. Under the Joint Proposal, the parties had agreed to amortize NYSEG's existing EDR in the amounts of $30.850 million in RY 1, $34.950 million in RY 2, and $39.100 million in RY 3. In addition, the Joint Proposal called for using the EDR to reimburse NYSEG for the Make Whole Provision, as discussed below. To further offset rates, NYSEG Electric should increase the amount of EDR being amortized (excluding any related to the Make Whole Provision) to $38.950 million in RY 2 and $71.600 million in RY 3. To the extent any small incremental change is needed to the revenue requirements based on our modifications, NYSEG may use a slightly different amount of EDR amortization to achieve the desired rate increases.

For RG&E Electric, the energy efficiency and heat pump collection modifications, along with the capitalization of GMEP, should be sufficient to achieve the modified rate increases via revised shaping/levelization. To the extent any small incremental change is needed to the revenue requirements based

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59 Ex. 41, Companies' Vegetation Management Panel Direct Testimony, p. 5; Ex. 259, Corrected Direct Testimony of William D. Yates, p. 31.

on our modifications, RG&E may adjust the amount of its nuclear insurance credits used to achieve the desired rate increases.

2. Annual Gas Revenue Increases

NYSEG

The Joint Proposal's revenue requirements support NYSEG's gas delivery rates being decreased by $10.675 million in RY 1, increased by $14.150 million in RY 2, and increased by $15.052 million in RY 3. As levelized/shaped, NYSEG's gas delivery rates would be decreased by $0.514 million or 0.3 percent in RY 1, increased by $3.350 million or 1.7 percent in RY 2, and increased by $5.269 million or 2.5 percent in RY 3. The RY 1 amounts include $0.985 million resulting from the largely revenue-neutral shift of energy efficiency costs to base rates and an offset in the amount of $1.656 million resulting from the amortization of previously underspent energy efficiency-related program costs. The amounts in RYs 2 and 3 each include approximately $1.9 million from the largely revenue-neutral shift of energy efficiency costs into base rates. For average residential customers, the proposed revenue changes would result in a bill decrease of approximately $0.02 or 0.0 percent in RY 1, a bill increase of approximately $0.53 or 0.6 percent in RY 2, and a bill increase of approximately $1.22 or 1.4 percent in RY 3.[60]

The proposed revenue requirement for RY 1 is significantly different from the $4.087 million increase proposed by NYSEG in rebuttal testimony and is closer to the $15.944 million gas base rate decrease originally recommended by DPS Staff. The Joint Proposal's gas revenue requirements for NYSEG reflect an overall reduction of $14.308 million resulting from the change from the 9.5 percent ROE and 50 percent common

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[60] The average residential customer refers to a residential gas heating customer using 90 therms per month.

equity to 50 percent debt ratio sought by the Companies to the 8.8 percent ROE and 48 percent common equity to 52 percent debt ratio recommended in the Joint Proposal.[61]

The proposed revenue requirements reflect capital spending reductions of over $100 million for projects that NYSEG delayed in implementing or excluded in entering into the Joint Proposal. NYSEG states that it reduced its overall planned capital expenditures by $52 million for the DeRuyter Pipeline project, $17 million for the Lansing/Freeville Pipeline project, $15 million for the Walton 124 Replacement project, $13 million for delayed implementation of AMI, and $5 million for the Boswell Hill Main Replacement project.[62] NYSEG also estimates that reductions to planned plant additions resulting from the Joint Proposal’s capital spending adjustments will lead to $4.7 million in lower revenue requirements over the course of the proposed rate plan.

The proposed gas revenue requirements also reflect approximately $13.7 million in benefits from the Tax Cuts and Jobs Act of 2017 and approximately $2.4 million in imputed productivity savings. The roll-in of EE/Heat Pump programs into base rates will be set at 85 percent of the levels set forth in the 2020 Energy Efficiency Order for RYs 1 and 2, with the difference allocated to the post-Rate Plan period. The revenue requirements also reflect a 25 percent decrease in O&M for collection-related costs and reductions to reflect the delayed start of additional contractors supporting the Damage Prevention program.

To offset a projected lower sales forecast, the revenue requirement would be increased by approximately $10.8

[61] Ex. 331, Companies’ Response to ALJ-1.

[62] Ex. 331, Companies’ Response to ALJ-2.

million in RY 1, and, with offsets in RYs 2 and 3, approximately $9.4 million overall. As a result of the proposed capital projects, rate base will be increased, leading to rates increasing by approximately $8.6 million in RY 1, $5.0 million in RY 2, and $5.4 million in RY 3. Depreciation costs would be increased by $9.4 million in RY 1, $2.7 million in RY 2, and $4.4 million in RY 3. The addition of FTEs would result in increases to labor and benefits (excluding Pension and OPEBs) of $3.8 million in RY 1, $1.5 million in RY 2, and $1.0 million in RY 3.

RG&E

The Joint Proposal's revenue requirements support RG&E's gas delivery rates being decreased by $10.943 million in RY 1, increased by $10.441 million in RY 2, and increased by $15.125 million in RY 3. As levelized/shaped, RG&E's gas delivery rates would be decreased by $1.127 million or 0.6 percent in RY 1, increased by $0.859 million or 0.5 percent in RY 2, and increased by $3.866 million or 2.1 percent in RY 3. The RY 1 amounts include $1.624 million from the largely revenue-neutral shift of energy efficiency costs into base rates and an offset in the amount of $2.903 million resulting from the amortization of previously underspent energy efficiency-related program costs. The amounts for energy efficiency costs increase by $1.009 million in RY 2 and by $1.479 million in RY 3. For average residential customers, the proposed revenue changes would result in a bill decrease of approximately $0.80 or 0.1 percent in RY 1, a bill increase of approximately $0.10 or 0.1 percent in RY 2, and an increase of approximately $0.81 or 1.1 percent in RY 3.

The proposed revenue requirements for RY 1 are significantly different from the $1.8 million decrease proposed by RG&E in rebuttal testimony and closer to the $22.5 million gas base rate decrease originally recommended by DPS Staff. RG&E's proposed gas revenue requirements reflect an overall reduction of $10.9 million resulting from the change from the 9.5 percent ROE and 50 percent common equity to 50 percent debt ratio the Companies originally proposed to the 8.8 percent ROE and 48 percent common equity to 52 percent debt ratio recommended in the Joint Proposal.[63]

The proposed revenue requirements reflect capital spending reductions of approximately $55 million for projects that RG&E delayed in implementing or excluded in entering into the Joint Proposal. RG&E states that it reduced its overall planned capital expenditures by $24 million for the CM-1 Transmission Project at Ballantyne Road, $15 million for the CM-#D Transmission Project at Route 441, $14 million for delayed implementation of AMI, $12 million for the CM-1A Transmission Project at Brockport, and $4 million for the MF120 Reinforcement Project at Paul Road.[64] RG&E also estimates that reductions to planned plant additions resulting from the Joint Proposal will lead to $5.2 million in lower revenue requirements over the course of the proposed rate plan.

The proposed gas revenue requirements also reflect approximately $8.9 million in benefits from the Tax Cuts and Jobs Act of 2017 and approximately $1.6 million in imputed productivity savings. The roll-in of EE/Heat Pump programs into base rates will be set at 85 percent of the levels set forth in the 2020 Energy Efficiency Order for RYs 1 and 2, with the difference allocated to the post-Rate Plan period. The revenue requirements also reflect a 25 percent decrease in O&M for collection-related costs and reductions to reflect the

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63 Ex. 331, Companies' Response to ALJ-1.

64 Ex. 331, Companies' Response to ALJ-2.

delayed start of additional contractors supporting the Damage Prevention program.

To offset a projected lower sales forecast, the revenue requirement would be increased by approximately $3.3 million in RY 1 and, with reductions in RYs 2 and 3, $1.7 million overall. As a result of the proposed capital projects, rate base will be increased, leading to rates increasing by approximately $4.9 million in RY 1, $3.4 million in RY 2, and $6.8 million in RY 3. Depreciation costs would be increased by $8.8 million in RY 1, $1.6 million in RY 2, and $3.7 million in RY 3. Increases to the number of outside contractors required to complete work would result in increases of $3.1 million in RY 1, $1.4 million in RY 2, and $0.2 million in RY 3.

Discussion

Unlike the proposed revenue increases for the Companies’ electric businesses, none of the parties directly challenge the revenue requirement changes proposed for the Companies’ gas businesses. Under the Joint Proposal, the Companies’ gas revenue requirements are decreasing in RY 1 and have moderate increases in the remaining two Rate Years. The signatory parties made significant efforts to keep rate increases down, and we find the proposed increases reasonable given the Companies’ demonstration of need and the major drivers associated with the rate increases. The proposed increases will allow the Companies to improve and maintain their gas systems and to continue to provide safe and reliable gas service. Moreover, various reconciliation measures provide ratepayers with protections from over- and under-spending. For these reasons, we find the gas rates proposed under the three-year rate plans to be just and reasonable.

3. Make Whole Provision

Because Commission approval of rates would occur after April 17, 2020, the Companies have requested and the signatory parties have agreed to a make-whole provision under which the Companies would recover shortfalls and refund over-collections, such that the Companies and their ratepayers would be in the same position had RY 1 rates gone into effect as of April 17, 2020. Revenue adjustments for the make-whole period would be calculated at the difference between sales revenues the Companies would have billed at new rates compared to the sales revenues at current rates during the period from April 17, 2020, until the date that new rates actually go into effect. The Companies would not compress RY 1 rates and would amortize EDR balances to cover the revenue increases associated with the make-whole period.

E. Cost of Capital and Capital Structure

The Joint Proposal's revenue requirements reflect for NYSEG an overall after-tax cost of capital of 6.10 percent and a cost of debt of 3.63 percent in RY 1; an overall after-tax cost of capital of 6.04 percent and a cost of debt of 3.52 percent in RY 2; and an overall after-tax cost of capital of 6.00 percent and a cost of debt of 3.42 percent in RY 3.[65] For RG&E, the Joint Proposal's revenue requirements reflect an overall after-tax cost of capital of 6.62 percent and a cost of debt of 4.62 percent in RY 1; an overall after-tax cost of capital of 6.48 percent and a cost of debt of 4.35 percent in RY 2, and an overall after-tax cost of capital of 6.37 percent and a cost of debt of 4.14 percent in RY 3.[66] The foregoing amounts include an

[65] Joint Proposal, Appendix A, p. 2.

[66] Joint Proposal, Appendix A, p. 4.

allowed ROE of 8.8 percent, a common equity ratio of 48.0 percent, and a long-term debt ratio of below 52.0 percent.[67] The ROE and common equity ratio are applicable across the three years of the Companies' electric and gas rate plans.

In testimony, NYSEG requested an after-tax cost of capital of 6.74 percent, based on a ROE of 9.50 percent, a cost of debt of 3.99 percent, and a common equity ratio of 50 percent. RG&E requested an after-tax cost of capital of 7.24 percent for the Rate Year, based on a ROE of 9.50 percent, a cost of debt of 4.98 percent, and a common equity ratio of 50 percent.

DPS Staff's testimony, relying on the Commission's cost of capital calculation in its generic financing methodology, recommended an after-tax cost of capital of 5.85 percent for NYSEG and an after-tax cost of capital of 6.33 percent for RG&E. For both Companies' cost of capital, DPS Staff recommended that the Commission use an allowed ROE of 8.2 percent and a common equity ratio of 48.0 percent. DPS Staff also recommended that the Commission employ a long-term debt cost of 3.69 percent for NYSEG and a long-term debt cost of 4.62 percent for RG&E.[68]

Two other parties submitted testimony for a recommended ROE. PULP's witness William Yates recommended that the Commission provide the Companies with an allowed ROE that does not exceed 9.0 percent so as to be consistent with the allowed ROE in recent rate orders for Central Hudson Gas and Electric, Niagara Mohawk Power Corporation d/b/a National Grid,

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[67] Joint Proposal, section VII and Appendix T, pp. 9–10.

[68] Ex. 175, DPS Staff Finance Panel Testimony, pp. 8–9.

and Orange and Rockland Utilities, Inc.[69] FFT submitted the testimony of Irene Weiser in which she recommended that the Commission allow no return on the Companies' gas plant and a ROE of no more than 8.0 percent on the Companies' electric plant, with an additional opportunity via incentives to earn an additional 1.0 percent through earnings adjustments.[70] FFT claims that no return on gas assets is warranted inasmuch as expanding the use of natural gas is against State policy. FFT states that, alternatively, the Commission could accelerate the depreciation of any gas assets.

Opposing the Joint Proposal, AARP and PULP take issue with the amount of difference between DPS Staff's litigated position and the ROE reflected in the Joint Proposal. PULP contends in its Opposition Comments that the Joint Proposal's ROE is likely much higher than DPS Staff would have supported in a litigated case.[71] In its Opposition Statement, AARP echoes PULP's statement and makes a point of noting that the Joint Proposal's ROE is 60 basis points higher than DPS Staff's litigated position. AARP argues that the 60 basis point difference is a risk premium that is attached to mitigate some of the risk of the forecasts underlying the Companies' revenue requirement over the three years covered by the rate plan. AARP maintains that such risk premium is higher than any awarded previously by the Commission.[72]

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[69] Ex. 259, Corrected Testimony of William D. Yates, C.P.A., pp. 32-33 (citing the Commission's Orders Adopting Joint Proposals in Cases 17-E-0459, 17-G-0460, 17-E-0238, 17-G-0239, 18-E-0067, and 18-G-0068).

[70] Ex. 286, Testimony of Irene Weiser, pp. 28-29.

[71] PULP Comments in Opposition, pp. 4–5.

[72] AARP Statement in Opposition, pp. 21–22.

In reply, DPS Staff contends that AARP’s position relies on a false premise that “ignores the negotiation process by the Signatory Parties in reaching a Joint Proposal, or the views and considerations of credit rating agencies.” DPS Staff also notes that if it were to update its testimony now using the Commission’s generic finance methodology, the result would be significantly greater than 8.2 percent. As such, DPS Staff maintains that the Joint Proposal’s 8.8 percent ROE is reasonable both in the greater context of the Joint Proposal and in the context of the current financial environment.[73]

In addition to the foregoing, the Joint Proposal contains a mechanism for sharing earnings that exceed the allowed ROE.[74] While the Joint Proposal’s Earnings Sharing Mechanism (ESM) contains a deadband whereby some additional earnings are retained in total by the Companies, for RY 1, the deadband is only 20 basis points above the allowed ROE before sharing begins. The deadband increases incrementally in the second and third Rate Years to 30 basis points and 40 basis points, respectively. After sharing begins, the first and second tiers of sharing are bounded each by 50 basis points and earnings are shared 50 percent to customer in the first tier and are 75 percent to customers in the second tier. For the final tier, customers receive 90 percent of any additional earnings above the threshold.

<u>Discussion</u>

The Joint Proposal’s 8.8 percent ROE is reasonable given the current financial market conditions as well as the increased financial and business risks inherent in setting rates over a multi-year period. Moreover, it is reasonable given DPS

[73] DPS Staff Reply Brief, p. 5.

[74] Joint Proposal, section VIII.

Staff's averment that the resulting update of its ROE testimony is significantly higher than 8.2 percent. In comparing it to a litigated outcome, the Joint Proposal's allowed ROE is significantly reduced from that requested by the Companies in their filings. It is equivalent to the ROE we allowed Con Edison in January 2020[75] and Central Hudson Gas and Electric Corporation in 2018, and, as recognized by PULP in its testimony, lower than that given to Niagara Mohawk Power Corporation d/b/a National Grid and Orange and Rockland Utilities, Inc. in their most recent rate cases.[76] The Joint Proposal adopts a fair return that is expected to allow the Companies to attract adequate capital to fund investments that will ensure continued provision of safe and adequate service in their respective service territories.

As for the increase of the Joint Proposal's ROE over the amount testified to by DPS Staff, the Joint Proposal properly recognizes the increased financial and business risks inherent in setting rates over a multi-year period. Even were we not to consider DPS Staff's statement that an updated ROE would be significantly higher than the 8.2 percent contained in its testimony, as we have recognized previously, the extended

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[75] Cases 19-E-0065, et al., Consolidated Edison Company of New York, Inc. - Rates, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans (issued January 16, 2020).

[76] Cases 18-E-0067, et al., Orange and Rockland Utilities, Inc. -Rates, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans (issued March 14, 2019); Cases 17-E-0459, et al., Central Hudson Gas and Electric Corporation - Rates, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans (issued June 14, 2018); 17-E-0238, et al., Niagara Mohawk Power Corporation d/b/a National Grid - Rates, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans (issued March 15, 2018).

term of the Joint Proposal inherently carries more financial risk as investors are subject to additional risk that economic conditions may change and the actual cost of capital could change during the three-year term, particularly during such uncertain times. Because the Joint Proposal locks in forecasted amounts for numerous significant elements of expense for the three-year term, the Companies are exposed to the business risk that its actual operating costs will turn out to be greater than those allowed for in rates. This aspect of multi-year rate plans and its impact on overall business risk has accordingly been recognized by the Commission when adopting the allowed ROEs incorporated in long-term rate plans.

In addition, customers are protected where cost savings are achieved by the ESM. The Joint Proposal's ESM is aggressive in limiting the amount of the deadband in which customers do not share in additional earnings, particularly in the first Rate Year. Thereafter, at no time does the Joint Proposal allow the Companies to retain 100 percent of additional earnings that exceed 40 basis points above the allowed ROE. The ROE and associated capital structure provisions are reasonable.

F. Capital Expenditures

1. Advanced Metering Infrastructure

The Joint Proposal includes capital allocated for the continued implementation of the Companies' AMI.[77] AMI consists of the replacement of old and obsolete analog meters with digital meters that can be read and supported through software platforms to provide the Companies and its customers with a variety of usage options.

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[77] Joint Proposal, section XXII and Appendix O.

The Joint Proposal includes funding for the Companies' estimated five-year costs of $489.1 million in capital expenditures for the implementation of AMI across all four businesses (NYSEG Electric and Gas and RG&E Electric and Gas). During the term of the rate plan, such funding will support the replacement of approximately 1.3 million existing electric meters and the replacement or upgrading of approximately 600,000 existing gas meters; the creation of a supporting telecommunications network covering 20,000 square miles to manage information flows between the meters in the field and the Companies' AMI operations center; and the development and implementation of an Information Technology (IT) infrastructure and software applications to collect, manage, store, and protect AMI information, support customer data needs to improve decisions regarding energy use and support innovative rate structures to encourage efficient customer consumption of energy.[78]

The Joint Proposal allows customers to "opt out" of receiving an AMI electric meter and AMI gas communications module during the initial AMI roll-out subject to a continuing monthly meter reading charge of $13.47 per month at NYSEG and $11.56 per month at RG&E. For meters that have already been installed, those customers may also "opt-out" of using an existing AMI meter or AMI gas communications module. NYSEG customers will be subject to a continued meter reading charge of $13.47 per month, and a $47.63 one-time charge applicable to exchange their existing AMI electric meter/gas module for a non-AMI meter, or a one-time charge of $65.51 if both an AMI electric meter and an AMI gas communications module are exchanged out. RG&E customers who subsequently elect to "opt-

[78] Joint Proposal, section XXII.A.

out" after an AMI meter/gas communications module has been installed will be charged $11.56 per month as an ongoing meter reading charge, and a one-time $43.68 charge for the exchange of an installed AMI meter or gas communications module exchange, or a one-time $58.24 charge where both electric and gas AMI services are exchanged.[79]

The Joint Proposal reflects the parties' agreement that the Companies anticipate AMI to be foundational to realizing New York State policy goals, and that AMI will allow customers access to new tools and information to effectively manage and reduce usage, establish new markets to promote the implementation of low carbon Distributed Energy Resources, and minimize environmental impacts. To this end, the Joint Proposal includes the Companies' anticipation that the enhanced capabilities of AMI meters will reduce certain O&M costs that will be reflected in customer rates over time; reduce the Companies' future levels of capital spending by avoiding investments in non-AMI meters and avoiding sensor costs otherwise required to support state energy policy; reduce electricity and natural gas usage and lowering bills through programs supported by the AMI platform, including conservation voltage reduction/volt-var optimization, information feedback such as usage alerts, and time-varying pricing; reduce CO2 emissions from the conservation efforts enabled by AMI and reductions in outage costs through faster outage detection and restoration; improve the equitable allocation of costs through improved meter accuracy, theft detection and write-off reductions; and enhance customer convenience and safety post-pandemic by eliminating the need for customers to provide access to indoor meters or submitting self-reads and providing more

[79] Joint Proposal, section XXII.A.

convenient service activation and account transfers through a remote meter service switch.[80]

The topic of AMI was addressed by many of the parties in pre-filed testimony prior to settlement discussions. FFT, MI, PULP, and UIU addressed AMI in their direct testimony. Irene Weiser, on behalf of FFT, testified about her experience with a NYSEG pilot program in which she served on the Energy Smart Community (ESC) advisory board, and expressed concern that the pilot had not demonstrated enough customer engagement and took issue with some of the alleged benefits of time variable pricing for AMI. Ultimately, she recommended delaying full-scale implementation of AMI further and extending the pilot program to the entirety of Tompkins County.[81] PULP opposes AMI deployment citing the Companies' inability to demonstrate any concrete customer benefits. Additionally, PULP cites its concerns that the Companies have not explained how they will handle service terminations through AMI in compliance with the HEFPA including the HEFPA requirement that customers be provided an opportunity to make a payment to the utility personnel at the time of termination, which PULP maintains requires utility personnel to visit the customer site at the time service termination is attempted.[82] In its initial testimony, the UIU rate panel proposed a nominal AMI opt-out charge of $3 per month.[83] Later, in its rebuttal, the UIU rate panel recommended that the Commission delay consideration of the Companies' AMI proposal to allow for a collaborative to discuss topics of cost allocation and the impact of AMI on the rates paid by individual

80 Joint Proposal, section XXII.A.

81 Ex. 286, Direct Testimony of Irene Weiser, pp. 13–15.

82 Ex. 259, Corrected Testimony of William D. Yates, pp. 46–48.

83 Ex. 215, Direct Testimony of UIU Rate Panel, pp. 67–69.

service classes or specific types of customers.[84] MI, noting that the Companies' AMI proposals would substantially increase the Companies' post rate case electric and gas delivery revenue requirements, opined that the allocation of AMI costs in future ECOS studies must recognize the extent to which each service class is responsible for the incurrence of AMI costs.[85] For its part, the DPS Staff Advanced Metering Infrastructure Panel supported the Companies' proposal and recommended that the Commission approve it with the caveat that certain issues that the DPS Staff panel raised in its testimony be addressed through the litigation process.[86]

The Joint Proposal contains a comprehensive plan that addresses the concerns raised by DPS Staff and by MI.[87] In its Statement in Support of the Joint Proposal, DPS Staff expresses its opinion that any concerns with the alleged benefits of time variable pricing for AMI and the lack of demonstration of customer benefits are addressed by DPS Staff's representation that operational savings alone justify the implementation of AMI.[88] DPS Staff states that because of those operational savings, even if customers do not modify their energy usage, they will benefit from AMI through changes in business operations and reductions in capital purchases, such as reduced meter reading, field work, and call center costs and avoided meter purchases and sensors, among others. DPS Staff also

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[84] Ex. 217, Rebuttal Testimony of UIU Rate Panel, pp. 30–38.

[85] Ex. 148, Direct Testimony of Jeffry Pollock, pp. 57-59.

[86] Ex. 161, DPS Staff Advanced Metering Infrastructure Panel, p. 10.

[87] DPS Staff Statement in Support of the Joint Proposal, pp. 80–81; Statement in Support of Joint Proposal by MI, p. 17.

[88] DPS Staff Statement in Support of the Joint Proposal, p. 81.

states that the Commission need not delay consideration of the Joint Proposal’s AMI provisions because doing so would delay customer benefits that are reflected in the benefit cost ratio presented on the record.[89]

In its Statement in Opposition, UIU continues to advocate for a separate proceeding to consider AMI. UIU posits that the benefit cost calculation relied on by the settling parties assumes a concurrent deployment between RG&E and NYSEG, but that when considered individually, RG&E’s benefit cost calculation is only slightly above 1, calling into question whether RG&E’s customers will actually realize any benefits. UIU also posits that the omission of an engaged stakeholder process for both Companies’ territories does not comport with the grave economic situation being faced by ratepayers in the context of the COVID-19 pandemic.[90] Finally, UIU argues that unlike the other capital projects in Appendix R of the Joint Proposal, AMI cannot be considered to be justified as necessary to maintain reliability and replace aging infrastructure.[91] UIU maintains that although AMI does have benefits, the technology is not otherwise necessary for the delivery of safe and reliable service, and so it is difficult from the outset to quantify the magnitude of cost for this project to ratepayers.[92]

In its Statement in Opposition, AARP contends that the electric portions of the Joint Proposal are not in the public interest primarily because they contain funding for the Companies’ AMI implementation. AARP claims that AMI implementation will both cost more and provide less benefits

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[89] DPS Staff Statement in Support of the Joint Proposal, p. 81

[90] UIU Statement in Opposition, pp. 3-4.

[91] Id., p. 6.

[92] Id.

than is claimed by the Companies and settling parties.[93] To establish the former, AARP refers to the ESC maintaining that "it is quite likely that the timeline for deployment of meters and communications network will take longer and cost more than currently projected" particularly because "the complexities of creating a telecommunications network covering 20,000 square miles to manage information flows between the meters in the field and the Companies' AMI operations center, described on page 42 of the Joint Proposal, totally underestimates the communication challenges in a rural service territory."[94] In contending that the benefits of AMI implementation are overstated, AARP notes that the ESC demonstrates that customer participation is very low and not in accord with the figures used to calculate the benefit cost analysis. AARP also questions the outage management benefits attributed to AMI, maintaining that the benefits expected in that area are much more likely to be directly attributable to improvement in vegetation management, not due to any implementation of AMI.[95] Similar concerns are expressed by the collection of Indicated Environmental Parties in their combined Statement in Opposition to the Electric portions of the Joint Proposal.[96]

In its Reply Statement, DPS Staff reiterates its expectation regarding the benefits to be achieved via AMI implementation. First, DPS Staff notes that criticisms of ESC customer participation are misplaced inasmuch as a function of the pilot programs under the Commission's Reforming the Energy

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93 AARP Statement in Opposition, pp. 27–29.

94 Id., pp. 28–29.

95 Id., p. 28

96 Indicated Environmental Parties Statement of Opposition of the NYSEG/RG&E Electric Joint Proposal, pp. 16–19.

Vision proceeding is to experiment with innovative rates and that the “rate tested in the ESC might not be representative of the rate that will ultimately be proposed for the entirety of the Companies’ service territories.”[97] DPS Staff notes that NYSEG’s existing time of use rate has over 100,000 customers participating and that the illustrative rate used in the AMI benefit cost analysis was a time-of-use rate that included Critical Peak Period pricing, different from the time variable rate used in the ESC pilot program. Additionally, DPS Staff states that even completely removing all electric customer behavioral change benefits only decreases the benefit cost ratio by approximately 0.10, demonstrating that AMI would still be cost beneficial as its resulting benefit cost ratio still exceeds 1.00.[98]

As for criticisms related to the costs being underestimated because of the need to include costs related to a backbone communications network, DPS Staff notes that this function is a completely different project related to the Companies’ DSIP under the REV proceeding and is therefore properly considered apart from the AMI implementation as it will serve many functions that are not AMI related.[99] As to the claim that the outage and restoration benefits are overstated and more attributable to improvements in vegetation management, DPS Staff notes that vegetation management does not have any significant impact on outage management benefits and that the customer outages for mitigation by the Resiliency Plan account for only eight percent of the customer outages mitigated by AMI’s outage

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[97] DPS Staff Statement in Reply, p. 4.

[98] Id.

[99] Id.

management functions.[100] Finally, as to charges that the costs are underestimated, DPS Staff notes that the Companies' AMI proposal remains subject to a cap on costs that, if exceeded, may only be recovered if the Commission allows it through a future filing. DPS Staff also notes that many of the cost elements considered are already under contracts pending Commission approval, and that those contracts include provisions by which the vendors share in the risk of cost overruns.[101]

Discussion

The Commission has issued several orders addressing implementation plans for AMI deployment. In particular, the Commission adopted minimum requirements for AMI functionality and guidance for assessing benefits and costs in a 2009 order.[102] The 2009 AMI Order established the Commission's expectation that the State's Transmission and Distribution utilities take the initiative to make proposals that would modernize their systems and incorporate AMI in a way that could reap customer benefits. The 2009 AMI Order indicates that AMI systems generally consist of three components: meters, a meter data management database, and a two-way communications network that links the meters and the database together and established minimum requirements for the functionality of those various components. Specific to the Companies, the 2009 AMI Order noted that the Companies had filed a joint plan for AMI deployment that should be evaluated to determine that plan's comportment with the Commission's minimum requirements. Since then, the Companies have engaged in AMI by

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[100] Id., pp. 4–5.

[101] Id., p. 5.

[102] Case 09-M-0074, In the Matter of Advanced Metering Infrastructure, Order Adopting Minimal Functional Requirements for Advanced Metering Infrastructure Systems and Initiating an Inquiry into Benefit-Cost Methodologies (issued February 13, 2009) (2009 AMI Order).

employing the ESC pilot program. Using the information gathered from that pilot and other sources, such as the experience of a corporate transmission and distribution affiliate located in another state, the Companies submitted their most recent AMI deployment plan with their rate filing.

We continue to support the deployment of AMI. Examining the record, we can see that the parties worked together to improve the Companies' plans as incorporated in the Joint Proposal. DPS Staff has adequately responded to the criticisms lodged by the opponents to the Joint Proposal with regard to that AMI implementation plan, particularly as to the benefit cost analysis. The plan is timely and reasonable, and is properly included in the rate plan.

AMI Benefit Implementation Plan

There are numerous quantified and unquantified benefits of AMI discussed in Appendix O (AMI-1) of the Joint Proposal. In addition, as technology evolves, additional benefits may be identified. To assist with understanding these benefits, tracking their completion, and to learn from the implementation of the AMI project, NYSEG and RG&E shall develop an AMI Benefit Implementation Plan (Implementation Plan), file that Implementation Plan with the Commission within 60 days of the issuance of this Order and begin to execute the Implementation Plan in a timely manner to fully achieve the benefits outlined in the Implementation Plan. The Implementation Plan will include: a description of the quantified and unquantified benefits that will be pursued; the general priority of two groups of benefits, quantified and unquantified; specific implementation action steps; schedules with specific interim milestones; updates, if applicable, to the forecasted 20-year net present value of quantified benefits and cost to achieve such benefits that are identified in Appendix O

(AMI-1) of the Joint Proposal; a Benefit Cost Analysis (BCA) of new capabilities that is planned to be implemented but not already included in Appendix O (AMI-1) of the Joint Proposal, if applicable; and available BCA of capabilities that the Companies are not certain will be implemented, if applicable. All quantified benefits identified in Appendix O (AMI-1) of the Joint Proposal shall be addressed in this Implementation Plan. In addition, the Implementation Plan shall include, but not be limited to, the following benefits: improved planning capability for a more dynamic, efficient, sustainable, and reliable energy network; improved planning capability for better investment decisions by the utility and distributed energy resource providers; improved electric and gas operational capabilities through increased visibility of system conditions for preventive action; AMI-related platform service revenues; reductions in theft of service, bad debt write-offs, and lost and unaccounted for gas/unaccounted for electricity due to improved meter accuracy; advanced street lighting; if applicable, any cost saving synergies with affiliates while implementing AMI; and grid-edge computing capabilities.

NYSEG and RG&E shall work with DPS Staff to develop this Implementation Plan. If a consensus on any aspect of the Implementation Plan cannot be reached between the Companies and DPS Staff, the Companies shall file their Implementation Plan, identifying in that filing the areas of disagreement for Commission consideration and approval. DPS Staff will have two weeks to submit comments in response to the Companies' filing.

Any need to substantially alter the timeline for implementing benefits so that the benefits would materialize during a different period than identified in the BCA model, the results of which are shown in Appendix O (AMI-1) of the Joint Proposal, in a material way or to not achieve such benefits identified in these files, these changes must be approved by the Director of the Office of Electric, Gas and Water. Such a request must be supported by clear and convincing support and should explain how alteration to benefits identified in Appendix O (AMI-1) of the Joint Proposal more effectively support the achievement of the benefit, if applicable, produces more benefits and/or less risk, or is done for technically reasons. Any proposals not to implement a benefit must be similarly justified. The Implementation Plan will describe how the utility will conduct outreach to vendors, other utilities, interested parties, and/or DPS Staff for input on making benefits materialize and achieve the vision discussed in Appendix O (AMI-1) of the Joint Proposal. As part of the Implementation Plan, NYSEG and RG&E will provide written updates on progress, as identified in its AMI Metrics in Appendix O (AMI-3) of the Joint Proposal. Additional interim updates will be necessary if the Companies experience significant schedule slippages or other deviations, as determined by the Director of the DPS Office of Electric, Gas and Water.

2. Vegetation Management

The Joint Proposal would increase NYSEG’s electric distribution vegetation management spending from $30 million annually to a total of $57.2 million for each of the three Rate Years. NYSEG’s routine electric distribution vegetation maintenance program would remain at the current budget amount of $30.0 million, a new Reclamation Program with a budget amount of $17.2 million per Rate Year would be added to reclaim circuits that have not been trimmed in over five years,[103] and a new

[103] The reclamation program will focus on circuits that have the worst total tree System Average Interruption Frequency performance, three-phase 34.5 kV circuits, and single phase 34.5 KV circuits. Joint Proposal, Appendix I, p. 2.

Danger Tree Program with a budget amount of $10 million per Rate Year would be added to address danger trees outside of NYSEG's distribution right-of-way, including ash trees. In addition, NYSEG would be required, after consultation with DPS Staff, to hire an independent outside contractor to provide review and oversight of NYSEG's vegetative management program.

The Joint Proposal would increase RG&E's electric distribution vegetation management spending from approximately $8.1 million to a total of $9.8 million in RY 1, $10.0 million in RY 2, and $10.2 million in RY 3. RG&E's routine electric distribution vegetative management budget would be $8.3 million in RY 1, $8.4 million in RY 2, and $8.6 million in RY 3. RG&E also would establish a new Danger Tree program with a budget amount of approximately $1.6 million for each of the three Rate Years, which would include ash trees.

Each Company would defer, with carryover, any annual Rate Year underspending on each of the identified distribution vegetation management programs. To moderate rate impacts, the costs for the Companies' danger tree programs would be deferred and amortized over five years. For example, NYSEG would spend $10 million each Rate Year for their Danger Tree Program but would collect from ratepayers a total of $2.0 million in RY 1, $4.0 million in RY 2, and $6.0 million in RY 3. The remainder would be collected over an additional four-year period following the term of the Rate Plan.

In testimony, the Companies requested incremental funding for distribution vegetation management in the total amount of $82.2 million for NYSEG and $9.6 million for RG&E. RG&E proposed to continue its five-year full-cycle vegetation management trimming program and NYSEG proposed to move to a five-year full-cycle distribution vegetation management program.[104] NYSEG's proposal included a budget of approximately $70.4 million in annual average costs for a five-year reclamation period, with an 18-month "ramp up" period and a ten-year amortization period.[105]

Nucor Steel opposed NYSEG's proposal to transition to a full-cycle distribution vegetation management program by first accelerating its spending through a reclamation program, stating that the customer impacts would be excessive and that NYSEG's efforts instead should target danger trees and address conditions at worst performing circuits.[106] RCI noted that many public commenters opposed NYSEG's requested increases and believed that the Companies' requested increases for reclamation should be paid by shareholders.[107] PULP stated that NYSEG's proposed reclamation costs were due to the lack of a system-wide trim cycle and should be recovered over a longer period of time than proposed by the Company in order to lower impacts on ratepayers.[108]

DPS Staff agreed with RG&E's initial proposal but not NYSEG's.[109] In addition, DPS Staff proposed that the Companies no longer be subject to vegetation management negative revenue adjustments (NRAs) for the failure to meet annual mileage targets because RG&E consistently has met its annual mileage

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[104] Currently, only NYSEG's service territories in Dutchess County are on a full five-year trimming cycle. Tr. 76.

[105] Ex. 41, Companies' Vegetation Management Panel Direct Testimony, pp. 4-5.

[106] Ex. 141, Radigan Direct Testimony, p. 5, 23-25.

[107] Ex. 220, Carol Chock Direct Testimony, p. 30.

[108] Ex. 259, Corrected Direct Testimony of William D. Yates, pp. 9, 30-31.

[109] Ex. 190, DPS Staff Vegetation Management Panel Testimony, pp. 11-14.

targets and NYSEG "historically has done a good job meeting their mileage targets."[110] DPS Staff also stated that the imposition of NRAs on NYSEG could have the undesired effect of making NYSEG focus trimming efforts on easier circuits to meet mileage goals rather than addressing more difficult circuits that have not been trimmed in several years.

The Joint Proposal essentially adopts DPS Staff's testimonial position. The Companies maintain that the enhanced electric distribution vegetation management programs provided for in the Joint Proposal will benefit customers because they are expected to reduce tree-related outages, which are a leading cause of service interruptions. The Companies assert that the proposed programs also have the potential to reduce storm restoration time and costs, improve system reliability, improve public safety, and reduce customer trim requests and associated costs.[111] The Companies state that the Joint Proposal takes significant steps to bring NYSEG closer to a full-cycle vegetation management program and appropriately balances rate impacts with NYSEG's vegetation management needs.

DPS Staff states that the increased funding provided for in the Joint Proposal will allow the Companies to improve system reliability by reducing tree-related outages. Although DPS Staff recognizes that the Joint Proposal does not place NYSEG on a five-year vegetation management cycle, it maintains that the Joint Proposal provides a "measured, cost conscious increased tree trimming budget with reliability at the forefront" and "reasonably balances a substantial increase in funding for vegetation management expenses and bill impact

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[110] Id., pp. 24-25.

[111] Companies' Statement in Support of Joint Proposal, p. 25.

mitigation."[112] DPS Staff notes that the program proposed for NYSEG focuses on reclamation efforts on circuits that have had reliability issues.

PULP and AARP acknowledge that vegetative management program spending for NYSEG is significantly higher in this proposal than in NYSEG's prior rate plans. However, PULP, AARP and the Indicated Environmental Parties oppose the Joint Proposal for failing to provide sufficient funding to allow NYSEG to adopt full-cycle vegetation management, noting that NYSEG is the only electric utility in New York not on a five-year trim cycle and stating that NYSEG has a greater outage rate due to trees touching power lines than any other New York utility. PULP also states that the Joint Proposal does not specify the duties of the independent outside contractor. AARP and the Indicated Environmental Parties argue that appropriate funding for NYSEG's vegetative management has fallen short as a result of prior Joint Proposals and remains insufficient here, resulting in vegetation management programs that do not provide safe and adequate service at just and reasonable rates. They argue that the Commission and DPS Staff have a long history of noting the deficiencies in NYSEG's vegetation management programs, and the Indicated Environmental Parties question why DPS Staff "could not use the strong arm of their regulatory authority to hold the Company accountable while also achieving the 5-year trim cycle that everyone agrees is recommended."[113] The Indicated Environmental Parties also state that NYSEG

[112] DPS Staff Reply Statement in Support of the Joint Proposal, p. 10.

[113] The Indicated Environmental Parties Statement in Opposition to the Joint Proposal as it Relates to the Companies' Electric Businesses, p. 15.

customers should not have to pay $17.3 million per year for reclamation of problem areas that NYSEG created.

The Commission has recognized that NYSEG frequently treated distribution vegetation management as a low priority prior to 2010.[114] An aggressive vegetation management program designed to decrease tree-related outages and improve reliability is of critical importance, especially in light of the tree-related power outages that NYSEG has experienced in recent years.[115] In addition, the Commission has stated that continued progress towards implementing full cycle vegetation at NYSEG is needed.[116] Since 2010, NYSEG has been making incremental progress toward a full cycle vegetation management program.[117] The budget for the distribution vegetation management programs proposed for NYSEG is almost double that of

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[114] Case 13-E-0117, New York State Electric & Gas Corporation Petition for Authorization to Implement Full-Cycle Distribution Vegetation Management, Order Denying Petition and Establishing Further Procedures (issued October 1, 2013), pp. 9-11; see also, Case 09-E-0715 et al., NYSEG and RG&E Electric and Gas Rates, Order Establishing Rate Plan (issued September 16, 2010), p. 65.

[115] See, Case 20-E-0045, In the Matter of 2019 Electric Reliability Performance in New York State, Staff 2019 Electric Reliability Performance Report (issued June 11, 2020), pp. 16-18; see also, Case 19-M-0285, In the Matter of Utility Preparation and Response to Power Outages During the March 2018 Winter and Spring Storms, Staff 2018 Winter and Spring Storm Report (issued June 17, 2019); Case 17-E-0594, Investigation into March 2017 Windstorm Related Power Outages, Staff Report on NYSEG and RG&E Electric Restoration and Communication Efforts (issued November 16, 2017).

[116] Case 13-E-0117, supra, Order Denying Petition and Establishing Further Procedures, p. 11.

[117] See, Case 09-E-0715 et al., supra, Order Establishing Rate Plan, p. 15; Case 15-E-0283, NYSEG and RG&E Electric and Gas Rates, Order Approving Electric and Gas Rate Plans in Accord with Joint Proposal (issued June 15, 2016), pp. 15, 35-36.

NYSEG’s current budget. While a five-year full-cycle vegetation management program remains the goal for NYSEG, we find that the distribution vegetation management programs proposed here appropriately bring NYSEG closer to that goal.

Although PULP blames the Joint Proposal process for not resulting in a full-cycle program for NYSEG in these cases, we find that view to be speculative. To be sure, the Joint Proposal process does involve compromise and concession. However, not all optimal results are accessible within the context of any rate case -- whether resulting from a Joint Proposal or full litigation -- if the Commission is also acting to protect ratepayers from unreasonable rate increases. For example, in this case, DPS Staff testified that NYSEG did not justify the costs for a full-cycle vegetation management program and raised various concerns with NYSEG’s proposal.[118] We are not addressing the merits of that testimony here, but note it only to establish that adoption of a full-cycle vegetation management program for NYSEG would not have been a foregone conclusion if this case had been fully litigated.

We believe that the distribution vegetation management plan in the Joint Proposal appropriately balances the need for increased vegetation management at NYSEG and the goal of moderating rate increases. As stated by DPS Staff, the Joint Proposal reasonably increases the scope of “NYSEG’s vegetation plan by tying all increased expenditures directly to circuits with poor reliability performance, while attempting to keep rate impacts to a minimum.”[119] Regarding PULP’s contention that the Joint Proposal lacks specific reference to the duties of the

[118] Ex. 190, DPS Staff Vegetation Management Testimony, pp. 9-11.

[119] DPS Staff Reply Statement in Support of the Joint Proposal, p. 10.

independent contractor, we note that the contractor's role will be defined in consultation with DPS Staff.

Moreover, we do not find the argument that ratepayers should not pay for the $17 million per year for NYSEG's reclamation program costs to be compelling and agree with DPS Staff that vegetation management costs are appropriately recovered from all customers who benefit from the results.[120] For both Companies, customers would continue to be protected by a downward-only reconciliation mechanism for vegetation management expenses, such that any shortfall in the amount expended by the Companies from funding level targets will be deferred for use in subsequent years. Finally, NYSEG's vegetation management program would be subject to review and oversight by an independent outside contractor hired by NYSEG after consultation with DPS Staff. Under all the circumstances, we find the proposed distribution vegetation management provisions reasonable and in the public interest.[121] As we have stated, we modify the Joint Proposal's Danger Tree Programs so that each rate year's expenses are recovered over ten years, and modify NYSEG Electric's Reclamation Program so that each year's costs are collected over ten years as well.

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[120] DPS Staff Reply Statement in Support of the Joint Proposal, p. 11. In testimony filed in the Companies' two prior rate cases, DPS Staff has stated that NYSEG has spent its allotted tree trimming budgets

[121] To the extent that commenters maintain that the Companies should remove from property the trees and branches they have trimmed, DPS Staff testified that, consistent with other utilities in New York State, the Companies have specifications on how to deal with wood waste and that property owners should be able to remove the wood waste on their own if the Companies those specifications. Ex. 190, Vegetation Management Panel Testimony, p. 9. We agree with DPS Staff that the Companies should not be removing tree waste using ratepayer dollars. Id.

3. Substation Modernization

The Joint Proposal would decrease NYSEG's initially proposed capital spending for substation modernization by $125 million over the 2020-2023 period.[122] AARP and the Indicated Environmental Parties object to this portion of the Joint Proposal, alleging that it "fail[s] to adequately maintain decaying substations."[123] They further argue that it is "not in the public interest for DPS Staff to deny funding to allow basic maintenance projects to proceed." AARP and the Indicated Environmental Parties do not offer evidence of the dollar amount of the need for substation modernization. Instead, they rely on DPS Staff's testimony that modernization is needed while objecting to DPS Staff's testimony that the initially requested capital spending allowance should be denied because the Companies failed to justify their proposed capital budget for these expenditures.[124] Apparently, although it is not entirely clear from their filings, AARP and the Indicated Environmental Parties support an allowance for substation modernization in the amount of the Companies' initial request. AARP reiterates its concerns in its Post-Hearing Brief, noting that the amount of funding in the Joint Proposal would address only between five and 10 substations in NYSEG's 432 substation system.[125]

DPS Staff agrees that it questioned in its testimony the scope, timing and cost estimates for some projects and opposed as unnecessary NYSEG's plan to hire an outside

[122] Response to ALJ Request No. NYRC-1490 (ALJ-2), attached to NYSEG/RG&E Reply Statement in Support of Joint Proposal.

[123] AARP and Indicated Environmental Parties Statement of Opposition to Joint Proposal, p. 7.

[124] Id., p. 16.

[125] AARP Post-Hearing Brief, p. 9.

consultant to survey all substations.[126] DPS Staff also agrees that the Joint Proposal did not fund everything the Companies requested, and that in several instances the funding was provided at a lower level than the Companies requested.[127] DPS Staff argues that it supported many projects that were appropriately justified. DPS Staff further argues that the substation modernization program was discussed at length during the confidential settlement meetings and that the signatory parties reached a reasonable compromise that was a fraction of the original request. DPS Staff asserts that the settlement in the Joint Proposal appropriately balances the requirement for safe and reliable service with the need to limit rate increase pressures. DPS Staff finally argues that the public interest is protected by the downward-only net plant reconciliation for the substation modernization project in the Joint Proposal, ensuring that ratepayers will be protected to any extent that NYSEG spends less than the agreed-upon amount.[128]

We conclude that the Joint Proposal represents a reasonable compromise between the Companies’ and DPS Staff’s initial positions. We agree with AARP and the Indicated Environmental Parties that ongoing substation modernization is essential for the provision of safe, reliable and adequate service. We are also concerned that the proposed amount appears to cover only a small subset of NYSEG’s substations. However, AARP and the Indicated Environmental Parties do not offer evidence of a specific necessary amount of expenditures beyond their apparent reliance on the Companies’ original proposal, which the Companies themselves are no longer supporting.

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[126] DPS Staff Statement in Reply to Opposition, p. 9.

[127] DPS Staff Reply Brief, p. 6.

[128] DPS Staff Statement in Reply to Oppositions, pp. 9-10.

We agree with DPS Staff that it is necessary to balance the amount of allowed expenditures against the burden of rate increases, and we note that AARP and the Environmental Parties object to “unjustified spending on capital projects” in other areas of this case[129] and argue that the overall proposed rate increase is too high.[130] We find that DPS Staff offered significant evidence and made cogent arguments in its testimony against the full initially requested allowance for the substation modernization program. This testimony could have supported significant disallowances from the Companies’ original request in a fully litigated case. This issue is clearly appropriate for a compromise, and we see no basis in the record for a compromise at an amount other than the amount proposed in the Joint Proposal.

Under these circumstances, we see no basis to upset the compromise in the Joint Proposal between the Companies’ and DPS Staff’s original positions, and we deny the objection of AARP and the Indicated Environmental Parties.

4. Other Capital Projects

AARP, the Indicated Environmental Parties and various commenters point to the pre-filed direct testimony by DPS Staff’s Electric Infrastructure and Operations Panel as establishing that the Joint Proposal contains capital projects for which the Companies provided little or no support.[131] In

129 AARP and Indicated Environmental Parties Statement of Opposition to Joint Proposal, p. 7.

130 Id., p. 6.

131 AARP Statement in Opposition to the Joint Proposal, pp. 23-25; The Indicated Environmental Parties Statement in Opposition to the Joint Proposal as it Relates to the Companies’ Electric Businesses, pp. 10-12; Afternoon Public Statement Hearing on August 26, 2020, pp. 44-45, 52-53, 61-62, 76-77; Evening Public Statement Hearing on August 27, p. 41.

making this argument, AARP, the Indicated Environmental Parties and the various commenters overlook further developments after DPS Staff filed its direct testimony.

In direct testimony, DPS Staff stated that the Companies provided inadequate information in support of various capital projects and raised concerns about the Companies' internal capital budget and review process with respect to the documentation provided to senior management for review and approval of capital projects.[132] Specifically, DPS Staff stated that the Companies did not provide adequate information in support of the following capital projects: the Bulk Electric System (BES) Program, the NERC Alert Priority III Program, the Rochester Area Reliability Project (RARP), NYSEG's Betterments Project, NYSEG's Substation Circuit Breaker Replacement Program, NYSEG's Non-AMI DSIP Grid Automation Project, NYSEG's Substation Modernization Program and NYSEG's Resiliency Plan Projects. DPS Staff recommended various adjustments to the Companies' capital budget requests for those programs and projects.

However, in rebuttal testimony, the Companies explained that, pursuant to project management best practices, capital projects have four major phases – initiation, planning, execution and closure. The Companies stated that the information available and presented to senior management as a project evolves through those phases is different and explains why the same level of justification and project level detail is not available for every project. The Companies also stated that, in response to Staff's testimony and based upon feedback from a recent management audit, they were redesigning their Capital Planning and Investment Decision Making Process to

[132] Ex. 197, DPS Staff Electric Infrastructure and Operations Panel Testimony, pp. 20-25.

reflect the best practices and experience of their affiliates.[133] Finally, the Companies provided further testimony and multiple exhibits in rebuttal to justify the specific projects and programs that DPS Staff initially indicated had lacked sufficient support.[134]

In its Reply Statement in Support of the Joint Proposal, DPS Staff states that its initial testimony recommended adjustments to the specified capital projects based on the information known at that time, but that the "Companies have provided additional information supporting projects through the discovery process and during confidential settlement negotiations."[135] DPS Staff represents that sufficient justification and support for the specified capital programs and projects has been submitted given the "considerable additional information" the Companies provided in rebuttal, the Companies' responses to various discovery requests, and as a result of several discussions by a Capital Expenditure Settlement Working Group that further refined the electric capital expenditures during settlement negotiations.[136]

We conclude that sufficient justification has been provided for the specified capital projects, many of which are continuing from prior rate plans, and determine that those projects and programs are in the public interest. The BES Program, for example, includes various projects to improve transmission reliability, modernize the Companies' bulk power

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[133] Ex. 80, Companies' Electric, Generation and Common Capital Expenditures Panel Rebuttal Testimony, pp. 8-9.

[134] Ex. 80, Companies' Electric, Generation and Common Capital Expenditures Panel Rebuttal Testimony, pp. 14-35; Exs. 110-129, 134, 135, CEE-R1 to CEE-R8.

[135] DPS Staff Reply Statement in Support of Joint Proposal, p. 8.

[136] Ex. 332, Response to ALJs' Question 9.

systems, and comply with various security and reliability requirements. As DPS Staff states, the "various projects categorized in the BES program will improve reliability and modernize the Companies' bulk power systems."[137] The remaining capital projects and their purposes are set forth in the footnote below.[138]

The proposed budgets for the specified capital projects are the result of compromise between the signatory parties in these proceedings and ensure that the Companies are implementing capital projects that will allow them to continue to provide safe and adequate service. Accordingly, we adopt the capital programs and projects that are included in Appendix R to the Joint Proposal.

Finally, although not referenced in the Joint Proposal, the Companies testified that they were redesigning

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[137] DPS Staff Reply Statement in Support, p. 9.

[138] The NERC Alert Priority III Program seeks to bring all 115 kV transmission lines in compliance with ground clearance standards established by the North American Electric Reliability Corporation. The Rochester Area Reliability Project is a large transmission capacity addition project to reinforce RG&E's transmission system. NYSEG's Betterments Project funds multiple smaller projects for the improvement of reliability, including reconductoring, pole replacements, switch replacements, regulator replacement and transformer replacement. NYSEG's Substation Circuit Breaker Replacement Project would allow for the replacement of and upgrades to circuit breakers that are in need of replacement and are obsolete. NYSEG's NON-AMI DSIP Grid Automation Project includes automating distribution single and three phase reclosers, single and three phase Supervisory Control and Data Acquisition switches, capacitor banks and voltage regulators. The Resiliency Plan projects seek to improve the Companies' electric systems to better withstand storms or other circumstances that may power interruptions. The Substation Modernization Projects involve upgrades to the Companies distribution substations, including increased remote monitoring and control capabilities.

their Capital Planning and Investment Decision Making Process and hoped to begin implementation in January 2020. Accordingly, we direct the Companies, within 90 days after issuance of this Order, to file a report with DPS Staff as to the status of their implementation of the redesigned Capital Planning and Investment Decision Making Process. The Companies and DPS Staff should confer as to the substance of such report and whether additional reports will be required. We expect that, if necessary, the Companies will work collaboratively with DPS Staff to ensure that the updated Capital Planning and Investment Decision Making Process appropriately addresses concerns raised in DPS Staff's direct testimony in these proceedings.

G. The Senior Study

The Joint Proposal requires NYSEG/RG&E to undertake seven special studies,[139] including a Senior Study that will "identify potential partnerships for senior customer outreach concerning EE opportunities, low income discounts and other senior customer-related opportunities."[140]

Appendix N of the Joint Proposal establishes the scope of the Senior Study, which includes the identification of potential partnerships and associated activities for senior customer outreach concerning energy efficiency opportunities, low income discounts, and other senior customer-related opportunities, and research into utility "best practices" in

[139] In addition to the Senior Study, the Joint Proposal provides that NYSEG/RG&E will conduct a Natural Gas System Resiliency Study, a Renewable Natural Gas Study, a Geothermal – District Energy Study, an Overall Natural Gas and Grid Modernization Report, a Depreciation Study Reflecting the CLCPA, and a Street Light Replacement Cost Study. Joint Proposal, ¶ XVII(J), p. 35; Appendix N.

[140] Joint Proposal, ¶ XVII(J), p. 35.

other States and service territories that have a higher than average percentage of seniors as customers.[141] The Joint Proposal also provides that interested parties will have additional opportunities for input into the scope of the Senior Study and that study results will be provided to them, but in only “some cases” will be filed with the Secretary.[142]

The Joint Proposal caps the costs associated with all seven special studies at $750,000, allocated between electric and gas customers, and provides that up to $500,000 will be devoted to two of the seven studies, the Natural Gas and Grid Modernization Report and the CLCPA Depreciation Study.[143] Thus, five of the seven studies, including the Senior Study, will share in the remaining funding of approximately $250,000. Notably, the Joint Proposal indicates that if the Commission initiates a separate statewide proceeding related to any of the seven studies, NYSEG/RG&E need not “necessarily” submit a study.[144]

In arguing that the Joint Proposal is not in the public interest, AARP asserts that the Senior Study does not balance the high rate increases that will be realized by customers in

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[141] Joint Proposal, Appendix N, p. 2. The scope of work for the Senior Study is expressly framed as follows:

> The Companies agree to conduct a study to identify potential partnerships for senior customer outreach concerning energy efficiency opportunities, low income discounts and other senior customer-related opportunities. The Companies will coordinate such study with DPS Staff. The scope of the study will include the identification of potential partnerships and associated activities. As part of the study, the Companies will research best practices of utilities in states/service territories that have higher-than-average percentages of seniors as customers.

[142] Joint Proposal, Appendix N, p. 2; Tr. 112-113.

[143] Id., p. 1.

[144] Id., p. 2.

the Rate Years when viewed with the Companies' poor reliability.[145] AARP claims that the Companies do not know the percentage of customers that are seniors in their service territories or the percentage of seniors who are participants in the Companies' energy efficiency programs.[146] AARP also claims that the term "senior" is not defined in the settlement document (Tr. 104, lines 21-24) and that DPS Staff is unconcerned about senior participation in the Companies' energy efficiency programs.[147] Finally, AARP complains that the Companies have refused to commit to implement the results of the Senior Study as part of the Joint Proposal.[148]

In its Statement in Support of the Joint Proposal, DPS Staff supports the objectives of the Senior Study and identifies what is expected from it:

> Increased outreach efforts to improve senior customer involvement related to energy efficiency, low income discounts, and other opportunities are reasonable and have the potential to increase this customer group's involvement and knowledge of the Companies' different programs, particularly those that may be beneficial to seniors on limited incomes. Given the growing numbers of customers who are aging into this demographic group, it is essential that their specific needs and concerns be studied and evaluated in order to establish best practices in providing assistance to these customers. The Companies are expected to work with Staff on this study and Staff finds the scope of the study to be reasonable and likely to provide actionable methods to improve customer service, and therefore it should be adopted.[149]

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[145] AARP Statement in Opposition, p. 11, n. 12.

[146] AARP Post-Hearing Brief, pp. 9-10 (citing Tr. 104-105).

[147] Tr. 103.

[148] Tr. 109.

[149] DPS Staff Statement in Support of Joint Proposal, p. 69.

DPS Staff also notes that the results of the Senior Study should benefit AARP's constituents and is a collaborative process in which all parties can participate.[150]

Discussion

We find that the Senior Study is intended to generate the kind of information that will further the public interest and may set forth specific proposed measures to be implemented for the benefit of senior citizens in the Companies' service territories.[151] We are concerned that both the Joint Proposal and the scope of work for the Senior Study in Appendix N lack the kind of detail necessary to assure that relevant information is generated in the Study and that the Companies recommend a definite plan of action on an established timeline for the benefit of senior citizens. The absence of these details in the Joint Proposal is not fatal to its overall merits, however, particularly in light of DPS Staff's position in its Statement in Support noting that the Senior Study is "likely to provide actionable" measures (emphasis added).[152] Thus, in adopting the Joint Proposal we clarify that the Companies are expected to set forth in the Senior Study actionable measures to be implemented for the benefit of seniors in their respective service territories on an established timeline. In the next rate case, the Commission may review, with DPS Staff's recommendations, the implementation of such measures.

We note that the Senior Study is only one of seven studies to be undertaken by the Companies. We believe that this general criterion – proposing actionable measures on a proposed timeline for consideration in the next rate case - should be

[150] DPS Staff Reply Brief, p. 6.

[151] Joint Proposal, Appendix N, p. 1.

[152] DPS Staff Statement in Support of Joint Proposal, p. 69.

applicable to all other required studies identified in the Joint Proposal. Specifically, those studies should generate relevant information and should set forth recommendations and a plan of action for implementation of proposed measures on a set timeline. This criterion assures that the studies required here under the Joint Proposal are cost-effective and result in meaningful action for the benefit of ratepayers.

In challenging the Senior Study, AARP complains that the Companies have not agreed to implement the study results or recommended measures. We do not believe that the Companies should agree now to implement results and measures that are not known at this time, particularly because the implementation costs relative to the anticipated benefits will have to be weighed before any implementation plan is developed. As part of its next rate plan, we expect the Companies to address the issue of implementation. AARP also complains that the word “senior” is not defined in the Joint Proposal for purposes of the Senior Study.[153] While AARP states that it has numerous members who are 50 years of age and over, a common understanding of the term “senior” would cover a range of ages starting between 60 to 65 years of age. However, we have no basis in the record to establish when a person should be considered a “senior” for purposes of the Senior Study and direct the Companies, with input from DPS Staff and other interested stakeholders, to determine this issue as part of the Senior Study. Finally, we clarify the Joint Proposal’s provision that purports to authorize NYSEG/RG&E from not “necessarily” having to submit the reports required under the Joint Proposal if a report related to

[153] AARP Post-Hearing Brief, pp. 9-10.

the same issues is required in any separate statewide proceeding initiated by the Commission.[154]

We believe that this provision could result in future disputes between the Companies, DPS Staff, and interested parties regarding whether a particular report, including the Senior Study, is covered in a statewide proceeding or is required in this one. The sheer breadth of the issues addressed in the seven studies required under the Joint Proposal here (e.g., Natural Gas System Resiliency Study, Renewable Natural Gas Study, Geothermal – District Energy Study, Overall Natural Gas and Grid Modernization Report, Depreciation Study Reflecting CLCPA, and a Street Light Replacement Cost Study) make this provision more far-reaching and potentially problematic if the Commission initiates a separate statewide proceeding about any of those issues.

We view this provision in the Joint Proposal to be subject to further Commission action for purposes of determining the Companies' obligations in both this and any separate statewide proceeding. To the extent that the Companies believe that they need not necessarily submit one or more of the seven reports required under the Joint Proposal, they shall first advise DPS Staff and then seek leave from the Commission to

[154] Joint Proposal, Appendix N, p. 2. This provision states: "To the extent the Commission institutes a statewide proceeding or initiative to study any of the subjects covered by the above-identified studies, <u>NYSEG or RG&E will not necessarily prepare or provide a separate report or study. The Companies will continue to produce their own report or study for any items not included in a statewide study or initiative</u>." (Emphasis added.) This provision is ambiguous and could also be read to authorize the Companies to refrain from submitting the appropriate report in the statewide proceeding, thereby representing an improper attempt to limit the Commission's authority in that proceeding. We reject this reading of the Joint Proposal.

forgo the required submission. In the event that the Commission determines that a report required under this Joint Proposal is unnecessary, it will determine the use of the remaining allocated funds for those reports.

H. Revenue Allocation

1. Electric Businesses

Initially, the Companies, Staff and intervenor parties sponsored testimony in these proceedings reflecting different positions regarding the appropriate Embedded Cost of Service (ECOS) studies to be relied upon and the methodologies to be used in determining how the Companies' revenue requirements should be allocated among customer classes. For example, UIU argued that in addition to the ECOS study classifying numerous electric distribution plant accounts as 50 percent customer related and 50 percent demand related, the Companies also should have considered their ECOS study classifying costs as 100 percent demand related in determining revenue allocation. In reaching a consensus on revenue allocation, the signatory parties agreed that the revenue allocation would not reflect any one ECOS study sponsored by any specific party to these proceedings.[155] The Companies also agreed to develop a method to perform a zero-intercept or minimum system study or other equitable allocation for classifying electric distribution plant between customer and demand and would file ECOS studies based on the results of that analysis in their next rate cases. They additionally agree to file in their next rate cases ECOS studies that classify certain accounts using a 50 percent demand/50 percent customer basis.

The electric revenue allocation process presented in the Joint Proposal consists first of separate allocations to

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[155] Joint Proposal, Appendix BB, p. 2.

service classes for energy efficiency costs associated with the EE Tracker, energy efficiency costs associated with heat pumps, AMI costs associated with IT infrastructure, AMI costs associated with all other investments and expenses, and distribution vegetation management costs for NYSEG. The remaining revenue requirements are allocated to service classes as set forth in Schedule C to Appendix B. The electric delivery revenue increases also account for adjustments to standby rates.

2. Gas Businesses

As with the electric businesses, the Companies, DPS Staff and various other parties offered different views on the type of ECOS studies and methodologies that should be used in allocating gas business revenues. For example, in pre-filed testimony, DPS Staff and MI recommended the use of an ECOS study with gas distribution mains allocated 50 percent demand and 50 percent customer.[156] UIU supported the allocation of distribution mains as 100 percent demand related.[157] Initially the Companies proposed to classify gas distribution mains as 100 percent demand, but modified their position in rebuttal testimony to allocate gas distribution mains 50 percent to demand and 50 percent to customers.[158] Similar to the treatment of the electric businesses, the gas revenue allocation in the Joint Proposal is not based any one ECOS study sponsored by any party and represents a compromised resolution. In addition, the Companies agree to provide in their next rate cases ECOS studies based on a zero-intercept or minimum system study or other equitable allocation for classifying gas distribution mains

[156] Ex. 334, DPS Staff Gas Rates Panel Testimony, pp. 6, 16-19; Ex. 148, Direct Testimony of Jeffry Pollack, pp. 29-35.

[157] Ex. 215, Direct Testimony of UIU Rate Panel, p. 29.

[158] Ex. 73, Rebuttal Testimony of David A. Heintz, pp. 15-16.

between customer and demand and ECOS studies that classify distribution mains as 100 percent demand-related.

The gas revenue allocation process presented in the Joint Proposal consists first of separate allocations to service classes for energy efficiency costs associated with the EE Tracker, AMI costs associated with IT infrastructure, and AMI costs associated with all other investments and expenses. The remaining revenue requirements are allocated to service classes as set forth in Schedule C to Appendix D. For NYSEG, revenue for the interruptible service classes are calculated based on discounted rates and allocated to all firm service classes except for SC No. 5 – Seasonal Gas Cooling Sales Service. Consistent with the 2020 Energy Efficiency Order, EE Tracker costs for energy efficiency programs will no longer be collected through an SBC and will be included in base delivery rates.[159]

3. Parties' Revenue Allocation Comments

The Companies, DPS Staff, MI and Nucor Steel are the only parties to comment specifically on the revenue allocations in the Joint Proposal, all agreeing with the resolution of the various issues regarding ECOS studies. The Companies state that the residual revenue requirement allocations to service classes was accomplished in a revenue neutral manner that addresses interclass surpluses and deficiencies, while considering overall customer impacts.[160] The Companies state that the Joint Proposal represents the product of extensive negotiations and agreement on revenue allocation among normally adverse parties and that

[159] Case 18-M-0084, Comprehensive Energy Efficiency Initiative, Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios through 2025 (issued January 16, 2020) (2020 Energy Efficiency Order), pp. 32, 65-66.

[160] Companies' Statement in Support of Joint Proposal, p. 59.

the proposed revenue allocation “moves toward a more cost-based rate design.”[161]

DPS Staff supports the methodologies used to determine the electric and gas revenue allocations in the Joint Proposal. DPS Staff states that the discrete allocations of certain costs are reasonable for various reasons, will mitigate bill impacts and will make bill increases more gradual.[162] DPS Staff states that the revenue allocations are intended to gradually move cost recovery to more closely align with costs as they are incurred. DPS Staff asserts that the revenue allocations are reasonable and should be adopted.[163]

MI states that revenue allocation is among the most important issues resolved in the Joint Proposal and that the electric and gas revenue allocations negotiated by the signatory parties are “reasonably and generally consistent with the cost-of-service evidence presented in these proceedings.”[164] MI agrees with the separate allocations for specific costs and for the Companies’ residual revenue requirements as based on cost causation principles. MI states that it is unlikely that it would have supported the Joint Proposal absent a satisfactory resolution of revenue allocations issues. MI contends that the “electric and gas revenue allocations contained in the Joint Proposal are cost-based and equitable, and, therefore, should be adopted by the Commission” without modification.[165]

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161 Companies’ Statement in Support of the Joint Proposal, p. 59.

162 DPS Staff Statement in Support of the Joint Proposal, p. 107.

163 DPS Staff Statement in Support of the Joint Proposal, p. 104, 110.

164 MI Statement in Support of the Joint Proposal, pp. 4, 16, 18.

165 MI Statement in Support of the Joint Proposal, p. 18.

In Nucor Steel's view, the discrete allocation of electric business costs for EE, AMI, the heat pump initiative, and NYSEG's distribution vegetation management costs was crucial "to appropriately allocating the costs based on cost causation and producing reasonable rate outcomes for all customers."[166] Nucor Steel maintains that, in addition to various other provisions of the Joint Proposal, the revenue allocation provisions overall reflect "a delicate balancing of a variety of competing concerns."[167]

Discussion

The revenue allocations agreed upon by the signatory parties, and adopted here, are intended to gradually move cost recovery to more closely align with actual costs incurred while considering bill impacts. We agree with the Companies, DPS Staff, MI and Nucor Steel that the proposed revenue allocations are reasonable and fair to the different classes of customers that the Companies serve and in the public interest. Parties that opposed the Joint Proposal did not generally raise issues about its assignment of revenues to the different rate classes. Moreover, no party opposing the Joint Proposal demonstrated that the Joint Proposal's revenue allocations are unreasonable. Accordingly, we adopt the proposed revenue allocations without change.

I. Rate Design

1. Electric Businesses

The electric delivery revenue requirements, discussed in Appendix BB to the Joint Proposal, would be recovered through a combination of monthly customer charges, volumetric delivery

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[166] Nucor Steel Statement in Support of Joint Proposal, pp. 4-5.

[167] Nucor Steel Statement in Support of Joint Proposal, p. 4.

charges and/or demand charges. The proposed increases to customer charges are discussed in a separate section later in this Order. The revenue requirements, net of customer charges for each service class, would be recovered through volumetric delivery charges for non-demand classes and through demand delivery charges for the demand classes. For service classes with both volumetric delivery charges and demand delivery charges, priority would be given to collect the remaining delivery revenue requirement through demand charges first and then through volumetric charges. Reactive charges remain unchanged from current levels.

Competitive service rates[168] are based on the ECOS studies filed as part of the Companies' rebuttal testimony in these proceedings. The Companies' current method for calculating the Merchant Function Charge and Purchase of Receivables discount would remain in place. NYSEG's Bill Issuance and Payment Processing Charge would increase from $0.81 to $0.90 per bill and RG&E's would increase from $0.72 to $0.93 per bill. Charges for metering costs would be eliminated and recovery of metering costs would be included in base rates.

The revenue increase allocated to the area and street lighting classes would be applied on an equal percent basis to the unit rates of each class. No revenue increases would be applied to newly added Light Emitting Diode (LED) options for RY 1, but the overall average increases will be applied to those options in RYs 2 and 3. The Companies agree to conduct a street light luminaires replacement cost study and present the results in their next rate cases. The Companies also modified their

[168] Competitive service rates cover the Bill Issuance and Payment Processing Charge, the Credit and Collections/Call Center Component of the Merchant Function Charge (MRC) and Purchase of Receivables discount, and the Administrative component of the MFC. Joint Proposal, Appendix B, p. 5.

pricing methodology for street light sales, as explained on page 6 of Appendix BB to the Joint Proposal.

For standby customers, the customer charges would be set at the same level as otherwise applicable service classifications. The remaining revenue requirement associated with standby rates for each service classification would be recovered through contract demand charges and as-used demand charges in proportion to the revenues collected through current contract demand and as-used demand charges.

The optional residential plug-in electric vehicle charging rates would be updated on a revenue-neutral basis to recover the total delivery revenues of the otherwise applicable service classes for each Rate Year. The customer charge is set at the same level as the SC No. 1 customer charge. The remaining revenue requirements would be recovered through peak and off-peak volumetric charges, in the same proportion as the Companies’ current peak and off-peak volumetric charges.

The rates under NYSEG’s ESC Rate Option Pilot are updated on a revenue-neutral basis to recover the total delivery revenues of the otherwise applicable service classes. The customer charges are set at the same level of the customer charges of the otherwise applicable service classes. For service classes with both volumetric delivery charges and demand delivery charges, the volumetric charges are set at the same rate as the otherwise applicable service classes. Reactive charges remain unchanged from current levels. The remaining delivery revenue requirement is recovered through peak and off-peak delivery charges of the respective service classes, in the same proportion as the current delivery charges.

For the Companies’ Economic Development customers, the discounted rates offered under NYSEG’s Economic Development Zone Incentive Program, RG&E’s Empire Zone Rates, and the Companies’

Excelsior Jobs Programs are updated based on the results of the marginal cost of service (MCOS) studies the Companies' filed in these proceedings.

2. Gas Businesses

The gas delivery revenue requirement for firm service classes would be recovered through customer charges and volumetric delivery charges. The proposed increases to customer charges are discussed in a separate section later in this Order. The revenue requirement, net of the customer charge revenue, would be recovered through volumetric delivery charges in proportion to the respective block rates for each service class.

For interruptible service classes, volumetric delivery rates would be capped at 70 percent of the customers' otherwise applicable service class's firm volumetric delivery rates. Customer charges for interruptible service classes would be set at the same level as the otherwise applicable service classes.

Delivery rates for stated Distributed Generation (DG) service classes designed in accordance with Commission orders[169] would be updated and the existing relationships between the DG rates of those service classes and the rates of the non-DG service classes would be maintained.

Competitive service rates are based on the ECOS studies filed as part of the Companies' rebuttal testimony in these proceedings. The Companies' current method for calculating the Merchant Function Charge and Purchase of Receivables discount would remain in place. NYSEG's Bill

[169] Case 02-M-0515, Proceeding on Motion of the Commission to Establish Gas Transportation rates for Distributed Generation Technologies, Order Providing for Distributed Generation Gas Service Classifications (issued April 24, 2003); Order Granting Rehearing in Part and Clarifying Order (issued December 3, 2003); Order Providing for Gas Service for Residential Distribution Generation (issued August 4, 2004).

Issuance and Payment Processing Charge would increase from $0.81 to $0.90 per bill and RG&E's would increase from $0.72 to $0.93 per bill.

For the Companies' Economic Development customers, the discounted rates offered under NYSEG's Economic Development Zone Incentive Program, RG&E's Empire Zone Rates, and the Companies' Excelsior Jobs Programs are updated based on the results of the Companies' MCOS studies in these proceedings.

Several modifications are proposed for the Gas Interruptible Service. NYSEG would provide gas interruptible service throughout its entire service territory and would eliminate the Incremental Interruptible Transportation Service. The minimum use requirement for customers to qualify for gas interruptible service at NYSEG would be 40,000 therms per month for the period from November through March. In constrained areas, as determined by the Companies, the minimum use requirement may be waived because the Companies would not have the ability to serve customers on a firm basis. Any difference between actual interruptible delivery revenues and any amount of delivery revenues that are embedded into base delivery rates would be reconciled annually and recovered or returned to all firm customers. Any credit or surcharge associated with the interruptible allocation would be included with the Revenue Decoupling Mechanism credit or surcharge on customer bills. The manner by which supply pricing for interruptible customers would be determined for each Company is set forth at pages 5-7 of Appendix DD to the Joint Proposal.

3. Parties' Comments on Rate Design

The Companies, DPS Staff, MI, Nucor Steel, NYPA and Walmart are the only parties that commented on the proposed rate design in the Joint Proposal. The Companies state that rate designs in the Joint Proposal represent a reasonable compromise between parties that frequently take adversarial positions and fairly balance the interests of the Companies, DPS Staff and the parties. The Companies assert that they agreed to significant modifications to their gas interruptible rates and tariffs that were recommended by DPS Staff to make interruptible service consistent with similar services by other New York gas utilities.

DPS Staff asserts that the electric and gas rates proposed in the Joint Proposal are within the range of changes advocated in testimony by the Companies, DPS Staff, and MI and, additionally, by Nucor Steel as to electric rates.[170] DPS Staff supports the proposal to maintain the relationship between the DG service classes and the rates of the non-DG service classes. DPS Staff maintains that the proposed rates are just, reasonable and in the public interest.

MI states that it supports the numerous agreements relating to rate design for large non-residential service classes that are reflected in the Joint Proposal.[171] MI states that the electric standby rate design makes sense and avoids potential rate design changes that might conflict with any actions that may be taken generically with respect to standby rate design.[172] In MI's view, the electric and gas rate designs are generally consistent with the cost-of-service evidence

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[170] DPS Staff Statement in Support of the Joint Proposal, pp. 109, 113.

[171] MI Statement in Support of the Joint Proposal, pp. 18-20.

[172] MI Statement in Support of the Joint Proposal, p. 20, citing Case 15-E-0751, In the Matter of the Value of Distributed Energy Resources, Notice Announcing Standby Rate Design Stakeholder Forum and Soliciting Comments (issued November 5, 2019), and Notice Extending Comment Period Related to Allocated Cost of Service Studies, and Standby and Buyback rates (issued December 24, 2019).

presented in these proceedings and should be adopted without modification.

Nucor Steel states that the Joint Proposal appropriately addresses the shift in energy efficiency cost recovery from the SBC to base rates by establishing a bill crediting mechanism for those customers that are currently exempt from the SBC. Nucor Steel also states that the increase to the customer charge for large industrial users is a more appropriate way to design rates for that class of customers than applying the class revenue increase to the demand charge.[173]

NYPA supports the change to the Companies' pricing methodology for street lights. NYPA states that the compromise reflected in the Joint Proposal eliminates unfair charges to municipalities seeking to purchase street light systems for the purpose of adopting economically efficient LED technology and should incentivize more municipal purchases of street light facilities.[174] NYPA maintains that the resolution of the street light pricing methodology is consistent with sound environmental, social and economic policies.

Walmart states that although the Joint Proposal does not adopt its specific recommendations for the design of NYSEG's SC No. 7 and RG&E's SC No. 8 rate classes, it is "satisfied that the resulting base rate impacts under the Joint Proposal for these rate classes are reasonable and fair in comparison with the rate exposure presented" under the Companies' original rate filings.[175] Walmart also maintains that the Joint Proposal falls within the range of reasonable results had the cases been fully litigated.

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[173] Nucor Steel Statement in Support, p. 5.

[174] NYPA Statement in Support, pp. 3-6.

[175] Walmart Statement in Support of the Joint Proposal, pp. 3-4.

Discussion

The proposed rate design has been agreed to by many parties and those parties who oppose the Joint Proposal have not raised any rate design issues, with the exception of customer charges, which are discussed separately below. We agree that the proposed rate design falls within the reasonable range of results that could have been expected if these cases were fully litigated. We conclude that rate designs proposed for the various service classes are fair and equitable.

J. Gas Matters

Introduction

The following brief timeline provides context for our discussion of the Joint Proposal's gas-related provisions.

On May 20, 2019, the Companies submitted their original rate filings, requesting gas rate increases of $6.3 million (NYSEG Gas) and $5.8 million (RG&E Gas) that would result in potential average monthly bill increases for residential customers of $1.05 and $1.56, respectively.[176] The filings referenced the Companies' Capital Plans for 2019 and 2020, which included proposed investments in infrastructure totaling $229 million (NYSEG Gas) and $171 million (RG&E Gas).[177]

On July 18, 2019, Governor Cuomo signed into law the CLCPA, which, as relevant here, mandates that 70 percent of New York's electricity be generated from renewable energy sources by 2030 and that, by 2040, the State's electricity supply be 100

[176] See May 20, 2019 Filing Letter from Joseph Syta to Department of Public Service Secretary Burgess, pp. 3, 5. These figures do not reflect the movement of energy efficiency costs into base rates.

[177] Id., p. 7.

percent free of greenhouse gas emissions.[178] In September 2019, DPS Staff and various intervening parties filed direct testimony in response to the Companies' filings,[179] with several such parties specifically opposing the gas-related provisions reflected therein on the basis that they were inconsistent with the CLCPA. On March 19, 2020, the Commission commenced Case 20-G-0131, which seeks to ensure, among other things, that gas utilities minimize infrastructure investments that may have long-term financial implications for customers and implement planning and operational practices that are consistent with the CLCPA.[180]

The instant Joint Proposal was filed on June 22, 2020, with DPS Staff describing its gas-related commitments as "progressive and unprecedented."[181] According to the Companies, meanwhile, the "number of parties that are signatories to the gas provisions of the Joint Proposal[182] is a testament to the leading-edge and innovative measures that the Companies and

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[178] See chapter 106 of the laws of 2019; Public Service Law §66-p (2). As defined in the CLCPA, greenhouse gases are substances emitted into the air that are likely to cause or contribute to anthropogenic climate change (that resulting from human activity); examples include carbon dioxide, nitrous oxide, methane, sulfur hexafluoride, hydrofluorocarbons and perfluorocarbons (see Environmental Conservation Law §75-0101).

[179] Ex. 62, Corrected Updated Revenue Requirements; the Companies submitted updates to their original filings in August 2019, with revised proposed rate increase of $9.4 million (NYSEG Gas) and $4.8 million (RG&E Gas).

[180] See Case 20-G-0131, Proceeding on Motion of the Commission in Regard to Gas Planning Procedures, pp. 4, 6-7.

[181] DPS Staff Statement in Support of the Joint Proposal, p. 7.

[182] Of the 23 total signatory parties to the Joint Proposal, 9 support just the gas-related proposals.

other Signatory Parties developed to advance [New York] State's ambitious climate goals."[183]

Background

In direct testimony, the Companies' Gas and Common Capital Expenditures Panel provided "asset condition replacement and reliability" forecasts ranging from $61 million to $85 million between 2019 and 2023 at NYSEG Gas and from $47 million to $77 million during the same years at RG&E Gas.[184] Key projects referenced by the panel included purportedly necessary enhancements to the DeRuyter pipeline and to the Lansing/Freeville pipeline, both of which are located in territory serviced by NYSEG.[185]

More specifically, in order to maintain safe and reliable service for gas customers served by the DeRuyter line, the Companies proposed the replacement of approximately 50 miles of aging 8-inch and 10-inch transmission mains with 12-inch mains, at a projected five-year cost of $53 million.[186] The Lansing/Freeville project was also designed to address reliability and capacity issues, with the proposed installation of 10-inch gas main along seven miles of West Dryden Road in the Lansing and Dryden areas, where the Companies have imposed a moratorium on new customer gas service due to existing reliability concerns; anticipated expenditures would exceed $16 million between 2021 and 2023.[187]

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[183] Ex. 138, New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation Statement in Support of the Joint Proposal, p. 5.

[184] Ex. 22, Gas and Common Capital Expenditures Panel direct testimony, pp. 7, 11 (May 20, 2019).

[185] Id., p. 13.

[186] Ex. 15, NYSEG and RG&E Five Year Capital Investment Plan 2019-2023, p. 213.

[187] Id., p. 221.

Various intervening parties opposed the Companies’ gas proposals, maintaining broadly that continued reliance on natural gas as an energy source was incompatible with the CLCPA and that, specifically, both the DeRuyter and Lansing/Freeville projects should be rejected. Robert Howarth, testifying on behalf of FFT for example, argued that a significant portion of New York’s total greenhouse gas emissions, particularly methane emissions, stem from the use of natural gas; thus, accomplishing those goals set forth in the CLCPA would require an immediate decrease in its use and the cessation of any natural gas expansion.[188] A panel of witnesses representing the RPCC testified similarly, maintaining that RG&E’s intention to invest “considerable rate payer dollars” on gas infrastructure for new residential customers was misguided and counterproductive to the ambitions of the CLCPA.[189] Relying on studies performed by the International Panel on Climate Change, the RPCC suggested that delaying actions that will reduce greenhouse gas emissions – e.g., “locking-in carbon emitting infrastructure” – will have irreversible consequences; the RPCC accordingly recommended that the Companies transition away from gas infrastructure investment and implement, for example, a heat pump program with income-based incentives for broad heat pump adoption.[190]

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[188] Ex. 337, Direct Testimony of Robert W. Howarth, pp. 9-10 (September 20, 2019). Howarth is an earth system scientist currently teaching at Cornell University, who has authored more than 200 peer-reviewed articles, the majority of which pertain to global climate change.

[189] Ex. 245, Direct testimony of Kristen Van Hooreweghe, Eric Williams and Sue Hughes-Smith, pp. 3, 5 (September 20, 2019). Based on the Companies’ filings, the RPCC estimated that RG&E planned on spending $483,423,000 on gas-related investments between 2019 and 2023 (id., p. 6).

[190] Id., pp. 4-5, 11.

Irene Weiser, also testifying on behalf of FFT, likewise contended that Company funds currently dedicated to gas expansion should instead be allotted to programs such as heat pump pilot projects.[191] Referring to the Lansing/Freeville pipeline and an associated benefit-cost analysis that would consider the project's deferred value for 10 years, Weiser cited the CLCPA's requirements and opined that "there is no credible scenario in which, 10 years from now, th[at] pipeline will be built."[192] Weiser added that constructing new gas lines or expanding the capacity of existing lines to provide for increased future usage will yield yet greater greenhouse gas emissions – an outcome clearly inconsistent with New York's express policy targets.[193]

Similar concerns were raised by Dennis Higgins in connection with the DeRuyter project, where he asserted that emissions' limitations set forth in the CLCPA will render the pipeline a stranded asset for the bulk of its service life.[194] In other words, while that service life is estimated at 70 years, the CLCPA intends the elimination of the fossil fuel market by 2050; thus future ratepayers should not be saddled

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[191] Ex. 286, Direct Testimony of Irene Weiser, pp. 22-23 (September 20, 2019). Weiser is a retired veterinarian and the co-founder of Fossil Free Tompkins, which she describes as "an unincorporated renewable energy advocacy campaign in Tompkins County (id., p. 3).

[192] Id., p. 21.

[193] Id., p. 26.

[194] Ex. 305, Direct Testimony of Dennis Higgins, pp. 5, 10, 13 (September 20, 2019). Higgins testified on his own behalf; he has masters' degrees in mathematics and computer science and has taught at various universities, including at the State University College of Oneonta for 32 years (id., p. 2).

with associated, unnecessary costs.[195] Rather, echoing much of the testimony described above, Higgins concluded that the public interest would be best served if “[r]ate-payer dollars [were not] spent on gas expansion or for any substantial gas capital investment, other than work minimally required for safety and reliability.”[196]

The direct testimony of two DPS Staff witnesses also warrants mention. As relevant here, DPS Staff witness Andrew Riebel performed engineering analyses of the Companies’ gas capacity and supply planning, as well as its proposed infrastructure projects, and concluded that both the DeRuyter and Lansing/Freeville pipeline projects should be removed from the Companies’ capital expenditures.[197] With regard to the former, Riebel noted the associated $53 million budget and observed that the Companies had not established they could obtain the additional supply of natural gas that would justify delivery through a larger capacity pipe.[198] As to the latter, Riebel opined that the Companies’ pursuit of alternative Non-Pipe Solutions was preferable to the $16.7 million expenditure.[199]

DPS Staff witness Davide Maioriello explained the difference between firm gas service and interruptible gas

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[195] Id., pp. 13, 22.

[196] Id., p. 5.

[197] Ex. 171, Direct Testimony of Andrew Riebel, pp. 2, 9 (September 2019). Riebel is a utility engineering specialist 3 assigned to the Office of Electric, Gas and Water. He has been an employee at the Department since 1990.

[198] Id., p. 9-10.

[199] Id., pp. 10-11.

service.[200] Whereas firm service does not contemplate interruptions in service – i.e., high priority end-users such as residential heating customers should not expect to lose service even during periods of high-peak demand – interruptible service does. Opting into interruptible service may nonetheless be beneficial to customers because they typically receive lower distribution rates throughout the year and can avoid paying overrun or penalty charges.[201] More generally, interruptible service maintains the reliability of gas supply for a utility's firm service customers and "reduce[s] the amount of permanent infrastructure [a] utility needs to build, maintain, and earn a return of investment on."[202]

Dennis Higgins submitted rebuttal testimony, taking issue with Riebel's rationale for recommending that the DeRuyter project be removed from the Companies' capital expenditures.[203] According to Higgins, Riebel implicitly suggested that DPS Staff might approve the DeRuyter proposal if the Companies did demonstrate an ability to obtain an adequate supply of natural gas to warrant expanding the line.[204] To the extent that such approval might then contemplate a future increased demand for natural gas, Higgins reiterated his assertion that this would

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[200] Ex. 336, Direct Testimony of Davide Maioriello, p. 9. Maioriello is a utility engineering specialist 3 assigned to the Office of Electric, Gas and Water. He has been an employee at the Department since 2005 (id., p. 2).

[201] Id., pp. 9-10. Customers participating in interruptible service programs are likely to have alternative fuel supplies, which they can turn on when a utility's gas service is interrupted; in doing so, they are not subject to the above-referenced charges.

[202] Id., p. 10.

[203] Ex. 309, Higgins-Riebel Rebuttal Testimony, p. 2.

[204] Id.

inhibit the goals of the CLCPA rather than further them.[205] He added, moreover, that Riebel neglected to consider the testimony provided by Maioriello vis-à-vis the benefits of interruptible service, claiming that such service provides “ample flexibility” for meeting any potential future demand fluctuations; while, again, increased future demand for natural gas should not be expected or desired, continued investment in related infrastructure expansion projects would be unnecessary even if demand indeed rises.[206]

Discussion

The Joint Proposal includes several provisions directly emanating from each of the concerns set forth above, all of which further New York State’s nation-leading policy objectives as articulated in the CLCPA.

In fact, the Joint Proposal expressly recognizes that compliance with the CLCPA demands proactive, forward-looking strategies. Accordingly, within 18 months of the issuance of this Order, the Companies have committed to preparing a report analyzing how their businesses will evolve within the context of the CLCPA’s express greenhouse gas reduction and renewable energy goals.[207] The report will evaluate possible means for, and potential obstacles to, reducing natural gas usage while contemporaneously modernizing the electric grid to support the widespread deployment of alternative renewables and beneficial electrification.[208] More specifically, “[t]he report shall provide a meaningful analysis of the scale, timing, and costs of achieving significant, quantifiable reductions in gas use, grid

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205 Id., p. 4.

206 Id., p. 3.

207 Ex. 136, Appendix M to Joint Proposal, p. 2.

208 Id.

improvements necessary to achieve various levels of renewables deployment and beneficial electrification, [as well as] potential financing mechanisms.”[209] It is notable that parties to the instant rate proceeding are welcome to offer input regarding the scope of the study.[210]

Turning to discrete topics such as the DeRuyter pipeline and the Lansing/Freeville pipeline, the capital budget reflected in the Joint Proposal lacks any future funding related to the planning, engineering, permitting or construction of either pipeline project,[211] nor will the pipelines be the subject of any article VII applications filed by NYSEG during the term of the rate plan.[212] As a means of advancing economic development, however, the Companies will petition the Commission in connection with the potential preferential reallocation of natural gas generated in the Lansing moratorium area to commercial and industrial customers.[213]

Regarding those customers served by the DeRuyter pipeline, NYSEG will structure its gas planning with the goal of achieving a zero-net increase in gas use during the term of this

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[209] Id.

[210] Id.

[211] Id., p. 2. The Companies will be permitted to act as necessary to ensure that both pipelines operate in conformance with all applicable laws and rules, as well as to protect the integrity of both pipelines in the event of emergency (id).

[212] Id., p. 3. As mentioned previously, both pipelines are situated in NYSEG service territory; it is notable that, in accordance with the Joint Proposal, NYSEG will amend its tariff to make gas interruptible service available to all eligible customers (id).

[213] Id., p. 6.

rate case.[214] In conjunction therewith, the Companies will actively pursue opportunities for reducing gas demand through targeted heat pump programs, building efficiency upgrades, district heating projects, non-gas Non-Pipes Alternatives (NPA) projects and other potential initiatives.[215] In order to maximize the benefits of these efforts, they will be concentrated in areas of the DeRuyter service territory and distribution network that the Companies identify as most likely to request load growth or expansion.[216]

On a more macro level, the Companies agree to structure their gas planning throughout their entire service territories with the goal of achieving a zero-net increase in billed gas use after the first year of the rate plan. Here, the achievement would mean that weather-normalized levels of billed-gas use for both Companies in RY 2 and RY 3 do not exceed the forecasted levels of gas use in RY 1.[217] The Companies will calculate the level of savings (in British thermal units, or BTUs) necessary to offset forecasted increase in gas use during RY 2 and RY 3 and pursue targeted heat pump programs, non-gas

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[214] Id., p. 1. For the purposes of this provision, zero-net gas increase means that the volume of gas flow through the DeRuyter pipeline during each of the three Rate Years shall not exceed the weather normalized volume of gas flow to the pipeline for the twelve-month period between May 2018 and April 2019 (id.).

[215] Id. In direct testimony, DPS Staff's Earnings Adjustment Mechanisms panel defined NPAs as "a portfolio of resources used to delay, reduce or eliminate the need for traditional capital investments to reinforce or expand gas supply and distribution infrastructure." Ex. 178, p. 93 (September 2019).

[216] Id.

[217] Id.; compare n. 42, supra. In RY 1, the forecasted levels of gas use are 56,037,087 Dths at NYSEG and 58,545,145 Dths at RG&E.

NPA projects, district heating projects and building efficiency upgrades to offset the increases.[218]

Beginning with the first full calendar quarter following issuance of this Order, and continuing every quarter thereafter, the Companies will provide the Commission with reports on their progress toward achieving these zero-net objectives – territory wide and in the DeRuyter service area.[219] The reports will include detailed statistics identifying the volume of actual billed gas use, the volume of billed gas use normalized for temperature, monthly billed use by sector, natural gas customer counts and any net change in natural gas customers by month.[220] To the extent it is available, information regarding customer use of building efficiency incentives and heat pumps, as well as the corresponding number of BTUs of energy saved, should be included in these quarterly reports.[221]

Several provisions in the Joint Proposal are designed to enhance the likelihood that the Companies achieve the foregoing zero-net increase in gas use goals. First, within one year of issuance of this Order, the Companies will cease all promotion of natural gas use on their websites and in other marketing materials, including emails and direct customer mailings.[222] Instead, customers will be informed about incentives involving alternate forms of energy consumption and

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218 Id.

219 Id.

220 Id.

221 Id.

222 Id., p. 4.

energy efficiency, as well as a related on-bill financing program sponsored by NYSERDA.[223]

Next, ongoing gas expansion pilot programs and conversion rebate programs – e.g., those that promote the transition from oil to gas – will be terminated; funds associated with a current such program at NYSEG will be redirected to an enhanced heat pump rebate program, while RG&E will commit $750,000 to a comparable program in its service territory.[224] Additionally, in consultation with DPS Staff, the Companies will evaluate the applicability of NPAs as alternatives to existing new pipeline construction or expansion projects.[225] NYSEG and RG&E will also modify their natural gas tariffs, limiting them to only the required allowances for service lines, mains and appurtenant facilities.[226]

The Joint Proposal also reflects the Companies' agreement to begin using more electric and hybrid vehicles, with both Companies agreeing to add at least five fully electric vehicles to their fleets every year between 2020 and 2023;[227] a program involving the augmented use of hybrid bucket trucks will also be commenced by the Companies in the first year of the rate plan.[228] Likewise in RY 1, the Companies will retain an expert in geothermal district systems and heat pump heating and cooling solutions to evaluate the feasibility of employing both throughout their entire service territories.[229] At the

[223] Id.

[224] Id.

[225] Id.

[226] Id.; see 16 NYCRR part 230.

[227] Id., p. 3.

[228] Id.

[229] Id., p. 4.

conclusion of the study, the Companies will file a report with the Commission that includes recommendations for associated pilot projects of various sizes and types, as well as related methods for cost recovery.[230]

Finally, the Companies will utilize data from calendar year 2020 to conduct a separate study on the potential depreciation impacts of recently enacted laws or climate change policies on their gas, electric and common assets.[231] The study, due for submission to the Commission by December 31, 2020, will particularly examine the effect of such laws and policies on average service lives, reserve deficiency/surplus, cost of removal, salvage value, depreciation rates and customer bills.[232] The results of the study, which will also include an assessment of the appropriate survivor curve, will inform the Companies' next base rate filing.[233]

Conclusion

The foregoing gas provisions are an important step toward achieving New York's ambitious climate-related policy goals, and we expect they will serve as a model in future rate cases. Indeed, they offer a road map for reducing the use of natural gas and minimizing gas infrastructure investments, while at the same time preserving the Companies' ability to provide reliable service at just and reasonable rates.

More specifically, the gas sections of the Joint Proposal reflect the Companies' commitment to achieving zero-net growth in gas sales, discontinuing the promotion of natural gas services, pursuing non-pipe alternatives and, among many other

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[230] Id.

[231] Id., p. 3.

[232] Id., p. 4.

[233] Id.

laudable initiatives, incentivizing the expanded use of heat pumps; at the same time, the Companies agree to conduct various topical, forward-thinking studies, including those related to geothermal district energy, natural gas system resiliency and the impacts of clean energy policies and laws on the future of gas businesses.

These objectives enjoy the broad support of ratepayer representatives, environmental advocacy groups, not-for-profit organizations and the public at large, including those individuals and entities whose concerns were discussed above. Fossil Free Tompkins and the Rochester People's Climate Coalition, for instance, were two of several entities that submitted a statement in support of the gas proposals, indicating that they "represent meaningful compromise among normally adversarial parties [and include] numerous provisions that begin to align the gas Companies' activities and planning with the Climate Leadership and Community Protection Act."[234] Likewise, at each of the recent virtual public statement hearings, many individuals spoke in favor of the gas provisions; illustrative examples include Lisa Marshall, who began her comments with "praise for the gas case settlement," Martha Robinson, who was "quite impressed with the gas rate case," and Matthew Gould, who "wholeheartedly support[s] the steps [the Companies] are taking towards sustainability in fossil fuel reduction."[235]

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[234] See Statement in Support, submitted by RCI, which was signed by the Alliance for a Green Economy, Binghamton Regional Sustainability Coalition, FFT, HeatSmart and the RPCC.

[235] See Virtual Public Statement Hearing Transcript, 1:00 PM on August 26, 2020, at 43, 72; Virtual Public Statement Hearing Transcript, 6:00 PM on August 26, 2020, p. 56.

We agree with each of these observations, finding that the gas provisions further the public interest and are entirely consistent with both the Climate Leadership and Community Protection Act and the Commission's initiatives as articulated in Case 20-G-0131.[236] Accordingly, we approve of and adopt those sections of the Joint Proposal related to gas.

K. Customer Service Provisions

1. Customer Service Performance Mechanisms

The terms of the Joint Proposal include service quality metrics and targets for each Company, with associated potential NRAs, with respect to their Public Service Commission Complaint Rate per 100,000 customers, Contact Satisfaction, Percent of Calls Answered in 30 Seconds, and Percent of Estimated Bills. NYSEG would be subject to approximately $9.5 million in total potential NRAs and RG&E would be subject to $5.9 million in total potential NRAs. Within thirty days after the end of each calendar year, the Companies would continue to file an annual report that details their performance on the service quality measures. The Joint Proposal would increase the missed appointment fee from $20 to $30 when the Companies fail to keep a designated appointment. An arrears component would be added to the Companies' existing Uncollectibles/Termination measure. The Companies would be eligible for PRAs in varying amounts depending on how they perform on the applicable metric targets.

The Joint Proposal's customer service performance mechanisms are more stringent or the same as those currently in place for the Companies. The customer service performance mechanisms provide sound incentives for the Companies to improve

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[236] See Proceeding on Motion of the Commission in Regard to Gas Planning Procedures (commenced March 19, 2020).

its customer service and provide reasonable earnings consequences based on the quality of services provided to customers in specific areas. The components of the customer service mechanism will encourage the Companies to further improve the customer service experience. We find these provisions sufficient and in the public interest.

2. Closure of Customer Service Walk-in Offices

Under section XVII.H of the Joint Proposal, the Companies would be permitted to close a total of six walk-in offices under a phased office closure schedule beginning June 1, 2021. Pursuant to the schedule of closures, RG&E would close its walk-in offices located on Waring Road in Rochester, as well as its Fillmore and Canandaigua offices in 2021. NYSEG would be allowed to close its walk-in offices in Lancaster and Hornell in 2021 and its walk-in office in Liberty in 2022. The Companies would provide quarterly reporting of customer usage of open offices, the number of individual customer appointments requested, and the number of appointments made. Any "material increase" in customer traffic in an office scheduled to be closed would be reviewed with DPS Staff and other parties prior to a scheduled closure to determine whether the closure should occur.[237]

All current employees assigned to any closed walk-in offices would be retained and continue with a job assignment located in the same Company division/region. In service areas where walk-in offices are closed, the Companies would implement a process for a customer to request a meeting with a customer service employee on an as-needed/as-requested basis. The

[237] The Joint Proposal defines a "material increase" as a 25 percent increase in representative-assisted transactions sustained consistently for at least a three-month period. The increase will be measured from a baseline provided by the Companies in direct testimony.

Companies would assign two full-time equivalent positions to assist with this workload.

In addition, the Companies would coordinate with Monroe, Chenango, Erie, Ontario, Steuben and Sullivan Counties to provide scheduled dates and times to have a NYSEG or RG&E Customer Advocate on site at the New York State Department of Social Services (DSS) for a minimum of two times per month per location. The locations of these DSS activities were selected to correspond to the locations of proposed office closures.

The Companies also would coordinate with the New York State Office of Temporary and Disability Assistance/DSS (OTDA) to expand the periodic location of Customer Advocates in additional counties, subject to the approval and schedule of the particular office. The Companies would provide DPS Staff and interested parties with an outreach implementation plan at least two months before the closure of each walk-in office. The Companies agree to provide outreach and communications regarding customer options for completing transactions and meeting with a Company representative in person, including communications at third-party payment locations, customer contact centers, Company websites, and remaining customer service walk-in offices, as well as including such information in bill inserts.

In pre-filed testimony, the Companies proposed to close fifteen of their eighteen customer service walk-in offices during May through October over a three-year period from 2020 to 2022. The Companies asserted that the previous closure of three customer service walk-in offices pursuant to their 2016 Rate Cases had no noticeable adverse impacts on customers and that staffing customer offices was not the most efficient use of resources given the advances in technology and availability of self-service options.[238] The Companies maintained that the volume of customer transactions at walk-in centers compared to all customer service transactions was only 3.9 percent at NYSEG and 6.0 percent at RG&E, that the number of payments processed at walk-in offices was decreasing each year, and that every service provided at walk-in offices was available through various other means, including the Companies' website, interactive voice response solutions, and customer contact centers. Finally, the Companies stated that security concerns also supported the proposed closure of customer service walk-in offices.

DPS Staff testified that it did not support the Companies' proposal to close fifteen walk-in offices, stating that the closure of so many offices would be disruptive and inconvenient to customers.[239] DPS Staff stated that walk-in offices continued to provide valuable services to many customers who cannot successfully conduct transactions through other means, including the elderly, disabled and low income customers. DPS Staff also did not support closure of the Waring Road office in Rochester because it was a high-volume office located in an urban area and reachable by public transportation. Recognizing "the significant decrease in customer visits to some of the Companies' walk-in offices over the past few years, the alternative methods of payment available, and the anticipated ability of customers to make payments at third-party locations at no charge," DPS Staff proposed that the Companies be allowed to close three of their lowest-usage walk-in offices and that

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[238] Ex. 6, Companies' Customer Service Panel Direct Testimony, p. 24.

[239] Ex. 183, DPS Staff Consumer Services Testimony, p. 59.

employees remain employed by the Companies after the office closures.[240]

In pre-filed testimony, PULP opposed the proposed closure of fifteen walk-in offices, stating that the walk-in offices offered services that low income and other vulnerable customers may desire or be required to perform in person, including the submission of detailed financial statement forms for renewal of account medical protection and certain deferred payment agreements, the reconnection of services at a walk-in office upon payment, and providing documentation needed to open a new account.[241] PULP expressed a concern that many of the people who use walk-in offices do not have computers, the internet, smart phones or other technologies to access non-payment-related customer services they now access through walk-in offices.

UIU testified in opposition to the proposed closure of fifteen walk-in offices, asserting that any savings the Companies' might obtain from the closures did not outweigh the potential difficulties that customers may encounter from the closures. UIU testified that, if the closures were approved, the Companies should look at deploying a mobile "hub" in those areas to allow customers to continue to have an opportunity for face-to-face interactions.[242]

IBEW Local 10 also opposed the closure of fifteen walk-in offices on the ground that many customers may not be able to take advantage of services available through technology

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[240] Id., pp. 61, 65.

[241] Ex. 259, William D. Yates Corrected Direct Testimony, pp. 38-40.

[242] Ex. 213, Direct Testimony of Gregg C. Collar, pp. 21-22.

and other options. IBEW Local 10 maintained that at least six of the NYSEG walk-in offices should remain open.

In rebuttal testimony, the Companies stated, among other things, that the specific recommended closure of the Waring Road office in Rochester was based on concerns for customer and employee safety.[243] The Companies also stated that the remaining customer service walk-in offices in Rochester are located a short distance from the Waring Road office and reachable by public transportation.

In their statement in support of the Joint Proposal, the Companies state that the Joint Proposal reflects significant compromise among the signatory parties with respect to the number and timing of proposed walk-in office closures. Both the Companies and DPS Staff further state that the Joint Proposal contains a number of provisions to ensure that customers are aware of and continue to have access to consistent and responsive customer service, including a process for customers to request in-person meetings with a customer service representative.

In addition, DPS Staff states that, after "detailed discussion of security issues at the Waring Road office during settlement negotiations, and re-examination of the increase in both the number and the severity of security incidents at the Waring Road location, DPS Staff concurs that the closure of this office would be prudent in order to eliminate further risk at this location" and given the other means that customers will have to receive assistance from and to transact business with the Companies.[244] DPS Staff additionally states that IBEW 10

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[243] Ex. 71, Companies' Customer Service Panel Rebuttal Testimony, p. 20.

[244] DPS Staff Statement in Support of the Joint Proposal, p. 66; Tr. 58-59.

agrees to the limited number of closures now proposed because of the condition that “all customer service employees working in the offices listed for closure retain employment in a similar position within their current service territory and that no customer service position be eliminated as a result of these closures.”[245] DPS Staff concludes that, as “a result of a continued decline in foot traffic, security incidents that have increased in both frequency and severity, and the implementation of more self-service options for customer assistance, Staff believes closing potentially up to six walk-in offices” is reasonable.[246]

PULP continues to oppose the closure of any of the Companies’ walk-in customer service offices. In its Statement in Opposition to the Joint Proposal, PULP maintains that no effective customer outreach plan is in place and that the record does not establish that the Companies asked their customers why some offices have low usage. PULP asserts that the assignment of two full-time employees to float between county DSS offices may not be sufficient to cover the territory included in and number of people affected by the office closures. Stating that the Erie County DSS is nearly five miles away from the closest NYSEG customer, PULP asserts that Company representatives located in county DSS offices may not be accessible to many customers, especially those without access to a personal vehicle. PULP states that the record does not support the Companies’ security concerns as a reason for the proposed closure of the Waring Road office. Finally, PULP notes that, in addition to the proposed closures, the Companies’ four remaining walk-in customer service offices will have reduced hours.

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[245] Id., p. 67.

[246] DPS Staff Reply Statement in Support of the Joint Proposal, p. 15.

In our view, the phased plan to close the six walk-in offices is a reasonable compromise in light of the original litigation positions of the parties. The closure of six walk-in offices as opposed to the fifteen originally proposed is closer to DPS Staff's and IBEW Local 10's litigation positions than the Companies' original position. The record establishes that five of the walk-in offices proposed for closure are experiencing decreased usage and are among those offices with the lowest number of customer representative-assisted transactions.[247] The Joint Proposal also protects against the closure of offices that may experience a material increase in activity by specifically providing that offices will be reevaluated for closure if there is a significant and sustained increase in customer usage for at least a three-month period prior to closure.

The Companies acknowledged that RG&E's Waring Road office was "busy," but testified that they recommended its closure for operational efficiencies and savings and due to "concern[s] with safety in the plaza where it is located."[248] DPS Staff states that, as a result of detailed discussions during settlement, it now agrees that closure of the Waring Road office would be appropriate due to the increased number and severity of security incidents at that location. Although the Waring Road office continues to have a relatively higher volume of transactions than the other walk-in offices proposed for closure, the closure of that office for safety concerns is reasonable under the circumstances, especially since RG&E still has two other walk-in offices located in Rochester that are 3.1

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[247] Ex. 183, DPS Staff Consumer Services Panel Testimony, p. 62.

[248] Ex. 71, Companies' Customer Service Panel Rebuttal Testimony, p. 20.

and 6.1 miles from the Waring Road office and reachable by public transportation.[249]

Moreover, although customers may no longer have access to six walk-in offices, the Joint Proposal provides a process for customers to request an in-person meeting with a customer service employee and requires the Companies to have customer advocates available at least two times a month at DSS offices chosen to correspond to areas in which closures would occur. As the Companies and DPS Staff note, customers also may avail themselves of alternate avenues of assistance, including customer service available by phone, website access, a credit card payment option, and payment options at Wal-Mart stores and Western Union locations.[250] Indeed, the record supports the conclusion that customers have increasingly conducted business with the utilities by other means, resulting in a downward trend in representative-assisted in-office transactions.[251] In addition, ratepayers would be provided with relevant information regarding the closures and alternative means for engaging with the Companies through a customer outreach implementation plan that will be provided to DPS Staff at least two-months prior to the closure of each walk-in office.

Given the above, and in light of the other customer service benefits included in the rate plans, we conclude that the compromise reflected in the Joint Proposal serves the public interest. For example, as discussed elsewhere, the rate plans include several provisions designed to address the immediate

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[249] Ex. 6, Companies' Customer Service Panel Direct Testimony, pp. 25-26; Ex. 71, Companies' Customer Service Panel Rebuttal Testimony, p. 21; Ex. 5, CSP-7.

[250] Ex. 71, Companies' Customer Service Panel Rebuttal Testimony, pp. 29-30.

[251] Ex. 6, Companies' Customer Service Panel Direct Testimony, pp. 27-32.

economic impacts resulting from the COVID-19 pandemic. The Companies also are eliminating the per-transaction fees for customers who pay their bills at authorized third-party locations and will file a plan to institute electronic deferred payment agreements for residential customers. To help ensure that the Companies' customers consistently receive a high quality of service, the Companies' will be subject to NRAs for failure to meet customer service performance metrics, including one that measures customer satisfaction. The NRAs are subject to doubling should either NYSEG or RG&E miss a specific customer service metric for two consecutive years. Under all the circumstances, we agree with DPS Staff that the Joint Proposal fosters the goal of maintaining good customer service while providing a reasonable time frame for office closures that reasonably reflect changes in customer behavior and the Companies' concerns with security.

L. Customer Charges

1. Fixed Monthly Customer Charges

The Joint Proposal recommends increases to the fixed customer charges for electric and gas. The Joint Proposal also provides that in the next rate case, the Companies will develop a method to perform a zero-intercept, minimum system study, or some other equitable allocation for classifying electric distribution plant costs of service and gas main costs of service on a 100 percent demand basis, and present the information in ECOS studies for "illustrative purposes" only.[252] In addition, the Companies will retain the right to recommend the use of any cost study they find appropriate.[253]

[252] Joint Proposal, Appendix BB, p. 1-2, Appendix DD, p. 1.

[253] Joint Proposal, Appendix BB, p. 1-2, Appendix DD, p. 1.

As previously noted, the signatory parties to the Joint Proposal represent that for purposes of revenue allocation and rate design, the negotiated electric and gas revenue allocations are not based on any single ECOS study presented in these proceedings and that there was no agreement on a single, optimal ECOS study methodology.[254] Instead, the Joint Proposal provides a manner by which different ECOS methodologies may be explored, analyzed and consulted in the Companies' next rate proceedings. Notwithstanding the foregoing, in urging the Commission's adoption of the Joint Proposal, the Companies and DPS Staff both rely on the ECOS and MCOS studies submitted in this record to provide fair mechanisms in determining the reasonableness of increases to the fixed customer charges.[255]

Although the customer charges for gas service classes are increased in a similar manner as those for electric service classes,[256] the parties opposing the Joint Proposal primarily assert objections only to the customer charge changes for electric service. The customer charge increases for electric are in RY 2 and RY 3 for most service classes but will affect some classes in RY 1 as detailed below.

2. Residential and Small Non-Residential Charges for Electric

The current monthly customer charge for NYSEG's residential and small non-residential service classes is $15.11.[257] The current customer charge for RG&E's residential and small non-residential service classes is $21.38. Both of

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[254] Companies' Statement in Support of the Joint Proposal, pp. 59-60.

[255] Id., pp. 60-61.

[256] Joint Proposal, p. 63; Appendix DD.

[257] Joint Proposal, Appendix CC, Schedule A-1, p. 1.

these customer charges have been in effect since the Commission’s 2010 order approving rates for both Companies.[258] The Commission’s 2016 order approving rates for both Companies adopted a Joint Proposal that did not recommend any increase to the then existing customer charges for these service classes at that time.[259]

Under the Joint Proposal, in RY 1, NYSEG’s residential and small non-residential classes will continue the existing customer charge and have no increase in service classifications SC No. 1 – Residential Service, SC No. 6 – General Service Non-Demand, SC No. 8 – Residential Day-Night Service, SC No. 9 – General Service Day-Night Service, and SC No. 12 – Residential Service Time-of-Use.[260] Similarly, RG&E’s residential and small non-residential classes will continue the existing customer charge and have no increases in RY 1 for service classifications SC No. 1 – Residential Service, SC No. 2 – General Service Small Use, and SC No. 4 – Residential Service Time of Use. The revenue increases for both Companies in RY 1 will be recovered through the volumetric (per kWh) delivery charges.

After RY 1, the customer charges for NYSEG’s residential and small non-residential service classes (SC No. 1,

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[258] Case 09-E-0715, Proceeding on Motion of the Commission as to Rates Charges, Rules and Regulations of New York State Electric & Gas Corporation for Electric Service; Case 09-E-0717, Proceeding on Motion of the Commission as to Rates Charges, Rules and Regulations of Rochester Gas and Electric Corporation for Electric Service, Order Establishing Rate Plan (issued and effective September 16, 2010), Joint Proposal, Appendix T, pp. 1, 43.

[259] Case 15-E-0283, Order Approving Electric and Gas Rate Plans in Accord with Joint Proposal (issued and effective June 15, 2016), p. 45 (“... customer charges for residential and small commercial electric and gas customers will not increase during the rate plans.”)

[260] Joint Proposal, p. 63; Appendix CC.

SC No. 6, SC No. 8, SC No. 9, SC No. 12) will increase from $15.11 to $16.05 in RY 2 and $17.00 in RY 3. Similarly, the customer charges for RG&E's residential and small non-residential service classes (SC-1, SC-2, and SC-4) will increase from $21.38 to $21.70 in RY 2 and to $22.00 in RY 3. The balance of the Joint Proposal's RY 2 and RY 3 revenue increases will be recovered through volumetric (per kWh) delivery charges.

3. Medium and Large Non-Residential Charges for Electric

For NYSEG's medium and large non-residential classes, there are no monthly customer charge increases in RY 1 for service classifications SC No. 2 – General Service Demand, SC No. 3P – General Service Demand Primary, SC No. 3S – General Service Demand Sub-transmission. Similarly, for RG&E's medium and large non-residential classes, there are no monthly customer charge increases in RY 1 for service classifications SC No. 3 – General Service 100 kW Minimum, SC No. 7 – General Service 12 kW Minimum, and SC No. 9 – General Service Time of Use.

In RY 2 and RY 3, customer charges will increase for NYSEG's medium and large non-residential service classifications, (SC No. 2 – General Service Demand; SC No. 3P – General Service Demand Primary; SC No. 3S – General Service Demand Sub-transmission) and for RG&E medium and large non-residential service classes (SC No. 3 – General Service 100 kW Minimum, SC No. 7 – General Service 12 kW Minimum and SC No. 9 – General Service Time of Use).

4. Demand Service Charges for Electric

For the electric non-residential demand service classes, fixed monthly charges will increase by 35 percent over the three Rate Years, with 25 percent of the increase occurring in RY 1 and the remainder of the increase over RY 2 and RY 3.[261]

[261] Companies' Statement in Support of the Joint Proposal, p. 60.

Thus, customer charges will increase in each of the Joint Proposal’s three Rate Years for NYSEG service classes SC No. 7-1 – Large General Service Secondary; SC No. 7-2 – Large General Service Primary; SC No. 7-3 – Large General Service Sub-transmission; and SC No. 7-4 – Large General Service Transmission. The fixed monthly charges also will increase in each of the three Rate Years for RG&E’s service classes SC-8P – Large General Service Primary; SC No. 8S – Large General Service Secondary; SC No. 8-ST Com – Large General Service Sub-transmission Commercial; ST No. 8-ST Industrial – Large General Service Sub-transmission Industrial; SC No. 8-T – Large General Service Transmission; and SC No. 8-Sub – Large General Service Substation.[262]

5. Customer Charges for Gas

For the Companies’ large non-residential service classes, such as NYSEG SC-1 - Large Firm Transportation and RG&E SC No. 3 - Large Firm Transportation, customer charges in the Joint Proposal would be increased by 35 percent over the three Rate Years, with the majority of the increase occurring in RY 1 and the remainder occurring in RY 2 and RY 3. For RG&E’s large non-residential class (SC No. 3HP), the customer charge is increased by the same percentage increase as the delivery per therm charges.

Customer charges remain unchanged for NYSEG service classes SC No. 5 – Seasonal Gas Cooling Firm Sales Service; SC No. 5 – Small Firm Transportation Service; and SC No. 9 – Industrial Manufacturing Firm Sales Service. For all other service classes, specifically residential firm sales and transportation, and small non-residential firm sales and

[262] Joint Proposal, p. 63; Appendix CC, pp. 4.

transportation), customer charges are not increased in RY 1 but are increased in RY 2 and RY 3.

6. Positions of Parties Opposing Increased Customer Charges

The Indicated Environmental Parties assert that the Joint Proposal's increased customer charges are "regressive" and contrary to New York's social, economic, and environmental policies because they do not advance energy affordability, conservation, and efficiency.[263] They claim that fixed customer charges benefit customers who use more electricity by reducing their total bills and unfairly redistribute system costs to those using the least amount of electricity. The Indicated Environmental Parties indicate that such charges "lock customers into a higher portion of their bill that they have no ability to control."[264]

Intervenor Richard W. Ford claims that the increased customer charges are not in the public interest and contradict the State's REV polices because energy conservation is disincentivized.[265] He states that the "social policy of New York is not to redistribute wealth from people in small apartments to people with large houses."[266] He claims that the Companies' claim that high fixed charges and lower usage charges are beneficial to low income customers with high electrical

[263] Indicated Environmental Parties Statement in Support of the Joint Proposal, pp. 19-20 (citing Hearing Exhibit 7: Whited, Melissa, T. Woolf, and J. Daniel. 2016. "Caught in a Fix: The Problem with Fixed Charges for Electricity." https://advocacy.consumerreports.org/wp-content/uploads/2016/02/Caught-in-a-Fix-FINAL-REPORT-20160208-2.pdf.

[264] Indicated Environmental Parties Statement in Support of the Joint Proposal, p. 20.

[265] Ford Statement in Opposition to the Joint Proposal, pp. 1-2.

[266] Id.

usage is disingenuous and that "[i]t is neither the duty of the companies nor the policy of the State of New York to make wasting energy affordable."[267] Mr. Ford also points out that the customer charges in neighboring states (e.g., Massachusetts, Rhode Island and Connecticut) are much lower ($5.50, $5.00, and $10.00, respectively) and well below the Companies' current ($15.11) and future proposed charges here ($16.05 and $17.00).

AARP similarly argues that the lower the fixed charge and the higher the volumetric charge, the greater the incentive for ratepayers to conserve energy and that the Joint Proposal's customer charge provisions are inconsistent with the Commission's energy affordability and climate change policies.[268]

7. Positions of Parties Supporting Increased Customer Charges

Both the Companies and DPS Staff rely on the ECOS and MCOS studies in support of increased customer charges because both studies indicate that residential customer charges are significantly less than the residential customer costs. The Companies assert that in RY 3, the phased-in residential customer charge increases agreed to in the Joint Proposal will be at the level proposed by the Companies in their direct testimony, which was supported by DPS Staff in its direct testimony as cost-justified and consistent with the development of cost-based rates and charges.[269] The Companies further assert

[267] Id. Mr. Ford also asserts that the Companies justified high fixed customer charges because transformer costs are proportional to the number of customers, but admitted a year ago that customers who use the most electricity use the most transformer capacity.

[268] AARP Post-Hearing Brief, p. 11.

[269] Ex. 176, DPS Staff Electric Rates Panel Testimony, p. 27; Companies' Reply Statement in Support of the Joint Proposal, pp. 17-18.

that even after the RY 3 increases, the Companies’ fixed monthly charges will still be significantly below the amounts supported by both the ECOS and MCOS studies. The Companies claim that the increased fixed monthly charges under the Joint Proposal creates “a more equitable rate structure” because any revenue not recovered through such charges “would increase the revenue to be recovered through per kWh charges which would result in a subsidy of low-use customer by high-use customers.”[270]

In response to the suggested reduction to the customer charges by the Indicated Environmental Parties and Mr. Ford, the Companies argue that the use of fixed monthly charges is an appropriate component of the structure for energy delivery rates and is intended to recover the cost of service by a service class regardless of the amount of demand or energy used.[271] The Companies dispute that the Joint Proposal’s increased fixed charges disproportionately impact low income customers because the “distribution of low income customers across usage levels is similar to the distribution of total customers in the service class” and that “[l]ow income customers are not disproportionately grouped at the lower use levels” as reflected in Appendix CC.[272]

In response to the argument made by multiple parties that customer charges are regressive and will disincentivize conservation, energy efficiency and distributed generation, the Companies claim that customers will continue to have incentives to reduce usage and save on supply costs per kWh delivery

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[270] Companies’ Reply Statement in Support of the Joint Proposal, p. 18.

[271] Companies’ Reply Statement in Support of the Joint Proposal, p. 18 (citing Rebuttal Testimony of NYSEG/RG&E Revenue Allocation and Rate Design Panel, pp. 15-17).

[272] Id., p. 19.

charges because the percent of variable charges on the monthly bills is higher than the percent of fixed charges when compared to current monthly residential bills using 600 kWh.[273] The Companies illustrate that for NYSEG's residential customers, the customer charge in RY 3 will be 21 percent of the total bill (including delivery and supply), while the variable usage charges will be 78 percent. For RG&E's residential customers, the customer charge in RY 3 will be 26 percent of the total bill, while the variable usage charges will be 73 percent.[274]

In support of the Joint Proposal, DPS Staff indicates that in proposing fixed customer service charges, the Companies used the results of their ECOS and MCOS studies as a "guide" and that the revenue requirement in the Joint Proposal, net of the customer charge revenue, will be recovered through volumetric delivery charges for the non-demand classes and through demand delivery charges for the demand classes.[275] DPS Staff further indicates that the charges "reasonably reflect the utilities' cost arrived at in the Joint Proposal, do not result in adverse bill impacts as shown in Appendix CC, and are fair and non-discriminatory to all customers."[276] DPS Staff also notes that the signatories to the Joint Proposal negotiated no increase to the electric fixed monthly charges in RY 1 to mitigate bill

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273 Id., Table 1.

274 Id.

275 DPS Staff Statement in Support of the Joint Proposal, p. 107; DPS Post-Hearing Reply Brief, p. 7.

276 DPS Staff Statement in Support of the Joint Proposal, p. 109. DPS Staff also notes that for service classes with both volumetric delivery charges and demand delivery charges, priority was given to collect the remaining delivery revenue requirement through demand charges first, and then through volumetric charges. Reactive charges remain unchanged from current levels.

impacts during the Covid-19 pandemic.[277] DPS Staff asserts that the positions the Environmental Parties, Mr. Ford and AARP advance in opposition to the increased customer charges are contrary to the Commission's cost-based rate design principle.[278] In addition, DPS Staff notes that concerns about harm to low income customers resulting from the increased charges is mitigated by increases to the discounts those customers receive.[279]

DPS Staff asserts that the Joint Proposal, as a whole and including the changes to the fixed monthly charges, meets the requirements of the Commission's Settlement Guidelines because it is consistent with the Commission's policies and goals, compares favorably with the likely result of a litigated case, fairly balances the interest of ratepayers and investors, and provides the Commission with a rational basis for its decision.[280]

MI supports the increases to the customer charges for large non-residential electric customers under the Joint Proposal because "they generally are consistent with the cost-of-service evidence presented in these proceedings."[281] MI asserts that by setting fixed customer charges in accordance with customer-related costs, intraclass subsidies are reduced or eliminated, and customers are provided with more accurate price

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[277] DPS Staff Post-Hearing Reply Brief, p. 7.

[278] DPS Staff Reply Statement in Support of the Joint Proposal, p. 19.

[279] Id., p. 19.

[280] Id., pp. 17-18.

[281] MI's Statement in Support, pp. 19-20.

signals.[282] MI notes that for large non-residential customers, an increase to the applicable Customer Charge of 25 percent is not necessarily onerous or materially impactful, because it constitutes a much-smaller percentage of the overall delivery bill than it does for residential and small non-residential customers, and it is offset by reductions in, or modest increases to, electric demand charges, which typically constitute the lion's share of the bill for "traditional" delivery service (that is, excluding surcharges and assessments) for large non-residential customers.[283]

Discussion

The Companies' ECOS and MCOS studies identify the relative cost of service for each customer class and the individual class revenue requirements and demonstrate that the current customer charges for the service classes are well below the customer-related cost of service.[284] Indeed, even with the Joint Proposal's electric increases to customer charges, these

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282 Id., p. 19, n. 26. In support of their position, MI cites the testimony of their expert, Jeffry Pollock, who indicates:

> Rates that primarily reflect cost-of-service considerations are equitable because each customer pays what it actually costs the utility to service the customer [including a reasonable rate of return] – no more and no less. If rates are not based on cost, then some customers must pay part of the cost of providing service to other customers, which is inequitable. When rates are designed so that customer, demand, and/or energy charges are properly designed, the resulting rate structure will be efficient because customers are provided with the proper incentive to minimize their costs, which will, in turn, minimize the costs to the utility.

Ex. 148, Direct Testimony of Jeffry Pollock, p. 39.

283 MI's Statement in Support, pp. 19-20.

284 Exs. 7, 23, and 59.

customer-related costs remain below the cost of service. To mitigate bill impacts to residential customers that might result from the customer charge increase during the current Covid-19 pandemic, the Joint Proposal maintains the existing charges during RY 1 and only modestly increases the fixed charges in RY 2 and RY 3, while maintaining a fair proportion of the total delivery bill cost in the variable usage charges.[285]

The Commission established two rate design principles in the REV Track 2 Order.[286] First, that rates should reflect cost causation, including embedded costs as well as long-run marginal and future costs; and second, that rates should encourage desired market and policy outcomes including energy efficiency and peak load reduction, improved grid resilience and flexibility, and reduced environmental impacts in a technology neutral manner.[287] The Commission also recognized that "[w]hile efficient cost recovery is the beginning of rate design, rates must also be designed to encourage price-responsive behavior to advance policy objectives," including energy efficiency and climate change objectives.[288] We are mindful of the Commission's finding in the National Fuel Gas order that "high fixed costs

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[285] Joint Proposal, p. 63, Appendices BB and CC.

[286] Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework(issued and effective May 19, 2016) (Track 2 Order).

[287] Track 2 Order, Appendix A.

[288] Track 2 Order, pp. 118-119, in which we found:

> Developing an incentive approach for energy efficiency is essential, in part because efficiency is critically important to State energy policy and the Clean Energy Standard, but also because efficiency is a field where REV begins a transition toward elevating market opportunities for greater achievement at lower cost to electricity customers.

can create a negative perception about the value of conservation efforts."[289] However, we do not see the Joint Proposal's relatively modest fixed charge increases as rising to a level that would alter customer perception of the value of conservation.

In considering the increased customer charges here, we reiterate that rate design should assure that price signals are sent to customers in order to promote energy efficiency and thereby address the State's aggressive climate change objectives. The Companies' customer charges have not increased since the Commission's 2010 rate order. We do not believe that the Joint Proposal's nominal increases to these charges will have significant bill impacts across the distribution of customers within any specific service class. Nor will they materially interfere with the State's energy efficiency and climate change objectives, as claimed by the Indicated Environmental Parties. Moreover, we find that the Joint Proposal's AMI program will provide customers with the kind of information that will foster "price signals and transparency" that are "essential to a healthy market,"[290] and therefore will advance the State's conservation and environmental objectives.

The Joint Proposal properly balances the need to restrain bill impacts during the financial difficulties presented by COVID-19 while also addressing the Companies' need to be properly compensated for the cost of service documented in this record. We therefore approve the increases to customer charges proposed in the Joint Proposal.

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[289] Case 16-G-0257, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of National Fuel Gas Distribution Corp. for Gas Service, Order Establishing Rates for Gas Service (issued and effective April 20, 2017), p. 93.

[290] Track 2 Order, p. 110.

M. Revenue Decoupling and Rate Adjustment Mechanisms

The Joint Proposal would continue the Companies' Revenue Decoupling Mechanisms (RDMs) and RAMs. The RDM, included in most utility rate plans, is designed to reconcile deviations in the projections of sales revenues from certain rate classes with the amounts actually collected and is intended to diminish any disincentive to encourage or otherwise support customer energy conservation efforts.[291] The RAM allows the Companies to return or collect the net balance of certain deferrals if in excess of established thresholds, including property taxes, Major Storm deferral balances, gas leak prone pipe replacement carrying costs, REV costs and fees that are not covered by another recovery mechanism, and costs associated with the implementation of any Commission-ordered EV program that are not covered by another recovery mechanism.[292] Beginning on July 1, 2021, the Companies would begin the five-year recovery of funds allocated for the Customer Bill Credits provided in the customer relief provisions of the Joint Proposal discussed previously.

AARP states that actual bill impacts under the Joint Proposal will be higher due to the operation of the RDM and RAM and urges the Commission to revisit the use of such mechanisms. Additionally, AARP would have the Commission note in the descriptions included in future rate case notices, press releases and other documents, the likely projected bill

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[291] See Case 03-E-0640, Proceeding on Motion of the Commission to Investigate Potential Electric Delivery Rate Disincentives against the Promotion of Energy Efficiency, Renewable Technologies and Distributed Generation, Order Requiring Proposals for Revenue Decoupling Mechanisms (issued April 20, 2007), pp. 2-3.

[292] Joint Proposal, Appendix W, p. 1.

increases resulting from operation of the RDM, RAM and other recovery mechanisms.[293] DPS Staff responds that AARP incorrectly states that the Joint Proposal excludes the RAM from projected bill impacts and that it is impossible to forecast bill impacts from the RDM because it is a symmetrical true up between forecasted and actual delivery revenues.[294]

Discussion

The Commission has required utilities to develop and implement RDMs.[295] Although RDMs may add a level of uncertainty to ratepayers during the rate plans, we find that on the balance these mechanisms benefit both the Companies and ratepayers. RDMs remain an important tool in rate plans to eliminate disincentives that may exist for utilities to promote cost-effective energy conservation, the increased use of renewable resources, and the decreased use of fossil fuels. RDMs symmetrically capture variances from sales forecasts due to economic events and forecasting errors. The RDMs therefore will account for changes in usage resulting from the COVID-19 pandemic. If residential usage goes up because more people are at home during the pandemic, the RDMs would result in a credit to customers.

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[293] AARP Post-Hearing Brief, pp. 2-3.

[294] DPS Staff Post-Hearing Reply Brief, p. 3.

[295] Cases 03-E-0640 and 06-G-0746, Proceeding on Motion of the Commission to Investigate Potential Electric Delivery Rate Disincentives Against the Promotion of Energy Efficiency, Renewable Technologies and Distributed Generation and Case 06-G-0746, In the Matter of the Investigation of Potential Gas Delivery Rate Disincentives Against the Promotion of Energy Efficiency Renewable Technologies and Distributed Generation, Order Requiring Proposals for Revenue Decoupling Mechanisms (issued April 20, 2007).

Similarly, we find that RAMs provide benefits to both the Companies and ratepayers. Rather than waiting until a rate plan ends for disposition of deferral amounts, RAMs allow deferrals to be collected from or paid to ratepayers in a timely fashion during the course of a rate plan. As stated in the order initially adopting RAMs for the Companies, RAMs reduce the amount of regulatory assets and liabilities on the books and reduce cash flow volatility, which may translate to strengthening their credit ratings, a benefit to both the Companies and their customers.[296] RAMs provide a streamlined process for the return or collection of the net balance of specified deferrals during the course of a rate plan.

We conclude that RDMs and RAMs provide benefits to the Companies and to ratepayers that outweigh any uncertainty their application may have on rates. Accordingly, we reject AARP’s request that their continued use be revisited in these cases.

N. Low Income Programs

Under the terms of the Joint Proposal, both NYSEG and RG&E would continue to assist low income customers through their existing energy affordability bill reduction and arrears forgiveness programs (collectively referred to as low income programs). NYSEG’s annual low income program budget would be $20.7 ($19.2 million for bill reduction and $1.5 million for arrears forgiveness) and RG&E’s would be $17.3 million ($16.2 million for bill reduction and $1.1 million for arrears forgiveness).

In the bill reduction program, eligible customers are placed in one of four “tiers” and receive monthly discounts

[296] Cases 15-E-0238, et al., NYSEG and RG&E – Electric and Gas Rates, Order Approving Electric and Gas Rate Plans in Accord with Joint Proposal, pp. 39-41.

ranging from $3.00 to $36.00; the parties have agreed that discount amounts will remain equal to or greater than current amounts unless the Commission orders that discount levels be modified in a statewide proceeding.[297] With respect to arrears forgiveness, it bears noting that DPS Staff originally approved of the Companies’ intention to discontinue that program.[298] The topic was revisited during settlement discussions surrounding the COVID-19 pandemic, however, after which it was determined by the sponsoring parties that customers would benefit from the program’s retention.

As is presently the case, the Companies will refer all low income program participants to the New York State Energy Research and Development Authority for energy efficiency and/or budget counseling. Likewise, the Companies will continue to provide the Secretary with quarterly reports indicating: (1) the number of customers enrolled in the bill reduction program; (2) the number of customers enrolled in the arrears forgiveness program; (3) the total amount held in arrears for the program; (4) the average amount in arrears; (5) the aggregate amounts of low income bill discounts; (6) the aggregate amounts of arrears

[297] See Case 20-M-0266, Proceeding on Motion of the Commission Regarding the Effects of COVID-19 on Utility Service, (the COVID-19 proceeding, commenced in June 2020) and Case 14-M-0565, Proceeding on Motion of the Commission to Examine Programs to Address Energy Affordability for Low Income Utility Customers (the Affordability proceeding, commenced in January 2015), both of which are ongoing. In the event more general modifications to low income programs arise out of the Affordability proceeding, the Companies would be held harmless from any associated increases and expenses and would be authorized to seek future recovery by deferring the difference between each Rate Year’s rate allowance and actual costs (see Ex. 136, Executed Joint Proposal with Appendices, Appendix Q, p. 2).

[298] Ex. 71, Customer Service Panel Rebuttal Testimony, p. 14.

forgiven; and (7) the number of customers who have defaulted out of the program.

Enrollment in the low income programs would remain automatic for any customers upon whose behalf the Companies receive payment via a HEAP grant. Although the Joint Proposal also contemplates expanding self-enrollment in the programs "to include any customer who is denied a HEAP grant, but who can provide confirmation that he or she is HEAP eligible through a denial letter," AARP and PULP are opposed to expansion in such a manner.

AARP, in fact, asserts that no such denial letter is issued to HEAP applicants; rather, OTDA "monitors the number of applications for HEAP grants and amounts of committed funding and closes the application process before funding is exhausted."[299] Regardless, according to AARP, the expansion proposal is inconsistent with state policy as articulated in the Affordability proceeding, where the Commission favorably noted an initiative undertaken by Con Edison involving participants of several social services programs, not merely HEAP.[300]

PULP shares that concern, adding in any event that almost 130,000 of the Companies' customers are HEAP recipients who have yet to be enrolled in the Companies' low income programs,[301] notwithstanding the Commission's direction in the Affordability proceeding that all such customers be enrolled "by no later than December 31, 2017."[302] To rectify this purported

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299 AARP New York, Post-Hearing Brief, p. 5.

300 Id.; see, Case 14-M-0565, supra, Order Approving Implementation Plans with Modifications, p. 15 (issued February 17, 2017).

301 Ex. 259, William D. Yates, Direct Testimony, p. 26; Ex. 262, Rebuttal Testimony, pp. 3-4.

302 See, Case 14-M-0565, supra, Order Approving Implementation Plans with Modifications, p. 32.

under-enrollment, PULP recommends that the Companies use lists of HEAP recipients provided to them by OTDA to identify and enroll eligible customers, manually enroll customers who self-identify as HEAP recipients during incoming telephone conversations in which the customers express an inability to pay their bills, and allow for similar enrollment during outbound collections communications.

In response, the Companies claim that the 130,000 figure is potentially overstated, as it is based on "full" OTDA county data even though much of a particular county may not be served by the Companies.[303] They nevertheless acknowledge that "there are opportunities to identify and enroll more customers receiving HEAP grants [in the low income] programs," adding that they have already implemented a file-sharing mechanism with OTDA and are continuing to explore alternative methods for broadening customer matching criteria.[304] DPS Staff, meanwhile, maintains that the goal of the Joint Proposal's "denial letter" provision is to maximize low income program enrollment within existing eligibility parameters.[305] To the extent that more comprehensive enrollment expansion measures are warranted, such as including recipients of government programs other than HEAP, DPS Staff asserts that those measures are more appropriately considered in the Affordability proceeding.[306]

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[303] For instance, the largest segment of Erie County's population resides in the City of Buffalo, which is not a NYSEG or RG&E territory; total Erie County OTDA HEAP figures would thus not provide an accurate reflection of potential low income program enrollees at either Company. See, Ex. 71, Customer Service Panel Rebuttal Testimony, p. 13.

[304] Ex. 71, Customer Service Panel Rebuttal Testimony, p. 14.

[305] DPS Staff Post-Hearing Reply Brief, p. 4.

[306] Id.

The ALJs made two “requests for information” from the Companies in connection with this issue. “ALJ-4” sought an explanation as to how a customer establishes HEAP eligibility with information contained in a HEAP denial letter. In response, the Companies stated that they

> “currently have a manual process in place whereby a customer can provide a HEAP grant letter showing the approval of HEAP for an alternate fuel provider. Upon receipt of this verification from the customer, he/she is enrolled in the Company’s Low Income Program. This same process will be utilized for a customer who meets HEAP eligibility requirements, but who does not actually receive a HEAP payment due to unavailability of funds. This denial letter must be provided to the customer by [OTDA]. Upon receipt of this verification from the customer, he/she will be enrolled in the Company’s Low- Income Program.”[307]

In “ALJ-10,” the Judges asked the Companies to “provide a current, redacted sample of the ‘HEAP Denial’ form letter” referenced in response to ALJ-4. A blank form was submitted that, as relevant here, advises an applicant that his or her application was denied because “[y]our household has received one or more notices informing you that all of the HEAP benefits for which you are eligible and which are available in the current program year have already been authorized.”[308]

In light of this language, we conclude that HEAP eligibility may be demonstrated by either the denial letter or the referenced notice. Moreover, akin to COVID-19 relief provisions involving deferred payment agreements – e.g., negotiating agreements verbally and being flexible with the submission, timeline and format of associated documentary

[307] Ex. 331, Responses to ALJ Questions 1-8.

[308] Ex. 333, Response to ALJ Question 10.

proof[309] – customers who self-identify as HEAP recipients during customer service-related conversations with NYSEG or RG&E representatives should be immediately enrolled in the Companies' low income programs and permitted to follow-up with the necessary denial letter or notice. Indeed, this practice is consistent with the Commission's direction in the Affordability proceeding[310] and particularly appropriate at a time when so many customers are struggling with financial uncertainty. As DPS Staff observes, that proceeding remains ongoing and may yet result in more expansive, statewide modifications to utility low income programs.

With the minor modifications described in the preceding paragraph, we adopt the terms of the low income programs set forth in the Joint Proposal, concluding that they are in the public interest and further our goal of creating a more protective, uniform system that improves energy affordability for low income households.

O. Resolution of Site Investigation and Remediation Dispute

The Site Investigation and Remediation (SIR) program expenses primarily relate to the costs of investigation, monitoring, cleanup, waste disposal and restoration of sites containing environmental contamination for which the Companies have been found to be wholly or partially responsible under applicable federal and State statutes. In testimony, DPS Staff noted that NYSEG has a SIR cost reserve balance of $9.2 million and recommended that the amount be credited approximately $30.7 million representing certain insurance proceeds as to which

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[309] Ex. 136, Joint Proposal, p. 10.

[310] See Case 14-M-0565, supra, Order Approving Implementation Plans with Modifications, p. 24.

NYSEG was unsuccessful in recovering in a lawsuit as related appeal costs.[311] NYSEG disputed DPS Staff's recommendations in rebuttal testimony.[312]

In light of the risks inherent in litigating the issue, the Joint Proposal requires NYSEG to reduce revenue requirements by $6.0 million per year for each of the three Rate Years to resolve these prudence-related claims against it.[313] This result is consistent with the resolution of similar issues in other cases[314] and provides a significant benefit to ratepayers by offsetting NYSEG's revenue requirements.

P. Storm Costs

The Joint Proposal provides for recovery of deferred NYSEG Electric storm costs of approximately $227.0 million, consisting of unamortized and unrecovered regulatory assets remaining from the 2016 Rate Plan and costs charged to the Major Storm Reserve during the 2016 Rate Plan. NYSEG's super storm regulatory asset of $74.8 million and non-super storm regulatory asset of $119.2 million are being amortized over ten years. The remaining non-super storm regulatory assets of $33.0 million are being amortized over five years.

The Joint Proposal provides for the recovery of net deferred RG&E Electric storm costs of approximately $49.0 million, consisting of unamortized regulatory liabilities remaining from the 2016 Rate Plan and costs charged to the Major

[311] Ex. 170, DPS Staff SIR Panel Testimony, pp. 23-27.

[312] Ex. 64, Companies' SIR Rebuttal Testimony, pp. 16-23.

[313] Joint Proposal, pp. 23-24.

[314] See, Cases 18-E-0067, et al., Orange and Rockland Utilities, Inc. – Electric and Gas Rates, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans (issued March 14, 2019), pp. 105-107.

Storm reserve during the 2016 Rate Plan. These net deferred storm costs are being amortized over five years.

The Major Storm annual rate allowance would be $25.6 million for NYSEG and $3.4 million for RG&E. A "Major Storm" is defined as a period of adverse weather during which service interruptions affect at least 10 percent of customers or results in customers being without electric service for more than 24 hours in an operating district. Once a storm satisfies the Major Storm definition, incremental maintenance costs incurred to restore service as a result of the event must reach a level of at least $750,000 for NYSEG and $500,000 for RG&E for expenses to be chargeable to the Major Storm Reserve.

NYSEG and RG&E would continue to use reserve accounting for Major Storm costs, which would be subject to a symmetrical reconciliation. The Major Storm Reserve accounting procedures would be modified to allow the Companies to charge the Major Storm Reserve in certain circumstances where pre-staging costs are incurred to obtain the assistance of contractors and/or utility companies providing mutual assistance in reasonable anticipation that a Major Storm will affect their electric operations but the event ultimately does not meet the Major Storm definition. As recommended by DPS Staff in testimony, pre-staging costs less than $250,000 would be charged to O&M expenses and pre-staging costs between $250,00 and $1.5 million for NYSEG and costs between $250,000 and $1.25 million for RG&E would be charged 85 percent to the Major Storm Reserve and 15 percent to O&M.[315] We agree with DPS Staff that dollar limitations on pre-staging costs rather than per-event limitations is reasonable because the number of storm events in a year are outside of the Companies' control, while the level of

[315] Ex. 197, DPS Staff Electric Infrastructure and Operations Panel Testimony, pp. 87-91.

spending necessary to adequately pre-stage for anticipated storms is within the Companies' control. The Joint Proposal provides a limitation of a reasonable range of expenses which allows the Companies to adequately prepare for events, with ranges which are higher than any pre-staging event costs incurred to date for either Company. Moreover, the dollar threshold limitation structure for pre-staging costs has been adopted by the Commission in other recent rate plans.[316]

As recommended by DPS Staff in testimony, the Joint Proposal subjects the Companies to additional reporting requirements after a Major Storm event.[317] These additional reporting requirements will provide a standardized format of documentation and enhance DPS Staff's review and audit of Major Storm Reserve charges.

Q. Electric Reliability

The Joint Proposal would maintain the Companies' existing Electric Reliability Performance Measures (ERPMs) and subject the Companies to NRAs if targets are not met. In addition, the Joint Proposal would implement a new Distribution Line Inspection (DLI) Program metric for the Companies to

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[316] See, Cases 19-E-0065, et al., Consolidated Edison – Rates, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans (issued January 16, 2020), pp. 44-45; Cases 18-E-0067, et al., Orange and Rockland Utilities, Inc. – Rates, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans (issued March 14, 2019), pp. 37-38.

[317] Ex. 187, DPS Staff Accounting Panel Testimony, pp. 73-75.

eliminate their backlog of Level II deficiencies.[318] Under the DLI Program, NYSEG and RG&E would be subject to NRAs of $2.0 million and $1.25 million, respectively, if they fail to make timely Level II repairs. The ERPMs and applicable NRAs are set forth in Appendix K to the Joint Proposal. The ERPMs and NRAs are reasonable and in the public interest because they maintain and enhance the Companies' focus on electric safety and reliability.

R. Gas Safety

Section XIV of the Joint Proposal would continue the Companies' gas safety performance mechanisms for leak backlog management, emergency response times, damage prevention, leak prone main (LPM) retirement, and for non-compliance with various gas safety regulations and procedures. The Joint Proposal would maintain or enhance target levels and potential positive revenue adjustments (PRAs) and NRAs. Each Company would be subject to a maximum annual potential NRA of 150 basis points for failing to meet the minimum levels of pipeline performance standards and would have the ability to earn a maximum of 16 basis points in PRAs annually for exceeding the targeted levels. Within sixty days after the end of each calendar year, the Companies would file with the Secretary a report on gas safety performance for the prior calendar year period. The gas safety performance

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[318] Level II deficiencies represent electric system conditions that are likely to fail prior to the next inspection cycle and represent a threat to safety and/or reliability should a failure occur prior to repair. Case 04-M-0159, Proceeding on Motion of the Commission to Examine the Safety of Consolidated Edison Company of New York, Inc.'s Electric Transmission and Distribution Systems, Order Adopting Changes to Electric Safety Standards (issued December 15, 2008), p. 16.

metrics and PRA and NRA levels are listed in Appendix L to the Joint Proposal.

1. Leak Management

The Joint Proposal establishes annual targets of a maximum of 50 for total leak backlog (Types 1, 2, 2A, and 3) for calendar years 2020, 2021 and 2022. If the Companies fail to meet those levels, they will incur an NRA of 15 basis points. The Joint Proposal also provides for the continuation of PRAs, up to a maximum of six basis points annually for achieving a total leak backlog between zero and three, a 10-day period at the end of the calendar year during which the Companies must be at or below the target levels, and a requirement that leaks failing a recheck inspection be included in the backlog for the calendar year the repair was completed.

The leak management program is aggressive as compared to the current program approved in the 2016 Rate Order that set annual targets of 100 total leaks. The metrics and applicable NRAs and PRAs will benefit ratepayers by improving system safety and will benefit the environment by resulting in lower methane emissions.

2. Emergency Response

The Emergency Response performance mechanism included in the Joint Proposal maintains the current minimum statewide emergency response targets and encourages additional improvements through positive revenue adjustments. The Company must respond to a minimum of 75 percent of emergency reports within 30 minutes, 90 percent within 45 minutes, and 95 percent within 60 minutes. The mechanism includes NRAs of 12, eight and five basis points, respectively, for failure to achieve targets. The emergency response metric provides an incentive for the Companies to respond quickly to emergency reports and therefore is in the public interest.

3. Damage Prevention

The Joint Proposal provides for a damage prevention performance mechanism designed to protect and prevent damage to natural gas pipes. This mechanism would establish total annual damages for each rate year and new tiers of negative revenue adjustments ranging from five to 20 basis points for each calendar year the targets are not attained. The damage prevention categories are set per 1,000 one-call tickets in each calendar year. This Joint Proposal’s tiered approach includes all damage prevention categories combined in a single measure. For a damage rate greater than 2.00 through 2.25, the Companies would incur and NRA of five basis points; for a damage rate greater than 2.25 through 2.50, the Companies would incur an NRA of 10 basis points; and for a damage rate greater than 2.50, the Companies would incur an NRA of 20 basis points. DPS Staff states that the damage prevention performance provisions set minimum targets based on the Companies’ recent performance and fall within the range of potential litigated outcomes. Under these circumstances, we agree with DPS Staff that the damage prevention performance metrics are in the public interest.

4. Leak Prone Main

The Joint Proposal continues the Companies’ existing targets for LPP retirement. Each Company must retire a minimum of 30 miles of LPP annually, or 90 miles cumulatively, from calendar year 2020 to 2022. If the annual mileage is not met, the three-year cumulative target will be used. Each Company would incur a 45 basis point NRA for the failure to meet the three-year cumulative target. For each full mile of LPM replaced in excess of the targets, the Companies would receive a PRA of two basis points up to a maximum of 10 basis points. The Companies are allowed to include LPM eliminations resulting from abandonment, disuse or any other means ending the use of LPM while still serving customer needs, including non-pipe alternative implemented in lieu of LPM replacements. Finally, the metric requires the use of a risk-based prioritization model and allows for the inclusion of Distribution Integrity Management Program pre-1971 wrapped steel, provided there is adequate justification and supporting documentation. The LPM metric advances State and Commission goals to decrease greenhouse gases from the environment and is in the public interest.

5. Gas Safety Violations Performance Metric

Under the terms of the Joint Proposal, the existing NRA for regulatory violations identified by DPS Staff during field and records audits would be modified. Only violations identified in DPS Staff field and record audit letters will be counted in this metric. The Joint Proposal defines “high risk” or “other risk” categories of violations, establishes thresholds, and sets NRAs for exceeding the established thresholds. Violations subject to a separate penalty proceeding will not be applied to this metric. The Joint Proposal also identifies procedures for the Companies to cure violations (within ten calendar days of a compliance meeting with DPS Staff). It limits the Companies’ exposure resulting from multiple violations of a single regulation and limits any negative revenue adjustment assessed to no more than 75 basis points. The Joint Proposal provides for DPS Staff to submit a final non-compliance audit report to the Secretary and recommends procedures for the Companies to dispute and appeal any DPS Staff findings in the report.

DPS Staff states that the gas safety violations performance metric in the Joint Proposal has been “standardized” with those of “other local distribution companies.”[319] This

[319] DPS Staff Statement in Support of the Joint Proposal, p. 51.

metric strikes the correct balance between achieving compliance and limiting the Companies’ exposure for multiple violations of the same regulation. It does not change the Companies’ obligations because more than ten violations of any given regulation not captured in this metric may still be subject to the development of a corrective action order or a penalty action under Public Service Law §§25 and 25-a. By providing a strong financial disincentive for non-compliance with minimum pipeline safety regulations, this metric promotes the safe and reliable operation of the Companies’ natural gas systems.

S. Economic Development

In addition to retaining the Companies’ current economic development programs and creating new Small and Large Business Customer COVID-19 Relief Programs for electric business customers, which were discussed earlier, the Joint Proposal would start a new Non-Residential Geothermal and Air Source Heat Pump Pilot Program also would be created. The Non-Residential Geothermal and Air Source Heat Pump Pilot Program would provide a one-time grant assistance per project to install geothermal or air source heat pump systems instead of natural gas heating in customer-owned facilities. Up to $3.155 million at NYSEG and $4.0 million at RG&E may be drawn from economic development reserve funds for this Pilot Program throughout the term of the proposed Rate Plans. In our view, the Non-Residential Geothermal and Air Source Heat Pump Pilot Program is reasonable given the changing energy landscape in New York and need to reduce reliance on fossil fuels.

T. Reforming the Energy Vision

Section XX of the Joint Proposal provides that, until such time as AMI is fully implemented in the Companies’ service territories, the Companies would continue to operate the ESC Project to test and explore implementation and deployment of REV initiatives. The revenue requirements in these cases reflect ESC capital amounts totaling approximately $1.1 million over the term of the rate plans and approximately $1.0 million annually in ESC O&M costs that would be subject to a downward-only reconciliation. Although it opposed continuation of the ESC program in testimony, DPS Staff states that the continuation of the ESC program pending full deployment of AMI in the Companies' service territories "represents a rational compromise" between the Companies' and DPS Staff's testimonial positions and will allow the Companies to continue using the ESC as a testbed for projects that require AMI functionality as AMI is being rolled out elsewhere in the Companies' service territories.[320] We agree that allowing the Companies to continue to use the ESC for those purposes is appropriate and will allow the Companies to seek new ways to use AMI to foster REV goals.

The Joint Proposal would allow NYSEG to implement the Java Station Energy Storage Project, a non-wires alternative consisting of appropriately-sized battery storage systems and associated technology to back up the Java substation. We agree with DPS Staff that company ownership and operation of the Java Station Energy Storage Project is a reasonable alternative to third-party ownership and resulted after a thorough and deliberative process failed to attract private market interest to address power quality and reliability at the Java substation. In addition, NYSEG would perform a second competitive procurement for the energy storage assets required at the Java substation.

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[320] DPS Staff Statement in Support of the Joint Proposal, p. 72.

The Companies would continue to facilitate the adoption of EVs through a Make-Ready EV Infrastructure Program, the addition of EV passenger vehicles and an increase in the number of RG&E's hybrid bucket trucks. The Make-Ready EV Infrastructure Program would incentivize installation of Level 2 chargers and direct-current fast chargers in the Companies' service territories, consistent with the DPS Staff whitepaper on electric vehicles and subject to modification by the Commission in the EV generic proceeding.[321] The program would offset expected interconnection construction and excess distribution facility costs for which the customer/developer would normally be responsible. These provisions of the Joint Proposal further REV-related goals and are in the public interest.

U. Non-Wires and Non-Pipes Alternatives

Section XXI of the Joint Proposal states that the Companies are committed to seeking Non-Wires Alternatives (NWAs) and NPAs to electric and gas capital investments where appropriate and cost-effective. General NWAs and NPAs costs not applicable to specific NWAs/NPAs projects would be considered O&M expenses. Costs incurred by the Companies for implementation of new NWAs and NPAs during the rate plans would be deferred with carrying costs, with recovery of amortized portions of such costs through a separate surcharge. The Joint Proposal also establishes identical incentive mechanisms for NWAs and NPAs, with an initial incentive equal to 30 percent of the present value of net benefits as forecasted with an added incentive equaling up to 50 percent of the difference between the forecast and actual final project cost.

[321] Case 18-E-0138, Electric Vehicle Proceeding.

If a NWA or NPA project displaces a capital project that is included in the targets for Average Electric or Gas Plant in Service balances under the Net Plant reconciliation, the target would be reduced to reflect the forecasted net plant associated with the displaced project. If the carrying charge on the net plant of any displaced project is higher than the recovery of the associated NWA or NPA project cost, the difference would be deferred for customer benefit. The Joint Proposal would continue the existing NWA-related Net Plant Reconciliation mechanism and implement a similar mechanism for NPAs, thereby subjecting the Companies to same framework for modifying the Net Plant in Service Targets to account for NWAs and NPAs that applies to all other investor-owned utilities in New York State.

Within six months after the Commission issues an order in these proceedings, the Companies would submit a BCA handbook for NPAs. The Companies would work with DPS Staff and other interested parties in developing the BCA Handbook for NPAs that would be consistent with the BCA Framework Order and updated as necessary subject to the requirements of the CLCPA. The signatory parties recommend that the Commission institute a statewide proceeding to develop BCA Handbooks for NPAs statewide and that such a proceeding take precedence over the NYSEG- and RG&E- specific efforts contained in the Joint.

The proposed treatment of NWAs would align the Companies' economic objectives with public policy promoting the integration of Distributed Energy Resources and will allow ratepayers to benefit from the Companies' efforts to seek cost-effective alternatives to traditional electric infrastructure investments. The new NPA mechanism will advance the Companies' ability to use non-traditional methods to defer or avoid traditional gas infrastructure to better address the goals established in the CLCPA and current gas system constraints.

V. Earnings Adjustment Mechanisms

As stated in DPS Staff testimony, EAMs are metrics and targets with financial rewards earned for meeting such targets, which are designed to align utility interests with State energy policy goals.[322] Section XXIV of the Joint Proposal would establish seven EAM metrics: (1) Electric Share the Savings, (2) Heat Pump Share the Savings, (3) Beneficial Electrification, (4) DER Utilization, (5) Electric Peak Reduction, (6) Gas Share the Savings, and (7) Gas Heating Load Peak Reduction. The Joint Proposal provides for maximum incentive amounts of up to approximately 65 basis points for NYSEG Electric, 55 basis points for RG&E Electric, and 25 basis points each for NYSEG and RG&E gas. Appendix X to the Joint Proposal sets forth the minimum, midpoint and maximum incentives fixed dollar amounts for each Company for all three RYs, with adjustments made to RY 1 to account for COVID-19 economic impacts. Incentives would be recovered through the Companies RAMs.

The basis points provided in the EAM incentives fall within the range advocated by the Companies (up to 100 basis points annually for electric EAMs and up to 60 basis points annually for the combined gas EAM) and the lower amounts proposed by DPS Staff.[323] The Share the Savings EAMs establish clear boundaries between the electric, heat pump and gas energy efficiency components in accordance with Commission guidance in the 2020 Energy Efficiency Order. DPS Staff states that the EAMs balance “shareholder, customer, environmental, and public

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[322] Ex. 178, DPS Staff EAMs Panel Testimony, p. 5.

[323] Ex. 19, Companies EE and EAM Panel Testimony, p. 10.

interests to establish new incentive mechanisms that will align the Companies' business activities with New York State energy and climate goals."[324] We agree with DPS Staff that the EAMs are in the public interest and would support energy efficiency programs, integration of new clean energy technologies from emerging markets, and demand management activities to manage electric and gas peak conditions.

W. Depreciation

The Joint Proposal includes new depreciation rates and associated plant accounts for all four of the Companies' businesses. The new depreciation rates and associated plant accounts are set forth in Appendix Z to the Joint Proposal. NYSEG Electric also would amortize its existing Electric depreciation reserve excess at values of $30.9 million in RY 1, $35.0 million in RY 2, and $39.1 million in RY 3. As described earlier, we have modified the Joint Proposal so that larger amounts of EDR are amortized for NYSEG Electric during RY 2 and RY 3. The depreciation rates are the result of compromise between the signatory parties, the reasonable range of a potential litigated outcome, and represent a reasonable middle ground that strikes a fair and equitable balancing of the signatory parties' respective concerns.

In addition, as was mentioned, the Companies would use EDR to cover the revenue increases associated with the make-whole period, rather than compressing rates during RY 1. The EDR amortization amounts used for the make-whole period would not be included in rate base in setting the revenue requirements and would not accrue carrying costs during the Rate Plans. Those carrying costs would have totaled approximately $3.5 million during the rate plans.

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[324] DPS Staff Statement in Support of the Joint Proposal, p. 89.

X. Net Plant Reconciliation

As with other recent New York utility rate plans, the Joint Proposal includes a tracking and reconciliation mechanism applicable to the Companies' net plant in service targets. Net Plant reconciliation mechanisms are discussed in section XXVIII of the Joint Proposal and Appendix S thereto. Targets would be established for Electric and Gas Net Plant and Depreciation Expense. Each company would reconcile on an annual basis its actual Electric and Gas Net Plant and Depreciation Expense to those targets. It is also proposed that the actual electric, gas and allocated common average net plant targets for each Rate Year be reconciled to the electric, gas and allocated common net plant targets on an annual basis. The impact of such reconciliations (positive or negative) would carry forward with each Rate Year and would be summed at the end of the rate plans. At that point, the Companies would defer any negative cumulative revenue requirement impact for the benefit of customers. Positive cumulative revenue requirement impacts would not be deferred.

Appendix R to the Joint Proposal includes a list of anticipated capital projects, but retains the Companies' rights to modify the type, timing, identity, nature and scope of any of the forecasted capital projects. Changes in the forecasted expenditures would be subject to reporting requirements and review by DPS Staff. Under the Joint Proposal, there would be individual net plant reconciliations with separate net plant targets with downward-only reconciliation and status reporting for RG&E Electric's Substation Modernization Project, the Resiliency Projects and the Companies' electric businesses, and the AMI Project at all four businesses.

With respect to AMI, the Joint Proposal incorporates DPS Staff's position to include a cumulative capital spend cap of $489.1 million for AMI, with the reconciliation calculated upon final completion of the project as described in Appendix S. The Joint Proposal requires that a net plant reconciliation for AMI capital expenditures be implemented for all AMI capital expenditures (that includes amounts allocated to both electric and gas customers). In the event the overall AMI capital costs are less than the $489.1 million AMI cap, the operation of the net plant reconciliation mechanism will create benefits for customers. To the extent that one or more of the Companies' businesses incur(s) total capital costs of more than the business's share of the $489.1 million, the Companies will have the opportunity to file a petition to the Commission requesting recovery of the amount over their share of the $489.1 million. The AMI Net Plant reconciliation mechanism provides customers with protections similar to the electric and gas net plant reconciliation mechanism and therefore is in the public interest.

Y. Reconciliations/Deferrals

Section XXIX of the Joint Proposal and Appendices T and U thereto provide for the treatment of certain costs as to whether they may be reconciled and deferred, either partially or fully. Such expenses include, among other things, labor; pensions and other post-employment benefits; property taxes; electric and gas vegetation management; management, operations and staffing audits; gas research and development; pipeline integrity; incremental maintenance; Economic Development programs; energy efficiency and heat pumps; and Low Income Programs.

Reconciliations address uncertainties that committing to a long-term rate plan can create. Therefore, their inclusion in Joint Proposals can facilitate agreement where the uncertainty or unpredictably of certain uncontrollable cost elements might give negotiating parties concern, thus preventing agreement. The reconciliation mechanisms discussed above support both the continued provision of adequate service to the Companies' customers and reasonably balance the identified risks of the rate plan term between customers and shareholders. The Joint Proposal's partial reconciliation provisions provide the Companies with an incentive to minimize actual expenses and, as such, are appropriate.

Z. Policy Proceedings

The Commission conducts proceedings associated with statewide policy objectives that may impact the Companies during the term of the Rate Plans. The Joint Proposal appropriately recognizes the Commission's ability to require the Companies to implement changes or take certain action pursuant to such policy proceedings during the term of the rate plans. With respect to the COVID-19, the signatory parties specifically request that the Commission recognize the COVID-19 related provisions incorporated into the Joint Proposal and state that "neither the Companies nor other Signatory Parties would be precluded or limited from advocating or opposition positions in response to the generic proceeding or prohibited from adopting and following the determinations made" in such proceeding. The signatory parties also properly recognize that the Joint Proposal does not limit the Commission's ability to require the Companies to take certain actions in the ongoing proceedings on REV[325] or as a result of the CLCPA.

[325] Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision.

AA. Audit Compliance

Public Service Law §66(19)(a) requires that management and operations audits of combination gas and electric corporations be performed at least once every five years. Pursuant to subdivision (c) of that section, the Commission must review a corporation's compliance with the most recent audit whenever a gas or electric corporation applies for a major change in rates. Here, in pre-filed testimony, DPS Staff addressed the status of three recently completed audits.[326]

In Case 16-M-0610, Overland Consulting, Inc. (Overland), conducted a comprehensive review of the Companies' overall performance and made 81 recommendations for improvement. The Commission thereafter approved the Companies' plan to implement all of the recommendations through 83 discrete projects, with the Commission placing particular emphasis on those recommendations pertaining to REV and Electric System Planning, Capital Construction Program Planning and Prioritization, Electric Outage Readiness and Gas System Planning and Safety.[327]

In its order approving the Companies' implementation

[326] Ex. 26, Staff testimony of Elizabeth Katz Toohey and Angela Morina. Staff also testified in connection with an ongoing Income Tax Accounting Audit prompted by alleged income tax accounting errors at various utilities (case 18-M-0013). That audit was undertaken by Schumaker and Company, Inc., which is evaluating whether the alleged errors in fact occurred and, if so, whether ratepayers consequently received the benefit of lower tax expenses in rates. Although Schumaker's final report has yet to be filed with the Commission, the Companies have not requested recovery of any costs associated with that audit in these rate proceedings.

[327] Case 16-M-0610, In the Matter of Comprehensive Management and Operations Audits of New York State Electric & Gas Corporation, Order Approving an Implementation Plan (issued August 8, 2019).

plan, the Commission noted that several projects were already complete, and the Companies have since filed timely submissions with the Commission reflecting the completion of 67 others. On June 30, 2020, citing the implementation complexities associated with five outstanding recommendations, the Companies requested extensions of time to complete them; the extension requests were deemed reasonable by DPS Staff and granted by the Director of the Office of Accounting, Audits and Finance by letter dated July 17, 2020.

In Case 13-M-0314, Overland was selected by the Commission to conduct an audit regarding the accuracy of the Companies' self-reported data with respect to electric reliability, gas safety and customer service. Overland's final audit report was released on April 20, 2016, and included 229 recommendations for improvement at the Companies.[328] By Order issued on March 10, 2017, the Commission approved the Companies' implementation plan.[329] On November 2, 2018, the Department of Public Service's Office of Accounting, Audits, and Finance confirmed that all of the recommendations relevant to the

[328] 87 of the 229 recommendations were either remanded by the Commission to case 15-M-0556 (customer service-related recommendations) or clarified by the Commission to ensure consistency with Staff/utility gas safety protocols.

[329] Case 13-M-0314, Issue a Request for Proposal for and Independent Third-Party Consultant to Conduct a Review of the Accuracy and Effectiveness of Certain Reliability and Customer Service Systems at all Gas and Combination Gas and Electric Utilities in New York State that Provide Statistics to the Commission on the Services They Provide Customers, Order Approving Implementation Plans (issued March 10, 2017).

Companies in Case 13-M-0314 had been implemented and were complete.[330]

In Case 13-M-0449, the Commission initiated an audit of the internal staffing levels and use of contractors for certain core utility functions at all major New York utilities. That audit was conducted by the Liberty Consulting Group, which made 18 recommendations for improvement at the Companies in a final audit report released on February 21, 2017. The Commission approved the Companies' implementation plan on December 15, 2017.[331] On April 22, 2020, the Director of the Office of Accounting, Audits, and Finance confirmed that all of the recommendations relevant to the Companies in case 13-M-0449 had been implemented and were complete.[332]

In light of the above, we find that the Companies have complied with the directions and recommendations made in each of these recent audits.

VI. EVALUATION UNDER SETTLEMENT GUIDELINES

A. Balance of Utility, Ratepayer and Shareholder Interests

The Joint Proposal is the product of many negotiation sessions noticed to all participating parties, and attended by, representatives of a large number of those parties, held both

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[330] Id., Letter Confirming the Completion of Implementation Oversight of Audit Recommendations, Doris Stout, Director, Office of Accounting, Audits and Finance to Kasi McLaughlin, Avangrid (November 2, 2018).

[331] Case 13-M-0449, In the Matter of a Focused Operations Audit of the Internal Staffing Levels and Use of Contractors for Selected Core Functions at the Major New York State Gas and Electric Utilities, Order Approving Implementation Plans (issued December 15, 2017).

[332] Id., NYSEG and RGE Staffing Audit Completion Letter, Doris Stout, Director, Office of Accounting, Audits and Finance to Joseph Syta, NYSEG and RG&E (April 22, 2020).

before and after the onset of the COVID-19 crisis. Both the gas provisions and the electric provisions of the Joint Proposal are joined by various parties with different interests. Although the gas provisions of the Joint Proposal have garnered broader support, opposition to the electric provisions of the Joint Proposal rests largely on the size of the proposed rate increases and on different opinions as to how the collected funds should be spent. While other valid choices could have been made by the signatory parties, we acknowledge that under normal circumstances the Joint Proposal would strike an appropriate balance between the interests of ratepayers and the long-term viability of the Companies. The Joint Proposal provides immediate rate relief from the economic effects of the COVID-19 pandemic, enables needed and mandatory infrastructure improvements, enhances vegetation management programs to improve system reliability, increases the Companies’ workforce, includes EAMs consistent with Commission policies, implements AMI to increase system reliability, resiliency and safety, and institutes fundamental changes to the Companies’ natural gas businesses in furtherance of reducing reliance on fossil fuels.

Rate increases are often needed to fund programs and capital investments that are necessary to ensure the provision of safe and reliable electric and gas service to the Companies’ customers, an express obligation of the Companies and the Commission’s rate-setting authority in Public Service Law §§65 and 66. The signatory parties took significant action to defer expenses, where appropriate, and to mitigate the effect of necessary expenses through the levelization/shaping of rates, modification of amortization periods, the use of excess depreciation reserve balances to address rate compression, and the use of other regulatory assets as offsets. Even with the Joint Proposal’s increases, the Companies would continue to have among the lowest residential delivery rates among investor-owned utilities in the State. However, given the unique circumstances created by the COVID-19 pandemic, we must modify certain elements of the electric rate increases to reduce the bill impacts as we have discussed previously.

The Joint Proposal benefits ratepayers by including an earnings-sharing mechanism, various downward-only reconciliation mechanisms, and negative revenue adjustments if the Companies miss established targets for certain customer service, electric reliability and gas safety performance metrics. Moreover, the Joint Proposal addresses the economic impacts from the COVID-19 crisis in ways that could not have been achieved in the context of litigation. Although more may be required to address the ongoing economic impacts resulting from the pandemic, the appropriateness of any additional measures needed to provide such relief will be considered by the Commission in its generic COVID-19 proceeding in Case 20-M-0266.

B. Consistency with Environmental, Social and Economic Policy

The terms of the Joint Proposal are consistent with current State and Commission policies and objectives. The Joint Proposal makes significant efforts to address the goals of the CLCPA by including various innovative proposals with respect to natural gas planning, consumption and promotion. We commend the parties for their combined efforts in reaching consensus on issues that must be addressed for the State to combat climate change and meet CLCPA mandates.

The Joint Proposal contains various programs and initiatives that further REV policies. The Joint Proposal provides for energy efficiency, heat pump and electric vehicle programs, and promotes NWAs and NPAs as alternatives to electric or gas capital investments where appropriate and cost-effective.

The Joint Proposal includes various EAMs related to energy efficiency and system efficiency, including targets for the reduction of system peak demand, for load factor improvement, and to increase the use of distributed energy resources. The implementation of AMI in the Companies' service territories ultimately will provide numerous benefits to ratepayers. All of these programs and initiatives will further the Commission's objective of making electric and gas systems more efficient, reliable, resilient, diverse, customer-centric and clean.

The provisions of the Joint Proposal promote various other State and Commission objectives. Among other things, the Joint Proposal provides for an enhanced low income program, continued economic development support, advancement of grid modernization efforts and distributed energy, appropriate incentive mechanisms, and continuation of gas safety mechanisms and remediation of leak prone pipe.

C. <u>Results within the Range of Likely Litigation Outcomes</u>

The voluminous record before us includes the litigation positions of the participating parties entered as exhibits at or after the evidentiary hearing. These exhibits clearly establish the broad range of outcomes that could have been pursued in litigation had the parties not entered into negotiated settlement. The terms of the Joint Proposal are a product of consensus and fall well within the range of potential litigated outcomes or otherwise provide benefits to ratepayers that could not have been achieved in litigation, making the settled outcome we achieve here today superior to what may have been achieved through a fully-litigated proceeding. Moreover, our modifications to the Joint Proposal will provide further relief to ratepayers in a manner that does not impact any of the necessary and desirable goals supported by the Joint Proposal.

VII. ALTERNATIVE ONE-YEAR RATE PLAN

Because we are making modifications to the Joint Proposal, we will require that the Companies confirm to the Commission their unqualified acceptance of the Multi-Year Rate Plan, as modified in and established by this Order, prior to its becoming effective. In the event that the Companies do not confirm their unqualified acceptance of the Modified Multi-Year Rate Plan established in this Order, then the revenue requirement that will be established effective April 17, 2020, will be as reflected in the Joint Proposal for each of the Companies for RY 1, without the levelizing and shaping effects created by the Joint Proposal, but with the additional modifications contained herein (and including the use of EDR for the make whole provision). The alternative rate terms, conditions, and provisions associated with the one-year revenue requirement that we adopt comprise the Joint Proposal as modified above with the additional following exceptions: 1) there will be no earnings sharing mechanism and 2) property taxes will not be subject to reconciliation. Additionally, the Companies would not be subject to the provisions related to Legislative, Accounting, Regulatory, Tax and Related Actions as contained in the Reconciliations/Deferrals section of the Joint Proposal, Section XXIX.M. If the Companies choose not to accept the modifications, then they should file tariff leaves reflecting this ordered alternative rate plan with such leaves to go into effect on a temporary basis until made permanent by the Commission after a compliance review has been completed.

VIII. CONCLUSION

We find that there is a sufficient record basis for our decision to adopt the terms proposed by the signatory parties as set forth in the attached Joint Proposal, with the modifications discussed in the body of this Order. The Statements in Support of the signatory parties and the record evidence on which those parties rely persuade us that these terms reflect an appropriate balance between our duties to protect consumers while ensuring the economic viability of the Companies. Further, the agreed-upon terms, resulting from the hard work and dedication of the parties to these proceedings, are consistent with our environmental, social and economic policies and those of the State. Accordingly, we find that the rate plans adopted herein provide just and reasonable rates, terms and conditions; and, consistent with the discussion herein, are in the public interest.

The Commission orders:

1. The rates, terms, conditions, and provisions of the Joint Proposal dated May 21, 2020, filed in these proceedings and attached hereto as Attachment 1, are modified as described in the Order above (hereinafter, Multi-Year Rate Plan) and adopted and incorporated to the extent consistent with the discussion herein. An officer of New York State Electric & Gas Corporation and an officer of Rochester Gas and Electric Corporation are directed to file with the Commission a letter confirming the unconditional acceptance by New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation, respectively, of the Multi-Year Rate Plan established in this Order by noon on November 23, 2020.

2. New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation are directed to file cancellation supplements, effective on not less than one day's notice, on or before November 24, 2020, cancelling the tariff amendments and supplements listed in Attachment 9.

3. In the event New York State Electric & Gas Corporation and Rochester Electric and Gas Corporation do not unconditionally accept the Multi-Year Rate Plan established by this Order, New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation are directed to file, on not less than three days' notice, to become effective on December 1, 2020, such tariff amendments, to be effective on a temporary basis, as are necessary to effectuate the One-Year Rate Plan described in the Order above and are further directed to file, within 30 days of the date of this Order, all necessary revised Appendices to the Joint Proposal, including, but not limited to Appendices F, J, R, S, T, W, X, Y, AA, BB, and CC, to reflect the One-Year Rate Plan described in the Order above.

4. In the event New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation unconditionally accept the Multi-Year Rate Plan established by this Order, New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation are authorized to file, on not less than three days' notice, to take effect on December 1, 2020, on a temporary basis, such tariff changes as are necessary to effectuate the terms of this Order for Rate Year 1, the 12-month period ending April 30, 2021, and are further directed to file, within 30 days of the date of this Order, all necessary revised Appendices to the Joint Proposal, including, but not limited to, Appendices F, J, R, S, T, W, X, Y, AA, BB, and CC, to reflect the Multi-Year Rate Plan established by this Order. New York State Electric & Gas Corporation and Rochester Gas & Electric Corporation are also authorized to file such tariff changes as are necessary to effectuate ratepayer charges and provisions pursuant to the terms adopted in this Order and to incorporate any provisions

that were previously approved by the Commission since the tariff amendments in Attachment 9 were filed.

5. New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation shall serve copies of its filings on all active parties to these proceedings. Any party wishing to comment on the tariff amendments may do so by filing its comments with the Secretary to the Commission and serving its comments upon all active parties within fourteen days of service of the tariff amendments. The amendments specified in the compliance filings shall not become effective on a permanent basis until approved by the Commission and will be subject to refund if any showing is made that the revisions are not in compliance with this Order.

6. In the event New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation unconditionally accept the Multi-Year Rate Plan established by this Order, New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation are directed to file such further tariff changes as are necessary to effectuate the terms and provisions for Rate Year 2, the twelve-month period ending April 30, 2022, and for Rate Year 3, the twelve-month period ending April 30, 2023. Such changes shall be filed on not less than 30 days' notice to be effective on a temporary basis until approved by the Commission.

7. The requirement of the Public Service Law §66(12)(b) that newspaper publication be completed prior to the effective date of the amendments for Rate Year 1 is waived; provided, however, that New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation shall file with the Secretary to the Commission, no later than six weeks following the effective date of the amendments, proof that a notice to the public of the changes set forth in the

amendments and their effective date has been published once a week for four consecutive weeks in one or more newspapers having general circulation in the service territory of each of New York State Electric & Gas Corporation’s and Rochester Gas and Electric Corporation’s businesses. The requirements of Public Service Law §66(12)(b) are not waived for tariff changes necessary to implement the rate plans in Rate Years 2 and 3.

8. New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation shall file, within 60 days of the issuance of this Order, an AMI Benefit Implementation Plan that is in compliance with the body of this Order.

9. New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation shall file, within 90 days after issuance of this Order, a report with DPS Staff as to the status of their implementation of the redesigned Capital Planning and Investment Decision Making Process.

10. In the Secretary’s sole discretion, the deadlines set forth in this Order may be extended. Any request for an extension must be in writing, must include a justification for the extension, and must be filed at least three days prior to the affected deadline.

11. These proceedings are continued.

By the Commission,

(SIGNED)

MICHELLE L. PHILLIPS
Secretary

BEFORE THE
NEW YORK STATE
PUBLIC SERVICE COMMISSION

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Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of New York State Electric & Gas Corporation for Electric Service	Case 19-E-0378
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of New York State Electric & Gas Corporation for Gas Service	Case 19-G-0379
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Rochester Gas and Electric Corporation for Electric Service	Case 19-E-0380
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Rochester Gas and Electric Corporation for Gas Service	Case 19-G-0381

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JOINT PROPOSAL

May 21, 2020

TABLE OF CONTENTS

APPENDICES

BEFORE THE
NEW YORK STATE
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of New York State Electric & Gas Corporation for Electric Service	Case 19-E-0378
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of New York State Electric & Gas Corporation for Gas Service	Case 19-G-0379
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Rochester Gas and Electric Corporation for Electric Service	Case 19-E-0380
Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Rochester Gas and Electric Corporation for Gas Service	Case 19-G-0381

JOINT PROPOSAL

I. INTRODUCTION

This Joint Proposal ("Proposal" or "Rate Plan") is made this 21 day of May 2020, by and among New York State Electric & Gas Corporation ("NYSEG"); Rochester Gas and Electric Corporation ("RG&E," and together with NYSEG, the "Companies"), which both sign on to the Proposal in its entirety; the New York State Department of Public Service Staff ("Staff"), which signs on to the Proposal in its entirety; Alliance for a Green Economy ("AGREE"), which signs on to the Proposal as it relates to the gas businesses of NYSEG and RG&E only; Binghamton Regional Sustainability Coalition, which signs on to the Proposal as it relates to the gas businesses of NYSEG and RG&E only; Bob Wyman, who signs on to the Proposal in its entirety; ChargePoint, Inc., which signs on to the Proposal as it relates to the electric businesses of NYSEG and RG&E only; Concerned Citizens of Oneonta, which signs on to the Proposal as it relates to the electric and gas businesses of NYSEG only; Dennis Higgins, who signs on to the Proposal as it relates to the gas businesses of NYSEG and RG&E only; Empire State Development Corporation, the New York State Department of Economic Development, which signs on to the Proposal in its entirety; Fossil Free Tompkins, which signs on to the Proposal as it relates to the gas businesses of NYSEG and RG&E only; HeatSmart, a program of Solar Tompkins Inc., which signs on to the Proposal as it relates to the gas businesses of NYSEG and RG&E only; International Brotherhood of Electrical Workers, Local Union 10 ("IBEW"), which signs on to this Proposal as it relates to the electric and gas businesses of NYSEG only; Keith Schue, who signs on to the Proposal as it relates to the gas businesses of NYSEG and RG&E only; Multiple Intervenors ("MI"), which signs on to the Proposal in its entirety;[1] New York Geothermal Energy Organization ("NY-GEO"), which signs on to the Proposal in its entirety; New York Power Authority ("NYPA"), which signs on to the Proposal as it relates to the electric businesses of NYSEG and RG&E only; Nucor Steel Auburn, Inc. ("Nucor"), which signs on to the Proposal as it relates to the electric and gas businesses of NYSEG only; Ratepayer and Community Intervenors, which signs on to the Proposal as it relates to the gas businesses of NYSEG and RG&E only; Rochester People's Climate Coalition ("RPCC"), which signs on to the Proposal as it relates to the gas businesses of NYSEG and RG&E only; Suzanne Winkler, who signs on to the Proposal as it relates to the gas business of NYSEG only; Walmart Inc., which signs onto this Proposal as it relates to the electric businesses of NYSEG and RG&E only; and other parties whose signature pages are or will be attached to this Proposal (collectively

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[1] MI is an association of approximately 60 large industrial, commercial and institutional energy consumers with manufacturing and other facilities located throughout New York State, including within the service territories of NYSEG and RG&E.

referred to herein as the "Signatory Parties"). This Proposal settles all contested issues among the Signatory Parties in the above-captioned cases.

The Signatory Parties acknowledge that this Proposal has been negotiated and reached during the COVID-19 Pandemic, which is a very rapidly evolving national health and economic crisis. As a result, the Proposal expressly addresses customer and other impacts related to the COVID-19 Pandemic, while recognizing that additional impacts or developments may emerge requiring further action.[2]

II. PROCEDURAL HISTORY

The Companies are operating under the Order Approving Electric and Gas Rate Plans in Accord with Joint Proposal,[3] that established the terms of a three-year electric and gas rate plan for the period from May 1, 2016 through April 30, 2019 ("2016 Rate Plan"). The 2016 Rate Plan contains provisions allowing the Companies to operate under the 2016 Rate Plan beyond April 30, 2019. The Companies "stayed-out" approximately one year before filing these rate proceedings. On May 20, 2019, the Companies filed new tariff leaves and testimony with the New York State Public Service Commission ("Commission" or "PSC") in support of proposed increases to their respective electric and gas delivery revenues to become effective on April 17, 2020.[4] Consistent with Commission practice, administrative law judges ("ALJs") were appointed to conduct the rate proceedings to review the Companies' rate filings. Parties to these

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2 See Section IV below.

3 Cases 15-E-0283 et al. - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of New York State Electric & Gas Corporation for Electric Service, Order Approving Electric and Gas Rate Plans in Accord with Joint Proposal (June 15, 2016).

4 On July 9, 2019, the Companies filed supplemental testimony related to Energy Efficiency ("EE") and Earnings Adjustment Mechanism ("EAM") targets.

proceedings engaged in discovery and the Companies responded to nearly 1,400 multi-part discovery requests.

On August 5, 2019, the Companies filed an update to their May 20, 2019 filing.[5] On or around September 20, 2019, Staff and other parties filed testimony in response to the Companies' filings.[6] The Companies filed rebuttal testimony on October 15, 2019.[7] Staff and other parties also filed rebuttal testimony on October 15, 2019.[8]

Consistent with the Commission's Settlement Guidelines[9] and Title 16 of the New York Codes, Rules and Regulations ("NYCRR"), Section 3.9, the Companies filed with the Commission and served on all parties a Notice of Impending Settlement Negotiations on October 11, 2019. On October 16, 2019, the Companies requested that the evidentiary hearing that had been scheduled to commence on October 28, 2019, be postponed to allow the parties to negotiate a settlement. As part of their request, the Companies agreed to a 30-day extension of the suspension period through and including May 16, 2020, subject to a make-whole provision that would keep the Companies and their customers in the same financial position they would have been absent the extension. Settlement negotiations began on October 22, 2019 and continued on November 12, 2019.

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5 The Companies filed additional updated information on August 8, 2019.

6 The other parties that filed testimony were Concerned Citizens of Oneonta; County of Westchester; Fossil Free Tompkins; Richard Ford; Dennis Higgins; IBEW; MI; Nucor; NYPA; the Public Utility Law Project of New York, Inc. ("PULP"); RPCC; Karl Seeley; the New York State Department of State, Division of Consumer Protection, Utility Intervention Unit ("UIU"); ChargePoint, Inc.; and Walmart, Inc. In addition, the County of Broome filed "Comments" on September 20, 2019.

7 The Companies filed corrected Rebuttal Testimony of David A. Heintz on October 18, 2019 to remove confidential headers inadvertently contained in the initially-filed version of the rebuttal testimony.

8 The other parties that filed rebuttal testimony were Dennis Higgins, MI, Nucor, NYPA, PULP, Bob Wyman, and UIU.

9 32 NYPSC 71, Cases 90-M-0255 et al. - Proceeding on Motion of the Commission Concerning its Procedures for Settlement and Stipulation Agreements, filed in C11175, Opinion, Order and Resolution Adopting Settlement Procedures and Guidelines, Opinion 92-2 (Mar. 24, 1991) ("Settlement Guidelines").

By letter dated November 15, 2019, the Companies agreed to further extend the suspension period through and including July 15, 2020 subject to a make-whole provision. Further settlement discussions occurred on December 19, 2019; January 14, 30 and 31, 2020; February 14 and 25, 2020; March 12 and 17, 2020. On March 19, 2020 the Commission issued an Order on the Extension of Maximum Suspension Period of Major Rate Filings granting the extension of the suspension period through and including July 15, 2020 and granting the make-whole from April 17, 2020 until the Commission issues a final rate decision in these proceedings.

By letter dated March 26, 2020, the Companies filed a request to further extend the suspension period through and including September 13, 2020 subject to the make-whole provision. This further suspension period was necessary to allow the parties time for additional settlement negotiations to address the COVID-19 Pandemic. Further settlement negotiations occurred on April 2, 16, 24, 30, 2020; and May 12, 13, 14 and 19, 2020. The settlement negotiations also included numerous additional "working group" meetings on specific issues that were held with the consent of all parties. All negotiations were held either in person or via teleconference, or both. All settlement negotiations were subject to the Commission's Settlement Guidelines and 16 NYCRR 3.9, and appropriate notices for negotiating sessions were provided.

The parties' settlement negotiations were successful and resulted in this Proposal which is presented to the Commission for its consideration. The Signatory Parties have developed a comprehensive set of terms and conditions for a three-year rate plan for NYSEG's and RG&E's electric and gas services. The terms of this Proposal, as set forth below and in the attached Appendices, balance the varied interests of the Signatory Parties including, but not limited to, providing customers with COVID-19 relief, improving system reliability, mitigating rate impacts to customers, and addressing certain gas matters.[10]

III. TERM AND EFFECTIVE DATE OF RATE CHANGES

The Companies filed tariffs for these rate cases with an effective date of April 17, 2020. During the period prior to new tariffs being implemented, the Companies will be made whole as noted in Section V(E). The Signatory Parties anticipate new rates will be effective September 1, 2020, if Commission approval is received prior to that date. If Commission approval occurs before or after the September 1, 2020 effective date for new tariffs, the Companies will make the requisite make-whole revenue adjustments to accommodate the change in the effective date of the tariffs.

For ease in accounting and tracking, the Rate Years for purposes of this Proposal will coincide with calendar months. The term of this Proposal is three years and fourteen days, commencing April 17, 2020 and continuing through April 30, 2023. However, for purposes of this Proposal, Rate Year 1 ("RY1") means the 12-month period starting May 1, 2020 and ending April 30, 2021; Rate Year 2 ("RY2") means the period starting May 1, 2021 and ending April 30, 2022; and Rate Year 3 ("RY3") means the period starting May 1, 2022 and ending April 30, 2023.

Various provisions in this Proposal will reflect a Rate Year basis while others will reflect a calendar year basis. Except as otherwise specified herein, all provisions of this Proposal will remain in effect until superseding rates and related terms become effective.

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[10] Appendices A through JJ are appended to and expressly incorporated by reference into this Proposal.

IV. COVID-19 PANDEMIC CUSTOMER RELIEF PROVISIONS

The Proposal contains numerous COVID-19 Pandemic provisions that reflect NYSEG and RG&E's central value of protecting the health and safety of their customers and employees. As indicated in Section II of the Proposal, above, the parties expended significant time and resources in settlement to reach a tentative agreement in principle prior to the unforeseen and sudden arrival of the COVID-19 Pandemic.

After deliberate consideration, most of the parties elected to continue active and positive settlement negotiations to adjust the Proposal to include additional direct customer assistance mechanisms as well as incorporate significant reductions in revenue requirement from NYSEG and RG&E electric and gas businesses. Notably, many of these provisions would neither be possible nor available outside of the multi-year settlement context.

The COVID-19 Pandemic provisions of the Proposal summarized below reflect a thoughtful and careful balancing of important customer support mechanisms, reduced rate impacts (particularly in RY1) and overall revenue requirement levels that will still provide the Companies with the resources necessary to enable them to continue providing adequate service at just and reasonable rates. The parties are proposing specific customer relief provisions to address the COVID-19 Pandemic. These customer relief provisions are identified below and embedded throughout the Proposal and Appendices:

(1) Suspension of disconnection for non-payment. Residential and Non-Residential disconnects for non-payment were suspended on March 13, 2020. This provision will remain in place until a date determined by the Companies in consultation with the Department of Public Service Staff or the Commission

(2) Suspension of certain customers charges including: late payment charges, reconnect fees, residential customer deposits, and same day turn on fees. This provision will remain in place until a date determined by the Companies in consultation with the Department of Public Service Staff or the Commission;

(3) Customer Bill Credits with an overall cap of $30.0 million which will directly benefit some of the Companies' most vulnerable residential and small commercial customers facing negative economic impacts as a result of the COVID-19 Pandemic. NYSEG will have an overall Company cap of $16.5 million and RG&E will have an overall Company cap of $13.5 million. Relief in the form of bill credits will begin in 2020 and occur over three phases.

When the bill credits are provided to customers, the Companies will create regulatory assets that will be recovered over five years beginning in July 2021 with carrying charges applied on the unrecovered balance using the Commission's Other Customer Capital rate. The recovery will be through the Rate Adjustment Mechanism ("RAM") for each business until the balance is fully recovered. As noted in Appendix W – Rate Adjustment Mechanism, the customer bill credits shall be recovered from those service classes which were eligible to receive the customer bill credits. Specifically, residential classes will be charged for the recovery of the residential bill credits and applicable non-residential service classes will be charged for the recovery of the non-residential bill credits. The Companies expect that the bill credits will be applied to customer accounts in Phase 1 starting with the billing cycle that starts about 30 days following a Commission order approving the Proposal. Phase 2 and Phase 3 bill credits are expected to begin with bill cycles during the months of October 2020 and January 2021, respectively.

The three phases of bill credits will be:

<u>Phase 1 (through May 31, 2020)</u>:

The first phase will provide customer relief through a one-time $100 maximum bill credit to approximately 133,000 customers[11] who meet the following criteria as of May 31, 2020:

- Residential
    - Low Income Programs participants
    - Customers on minimum payment agreements, but not enrolled in the Low Income Programs
- Small Commercial
    - Customers on payment agreements
    - Customers in arrears

<u>Phase 2 (June 1, 2020 through August 31, 2020)</u>:

The Companies recognize that there will be customers who do not currently meet Phase 1 criteria who will be economically impacted by this Pandemic, but would become eligible under the criteria noted below between June 1, 2020 and August 31, 2020. In an effort to

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11 Eligible customer counts as of April 2020 are: NYSEG Residential = 60,717; RG&E Residential = 47,041. NYSEG small commercial = 17,311; RG&E small commercial = 7,906.

assist these newly payment-challenged customers, one-time bill credits will be provided to these customers. These credits will be a maximum of $100 per customer. If sufficient funding under the total Company caps noted above is not available to provide $100 to each newly qualifying customer, then a reduced amount will be provided to each newly qualifying customer using the formula "Total Company Cap less Company Bill Credits provided in Phase 1" divided by the number of newly qualified customers. Credits will be provided in Phase 2 only to customers who did not receive a bill credit in Phase 1.

Phase 2 credits will be provided to customers who meet the following criteria between June 1, 2020 and August 31, 2020:

- Residential
    - New Home Energy Assistance Program ("HEAP") recipients (and therefore new Low Income Program participants)
    - New minimum payment agreement

- Small commercial
    - New payment agreement

Phase 3 (September 1, 2020 through November 30, 2020):

The Companies recognize that there will be customers who do not currently meet Phase 1 or Phase 2 criteria who will be economically impacted by this Pandemic, and would become eligible under the criteria noted below between September 1, 2020 and November 30, 2020. In an effort to assist these newly payment-challenged customers, one-time bill credits will be provided to these customers. These credits will be a maximum of $100 per customer. If sufficient funding under the total Company caps noted above is not available to provide $100 to each newly qualifying customer, then a reduced amount will be provided to each newly qualifying customer using the formula "Total Company Cap less Company Bill Credits provided in Phases 1 and 2" divided by the number of newly qualified customers. Credits will be provided in Phase 3 only to customers who did not receive a bill credit in either Phase 1 or Phase 2.

Phase 3 credits will be provided to customers who meet the following criteria between September 1, 2020 and November 30, 2020:

- Residential
    - New HEAP recipients (and therefore new Low Income Program participants)
    - New minimum payment agreement

- Small commercial
    - New payment agreement

The Customer Bill Credit Program will end with Phase 3, even if a Company has not reached the previously indicated cap level.

Any modifications to this treatment could be determined in any future generic proceeding addressing the COVID-19 Pandemic.

(4) A new COVID-19 Grant Assistance Program within the Companies' overall Economic Development Program intended to help challenged electric business customers, including Large Commercial and Industrial Customers.

The Economic Development COVID-19 Grant Assistance Program is intended to be independent of other governmental assistance being provided at the local, state, and federal level. The proposed COVID-19 program will be comprised of two sub-programs: a Small Business Customer Program and a Large Business Customer Program. Funding will come from the Companies' already proposed levels of economic development spending and will be up to $2 million per year ($1 million for each Company) under the Companies' Small Business Customer Program and up to $4 million per year ($2 million for each Company) under the Companies' Large Business Customer Program. Details regarding the eligibility of customers for the programs are set forth in Appendix V. Key aspects of these proposed programs include a $15,000 cap per project for small businesses, and a $50,000 cap per project for large businesses. Large customers would be primarily those electric customers in the SC 7 rate classes at NYSEG with peak demand of 500kW or greater and the SC 8 rate class at RG&E with peak demand of 300kW or greater. These COVID-19 grant assistance programs would be in place during the term of the Rate Plan and then would be discontinued.

(5) Maintaining an arrears forgiveness program as part of the Companies' Low Income Program, and expanding self-enrollment in the Companies' Low Income Program to include any customer who is denied a HEAP grant, but who can provide confirmation via a denial letter that he or she is HEAP eligible.

(6) Instituting more flexible deferred payment agreement ("DPA") provisions:

- Negotiate/re-negotiate a DPA based on a customer's ability to pay, regardless of a customer's prior payment and DPA history;
- Negotiate agreements verbally, sending written confirmation to customers for signature (honor agreement regardless of whether agreement is signed);
- If documentation to support a financial statement form is required, there will be flexibility regarding the timeline and format within which customers submit the documentation (honor agreement while awaiting the documentation)
- Institute flexible terms for non-residential DPAs; and
- Continue process to implement electronic DPAs.

(7) In order to ensure that the resumption of disconnect of service for non-payment happens in a gradual fashion, the Companies will modify disconnect for non-pay actions to align with the timeline shown below:

Dunning Action	Current Process	Proposed Process 2020	Proposed Process through Q2 2021	Proposed Process though Q4 2021	2022 (Assume Normal Process Resumes)
Additional Call Attempt*	N/A	In Advance of Field Order	In Advance of Field Order	In Advance of Field Order	N/A
Minimum Days Past Due for Disconnect	30 Day Arrears	90 Day Arrears	60 Day Arrears	60 Day Arrears	30 Day Arrears
Minimum Dollars for Field Disconnect	$75	$200	$150	$100	$75

*outside of cold weather time period; normal process continues for 72 hour advance notice during cold weather period

The Proposal also suspends disconnects for customers coded as Elderly, Blind, or Disabled for three months following resumption of residential disconnects for non-payment.

(8) The Companies will not permanently close any Customer Walk-in Offices through June 2021 to support customers. As agreed, the Companies will provide reports of customer traffic in each customer office. The agreed-upon office closures will commence after June 2021 provided, however, that any material increase in traffic in an office above the levels existing at the time the Companies filed their initial testimony will be reviewed with Staff to determine if the closure of that office is still appropriate.

(9) In order to notify customers of potential assistance available to help with their utility bill, the Companies will perform additional outreach to include the items outlined below.

a. Outbound Calling Campaigns
b. Bill Messages
c. EnergyLines Bill Insert
d. Websites
e. E-mails
f. IVR messaging

The Companies agree to file an updated Outreach Plan including these items within 60 days of the Commission's issuance of an order approving the Proposal in these proceedings.

(10) The Companies will engage in additional customer advocate communications, including expanded community and agency outreach to ensure new groups of vulnerable populations are aware of internal and external assistance programs and payment options. The Companies will also engage in additional municipal outreach and communication regarding available programs.

To complement these direct customer relief provisions, the Proposal's Revenue Requirement shows significant reductions from the Companies' originally-filed testimony and reflects COVID-19 Pandemic impacts as discussed in Section V below.

V. REVENUE REQUIREMENTS INCLUDING COVID-19 PANDEMIC IMPACTS

The Signatory Parties agree to the rate changes for each of the Companies for the Rate Years described in this Proposal and the Appendices incorporated herein. Consistent with the Commission's Order Adopting Accelerated Energy Efficiency Targets issued on December 13, 2018 in Case 18-M-0084[12] and Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025 issued on January 16, 2020 in Case 18-M-0084,[13] the cost of the Companies' EE/heat pump programs will now be collected in base rates rather than through a separate EE surcharge. Thus, the Signatory Parties expressly note that the Companies' revenue requirements and base delivery rates include EE Tracker costs for EE programs that are administered by the Companies and currently collected through the System Benefits Charge ("SBC"), as well as incremental EE spending mandated by the Commission, as adjusted due to the COVID-19 Pandemic as noted below. The base delivery rates also include costs associated with Electric Heat Pump programs administered by the Companies, as well as incremental Heat Pump programs mandated by the Commission. Upon implementation of new delivery rates, the Companies will discontinue the EE Tracker component of the SBC surcharge currently applied to customer bills. In addition, the revenue requirements in this Proposal reflect the impacts of the Tax Cut and Jobs Act of 2017. Tax credits associated with the Commission's August 9, 2018 Order Determining Rate Treatment for Tax Changes issued in Case 17-M-0815 will cease with the implementation of the Proposal.[14]

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12 Case 18-M-0084 - In the Matter of a Comprehensive Energy Efficiency Initiative, Order Adopting Accelerated Energy Efficiency Targets (Dec. 13, 2018).

13 Case 18-M-0084, Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025 (Jan. 16, 2020) ("January 16, 2020 Order").

14 Case 17-M-0815 – Proceeding on Motion of the Commission on Changes in Law that May Affect Rates, Order Determining Rate Treatment for Tax Changes (Aug. 9, 2018).

Customers taking electric service from the Companies that are currently exempt from paying the SBC will continue to receive an exemption from costs associated with EE Tracker and Electric Heat Pump programs through a delivery rate credit that will be listed on those customers' bills.

NYSEG Electric and RG&E Electric revenue requirements reflect the resolution of Cases 19-E-0105 and 19-E-0106 - Response to Power Outages During the 2018 Winter and Spring Storms. NYSEG Electric and RG&E Electric revenue requirements also reflect the amortization of $9.0 million and $1.5 million, respectively, in regulatory liabilities over three years as moderators to electric delivery rates.

A. Adjustments Due to COVID-19 Pandemic

1. Adjustments to Revenue Requirements (Increase / Decrease)

The Signatory Parties focused on and achieved in the Proposal further reductions in RY1 increases at both NYSEG Electric and RG&E Electric in response to the COVID-19 Pandemic. There will be no increase at NYSEG Gas in RY1 or RG&E Gas in RY1 and RY2.

2. Generic Proceeding

To the extent the Commission initiates a generic proceeding to address COVID-19 Pandemic related matters including incremental savings and costs (e.g., uncollectible expense, late payment charges, travel, collection activity, etc.), the Signatory Parties request the Commission recognize the many COVID-19 provisions already incorporated into the Proposal.[15] However, neither the Companies nor other Signatory Parties would be precluded or limited from

[15] For the avoidance of doubt, the Signatory Parties agree that nothing in this Proposal precludes or limits the Companies from being granted or seeking recovery or deferral of any incremental costs related to the COVID-19 Pandemic. Similarly, all other Signatory Parties reserve all rights to take and pursue positions with respect to such filings by the Companies.

advocating or opposing positions in response to the generic proceeding or prohibited from adopting and following the determinations made in such a generic proceeding.

3. Operations & Maintenance Changes

This Proposal also reflects adjustments in RY1 costs for certain operations and maintenance ("O&M") items to accommodate the COVID-19 Pandemic, such as:

(1) RY1 now reflects a $5.7 million decrease at NYSEG Electric and $2.95 million decrease at RG&E Electric to adjust the start for the Grid Model Enhancement Project. The full project will begin in RY2;

(2) A 25% decrease in RY1 O&M for collection-related costs for all four businesses;

(3) An increase in each Rate Year's O&M costs to maintain the Arrears Forgiveness Program at the 2016 Rate Plan levels;

(4) A reduction in RY1 O&M at the Gas businesses to reflect the delayed start of the additional contractors supporting the Damage Prevention program. The full program costs are reflected beginning in RY2; and

(5) A 20% reduction in travel costs to reflect New York State, federal and corporate restrictions on non-essential travel.

4. Inflation Update

The Companies updated inflation to reflect actual inflation through the first quarter of 2020 and the April 10, 2020 Blue Chip Forecast. This additional update reduced RY1-RY3 revenue requirements by an additional $10.9 million across all four businesses.

5. Capital Projects

The Companies' rate base as reflected in this Proposal has been adjusted for the following plant in service modifications in response to the COVID-19 Pandemic:

(1) Delay of advanced metering infrastructure ("AMI") meter deployment by 12 months and certain information technology ("IT") related AMI requirements by 6-12 months, effectively moving full deployment from year three to year four, while maintaining implementation of the upgraded billing system on the current schedule to assure billing system readiness when AMI meters are installed; and

(2) Delay in spending for over 30 gas and electric projects resulting in a related delay in cash flows and in-service dates.

6. Suspension of Certain Customer Charges

As discussed in Section V the following customer service fees/charges have been suspended by the Companies: late payment charges; reconnect fees, residential customer deposits and same day turn on fees. While the Companies have suspended collection of these fees at this time, such fees are included in the forecasted revenue requirement for the Companies at their pre-Pandemic levels. Any modifications to this treatment could be determined in any future generic proceeding addressing the COVID-19 Pandemic.

7. Uncollectible Expense

The delivery uncollectible expense is included in the forecasted revenue requirement for the Companies at their pre-Pandemic levels. Supply uncollectible expense is a component included in the merchant function charge and the purchase of receivables from energy service companies based on the applicable methodologies. Any modifications to this treatment could be determined in any future generic proceeding addressing the COVID-19 Pandemic.

8. Debt Reconciliation

The Companies' average fixed rate debt costs rates were updated to reflect market conditions as of May 2020. The Companies will symmetrically reconcile fixed and variable rate debt costs (the Companies currently do not have any variable rate debt in their debt portfolios). This debt reconciliation is delineated in Appendix T.

9. Energy Efficiency

As detailed in Section XXIII of this Proposal, EE/Heat Pump Program costs will be rolled into delivery rates. Any differences between the amounts collected by the EE Tracker surcharge currently in place at all businesses and the amounts that otherwise would have been collected during the make-whole period will be deferred in a regulatory asset or regulatory liability. In consideration of COVID-19 impacts, the roll-in of EE/Heat Pump targeted programs into base rates will be adjusted as set forth in Appendices B, C, D, and E. For NYSEG Electric only, the RY1 level will be set at 80% of the levels set forth in the Commission's January 16, 2020 Order, RY2 will be at 85% and RY3 will be at 90%, with the difference allocated to the post-Rate Plan period. For RG&E Electric, NYSEG Gas, and RG&E Gas, the RY1 and RY2 levels will be set at 85% of the levels set forth in Commission's January 2020 Order, with the difference allocated to the post Rate Plan period. To the extent required, delivery rates will be adjusted in RY4 and RY5.

10. Amortization Modifications

Vegetation management activities, including Danger Tree removal spending, is discussed further in Section IX of the Proposal. However, in recognition of the COVID-19 pandemic and in an effort to moderate RY1 increases, as set forth in Appendix I, vegetation management danger tree costs will be deferred and amortized over five years resulting in over a $9 million revenue requirement reduction in RY1 and a cumulative reduction of over $20 million over the three year Rate Plan period. The vegetation management danger tree cost amortization will be recovered from customers utilizing the same revenue allocation used for other incremental distribution vegetation management costs.

To further assist with RY1 revenue requirement pressures, the Superstorm deferral amortization period is also lengthened from five to ten years resulting in a $3.7 million revenue requirement reduction in RY1 and a cumulative $11.2 million reduction over the three-year Rate Plan.

B. NYSEG Electric and Gas Rate Levels

1. NYSEG Electric Revenue Requirement

The dollar amount and percentage increase in NYSEG Electric delivery revenue requirements both with and without the application of EE/heat pumps rolled into base rates, and with and without levelization/shaping are shown on Appendix A.[16] The delivery revenue requirement increases for NYSEG Electric were levelized in RY2 and RY3 to smooth the increases as depicted in Appendix A. NYSEG Electric's revenue requirements for RY1, RY2 and RY3 are also shown on Appendix B.

2. NYSEG Gas Revenue Requirement

The dollar amount and percentage impact on NYSEG Gas delivery revenue requirements both with and without the application of EE and shaping are shown on Appendix A, including no delivery revenue requirement increase in RY1.[17] NYSEG Gas revenue requirements for RY1, RY2 and RY3 are also shown on Appendix C.

C. RG&E Electric and Gas Rate Levels

1. RG&E Electric Revenue Requirement

The dollar amount and percentage increase in RG&E Electric delivery revenue requirements both with and without the application of EE / heat pumps rolled into base rates, and with and without levelization are shown on Appendix A.[18] The RG&E Electric delivery impacts

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[16] Appendix A also includes the overall rate increase with and without the application of EE / heat pumps rolled into base rates, and rate increases with and without rate levelization/shaping. Individual service class rates and bill impacts will differ for all businesses (NYSEG Electric, NYSEG Gas, RG&E Electric, and RG&E Gas) from Appendix A to reflect changes associated with specific rate designs identified in Appendices BB, CC, DD and EE.

[17] See id.

[18] See id.

have been shaped in RY1 and levelized in RY2 and RY3 as shown on Appendix A. RG&E Electric's revenue requirements for RY1, RY2 and RY3 are also shown on Appendix D.

2. RG&E Gas Revenue Requirement

The dollar amount and percentage impacts on RG&E Gas delivery revenue requirements both with and without the application of EE and shaping are shown on Appendix A, including no delivery revenue requirement changes in RY1 and RY2.[19] RG&E Gas revenue requirements for RY1, RY2 and RY3 are also shown on Appendix E.

D. Description of Revenue Requirement

The major provisions and key text associated with NYSEG and RG&E Electric and Gas Revenue Requirements are provided in Appendix F, including electric and gas common allocation factors which are also provided in Appendix GG.

E. Make-Whole Provisions

Since Commission approval of RY1 rates will occur after April 17, 2020, the Companies have requested, and the Signatory Parties have agreed to, a make-whole provision whereby the Companies will recover shortfalls and refund over-collections such that the Companies and their customers would be in the same position had RY1 rates gone into effect on the effective date of April 17, 2020.[20]

NYSEG Electric and RG&E Electric will not compress RY1 rates. The Companies will amortize Excess Depreciation Reserve ("EDR") balances to cover the revenue increases associated with the make-whole period. In recognition of the COVID-19 Pandemic, the

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[19] See id.

make-whole EDR amortization amounts will neither be included in rate base in setting revenue requirements, nor will these amounts accrue carrying costs during the Rate Plan. The foregone carrying costs associated with this COVID-19 Pandemic concession is approximately $3.5 million during the Rate Plan. At NYSEG Gas and RG&E Gas, there are no RY1 revenue increases and any adjustment will be within the revenue shaping deferrals.

VI. ACTIONS PURSUANT TO THE REFORMING THE ENERGY VISION PROCEEDING AND CLIMATE LEADERSHIP AND COMMUNITY PROTECTION ACT

The Companies may be affected during the Rate Plan by the ongoing Case 14-M-0101 - Proceeding on Motion of the Commission in Regard Reforming the Energy Vision ("REV") and its companion REV cases (the "REV-Related Proceedings"). This Proposal does not limit the Commission's ability to require the Companies to take certain actions pursuant to the REV and REV-Related Proceedings and to provide for cost recovery of incremental costs of such actions in separate orders. The Signatory Parties reserve all their administrative and judicial rights to take and pursue their respective positions regarding all issues and Commission proposals, actions and initiatives regarding REV and the REV-Related Proceedings.

The Signatory Parties also may be affected during the Rate Plan by measures implemented pursuant to the New York State Climate Leadership and Community Protection Act ("CLCPA") enacted in 2019 and any related proceedings, requirements, regulations, proposals or activities (the "CLCPA Proceedings"). Nothing in this Proposal precludes or limits the Companies from seeking recovery of incremental costs associated with: (1) implementation of

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[20] Revenue adjustments for the make-whole period will be calculated as the difference between: (1) sales revenues NYSEG and RG&E would have billed at new rates and the date new rates actually go into effect; and (2) the same level of sales revenues at current rates. The revenue adjustments will include all applicable surcharges and carrying charges and will be subject to reconciliation in accordance with all applicable adjustment mechanisms.

the CLCPA or the CLCPA Proceedings; (2) necessary transmission reinforcements; or (3) proactively addressing climate change impacts on their service territories and infrastructure. Similarly, all other Signatory Parties reserve all rights to take and pursue positions with respect to such filings by the Companies.

VII. RETURN ON EQUITY AND COMMON EQUITY RATIO

The allowed rate of return on common equity ("ROE") for NYSEG Electric, NYSEG Gas, RG&E Electric and RG&E Gas (individually, "Business" and collectively, "Businesses") will be 8.80%. The common equity ratio for setting rates for each Business will be 48.00%.

VIII. EARNINGS SHARING MECHANISM

A. Earnings Sharing Levels

The Earnings Sharing Mechanism ("ESM") applicable to each Business will be based on Rate Year ESM thresholds as set forth in the following table and as further described below:

Customers / Shareholders	RY1 Earned ROE	RY2 Earned ROE	RY3 Earned ROE
50%/50%	> 9.00% to 9.50%	> 9.10% to 9.60%	> 9.20% to 9.70%
75%/25%	> 9.50% to 10.00%	> 9.60% to 10.10%	> 9.70% to 10.20%
90%/10%	> 10.00%	> 10.10%	> 10.20%

For RY1, the first 20 basis points (between 8.8% ROE and 9.0% ROE) will be the deadband threshold with no sharing. For RY2, the first 30 basis points (between 8.8% ROE and 9.1% ROE) will be the deadband threshold with no sharing. For RY3, the first 40 basis points (between 8.8% ROE and 9.2% ROE) will be the deadband threshold with no sharing.

One-half of the revenue requirement equivalent of the first additional 50 basis points of any shared earnings above the top end of the deadband for each Rate Year (above 9.0% for RY1, 9.1% for RY2, and 9.2% for RY3) will be deferred for the benefit of customers and the remaining one-half of any such earnings will be retained by the Companies.

Customers and the Companies will share (75/25) the revenue requirement equivalent of the next 50 basis points of any shared earnings (in excess of 9.5% in RY1, 9.6% in RY2, and 9.7% in RY3).

Customers and the Companies will share (90/10) the revenue requirement equivalent of all other shared earnings in excess of 10.0% in RY1, 10.1% in RY2, and 10.2% in RY3.

B. Common Equity Ratio

For purposes of determining earnings above the earnings sharing threshold, ROE calculations for each Business will reflect the lesser of: (1) each Company's aggregate actual average common equity ratio; or (2) 50%. Each Company's common equity ratio will be calculated based on a 13-month average excluding Other Comprehensive Income.

C. Applicability to Future Years

The earnings sharing thresholds set forth herein for each Company will continue for future Rate Years at the same levels identified for RY3 until new delivery rates and terms are reset by the Commission. Such calculations will continue to be performed on a Rate Year basis in the same manner as set forth above.

D. Annual ESM Compliance Filings

The Companies shall compute and submit to the Secretary to the Commission the ROE for each Business consistent with the methodology set forth in Appendix G.

IX. ELECTRIC VEGETATION MANAGEMENT

The NYSEG Electric distribution vegetation management spending will increase to a total of $57.2 million annually for each of the three Rate Years and will include the elements noted below. NYSEG Electric routine distribution vegetation management spending will be $30.0 million annually for each of the three Rate Years. In addition, NYSEG Electric will establish a new distribution vegetation management Reclamation Program with a planned spending of $17.2 million annually for each of the three Rate Years. The $17.2 million of incremental distribution vegetation management expenditures for the Reclamation Program will be used to reclaim circuits that have not been trimmed in over five years. In addition, NYSEG Electric will establish a new Danger Tree program to address danger trees outside of the distribution right-of-way, including but not limited to, ash trees. The planned spending for NYSEG Electric's new Danger Tree program is $10.0 million annually for each of the three Rate Years. The Danger Tree program costs for each Rate Year will be deferred and amortized over five years.

The RG&E Electric distribution vegetation management spending will increase to a total of $9.8 million in RY1, $10.0 million in RY2 and $10.2 million in RY3. RG&E Electric's routine distribution vegetation management rate allowance will be $8.3 million in RY1, $8.4 million in RY2 and $8.6 million in RY3. In addition, RG&E Electric will establish a new Danger Tree program to address danger trees outside of the distribution right-of-way, including but not limited to, ash trees. The planned spending for the new Danger Tree program is $1.575 million annually for each of the three Rate Years. The Danger Tree program costs for each Rate Year will be deferred and amortized over five years.

Each Company will defer, with carryover, any annual Rate Year under-spending on each of the identified distribution vegetation management programs as set forth in Appendix I.

NYSEG and RG&E transmission vegetation management programs will continue, at the funding levels shown in Appendix T.

A description of the electric distribution and transmission vegetation management programs and reporting requirements for NYSEG Electric and RG&E Electric is set forth in Appendix I.

X. STORM COSTS

This Proposal reflects the recovery of deferred NYSEG Electric storm costs of approximately $227.0 million composed of unamortized and unrecovered regulatory assets remaining from the 2016 Rate Plan and costs charged to the Major Storm Reserve during the 2016 Rate Plan. The NYSEG super storm regulatory asset of $74.8 million and the non-super storm regulatory asset of $119.2 million from the 2016 Rate Plan are being amortized over ten years. The remaining non-super storm regulatory assets of $33.0 million from the 2016 Rate Plan are being amortized over five years as depicted on Appendix B, Schedule H.

This Proposal reflects the recovery of net deferred RG&E Electric storm costs of approximately $49.0 million composed of unamortized regulatory liabilities remaining from the 2016 Rate Plan and costs charged to the Major Storm Reserve during the 2016 Rate Plan. This net deferred storm cost is being amortized over five years, as depicted on Appendix D, Schedule H.

The Major Storm definition and Major Storm Reserve Accounting procedures, including accounting for pre-staging costs, are set forth in Appendix H. The Major Storm annual rate allowance for NYSEG Electric is $25.58 million and the Major Storm annual rate allowance for RG&E Electric is $3.40 million. NYSEG Electric and RG&E Electric will continue to employ reserve accounting for qualifying Major Storm costs as defined in Appendix H.

The Minor Storm amount included in rates for NYSEG Electric is $3.80 million annually. The RG&E Electric annual Minor Storm amount included in rates is $1.0 million. There is no deferral or reserve accounting for Minor Storm costs included in this Proposal.

XI. SITE INVESTIGATION AND REMEDIATION DISPUTE

In the context of this overall Rate Plan, NYSEG will reduce future revenue requirements by $6.0 million per year for each of the three Rate Years and would not continue beyond RY3.

This adjustment is reflected in Appendices B and C. This adjustment fully resolves and settles any and all prudence related claims against the Company relating to Site Investigation and Remediation ("SIR") notice issues involving third-party insurers, including claims involving, among other things, the recovery of attorneys' fees and carrying charges.

XII. ACCOUNTING AND TAX MATTERS

The Companies will reflect certain accounting changes as set forth in Appendix J, including new units of property for energy storage assets, capitalizations of certain payments made to third-party entities, consistent capitalization of computer software, capitalization of certain New York State Department of Transportation Fees, recognition of regulatory assets and liabilities under International Financial Reporting Standards ("IFRS") similar to those allowed under GAAP, and capitalization of AMI load side cable repairs. Also covered in Appendix J are various tax matters.[21]

XIII. ELECTRIC RELIABILITY

This Proposal maintains NYSEG's and RG&E's current Electric Reliability Performance Measures, including the System Average Interruption Frequency Index ("SAIFI") and the Customer Average Interruption Duration Index ("CAIDI"). This Proposal also adopts a new Distribution Line Inspection Program metric for Level II deficiencies (consistent with the safety orders issued in Case 04-M-0159). The specific metrics, targets and associated negative revenue

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[21] On January 11, 2018, in Case 18-M-0013, the Commission initiated a third-party audit of the Companies' Power Tax and Unfunded Regulatory Asset balances. This audit is still ongoing. The Signatory Parties reserve all of their administrative and judicial rights to take and pursue their respective positions with respect to all issues, rulings, matters and decisions in Case 18-M-0013. Final Commission-ordered differences resulting from the Staff audit will be applied to the PowerTax regulatory asset or Unfunded regulatory asset and amortized over the remaining life.

adjustments ("NRAs"), as well as the reporting requirements associated with NYSEG's and RG&E's Electric Reliability Performance Measures, are set forth in Appendix K.

XIV. GAS SAFETY

A. Gas Safety Performance Measures

This Proposal establishes Gas Safety Performance Measures for NYSEG and RG&E. The specific metrics, targets and associated NRAs and positive revenue adjustments ("PRAs"), as well as the reporting requirements associated with NYSEG's and RG&E's Gas Safety Performance Measures, are set forth in Appendix L.

B. First Responder Training

The Companies will work with Staff, local fire departments, and emergency management organizations ("First Responders") to adopt the principles of the Pipeline Emergency Responders Initiative ("PERI").[22] The Companies also agree to continue conducting scenario and hands-on drill trainings for First Responders.

As part of their annual gas safety performance compliance filings, the Companies will file with the Secretary to the Commission information regarding their First Responder Training efforts, including the dates and times of the drills, who was in attendance, what topics were reviewed, and any applicable recommendations.

C. Residential Methane Detection Program

The Companies agree to discuss with Staff and implement a Residential Methane Detection ("RMD") Program that distributes RMDs to targeted customers (e.g., low income customers) and involves RMD-related gas safety outreach and education. Within 120 days of the Commission's issuance of a final order in these proceedings, the Companies will file with the

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

Secretary to the Commission an implementation plan for their RMD Program, which will include deployment strategies, specific RMD units to be utilized and associated costs.

The RMD Program will be funded by NRAs as noted in Appendix T. If NRA-related regulatory liabilities are less than actual expenditures, the differences will be deferred and ultimately collected from customers. If funding is in excess of planned RMD Program expenditures, any excess will rollover to potentially offset additional planned RMD expenditures in future years.

D. Inside Service Line Inspections

To reduce costs, the Companies agree to coordinate inside service line inspections with other activities, including but not limited to, meter replacements, complaint investigations, and the removal of inactive meters. The Companies also agree to work with Staff to submit a procedure within 120 days of the Commission's issuance of a final order in these proceedings by which they will automatically apply a provision (e.g., a $100 surcharge) to customers whose buildings cannot be accessed for inspection. This automatic provision would apply, for example after one refusal, two scheduled and then cancelled appointments, or if customers do not respond to notifications. The amounts collected under this provision will be used to offset the cost of the inside service line inspections.

E. Outside Meters

The Companies will continue to implement their longstanding practice of relocating meters from inside to outside of a building when performing service line replacements (whether by insertion or direct bury), service line repairs and transfers, or new service installations, and where the relocation can feasibly be performed. The Companies agree to provide Staff meter relocation statistics upon request.

F. Inactive Accounts

The Companies agree that metered gas for inactive accounts will be removed from the calculation of Lost and Unaccounted For Gas for those inactive accounts with an installed and operating AMI meter and for which the Companies have been able to obtain relevant usage data other than through an installed and operating AMI meter.

G. Pipeline Safety Management Systems

The Companies will participate in a Northeast Gas Association ("NGA") study related to Pipeline Safety Management Systems. To the extent the Companies incur costs based on the study's results or recommendations, these costs would be deferred. Expenses beyond the initial "Gap Analysis" coordinated by the NGA will be subject to deferral treatment for future recovery.

XV. GAS MATTERS

In response to New York's recent actions to promote clean energy along with the focus on the nexus between energy and the environment, the Signatory Parties worked diligently to reach agreement on a progressive set of commitments regarding the Companies' natural gas businesses and related to climate change. The Commitments are set forth in Appendix M and include an objective to achieve a net zero increase in gas use, an increased emphasis on non-pipe alternatives and a commitment to study how the gas business may change in light of the goals of the CLCPA.

XVI. SPECIAL STUDIES

As detailed in Appendix N, the Companies will undertake the following special studies: (1) Senior Customer Study for Customer Service; (2) Natural Gas System Resiliency Study; (3) Renewable Natural Gas Study; (4) Geothermal – District Energy Study; (5) Overall Natural Gas and Grid Modernization Report; (6) Depreciation Study Reflecting the CLCPA; and (7) Street Light Replacement Cost Study (collectively, the "Special Studies").

As shown on Appendix N, the Companies will cap the overall spending on the Special Studies to an incremental $750,000 across all four Businesses. The first $250,000 of NYSEG Special Study costs will be covered by a re-allocation of shareholder funds related to the cessation of certain rebate programs, as discussed further in Appendix M. The remaining $500,000, which covers both NYSEG and RG&E, has been included in the Companies' revenue requirements as reflected in Appendices B-E. In addition to the seven studies noted above, the Companies will also perform a Renewables Integration Study consistent with paragraph 23 of Appendix F, which has a separate cost cap of $250,000 in total between NYSEG and RG&E.

XVII. CUSTOMER SERVICE

The Customer Service provisions are set forth in Appendix P and will be in effect for the term of the Rate Plan and thereafter unless and until changed by Commission. As highlighted in Section IV, above, regarding the COVID-19 Pandemic Provisions set forth in this Proposal, the Companies have put many actions into place to benefit customers. Key among these is the Customer Bill Credit program that will assist customers in the aftermath of the pandemic. Specific details on the Bill Credit program are set forth in Appendix P.

The following provisions identify key components of the Companies' customer service programs.

A. Customer Service Performance Indicator Metrics and Targets

Appendix P establishes threshold performance levels for designated aspects of service performance. The specific service quality metrics, targets and NRAs for NYSEG and RG&E are set forth in Appendix P. The metrics will be in effect beginning with calendar year 2021. Specific NRAs for each Company and each metric are also shown in Appendix P. Any NRAs incurred will accrue interest at a rate, as outlined in Section XXIV(V) of this Proposal, and interest will be applied from the date incurred until disposed of by the Commission. The NRA for an individual measure will double if the Company misses any of the target levels for that particular measure for two consecutive calendar years. Additional details concerning the doubling provisions are included in Appendix P.

In the 2016 Rate Plan, the following calendar year customer service metrics were established based on the Companies' annual Service Quality Performance Mechanism ("SQPM") reports: (1) PSC Complaint Rate; (2) Contact Satisfaction; (3) Calls Answered in 30 Seconds; and (4) Estimated Meter Reads.

In RG&E's 2017 annual customer service filing, it reported two NRAs: $175,000 for failure to meet the Calls Answered in 30 Seconds metric target, and $350,000 for failure to meet the Estimated Meter Reads metric target. Staff conducted an audit of the Companies' 2016, 2017, and 2018 data provided in the quarterly and annual SQPM reports and confirmed that NYSEG did not incur any customer service NRAs and RG&E incurred the two reported NRAs.[23]

The Signatory Parties agree that RG&E deferred $525,000, which will be used in RY1, RY2 and RY3 for the benefit of customers as shown in Appendix AA (RG&E Electric and RG&E Gas, "Service Quality Performance" line items). As set forth in the 2016 Rate Plan, the deferred amount accrued interest utilizing the pre-tax rate of return of 10.26% for the rate year ending April 30, 2018.[24]

B. Reporting Requirements

Each Company will submit the results of its Customer Service Performance Indicators in compliance with the Customer Service Reporting Metrics Order. A final report will be

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[23] Staff also audited the Companies' monthly Customer Service Performance Indicators reports which were required to be filed based on Case 15-M-0566 - In the Matter of Revisions to Customer Service Performance Indicators Applicable to Gas and Electric Corporations, Order Adopting Revisions to Customer Service Reporting Metrics (Aug. 4, 2017) (the "Customer Service Reporting Metrics Order").

[24] 2016 Rate Plan at Appendix A.

submitted for each calendar year within 30 days of the end of the calendar year. The final report will also state whether a revenue adjustment is applicable, and if so, the amount of the revenue adjustment. The Companies will provide all supporting workpapers related to reported performance when the final report is submitted.

C. Missed Appointments

In the event the Companies miss a scheduled appointment with a residential customer, the Companies will provide a credit of $35.00 to such customer. The Companies will include in their respective annual Service Quality Performance Measures reports the total number of credits provided in the calendar year and the total dollar amount of the credits given to residential customers. The Companies will send to Staff, confidentially, a list of the customers who received a credit, total number of all missed appointments, and information on any customers who did not receive a credit, yet qualified, in the information reported. The Companies will provide all supporting workpapers related to reported performance when the final report is submitted.

D. Uncollectibles/Terminations/Arrears Measure

The Companies will add an arrears component to the existing Uncollectibles/Termination measure. Appendix P includes information concerning specific components of the Uncollectibles/Termination/Arrears measure. Each Company will be eligible for full PRAs if the results for all three components (i.e., uncollectibles, terminations and arrears) are below the lower targets identified in Appendix P. Appendix P also identifies the circumstances in which the Companies can earn a partial PRA.

E. Credit and Debit Card Fees

Customers will continue to be permitted to pay their NYSEG or RG&E bill with a credit or debit card without incurring a fee from either the Companies or a third-party agent processing such payments. Upon expiration of the current third-party vendor processing agreement, the Companies will pursue a competitive bidding process for credit card merchant services. Each Company shall reconcile actual expenditures to the rate allowance for credit and debit card fees as included in Appendix T.

F. Third-Party Agent Fees

The Companies will eliminate per-transactions fees for customers who pay their bill at authorized payment locations with an authorized third-party pay agent. Each Company shall reconcile actual expenditures associated with any third-party pay agent fees to the rate allowance for such fees as included in Appendix T.

G. Electronic Deferred Payment Agreements

The Home Energy Fair Practices Act and the implementing regulations set forth in 16 NYCRR § 11.10 govern DPAs between residential customers and the Companies. Within three months of the issuance of a final Commission order in these proceedings, the Companies will file a plan to implement an electronic DPA ("e-DPA") process for residential customers.

H. Walk-In Offices

Beginning June 1, 2021, the Companies shall be permitted to close designated walk-in office locations based upon the following phased office closure schedule. As agreed below, the Companies will provide reports of customer traffic in each customer office. Any material increase in traffic in an office will be reviewed with Staff and other parties to determine if the closure is still appropriate. A material increase is defined as a 25% increase in representative-assisted transactions (from the baseline provided in the Companies' testimony) sustained consistently for at least a three-month period.

(1) RG&E Office located at 256 Waring Road, Rochester, New York 14609 – 2021 closure.

(2) RG&E Office located at 32 Main Street, Fillmore, New York 14735 – 2021 closure.

(3) RG&E Office located at 79 Clark Street, Canandaigua, New York 14424 – 2021 closure.

(4) NYSEG Office located at 150 Erie Street, Lancaster, New York 14086 – 2021 closure.

(5) NYSEG Office located at 7760 Industrial Park Road, Hornell, New York 14843 – 2021 closure.

(6) NYSEG Office located at 26 Wierk Avenue, Liberty, New York 12754 – 2022 closure.

All current employees assigned to a walk-in office that will be closed will continue with a job assignment to be located in that same Company division/region.

The Companies shall be permitted to modify the hours of the following walk-in office locations based upon the following office hours-change schedule:

(1) NYSEG Office located at 73 Wright Circle, Auburn, New York 13021 ("Auburn Office"). The new walk-in hours for the Auburn Office will be modified to be two days per week from 9 a.m. to 4 p.m.

(2) NYSEG Office located at 65 Country Club Road, Oneonta, New York 13820 ("Oneonta Office"). The new walk-in hours for the Oneonta Office will be modified to be two days per week from 9 a.m. to 4 p.m.

(3) NYSEG Office located at 1387 Dryden Road, Ithaca, New York 14850 ("Ithaca Office"). The new walk-in hours for the Ithaca Office will be modified to be two days per week from 9 a.m. to 4 p.m.

(4) RG&E Office located at 14 State Street, Sodus, New York 14551 ("Sodus Office"). The new walk-in hours for the Sodus Office will be modified to be two days per week from 9 a.m. to 4 p.m.

NYSEG and RG&E shall provide a customer outreach implementation plan to Staff and interested parties to these proceedings a minimum of two months prior to the closure of each walk-in office identified above. In the event NYSEG or RG&E proposes to close any additional walk-in office(s), the applicable Company must first file a petition with the Commission and obtain Commission approval for such office closure.

In those service areas in which the Companies will be closing a walk-in office as identified above, the Companies agree to implement a process for a customer to request a meeting with a Customer Service employee. A Customer Service employee will schedule meetings with customers on an as-needed/as-requested basis. The Companies will assign two full-time equivalents to assist with this workload.

The Companies will coordinate with the following counties to provide scheduled dates and times to have a NYSEG or RG&E Customer Advocate on site at the New York State Department of Social Services ("DSS") office for a minimum of two times per month, per location, subject to the approval and schedule of the particular DSS location: Monroe, Chenango, Erie, Ontario, Steuben, and Sullivan. These offices have been selected to correspond with those walk-in office locations identified above that the Companies will close. The Companies will make reasonable efforts to coordinate with the DSS offices so that Company representatives are located in a prominent and easily accessible area for customers. The Companies will also coordinate with the New York State Office of Temporary and Disability Assistance/DSS ("OTDA") to expand the periodic location of Customer Advocates in additional counties subject to the approval and schedule of the particular New York State Department of Human Services location.

The Companies agree to provide outreach and communications regarding options for completing transactions as well as meeting with a Company representative in person. These communications will be made through multiple channels, including but not limited to, third-party payment locations, customer contact centers, Company websites, bill inserts and remaining open offices.

The Companies will provide quarterly reporting of customer usage of open offices, the number of individual customer appointments requested (individually reported for appointments with Customer Service employee and for those at NYS Department of Social Services offices), and the number of appointments made. During the Rate Plan, the Companies will identify and report other relevant information.

I. Voluntary Protections During Periods of Extreme Cold and Heat

The Companies will implement the following excessive cold weather moratorium pledges and heat provisions.

1. <u>Cold Weather Protections</u>

NYSEG and RG&E will commit to additional winter protections for residential customers during the cold weather period of November 1 through April 15 ("Cold Weather Period"). These protections include:

(1) The Companies will provide the customer with continued or restored service regardless of the amount due and/or the customer's payment status when a HEAP payment has been accepted by the Companies during the Cold Weather Period. This excludes "Heat Included" benefits for households that pay for heat as a portion of their rental cost as explained in the OTDA HEAP information outline;

(2) During the Cold Weather Period, the Companies will consider any Regular and Emergency HEAP payment as entitling the applicant to a fair and reasonable DPA regardless of any previous DPA or e-DPA defaults;

(3) The Companies will refrain from scheduling residential service terminations on days when the local weather forecast predicts below-freezing (32 degrees) temperatures; and

(4) NYSEG and RG&E will establish a voluntary moratorium on winter terminations for customers who are elderly, blind or disabled.

2. Excessive Heat Protections

NYSEG and RG&E will suspend residential terminations during a heat advisory. A heat advisory is in place when the heat index is forecasted at 95 degrees for two or more consecutive days and/or when the heat index is forecasted at 100 degrees for one or more consecutive days. The Companies will use the forecasts provided by the United States National Weather Service.

J. Senior Study

The Companies agree to conduct a study to identify potential partnerships for senior customer outreach concerning EE opportunities, low income discounts and other senior customer-related opportunities. The Companies will coordinate such study with Staff. More information regarding this study is identified in Appendix N.

XVIII. ECONOMIC DEVELOPMENT

The Companies retain under the Proposal a set of economic development programs. A listing of these programs is provided in Appendix V, including information on the Companies' implementation of a Non-Residential Geothermal Air Source and Heat Pump Pilot Program. The Companies will also enhance the economic development process as noted in Appendix V. Each Company shall reconcile actual expenditures to the rate allowance for Economic Development as included in Appendix T. As noted in Section IV above, the Economic Development Programs have also been enhanced with an Economic Development COVID-19 Grant Assistance Program for electric business customers.

XIX. LOW INCOME PROGRAMS

This Rate Plan continues Low Income Programs for NYSEG and RG&E which are more fully described in Appendix Q. The Companies will continue their existing enrollment procedure for HEAP recipients whereby the Companies enroll a customer when they receive payment associated with a HEAP grant. All HEAP recipients will be eligible for the Low

Income Programs at NYSEG and RG&E. Additionally, self-enrollment in the Companies' Low Income Program will be expanded to include any customer who is denied a HEAP grant, but who can provide confirmation that he or she is HEAP eligible through a denial letter.

The annual budget levels for the Companies' respective Low Income Programs are shown in Appendix Q. Eligible customers will receive the discounts on their monthly bill in the amounts shown in Appendix Q. The monthly bill discount reduction amounts will be broken into four tiers in the manner and the dollar amounts shown in Appendix Q.

The Arrears Forgiveness program will be maintained at an annual budget of $1.5 million and $1.13 million at NYSEG and RG&E respectively.

All customers enrolled in a Low Income Program will be referred to the New York State Energy Research and Development Authority's ("NYSERDA") Empower program for EE and/or budget counseling or similar program.

The Companies will provide quarterly reports to the Secretary on the following Low Income Program components:

(1) Number of customers enrolled in the Bill Reduction program;
(2) Number of customers enrolled in the Arrears Forgiveness program;
(3) Total amount held in arrears for the program;
(4) Average amount in arrears;
(5) Aggregate amounts of low income bill discounts;
(6) Aggregate amount of arrears forgiven; and
(7) Number of customers who have defaulted off the program.

There is a Low Income Proceeding (Case 14-M-0565) pending before the Commission that may modify the Companies' Low Income Programs. To the extent the Commission orders modification to the Companies' Low Income Programs, the Companies will be held harmless from any increase in expenses associated with the revised or new Low Income Programs and will be authorized to defer the difference between the rate allowance during each Rate Year and the actual costs for Low Income Programs for future recovery.

XX. REFORMING THE ENERGY VISION

A. Energy Smart Community ("ESC")

Until such time as AMI is fully implemented in the Companies' service territories, the Companies will continue to operate the ESC as a test-bed for future technology and processes related to system planning, grid operations, and market services.

The revenue requirement in these cases reflects approximately $1.0 million annually (subject to a downward-only reconciliation as shown on Appendix T) in ESC O&M costs as reflected in Appendix B and ESC capital amounts totaling approximately $1.1 million over the term of the Rate Plan.

B. REV Incremental Costs

The Companies will include REV and REV-related incremental costs, including regulatory, consulting and legal costs, in the RAM described in Section XXV and Appendix W. To the extent that alternative cost recovery mechanisms are in place or are put in place for specific REV and REV-related incremental costs, the Companies will not include those REV and REV-related incremental costs in the RAM.

C. Energy Storage

During the term of the Rate Plan, NYSEG will implement the Java Station Energy Storage Project consisting of an appropriately sized battery storage system and associated technology to back up the Java substation. As part of the implementation process, NYSEG will perform a second competitive procurement for the back-up solution portion of the Java Station Energy Storage Project.

D. Electric Vehicles

The Companies will continue to facilitate the adoption of electric vehicles ("EVs") through the programs described below. Incremental costs associated with the implementation of Commission-ordered EV programs for which recovery is not provided for in the respective Commission orders will be deferred and collected under the RAM.

1. Make-Ready EV Infrastructure Program

The Companies will implement a Make-Ready EV Infrastructure program to incent Level 2 and direct current fast chargers ("DCFC") to be installed in the Companies' service territories consistent with the Staff whitepaper on electric vehicles[25] or as modified by any order the Commission issues in Case 18-E-0138 ("EV Proceeding"). The program will offset expected interconnection construction and excess distribution facility costs for which the customer/ developer would normally be responsible. Costs of charger supply equipment (e.g., station, power blocks, or modules), including costs associated with connecting such equipment as well as costs associated with any co-located distributed generation or energy storage system, will not be eligible for the program. Consistent with the EV Whitepaper:

(1) New Level 2 stations that use SAE J1772 plug technology and meet the Level 2 Make Ready Program criteria would qualify for utility-funded make-ready of up to 90% of eligible make-ready costs.
(2) Other new Level 2 stations that use SAE J1772 plug technology but do not meet the additional eligibility criteria would quality for utility-funded make-ready for up to 50% of eligible make-ready costs.
(3) New DCFC stations serving light duty vehicles that meet DCFC Make-Ready Program criteria would pay up to 90% of the eligible costs.
(4) All other new DCFC stations serving light duty vehicles, including stations that exclusively install proprietary plug types, would be eligible for utility-funded make-ready for 50% of eligible make-ready costs.

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[25] Case 18-E-0138 - Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure, Department of Public Service Staff Whitepaper Regarding Electric Vehicle Supply Equipment and Infrastructure (Jan. 13, 2020) ("EV Whitepaper"),

The Companies will implement any cost containment measures adopted by the Commission in the EV Proceeding (e.g., program participation caps, total budget caps, and caps on participant incentives).

To facilitate an efficient process for developers to participate in the Make Ready program, the Companies will provide a single point of contact through which the developers can coordinate on make ready projects. The Companies will also provide an initial desktop analysis for proposed locations of EV charging stations.

The Companies will work with transit agencies within their service territories to identify make ready investments that will support electrification of bus fleet.

2. EV and Hybrid Fleet

The Companies will add five electric vehicles (passenger cars) per year, per Company, to their fleet assets over the next four years. RG&E will also begin a program to increase the number of hybrid bucket trucks over the next four years, starting with one in 2020, which will be evaluated to determine the level of future additions.

XXI. NON-WIRES ALTERNATIVES AND NON-PIPES ALTERNATIVES

A. General

The Companies are committed to seeking Non-Wires Alternatives ("NWA") and Non-Pipes Alternatives ("NPA") solutions to electric or gas capital investments where those solutions are appropriate and cost-effective. The Companies' approach for NWA and NPA is to provide safe and reliable alternatives to traditional capital investment projects. For more information on NPAs, see Appendix M.

B. Recovery of Costs

The Companies will recover costs of their NWA and NPA programs as follows:

(1) General NWA/NPA costs not applicable to specific NWA/NPA projects will be considered O&M expenses.

(2) Costs incurred by the Companies for implementation of new NWAs during the Rate Plan will be deferred with carrying costs.[26] Recovery of such costs will be amortized over a 10-year period, with offsetting credits to the extent that an NWA Project defers the need for a traditional infrastructure project included in the Company's Average Electric Plant in Service Balance. During the term of the Rate Plan and until base rates are reset, the amortized portion of such costs will be recovered through the Non-Bypassable Charge ("NBC"). Any unamortized costs plus carrying charges will be incorporated into base rates when electric base rates are reset.

(3) Costs incurred by the Companies for implementation of new NPAs during the Rate Plan will be deferred with carrying costs. Recovery of such costs will be amortized over the anticipated "used and useful" life of installed assets and equipment with offsetting credits to the extent that an NPA Project defers the need for a traditional infrastructure project included in the Company's Average Gas Plant in Service Balance. NPA projects without a clearly measurable period for amortization shall use a 20-year default amortization period. During the term of the Rate Plan and until base rates are reset, the amortized portion of such costs will be recovered through a separate surcharge. Any unamortized costs plus carrying charges will be incorporated into base rates when gas base rates are reset.

(4) Costs incurred by the Companies to advance wires or pipeline projects which are ultimately deferred or avoided by an NWA or NPA would be deferred for future recovery and would remain in Construction Work in Progress until addressed in a future proceeding.

C. NPA Benefit Cost Analysis

The Companies agree to work with Staff and interested parties to develop a Benefit-Cost Analysis ("BCA") Handbook for NPAs consistent the Order Establishing the Benefit Cost Analysis Framework issued on January 21, 2016 in Case 14-M-0101[27] within six months of the

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[26] Carrying costs shall be at the pre-tax weighted average cost of capital.

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

Commission's approval of this Proposal as described in Appendix M. Such BCA Handbook will be updated as necessary subject to the requirements of the CLCPA.

The Signatory Parties will also recommend to the Commission that it institute a statewide proceeding to develop BCA Handbooks for NPAs statewide. In the event that the Commission implements such a statewide proceeding, the statewide proceeding will take precedence over the NYSEG- and RG&E-specific effort.

D. Effect on Net Plant Reconciliation

In the event the Companies utilize a NWA/NPA to replace or defer a transmission and distribution ("T&D") solution which is included in the Net Plant Targets, as described in Appendix S, and the Depreciation Targets, also described in Appendix S, the revenue requirement impact of the replaced or displaced project, with carrying costs, will be deferred for future customer benefit and the Companies' Net Plant and Depreciation Targets will be adjusted accordingly.

To the extent an NWA project results in the Company displacing a capital project that is reflected in the targets for Average Electric Plant in Service Balances under the Net Plant Reconciliation ("NPR"), the target(s) will be reduced to exclude the forecasted net plant associated with the displaced project. The carrying charge associated with the displaced project will be applied as a credit against the recovery of the associated NWA project costs to be recovered from customers. In the event that the carrying charge on the net plant of any displaced project is higher than the recovery of the associated NWA project costs, the difference will be deferred for the benefit of customers.

To the extent an NPA project results in the Company displacing a capital project that is reflected in the targets for Average Gas Plant in Service Balances under the NPR, the target(s) will be reduced to exclude the forecasted net plant associated with the displaced project. The carrying charge associated with the displaced project will be applied as a credit against the recovery of the associated NPA project costs to be recovered from customers. In the event that the carrying charge on the net plant of any displaced project is higher than the recovery of the associated NPA project costs, the difference will be deferred for the benefit of customers.

For example, if the implementation of an NWA or NPA solution was able to defer for four years the need for a $5.0 million T&D investment that was assumed to have occurred at the beginning of RY2, then the Net Plant targets for both RY2 and RY3 would be reduced by $5.0 million from the levels included in Appendix S.

E. NWA and NPA Incentives

The Companies will earn and recover incentives for NWAs and NPAs as discussed in Appendix HH.

XXII. ADVANCED METERING INFRASTRUCTURE

The Proposal includes the implementation of an AMI system for all Businesses. Extensive details regarding AMI are set forth in Appendix O. Appendix O is further broken down into four subparts that address the following areas:

(1) Appendix O (AMI-1): AMI Detailed Description and AMI Costs and Benefits
(2) Appendix O (AMI-2): Customer Outreach and Engagement Plan ("O&E Plan")
(3) Appendix O (AMI-3): AMI Metrics
(4) Appendix O (AMI-4): AMI Security Plan.

A. AMI Overview

The Companies have estimated $489.1 million in capital expenditures for the implementation of AMI across all four Businesses which includes the following:

(1) Replacing approximately 1.3 million existing electric meters;

(2) Replacing or upgrading approximately 600,000 existing gas meters;

(3) Creating a supporting telecommunications network covering 20,000 square miles to manage information flows between the meters in the field and the Companies' AMI operations center; and

(4) Information Technology ("IT") infrastructure and software applications to collect, manage, store, and protect AMI information, support customer data needs to improve decisions regarding energy use and support innovative rate structures to encourage efficient customer consumption of energy.

The Companies propose to begin development of the IT infrastructure platform and applications in the third quarter of 2020 (i.e., a six month delay from their original plan) so that the infrastructure is in place to go into service when the meter deployment effort begins in the second quarter of 2022. The Companies have planned a three-year field effort to replace or upgrade customer meters and install the communications network which will end during the first half of 2025. As one component of determining the deployment schedule, outage experience will be considered in deployment prioritization.

Customers may elect to "opt out" of receiving an AMI electric meter and AMI gas communications module during the initial AMI roll-out and become subject to a continuing monthly meter reading charge of $13.47 per month at NYSEG and $11.56 per month at RG&E.

Customers may also elect subsequently to "opt-out" of having an AMI meter or AMI gas communications module which have already been installed at their location. For those customers at NYSEG, there will be a continued meter reading charge of $13.47 per month. There would also be a $47.63 one-time charge applicable to exchange their existing AMI electric meter/gas module for a non-AMI meter, and a one-time charge of $65.51 if both an AMI electric meter and an AMI gas communications module are exchanged out. For RG&E customers who subsequently elect to "opt-out" after and AMI meter/gas communications module has been installed, these charges will be $11.56 per month (ongoing meter reading charge), $43.68 (one-time AMI meter or gas communications module exchange) and $58.24 (one-time AMI electric meter and gas communications module combined exchange), respectively. In addition, the Companies will note in their AMI customer information materials that, upon request, the Companies will offer customers a payment plan to cover the above-referenced one-time exchange charges.

The AMI meter and communications platform differs from the current metering platform in the following ways. AMI meters:

(1) measure customer consumption in much smaller intervals compared with the monthly or bi-monthly time periods associated with current metering and remotely collect consumption measurements rather than collect usage data through on-site visits by meter readers;

(2) remotely connect and disconnect service through the AMI operations center rather than through on-site visits;

(3) automatically report outages and outage restorations;

(4) automatically report safety issues that require repairs;

(5) automatically detect tampering that may be related to theft of service;

(6) support accurate measurement of distributed energy resources ("DER") located at the customer premises and/or on the distribution circuits;

(7) monitor distribution line voltage and transformer loads; and

(8) provide more timely and complete meter reads for billing purposes, thus eliminating nearly all estimated meter reads.

A more detailed description of the functionality of the AMI system to be deployed is contained Appendix O (AMI-1).

Appendix O (AMI-1) also summarizes various guidelines for meters, including: specific requirements for electric and gas meter testing protocols; requirements for micro-arcing and magnetic theft detection capability for commercial/industrial and residential meters and Home Area Network capability. In addition, on an as-needed basis, the Companies will replace the electric service wire between the meter pan and the residential customer electric panel box. The costs associated with these replacements will be treated as capital costs.

B. AMI System Benefits

The Companies consider AMI to be a foundational system for realizing New York State policy goals to empower customers through new tools and information to effectively manage and reduce usage, establish new markets to promote the implementation of low carbon DER, and minimize environmental impacts. The Companies anticipate that the enhanced capabilities of AMI meters will provide a wide variety of customer benefits, including:

(1) reducing certain O&M costs which will be reflected in customer rates over time;

(2) reducing the Companies' future levels of capital spending, which should also help to lower customer rates by avoiding investments in non-AMI meters and avoiding sensor costs otherwise required to support state energy policy;

(3) reducing electricity and natural gas usage and lowering bills through programs supported by the AMI platform, including conservation voltage reduction/volt-var optimization (CVR/VVO), information feedback such as usage alerts, and time-varying pricing;

(4) generating societal benefits for all customers through reduced CO_2 emissions from the conservation efforts enabled by AMI and reductions in outage costs through faster outage detection and restoration;

(5) improving the equitable allocation of costs through improved meter accuracy, theft detection and write-off reductions; and

(6) enhancing customer convenience and safety post-Pandemic by eliminating the need for customers to provide access to indoor meters or submitting self-reads and providing more convenient service activation and account transfers through a remote meter service switch.

Further discussion of the types of benefits that are achievable through AMI can be found in Appendix O (AMI-1). The Companies have quantified many of the expected benefits outlined above and compared them to the cost of AMI deployment and operation via use of a BCA, which is set forth in Appendix O (AMI-1).

Table 1 below shows the Companies' expected net benefits and the benefit/cost ratio applying the Societal Cost Test for the combined Companies, and for each individual Company,[28] on a net present value ("NPV") basis for the period from 2019 through 2044. The Companies project that the investment in AMI is estimated to result in substantial net benefits to society totaling over $287 million NPV. The societal Benefit/Cost ratio of 1.51 is a robust indicator that AMI should deliver significant economic value to the Companies' customers. Net benefits are also positive and significant for each Company.

Table 1: Societal Benefit/Cost Analysis for Combined Companies ($M)

BCA Metric	NYSEG	RGE	Combined Companies
Benefits	$604.2	$225.7	$829.9
Costs	($360.8)	($188.4)	($549.2)
Net Benefits	$243.4	$37.4	$280.7
B/C Ratio	1.67	1.20	1.51

A more detailed breakdown of the benefits and costs underlying the estimates is provided in Appendix O (AMI-1).

C. Customer Outreach and Engagement Plan

Customer outreach and engagement are essential to the successful and beneficial deployment of AMI. Under the Companies' plans, customers will be educated about why AMI is being deployed and the customer opportunities and benefits that AMI will provide. Customers will also be informed about the deployment process. The Customer O&E Plan will engage employees, customers, community resources and other interested stakeholders to enable customers to understand and take advantage of the benefits of AMI. Appendix O (AMI-2) contains a detailed discussion of the O&E Plan and its development.

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28 The Societal Cost Test presented for each individual Company reflects the shared cost of both Companies investing in AMI.

D. AMI Metrics

Appendix O (AMI-3) contains a list of 25 metrics that the Companies will use to assess AMI deployment and operation.

E. AMI Security Plan

As an integrated system of smart meters, communications networks and data management systems enabling two-way communications between utilities and customers, AMI faces three primary security threats: customer attacks, insider attacks and terrorist or nation-state attacks. Appendix O (AMI-4) documents the Companies' security plan, developed to reduce the risk of such threats materializing.

F. Capital Spend Cap/Net Plant Reconciliation

The capital costs for AMI are subject to a cumulative capital spend cap ("AMI Cap") with the reconciliation calculated upon final completion of the project. In addition, over the three-year term of the Rate Plan, AMI net plant in service will be subject to a net plant reconciliation as detailed in Appendix S. In the event the overall AMI capital costs are less than the $489.1 million AMI Cap, the operation of the net plant reconciliation mechanism will create benefits for customers. To the extent that one or more of the Companies' Businesses incur total capital costs of more than the Business's share of the $489.1 million, the Companies will have the opportunity to file a petition to the Commission requesting recovery of the amount over their share of the $489.1 million. The other Signatory Parties reserve all rights to challenge such recovery.

XXIII. ENERGY EFFICIENCY

Beginning with the start of RY1, the Companies' base electric and gas delivery rates reflect EE program costs for each Rate Year. These costs were previously collected through the "EE Tracker" portion of the SBC. In the January 16, 2020 Order, the Commission included utility specific electric and gas budgets and targets for years 2020-2025. The base delivery rates being implemented in this Proposal reflect both EE programs and electric heat pump programs pursuant to the January 16, 2020 Order. The revenue requirements established by this Proposal generally reflect the budgets adopted in the January 16, 2020 Order. In recognition of the COVID-19 Pandemic, the budget amounts reflected in RY1-RY3 have been reduced from the amounts reflected in the January 16, 2020 Order. The Signatory Parties recognize that the adjustments to the RY1-RY3 budgets do not reduce the overall budgets for years 2020-2025 established in the January 16, 2020 Order and if, in any of the Rate Years the Companies spend more on EE than what is collected, the Companies can defer the amount to be reconciled against the entire 2020-2025 EE budget. Upon implementation of new delivery rates, the Companies will discontinue the SBC-EE Tracker component of the SBC currently applied to customer bills. Costs associated with NYSERDA programs will continue to be collected through the SBC. The total amount included in base electric and gas delivery rates include an offset related to the amortization of previously underspent EE-related program funds from 2019 and prior years. Please refer to Appendix Y which provides additional details regarding the Companies' EE programs. The amounts that are included in base electric and gas delivery rates for each Rate Year for each Business are included in Appendices B, C, D, and E. To the extent required, delivery rates will be adjusted in RY4 and RY5.

XXIV. EARNINGS ADJUSTMENT MECHANISMS

Commencing with the term of the Rate Plan, the Companies will implement for the first time the following seven EAMs: (1) Electric Share the Savings; (2) Heat Pump Share the Savings; (3) Beneficial Electrification; (4) DER Utilization; (5) Electric Peak Reduction; (6) Gas Share the Savings; and (7) Gas Heating Load Peak Reduction. These EAMs are more fully described in Appendix X and will be applicable on a Rate Year basis. Appendix X contains the EAMs and the incentives associated with each EAM's minimum, midpoint, and maximum values. Appendix X reflects certain COVID-19 adjustments to targets and incentive levels in RY1.

A. EAM Reporting Requirements

On July 31, 2021, 2022, and 2023, NYSEG and RG&E will each make a compliance filing ("EAM Compliance Filing") to the Commission showing the calculation of incentives earned under each EAM for the Rate Year preceding the filing. Within 30 calendar days of filing the EAM Compliance Filing, the Companies will convene an informational meeting either in person or via teleconference of all interested parties to these proceedings to review the Companies' calculation of the EAM for each Business. The Companies will also file with the Secretary quarterly reports no later than 60 days after the end of each calendar quarter to describe the Companies' progress toward each EAM's metric's targets, the actions taken by the Companies to achieve target performance, and a forecast of whether the Companies expect to meet annual EAM targets.

B. Calculation of Achieved Incentive Amounts

The total available incentive amounts (in dollars) for each Company will be fixed for all three Rate Years (RY1, RY2, and RY3) and subject to adjustments for RY1 related to COVID-19 as detailed in Appendix X.

For the Electric Share the Savings, Heat Pump Share the Savings,[29] and the Gas Share the Savings EAMs, the available incentive amounts will be governed by the savings formula set forth in Appendix X. For these EAMs, the Companies will retain 30% of gross savings (in dollars) above the baseline target and budget amounts.

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[29] In the event NYSEG or RG&E undertake NPAs which include heat pumps as part of the solution, the Companies will not include those heat pumps associated with any such project in the calculation of the Heat Pump Share the Savings EAM or the Beneficial Electrification EAM.

For the Beneficial Electrification, DER Utilization, Electric Peak Reduction, and Gas Heating Load Peak Reduction EAMs, the Companies will receive a dollar amount (rounded to the nearest dollar) equivalent to the linear interpolation of achievement, based on actual performance relative to the target levels for each Rate Year (as given in each Company's respective Target Summary). For example, for RY1 for NYSEG, suppose the Company achieves for the Beneficial Electrification EAM a Lifetime CO_2 savings of 367,839 tons (as calculated pursuant to the description in Appendix X). This achievement level is halfway between the "minimum" and "midpoint" target levels. Thus, the Company's earned EAM incentive would be the linear interpolation of the "minimum" and "midpoint" dollar amounts detailed in Appendix X, in this case the average of those two values for a total of $603,972 (the average of $402,648 and $805,296).

C. Recovery of EAM Incentives

The Companies will be permitted to recover earned EAM incentives through a surcharge mechanism beginning 90 days after making its EAM Compliance Filing. NYSEG shall recover earned Electric EAMs through its NBC and earned Gas EAMs through a separate surcharge. RG&E shall recover earned Electric EAMs through its NBC and earned Gas EAMs through a separate surcharge. To determine responsibility for earned EAM awards among service classifications, the Companies will allocate the Electric Share the Savings and Heat Pump Share the Savings EAMs using the same allocation method to allocate Energy Efficiency-EE Tracker costs to service classes.

For NYSEG, the Energy Efficiency-EE Tracker cost allocation is as follows: (1) 83.81% is based on energy (i.e., kWh); (2) 5.84% is based on a 2 Coincident Peak ("CP") demand allocator; (3) 4.34% is based on a 12 CP demand allocator; (4) 2.42% is based on a primary non-coincident peak (“NCP”) demand allocator; and (5) 3.59 % is based on a secondary NCP demand allocator.

For RG&E, the Energy Efficiency-EE Tracker cost allocation is as follows: (1) 83.43% is based on energy; (2) 6.53% is based on a 1CP demand allocator; (3) 3.38% is based on a 12 CP demand allocator; (4) 1.72% is based on a primary NCP demand allocator; and (5) 4.95% is based on a secondary NCP demand allocator.

The Companies will allocate EAM awards to service classifications for the Beneficial Electrification EAM using transmission demand (12 CP), primary demand, secondary demand, and energy allocators with each carrying equal weight using the energy allocator. For the DER Utilization EAM, the Companies will allocate EAM awards to service classifications using transmission demand (12CP), primary demand, secondary demand, and energy allocators with each carrying equal weight. For the Electric Peak Reduction EAM, the Companies will allocate EAM awards to service classifications using the transmission demand allocator (12 CP). For the Gas Share the Savings EAM, the Companies will allocate EAM awards to service classifications using the same allocation method to allocate Energy Efficiency-EE Tracker costs to service classes for both Companies, where the 83.81% is based on energy (i.e., therms) and 16.19% is based on peak day design demand allocator. For the Gas Heating Load Peak Demand EAM, the Companies will allocate EAM awards to service classifications using the gas peak day design demand allocator.

The calculation of the earned incentives is subject to review and adjustment by the Commission.

D. EAM Scorecard Metrics

The Companies will track and report the progress of three EAM Scorecard metrics: Locational System Relief Value (“LSRV”) Load Factor; Residential Electric Energy Intensity;

and Commercial Electric Energy Intensity. The Companies shall report progress on each of its Scorecard metrics as part of its annual EAM Compliance Filing. To facilitate possible development of new EAMs for proposal in a future rate proceeding, the Companies will track for a scorecard load factors at various LSRV areas on their respective distribution systems. The development of a Load Factor EAM at LSRV circuits/areas will require AMI for hourly usage data. Thus, the Companies' scorecard shall depend upon the installation of AMI at appropriate circuits. The Companies will also track Energy Intensity Data for a scorecard. The Residential Electric Energy Intensity metric will be calculated as the annual weather-normalized Residential MWh sales divided by the 12-month average of number of residential customers. For the purposes of this metric, residential customers are defined as customers taking service under Service Classifications 1, 8, and 12 for NYSEG, and Service Classifications 1, 4-I and 4-II for RG&E. The weather-normalized MWh sales used for this metric will be reduced by the aggregate MWh of electricity produced by Community Distributed Generation resources allocated to the relevant service classifications and adjusted to exclude the impacts of beneficial electrification technologies, such as incremental EV charging and heat pump usage.

The Commercial Electric Energy Intensity metric will be calculated as the annual weather-normalized Commercial MWh sales divided by the 12-month average of number of commercial customers. For the purposes of this metric, commercial customers are defined as customers taking service under Service Classifications 2, 6, and 9 for NYSEG, and Service Classifications 2, 3, 7, and 9 for RG&E. The weather-normalized MWh sales used for this metric will be reduced by the aggregate MWh of electricity produced by Community Distributed Generation resources allocated to the relevant service classifications and adjusted to exclude the impacts of beneficial electrification technologies such as incremental EV charging and heat pump usage.

XXV. RATE ADJUSTMENT MECHANISM

Each Business will continue a RAM to return or collect Customer Bill Credits and the net balance of other RAM Eligible Deferrals and Costs, including: (1) property taxes; (2) Major Storm deferral balances; (3) gas leak prone pipe replacement; (4) REV costs and fees which are not covered by other recovery mechanisms; and (5) costs associated with the implementation of any Commission-ordered EV program which are not covered by any other cost recovery mechanisms. The policies and procedures with respect to the RAM are set forth in Appendix W. As set forth therein, the annual RAM recovery/return shall be limited to: (1) $22.2 million for NYSEG Electric; (2) $5.3 million for NYSEG Gas; (3) $12.3 million for RG&E Electric; and (4) $4.5 million for RG&E Gas.

Beginning July 1, 2020, the RAM for NYSEG Electric will recover deferred costs as originally designed. Beginning July 1, 2021, the RAM at all four Businesses will begin the five-year recovery of up to $30 million of Customer Bill Credits provided in the customer relief provisions as discussed in Section IV. Customer Bill Credits shall be recovered from those service classes which were eligible to receive the customer bill credits. Specifically, residential classes will be charged for the recovery of the residential bill credits and applicable non-residential service classes will be charged for the recovery of the non-residential bill credits. The RAM component for collecting the Customer Bill Credits will not be collected from those service classes ineligible to receive the Customer Bill Credits.

XXVI. PERFORMANCE INCENTIVE MECHANISMS

NYSEG and RG&E are each authorized to receive certain positive incentives as set forth in Appendices L, P and II.

XXVII. DEPRECIATION

A. Rates

Depreciation rates (lives and salvage rates) to be used by all Businesses, and the plant accounts upon which they will be used, are agreed to as part of this Proposal. The new depreciation rates and associated plant accounts are set forth in Appendix Z.

B. Excess Depreciation Reserve

NYSEG Electric and RG&E Electric, as indicated previously in Section V above, will amortize EDR to cover the make-whole period.

Separately, NYSEG Electric will amortize the amounts shown on Appendix B as explained in Appendix F. The RY3 amortization level will continue beyond RY3 until changed by the Commission.

XXVIII. NET PLANT RECONCILIATION

A. Net Plant Targets and Depreciation Targets

Each Business shall reconcile downward its actual Electric and Gas Net Plant and Book Depreciation to the Targets set forth in this Proposal for each of the Rate Years with the exception of the individual projects described below. The Net Plant targets are based on the Rate Year Electric and Gas Net Plants amounts set forth in Appendix S. There will be individual Net Plant Reconciliations with separate net plant targets with downward-only reconciliation and related status reporting for the following projects: the Rochester Area Reliability Project (RG&E Electric); the NYSEG Electric Substation Modernization Project; the Resiliency Projects at RG&E Electric and NYSEG Electric; and AMI at all four Businesses.

The depreciation targets reflect the depreciation rates included in this Proposal as set forth in Appendix Z.

The annual reconciliations and dispositions in this Section will be calculated separately for the four Businesses (i.e., NYSEG Electric and Gas and RG&E Electric and Gas) as well as for the individual projects identified above. An example of the annual reconciliation calculation is shown on Appendix S.

Net Plant and Depreciation targets will be adjusted for: (1) any asset sales requiring New York State Public Service Law ("PSL") § 70 approval that occur prior to or during the Rate Plan period; and (2) any electric or gas projects deferred or avoided through an NWA or NPA.

Actual Electric, Gas and Allocated Common as well as individual projects and Average Net Plant for each Rate Year will be reconciled to the Electric, Gas and Allocated Common Net Plant targets on an annual basis for RY1, RY2 and RY3.

The revenue requirement impact (i.e., return and depreciation) for each Business resulting from the difference (whether positive or negative) between actual average Electric, Gas and Allocated Common Net Plant Balances and the Net Plant targets will carry forward for each Rate Year and be summed at the end of the Rate Plan.

If at the end of the Rate Plan the cumulative revenue requirement impact from the Electric or Gas and Allocated Common Net Plant reconciliation is negative (i.e., lower Net Plant plus depreciation than the targets), the Companies will defer the revenue requirement impact for the benefit of customers of that Electric or Gas Business.

If at the end of the Rate Plan the cumulative revenue requirement impact for, separately, Electric or Gas and Allocated Common Net Plant reconciliation is positive, there will be no deferral for that Business.

The Companies have the flexibility over the term of the Rate Plan to modify the type, timing, identity, nature and scope of capital projects from those currently forecasted subject to the Net Plant Reconciliation provisions set forth above and the capital reporting provisions set forth below.

B. Capital Expenditure Reporting

Appendix R provides a list of the planned capital expenditures for the four Businesses for calendar years 2020-2023.

The Companies will file with the Secretary to the Commission, with a copy provided to Staff, the following:

(1) Quarterly Report – For the projects identified below, this report will provide a variance report between actual and forecasted expenditures, including project changes due the last day of the month following the calendar quarter (i.e., Quarter 1 due April 30, Quarter 2 due July 31, Quarter 3 due October 31, and Quarter 4 due January 30) for each such project that experiences a plus or minus 10% cost variation.

(2) Annual Report – For projects identified below, this report will provide a variance report between actuals to Appendix R at the close of the year due on March 15 of the following year. The report will include an explanation for removing or revising capital projects currently listed in Appendix R or adding new capital projects to those listed in Appendix R. Upon request, the Companies will meet with Staff to review this annual capital expenditure report.

(3) Five Year Plan Report – This report will include the projected five-year capital plan and budget with descriptions of the projects outlined below. It will be due on April 1. The Companies will continue to file with the Secretary to the Commission on an annual basis their respective five-year projected capital plans and budgets.

The Companies will provide the above-referenced reports on electric capital projects greater than $1.0 million, gas capital projects greater than $500,000 and common capital projects greater than $500,000. For each such project that experiences a cost delta of plus or minus 10% or a timeline delta of plus or minus six months, the Companies will include a narrative explanation of the variation in the Quarterly and Annual report. The Companies will also provide a narrative on project design, permitting, and/or construction status (including a construction schedule for each project), and capital project documentation for any ongoing projects, as well as a description of any new projects or programs in the Annual Report. The summary of capital expenditures for all capital projects and programs, including all ongoing and active construction projects and programs will be provided in the same format as Appendix R. The Quarterly Report and Annual Report will include an explanation for removing or revising capital projects currently listed in Appendix R or adding new capital projects to those listed in Appendix R. The Companies will also provide to Staff project justifications and prioritization consistent with the Companies' Capital Investment Prioritization Strategies for newly identified projects.

XXIX. RECONCILIATIONS / DEFERRALS

The Companies will reconcile certain costs and related items as set forth in Appendix T and U with key items discussed below.

A. Labor

The reconciliation mechanism is set forth in Appendix U. The employee headcount reconciliation includes a separate reconciliation of line workers at NYSEG Electric and RG&E Electric.

B. Pensions / Other Post-Employment Benefits ("OPEBs")

The Companies will remain on the Commission's Pension Policy Statement[30] and subject to the Pension Policy Statement's reconciliation and deferral provisions. Accordingly, the Companies will reconcile their actual Pensions and OPEB expenses in conformance with the Pension Policy Statement to the level allowed in the rates set forth in Appendix T. Non-qualified

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[30] Case 91-M-0890 – In the Matter of the Development of a Statement of Policy Concerning the Accounting and Ratemaking Treatment for Pensions and Postretirement Benefits Other than Pensions, Statement of Policy and Order Concerning the Accounting and Ratemaking Treatment for Pensions and Postretirement Benefits Other Than Pensions (Sept. 7, 1993).

plan costs are excluded from the reconciliation. Each Company continues to include their OPEB internal reserve in rate base and therefore is not required to accrue interest on that internal reserve.

C. Property Taxes

If the level of actual expense for property taxes, including any property tax refunds received, varies in any Rate Year from the projected level provided in rates, which levels are set forth in Appendix T, 90% of the variation will be deferred and either recovered from or credited to customers, subject to the following cap: each Company's 10% share of property tax expenses above or below the level in rates is capped at an annual amount equal to 10 basis points on common equity for each Rate Year. The Companies will defer on their books of account, for recovery from or credit to customers, 100% of the variation above or below the level at which the cap takes effect.

The Companies' property tax saving efforts (e.g., economic obsolescence, tax challenges) shall be reflected in actual results net of related, incremental costs to achieve.

D. Electric and Gas Vegetation Management

A downward-only reconciliation mechanism for the Companies' Distribution Electric Vegetation Management programs applies, as set forth in Appendix T. The Companies also will utilize a downward-only reconciliation mechanism for their Gas Vegetation Management as set forth in Appendix T.

E. Management, Operations and Staffing Audit Expenses

The Companies have reflected the estimated incremental costs of implementing management audit recommendations from its last management audit in rates. The Companies will symmetrically reconcile these costs, with an overall cap for deferral of 25% of the amount included in rates. Additionally, the Companies will defer expenses associated with consultants for any management, operations, staffing or other audit initiated by the Commission.

F. Gas Research and Development ("R&D")

Each Company shall reconcile actual expenditures for gas R&D expenditures and related tax credits with the amount provided in rates on an annual basis.

G. Pipeline Integrity Costs

The Companies shall reconcile actual expenditures for gas distribution and transmission Pipeline Integrity costs on an individual Company basis with the amount provided in rates on an annual basis as set forth in Appendix T. If the amount expended is less than the amount allowed in rates, the individual Company shall defer the difference which shall be carried over and may be used in a future year for Pipeline Integrity costs.

H. Incremental Maintenance

There will be a downward-only reconciliation mechanism with carryover for the total Incremental Maintenance on an individual Business basis with the amount provided in rates on an annual basis. The specific programs and rate allowances included as part of Incremental Maintenance are depicted in Appendix T. At the end of each Rate Year, the amount expended, in total, for Incremental Maintenance will be compared with the amount allowed in rates and will be included in the Companies' annual compliance filing. If the amount expended is less than the amount allowed in rates, the individual Company shall defer the difference which shall be carried over and may be used in a future year for Incremental Maintenance costs.

I. Manhole Maintenance Program Funding

With respect to costs associated with new requirements by the City of Rochester for manhole maintenance, RG&E will establish a 100% downward reconciliation and a 100%

upward reconciliation of the first 25% spending above the amount allowed in rates, and 50/50 sharing (deferral/Company) of any amounts spent above the 125% level.

J. Energy Smart Community

A downward-only reconciliation mechanism for the ESC applies, as set forth in Appendix T.

K. Reserve Accounting Treatment for Environmental Remediation Costs

The amounts included in rates for Environmental Remediation are set forth in Appendix T. NYSEG and RG&E will continue to utilize reserve accounting for Environmental Remediation costs.

L. Storm Reserve Accounting

The Storm Reserve Accounting procedures and operations are set forth in Appendix H. NYSEG and RG&E will continue to utilize reserve accounting for Major Storm costs, including qualified pre-staging and mobilization costs.

M. Legislative, Accounting, Regulatory, Tax and Related Actions

If the Commission has not addressed or does not otherwise address the treatment of a legislative, accounting, regulatory, tax, fee,[31] or government-mandated action (e.g., through a surcharge or credit) via a generic or Company-specific proceeding, NYSEG and RG&E will defer on a Rate Year basis the incremental cost or savings resulting from such legislative, accounting, regulatory, tax, fee, or government-mandated action occurring during the term of this Proposal as long as the incremental annual pre-tax change in expense is greater than: (1) $2.0 million for NYSEG Electric; (2) $1.0 million for NYSEG Gas; (3) $1.5 million for RG&E

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[31] For purpose of this Section, the term "fees" is defined as charges (however labeled), imposed by state, local, municipal, quasi-governmental entities, or special districts on the Companies and/or their operations. Examples include, but are not limited to, franchise fees, special franchise fees, permit fees, road use fees, or other special use charges.

Electric; and (4) $1.0 million for RG&E Gas, and the relevant Company is not earning above the first earnings sharing threshold amounts set forth in Section VIII. If the above dollar thresholds are triggered, the Company will defer the entire amount of incremental cost changes. Subject to the limitations set forth above in this Section, the Companies will defer the revenue requirement impact of all tax expense and associated interest recorded as the result of federal, state and local tax audits.

N. Nuclear Electric Insurance Limited ("NEIL") Credits

The NYSEG Electric and RG&E Electric revenue requirements include NEIL credits and the Companies will defer the difference between the amounts reflected in rates and actual credits received. The NEIL credit amounts included in the revenue requirements are reflected on Appendix B and Appendix D.

O. Economic Development

Economic Development programs are symmetrically reconcilable with carry-forwards.

P. Low Income Program

The Low Income Program reconciliations are set forth in Appendices Q and T.

Q. Department of Energy Liability

The carrying costs of an RG&E Department of Energy liability will be reconciled and deferred as set forth in Appendix T.

R. Debt Cost Reconciliation

The Companies will reconcile their overall debt cost (based on interest rates) as set forth in Appendix T.

S. Energy Efficiency / Heat Pumps

EE/Heat Pump costs are symmetrically reconcilable with carry-forwards as set forth in greater detail in Appendix T.

T. Electric Vehicles

Costs associated with the implementation of any Commission-ordered EV program, including but not limited to customer incentive program costs, will be reconciled and recoverable through the RAM as described in Appendix W, to the extent those costs are not recoverable through an alternate Commission approved mechanism.

U. Additional Reconciliation / Deferral Provisions

In addition to the foregoing reconciliation provisions, other applicable existing reconciliations and/or deferral accounting for other tariffed items (e.g., NBC) will continue in effect through the term of the Rate Plan and thereafter until modified or discontinued by the Commission.

The Companies shall retain the right to petition the Commission for authorization to defer on their books of account extraordinary expenditures not otherwise addressed by this Proposal, including but not limited to flood, riot, terrorism, cyber terrorism, cyber-attack, sabotage, war, epidemics, pandemic, declaration of a local, state or federal disaster in the service area, and Acts of God.

V. Interest on Deferred Items

Unless otherwise specified, the Companies will accrue interest on all deferred amounts not embedded in rates using the applicable pre-tax rate of return for NYSEG Electric and Gas and RG&E Electric and Gas on the after-tax balance of amounts deferred.

W. Post-Term Amortization

After the term of the Rate Plan, the Companies will defer the revenue requirement effect associated with expiring amortizations, the SIR dispute resolution in Section XI above, and any RY3 rate levelization/shaping deferral, as shown in Appendix AA.

XXX. COST OF SERVICE, REVENUE ALLOCATION AND RATE DESIGN ISSUES

A. Electric Cost of Service, Revenue Allocation and Rate Design

The provisions associated with the Companies' electric cost of service, revenue allocation and rate design are set forth in detail in Appendix BB.

B. Electric Rates and Customer Bill Impacts

The electric rates by service classification for each Rate Year are set forth in Appendix CC. The estimated customer bill impacts by Rate Year for the majority of the electric service classifications are also set forth in Appendix CC.

C. Gas Cost of Service, Revenue Allocation and Rate Design

The provisions associated with the Companies' gas cost of service, revenue allocation and rate design are set forth in detail in Appendix DD.

D. Gas Rates and Customer Bill Impacts

The gas rates by service classification for each Rate Year are set forth in Appendix EE. The estimated customer bill impacts by Rate Year for the majority of the gas service classifications are also set forth in Appendix EE.

XXXI. REVENUE DECOUPLING MECHANISM

A. Electric

NYSEG and RG&E will continue an Electric Revenue Decoupling Mechanism ("RDM") on a total revenue per class basis. Any Customer Bill Credits noted in Section IV above will not be reflected in the RDM. Appendix FF sets forth the RDM process and the electric service classes covered by the RDM and the RY1, RY2, and RY3 targets for each service class (and in certain instances sub-classes). The RY3 targets will repeat annually until changed by the Commission.

For reconciliation purposes, the Companies will group together all residential RDM classes, but will maintain individual non-residential RDM service classes. Street Lighting service classes will continue to be subject to the RDM. The RDM will apply to all service classes under each Company's respective Street Lighting tariff. RDM adjustments would apply to lamp charges or volumetric delivery charges, as applicable. The RDM will be adjusted for each Company's streetlighting service class to account for streetlighting accounts where customers move to a delivery only streetlighting class. The RDM adjustment will account for the change in customer revenues between the customers former service class and the new service class. The RDM will not apply to Area Lighting.

B. Gas

NYSEG and RG&E will continue a Gas RDM. However, effective with RY1, the Gas RDMs will no longer be on a revenue per customer basis. The NYSEG and RG&E Gas RDMs will now be on a total revenue per class basis, the same approach as the NYSEG and RG&E Electric RDM. Any Customer Bill Credits noted in Section IV above will not be reflected in the RDM. Appendix FF sets forth the RDM process and the gas service classes covered by the RDM and the RY1, RY2, and RY3 targets. The RY3 targets will repeat annually until changed by the Commission.

For reconciliation purposes, each Company will maintain two RDM classes: residential and non-residential.

XXXII. OTHER

A. Electric Sales Forecast Models

To facilitate Staff review, the Companies will produce in their next rate case filing, electric sales forecast models reproducible by Staff. The Companies will facilitate Staff's review by reproducing the Companies' models and forecasts using a widely available statistical platform used by Staff (e.g., Stata, Eviews, SAS). The model results and relevant workpapers associated with the Companies' reproduction will be provided to Staff.

B. Street Lighting Items

The pricing methodology for street lighting sales will be comprised of the Net Book Value ("NBV") plus an Administrative and General loader of 4.5% of NBV and a Customer Protection Overhead of 15% of NBV. Further adjustments to the closing sales price will occur only if the increase in NBV between the sales price proposal and closing price exceeds the 15% Customer Protection Overhead calculated on the originally quoted NBV, as detailed further in Appendix BB. No fewer than 30 days before the closing date, the Companies will provide detailed reports to municipalities related to assets included in a sale to support any NBV adjustments.

NYSEG and RG&E will revise their tariff to accommodate unmetered service for Smart City technologies with known and predictable usage, and in conformance with the Companies' pole attachment requirements.

C. Natural Gas Interruptible Service

Natural gas interruptible service is detailed in Appendix DD.

D. Gas Cost Incentive Mechanism ("GCIM")

The optimization activities under the GCIM provide benefits to customers and proper incentives to the Companies and, thus, will be extended. Savings under NYSEG's and RG&E's GCIM will continue to be shared as follows: (1) 85% / 15% (customer/shareholder) for non-migration capacity release; (2) 85% / 15% (customer/shareholder) for off-system sales net of gas costs and related optimization transactions; and (3) 80% / 20% (customer/shareholder) for local production.

E. Electric Cost Incentive Mechanisms

1. Homer City Generating Station Optimization Revenues

NYSEG will share 80% / 20% between customers and shareholders the cost savings resulting from optimization activities associated with NYSEG's grandfathered transmission entitlements of up to 471 MW from the Homer City Generating Station, located in PJM Interconnection LLC regional transmission organization, into the New York Independent System Operator, Inc. regional transmission organization. The optimization of these entitlements will benefit all delivery customers through lower electric supply costs in the NBC.

2. Procurement of Environmental Attributes

The Companies will share 80% / 20% between customers and shareholders any savings associated with procurement activities for Tier-1 eligible renewable energy certificates ("REC Certificates") as defined in the Commission's August 1, 2016 Order Adopting a Clean Energy Standard issued in Case 15-E-0302[32] through the two-step process detailed in Appendix II.

XXXIII. COMPLIANCE AND REPORTING REQUIREMENTS

The compliance and reporting requirements set forth in this Proposal are set forth in Appendix JJ.

XXXIV. MISCELLANEOUS PROVISIONS

A. 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).

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[32] Case 15-E-0302 - Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard, Order Adopting Clean Energy Standard (Aug. 1, 2016).

Nothing herein precludes NYSEG or RG&E from filing a new general rate case for electric or gas base delivery rates to be effective on or after May 1, 2023. Except pursuant to rate changes permitted by this Section, the Companies will not file rates to become effective prior to May 1, 2023.

Changes to the Companies' base delivery service rates during the term of the Rate Plan will not be permitted except for the changes provided for or detailed in this Proposal and, subject to Commission approval, changes as a result of the following circumstances.

a. A minor change, whose revenue effect is *de minimis* or essentially offset by associated changes within the same class so that the difference in the revenues that NYSEG's and RG&E's base delivery service rates are designed to produce overall before such a change is *de minimis*, may be made to any individual base delivery service rate or rates. 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 Rate Plan.

b. Upon the occurrence, at any time, of circumstances that in the judgment of the Commission so threaten, respectively, NYSEG's or RG&E's economic viability or ability to maintain safe, reliable and adequate service as to warrant an exception to the limitations on rate changes provided for or detailed in this Proposal, NYSEG or RG&E will be permitted to file for an increase in base delivery service rates.

c. The Signatory Parties recognize that the Commission reserves the authority to act on the level of NYSEG's and RG&E's 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 this Proposal as to render NYSEG's and RG&E's rates unjust or unreasonable or insufficient for the provision of safe and adequate service.

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 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.

B. Request for Exemption from Disclosure

Nothing in this Proposal prevents the Companies from seeking a request for exemption from disclosure under 16 NYCRR Part 6 for all or any part(s) of any document or report filed with the Commission (or submitted to Staff) in accordance with this Proposal or prohibits or restricts any other party from challenging any such request.

C. Dispute Resolution

In the event of any disagreement over the interpretation of this Proposal or the implementation of any of the provisions of this Proposal which cannot be resolved informally among the parties, such disagreement will be resolved as follows: the parties promptly will confer and, in good faith, will attempt to resolve such disagreement. If any such disagreement cannot be resolved by the parties, then the matter will be submitted to an ALJ designated by the Chief ALJ for a determination on an expedited basis using alternative dispute resolution techniques or such other procedures as the ALJ decides are appropriate under the circumstances. Within 15 days from the ALJ's decision, any party may petition the Commission for relief from the ALJ's determination on the disputed matter.

D. Provisions Not Separable

The Signatory Parties intend this Proposal to be a complete resolution of all the issues in Cases 19-E-0378, 19-G-00379, 19-E-0380 and 19-G-0381.[33] The terms of this Proposal are submitted as an integrated whole. If the Commission does not accept this Proposal according to its terms as the basis of the resolution of all issues addressed without change or condition, each Signatory Party shall have the right to withdraw from this Proposal upon written notice to the Commission within ten days of the Commission's issuance of a final order in these proceedings. Upon such a withdrawal, that Signatory Party shall be free to pursue its respective positions in these proceedings without prejudice, and this Proposal shall not be used in evidence or cited against any such Signatory Party or used for any other purpose. It is also understood that each provision of this Proposal is in consideration and support of all the other provisions, and expressly conditioned upon 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.

E. Provisions Not Precedent

The terms and provisions of this Proposal apply solely to, and are binding only in, the context of the purposes and results of this Proposal. None of the terms or provisions of this Proposal, nor any methodology or principle utilized herein, and none of the positions taken herein by any Signatory Party may be referred to, cited, or relied upon by any other Signatory Party in any fashion as binding precedent in any other proceeding before the 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 and except as may be necessary in explaining derivation of specific costs or accounting treatments as relevant to future ratemaking proceedings. Concessions made by Signatory Parties on various electric and gas issues included in this Proposal do not preclude those parties from addressing such issues in future rate proceedings or in other proceedings. This Proposal shall not be construed, interpreted or otherwise deemed in any respect to constitute an admission by any Signatory Party regarding any allegation, contention, or issue raised in these proceedings or addressed in this Proposal.

F. Submission of Proposal

Each Signatory Party agrees to submit this Proposal to the Commission, to support and request its adoption by the Commission, and not to take a position in these proceedings. The Signatory Parties believe that the resolution of the issues, as set forth in this Proposal, is just and reasonable and otherwise in accordance with the PSL, the Commission's regulations and applicable Commission precedent. The Signatory Parties believe that this Proposal will satisfy the requirements of PSL § 65(1) that NYSEG and RG&E provide safe and adequate service at just and reasonable rates.

G. Effect of Commission Adoption of Terms of the 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 PSL. The Signatory 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.

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[33] The Signatory Parties have agreed to a process to address further actions to be taken in the future to fully effectuate this Proposal. See Section XXIX (Further Assurances).

H. 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.

I. 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 Companies or any party to petition the Commission for any purpose with respect to the service(s) not specified in such term or provision.

J. Execution

This Proposal may be executed in one or more counterparts, all of which taken together shall constitute one and the same instrument which shall be binding upon each Signatory Party when its executed counterpart is filed with the Secretary to the Commission. This Proposal will be binding on each and every Signatory Party when the counterparts have been executed. In the event that any signature is delivered by facsimile transmission or by e-mail delivery of a “pdf” format data file, such signature shall create a valid and binding obligation of the party executing (or on whose behalf such signature is executed) with the same force and effect as if such facsimile or “pdf” signature page were an original thereof.

K. Entire Agreement

This Proposal, including all attachments, exhibits and appendices, if any, represents the entire agreement of the Signatory Parties with respect to the matters resolved herein.

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.

40006.43 1924677

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed as of the date first written above by their respective officers thereunto duly authorized.

NEW YORK STATE ELECTRIC & GAS CORPORATION

May 20, 2020 By: ______________________________

Name: Steven R. Adams
Title: Vice President, Regulatory Strategy, Avangrid Service Company on behalf of NYSEG

By: ______________________________

Name: Joseph J. Syta
Title: Vice President, Controller and Treasurer

ROCHESTER GAS AND ELECTRIC CORPORATION

May 20, 2020 By: ______________________________

Name: Steven R. Adams
Title: Vice President, Regulatory Strategy, Avangrid Service Company on behalf of RG&E

By: ______________________________

Name: Joseph J. Syta
Title: Vice President, Controller and Treasurer

NEW YORK STATE DEPARTMENT OF PUBLIC SERVICE

June 22, 2020

By: John Favreau

Name: John Favreau

Title: Staff Counsel

ALLIANCE FOR A GREEN ECONOMY (AGREE)*

May 20, 2020

By: Jessica Azulay

Name: Jessica Azulay
Title: Executive Director

* Alliance for Green Economy signs on to the Proposal as it relates to the gas businesses of NYSEG and RG&E only and not the electric businesses of NYSEG an RG&E.

BOB WYMAN

May 20, 2020

By: ______________________
Name: Bob Wyman

BINGHAMTON REGIONAL SUSTAINABILITY COALITION*

May 20, 2020

By: Adam Flint

Name: Adam Flint

Title: Director of Clean Energy Programs

* Binghamton Regional Sustainability Coalition signs on to the Proposal as it relates to the gas businesses of NYSEG and RG&E only, and not the electric businesses of NYSEG and RG&E.

CHARGEPOINT, INC.*

May 20, 2020

By: ______________________
Name: Kevin George Miller
Title: Director of Public Policy

* ChargePoint, Inc. signs on to the Proposal as it relates to the electric businesses of NYSEG and RG&E only.

CONCERNED CITIZENS OF ONEONTA*

May 20, 2020

By: Colleen Blacklock
Name: Colleen Blacklock
Title: Representative

* Concerned Citizens of Oneonta signs on to the Proposal as it relates to the electric and gas businesses of NYSEG only.

CONCERNED CITIZENS OF ONEONTA*

May 20, 2020

By: Arthur J. Rorick
Name: Arthur J. Rorick
Title:

* Concerned Citizens of Oneonta signs on to the Proposal as it relates to the electric and gas businesses of NYSEG only.

DENNIS HIGGINS*

May 20, 2020

By: ______________________
Name: Dennis Higgins

* Dennis Higgins signs on to the Proposal as it relates to the gas businesses of NYSEG and RG&E only.

EMPIRE STATE DEVELOPMENT CORPORATION, THE NEW YORK STATE DEPARTMENT OF ECONOMIC DEVELOPMENT

May 20, 2020

By: V. Ravaschiere

Name: Vincent Ravaschiere

Title: Senior Vice President

FOSSIL FREE TOMPKINS*

May 21, 2020

By: Irene Weiser

Name: Irene Weiser
Title: Coordinator

* Fossil Free Tompkins signs on to the Proposal as it relates to the gas businesses of NYSEG and RG&E, and opposes the Proposal as it relates to the electric businesses of NYSEG and RG&E.

HEATSMART, A PROGRAM OF SOLAR TOMPKINS, INC.*

May 20, 2020

By: Brian Eden
Name: Brian Eden
Title: Chair

* HeatSmart, a program of Solar Tompkins Inc., signs on to the Proposal as it relates to the gas businesses of NYSEG and RG&E only and not to the electric businesses of NYSEG and RG&E.

INTERNATIONAL BROTHERHOOD OF ELECTRICAL WORKERS LOCAL UNION 10*

May 20, 2020

By: /s/ *Richard J. Koda*

Name: Richard Koda
Koda Consulting, Inc.
Representative for International Brotherhood of Electrical Workers, Local Union 10

* International Brotherhood of Electrical Workers, Local Union 10 signs on to the Proposal as it relates to the electric and gas businesses of NYSEG only.

KEITH SCHUE*

May 20, 2020

By: Keith Schue
Name: Keith Schue

* Keith Schue signs on to the Proposal as it relates to the gas businesses of NYSEG and RG&E only.

MULTIPLE INTERVENORS

/s/ Michael B. Mager

May 20, 2020

By: ______________________________

Name: Michael B. Mager
Couch White, LLP
Counsel to Multiple Intervenors

NUCOR STEEL AUBURN, INC.*

May 20, 2020

By:
Name: James W. Brew
Stone Mattheis Xenopoulos & Brew P.C.
Counsel to Nucor Steel Auburn, Inc.

* Nucor Steel Auburn, Inc. signs on to the Proposal as it relates to the electric and gas businesses of NYSEG only.

NEW YORK GEOTHERMAL ENERGY ORGANIZATION

May 20, 2020

By: Bill Nowak

Name: Bill Nowak

Title: Executive Director

NEW YORK POWER AUTHORITY*

May 20, 2020

By: ______________________
Name: Sarah Salati
Title: Executive Vice President & Chief Commercial Officer

* New York Power Authority signs on to the Proposal as it relates to the electric businesses of NYSEG and RG&E only. NYPA takes no position regarding the gas businesses of NYSEG and RG&E.

RATEPAYER AND COMMUNITY INTERVENORS*

May 20, 2020

By: ______________________
Name: Carol Chock
Title: President

* Ratepayer and Community Intervenors signs on to the Proposal as it relates to the gas businesses of NYSEG and RG&E only and not to the electric businesses.

ROCHESTER PEOPLE'S CLIMATE COALITION*

May 20, 2020

By: Kl V. V.
Name: Kristen Van Hooreweghe
Title: Project Manager

* Rochester People's Climate Coalition signs on to the Proposal as it relates to the gas businesses of NYSEG and RG&E only. RPCC is not signing the NYSEG/RG&E electric cases.

SUZANNE WINKLER *

May 20, 2020

By: [signature]
Name: Suzanne Winkler

* Suzanne Winkler signs on to the Proposal as it relates to the gas business of NYSEG only.

WALMART INC.*

May 20, 2020

By:

Name: Barry Naum
Spilman Thomas & Battle, PLLC
Counsel to Walmart Inc.

* Walmart Inc. signs on to the Proposal as it relates to the electric businesses of NYSEG and RG&E only.

Case 19-E-0378, et al. **Appendix A**
Joint Proposal

NYSEG and RG&E
Rate Increase (Decrease) Summary
($000)

		A	B	C	D	E	F
		Rate Increase (Decrease) Summary					
		Without Rate Levelization / Shaping			**With Rate Levelization / Shaping**		
		Rate Year 1 TME 4/30/21	Rate Year 2 TME 4/30/22	Rate Year 3 TME 4/30/23	Rate Year 1 TME 4/30/21	Rate Year 2 TME 4/30/22	Rate Year 3 TME 4/30/23
	Rate Increase (Decrease) - with EE						
1	NYSEG Electric	$ 45,684	$ 99,200	$ 59,063	$ 45,684	$ 84,770	$ 88,565
2	NYSEG Gas	(10,675)	14,150	15,052	(514)	3,350	5,269
3	RG&E Electric	(3,344)	53,159	37,791	15,238	28,064	30,721
4	RG&E Gas	(10,943)	10,441	15,125	(1,127)	859	3,866
5	**Total**	$ 20,721	$ 176,951	$ 127,031	$ 59,280	$ 117,044	$ 128,420
	Rate Increase (Decrease) - without EE						
6	NYSEG Electric	$ 34,680	$ 85,937	$ 49,920	$ 34,680	71,507	79,422
7	NYSEG Gas	(10,161)	12,376	13,121	-	1,576	3,338
8	RG&E Electric	(7,882)	48,017	32,455	10,700	22,922	25,385
9	RG&E Gas	(9,816)	9,582	13,642	-	-	2,383
10	**Total**	$ 6,821	$ 155,912	$ 109,139	$ 45,380	$ 96,005	$ 110,528
	Delivery Rate Increase (Decrease) with EE						
11	NYSEG Electric	6.1%	12.5%	6.6%	6.1%	10.6%	9.9%
12	NYSEG Gas	(5.2%)	7.2%	7.2%	(0.3%)	1.7%	2.5%
13	RG&E Electric	(0.7%)	12.0%	7.6%	3.4%	6.3%	6.2%
14	RG&E Gas	(6.1%)	6.2%	8.4%	(0.6%)	0.5%	2.1%
	Delivery Rate Increase (Decrease) without EE						
15	NYSEG Electric	4.6%	10.9%	5.7%	4.6%	9.1%	9.1%
16	NYSEG Gas	(4.9%)	6.3%	6.3%	0.0%	0.8%	1.6%
17	RG&E Electric	(1.8%)	11.0%	6.7%	2.4%	5.2%	5.2%
18	RG&E Gas	(5.5%)	5.6%	7.6%	0.0%	0.0%	1.3%
	Overall Rate Increase (Decrease) without EE						
19	NYSEG Electric	2.3%	5.6%	3.1%	2.3%	4.7%	4.9%
20	NYSEG Gas	(2.3%)	2.9%	3.0%	0.0%	0.4%	0.8%
21	RG&E Electric	(1.0%)	6.3%	4.0%	1.4%	3.0%	3.1%
22	RG&E Gas	(2.3%)	2.3%	3.2%	0.0%	0.0%	0.6%

NYSEG Electric
Rate Change Levelization Worksheet - without Energy Efficiency
($000)

		A	B	C	D
		Rate Year 1 TME 4/30/21	Rate Year 2 TME 4/30/22	Rate Year 3 TME 4/30/23	Total
	Pre-Levelization Information				
1	Delivery Rate Increase without EE [1]	$ 34,680	$ 85,937	$ 49,920	
2	Delivery Revenues Before Increase without EE [2]	752,198	785,694	869,933	
3	Pre-Levelization Rate Increase % without EE	4.6%	10.9%	5.7%	
	Rate Change Levelization Calculation				
4	Delivery Rate Increase - Total	$ 34,680	$ 85,937	$ 49,920	
5	Period Levelization Deferral	-	(14,430)	29,502	
6	Delivery Rate Increase - Post Levelization	$ 34,680	$ 71,507	$ 79,422	
7	Delivery Revenues Before Increase without EE	752,198	785,694	869,933	
8	Post-Levelization Rate Increase % - Delivery without EE	4.6%	9.1%	9.1%	
	Carrying Costs Calculation				
9	Starting Levelization Deferral	-	-	14,752	
10	Levelization Deferral	-	14,430	(15,072)	
11	Accrued Carrying Costs	-	322	320	
12	Ending Levelization Deferral	-	14,752	0	
13	Average Levelization Deferral	-	7,215	7,216	
14	x 1 - Effective Tax Rate	73.9%	73.9%	73.9%	
15	Post-Tax Levelization Deferral	-	5,329	5,330	
16	Post-Tax WACC	6.10%	6.04%	6.00%	
17	Accrued Carrying Costs	-	322	320	$ 642
	Verification				
18	Pre-Levelization Cumulative Delivery Rate Increase	$ 104,039	$ 171,873	$ 49,920	$ 325,832
19	Post-Levelization Cumulative Delivery Rate Increase	104,039	143,013	79,422	326,474
20	Less: Carrying Costs (from line 17)				642
21	Total - Cross Check				$ 325,832

	Post-Tax WACC	LTD	Customer Dep	Equity	Total
	Rate Year 1 Calculation				
22	Weight	51.61%	0.39%	48.00%	100.00%
23	Cost Rate	3.63%	0.90%	8.80%	
24	Percent	1.88%	0.00%	4.22%	6.10%
	Rate Year 2 Calculation				
25	Weight	51.67%	0.33%	48.00%	100.00%
26	Cost Rate	3.52%	0.90%	8.80%	
27	Percent	1.82%	0.00%	4.22%	6.04%
	Rate Year 3 Calculation				
28	Weight	51.71%	0.29%	48.00%	100.00%
29	Cost Rate	3.42%	0.90%	8.80%	
30	Percent	1.77%	0.00%	4.22%	6.00%

Notes:
1) Pre-Levelization Delivery Rate Increase without EE = Appendix A, Page 1, Line 6, Cols. A - C
2) Pre-Levelization Delivery Revenues Before Increase without EE = Appendix B, Schedule B, line 9 less:
  a) Rate year levelized rate increase amount;
  b) Prior year EE amount from Appendix B, Schedule C line 77 divided by retention factor of 0.98343

NYSEG Gas
Rate Change Shaping Worksheet - without Energy Efficiency
($000)

		A	B	C	D
		Rate Year 1 TME 4/30/21	Rate Year 2 TME 4/30/22	Rate Year 3 TME 4/30/23	Total
	Pre-Shaping Information				
1	Delivery Rate Increase without EE [1]	$ (10,161)	$ 12,376	$ 13,121	
2	Delivery Revenues Before Increase without EE [2]	205,359	196,330	208,998	
3	Pre-Shaping Rate Increase % without EE	(4.9%)	6.3%	6.3%	
	Rate Change Shaping Calculation				
4	Delivery Rate Increase - Total	$ (10,161)	$ 12,376	$ 13,121	
5	Period Shaping Deferral	10,161	(10,800)	(9,783)	
6	Delivery Rate Increase - Post Shaping	$ -	$ 1,576	$ 3,338	
7	Delivery Revenues Before Increase without EE	205,359	196,330	208,998	
8	Post-Shaping Rate Increase % - Delivery without EE	0.0%	0.8%	1.6%	
	Carrying Costs Calculation				
9	Starting Shaping Deferral	-	(10,390)	(10,201)	
10	Shaping Deferral	(10,161)	639	10,422	
11	Accrued Carrying Costs	(229)	(450)	(221)	
12	Ending Shaping Deferral	(10,390)	(10,201)	0	
13	Average Shaping Deferral	(5,081)	(10,071)	(4,990)	
14	x 1 - Effective Tax Rate	73.9%	73.9%	73.9%	
15	Post-Tax Shaping Deferral	(3,753)	(7,439)	(3,686)	
16	Post-Tax WACC	6.10%	6.04%	6.00%	
17	Accrued Carrying Costs	(229)	(450)	(221)	$ (900)
	Verification				
18	Pre-Shaping Cumulative Delivery Rate Increase	$ (30,483)	$ 24,752	$ 13,121	$ 7,390
19	Post-Shaping Cumulative Delivery Rate Increase	-	3,152	3,338	6,491
20	Less: Carrying Costs (from line 17)				(900)
21	Total - Cross Check				$ 7,390
	Post-Tax WACC	LTD	Customer Dep	Equity	Total
	Rate Year 1 Calculation				
22	Weight	51.61%	0.39%	48.00%	100.00%
23	Cost Rate	3.63%	0.90%	8.80%	
24	Percent	1.88%	0.00%	4.22%	6.10%
	Rate Year 2 Calculation				
25	Weight	51.67%	0.33%	48.00%	100.00%
26	Cost Rate	3.52%	0.90%	8.80%	
27	Percent	1.82%	0.00%	4.22%	6.04%
	Rate Year 3 Calculation				
28	Weight	51.71%	0.29%	48.00%	100.00%
29	Cost Rate	3.42%	0.90%	8.80%	
30	Percent	1.77%	0.00%	4.22%	6.00%

Notes:
1) Pre-Shaping Delivery Rate Increase without EE = Appendix A, Page 1, Line 7, Cols. A - C
2) Pre-Shaping Delivery Revenues Before Increase without EE = Appendix C, Schedule B, line 9 less:
   a) Rate year levelized rate increase amount;
   b) Prior year EE amount from Appendix C, Schedule C line 70 divided by retention factor of 0.98012

RG&E Electric
Rate Change Levelization Worksheet - without Energy Efficiency
($000)

		A	B	C	D
		Rate Year 1 TME 4/30/21	Rate Year 2 TME 4/30/22	Rate Year 3 TME 4/30/23	Total
	Pre-Levelization Information				
1	Delivery Rate Increase without EE [1]	$ (7,882)	$ 48,017	$ 32,455	
2	Delivery Revenues Before Increase without EE [2]	446,030	437,685	484,624	
3	Pre-Levelization Rate Increase % without EE	(1.8%)	11.0%	6.7%	
	Rate Change Levelization Calculation				
4	Delivery Rate Increase - Total	$ (7,882)	$ 48,017	$ 32,455	
5	Period Levelization Deferral	18,582	(25,095)	(7,071)	
6	Delivery Rate Increase - Post Levelization	$ 10,700	$ 22,922	$ 25,385	
7	Delivery Revenues Before Increase without EE	446,030	437,685	484,624	
8	Post-Levelization Rate Increase % - Delivery without EE	2.4%	5.2%	5.2%	
	Carrying Costs Calculation				
9	Starting Levelization Deferral	-	(19,036)	(13,278)	
10	Levelization Deferral	(18,582)	6,513	13,584	
11	Accrued Carrying Costs	(454)	(755)	(305)	
12	Ending Levelization Deferral	(19,036)	(13,278)	0	
13	Average Levelization Deferral	(9,291)	(15,779)	(6,486)	
14	x 1 - Effective Tax Rate	73.9%	73.9%	73.9%	
15	Post-Tax Levelization Deferral	(6,863)	(11,655)	(4,791)	
16	Post-Tax WACC	6.62%	6.48%	6.37%	
17	Accrued Carrying Costs	(454)	(755)	(305)	$ (1,515)
	Verification				
18	Pre-Levelization Cumulative Delivery Rate Increase	$ (23,645)	$ 96,034	$ 32,455	$ 104,844
19	Post-Levelization Cumulative Delivery Rate Increase	32,100	45,844	25,385	$ 103,329
20	Less: Carrying Costs (from line 17)				(1,515)
21	Total - Cross Check				$ 104,844

	Post-Tax WACC	LTD	Customer Dep	Equity	Total
	Rate Year 1 Calculation				
22	Weight	51.79%	0.21%	48.00%	100.00%
23	Cost Rate	4.62%	0.90%	8.80%	
24	Percent	2.39%	0.00%	4.22%	6.62%
	Rate Year 2 Calculation				
25	Weight	51.82%	0.18%	48.00%	100.00%
26	Cost Rate	4.35%	0.90%	8.80%	
27	Percent	2.26%	0.00%	4.22%	6.48%
	Rate Year 3 Calculation				
28	Weight	51.84%	0.16%	48.00%	100.00%
29	Cost Rate	4.14%	0.90%	8.80%	
30	Percent	2.15%	0.00%	4.22%	6.37%

Notes:
1) Pre-Levelization Delivery Rate Increase without EE = Appendix A, Page 1, Line 8, Cols. A - C
2) Pre-Levelization Delivery Revenues Before Increase without EE = Appendix D, Schedule B, line 10 less:
a) Rate year levelized rate increase amount;
b) Prior year EE amount from Appendix D, Schedule C line 77 divided by retention factor of 0.97841

RG&E Gas
Rate Change Shaping Worksheet - without Energy Efficiency
($000)

		A	B	C	D
		Rate Year 1 TME 4/30/21	Rate Year 2 TME 4/30/22	Rate Year 3 TME 4/30/23	Total
	Pre-Shaping Information				
1	Delivery Rate Increase without EE [1]	$ (9,816)	$ 9,582	$ 13,642	
2	Delivery Revenues Before Increase without EE [2]	178,886	170,230	180,253	
3	Pre-Shaping Rate Increase % without EE	(5.5%)	5.6%	7.6%	
	Rate Change Shaping Calculation				
4	Delivery Rate Increase - Total	$ (9,816)	$ 9,582	$ 13,642	
5	Period Shaping Deferral	9,816	(9,582)	(11,259)	
6	Delivery Rate Increase - Post Shaping	$ -	$ -	$ 2,383	
7	Delivery Revenues Before Increase without EE	178,886	170,230	180,253	
8	Post-Shaping Rate Increase % - Delivery without EE	0.0%	0.0%	1.3%	
	Carrying Costs Calculation				
9	Starting Shaping Deferral	-	(10,056)	(10,777)	
10	Shaping Deferral	(9,816)	(234)	11,025	
11	Accrued Carrying Costs	(240)	(487)	(248)	
12	Ending Shaping Deferral	(10,056)	(10,777)	0	
13	Average Shaping Deferral	(4,908)	(10,173)	(5,265)	
14	x 1 - Effective Tax Rate	73.9%	73.9%	73.9%	
15	Post-Tax Shaping Deferral	(3,625)	(7,514)	(3,889)	
16	Post-Tax WACC	6.62%	6.48%	6.37%	
17	Accrued Carrying Costs	(240)	(487)	(248)	$ (975)
	Verification				
18	Pre-Shaping Cumulative Delivery Rate Increase	$ (29,448)	$ 19,164	$ 13,642	$ 3,358
19	Post-Shaping Cumulative Delivery Rate Increase	-	-	2,383	2,383
20	Less: Carrying Costs (from line 17)				(975)
21	Total - Cross Check				$ 3,358

	Post-Tax WACC	LTD	Customer Dep	Equity	Total
	Rate Year 1 Calculation				
22	Weight	51.79%	0.21%	48.00%	100.00%
23	Cost Rate	4.62%	0.90%	8.80%	
24	Percent	2.39%	0.00%	4.22%	6.62%
	Rate Year 2 Calculation				
25	Weight	51.82%	0.18%	48.00%	100.00%
26	Cost Rate	4.35%	0.90%	8.80%	
27	Percent	2.26%	0.00%	4.22%	6.48%
	Rate Year 3 Calculation				
28	Weight	51.84%	0.16%	48.00%	100.00%
29	Cost Rate	4.14%	0.90%	8.80%	
30	Percent	2.15%	0.00%	4.22%	6.37%

Notes:
1) Pre-Shaping Delivery Rate Increase without EE = Appendix A, Page 1, Line 9, Cols. A - C
2) Pre-Shaping Delivery Revenues Before Increase without EE = Appendix E, Schedule B, line 9 less:
a) Rate year levelized rate increase amount;
b) Prior year EE amount from Appendix E, Schedule C line 67 divided by retention factor of 0.9695

New York State Electric & Gas Corporation

Electric Department

Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023

New York State Electric & Gas Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Rate of Return Statement
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
	Operating Revenues			
1	Sales Revenue	$ 752,198	$ 796,698	$ 894,201
2	Impact of Rate Increase	45,684	84,770	88,565
3	Late Payments	4,727	5,377	5,747
4	Total Retail Revenue	802,609	886,845	988,512
5	Other Revenue	167,395	149,718	110,159
6	**Total Revenue**	970,004	1,036,563	1,098,672
7	Gross Revenue Taxes	11,344	12,896	13,803
8	Net Revenue	958,660	1,023,667	1,084,869
9	O&M Expenses	527,321	563,432	582,361
10	Depreciation & Amortizations	132,620	141,719	157,695
11	Taxes Other Than Income Taxes	113,053	114,762	116,831
12	**Total Operating Expenses**	772,993	819,914	856,887
13	**Operating Income Before Income Taxes**	185,667	203,754	227,981
14	Income Taxes	36,902	40,776	45,868
15	**Operating Income Available for Return**	$ 148,765	$ 162,977	$ 182,114
16	**Rate Base**	$ 2,437,398	$ 2,696,647	$ 3,037,309
17	**Rate of Return**	6.10%	6.04%	6.00%
18	**Return on Equity**	8.80%	8.80%	8.80%
	Calculation of Return on Equity			
19	Operating Income Available for Return	$ 148,765	$ 162,977	$ 182,114
20	Less: Interest Expense	(45,809)	(49,071)	(53,818)
21	**Balance for Common**	102,956	113,906	128,296
22	Rate Base	2,437,398	2,696,647	3,037,309
23	Common Equity Percentage	48%	48%	48%
24	**Equity Component of Rate Base**	1,169,951	1,294,391	1,457,908
25	Balance for Common	102,956	113,906	128,296
26	Equity Component of Rate Base	1,169,951	1,294,391	1,457,908
27	**Return on Equity**	8.80%	8.80%	8.80%
	Revenue Requirement Value of 1bp ROE			
28	Net Income Attributable to 1bp of ROE (line 24 x 1bp)	$ 117	$ 129	$ 146
29	/ Retention Factor including FIT/SIT	72.64%	72.64%	72.64%
30	**Revenue Requirement Value of 1bp ROE**	$ 161	$ 178	$ 201

New York State Electric & Gas Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Revenue
($000)

			A	B	C
			Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
		Sales Revenue			
1		Gross Base Delivery	$ 646,045	$ 691,209	$ 788,794
2		Plus: Rate Increase	45,684	84,770	88,565
3		BIPP Charges	8,211	8,229	8,251
4		Net Base Delivery Charges	699,940	784,208	885,610
5	a	Clean Energy Fund	68,091	66,401	64,581
6		Dynamic Load Management Surcharge	4,556	4,791	5,026
7		MFC/POR - Credit/Coll/Call Ctr/Admin	14,600	14,600	14,600
8		Gross Revenue Tax	10,694	11,468	12,948
9		**Total Sales Revenue**	$ 797,882	$ 881,469	$ 982,766
10		Late Payments	4,727	5,377	5,747
		Other Revenue			
11		Other Sales Income	1,068	1,068	1,068
12		Company Use Delivery	1,420	1,450	1,480
13		Damage and Third Party Payments	7,385	7,540	7,698
14		Rent Revenue	5,778	5,899	6,023
15		Wholesale Transmission Revenue	49,165	49,165	49,165
16		SIR Adjustment	4,816	4,816	4,816
17		Connect / Disconnect & Other	157	157	157
18		COVID-19 - General Inflation Adjustment (lines 12-14)	(192)	(246)	(281)
19		**Total**	$ 69,597	$ 69,849	$ 70,127
		Deferrals & Amortizations			
20		Excess Depreciation Reserve Amortization	30,850	34,950	39,100
21		Excess DIT - TCJA - Protected Amortization	7,728	7,380	7,325
22		Excess DIT - TCJA - Protected Pre-RY1 Liability	16,678	-	-
23		Excess DIT - TCJA - Unprotected Amortization	21,803	21,803	21,803
24		Federal Tax Reform - Jan-Sep 2018 Savings Amortization	19,433	-	-
25		Rate Increase Levelization Deferral	-	14,430	(29,502)
26		Rate Increase Levelization Amortization	1,305	1,305	1,305
27		**Total**	$ 97,798	$ 79,869	$ 40,032
28		**Total Other Revenues + Deferrals & Amortizations**	$ 167,395	$ 149,718	$ 110,159
29		**Total**	**$ 970,004**	**$ 1,036,563**	**$ 1,098,672**

New York State Electric & Gas Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Operation & Maintenance Expense
($000)

			A	B	C
			Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
		O&M Expenses			
1	b	Labor / Payroll	$ 113,630	$ 121,821	$ 128,702
2		Variable Compensation	1,516	1,626	1,717
3		401K	4,057	4,377	4,692
4		Productivity	(2,422)	(3,086)	(3,229)
5		Medical Benefits	11,550	12,468	13,022
6		Other Employee Benefits	2,156	2,201	2,247
7		Electric Reliability Organization - NERC	391	413	436
8	c	Uncollectibles	6,926	7,623	8,113
9		Insurance	2,148	2,193	2,239
10		Workers Comp	2,306	2,354	2,404
11		Injury / Damages	1,955	1,996	2,038
12		ASC Costs	55,319	56,481	57,667
13		Outside Services	46,833	46,029	41,974
14		Legal / Regulatory Expense	2,265	2,296	2,327
15		Vehicle Depreciation	5,667	6,421	7,025
16		Security	676	690	705
17	d	Storm - Major	25,582	25,582	25,582
18		Storm - Minor	3,800	3,800	3,800
19	e	Low Income Program	14,408	14,408	14,408
20	f	Credit & Debit Card Fees	2,040	2,773	3,251
21		CS Enhancements	550	513	527
22		Stray Voltage	1,785	1,823	1,861
23	g	Vegetation Management - Distribution	47,203	47,203	47,203
24		Vegetation Management - Transmission	6,395	6,529	6,666
25		AMI - Incremental O&M	-	1,506	4,019
26		AMI - Incremental O&M Savings	-	-	(428)
27		Occupancy/Overhead costs	7,801	7,965	8,133
28	h	EE Tracker	12,578	22,017	28,458
29	h	EE Heat Pumps	6,137	9,742	12,292
30		NWA General Costs	170	170	170
31		New Studies	192	-	-
32		All Other O&M General Inflator Items	29,574	31,362	32,021
33	i	Pension	17,854	17,854	17,854
34	j	OPEBs	(1,646)	(223)	20
35	k	Economic Development	5,052	5,052	5,052
36	l	Environmental Remediation	15,000	15,000	15,000
37	m	Incremental Maintenance	616	1,460	1,033
38	n	Management / Operations / Staffing Audit	22	22	22
39	o	NEIL Credits	(352)	(352)	(352)
40	p	REV Incremental Costs	9,330	9,575	10,086
41	q	COVID-19 Pandemic Adjustment	(5,700)	-	-
42		COVID-19 - General Inflation Adj. (lines 6, 9-13, 16, 22, 24, 27, & 32)	(1,818)	(2,334)	(2,660)
43		**Total Delivery O&M Expense**	$ 451,548	$ 487,349	$ 506,098
		Surcharge Expenses			
44	a	Clean Energy Fund (CEF)	$ 68,091	$ 66,401	$ 64,581
45		**Total Surcharges**	$ 68,091	$ 66,401	$ 64,581
46		**Amortizations - Refer to Schedule H for Detailed Information**	$ 7,682	$ 9,682	$ 11,682
47		**Total O&M Plus Surcharges & Amortizations**	**$ 527,321**	**$ 563,432**	**$ 582,361**

New York State Electric & Gas Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Operation & Maintenance Expense
($000)

			A	B	C
			Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
		Amount in Rates			
48	b	Labor	$ 113,630	$ 121,821	$ 128,702
49	c	Uncollectibles	6,926	7,623	8,113
50	d	Storm - Major	25,582	25,582	25,582
51	e	Low Income Program	14,408	14,408	14,408
52	f	Credit & Debit Card Fees	2,040	2,773	3,251
53	g	Vegetation Management - Distribution	47,203	47,203	47,203
54	i	Pension	17,854	17,854	17,854
55	j	OPEBs	(1,646)	(223)	20
56	k	Economic Development	5,052	5,052	5,052
57	l	Environmental Remediation	15,000	15,000	15,000
58	m	Incremental Maintenance	616	1,460	1,033
59	n	Management / Operations / Staffing Audit	22	22	22
60	o	NEIL Credit	(352)	(352)	(352)
61	p	REV	9,330	9,575	10,086
62	q	COVID-19 Pandemic Adjustment	(5,700)	-	-
63		Total	$ 249,965	$ 267,797	$ 275,974
		Low Income Program Summary			
64		Bill Reduction	$ 13,252	$ 13,252	$ 13,252
65		Arrearage Forgiveness	1,157	1,157	1,157
66	e	Total Low Income Program	$ 14,408	$ 14,408	$ 14,408
		Economic Development Reconciliation			
67	k	Total Economic Development Program	$ 5,052	$ 5,052	$ 5,052
68	k	Rate Discounts	$ -	$ -	$ -
69	k	Economic Development Deferral	-	-	-
		Non-Rate discounts:			
70	k	Economic Development - O&M	5,052	5,052	5,052
71		Total Rate and Non-Rate Discounts	$ 5,052	$ 5,052	$ 5,052
		CEF Reconciliation			
		Revenue			
72	a	Clean Energy Fund	$ 68,091	$ 66,401	$ 64,581
		Expense			
73	a	Clean Energy Fund	$ 68,091	$ 66,401	$ 64,581
		Energy Efficiency - Base Delivery			
		O&M Expense			
74	h	EE Tracker	$ 12,578	$ 22,017	$ 28,458
75	h	EE Heat Pumps	6,137	9,742	12,292
76		EE Regulatory Amorts (refer to Schedule H)	(7,893)	(7,893)	(7,893)
77		Total Energy Efficiency - Base Delivery	$ 10,822	$ 23,866	$ 32,857

New York State Electric & Gas Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Depreciation & Amortizations
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
1	**Depreciation Expense**	**$ 132,620**	**$ 141,719**	**$ 157,695**

New York State Electric & Gas Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Operating Taxes
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
	Gross Revenue Taxes			
1	Total Retail Revenue	$ 797,882	$ 881,469	$ 982,766
2	Average GRT Rate	1.42%	1.46%	1.40%
3	Total Gross Revenue Tax	$ 11,344	$ 12,896	$ 13,803
	Other Operating Taxes			
4	Property Taxes	$ 100,367	$ 101,680	$ 103,010
5	Payroll Taxes	12,685	13,083	13,822
6	Total Other Operating Taxes	$ 113,053	$ 114,762	$ 116,831
7	**Total**	**$ 124,396**	**$ 127,658**	**$ 130,634**

New York State Electric & Gas Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Income Taxes
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
1	Operating Income Before Income Taxes	$ 185,667	$ 203,754	$ 227,981
2	Interest Expense	(45,809)	(49,071)	(53,818)
3	Book Income Before Income Taxes (Adjusted for Tax Items)	139,857	154,683	174,164
4	Federal Income Taxes @ 21.000%	29,370	32,483	36,574
5	State Taxes @ 6.500%	9,091	10,054	11,321
6	Fed Benefit of State Tax Deduction @ 1.365%	(1,909)	(2,111)	(2,377)
7	Total Federal & State @ Statutory Rates	36,552	40,426	45,518
	Permanent Differences			
8	Meals and Entertainment	350	350	350
9	Subtotal: Permanent Differences	350	350	350
10	**Delivery Income Taxes (Lines 7 & 9)**	**$ 36,902**	**$ 40,776**	**$ 45,868**

New York State Electric & Gas Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Capital Structure Summary Schedule
($000)

		A	B	C	D	E
		Weight	**Cost Rate**	**Percent**	**Tax Gross-up**	**Before Tax**
	Rate Year 1					
1	Long Term Debt	51.61%	3.63%	1.88%		1.88%
2	Customer Deposits	0.39%	0.90%	0.00%		0.00%
3	Total Debt	52.00%		1.88%		1.88%
4	Common Equity	48.00%	8.80%	4.22%	1.49%	5.72%
5	Total	100.00%		6.10%		7.60%
	Rate Year 2					
6	Long Term Debt	51.67%	3.52%	1.82%		1.82%
7	Customer Deposits	0.33%	0.90%	0.00%		0.00%
8	Total Debt	52.00%		1.82%		1.82%
9	Common Equity	48.00%	8.80%	4.22%	1.49%	5.72%
10	Total	100.00%		6.04%		7.54%
	Rate Year 3					
11	Long Term Debt	51.71%	3.42%	1.77%		1.77%
12	Customer Deposits	0.29%	0.90%	0.00%		0.00%
13	Total Debt	52.00%		1.77%		1.77%
14	Common Equity	48.00%	8.80%	4.22%	1.49%	5.72%
15	Total	100.00%		6.00%		7.49%

	Interest Expense	**Rate Year 1**	**Rate Year 2**	**Rate Year 3**
16	Rate Base	$ 2,437,398	$ 2,696,647	$ 3,037,309
17	Weighted Cost of Debt	1.88%	1.82%	1.77%
18	Interest Expense	$ 45,809	$ 49,071	$ 53,818

New York State Electric & Gas Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Regulatory Amortizations
($000)

		A	B	C	D	E
		Starting Rate Year Asset / (Liab) Balance	Amortization Period (years)	Inc / (Exp) Rate Year 1 Amortization 4/30/2021	Inc / (Exp) Rate Year 2 Amortization 4/30/2022	Inc / (Exp) Rate Year 3 Amortization 4/30/2023
	3-Year Term Amortizations					
1	2018 Windstorm Settlement - Case 19-E-0105	$ (9,000)	3	$ 3,000	$ 3,000	$ 3,000
2	2019 Order - Case 19-E-0302	(2,500)	3	833	833	833
3	NRA - SAIFI	(7,000)	3	2,333	2,333	2,333
4	ACF ASGA - JP Stip 56	(1,300)	3	433	433	433
5	ASGA	2,185	3	(728)	(728)	(728)
6	Bonus Depreciation NCR	(8,485)	3	2,828	2,828	2,828
7	CAIDI/SAIFI Study	19	3	(6)	(6)	(6)
8	CapEx Customer Credit 07-M-0906 Merger Order	(1,473)	3	491	491	491
9	CapEx Shareholder Deferral	2,272	3	(757)	(757)	(757)
10	Cost to Achieve Efficiency Initiatives	139	3	(46)	(46)	(46)
11	Def Inc Tax Deferral - Book Depr Rate Change	(1,067)	3	356	356	356
12	Economic Development - Remaining Amort (15-E-0283 Appx. V)	1,612	3	(537)	(537)	(537)
13	Economic Development - New Amortization	(4,766)	3	1,589	1,589	1,589
14	EEPS	(108)	3	36	36	36
15	EE Tracker	(23,571)	3	7,857	7,857	7,857
16	ESM	(2,622)	3	874	874	874
17	Excess DIT - New York State Tax Rate change	73	3	(24)	(24)	(24)
18	Medicare Subsidy NCR	(1,802)	3	601	601	601
19	MHP Meter Costs	2	3	(1)	(1)	(1)
20	Mixed Use 263(a) NCR	(6,187)	3	2,062	2,062	2,062
21	NYPA Ancillaries	6	3	(2)	(2)	(2)
22	PBA Utilization	(2,958)	3	986	986	986
23	Stray Voltage	(4,967)	3	1,656	1,656	1,656
24	Theoretical Reserve Inc Tax Flow Through	(6,291)	3	2,097	2,097	2,097
25	Unit of Property CTA	21	3	(7)	(7)	(7)
26	Post Term Amortization Deferral - 2010 Joint Proposal	3,915	3	(1,305)	(1,305)	(1,305)
27	**Subtotal**	**$ (73,853)**		**$ 24,618**	**$ 24,618**	**$ 24,618**
	Other Than 3-Year Amortizations					
28	Credit & Debit Card Fees	$ 4,257	5	$ (851)	$ (851)	$ (851)
29	Environmental - Remaining Amort (15-E-0283 Appx. V)	(11,112)	7	1,587	1,587	1,587
30	Environmental - New Amortization	5,519	7	(788)	(788)	(788)
31	Fixed Rate Debt	(27,510)	5	5,502	5,502	5,502
32	Incremental Maintenance	(2,560)	5	512	512	512
33	Low Income Program - Remaining Amort (15-E-0283 Appx. V)	(1,221)	5	244	244	244
34	Low Income Program - New Amortization	1,547	5	(309)	(309)	(309)
35	Management Audit - Remaining Amort (15-E-0283 Appx. V)	(25)	5	5	5	5
36	Management Audit - New Amortization	835	5	(167)	(167)	(167)
37	NEIL Credit	(600)	5	120	120	120
38	NRA - CAIDI	(3,722)	5	744	744	744
39	NY Transco	(2,745)	5	549	549	549
40	OPEB Deferral - Remaining Amort (15-E-0283 Appx. V)	(12,170)	5	2,434	2,434	2,434
41	OPEB Deferral - New Amortization	(7,597)	5	1,519	1,519	1,519
42	Pension Deferral - Remaining Amort (15-E-0283 Appx. V)	19,262	5	(3,852)	(3,852)	(3,852)
43	Pension Deferral - New Amortization	40,153	5	(8,031)	(8,031)	(8,031)
44	Pole Attachment Revenue Requirement	4,374	5	(875)	(875)	(875)
45	PRA - Terminations & Uncollectibles	778	5	(156)	(156)	(156)
46	Property Tax Deferral - Remaining Amort (15-E-0283 Appx. V)	8,469	5	(1,694)	(1,694)	(1,694)
47	Property Tax Deferral - New Amortization	(15,024)	5	3,005	3,005	3,005
48	PSC Assessment	(263)	5	53	53	53
49	Rate Increase Levelization (reflected in Revenue)	(6,526)	5	1,305	1,305	1,305
50	REV Incremental Costs	10,490	5	(2,098)	(2,098)	(2,098)
51	Reliability Support Services	(13)	5	3	3	3
52	Storm - Non-Superstorm - Remaining Amort (15-E-0283 Appx. V)	32,986	5	(6,597)	(6,597)	(6,597)
53	Storm - Non-Superstorm - New Amortization	119,194	10	(11,919)	(11,919)	(11,919)
54	Storm - Superstorm	74,754	10	(7,475)	(7,475)	(7,475)
55	Variable Rate Debt - Remaining Amort (15-E-0283 Appx. V)	(2,371)	5	474	474	474
56	Variable Rate Debt - New Amortization	(2,950)	5	590	590	590
57	Vegetation Management - Danger Tree Deferral $10M per year beginning in RY1		5	(2,000)	(4,000)	(6,000)
58	**Subtotal**	**$ 226,211**		**$ (28,167)**	**$ (30,167)**	**$ (32,167)**
	Income Tax Related Amortizations					
59	Excess DIT - TCJA - Protected Amortization (reflected in Revenue)	$ (296,621)	ARAM	$ 7,728	$ 7,380	$ 7,325
60	Excess DIT - TCJA - Protected Pre-RY1 Liability (reflected in Revenue)	(16,678)	1	16,678	-	-
61	Excess DIT - TCJA - Unprotected Amortization (reflected in Revenue)	(65,409)	3	21,803	21,803	21,803
62	Federal Tax Reform - Jan-Sep 2018 Savings Amortization (reflected in Revenue)	(19,433)	1	19,433	-	-
63	PowerTax Regulatory Asset	82,038	23	(3,567)	(3,567)	(3,567)
64	Unfunded Future Income Taxes	(36,274)	46	789	789	789
65	Unfunded Future Income Taxes - NCR	243	5	(49)	(49)	(49)
66	**Subtotal**	**$ (352,134)**		**$ 62,815**	**$ 26,356**	**$ 26,301**
67	**Total - NYSEG Electric**	**$ (199,776)**		**$ 59,266**	**$ 20,807**	**$ 18,752**

New York State Electric & Gas Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Rate Base
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
	Rate Base			
1	Utility Plant	$ 5,284,213	$ 5,597,667	$ 6,010,163
2	Depreciation Reserve	(2,320,976)	(2,389,571)	(2,471,373)
3	Materials & Supplies	13,142	13,418	13,699
4	Prepayments	40,397	41,245	42,111
5	O&M Working Capital per the FERC Formula	64,089	68,266	70,321
6	Non-Int Bearing Cust Advances	(28,133)	(28,133)	(28,133)
7	Deferred Debits & Credits	(143,453)	(118,027)	(86,459)
8	Deferred Income Taxes	(448,524)	(465,266)	(490,472)
9	Deferred Investment Tax Credit	(12,129)	(11,725)	(11,321)
10	Total Before Earnings Base-Capitalization Adjustment	$ 2,448,625	$ 2,707,874	$ 3,048,536
11	Earnings Base-Capitalization Adjustment	(11,227)	(11,227)	(11,227)
12	**Total**	**$ 2,437,398**	**$ 2,696,647**	**$ 3,037,309**

New York State Electric & Gas Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Deferred Debits and Credits -Average Balances
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
	Regulatory Assets & Liabilities:			
1	2019 Order - Case 19-E-0302	$ (2,083)	$ (1,250)	$ (417)
2	NRA - SAIFI	(5,833)	(3,500)	(1,167)
3	2018 Windstorm Settlement - Case 19-E-0105	(7,500)	(4,500)	(1,500)
4	Credit & Debit Card Fees	3,831	2,980	2,128
5	Economic Development - Remaining Amort (15-E-0283 Appx. V)	1,343	806	269
6	Economic Development - New Amortization	(3,972)	(2,383)	(794)
7	EEPS	(90)	(54)	(18)
8	EE Tracker	(19,642)	(11,785)	(3,928)
9	Environmental - Remaining Amort (15-E-0283 Appx. V)	(10,318)	(8,731)	(7,143)
10	Environmental - New Amortization	5,125	4,336	3,548
11	Fixed Rate Debt	(24,759)	(19,257)	(13,755)
12	Incremental Maintenance	(2,304)	(1,792)	(1,280)
13	Low Income Program - Remaining Amort (15-E-0283 Appx. V)	(1,099)	(855)	(610)
14	Low Income Program - New Amortization	1,392	1,083	774
15	Management Audit - Remaining Amort (15-E-0283 Appx. V)	(23)	(18)	(13)
16	Management Audit - New Amortization	751	584	417
17	NEIL Credit	(540)	(420)	(300)
18	MTA Surcharge	338	-	-
19	NRA - CAIDI	(3,350)	(2,605)	(1,861)
20	NY Transco	(2,471)	(1,922)	(1,373)
21	OPEB Deferral - Remaining Amort (15-E-0283 Appx. V)	(10,953)	(8,519)	(6,085)
22	OPEB Deferral - New Amortization	(6,837)	(5,318)	(3,799)
23	Pension Deferral - Remaining Amort (15-E-0283 Appx. V)	17,336	13,484	9,631
24	Pension Deferral - New Amortization	36,138	28,107	20,077
25	Pole Attachment Revenue Requirement	3,937	3,062	2,187
26	PRA - Terminations & Uncollectibles	700	545	389
27	Property Tax Deferral - Remaining Amort (15-E-0283 Appx. V)	7,623	5,929	4,235
28	Property Tax Deferral - New Amortization	(13,522)	(10,517)	(7,512)
29	PSC Assessment	(237)	(184)	(132)
30	Rate Increase Levelization	(5,874)	(4,568)	(3,263)
31	REV Incremental Costs	9,441	7,343	5,245
32	Reliability Support Services	(11)	(9)	(6)
33	Storm - Non-Superstorm - Remaining Amort (15-E-0283 Appx. V)	29,688	23,090	16,493
34	Storm - Non-Superstorm - New Amortization	113,234	101,315	89,396
35	Storm - Superstorm	71,017	63,541	56,066
36	Variable Rate Debt - Remaining Amort (15-E-0283 Appx. V)	(2,134)	(1,659)	(1,185)
37	Variable Rate Debt - New Amortization	(2,655)	(2,065)	(1,475)
38	Vegetation Management - Danger Tree Deferral	4,000	11,000	16,000
39	ACF ASGA - JP Stip 56	(1,083)	(650)	(217)
40	ASGA	1,821	1,093	364
41	Bonus Depreciation NCR	(7,071)	(4,242)	(1,414)
42	CAIDI/SAIFI Study	16	10	3
43	CapEx Customer Credit 07-M-0906 Merger Order	(1,228)	(737)	(246)
44	CapEx Shareholder Deferral	1,894	1,136	379
45	Cost to Achieve Efficiency Initiatives	116	69	23
46	Def Inc Tax Deferral - Book Depr Rate Change	(889)	(534)	(178)
47	ESM	(2,185)	(1,311)	(437)
48	Excess DIT - New York State Tax Rate change	61	37	12
49	Medicare Subsidy NCR	(1,501)	(901)	(300)
50	MHP Meter Costs	2	1	0

New York State Electric & Gas Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Deferred Debits and Credits -Average Balances
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
51	Mixed Use 263(a) NCR	(5,156)	(3,093)	(1,031)
52	NYPA Ancillaries	5	3	1
53	PBA Utilization	(2,465)	(1,479)	(493)
54	Stray Voltage	(4,139)	(2,483)	(828)
55	Theoretical Reserve Inc Tax Flow Through	(5,242)	(3,145)	(1,048)
56	Unit of Property CTA	17	10	3
57	Post Term Amortization Deferral - 2010 Joint Proposal	3,262	1,957	652
58	Excess DIT - TCJA - Protected Amortization	(292,757)	(285,203)	(277,850)
59	Excess DIT - TCJA - Protected Pre-RY1 Liability	(8,339)	-	-
60	Excess DIT - TCJA - Unprotected Amortization	(54,507)	(32,704)	(10,901)
61	Federal Tax Reform - Jan-Sep 2018 Savings Amortization	(9,717)	-	-
62	PowerTax Regulatory Asset	80,255	76,688	73,121
63	Unfunded Future Income Taxes	(35,880)	(35,091)	(34,302)
64	Unfunded Future Income Taxes - NCR	219	170	122
65	Subtotal	$ (164,804)	$ (115,106)	$ (85,327)
	Other Deferred Assets & Liabilities:			
66	Accrued Pension	$ 87,938	$ 59,007	$ 56,889
67	Accident & Sickness Reserve	-	-	-
68	Commodity Hedge Margin	-	-	-
69	Gain / Loss on Reacquired Debt	12,661	12,661	12,661
70	Injuries & Damages Reserve	(9,406)	(9,406)	(9,406)
71	Marcy South	-	-	-
72	NBWC True-up	-	-	-
73	OPEB Reserve	(72,024)	(67,365)	(63,459)
74	Preliminary Engineering	6,155	6,155	6,155
75	PSC Assessment	(252)	(252)	(252)
76	Purchase of Receivables	107	107	107
77	RDM	-	-	-
78	SFAS-112	(3,833)	(3,833)	(3,833)
79	Workman's Comp Reserve	-	-	-
80	All Other	6	6	6
81	Subtotal	$ 21,351	$ (2,920)	$ (1,132)
82	**Grand Total**	**$ (143,453)**	**$ (118,027)**	**$ (86,459)**

New York State Electric & Gas Corporation
Gas Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023

New York State Electric & Gas Corporation
Gas Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Rate of Return Statement
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
	Operating Revenues			
1	Sales Revenue	$ 205,359	$ 195,760	$ 210,208
2	Impact of Rate Increase	(514)	3,350	5,269
3	Late Payments	1,317	1,429	1,532
4	Total Retail Revenue	206,162	200,540	217,009
5	Other Revenue	541	20,416	18,385
6	**Total Revenue**	206,703	220,956	235,394
7	Gross Revenue Taxes	3,193	3,474	3,733
8	Net Revenue	203,510	217,482	231,661
9	O&M Expenses	91,654	98,216	102,727
10	Depreciation & Amortizations	37,718	40,338	44,696
11	Taxes Other Than Income Taxes	23,763	24,116	24,479
12	**Total Operating Expenses**	153,135	162,670	171,902
13	**Operating Income Before Income Taxes**	50,375	54,812	59,759
14	Income Taxes	9,963	10,921	11,978
15	**Operating Income Available for Return**	$ 40,412	$ 43,891	$ 47,781
16	**Rate Base**	$ 662,114	$ 726,225	$ 796,905
17	**Rate of Return**	6.10%	6.04%	6.00%
18	**Return on Equity**	8.80%	8.80%	8.80%
	Calculation of Return on Equity			
19	Operating Income Available for Return	$ 40,412	$ 43,891	$ 47,781
20	Less: Interest Expense	(12,444)	(13,215)	(14,120)
21	**Balance for Common**	27,968	30,676	33,661
22	Rate Base	662,114	726,225	796,905
23	Common Equity Percentage	48%	48%	48%
24	**Equity Component of Rate Base**	317,815	348,588	382,514
25	Balance for Common	27,968	30,676	33,661
26	Equity Component of Rate Base	317,815	348,588	382,514
27	**Return on Equity**	8.80%	8.80%	8.80%
	Revenue Requirement Value of 1bp ROE			
28	Net Income Attributable to 1bp of ROE (line 24 x 1bp)	$ 32	$ 35	$ 38
29	/ Retention Factor including FIT/SIT	72.40%	72.40%	72.40%
30	**Revenue Requirement Value of 1bp ROE**	$ 44	$ 48	$ 53

New York State Electric & Gas Corporation
Gas Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Revenue
($000)

			A	B	C
			Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
		Sales Revenue			
1		Gross Base Delivery	$ 196,105	$ 186,706	$ 200,902
2		Plus: Rate Increase	(514)	3,350	5,269
3		BIPP Charges	1,783	1,790	1,797
4		Net Base Delivery Charges	197,374	191,846	207,967
5		R&D Surcharge	650	650	650
6		MFC/POR - Credit/Coll/Call Ctr/Admin	3,376	3,376	3,376
7	a	NYSERDA EE Surcharge	77	0	0
8		Gross Revenue Tax	3,368	3,240	3,484
9		**Total Sales Revenue**	$ 204,845	$ 199,111	$ 215,477
10		Late Payments	1,317	1,429	1,532
		Other Revenue			
11		Rent Revenue	143	143	143
12		Damage and Third Party Payments	461	471	481
13		Other Sales Income	54	54	54
14		Company Use Delivery	342	350	357
15		SIR Adjustment	1,184	1,184	1,184
16		Connect / Disconnect & Other	25	25	25
17		COVID-19 - General Inflation Adjustment (lines 12 & 14)	(11)	(14)	(15)
18		**Total**	$ 2,199	$ 2,213	$ 2,229
		Deferrals & Amortizations			
19		Excess DIT - TCJA - Protected Amortization	1,869	1,785	1,772
20		Excess DIT - TCJA - Protected Pre-RY1 Liability	1,345	1,345	1,345
21		Excess DIT - TCJA - Unprotected Amortization	1,846	1,846	1,846
22		Federal Tax Reform - Jan-Sep 2018 Savings Amortization	2,032	1,016	-
23		Rate Increase Shaping Deferral	(10,161)	10,800	9,783
24		Rate Increase Levelization Amortization	1,411	1,411	1,411
25		**Total**	$ (1,658)	$ 18,203	$ 16,157
26		**Total Other Revenues + Deferrals & Amortizations**	$ 541	$ 20,416	$ 18,385
27		**Total**	**$ 206,703**	**$ 220,956**	**$ 235,394**

New York State Electric & Gas Corporation
Gas Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Operation & Maintenance Expense
($000)

			A	B	C
			Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
		O&M Expenses			
1	b	Labor / Payroll	$ 31,991	$ 33,315	$ 34,202
2		Variable Compensation	408	425	436
3		401k	1,135	1,173	1,224
4		Productivity	(669)	(834)	(855)
5		Medical Benefits	3,235	3,313	3,369
6		Other Employee Benefits	506	517	528
7	c	Uncollectibles	2,040	2,187	2,346
8		Insurance	524	535	546
9		Workers Comp	562	574	586
10		Injury / Damages	1,288	1,315	1,343
11		ASC Costs	13,057	13,331	13,611
12		Outside Services	5,838	5,804	5,938
13		Legal / Regulatory Expense	608	617	626
14		Vehicle Depreciation	856	1,042	1,190
15		Security	165	168	172
16	d	Low Income Program	6,298	6,298	6,298
17	e	Credit & Debit Card Fees	609	828	971
18		CS Enhancements	164	153	157
19		Communications - Reporting Gas Odors	650	639	652
20		Gas Utilization	333	333	333
21		AMI - Incremental O&M	-	469	904
22		AMI - Incremental O&M Savings	-	-	(75)
23		Occupancy/Overhead costs	2,375	2,425	2,476
24	a	EE Tracker	966	2,858	4,751
25		NPA General Costs	170	170	170
26		New Studies	47	-	-
27		All Other O&M General Inflator Items	6,375	6,914	7,059
28	f	Pension	5,474	5,474	5,474
29	g	OPEBs	(486)	(61)	12
30	h	Economic Development	200	200	200
31	i	Environmental Remediation	4,300	4,300	4,300
32	j	Incremental Maintenance	2,800	4,048	4,133
33	k	Integrity of Gas Pipeline	1,434	1,434	1,434
34	l	Management / Operations / Staffing Audit	75	75	75
35	m	Research & Development	1,703	1,715	1,728
36	n	Vegetation Management	600	613	625
37		COVID-19 - General Inflation Adjustment (lines 6, 8-12, 15, 23, 27, & 36)	(345)	(443)	(505)
38		**Total Delivery O&M Expense**	$ 95,286	$ 101,924	$ 106,435
		Surcharge Expenses			
39	a	NYSERDA EE Surcharge	77	0	0
40		**Total Surcharges**	**$ 77**	**$ 0**	**$ 0**
41		**Amortizations - Refer to Schedule H for Detailed Information**	$ (3,708)	$ (3,708)	$ (3,708)
42		**Total O&M Plus Surcharges & Amortizations**	**$ 91,654**	**$ 98,216**	**$ 102,727**

New York State Electric & Gas Corporation
Gas Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Operation & Maintenance Expense
($000)

			A	B	C
			Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
		Amount in Rates			
43	b	Labor / Payroll	$ 31,991	$ 33,315	$ 34,202
44	c	Uncollectibles	2,040	2,187	2,346
45	d	Low Income Program	6,298	6,298	6,298
46	e	Credit & Debit Card Fees	609	828	971
47	f	Pension	5,474	5,474	5,474
48	g	OPEBs	(486)	(61)	12
49	h	Economic Development	200	200	200
50	i	Environmental Remediation	4,300	4,300	4,300
51	j	Incremental Maintenance	2,800	4,048	4,133
52	k	Integrity of Gas Pipeline	1,434	1,434	1,434
53	l	Management / Operations / Staffing Audit	75	75	75
54	m	Research & Development	1,703	1,715	1,728
55	n	Gas Distribution Vegetation Management	600	613	625
56		Total	$ 57,038	$ 60,426	$ 61,798
		Low Income Program Summary			
57		Bill Reduction	$ 5,954	$ 5,954	$ 5,954
58		Arrearage Forgiveness	344	344	344
59		Low Income Match Program	-	-	-
60	d	Total Low Income Program	$ 6,298	$ 6,298	$ 6,298
		Economic Development Reconciliation			
61	h	Total Economic Development Program	$ 200	$ 200	$ 200
62	h	Rate Discounts	-	-	-
63	h	Economic Development Deferral	-	-	-
		Non-Rate discounts:			
64	h	Economic Development - O&M	$ 200	$ 200	$ 200
65		Total Rate and Non-Rate Discounts	$ 200	$ 200	$ 200
		Energy Efficiency - Base Delivery			
		Revenue			
66	a	Energy Efficiency - Base Delivery	$ 77	$ 0	$ 0
67			$ 77	$ 0	$ 0
		O&M Expense			
68	a	EE Tracker & NYSERDA EE	$ 1,043	$ 2,858	$ 4,751
69		EE Regulatory Amorts (refer to Schedule H)	(1,624)	(1,624)	(1,624)
70			$ (581)	$ 1,235	$ 3,127

New York State Electric & Gas Corporation
Gas Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Depreciation & Amortizations
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
1	**Depreciation Expense**	**$ 37,718**	**$ 40,338**	**$ 44,696**

New York State Electric & Gas Corporation
Gas Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Operating Taxes
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
	Gross Revenue Taxes			
1	Total Retail Revenue	$ 204,845	$ 199,111	$ 215,477
2	Average GRT Rate	1.56%	1.74%	1.73%
3	Total Gross Revenue Tax	$ 3,193	$ 3,474	$ 3,733
	Other Operating Taxes			
4	Property Taxes	$ 20,337	$ 20,604	$ 20,874
5	Payroll Taxes	3,426	3,512	3,606
6	Total Other Operating Taxes	$ 23,763	$ 24,116	$ 24,479
7	**Total**	**$ 26,956**	**$ 27,590**	**$ 28,213**

New York State Electric & Gas Corporation
Gas Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Income Taxes
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
1	Operating Income Before Income Taxes	$ 50,375	$ 54,812	$ 59,759
2	Interest Expense	(12,444)	(13,215)	(14,120)
3	Book Income Before Income Taxes (Adjusted for Tax Items)	37,931	41,597	45,639
4	Federal Income Taxes @ 21.000%	7,965	8,735	9,584
5	State Taxes @ 6.500%	2,466	2,704	2,967
6	Fed Benefit of State Tax Deduction @ 1.365%	(518)	(568)	(623)
7	Total Federal & State @ Statutory Rates	9,913	10,871	11,928
	Permanent Differences			
8	Meals and Entertainment	50	50	50
9	Subtotal: Permanent Differences	50	50	50
10	**Delivery Income Taxes (Lines 7 & 9)**	**$ 9,963**	**$ 10,921**	**$ 11,978**

New York State Electric & Gas Corporation
Gas Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Capital Structure Summary Schedule
($000)

		A	B	C	D	E
		Weight	**Cost Rate**	**Percent**	**Tax Gross-up**	**Before Tax**
	Rate Year 1					
1	Long Term Debt	51.61%	3.63%	1.88%		1.88%
2	Customer Deposits	0.39%	0.90%	0.00%		0.00%
3	Total Debt	52.00%		1.88%		1.88%
4	Common Equity	48.00%	8.80%	4.22%	1.49%	5.72%
5	Total	100.00%		6.10%		7.60%
	Rate Year 2					
6	Long Term Debt	51.67%	3.52%	1.82%		1.82%
7	Customer Deposits	0.33%	0.90%	0.00%		0.00%
8	Total Debt	52.00%		1.82%		1.82%
9	Common Equity	48.00%	8.80%	4.22%	1.49%	5.72%
10	Total	100.00%		6.04%		7.54%
	Rate Year 3					
11	Long Term Debt	51.71%	3.42%	1.77%		1.77%
12	Customer Deposits	0.29%	0.90%	0.00%		0.00%
13	Total Debt	52.00%		1.77%		1.77%
14	Common Equity	48.00%	8.80%	4.22%	1.49%	5.72%
15	Total	100.00%		6.00%		7.49%

	Interest Expense	**Rate Year 1**	**Rate Year 2**	**Rate Year 3**
16	Rate Base	$ 662,114	$ 726,225	$ 796,905
17	Weighted Cost of Debt	1.88%	1.82%	1.77%
18	Interest Expense	$ 12,444	$ 13,215	$ 14,120

New York State Electric & Gas Corporation
Gas Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Regulatory Amortizations
($000)

		A	B	C	D	E
		Starting Rate Year Asset / (Liab) Balance	Amortization Period (years)	Inc / (Exp) Rate Year 1 Amortization 4/30/2021	Inc / (Exp) Rate Year 2 Amortization 4/30/2022	Inc / (Exp) Rate Year 3 Amortization 4/30/2023
	3-Year Term Amortizations					
1	Bonus Depreciation NCR	$ (1,529)	3	$ 510	$ 510	$ 510
2	Cost to Achieve Efficiency Initiatives	(15)	3	5	5	5
3	EEPS	(25)	3	8	8	8
4	EEPS Loss Revenue Gas	4	3	(1)	(1)	(1)
5	EE Tracker	(4,846)	3	1,615	1,615	1,615
6	Excess DIT - New York State Tax Rate change	1,532	3	(511)	(511)	(511)
7	Gains/Losses on Surplus Sales - Gas	(9)	3	3	3	3
8	Gas Phase 2A/B	11	3	(4)	(4)	(4)
9	Gas R&D Tax Credit	(163)	3	54	54	54
10	IRS Audit	11	3	(4)	(4)	(4)
11	Medicare Subsidy NCR	(1,046)	3	349	349	349
12	Mixed Use 263(a) NCR	(1,811)	3	604	604	604
13	Net Plant Reconciliation	(30)	3	10	10	10
14	Outreach & Education	67	3	(22)	(22)	(22)
15	Pension Costs	(1,790)	3	597	597	597
16	PBA Utilization	51	3	(17)	(17)	(17)
17	Sarbanes-Oxley	40	3	(13)	(13)	(13)
18	Seneca Pipeline Integrity Initiative	(47)	3	16	16	16
19	Seneca Storage	(47)	3	16	16	16
20	Seneca Sale - ASGA Amort	(289)	3	96	96	96
21	Seneca Sale - Operational Savings	(133)	3	44	44	44
22	Unit of Property CTA	437	3	(146)	(146)	(146)
23	Post Term Amortization Deferral - 2010 Joint Proposal	(875)	3	292	292	292
24	**Subtotal**	**$ (10,503)**		**$ 3,501**	**$ 3,501**	**$ 3,501**
	Other Than 3-Year Amortizations					
25	Community Development Fund	$ (150)	5	$ 30	$ 30	$ 30
26	Credit & Debit Card Fees	1,266	5	(253)	(253)	(253)
27	Economic Development - Remaining Amort (15-E-0283 Appx. V)	(389)	0	-	-	-
28	Economic Development - New Amortization	(1,676)	0	-	-	-
29	Environmental - Remaining Amort (15-E-0283 Appx. V)	(3,705)	7	529	529	529
30	Environmental - New Amortization	143	7	(20)	(20)	(20)
31	ESM	(2,758)	5	552	552	552
32	Fixed Rate Debt	(9,307)	5	1,861	1,861	1,861
33	Gas R&D Deferral - Remaining Amort (15-E-0283 Appx. V)	(1,045)	5	209	209	209
34	Gas R&D Deferral - New Amortization	(558)	5	112	112	112
35	Incremental Maintenance - Remaining Amort (15-E-0283 Appx. V)	(7)	5	1	1	1
36	Incremental Maintenance - New Amortization	(155)	5	31	31	31
37	Low Income Program - Remaining Amort (15-E-0283 Appx. V)	3,199	5	(640)	(640)	(640)
38	Low Income Program - New Amortization	1,202	5	(240)	(240)	(240)
39	Management Audit - Remaining Amort (15-E-0283 Appx. V)	(96)	5	19	19	19
40	Management Audit - New Amortization	274	5	(55)	(55)	(55)
41	NRA - Gas Safety	-	0	-	-	-
42	OPEB Deferral - Remaining Amort (15-E-0283 Appx. V)	(2,564)	5	513	513	513
43	OPEB Deferral - New Amortization	(776)	5	155	155	155
44	Pension Deferral - Remaining Amort (15-E-0283 Appx. V)	5,843	5	(1,169)	(1,169)	(1,169)
45	Pension Deferral - New Amortization	11,167	5	(2,233)	(2,233)	(2,233)
46	Gas Pipeline Integrity Costs - Remaining Amort (15-E-0283 Appx. V)	(97)	5	19	19	19
47	Gas Pipeline Integrity Costs - New Amortization	(429)	5	86	86	86
48	PRA - Leak Prone Main	716	5	(143)	(143)	(143)
49	PRA - Gas Enhancement Performance Incentive	45	5	(9)	(9)	(9)
50	PRA - Terminations & Uncollectibles	164	5	(33)	(33)	(33)
51	Property Tax Deferral - Remaining Amort (15-E-0283 Appx. V)	2,110	5	(422)	(422)	(422)
52	Property Tax Deferral - New Amortization	(2,560)	5	512	512	512
53	PSC Assessment	(123)	5	25	25	25
54	Rate Increase Levelization Amortization (reflected in Revenue)	(7,055)	5	1,411	1,411	1,411
55	REV Incremental Costs	12	5	(2)	(2)	(2)
56	Variable Rate Debt - Remaining Amort (15-E-0283 Appx. V)	(690)	5	138	138	138
57	Variable Rate Debt - New Amortization	(876)	5	175	175	175
58	Vegetation Management - Remaining Amort (15-E-0283 Appx. V)	(23)	5	5	5	5
59	Vegetation Management - New Amortization	(91)	5	18	18	18
60	**Subtotal**	**$ (8,989)**		**$ 1,181**	**$ 1,181**	**$ 1,181**
	Income Tax Related Amortizations					
61	Excess DIT - TCJA - Protected Amortization (reflected in Revenue)	$ (71,752)	ARAM	$ 1,869	$ 1,785	$ 1,772
62	Excess DIT - TCJA - Protected Pre-RY1 Liability (reflected in Revenue)	(4,035)	3	1,345	1,345	1,345
63	Excess DIT - TCJA - Unprotected Amortization (reflected in Revenue)	(18,458)	10	1,846	1,846	1,846
64	Federal Tax Reform - Jan-Sep 2018 Savings Amortization (reflected in Revenue)	(3,048)	1.5	2,032	1,016	-
65	PowerTax Regulatory Asset	7,720	35	(221)	(221)	(221)
66	Unfunded Future Income Taxes	25,262	46	(549)	(549)	(549)
67	Unfunded Future Income Taxes - NCR	(6,035)	5	1,207	1,207	1,207
68	**Subtotal**	**$ (70,345)**		**$ 7,529**	**$ 6,429**	**$ 5,400**
69	**Total - NYSEG Gas**	**$ (89,838)**		**$ 12,212**	**$ 11,111**	**$ 10,082**

New York State Electric & Gas Corporation
Gas Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Rate Base Summary Schedule
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
	Rate Base			
1	Utility Plant	$ 1,291,886	$ 1,382,989	$ 1,482,803
2	Depreciation Reserve	(474,337)	(503,395)	(538,020)
3	Materials & Supplies	3,865	3,946	4,029
4	Prepayments	8,434	8,611	8,792
5	O&M Working Capital per the FERC Formula	11,665	12,467	13,011
6	Non-Int Bearing Cust Advances	(497)	(497)	(497)
7	Deferred Debits & Credits	(78,878)	(74,495)	(63,362)
8	Deferred Income Taxes	(93,792)	(97,276)	(103,831)
9	Deferred Investment Tax Credit	(617)	(511)	(405)
10	Total Before Earnings Base-Capitalization Adjustment	$ 667,729	$ 731,841	$ 802,521
11	Earnings Base-Capitalization Adjustment	(5,616)	(5,616)	(5,616)
12	**Total**	**$ 662,114**	**$ 726,225**	**$ 796,905**

New York State Electric & Gas Corporation
Gas Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Deferred Debits and Credits
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
	Regulatory Assets & Liabilities:			
1	Community Development Fund	$ (135)	$ (105)	$ (75)
2	Credit & Debit Card Fees	1,139	886	633
3	Economic Development - Remaining Amort (15-E-0283 Appx. V)	(389)	(389)	(389)
4	Economic Development - New Amortization	(1,676)	(1,676)	(1,676)
5	EEPS	(21)	(13)	(4)
6	EE Tracker	(4,038)	(2,423)	(808)
7	Environmental - Remaining Amort (15-E-0283 Appx. V)	(3,441)	(2,911)	(2,382)
8	Environmental - New Amortization	133	112	92
9	ESM	(2,482)	(1,931)	(1,379)
10	Fixed Rate Debt	(8,376)	(6,515)	(4,653)
11	Gas R&D Deferral - Remaining Amort (15-E-0283 Appx. V)	(940)	(731)	(522)
12	Gas R&D Deferral - New Amortization	(502)	(391)	(279)
13	Incremental Maintenance - Remaining Amort (15-E-0283 Appx. V)	(6)	(5)	(4)
14	Incremental Maintenance - New Amortization	(139)	(108)	(77)
15	Low Income Program - Remaining Amort (15-E-0283 Appx. V)	2,879	2,239	1,599
16	Low Income Program - New Amortization	1,082	841	601
17	Management Audit - Remaining Amort (15-E-0283 Appx. V)	(86)	(67)	(48)
18	Management Audit - New Amortization	247	192	137
19	MTA Surcharge	30	30	30
20	NRA - Gas Safety	-	-	-
21	OPEB Deferral - Remaining Amort (15-E-0283 Appx. V)	(2,307)	(1,795)	(1,282)
22	OPEB Deferral - New Amortization	(698)	(543)	(388)
23	Pension Deferral - Remaining Amort (15-E-0283 Appx. V)	5,259	4,090	2,921
24	Pension Deferral - New Amortization	10,050	7,817	5,583
25	Gas Pipeline Integrity Costs - Remaining Amort (15-E-0283 Appx. V)	(87)	(68)	(48)
26	Gas Pipeline Integrity Costs - New Amortization	(386)	(300)	(214)
27	PRA - Leak Prone Main	645	501	358
28	PRA - Gas Enhancement Performance Incentive	41	32	23
29	PRA - Terminations & Uncollectibles	148	115	82
30	Property Tax Deferral - Remaining Amort (15-E-0283 Appx. V)	1,899	1,477	1,055
31	Property Tax Deferral - New Amortization	(2,304)	(1,792)	(1,280)
32	PSC Assessment	(111)	(86)	(62)
33	Rate Increase Levelization Amortization	(6,350)	(4,939)	(3,528)
34	REV Incremental Costs	11	8	6
35	Variable Rate Debt - Remaining Amort (15-E-0283 Appx. V)	(621)	(483)	(345)
36	Variable Rate Debt - New Amortization	(788)	(613)	(438)
37	Vegetation Management - Remaining Amort (15-E-0283 Appx. V)	(20)	(16)	(11)
38	Vegetation Management - New Amortization	(82)	(64)	(46)
39	Bonus Depreciation NCR	(1,274)	(764)	(255)
40	Cost to Achieve Efficiency Initiatives	(13)	(8)	(3)
41	EEPS Loss Revenue Gas	4	2	1
42	Excess DIT - New York State Tax Rate change	1,277	766	255
43	Gains/Losses on Surplus Sales - Gas	(8)	(5)	(2)
44	Gas Phase 2A/B	9	5	2
45	Gas R&D Tax Credit	(136)	(82)	(27)
46	IRS Audit	9	5	2
47	Medicare Subsidy NCR	(872)	(523)	(174)
48	Mixed Use 263(a) NCR	(1,509)	(906)	(302)
49	Net Plant Reconciliation	(25)	(15)	(5)

New York State Electric & Gas Corporation
Gas Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Deferred Debits and Credits
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
50	Outreach & Education	56	34	11
51	Pension Costs	(1,492)	(895)	(298)
52	PBA Utilization	42	25	8
53	Sarbanes-Oxley	33	20	7
54	Seneca Pipeline Integrity Initiative	(39)	(23)	(8)
55	Seneca Storage	(39)	(23)	(8)
56	Seneca Sale - ASGA Amort	(240)	(144)	(48)
57	Seneca Sale - Operational Savings	(111)	(67)	(22)
58	Unit of Property CTA	364	218	73
59	Post Term Amortization Deferral - 2010 Joint Proposal	(729)	(438)	(146)
60	Excess DIT - TCJA - Protected Amortization	(70,818)	(68,990)	(67,212)
61	Excess DIT - TCJA - Protected Pre-RY1 Liability	(3,362)	(2,017)	(672)
62	Excess DIT - TCJA - Unprotected Amortization	(17,535)	(15,689)	(13,843)
63	Federal Tax Reform - Jan-Sep 2018 Savings Amortization	(2,032)	(508)	-
64	PowerTax Regulatory Asset	7,610	7,389	7,168
65	Unfunded Future Income Taxes	24,988	24,439	23,889
66	Unfunded Future Income Taxes - NCR	(5,431)	(4,224)	(3,017)
67	Subtotal	$ (83,702)	$ (72,040)	$ (61,443)
	Other Deferred Assets & Liabilities:			
68	Accrued Pension	$ 26,369	$ 17,694	$ 17,059
69	Gain / Loss on Reacquired Debt	3,739	3,739	3,739
70	Injuries & Damages Reserve	(2,778)	(2,778)	(2,778)
71	OPEB Reserve	(21,597)	(20,200)	(19,029)
72	Preliminary Engineering	112	112	112
73	PSC Assessment	(238)	(238)	(238)
74	Purchase of Receivables	127	127	127
75	SFAS-112	(943)	(943)	(943)
76	Other	32	32	32
77	Subtotal	$ 4,823	$ (2,455)	$ (1,919)
78	**Grand Total**	**$ (78,878)**	**$ (74,495)**	**$ (63,362)**

Rochester Gas and Electric Corporation

Electric Department

Revenue Requirement for Forecast Years Ending April 30, 2021, 2022, 2023

Rochester Gas and Electric Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Rate of Return Statement
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
	Operating Revenues			
1	Sales Revenue	$ 446,030	$ 442,223	$ 494,304
2	Impact of Rate Increase	15,238	28,064	30,721
3	Late Payments	2,191	2,466	2,582
4	Total Retail Revenue	463,458	472,753	527,606
5	Other Revenue	1,814	43,408	23,229
6	**Total Revenue**	465,273	516,161	550,835
7	Gross Revenue Taxes	6,544	7,475	8,100
8	Net Revenue	458,728	508,686	542,735
9	O&M Expenses	170,220	183,586	190,076
10	Depreciation & Amortizations	74,181	82,604	92,053
11	Taxes Other Than Income Taxes	92,399	97,268	102,478
12	**Total Operating Expenses**	336,800	363,458	384,607
13	**Operating Income Before Income Taxes**	121,928	145,228	158,128
14	Income Taxes	22,601	27,349	30,184
15	**Operating Income Available for Return**	$ 99,327	$ 117,879	$ 127,944
16	**Rate Base**	$ 1,500,899	$ 1,818,579	$ 2,008,301
17	**Rate of Return**	6.62%	6.48%	6.37%
18	**Return on Equity**	8.80%	8.80%	8.80%
	Calculation of Return on Equity			
19	Operating Income Available for Return	$ 99,327	$ 117,879	$ 127,944
20	Less: Interest Expense	(35,929)	(41,063)	(43,113)
21	**Balance for Common**	63,398	76,817	84,831
22	Rate Base	1,500,899	1,818,579	2,008,301
23	Common Equity Percentage	48%	48%	48%
24	**Equity Component of Rate Base**	720,431	872,918	963,984
25	Balance for Common	63,398	76,817	84,831
26	Equity Component of Rate Base	720,431	872,918	963,984
27	**Return on Equity**	8.80%	8.80%	8.80%
	Revenue Requirement Value of 1bp ROE			
28	Net income Attributable to 1bp of ROE (line 24 x 1bp)	$ 72	$ 87	$ 96
29	/ Retention Factor including FIT/SIT	72.27%	72.27%	72.27%
30	**Revenue Requirement Value of 1bp ROE**	$ 100	$ 121	$ 133

Rochester Gas and Electric Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Revenue
($000)

			A	B	C
			Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
		Sales Revenue			
1		Gross Base Delivery	$ 391,424	$ 388,374	$ 440,544
2		Plus: Rate Increase	15,238	28,064	30,721
3	a	Less: Economic Development Discounts	(24)	-	-
4		BIPP Charges	2,676	2,682	2,688
5		Net Base Delivery Charges	409,314	419,120	473,952
6	b	Clean Energy Fund	36,980	35,880	34,697
7		Dynamic Load Management Surcharge	2,821	3,055	3,292
8		MFC/POR - Credit/Coll/Call Ctr/Admin	5,559	5,559	5,559
9		Gross Revenue Tax	6,594	6,673	7,525
10		**Total Sales Revenue**	$ 461,267	$ 470,287	$ 525,025
11		Late Payments	2,191	2,466	2,582
		Other Revenue			
12		Property and Pole Rent Revenue	1,490	1,521	1,553
13		Damage and third party payments	1,878	1,917	1,958
14		Other	369	369	369
15		Product and Service Sales	51	51	51
16		Company Use - Delivery	788	805	821
17		Connect/Disconnect Service Income	257	257	257
18		COVID-19 - General Inflation Adjustment (lines 12, 13, & 16)	(55)	(70)	(80)
19		**Total**	$ 4,778	$ 4,850	$ 4,929
		Deferrals & Amortizations			
20		Excess DIT - TCJA - Protected Amortization	3,963	4,119	4,196
21		Excess DIT - TCJA - Protected Pre-RY1 Liability	2,986	2,986	2,986
22		Excess DIT - TCJA - Unprotected Amortization	4,119	4,119	4,119
23		Federal Tax Reform - TCJA Jan-Sep 2018 Savings Amortization	4,622	2,311	-
24		Rate Increase Levelization Deferral	(18,582)	25,095	7,071
25		Rate Increase Shaping Amortization	(73)	(73)	(73)
26		**Total**	$ (2,964)	$ 38,558	$ 18,299
27		**Total Other Revenues + Deferrals & Amortizations**	$ 1,814	$ 43,408	$ 23,229
28		**Total**	**$ 465,273**	**$ 516,161**	**$ 550,835**

Rochester Gas and Electric Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Operation & Maintenance Expense
($000)

			A	B	C
			Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
		O&M Expenses			
1	c	Labor / Payroll	$ 39,404	$ 41,319	$ 42,730
2		Variable Compensation	1,183	1,240	1,282
3		401K	1,802	2,003	2,194
4		Productivity	(884)	(1,101)	(1,130)
5		Medical Benefits	3,428	3,548	3,649
6		Other Employee Benefits	658	672	686
7	r	Uncollectibles	5,442	5,971	6,414
8		Insurance	975	995	1,016
9		Workers Comp	1,264	1,291	1,318
10		Injury / Damages	406	414	423
11		ASC Costs	23,190	23,677	24,174
12		Outside Services	18,762	18,800	18,476
13		Legal / Regulatory Expense	1,634	1,657	1,680
14		Vehicle Depreciation	1,857	1,958	2,061
15	p	Storm - Major	3,400	3,400	3,400
16		Storm - Minor	1,000	1,000	1,000
17	f	Vegetation Management - Distribution	8,270	8,443	8,621
18		Vegetation Management - Transmission	2,176	2,222	2,269
19		Security	1,067	1,089	1,112
20	n	Low Income Program	11,837	11,837	11,837
21	o	Credit & Debit Card Fees	884	1,121	1,345
22		CS Enhancements	191	166	166
23		Stray Voltage	1,043	1,065	1,087
24		Electric Reliability Organization _NERC	147	156	167
25		AMI - Incremental O&M	-	647	1,616
26		AMI - Incremental O&M Savings	-	-	(350)
27		Occupancy/Overhead costs	4,448	4,541	4,637
28	k	EE Tracker	8,546	13,182	17,910
29	k	EE Heat Pumps	786	1,181	1,674
30		NWA General Costs	100	100	100
31		New Studies	176	-	-
32		All Other O&M General Inflator Items	10,262	11,369	11,607
33	d	Pension	5,805	5,805	5,805
34	e	OPEBs	990	1,068	838
35	a	Economic Development	7,000	7,000	7,000
36	l	Environmental Remediation	988	988	988
37	j	Incremental Maintenance	2,087	5,298	5,875
38	g	Management / Operations / Staffing Audit	21	21	21
39	q	NEIL Credits	(3,613)	(3,688)	(3,766)
40	h	REV Incremental Costs	4,741	4,721	4,980
41	i	COVID-19 Pandemic Adjustment	(2,950)	-	-
42		COVID-19 - General Inflation Adj. (lines 6, 8-12, 18, 19, 23, 27, 32, & 39)	(716)	(919)	(1,048)
43		**Total Delivery O&M Expense**	$ 167,807	$ 184,257	$ 193,866
		Surcharge Expense			
44	b	Clean Energy Fund (CEF)	$ 36,980	$ 35,880	$ 34,697
45		**Total Surcharges**	$ 36,980	$ 35,880	$ 34,697
46		**Amortizations - Refer to Schedule H for Detailed Information**	$ (34,567)	$ (36,552)	$ (38,487)
47		**Total O&M Plus Surcharges & Amortizations**	**$ 170,220**	**$ 183,586**	**$ 190,076**

Rochester Gas and Electric Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Operation & Maintenance Expense
($000)

			A	B	C
			Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
		Amount in Rates			
48	c	Labor / Payroll	$ 39,404	$ 41,319	$ 42,730
49	d	Pension	5,805	5,805	5,805
50	e	OPEBs	990	1,068	838
51	f	Vegetation Management	8,270	8,443	8,621
52	g	Management Audit	21	21	21
53	h	REV	4,741	4,721	4,980
54	i	COVID-19 Pandemic Adjustment	(2,950)	-	-
55	j	Incremental Maintenance	2,087	5,298	5,875
56	l	Environmental Remediation	988	988	988
57	a	Economic Development	7,024	7,000	7,000
58	n	Low Income Program	11,837	11,837	11,837
59	o	Credit & Debit Card Fee Deferral	884	1,121	1,345
60	p	Storm Deferral	3,400	3,400	3,400
61	q	NEIL Credit	(3,613)	(3,688)	(3,766)
62	r	Uncollectibles	5,442	5,971	6,414
63		Total	$ 84,331	$ 93,304	$ 96,088
		Low Income Program Summary			
64		Arrearage Forgiveness	$ 619	$ 619	$ 619
65		Bill Reduction	11,218	11,218	11,218
66	n	Total Low Income Program	$ 11,837	$ 11,837	$ 11,837
		Economic Development Reconciliation			
67	a	Total Economic Development Program	$ 7,024	$ 7,000	$ 7,000
68	a	Rate Discounts	$ 24	$ -	$ -
		Non-Rate discounts:			
69	a	Economic Development - O&M	7,000	7,000	7,000
70		Total Rate and Non-Rate Discounts	$ 7,024	$ 7,000	$ 7,000
		CEF Reconciliation			
		Revenue			
71	b	Clean Energy Fund	$ 36,980	$ 35,880	$ 34,697
72			$ 36,980	$ 35,880	$ 34,697
		Expense			
73	b	Clean Energy Fund	$ 36,980	$ 35,880	$ 34,697
		Energy Efficiency - Base Delivery			
		O&M Expense			
74	k	EE Tracker	$ 8,546	$ 13,182	$ 17,910
75	k	EE Heat Pumps	786	1,181	1,674
76		EE Regulatory Amorts (refer to Schedule H)	(4,892)	(4,892)	(4,892)
77		Total Energy Efficiency - Base Delivery	$ 4,440	$ 9,471	$ 14,692

Rochester Gas and Electric Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Depreciation & Amortizations
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
1	**Depreciation Expense**	**$ 74,181**	**$ 82,604**	**$ 92,053**

Rochester Gas and Electric Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Operating Taxes
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
	Gross Revenue Taxes			
1	Total Retail Revenue	$ 461,267	$ 470,287	$ 525,025
2	Average GRT Rate	1.42%	1.59%	1.54%
3	Total Gross Revenue Tax	$ 6,544	$ 7,475	$ 8,100
	Other Operating Taxes			
4	Property Taxes	$ 88,443	$ 93,255	$ 98,328
5	Payroll Taxes	3,956	4,014	4,151
6	**Total Other Operating Taxes**	$ 92,399	$ 97,268	$ 102,478
7	**Total**	**$ 98,944**	**$ 104,743**	**$ 110,578**

Rochester Gas and Electric Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Income Taxes
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
1	Operating Income Before Income Taxes	$ 121,928	$ 145,228	$ 158,128
2	Interest Expense	(35,929)	(41,063)	(43,113)
3	Book Income Before Income Taxes (Adjusted for Tax Items)	85,999	104,165	115,015
4	Federal Income Taxes @ 21.000%	18,060	21,875	24,153
5	State Taxes @ 6.500%	5,590	6,771	7,476
6	Fed Benefit of State Tax Deduction @ 1.365%	(1,174)	(1,422)	(1,570)
7	Total Federal & State @ Statutory Rates	22,476	27,224	30,059
	Permanent Differences			
8	Meals and Entertainment	125	125	125
9	Subtotal: Permanent Differences	125	125	125
10	**Delivery Income Taxes (Lines 7 & 9)**	**$ 22,601**	**$ 27,349**	**$ 30,184**

Rochester Gas and Electric Corporation
Electric Department
Revenue Requirement for Forecast Years Ending April 30, 2021, 2022, 2023
Capital Structure Summary Schedule
($000)

		A	B	C	D	E
		Weight	**Cost Rate**	**Percent**	**Tax Gross-up**	**Before Tax**
	Rate Year 1					
1	Long Term Debt	51.79%	4.62%	2.39%		2.39%
2	Customer Deposits	0.21%	0.90%	0.00%		0.00%
3	Total Debt	52.00%		2.39%		2.39%
4	Common Equity	48.00%	8.80%	4.22%	1.49%	5.72%
5	Total	100.00%		6.62%		8.11%
	Rate Year 2					
6	Long Term Debt	51.82%	4.35%	2.26%		2.26%
7	Customer Deposits	0.18%	0.90%	0.00%		0.00%
8	Total Debt	52.00%		2.26%		2.26%
9	Common Equity	48.00%	8.80%	4.22%	1.49%	5.72%
10	Total	100.00%		6.48%		7.98%
	Rate Year 3					
11	Long Term Debt	51.84%	4.14%	2.15%		2.15%
12	Customer Deposits	0.16%	0.90%	0.00%		0.00%
13	Total Debt	52.00%		2.15%		2.15%
14	Common Equity	48.00%	8.80%	4.22%	1.49%	5.72%
15	Total	100.00%		6.37%		7.87%

	Interest Expense	**Rate Year 1**	**Rate Year 2**	**Rate Year 3**
16	Rate Base	$ 1,500,899	$ 1,818,579	$ 2,008,301
17	Weighted Cost of Debt	2.39%	2.26%	2.15%
18	Interest Expense	$ 35,929	$ 41,063	$ 43,113

Rochester Gas and Electric Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Regulatory Amortizations
($000)

		A	B	C	D	E
		Starting Rate Year Asset / (Liab) Balance	Amortization Period (years)	Inc / (Exp) Rate Year 1 Amortization 4/30/2021	Inc / (Exp) Rate Year 2 Amortization 4/30/2022	Inc / (Exp) Rate Year 3 Amortization 4/30/2023
	Specific or 3-Year Term Amortizations					
1	ASGA	$ (10,851)	Specific	$ 5,370	$ 5,481	$ -
2	Bonus Depreciation NCR	(18,974)	Specific	3,795	5,984	9,195
3	Fixed Rate Debt	(16,501)	Specific	3,300	3,300	7,820
4	2018 Windstorm Settlement - Case 19-E-0105	(1,500)	3	500	500	500
5	EEPS	(53)	3	18	18	18
6	EE Tracker	(14,624)	3	4,875	4,875	4,875
7	**Subtotal**	**$ (62,503)**		**$ 17,857**	**$ 20,157**	**$ 22,407**
	Other Than 3-Year Amortizations					
8	Allegheny Sale Loss and Savings	$ (5,121)	5	$ 1,024	$ 1,024	$ 1,024
9	Beebee Decommissioning	(764)	5	153	153	153
10	CAIDI/SAIFI Study	95	5	(19)	(19)	(19)
11	Cap Ex NCR 03-E-0765, 03-G-0766	3,401	5	(680)	(680)	(680)
12	CapEx Customer Credit 07-M-0906 Merger Order	(10,000)	5	2,000	2,000	2,000
13	Cost to Achieve Efficiency Initiatives	105	5	(21)	(21)	(21)
14	Credit & Debit Card Fees	1,781	5	(356)	(356)	(356)
15	Economic Development - Remaining Amort (15-E-0283 Appx. V)	(17,052)	$3M/Yr	3,000	3,000	3,000
16	Economic Development - New Amortization	(571)	0	-	-	-
17	Electric Reliability Organization	304	5	(61)	(61)	(61)
18	Environmental - Remaining Amort (15-E-0283 Appx. V)	(21,617)	7	3,088	3,088	3,088
19	Environmental - New Amortization	(14,550)	7	2,079	2,079	2,079
20	ESM - Remaining Amort (15-E-0283 Appx. V)	(5,422)	5	1,084	1,084	1,084
21	ESM - New Amortization	(2,170)	5	434	434	434
22	Excess DIT - New York State Tax Rate change - Remaining Amort (15-E-0283 Appx. V)	(2,898)	5	580	580	580
23	Incremental Maintenance - New Amortization	(167)	5	33	33	33
24	IRS Audit - 1998-2001 - Remaining Amort (15-E-0283 Appx. V)	70	5	(14)	(14)	(14)
25	Low Income Program - Remaining Amort (15-E-0283 Appx. V)	(3,634)	5	727	727	727
26	Low Income Program - New Amortization	20,296	5	(4,059)	(4,059)	(4,059)
27	Management Audit - Remaining Amort (15-E-0283 Appx. V)	(217)	5	43	43	43
28	Management Audit - New Amortization	50	5	(10)	(10)	(10)
29	Medicare Part D	(241)	5	48	48	48
30	MHP Meter Costs - Remaining Amort (15-E-0283 Appx. V)	(4)	5	1	1	1
31	Mixed Use 263(a) NCR - Remaining Amort (15-E-0283 Appx. V)	(4,241)	5	848	848	848
32	NEIL Credit	(6,357)	5	1,271	1,271	1,271
33	Net Plant Reconciliation - Remaining Amort (15-E-0283 Appx. V)	(9,623)	5	1,925	1,925	1,925
34	Net Plant Reconciliation - New Amortization	(12,978)	5	2,596	2,596	2,596
35	Nine Mile II - TCCs - Remaining Amort (15-E-0283 Appx. V)	(11,472)	5	2,294	2,294	2,294
36	Nine Mile II - TCCs - New Amortization	(9,673)	5	1,935	1,935	1,935
37	Nuclear Fuel DOE Liability True-up - Remaining Amort (15-E-0283 Appx. V)	(12,188)	5	2,438	2,438	2,438
38	Nuclear Fuel DOE Liability True-up - New Amortization	2,888	5	(578)	(578)	(578)
39	NYS Tax Audit - Remaining Amort (15-E-0283 Appx. V)	228	5	(46)	(46)	(46)
40	NYS Tax Rate - New Amortization	(319)	5	64	64	64
41	OPEB Deferral	(1,559)	5	312	312	312
42	OPEB Deferral - New Amortization	(219)	5	44	44	44
43	PBA Utilization	(32,987)	5	6,597	6,597	6,597
44	Pension Deferral - Remaining Amort (15-E-0283 Appx. V)	21,403	5	(4,281)	(4,281)	(4,281)
45	Pension Deferral - New Amortization	8,101	5	(1,620)	(1,620)	(1,620)
46	PRA - Terminations & Uncollectibles	171	5	(34)	(34)	(34)
47	Property Tax	(12,105)	5	2,421	2,421	2,421
48	Rate Increase Shaping (reflected in Revenue)	364	5	(73)	(73)	(73)
49	Property Tax 481(a) - NCR	(346)	5	69	69	69
50	PSC Assessment	(126)	5	25	25	25
51	REV Incremental Costs	5,013	5	(1,003)	(1,003)	(1,003)
52	Russell Decommissioning	4,143	5	(829)	(829)	(829)
53	ROW Tree Trim	1,480	5	(296)	(296)	(296)
54	Sarbanes-Oxley	386	5	(77)	(77)	(77)
55	Service Quality Performance	(393)	5	79	79	79
56	SO2 Allowance	(829)	5	166	166	166
57	Storm - Non-Superstorm - Remaining Amort (15-E-0283 Appx. V)	(4,163)	5	833	833	833
58	Storm - Non-Superstorm - New Amortization	53,183	5	(10,637)	(10,637)	(10,637)
59	Stray Voltage	585	5	(117)	(117)	(117)
60	Theoretical Reserve Inc Tax Flow Through- Remaining Amort (15-E-0283 Appx. V)	(6,279)	5	1,256	1,256	1,256
61	Unit of Property CTA	76	5	(15)	(15)	(15)
62	Variable Rate Debt- Remaining Amort (15-E-0283 Appx. V)	(284)	5	57	57	57
63	Variable Rate Debt - New Amortization	1,447	5	(289)	(289)	(289)
64	Vegetation Management	(682)	5	136	136	136
65	Vegetation Management - Danger Tree Deferral $1.575M per year beginning in RY1		5	(315)	(630)	(945)
66	Post Term Amortization Deferral - 2010 JP	(1,590)	5	318	318	318
67	**Subtotal**	**$ (87,269)**		**$ 14,548**	**$ 14,233**	**$ 13,918**
	Income Tax Related Amortizations					
68	Excess DIT - TCJA - Protected Amortization (reflected in Revenue)	(207,111)	ARAM	3,963	4,119	4,196
69	Excess DIT - TCJA - Protected Pre-RY1 Liability (reflected in Revenue)	(8,957)	3	2,986	2,986	2,986
70	Excess DIT - TCJA - Unprotected Amortization	(12,358)	3	4,119	4,119	4,119
71	Federal Tax Reform - Jan-Sep 2018 Savings Amortization (reflected in Revenue)	(6,934)	1.5	4,623	2,311	-
72	PowerTax Regulatory Asset	36,031	35	(1,029)	(1,029)	(1,029)

Rochester Gas and Electric Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Regulatory Amortizations
($000)

		A	B	C	D	E
		Starting Rate Year Asset / (Liab) Balance	Amortization Period (years)	Inc / (Exp) Rate Year 1 Amortization 4/30/2021	Inc / (Exp) Rate Year 2 Amortization 4/30/2022	Inc / (Exp) Rate Year 3 Amortization 4/30/2023
73	Unfunded Future Income Taxes	132,082	46	(2,871)	(2,871)	(2,871)
74	Unfunded Future Income Taxes - NCR	(29,947)	5	5,989	5,989	5,989
75	**Subtotal**	**$ (97,195)**		**$ 17,780**	**$ 15,624**	**$ 13,390**
76	**Total - RG&E Electric**	**$ (246,967)**		**$ 50,185**	**$ 50,014**	**$ 49,715**

Rochester Gas and Electric Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Rate Base
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
	Rate Base			
1	Utility Plant	$ 2,955,185	$ 3,305,738	$ 3,526,565
2	Depreciation Reserve	(866,717)	(929,092)	(993,075)
3	Materials & Supplies	9,126	9,318	9,513
4	Prepayments	34,602	35,328	36,070
5	O&M Working Capital per the FERC Formula	24,918	26,771	27,769
6	Non Interest Bearing Customer Advances	(2,610)	(2,610)	(2,610)
7	Deferred Debits & Credits	(376,459)	(319,026)	(257,538)
8	Deferred Income Taxes	(273,495)	(304,197)	(334,743)
9	Total Before Earnings Base-Capitalization Adjustment	$ 1,504,549	$ 1,822,229	$ 2,011,951
10	Earnings Base-Capitalization Adjustment	(3,650)	(3,650)	(3,650)
11	**Total**	**$ 1,500,899**	**$ 1,818,579**	**$ 2,008,301**

Rochester Gas and Electric Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Deferred Debits and Credits
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
	Regulatory Assets & Liabilities:			
1	2018 Windstorm Settlement - Case 19-E-0105	$ (1,250)	$ (750)	$ (250)
2	Allegheny Sale Loss and Savings	(4,608)	(3,584)	(2,560)
3	ASGA	(8,166)	(2,740)	(0)
4	Beebee Decommissioning	(688)	(535)	(382)
5	Bonus Depreciation NCR - Remaining Amort (15-E-0283 Appx. V)	(17,077)	(12,187)	(4,597)
6	CAIDI/SAIFI Study	86	67	48
7	Cap Ex NCR 03-E-0765, 03-G-0766	3,061	2,381	1,701
8	CapEx Customer Credit 07-M-0906 Merger Order	(9,000)	(7,000)	(5,000)
9	Cost to Achieve Efficiency Initiatives	94	73	52
10	Credit & Debit Card Fees	1,603	1,247	891
11	Economic Development	(15,552)	(12,552)	(9,552)
12	Economic Development - New Amortization	(571)	(571)	(571)
13	EEPS	(44)	(27)	(9)
14	EE Tracker	(12,186)	(7,312)	(2,437)
15	Electric Reliability Organization	273	213	152
16	Environmental - Remaining Amort (15-E-0283 Appx. V)	(20,073)	(16,985)	(13,897)
17	Environmental - New Amortization	(13,511)	(11,432)	(9,354)
18	ESM - Remaining Amort (15-E-0283 Appx. V)	(4,880)	(3,796)	(2,711)
19	ESM - New Amortization	(1,953)	(1,519)	(1,085)
20	Excess DIT - New York State Tax Rate change - Remaining Amort (15-E-0283 Appx. V)	(2,608)	(2,029)	(1,449)
21	Fixed Rate Debt	(14,851)	(11,551)	(5,990)
22	Incremental Maintenance	(150)	(117)	(84)
23	IRS Audit - 1998-2001 - Remaining Amort (15-E-0283 Appx. V)	63	49	35
24	Low Income Program - Remaining Amort (15-E-0283 Appx. V)	(3,270)	(2,544)	(1,817)
25	Low Income Program - New Amortization	18,267	14,207	10,148
26	Major Storm Reserve - Remaining Amort (15-E-0283 Appx. V)	(3,747)	(2,914)	(2,082)
27	Major Storm Reserve - New Amortization	47,865	37,228	26,592
28	Management Audit - Remaining Amort (15-E-0283 Appx. V)	(195)	(152)	(108)
29	Management Audit - New Amortization	45	35	25
30	Medicare Part D	(217)	(169)	(121)
31	MHP Meter Costs	(4)	(3)	(2)
32	Mixed Use 263(a) NCR - Remaining Amort (15-E-0283 Appx. V)	(3,817)	(2,968)	(2,120)
33	NEIL Credit	(5,721)	(4,450)	(3,178)
34	Net Plant Reconciliation - Remaining Amort (15-E-0283 Appx. V)	(8,661)	(6,736)	(4,812)
35	Net Plant Reconciliation - New Amortization	(11,681)	(9,085)	(6,489)
36	Nine Mile II - TCCs - Remaining Amort (15-E-0283 Appx. V)	(10,325)	(8,031)	(5,736)
37	Nine Mile II - TCCs - New Amortization	(8,705)	(6,771)	(4,836)
38	Nuclear Fuel DOE Liability True-up - Remaining Amort (15-E-0283 Appx. V)	(10,969)	(8,531)	(6,094)
39	Nuclear Fuel DOE Liability True-up - New Amortization	2,599	2,022	1,444
40	NYS Tax Audit - Remaining Amort (15-E-0283 Appx. V)	205	159	114
41	NYS Tax Rate - New Amortization	(287)	(223)	(160)
42	OPEB Deferral - Remaining Amort (15-E-0283 Appx. V)	(1,403)	(1,091)	(779)
43	OPEB Deferral - New Amortization	(197)	(153)	(109)
44	PBA Utilization	(29,688)	(23,091)	(16,493)
45	Pension Deferral - Remaining Amort (15-E-0283 Appx. V)	19,263	14,982	10,702
46	Pension Deferral - New Amortization	7,291	5,671	4,051
47	PRA - Terminations & Uncollectibles	154	120	86
48	Property Tax	(10,895)	(8,474)	(6,053)
49	Rate Increase Shaping	328	255	182
50	Property Tax 481(a) - NCR	(311)	(242)	(173)
51	PSC Assessment	(113)	(88)	(63)
52	REV Incremental Costs	4,512	3,509	2,507
53	Russell Decommissioning	3,729	2,900	2,072

Rochester Gas and Electric Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Deferred Debits and Credits
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
54	ROW Tree Trim	1,332	1,036	740
55	Sarbanes-Oxley	348	271	193
56	Service Quality Performance	(354)	(275)	(197)
57	SO2 Allowance	(746)	(580)	(414)
58	Stray Voltage	526	409	292
59	Theoretical Reserve Inc Tax Flow Through- Remaining Amort (15-E-0283 Appx. V)	(5,651)	(4,395)	(3,139)
60	Unit of Property CTA	68	53	38
61	Variable Rate Debt- Remaining Amort (15-E-0283 Appx. V)	(256)	(199)	(142)
62	Variable Rate Debt - New Amortization	1,302	1,013	723
63	Vegetation Management	(614)	(477)	(341)
64	Vegetation Management - Danger Tree Deferral	630	1,733	2,520
65	Post Term Amortization Deferral - 2010 JP	(1,431)	(1,113)	(795)
66	Excess DIT - TCJA - Protected Amortization	(205,130)	(201,089)	(196,931)
67	Excess DIT - TCJA - Protected Pre-RY1 Liability	(7,465)	(4,479)	(1,493)
68	Excess DIT - TCJA - Unprotected Amortization	(10,298)	(6,179)	(2,060)
69	Federal Tax Reform - Jan-Sep 2018 Savings Amortization	(4,623)	(1,156)	-
70	PowerTax Regulatory Asset	35,516	34,487	33,457
71	Unfunded Future Income Taxes	130,647	127,775	124,904
72	Unfunded Future Income Taxes - NCR	(26,953)	(20,963)	(14,974)
73	Subtotal	$ (221,087)	$ (169,412)	$ (117,973)
	Other Deferred Assets & Liabilities:			
74	Commodity Hedge Margin	-	-	-
75	DOE Liability	(125,931)	(125,931)	(125,931)
76	FAS-112 Post Employment Benefit Liability	(1,037)	(1,037)	(1,037)
77	Preliminary Survey and Investigation	407	407	407
78	Pension Asset	(15,490)	(11,628)	(3,514)
79	Loss on Reacquired Debt	4,369	4,369	4,369
80	Net (Gains)/Losses on Interest Rate Hedges	28,614	28,307	28,000
81	NBC True-Up	-	-	-
82	OPEB Reserve	(43,825)	(41,621)	(39,380)
83	PSC Assessment - General	-	-	-
84	Injuries and Damages Reserve	(3,407)	(3,407)	(3,407)
85	RDM	-	-	-
86	Workers Comp Reserve	-	-	-
87	All Other	928	928	928
88	**Subtotal**	$ (155,372)	$ (149,614)	$ (139,566)
89	**Grand Total**	**$ (376,459)**	**$ (319,026)**	**$ (257,538)**

Rochester Gas and Electric Corporation

Gas Department

Revenue Requirement for Forecast Years Ending April 30, 2021, 2022, 2023

Rochester Gas and Electric Corporation
Gas Department
Revenue Requirement for Forecast Years Ending April 30, 2021, 2022, 2023
Rate of Return Statement
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
	Operating Revenues			
1	Sales Revenue	$ 178,886	$ 169,026	$ 179,985
2	Impact of Rate Increase	(1,127)	859	3,866
3	Late Payments	2,089	2,234	2,420
4	Total Retail Revenue	179,848	172,119	186,270
5	Other Revenue	(5,784)	12,950	13,938
6	**Total Revenue**	174,064	185,069	200,208
7	Gross Revenue Taxes	3,603	3,869	4,213
8	Net Revenue	170,461	181,200	195,996
9	O&M Expenses	66,481	71,375	74,922
10	Depreciation & Amortizations	31,375	32,977	36,566
11	Taxes Other Than Income Taxes	31,242	32,888	34,633
12	**Total Operating Expenses**	129,098	137,240	146,121
13	**Operating Income Before Income Taxes**	41,364	43,960	49,874
14	Income Taxes	7,648	8,264	9,504
15	**Operating Income Available for Return**	$ 33,716	$ 35,696	$ 40,370
16	**Rate Base**	$ 509,465	$ 550,697	$ 633,677
17	**Rate of Return**	6.62%	6.48%	6.37%
18	**Return on Equity**	8.80%	8.80%	8.80%
	Calculation of Return on Equity			
19	Operating Income Available for Return	$ 33,716	$ 35,696	$ 40,370
20	Less: Interest Expense	(12,196)	(12,434)	(13,603)
21	**Balance for Common**	21,520	23,261	26,766
22	Rate Base	509,465	550,697	633,677
23	Common Equity Percentage	48%	48%	48%
24	**Equity Component of Rate Base**	244,543	264,334	304,165
25	Balance for Common	21,520	23,261	26,766
26	Equity Component of Rate Base	244,543	264,334	304,165
27	**Return on Equity**	8.80%	8.80%	8.80%
	Revenue Requirement Value of 1bp ROE			
28	Net income Attributable to 1bp of ROE (line 24 x 1bp)	$ 24	$ 26	$ 30
29	/ Retention Factor including FIT/SIT	71.61%	71.61%	71.61%
30	**Revenue Requirement Value of 1bp ROE**	$ 34	$ 37	$ 42

Rochester Gas and Electric Corporation
Gas Department
Revenue Requirement for Forecast Years Ending April 30, 2021, 2022, 2023
Revenue
($000)

			A	B	C
			Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
		Sales Revenue			
1		Gross Base Delivery	$ 167,912	$ 158,312	$ 169,020
2		Plus: Rate Increase	(1,127)	859	3,866
3		BIPP Charges	1,968	1,977	1,984
4		Net Base Delivery Charges	168,754	161,147	174,870
5		MFC/POR - Credit/Coll/Call Ctr/Admin	4,780	4,780	4,780
6	a	NYSERDA EE Surcharge	74	-	-
7		R&D Surcharge	314	314	314
8		Gross Revenue Tax	3,837	3,644	3,886
9		**Total Sales Revenue**	$ 177,759	$ 169,885	$ 183,850
10		Late Payments	2,089	2,234	2,420
		Other Revenue			
11		Reconnection, WMS, Line Extensions, Misc.	89	89	89
12		Damage Billing	94	96	98
13		Other	443	452	462
14		COVID-19 - General Inflation Adjustment (lines 12-13)	(7)	(9)	(10)
15		**Total**	$ 619	$ 628	$ 638
		Deferrals & Amortizations			
16		Excess DIT - TCJA - Protected Amortization	1,289	1,339	1,364
17		Excess DIT - TCJA - Protected Pre-RY1 Liability	971	971	971
18		Excess DIT - TCJA - Unprotected Amortization	(295)	(295)	(295)
19		Federal Tax Reform - TCJA Jan-Sep 2018 Savings Amortization	1,448	724	-
20		Rate Increase Shaping Deferral	(9,816)	9,582	11,259
21		**Total**	$ (6,403)	$ 12,322	$ 13,300
22		**Total Other Revenues + Deferrals & Amortizations**	$ (5,784)	$ 12,950	$ 13,938
23		**Total**	**$ 174,064**	**$ 185,069**	**$ 200,208**

Rochester Gas and Electric Corporation
Gas Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Operation & Maintenance Expense
($000)

			A	B	C
			Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
		O&M Expenses			
1	b	Labor / Payroll	$ 20,650	$ 21,584	$ 22,263
2		Variable Compensation	460	481	496
3		401K	941	996	1,075
4		Productivity	(453)	(563)	(576)
5		Medical Benefits	1,825	1,873	1,916
6		Other Employee Benefits	386	394	402
7	l	Uncollectibles	3,136	3,361	3,653
8		Insurance	468	478	488
9		Workers Comp	607	620	633
10		Injury / Damages	25	26	27
11		ASC Costs	10,841	11,069	11,301
12		Outside Services	6,813	6,800	6,949
13		Legal / Regulatory Expense	815	827	840
14		Vehicle Depreciation	744	785	826
15		Security	512	523	534
16	j	Low Income Program	5,457	5,457	5,457
17	k	Credit & Debit Card Fees	723	917	1,100
18		CS Enhancements	155	135	135
19		Communications - Reporting Gas Odors	313	294	300
20		Gas Utilization	198	198	199
21		AMI - Incremental O&M	-	542	941
22		AMI - Incremental O&M Savings	-	-	(172)
23		Occupancy/Overhead costs	2,815	2,874	2,934
24	a	EE Tracker	1,574	2,554	3,991
25		NPA General Costs	100	100	100
26		New Studies	85	-	-
27		All Other O&M General Inflator Items	5,583	6,127	6,261
28	c	Pension	3,244	3,244	3,244
29	d	OPEBs	541	584	458
30	i	Economic Development	200	200	200
31	h	Environmental Remediation	370	370	370
32	g	Incremental Maintenance	6,151	7,497	7,585
33	n	Integrity of Gas Pipeline	2,720	2,720	2,720
34	f	Management / Operations / Staffing Audit	74	74	74
35	m	Research & Development	1,244	1,255	1,266
36	e	Vegetation Management	361	369	376
37		COVID-19 - General Inflation Adjustment (lines 6, 8-12, 15, 23, 27, & 36)	(308)	(395)	(450)
38		**Total Delivery O&M Expense**	$ 79,374	$ 84,371	$ 87,918
		Surcharge Expenses			
39	a	NYSERDA EE Surcharge	$ 74	$ -	$ -
40		**Total Surcharges**	**$ 74**	**$ -**	**$ -**
41		**Amortizations - Refer to Schedule H for Detailed Information**	$ (12,967)	$ (12,996)	$ (12,996)
42		**Total O&M Plus Surcharges & Amortizations**	**$ 66,481**	**$ 71,375**	**$ 74,922**

Rochester Gas and Electric Corporation
Gas Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Operation & Maintenance Expense
($000)

			A	B	C
			Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
		Amount in Rates			
43	b	Labor / Payroll	$ 20,650	$ 21,584	$ 22,263
44	c	Pension	3,244	3,244	3,244
45	d	OPEBs	541	584	458
46	e	Vegetation Management	361	369	376
47	f	Management Audit	74	74	74
48	g	Incremental Maintenance	6,151	7,497	7,585
49	h	Environmental Remediation	370	370	370
50	i	Economic Development	200	200	200
51	j	Low Income Program	5,457	5,457	5,457
52	k	Credit & Debit Card Fee Deferral	723	917	1,100
53	l	Uncollectibles	3,136	3,361	3,653
54	m	Gas R&D	1,244	1,255	1,266
55	n	Gas Pipeline Integrity Costs	2,720	2,720	2,720
56		Total	$ 44,873	$ 47,632	$ 48,767
		Low Income Program Summary			
57		Bill Reduction	$ 4,946	$ 4,946	$ 4,946
58		Arrearage Forgiveness	511	511	511
59	j	Total Low Income Program	$ 5,457	$ 5,457	$ 5,457
		Economic Development Reconciliation			
60	i	Total Economic Development Program	$ 200	$ 200	$ 200
		Non-Rate discounts:			
61	i	Economic Development - O&M	$ 200	$ 200	$ 200
62		Total Rate and Non-Rate Discounts	$ 200	$ 200	$ 200
		Energy Efficiency - Base Delivery			
		Revenue			
63	a	Energy Efficiency - Base Delivery	$ 74	$ -	$ -
64		Total	$ 74	$ -	$ -
		O&M Expense			
65	a	EE Tracker & NYSERDA EE	$ 1,648	$ 2,554	$ 3,991
66		EE Regulatory Amorts (refer to Schedule H)	(2,814)	(2,814)	(2,814)
67			$ (1,166)	$ (260)	$ 1,177

Rochester Gas and Electric Corporation
Gas Department
Revenue Requirement for Forecast Years Ending April 30, 2021, 2022, 2023
Depreciation & Amortizations
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
1	**Depreciation Expense**	**$ 31,375**	**$ 32,977**	**$ 36,566**

Rochester Gas and Electric Corporation
Gas Department
Revenue Requirement for Forecast Years Ending April 30, 2021, 2022, 2023
Operating Taxes
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
	Gross Revenue Taxes			
1	Total Retail Revenue	$ 177,759	$ 169,885	$ 183,850
2	Average GRT Rate	2.03%	2.28%	2.29%
3	GRT on Sales Revenues	$ 3,603	$ 3,869	$ 4,213
	Other Operating Taxes			
4	Property Taxes	$ 29,394	$ 30,993	$ 32,679
5	Payroll Taxes	1,848	1,894	1,954
6	**Total Other Operating Taxes**	$ 31,242	$ 32,888	$ 34,633
7	**Total**	**$ 34,845**	**$ 36,757**	**$ 38,846**

Rochester Gas and Electric Corporation
Gas Department
Revenue Requirement for Forecast Years Ending April 30, 2021, 2022, 2023
Income Taxes
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
1	Operating Income Before Income Taxes	$ 41,364	$ 43,960	$ 49,874
2	Interest Expense	(12,196)	(12,434)	(13,603)
3	Book Income Before Income Taxes (Adjusted for Tax Items)	29,168	31,526	36,271
4	Federal Income Taxes @ 21.000%	6,125	6,620	7,617
5	State Taxes @ 6.500%	1,896	2,049	2,358
6	Fed Benefit of State Tax Deduction @ 1.365%	(398)	(430)	(495)
7	Total Federal & State @ Statutory Rates	7,623	8,239	9,479
	Permanent Differences			
8	Meals and Entertainment	25	25	25
9	Subtotal: Permanent Differences	25	25	25
10	**Delivery Income Taxes (Lines 7 & 9)**	**$ 7,648**	**$ 8,264**	**$ 9,504**

Rochester Gas and Electric Corporation
Gas Department
Revenue Requirement for Forecast Years Ending April 30, 2021, 2022, 2023
Capital Structure Summary Schedule
($000)

		A	B	C	D	E
		Weight	**Cost Rate**	**Percent**	**Tax Gross-up**	**Before Tax**
	Rate Year 1					
1	Long Term Debt	51.79%	4.62%	2.39%		2.39%
2	Customer Deposits	0.21%	0.90%	0.00%		0.00%
3	Total Debt	52.00%		2.39%		2.39%
4	Common Equity	48.00%	8.80%	4.22%	1.49%	5.72%
5	Total	100.00%		6.62%		8.11%
	Rate Year 2					
6	Long Term Debt	51.82%	4.35%	2.26%		2.26%
7	Customer Deposits	0.18%	0.90%	0.00%		0.00%
8	Total Debt	52.00%		2.26%		2.26%
9	Common Equity	48.00%	8.80%	4.22%	1.49%	5.72%
10	Total	100.00%		6.48%		7.98%
	Rate Year 3					
11	Long Term Debt	51.84%	4.14%	2.15%		2.15%
12	Customer Deposits	0.16%	0.90%	0.00%		0.00%
13	Total Debt	52.00%		2.15%		2.15%
14	Common Equity	48.00%	8.80%	4.22%	1.49%	5.72%
15	Total	100.00%		6.37%		7.87%

	Interest Expense	**Rate Year 1**	**Rate Year 2**	**Rate Year 3**
16	Rate Base	$ 509,465	$ 550,697	$ 633,677
17	Weighted Cost of Debt	2.39%	2.26%	2.15%
18	Interest Expense	$ 12,196	$ 12,434	$ 13,603

Rochester Gas and Electric Corporation
Gas Department
Revenue Requirement for Forecast Years Ending April 30, 2021, 2022, 2023
Regulatory Amortizations
($000)

		A	B	C	D	E
		Starting Rate Year Asset / (Liab) Balance	Amortization Period (years)	Inc / (Exp) Rate Year 1 Amortization 4/30/2021	Inc / (Exp) Rate Year 2 Amortization 4/30/2022	Inc / (Exp) Rate Year 3 Amortization 4/30/2023
	1 & 3-Year Term Amortizations					
1	NRA - Damage Prevention	$ (550)	1	$ 550	$ -	$ -
2	PRA - Leak Prone Main	579	1	(579)	-	-
3	EE Tracker	(1,006)	3	335	335	335
4	**Subtotal**	**$ (978)**		**$ 307**	**$ 335**	**$ 335**
	Other Than 1 & 3-Year Amortizations					
5	Bonus Depreciation NCR	$ (14,295)	5	$ 2,859	$ 2,859	$ 2,859
6	Cap Ex NCR 03-G-0766	646	5	(129)	(129)	(129)
7	Cost to Achieve Efficiency Initiatives	114	5	(23)	(23)	(23)
8	Community Development Fund	(150)	5	30	30	30
9	Credit & Debit Card Fees	1,466	5	(293)	(293)	(293)
10	Economic Development - Remaining Amort (15-E-0283 Appx. V)	(1,127)	0	-	-	-
11	Economic Development - New Amortization	(669)	0	-	-	-
12	Energy Efficiency Portfolio Standard - Remaining Amort (15-E-0283 Appx. V)	35	5	(7)	(7)	(7)
13	EEPS - New Amortization	(12,394)	5	2,479	2,479	2,479
14	Environmental - Remaining Amort (15-E-0283 Appx. V)	(8,787)	7	1,255	1,255	1,255
15	Environmental - New Amortization	(7,610)	7	1,087	1,087	1,087
16	Excess DIT - New York State Tax Rate change	(840)	5	168	168	168
17	Fixed Rate Debt	(4,268)	5	854	854	854
18	Gas ESM - Remaining Amort (15-E-0283 Appx. V)	(1,111)	5	222	222	222
19	Gas ESM - New Amortization	(1,824)	5	365	365	365
20	Incremental Maintenance - Remaining Amort (15-E-0283 Appx. V)	(266)	5	53	53	53
21	Incremental Maintenance - New Amortization	(532)	5	106	106	106
22	IRS Audit - 1998-2001	(199)	5	40	40	40
23	Low Income Program - Remaining Amort (15-E-0283 Appx. V)	(855)	5	171	171	171
24	Low Income Program - New Amortization	(8,841)	5	1,768	1,768	1,768
25	Management Audit - Remaining Amort (15-E-0283 Appx. V)	(38)	5	8	8	8
26	Management Audit - New Amortization	37	5	(7)	(7)	(7)
27	Medicare Part D	(362)	5	72	72	72
28	Mixed Use 263(a) NCR	(1,585)	5	317	317	317
29	Net Plant Reconciliation	(67)	5	13	13	13
30	NRA - Gas Safety	-	0	-	-	-
31	NYS Tax Audit	624	5	(125)	(125)	(125)
32	NYS Tax Rate	(516)	5	103	103	103
33	OPEB Deferral - Remaining Amort (15-E-0283 Appx. V)	(1,070)	5	214	214	214
34	OPEB Deferral - New Amortization	(1,019)	5	204	204	204
35	PBA Utilization	348	5	(70)	(70)	(70)
36	Pension Deferral - Remaining Amort (15-E-0283 Appx. V)	12,971	5	(2,594)	(2,594)	(2,594)
37	Pension Deferral - New Amortization	(1,670)	5	334	334	334
38	Gas Pipeline Integrity Costs - Remaining Amort (15-E-0283 Appx. V)	677	5	(135)	(135)	(135)
39	Gas Pipeline Integrity Costs - New Amortization	(715)	5	143	143	143
40	PRA - Gas Enhancement Performance Incentive	391	5	(78)	(78)	(78)
41	PRA - Terminations & Uncollectibles	132	5	(26)	(26)	(26)
42	Property Tax Deferral - Remaining Amort (15-E-0283 Appx. V)	(18,324)	5	3,665	3,665	3,665
43	Property Tax Deferral - New Amortization	(4,267)	5	853	853	853
44	Property Tax 481(a) - NCR	(151)	5	30	30	30
45	PSC Assessment	(295)	5	59	59	59
46	Purchase of Receivables Discount	1,335	5	(267)	(267)	(267)
47	Gas R&D Deferral - Remaining Amort (15-E-0283 Appx. V)	(135)	5	27	27	27
48	Gas R&D Deferral - New Amortization	(252)	5	50	50	50
49	Gas R&D Tax Credit	(190)	5	38	38	38
50	REV	3	5	(1)	(1)	(1)
51	Sarbanes-Oxley	194	5	(39)	(39)	(39)
52	Service Quality Performance Program - Remaining Amort (15-E-0283 Appx. V)	(415)	5	83	83	83
53	Service Quality Performance Program - New Amortization	(618)	5	124	124	124
54	Unit of Property CTA	232	5	(46)	(46)	(46)
55	Variable Rate Debt - Remaining Amort (15-E-0283 Appx. V)	14	5	(3)	(3)	(3)
56	Variable Rate Debt - New Amortization	543	5	(109)	(109)	(109)
57	Vegetation Management- Remaining Amort (15-E-0283 Appx. V)	(228)	5	46	46	46
58	Vegetation Management- New Amortization	(267)	5	53	53	53
59	Post Term Amortization Deferral - 2010 JP	4,520	5	(904)	(904)	(904)
60	**Subtotal**	**$ (71,672)**		**$ 13,038**	**$ 13,038**	**$ 13,038**
	Income Tax Related Amortizations					
61	Excess DIT - TCJA - Protected Amortization (reflected in Revenue)	$ (67,341)	ARAM	$ 1,289	$ 1,339	$ 1,364
62	Excess DIT - TCJA - Protected Pre-RY1 Liability (reflected in Revenue)	(2,912)	3	971	971	971
63	Excess DIT - TCJA - Unprotected Amortization (reflected in Revenue)	2,946	10	(295)	(295)	(295)
64	Federal Tax Reform - Jan-Sep 2018 Savings Amortization (reflected in Revenue)	(2,173)	1.5	1,449	724	-
65	PowerTax Regulatory Asset	11,510	30	(384)	(384)	(384)
66	Unfunded Future Income Taxes	25,939	46	(564)	(564)	(564)
67	Unfunded Future Income Taxes - NCR	(2,848)	5	570	570	570
68	Subtotal - Income Tax related	**$ (34,880)**		**$ 3,035**	**$ 2,362**	**$ 1,663**
69	**Total - RG&E Gas**	**$ (107,530)**		**$ 16,381**	**$ 15,736**	**$ 15,036**

Rochester Gas and Electric Corporation
Gas Department
Revenue Requirement for Forecast Years Ending April 30, 2021, 2022, 2023
Rate Base Summary Schedule
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
	Rate Base			
1	Utility Plant	$ 1,113,112	$ 1,164,651	$ 1,256,647
2	Depreciation Reserve	(438,878)	(462,390)	(484,993)
3	Materials & Supplies	2,952	3,014	3,077
4	Prepayments	11,482	11,723	11,969
5	O&M Working Capital per the FERC Formula	9,539	10,126	10,533
6	Non Interest Bearing Customer Advances	(9)	(9)	(9)
7	Deferred Debits & Credits	(122,265)	(102,904)	(81,878)
8	Deferred Income Taxes	(63,905)	(70,953)	(79,108)
9	Total Before Earnings Base-Capitalization Adjustment	$ 512,026	$ 553,258	$ 636,237
10	Earnings Base-Capitalization Adjustment	(2,561)	(2,561)	(2,561)
11	**Total**	**$ 509,465**	**$ 550,697**	**$ 633,677**

Rochester Gas and Electric Corporation
Gas Department
Revenue Requirement for Forecast Years Ending April 30, 2021, 2022, 2023
Deferred Debits and Credits
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
	Regulatory Assets & Liabilities:			
1	Bonus Depreciation Deferral	$ (12,866)	$ (10,007)	$ (7,148)
2	Cap Ex NCR 03-G-0766	581	452	323
3	Cost to Achieve Efficiency Initiatives	102	79	57
4	Community Development Fund	(135)	(105)	(75)
5	Credit & Debit Card Fees	1,319	1,026	733
6	Economic Development - Remaining Amort (15-E-0283 Appx. V)	(1,127)	(1,127)	(1,127)
7	Economic Development - New Amortization	(669)	(669)	(669)
8	EE Tracker	(839)	(503)	(168)
9	Energy Efficiency Portfolio Standard - Remaining Amort (15-E-0283 Appx. V)	32	25	18
10	EEPS - New Amortization	(11,154)	(8,676)	(6,197)
11	Environmental - Remaining Amort (15-E-0283 Appx. V)	(8,159)	(6,904)	(5,649)
12	Environmental - New Amortization	(7,066)	(5,979)	(4,892)
13	Excess DIT - New York State Tax Rate change	(756)	(588)	(420)
14	Fixed Rate Debt	(3,841)	(2,988)	(2,134)
15	Gas ESM - Remaining Amort (15-E-0283 Appx. V)	(1,000)	(778)	(556)
16	Gas ESM - New Amortization	(1,642)	(1,277)	(912)
17	Incremental Maintenance - Remaining Amort (15-E-0283 Appx. V)	(240)	(187)	(133)
18	Incremental Maintenance - New Amortization	(479)	(372)	(266)
19	IRS Audit - 1998-2001	(179)	(139)	(100)
20	Low Income Program - Remaining Amort (15-E-0283 Appx. V)	(770)	(599)	(428)
21	Low Income Program - New Amortization	(7,957)	(6,189)	(4,421)
22	Management Audit - Remaining Amort (15-E-0283 Appx. V)	(34)	(27)	(19)
23	Management Audit - New Amortization	33	26	18
24	Medicare Part D	(326)	(254)	(181)
25	Mixed Use 263(a) NCR	(1,427)	(1,110)	(793)
26	Net Plant Reconciliation	(60)	(47)	(33)
27	NRA - Gas Safety	-	-	-
28	NRA - Damage Prevention	(275)	-	-
29	NYS Tax Audit	561	436	312
30	NYS Tax Rate	(464)	(361)	(258)
31	OPEB Deferral - Remaining Amort (15-E-0283 Appx. V)	(963)	(749)	(535)
32	OPEB Deferral - New Amortization	(917)	(713)	(509)
33	PBA Utilization	314	244	174
34	Pension Deferral - Remaining Amort (15-E-0283 Appx. V)	11,674	9,080	6,486
35	Pension Deferral - New Amortization	(1,503)	(1,169)	(835)
36	Gas Pipeline Integrity Costs - Remaining Amort (15-E-0283 Appx. V)	609	474	339
37	Gas Pipeline Integrity Costs - New Amortization	(643)	(500)	(357)
38	PRA - Gas Enhancement Performance Incentive	352	274	196
39	PRA - Leak Prone Main	289	-	-
40	PRA - Terminations & Uncollectibles	119	93	66
41	Property Tax Deferral - Remaining Amort (15-E-0283 Appx. V)	(16,492)	(12,827)	(9,162)
42	Property Tax Deferral - New Amortization	(3,840)	(2,987)	(2,134)
43	Property Tax 481(a) - NCR	(136)	(106)	(76)
44	PSC Assessment	(266)	(207)	(148)
45	Purchase of Receivables Discount	1,202	935	668
46	Gas R&D Deferral - Remaining Amort (15-E-0283 Appx. V)	(122)	(95)	(68)
47	Gas R&D Deferral - New Amortization	(227)	(177)	(126)
48	Gas R&D Tax Credit	(171)	(133)	(95)
49	REV	2	2	1
50	Sarbanes-Oxley	175	136	97
51	Service Quality Performance Program - Remaining Amort (15-E-0283 Appx. V)	(374)	(291)	(208)
52	Service Quality Performance Program - New Amortization	(556)	(432)	(309)
53	Unit of Property CTA	209	162	116
54	Variable Rate Debt - Remaining Amort (15-E-0283 Appx. V)	13	10	7
55	Variable Rate Debt - New Amortization	489	380	272

Rochester Gas and Electric Corporation
Gas Department
Revenue Requirement for Forecast Years Ending April 30, 2021, 2022, 2023
Deferred Debits and Credits
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
56	Vegetation Management- Remaining Amort (15-E-0283 Appx. V)	(205)	(160)	(114)
57	Vegetation Management- New Amortization	(240)	(187)	(133)
58	Post Term Amortization Deferral - 2010 JP	4,068	3,164	2,260
59	Excess DIT - TCJA - Protected Amortization	(66,697)	(65,383)	(64,031)
60	Excess DIT - TCJA - Protected Pre-RY1 Liability	(2,427)	(1,456)	(485)
61	Excess DIT - TCJA - Unprotected Amortization	2,798	2,504	2,209
62	Federal Tax Reform - Jan-Sep 2018 Savings Amortization	(1,449)	(362)	-
63	PowerTax Regulatory Asset	11,318	10,935	10,551
64	Unfunded Future Income Taxes	25,657	25,093	24,529
65	Unfunded Future Income Taxes - NCR	(2,563)	(1,994)	(1,424)
66	Subtotal	$ (99,340)	$ (83,282)	$ (67,896)
	Other Deferred Assets & Liabilities:			
67	FAS-112 Post Employment Benefit Liability	(652)	(652)	(652)
68	Injuries and Damages Reserve	(2,142)	(2,142)	(2,142)
69	Loss on Reacquired Debt	1,412	1,412	1,412
70	Net (Gains)/Losses on Interest Rate Hedges	10,788	10,788	10,788
71	OPEB Reserve	(23,866)	(22,666)	(21,445)
72	Pension Asset	(8,436)	(6,332)	(1,914)
73	PSC Assessment - General	(148)	(148)	(148)
74	Preliminary Survey and Investigation	163	163	163
75	All Other	(45)	(45)	(45)
76	Subtotal	$ (22,925)	$ (19,622)	$ (13,983)
77	**Grand Total**	**$ (122,265)**	**$ (102,904)**	**$ (81,878)**

Key Text Associated with Revenue Requirement

New York State Electric & Gas Corporation – Electric
New York State Electric & Gas Corporation – Gas
Rochester Gas and Electric Corporation – Electric
Rochester Gas and Electric Corporation – Gas

The text provided below is intended to assist in explaining the amounts included in the revenue requirement as depicted in Appendices B through E.

Revenue

1) **Delivery Revenues:** Delivery Revenues reflect the forecast sales, units, customers and revenues for each applicable service class. Delivery revenues changes are provided on Appendix A - Summary Rate Increase Schedule and in detail on Appendices B through E - Revenue Requirements Schedules, Schedule B Revenues. Rate levelization and/or shaping has occurred at all Businesses, i.e., NYSEG Electric, NYSEG Gas, RG&E Electric and RG&E Gas. NYSEG Gas has no increase in Rate Year 1 and RG&E Gas has no increase in Rate Years 1 and 2. The rate levelization deferral is depicted on Schedule B under "Deferrals & Amortizations."

2) **NYSEG Electric Wholesale Transmission Revenues:** Wholesale Transmission Revenues for NYSEG Electric have been set at $49.165 million annually. Any difference between actual transmission revenues and the level embedded in Delivery rates is recovered or returned through the Non-Bypassable Wires Charge (NBC).

3) **NYSEG Electric Excess Depreciation Reserve ("EDR"):** The revenue requirement for NYSEG Electric includes an EDR amortization of $30.85 million in Rate Year 1, $34.95 million in Rate Year 2 and $39.1 million in Rate Year 3. No EDR amortization is included in revenue requirement for each of the remaining Businesses, i.e., NYSEG Gas, RG&E Electric and RG&E Gas. NYSEG will continue to amortize $39.1 million annually beyond RY3 until new rates become effective in a subsequent rate case proceeding.

   In addition, to eliminate the rate compression associated with the make whole period, NYSEG Electric and RG&E Electric will amortize Excess Depreciation Reserve balances to offset the revenue increases associated with the make whole period. These make whole EDR amortization amounts will neither be included in rate base in setting revenue requirements, nor will they accrue carrying costs during the rate plan term.

4) **Other Revenue – Street Lighting:** The revenue requirement includes an update for sales of street lighting assets to municipalities that occurred since the Companies' initial filing forecast and for street lighting sales that have occurred prior to the start of the rate plan.

5) **Energy Efficiency:** The Companies' revenue requirement reflects amounts for Energy Efficiency program and Heat Pump program generally consistent with the January 2020 EE Order and the proposed utilization of unspent funds through 2019. Any difference between

actual energy efficiency costs and the level embedded in delivery rates (including the amounts being collected in a surcharge prior to their inclusion in delivery rates) is fully reconciled. To moderate revenue requirements in Rate Years 1 and 2, for NYSEG Gas, RG&E Electric, and RG&E Gas, the amounts included in the January 2020 EE Order have been reduced by 15%, and at NYSEG Electric the RY1 amount has been reduced by 20%, the RY2 amount by 15%, and the RY3 amount by 10%. These changes do not impact the total 2020 – 2025 EE and Heat Pump budget amounts noted in the January 2020 EE Order. To the extent required, delivery rates would be adjusted in Rate Years 4 and 5 accordingly.

Operation and Maintenance Expenses

6) **Labor / Payroll:** The revenue requirement for all Businesses reflects the labor and payroll amounts as agreed. This item will have a downward reconciliation with carryover as detailed in Appendix U – Labor Reconciliation.

7) **Variable Compensation:** The revenue requirement for all Businesses includes the customer-driven portion of variable compensation.

8) **Productivity:** The Productivity offset embedded in revenue requirement for all Businesses is set at 1.25% in Rate Year 1 and 1.5% in Rate Years 2 and 3 and utilizes a traditional base (labor, variable compensation, 401(k), medical benefits, other employee benefits, OPEBs, Pension, Payroll Taxes and ASC labor and benefits).

9) **Pension:** Pension costs reflect the Companies' actuarial calculation with an expected return on assets of 7.2% beginning in 2020 and then decreasing by 10 basis points per year.

10) **Insurance – NEIL Credits:** The revenue requirement includes NEIL credits based on Historical Test Year amounts received, grown for general inflation. The Companies will defer the difference between the amounts reflected in rates and any actual credits received. The NEIL credit amounts included in the revenue requirement are reflected on Appendix T - Reconciliation Targets.

11) **Avangrid Service Corporation ("ASC") Costs:** The revenue requirement reflects the removal of 100% of Global Mobility costs from test year ASC costs and inclusion of 25% of relocation costs.

12) **Legal and Regulatory Rate Case Costs:** The revenue requirement includes $5.2 million of rate case legal and consultant costs and is being amortized over three years.

13) **Major Electric Storm Cost:** The Major Electric Storm annual rate allowance for NYSEG Electric is $25.582 million and the Major Electric Storm annual rate allowance for RG&E Electric is $3.40 million. NYSEG Electric and RG&E Electric will continue to employ reserve accounting for qualifying major storms as described in Appendix H - Storm Costs Accounting (Major and Minor).

14) **Minor Electric Storm Cost:** The Minor Electric Storm amount included in rates for NYSEG Electric is $3.80 million annually. The RG&E Minor Electric Storm amount included in rates is $1.0 million annually. There is no deferral or reserve accounting for Minor Storm costs.

15) **Pre-staging Storm Costs:** The Companies will defer incremental pre-staging and mobilization costs associated with storms that do not materialize as major storms, with a lower threshold of $0.250 million per event for NYSEG and RG&E and an upper threshold set at $1.5 million per event for NYSEG and $1.25 million per event for RG&E with 85/15 sharing (Reserve/Company) if incremental costs exceed the upper threshold.

16) **Incremental Maintenance Costs:** The revenue requirement reflects the Electric and Gas Incremental Maintenance costs, as adjusted to reflect reduced spending in RY1 in the two gas businesses as part of the COVID-19 efforts to moderate customer impacts, for various initiatives as identified in Appendix T - Reconciliation Targets.

17) **Electric Distribution Vegetation Management Costs:** The agreed upon spending includes Distribution Vegetation Management costs for NYSEG Electric of $57.2 million each Rate Year (inclusive of reclamation costs and a new Danger Tree Program) with downward reconciliation with carryover as described in Appendix I - Electric Distribution and Transmission Vegetation Management and Appendix T – Reconciliation Targets. The RG&E Electric agreed upon spending includes Distribution Vegetation Management costs (normal plus Danger Tree) for RY1 of $9.845 million, RY2 costs of $10.018 million and RY3 costs of $10.196 million with downward reconciliation with carryover as detailed in Appendix I and Appendix T. The Danger Tree costs for each Company are reflected in revenue requirements through an amortization of each rate year's costs over a five year period.

18) **Electric Transmission Vegetation Management Costs:** As detailed in Appendix I, the revenue requirement includes Electric Transmission Vegetation Management costs for NYSEG Electric of $6.395 million for RY1, $6.529 million for RY2 and $6.666 million for RY3. RG&E Electric includes Transmission Vegetation Management costs of $2.176 million for RY1, $2.222 million for RY2 and $2.269 million for RY3.

19) **Environmental Remediation:** The revenue requirement includes an ongoing level of Environmental Remediation costs as shown on Appendices B through E as well as Appendix T. The Companies will continue to utilize reserve accounting for environmental remediation costs.

20) **Economic Development:** The revenue requirement reflects an ongoing level of Economic Development costs. As noted in the Proposal, NYSEG Electric has offset annual costs through an amortization over three years of prior year unspent Economic Development amounts. RG&E annual costs also include an offset through an amortization of $3 million per year of prior year unspent amounts. Economic Development amounts will continue to be symmetrically reconciled. In light of the COVID-19 pandemic, the Companies have included in its portfolio of proposed Economic Development programs a new program that will help

small and large electric business customers. The Economic Development COVID-19 Grant Assistance Program is focused on economic recovery and retention efforts and will be comprised of two sub-programs; a Small Business Customer Program and a Large Business Customer Program. Funding will come from the Companies' proposed levels of economic development spending and will be capped at $2 million per year ($1 million for each Company) under our Small Business Customer Program and up to $4 million per year ($2 million for each Company) under our Large Business Customer Program. Details regarding the eligibility of customers for the programs are set forth in Appendix V.

21) **Low Income Program Costs:** The revenue requirement includes costs for Low Income Program bill reduction costs as detailed in Appendix Q - Low Income Programs. The arrears forgiveness portion of the program has been continued at the levels of funding currently included in delivery rates ($1.5m at NYSEG and $1.13m at RG&E). Any unspent Arrears Forgiveness funding will first be utilized to offset any actual spending which is over the planned amount in the Bill Reduction Program. If there are additional unspent Low Income Program funds at the end of Rate Year 3, these funds will be used to offset the accumulated regulatory asset at each Company related to the provision of the three phases of bill credits (part of COVID-19 provisions). Any overspend for the Low Income Programs will continue to be reconcilable.

22) **Management and Operational Audit Costs:** The Companies have reflected the estimated incremental costs of implementing management audit recommendations from its last management audit in revenue requirements. The Companies will symmetrically reconcile these costs, with an overall cap for deferral of 25% of the amount included. Additionally, the Companies will defer expenses associated with consultants for any management, operations, staffing or other audit initiated by the Commission.

23) **Renewables Integration Study Costs:** The Companies have included a total cap of $250 thousand in revenue requirement for incremental costs related to this study, which would be planned to be complete within one year following the approval of the Joint Proposal. The proposed and final scope of this study will be shared with interested parties to these rate cases, and the scope will reflect the activities being undertaken by the Companies as part of Case 20-E-0197 – "Order on Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act". The completed study shall be filed at the Commission to be noticed and subject to comments. The study should (after consideration of Case 20-E-0197):

   a. be completed for the Companies' service territories through analysis of congestion that may result from planned renewable projects in the NYISO interconnection queue and Article 10 proposals
   b. identify options for upgrading the local transmission system and the cost of those upgrades
   c. reflect benefits including the estimated increase in deliverable renewable power, increased reliability or resiliency and the associated beneficiaries (projects should be ranked according to the estimated benefits relative to the estimated capital cost

d. examine, to the extent possible, potential synergies between the upgrades needed to increase the deliverability of renewable power and the Companies' already planned capital expenditures.

24) **New Studies Costs:** The Companies have included in revenue requirement the cumulative costs for a number of other new studies, with incremental costs capped at $750 thousand across all businesses. The first $250 thousand of NYSEG New Studies costs will be covered by a reallocation of shareholder funds related to the cessation of certain rebate programs as discussed in Appendix M – Gas Matters and Climate Change Initiatives. Refer to Appendix N – Scope of Special Studies for more detail.

25) **Electric and Gas Common Allocation Factors:** The common allocation factors are shown in Appendix GG - Common Allocation Factors.

26) **General Inflation Factors:** The general inflation factors applied to amounts subject to inflationary changes reflect actual inflation through the first quarter of 2020 and the April 10, 2020 Blue Chip forecast. The inflation rate applied to test year costs through the beginning of RY1 is 3.51%, the rate applied from RY1 to RY2 is 1.75%, and the rate applied from RY2 to RY3 is 1.9%.

<u>**Depreciation**</u>

27) **Depreciation:** The revenue requirement reflects the depreciation rates as shown on Appendix Z - Depreciation Factors and Rates. Depreciation rates (lives and salvage rates) to be used by all Businesses, and the plant accounts upon which they will be used, are agreed to as part of this Proposal.

28) **EDR:** The continued amortization of EDR (at updated levels) in the NYSEG Electric Business is shown in Other Revenues. Additionally, as noted in paragraph 3 of this Appendix, NYSEG Electric and RG&E Electric will amortize Excess Depreciation Reserve balances to cover the revenue increase associated with the make whole period.

29) **Beebee and Russell Decommissioning:** The remaining deferred amounts associated with the reconciliation of the estimated total costs with the actual total costs associated with the completion of the decommissioning efforts at both the Beebee and Russell sites are built into RG&E Electric revenue requirements with a 5-year amortization, as noted on Schedule D of Appendix D.

<u>**Operating Taxes**</u>

30) **Property Taxes:** The revenue requirement includes the forecast level of Property Tax expense. The Companies will reconcile property taxes in accordance with the text of the Proposal and with Appendix T – Reconciliation Targets.

Income Taxes

31) **Income Taxes – Tax Cut and Jobs Act:** The revenue requirement of the four Businesses reflects the impacts of these changes as agreed. See Appendix J – Accounting and Tax Matters. Amortization of Excess Protected and Unprotected Deferred Federal Income Tax balances due to the Tax Act are being returned to customers as depicted on Appendix AA.

Capital Structure

32) **Capital Structure:** The revenue requirement includes the utilization of a 48% common equity ratio and a return on equity ratio of 8.8% for all Businesses as detailed on Appendices B through E, Schedule G.

Amortizations

33) **Amortizations:** The revenue requirement for NYSEG Electric and NYSEG Gas includes a number of regulatory amortizations, the majority of which will be amortized over 3 or 5 years as detailed in Appendices B and C, Schedules H and in Appendix AA. The exceptions for NYSEG Electric and NYSEG Gas are Environmental, Storm – Non-Superstorm, Economic Development and Income Tax related items. The revenue requirement for RG&E Electric and RG&E Gas only includes regulatory amortizations, the majority of which will be amortized over 3 or 5 years as detailed in Appendices D and E, Schedules H and Appendix AA. The exceptions for RG&E Electric and RG&E Gas are Economic Development, Environmental and Income Tax Related items. Additionally, RG&E has shaped the ASGA, Bonus Depreciation, Fixed Rate Debt, NRA – Damage Prevention and PRA – Leak Prone Main amortizations.

Rate Base

34) **Rate Base:** The Rate Base amounts utilized in revenue requirement are detailed on Appendices B through E, Schedule I.

Deferred Debits and Credits

35) **Deferred Debits and Credits:** The Deferred Debit and Credit amounts included in revenue requirement are detailed on Appendices B through E, Schedule J.

Calculation of Regulatory Earnings

New York State Electric & Gas Corporation – Electric
New York State Electric & Gas Corporation – Gas
Rochester Gas and Electric Corporation – Electric
Rochester Gas and Electric Corporation – Gas

Overview

For each Rate Year, for purposes of determining whether a Company's regulatory earnings are above the earnings sharing thresholds designated in Section VIII of the Joint Proposal, the calculation of return on common equity capital will start with the "per books" earnings computed from the Company's books of account for each Rate Year. Items that will be adjusted/excluded from the "per books" earnings are listed below.

Excluded Items

- Performance-based revenue adjustments
- EAMs
- Any Commission-approved ratemaking incentives (e.g., NWA/NPA incentives, Company share of favorable property tax deferrals) and revenue adjustments in effect during the applicable Rate Year
- All amounts charged to Other Income and Deductions consistent with the Uniform System of Accounts not considered part of cost of service
- Costs related to non-qualified pension plans
- Allowance for Funds Used During Construction
- Reconciliation deferrals will be adjusted to ensure no doubling of impacts through operation of the deferral mechanism and earnings sharing.

Interest Synchronization

Adjustments to interest expense and associated income taxes relating to the synchronization of interest expense with the capital structure supporting rate base will be reflected in the calculation of regulatory earnings.

Common Equity Ratio

Earnings computations will reflect the lesser of: (i) an equity ratio equal 50%, or (ii) the applicable Company's actual average common equity ratio. The 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.

Post Initial Term

The earnings sharing thresholds for any twelve month period following the expiration of RY3 will continue at RY3 levels until base delivery rates are reset by the Commission.

Reporting

Regulatory earning calculations will be performed on an annual basis in the same manner as set forth above, starting with the twelve months ended April 30, 2021. The Companies shall compute and submit to the Secretary to the Commission the ROE for each Business for the preceding Rate Year within 90 days following the end of each such Rate Year.

Storm Cost Accounting (Major and Minor)

New York State Electric & Gas Corporation – Electric
Rochester Gas and Electric Corporation – Electric

Major Storm Definition

A Major Storm will be defined as a period of adverse weather during which service interruptions affect at least 10% of customers or more and / or results in customers being without electric service for more than 24 hours in an operating district (16 NYCRR Part 97). For any operating district which does not meet the Major Storm definition above, incremental restoration costs related to that operating district will not be eligible for reserve accounting.

Except as otherwise provided herein, once a storm satisfies the Major Storm definition, incremental maintenance costs incurred to restore service as a result of the event must reach a level of at least $750,000 for NYSEG and $500,000 for RG&E in order for expenses related to the adverse weather event to be chargeable to the Major Storm Reserve.

Storm events that do not meet the definition of a Major Storm will be considered a Minor Storm, and no costs associated with restoration related to the Minor Storm would be charged to the Major Storm Reserve, other than incremental pre-staging and mobilization costs that qualify under the thresholds and limits described below.

Annual Allowance

The annual allowance for Major Storms will be $25.6 million for NYSEG and $3.4 million for RG&E. The annual O&M allowance for Minor Storms will be $3.8 million for NYSEG and $1.0 million for RG&E. Major Storm costs will continue to utilize reserve accounting and allow a symmetrical reconciliation. Minor Storm costs will be expensed with no reserve accounting nor reconciliation treatment.

To the extent that either Company incurs incremental Major Storm expenses in excess of the amount accrued in the Major Storm Reserve, that Company will defer those excess expenses for recovery from customers. To the extent that either Company incurs Major Storm expenses less than the amount accrued in the Major Storm Reserve, the Company will defer the variation for future ratepayer benefit.

Deferred Major Storm costs/benefits is one of the items included in NYSEG or RG&E's Rate Adjustment Mechanism ("RAM"). The reserve balance, whether a debit balance or credit balance, will accrue carrying charges as delineated in the discussion of the Companies' RAM in Appendix W.

Calculation of Per Storm Threshold

If a storm meets the primary definition of a Major Storm noted above, the incremental restoration costs for each operating district that meets the Major Storm definition will be totaled and compared to the per storm threshold ($750,000 for NYSEG and $500,000 for RG&E). If the total incremental costs for all Major Storm districts are equal to or greater than the per storm threshold, the restoration costs for those operating districts determined to be major only will be charged to the storm reserve. If the total incremental costs fail to meet the per storm threshold, the storm costs will be considered Minor Storm costs and charged to the appropriate categories of O&M expenses.

Costs Chargeable to the Major Storm Reserve

The following types of incremental restoration costs are appropriately charged to the Major Storm Reserve: incremental labor and the related applicable payroll taxes; and incremental accounts payable. Incremental labor is overtime paid to union and non-union employees, including managers, consistent with current corporate pay policies in conjunction with the storm event. Incremental accounts payable include but are not limited to: tree trimming; mutual aid; other contractor / temporary employees; communication (excluding communication costs for cell phone usage); dry ice; water; lodging; food; miscellaneous employee expenses; transportation expenses that do not originate from the Companies; use taxes; and materials and supplies costs that the Companies would not have incurred except for the Major Storm event.

All incremental costs associated with restoration efforts that occur during a Major Storm and within ten days following the date on which the Company is able to serve all customers after such an event will be charged to the Major Storm Reserve consistent with meeting the thresholds and guidance stated above. The trigger of ten days does not refer to completion or receipt of billing from vendors or mutual aid-providing entities, but rather to the restoration of service to all customers. If incremental restoration efforts take place more than ten days following restoration of the ability to serve all customers, the Companies have the right to petition the Commission for authorization to charge costs related to those efforts to the Major Storm Reserve and these amounts would not be subject to the Commission's traditional "three-prong" deferral test.

Costs Not Chargeable to the Major Storm Reserve

Costs not chargeable against the Major Storm Reserve include: straight-time payroll; fleet costs other than fuel; employee benefits costs; building cleaning expenses; loaders for stores and occupancy; and costs that are appropriately capitalized. Insurance proceeds associated with the storm event should be credited to the reserve. Inter-company regular pay and benefits charged to a sister company and treated as incremental labor by that sister company in conjunction with storm restoration for mutual aid will be credited to the Major Storm Reserve of the entity providing the mutual aid.

Storm Preparation (Pre-Staging and Mobilization) Costs

Each of NYSEG and RG&E are authorized to charge its respective Major Storm Reserves for incremental costs incurred to stage materials and employees in appropriate geographic areas in anticipation of where a storm is expected, and to obtain the assistance of and mobilize contractors and/or utility companies providing mutual assistance in reasonable anticipation that a storm will affect its electric operations to the degree meeting the criteria of a Major Storm, but which event ultimately does not meet the definition of a Major Storm. There are certain thresholds and limits that apply to this authorization to charge the Major Storm Reserve: (1) the incremental pre-staging costs must exceed $250,000 per event; (2) once the minimum threshold is met, 100% of the incremental costs incurred up to a total of $1.5 million (for NYSEG) and $1.25 million (for RG&E) are chargeable to the Major Storm Reserve; (3) if incremental pre-staging and mobilization costs are in excess of $1.50 million (NYSEG) or $1.25 million (RG&E) per event, the relevant Company will be allowed to charge 85% of such excess costs to the Major Storm Reserve, and the Companies will expense 15% of such costs in the year incurred. The Companies may file a petition requesting deferral of the 15% Company share of the excess pre-staging and mobilization costs per event. Each such petition will be subject to the Commission's three-part test traditionally applied to petitions requesting deferral accounting treatment.

The cost to obtain and mobilize contractors and mutual assistance includes the cost of travel to and from locations identified to support NYSEG and/or RG&E. If the incremental pre-staging and mobilization costs for a storm that does not ultimately meet the definition of a Major Storm is less than the $250,000 threshold as described above, the relevant Company will charge the costs to O&M expense.

Reporting Requirements

After each Major Storm event or Pre-Staging event which results in costs charged to the Major Storm Reserve, the Companies shall submit a report with supporting documentation to Staff within 120 days of the such Major Storm or Pre-Staging event. The Companies may update the report within 90 days of providing the initial report on the event to provide any updates to cost or other information. Any additional costs for invoices received which are associated with the event beyond this time will be charged to O&M expense rather than to the Major Storm Reserve, subject to the Companies' right to petition noted in the "Costs Chargeable to the Major Storm Reserve" above.

For each Major Storm or Pre-Staging event, the Companies' report shall provide the following:

1. Information to support that the event qualified as a Major Storm, or did not qualify as a Major Storm in the case of a Pre-Staging event, a summary of total costs of the storm event broken out between expense categories and capital, and further broken down by operating district.
2. Storm number, storm event date and the associated Work Breakdown Structure numbers, and invoices and supporting documentation, including but not limited to:
    a. Excel workpapers
    b. SAP screenshots
    c. Amended vendor contracts
    d. Procurement card statements
    e. Itemized receipts or other supporting documentation for the various incremental cost components (overtime, contractors, materials, employee related costs, and inter-company costs)
    f. Quantification of the number of Full-Time Equivalents used to prepare for expected storm events (internal employees, external contractors and mutual assistance, sister-company employees)

Electric Distribution and Transmission Vegetation Management

New York State Electric & Gas Corporation – Electric
Rochester Gas and Electric Corporation – Electric

NYSEG Electric – Routine Distribution Vegetation Management

NYSEG will utilize the following schedule and Rate Year funding levels for its distribution system routine vegetation management:

NYSEG Routine Distribution	
Year	**Annual Funding Level**
Rate Year 1	$30.0 million
Rate Year 2	$30.0 million
Rate Year 3	$30.0 million

RG&E Electric – Routine Distribution Vegetation Management

RG&E will continue its full-cycle vegetation management trimming for its distribution system and will utilize the following schedule and Rate Year funding levels:

RG&E Routine Distribution	
Year	**Annual Funding Level**
Rate Year 1	$8.3 million
Rate Year 2	$8.4 million
Rate Year 3	$8.6 million

NYSEG Electric – Reclamation Program Distribution Vegetation Management

NYSEG will establish a new Reclamation Program for its distribution system vegetation management utilizing the following schedule and Rate Year funding levels:

NYSEG Reclamation Program	
Year	**Annual Funding Level**
Rate Year 1	$17.2 million
Rate Year 2	$17.2 million
Rate Year 3	$17.2 million

The $17.2 million of incremental distribution vegetation management expenditures associated with the Reclamation Program will be used for the reclamation of circuits that have not been trimmed in over five years in three focused areas: circuits that have the worst total tree System Average Interruption Frequency ("SAIFI") performance (a subset of which is set forth below); three-phase 34.5 kV circuits that have not been trimmed in over five years; and single phase 34.5 kV circuits that have not been trimmed in over five years.

NYSEG Reclamation Program: Circuit Prioritization List			
List	**Division**	**Circuit**	**Kv**
		BEGIN CONFIDENTIAL INFORMATION <	
1	Binghamton	[redacted]	12.5
2	Elmira	[redacted]	12.5
3	Elmira	[redacted]	12.5
4	Ithaca	[redacted]	4.8
5	Lancaster	[redacted]	12.5
6	Lancaster	[redacted]	34.5
7	Lancaster	[redacted]	12.5
8	Lancaster	[redacted]	34.5
9	Lancaster	[redacted]	4.8
10	Lancaster	[redacted]	12.5
11	Liberty	[redacted]	12.5
12	Oneonta	[redacted]	34.5
13	Oneonta	[redacted]	34.5
14	Oneonta	[redacted]	12.5
15	Oneonta	[redacted]	12.5
16	Plattsburgh	[redacted]	34.5
17	Plattsburgh	[redacted]	12.5
		> END CONFIDENTIAL INFORMATION	

NYSEG Electric and RG&E Electric – Danger Tree Programs

NYSEG and RG&E will each establish a new Danger Tree Program for their distribution system vegetation management utilizing the following schedules and Rate Year funding levels:

NYSEG Danger Tree Program	
Year	**Annual Funding Level**
Rate Year 1	$10.0 million
Rate Year 2	$10.0 million
Rate Year 3	$10.0 million

RG&E Danger Tree Program	
Year	**Annual Funding Level**
Rate Year 1	$1.575 million
Rate Year 2	$1.575 million
Rate Year 3	$1.575 million

The new Danger Tree programs will address danger trees outside of each Company's distribution right-of-way, including but not limited to ash trees. Tree removal will focus on the three-phase portions of the Companies' distribution systems to obtain the maximum impact. The revenue requirements reflect the deferral of the spending in each rate year of the above danger tree amounts, with each rate year's spend amount amortized over a five-year period.

Electric Distribution Vegetation Management Reconciliation

NYSEG and RG&E will each track routine distribution vegetation management, danger tree program, and reclamation program (NYSEG only) spending separately. Each program will be subject to a downward-only reconciliation, with carry-forward, as set forth below.

For purposes of the downward-only reconciliation, each Company will calculate any underage in spending for each of the identified distribution vegetation management programs for each Rate Year. If the amount expended by a Company for any of the distribution vegetation management programs is less than the Company's funding level targets, that Company will defer the shortfall for potential use in subsequent rate years.

Electric Distribution Vegetation Management Reporting and Oversight

The Companies will report to the Secretary to the Commission on a quarterly basis (i.e., by March 15th, June 15th, September 15th and December 15th of each year) the prior quarter's distribution vegetation management expenditures. The quarterly reports will include, broken down by month and contractor: the number of miles trimmed; circuit names, numbers, voltage, phase, and locations; danger tree program expenditures; and reclamation program expenditures

(NYSEG only). The quarterly reports will also specify the number of danger trees identified and removed, the species of each danger tree, and the circuit where the danger tree was located.

NYSEG also agrees that it will, after consultation with DPS Staff, hire an independent outside contractor to provide review and oversight of the Company's Vegetation Management program. The costs associated with this outside contractor will be allocated across the three separate programs.

NYSEG Electric – Transmission Vegetation Management

NYSEG's vegetation management trimming for its transmission system will utilize the following schedule and Rate Year funding levels:

Transmission	
Year	**Annual Funding Level**
Rate Year 1	$6.4 million
Rate Year 2	$6.5 million
Rate Year 3	$6.7 million

RG&E Electric – Transmission Vegetation Management

RG&E's vegetation management trimming for its transmission system will utilize the following schedule and Rate Year funding levels:

Transmission	
Year	**Annual Funding Level**
Rate Year 1	$2.2 million
Rate Year 2	$2.2 million
Rate Year 3	$2.3 million

Accounting and Tax Matters

New York State Electric & Gas Corporation – Electric
New York State Electric & Gas Corporation – Gas
Rochester Gas and Electric Corporation – Electric
Rochester Gas and Electric Corporation – Gas

Accounting Matters

Units of Property

New York State Electric & Gas Corporation ("NYSEG") and Rochester Gas and Electric Corporation ("RG&E" and together, the "Companies") will separately identify a generic unit of property (Battery Storage Equipment) for FERC/PSC account 363 to accommodate the implementation of various required energy storage projects. A ten-year depreciation life has been associated with this account, as shown on Appendix Z.

Capitalization of Payments Made to Third-Party Entities

The Companies will capitalize and amortize / depreciate payments made to third-party entities for the installation and upgrade of equipment at facilities owned by these third-party entities when those installations and upgrades are required to support the completion of major capital projects at NYSEG or RG&E. Previously, the Companies' Electric Businesses have treated comparable payments to these entities as an O&M cost. Staff and the Companies agree that the Companies should utilize an alternative accounting approach that capitalizes these types of project payments made to third-party entities when they are in excess of $500,000.

The Companies' Gas Businesses will continue to capitalize payments made to pipeline companies or other third parties for capital project costs consistent with past practice, including avoided capital costs at gate stations and local production taps. The Companies have identified one specific project where RG&E can eliminate a local production tap replacement that would have cost approximately $415,000 with making a payment to a local producer to upgrade their well system at a cost of approximately $130,000.

Gas Mains and Services

The Companies will continue to capitalize, with the cost of new mains, the associated costs to tie existing services to the new mains. The Companies also will capitalize, with the cost of new services, the reconnection of customer house lines when services are replaced or relocated. These costs are not included in the Companies' O&M revenue requirements.

Computer Software Shared by NYSEG and RG&E

To keep the accounting for computer software consistent between the two Companies, in situations where the cost of new or updated software which is shared between NYSEG and RG&E exceeds a $500,000 threshold for one of the two Companies, the software is capitalized at both Companies. This approach has been reflected in the Capital and O&M amounts in this Joint Proposal.

NYSDOT Fiber Optic Permitting

The NYSDOT beginning in 2020 started to demand NYSEG and RG&E pay certain permitting fees associated with capital projects that involve installation of fiber optic cable. Specifically, citing Transportation Corporations Law, Section 7 ("TCL §7"), NYSDOT wants to charge the Companies an annual occupancy and use fee for fiber optic installations within the New York State right-of-way. NYSEG and RG&E disagree with the requirement, as it appears that TCL §7 applies solely to "fiber optic utilities," and not to electric and gas utilities.

However, to the extent NYSDOT's fiber optic use and occupancy fees become necessary, either prospectively or retrospectively, the Companies will (i) capitalize the first-year fee imposed on new projects, as well as fees imposed retroactively on existing installations, and (ii) record the annual fees imposed on these projects in year two and beyond as O&M, subject to the Reconciliation/Deferral provisions identified in section XXIX (M) of the Joint Proposal.

Allowance for Recognition under International Financial Reporting Standards ("IFRS")

To allow for the recognition of assets and liabilities under IFRS accounting similar to those allowed under GAAP, NYSEG and RG&E have the right to receive full compensation or obligation to return certain regulatory deferrals for the Customer Bill Credits, Vegetation Management Danger Tree deferrals and Revenue Decoupling Mechanism Deferrals independent of future demand or other contingent events, including in the event of no longer having a continuation of service.

Nothing in the above paragraph alters the right of the Companies to record regulatory assets and liabilities under Generally Accepted Accounting Principles.

AMI Installation-Related Service Wire Replacements

During the implementation of AMI electric meters, the Companies may find that, for safety reasons, the electric service wire between the meter pan and the residential customer electric panel box should be replaced. The Companies will replace the load-side service wire and charge the respective costs to capital instead of to O&M.

Tax Matters

2017 Tax Cuts and Jobs Act (Tax Act)

The revenue requirement of the four Businesses reflects adjustments associated with the Tax Act, including amortizations of protected and unprotected Excess Accumulated Deferred Income Tax (“ADIT”) balances. The amortization amounts and periods are shown on Appendix AA.

Excess ADITs Related to Pre 2018 balances

The revenue requirement of the four Businesses Areas reflects the refunding of Excess Accumulated Deferred Income. The table below provides the relevant amortization.

Business Area	Protected – Pre Rate Year 1	Protected – Other	Unprotected
NYSEG Electric	1 Year	ARAM	3 Years
NYSEG Gas	3 Years	ARAM	10 Years
RG&E Electric	3 Years	ARAM	3 Years
RG&E Gas	3 Years	ARAM	10 Years

Post 2017 Tax Savings Attributable to the Federal Tax Rate Decrease

NYSEG Electric will amortize the income tax savings attributable to the post 2017 effects of the federal tax rate decrease (from 35 to 21%) over 1 year and NYSEG Gas, RG&E Electric and RG&E Gas will amortize their respective balances over 1.5 years starting from RY1.

PowerTax Regulatory Asset

The revenue requirement of the four Businesses reflects the recovery of the deferred PowerTax regulatory asset. The recovery period is over the residual portion of the average remaining book life for each respective Business determined in Cases 15-E-0283, et.al. Specifically, the NYSEG Electric PowerTax regulatory asset will be amortized over 23 years; the NYSEG Gas PowerTax regulatory asset will be amortized over 35 years; the RG&E Electric PowerTax regulatory asset will be amortized over 35 years; and the RG&E Gas PowerTax regulatory asset will be amortized over 30 years.

On January 11, 2018, in Case 18-M-0013, the Commission initiated a third-party audit of the Companies’ Power Tax and Unfunded Regulatory Asset balances. This audit is still ongoing. Staff and the Companies will work together to resolve any differences. Differences that cannot be resolved will be submitted to the Commission’s Alternative Dispute Resolution process for resolution. The Signatory Parties reserve all of their administrative and judicial rights to take and pursue their respective positions with respect to all issues, rulings, matters and decisions in Case 18-M-0013. Final agreed-upon or Commission-ordered differences resulting from the Staff audit will be applied to the PowerTax Regulatory Asset and amortized over the remaining life.

Normalization and Unfunded Income Tax Regulatory Assets

The revenue requirement of the four Businesses reflects full tax normalization as of May 1, 2016; as adjusted in December 2019 to conform to the requirements of ASC-980-740-25. NYSEG and RG&E are authorized to maintain normalization of all federal and state book / tax temporary differences on their books and records except Equity AFUDC tax effects which will be part of the unfunded deferred tax provision consistent with the treatment prior to the implementation of full normalization. The Companies' revenue requirements treat the Unfunded Income Tax regulatory asset at each Business as began amortization over a 50-year period in the 2016 Rate Plan. Appendix AA illustrates the amortization of the unfunded balances to be over 46 years in this rate plan.

On January 11, 2018, in Case 18-M-0013, the Commission initiated a third-party audit of the Companies' Power Tax and Unfunded Regulatory Asset balances. This audit is still ongoing. Staff and the Companies will work together to resolve any differences. Differences that cannot be resolved will be submitted to the Commission's Alternative Dispute Resolution process for resolution. The Signatory Parties reserve all of their administrative and judicial rights to take and pursue their respective positions with respect to all issues, rulings, matters and decisions in Case 18-M-0013. Final agreed-upon or Commission-ordered differences resulting from the Staff audit will be applied to the Unfunded Income Tax Regulatory Asset and amortized over the remaining life.

Tax Audits

The Companies will defer the revenue requirement impact of all tax expense and associated interest recorded as the result of federal, state and local tax audits.

Electric Reliability Measures

New York State Electric & Gas Corporation – Electric
Rochester Gas and Electric Corporation – Electric

Electric Company Reliability Performance

Beginning in 2020 and continuing until changed by the Commission, should NYSEG Electric or RG&E Electric fail to meet any of the reliability performance targets[1] set forth below during any calendar year, the associated negative electric system reliability revenue adjustment will apply as outlined in the following table:

	Performance Target	Base Revenue Adjustment
Frequency (SAIFI)		
NYSEG		
Minimum Threshold	1.20	$3,500,000
Maximum Threshold	1.26	$7,000,000
RG&E	0.90	$5,000,000
Duration (CAIDI)		
NYSEG		
Minimum Threshold	2.08	$3,500,000
Maximum Threshold	2.18	$7,000,000
RG&E	1.90	$5,000,000

Events Outside of the Companies' Control

Factors beyond the control of the Companies ("Non-Utility Control Outages") could adversely affect the ability of each Company to meet the electric reliability performance measure targets established in this Appendix. Non-Utility Control outages include, but are not limited to, outages due to the following: (1) vandalism; (2) unexpected deforestation (e.g., Emerald Ash Borer); (3) foreign utility supply; (4) motor vehicle accidents; (5) weather; (6) strategic pole hits; (7) disruptions in neighboring utility systems. Accordingly, the Companies do not waive and expressly retain their right to petition the Commission for a waiver, release, or other relief related to a Company's failure to meet the targets set forth in this Appendix as a result of these factors and others beyond the Company's control. The Companies may petition the Commission to request that Non-Utility Control outages be exempt from SAIFI and CAIDI calculations within 45 days after such an outage occurs.

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1 "SAIFI" is System Average Interruption Frequency Index. "CAIDI" is Customer Average Interruption Duration Index.

Distribution Line Inspection ("DLI") Program Metric for Level II Deficiencies

NYSEG and RG&E will also be subject to a negative revenue adjustment ("NRA") of $2.0 million and $1.25 million, respectively, if less than 80 percent of Level II deficiencies (as defined in the Safety Orders in Case 04-M-0159) that are required to be repaired are not permanently repaired as set forth below . This measure is evaluated on a calendar year basis and will be reported in the March 15 Reliability Report identified below.

- Year ended 12/31/2020 – The negative revenue adjustment shall be applied if less than eighty percent (80%) of Level II deficiencies discovered in 2019 that are required to be repaired are not repaired by 12/31/2020.

- Year ended 12/31/2021 – The negative revenue adjustment shall be applied if less than eighty percent (80%) of Level II deficiencies from 2020 findings that are required to be repaired are not repaired on time – AND – if less than ninety seven percent (97%) of Level II deficiencies from 2019 findings and years prior going back to 2012 are not repaired by year ended 12/31/2021.

- Year ended 12/31/2022 – The negative revenue adjustment applies if less than eighty percent (80%) of Level II deficiencies from 2021 findings that are required to be repaired are not repaired on time – AND – if less than ninety seven percent (97%) of Level II deficiencies from 2020 findings and years prior going back to 2012 are not repaired by year ended 12/31/2022.

- The reporting criteria and negative revenue adjustments are to continue annually until modified by the Commission.

- The Companies will continue to provide Staff on a quarterly basis, the Summary of Deficiencies and Repairs Spreadsheet.

Extraordinary Circumstances

Where a Company can demonstrate that extraordinary circumstances prevented it from achieving the target levels for each 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.

Reporting Requirements

By March 15th of each year, each Company shall file with the Secretary to the Commission a report on electric reliability for the prior calendar year period.

Gas Safety Performance Measures

New York State Electric & Gas Corporation – Gas
Rochester Gas and Electric Corporation – Gas

For the Term of the Proposal, beginning in Calendar Year ("CY") 2020 and until changed by the Commission, the Companies shall be subject to the following gas safety performance measures. The Companies will also be subject to negative revenue adjustments ("NRAs") for failing to meet the performance targets described below as well as positive revenue adjustments ("PRAs") for exceeding such targets as set forth below. The gas safety performance measures (and associated NRAs and PRAs) are based on the Commission's rules and regulations in effect as of the signing of this Proposal. Any new rules or regulations would not be included in the determination of any NRAs or PRAs.

Leak Prone Main

Beginning in CY 2020, NYSEG and RG&E will be subject to the following leak prone main mileage targets and associated revenue adjustments:

Leak Prone Main Removal				
		CY 2020	CY 2021	CY 2022
Total	Target (Miles)	< 30	< 30	< 30
	NRA	15	15	15
	Target (Miles)	32 to 32.99 33 to 33.99 34 to 34.99 35 to 35.99 ≥ 36	32 to 32.99 33 to 33.99 34 to 34.99 35 to 35.99 ≥ 36	32 to 32.99 33 to 33.99 34 to 34.99 35 to 35.99 ≥ 36
	PRA	2 4 6 8 10	2 4 6 8 10	2 4 6 8 10
Cumulative	Target (Miles)	< 90		
	NRA	45		

As set forth above, NYSEG and RG&E will replace, at a minimum, the following miles of leak prone main:[1] (1) 30 miles in CY 2020; (2) 30 miles in CY 2021; and (3) 30 miles in CY 2022. If either NYSEG or RG&E fails to meet these annual mileage targets, the applicable Company will incur an NRA of 15 basis points.

[1] NYSEG and RG&E may include Distribution Integrity Management Plan pre-1971 wrapped steel to meet the Leak Prone Pipe annual mileage target provided that the applicable Company provides adequate justification and supporting documentation to Staff.

If the annual mileage target is not met in either CY 2020, 2021 or 2022, then a 3-year cumulative target of 90 miles can be used as the target. If the 3-year cumulative target is being utilized as the annual mileage target, then a combined NRA of 45 basis points will be incurred if the target is not met.

The annual leak prone pipe mileage targets will continue for future calendar years at the same levels identified for CY 2022 until changed by the Commission.

Beginning in CY 2020, in the event NYSEG or RG&E replaces or eliminates Leak Prone Main in excess of their mileage targets and associated mileage buffer (i.e., 32 miles), for each full mile in excess of the applicable target, the Company shall receive a PRA of 2 basis points per additional mile,[2] capped at a maximum of 5 miles (i.e., 10 basis points) per calendar year which the Companies will defer for future recovery. This positive incentive mechanism will continue until changed by the Commission. For the avoidance of doubt, the Companies are expressly authorized to include Leak Prone Main eliminations (abandonment, disuse or any other method that terminates use of the Leak Prone Main while still serving the customer, including but not limited to Non-Pipe Alternatives implemented in lieu of Leak Prone Main replacements) in this deferral mechanism.

NYSEG and RG&E will continue to inspect all newly-installed pipelines to ensure that they are completed in accordance with applicable procedures and regulations. The Companies' on-site inspection efforts will be commensurate with their LPP removal targets to ensure that the quality of pipe going into service meets current workmanship and installation standards.

Leak Backlog Management

Beginning in CY 2020, NYSEG and RG&E will be subject to the following leak backlog management targets and associated revenue adjustments:

Leak Management				
		CY 2020	CY 2021	CY 2022
Total	Target (Leaks)	> 50	> 50	> 50
	NRA	15	15	15
	Target (Leaks)	11 to 20 3 to 10 0 to 3	11 to 20 3 to 10 0 to 3	11 to 20 3 to 10 0 to 3
	PRA	2 4 6	2 4 6	2 4 6

2 For example, 32.99 leak prone pipe miles replaced will result in a PRA of 2 basis points.

The year-end total leak backlog (Types 1, 2, 2A and 3) target for each Company in CY 2020, 2021 and 2022 is 50 leaks. If the year-end total leak backlog exceeds this target, the Company will incur an NRA of 15 basis points.

If the year-end total leak backlog for either RG&E or NYSEG is between: 11-20 leaks (inclusive), the Company will incur a PRA of 2 basis points; 3-10 leaks, the Company will incur a PRA of 4 basis points; and 0-3 leaks, the Company will incur a PRA of 6 basis points.

Targets for total leak backlogs can be met at any point from December 21 to December 31 of each CY. For Type 1, 2 and 2A leak repairs the Companies must conduct a follow-up inspection between 14 and 30 days following the repair date to validate the repair before the elimination of a leak will be considered a valid leak repair for purposes of this metric. Consistent with applicable DPS regulations, 14 to 30 day rechecks are not required for Type 3 leak repairs and thus the Companies are not required to conduct 14-30 day rechecks before a Type 3 leak repair is considered a valid repair for purposes of this metric. Leaks failing recheck will be included in the backlog for the CY the repair was completed.

Emergency Response

Beginning in CY 2020, NYSEG and RG&E will be subject to the following emergency response targets and associated NRAs:

Emergency Response Times				
		CY 2020	CY 2021	CY 2022
30 Minute	Target (%)	< 75	< 75	< 75
	NRA	12	12	12
45 Minute	Target (%)	< 90	< 90	< 90
	NRA	8	8	8
60 Minute	Target (%)	< 95	< 95	< 95
	NRA	5	5	5

As set forth above, for CY 2020, 2021 and 2022, NYSEG and RG&E will respond to:

(1) 75% of all gas leak and odor calls within 30 minutes each calendar year. If NYSEG or RG&E fails to meet this target, it will incur a 12-basis point NRA.
(2) 90% of all gas leak and odor calls within 45 minutes each calendar year. If NYSEG or RG&E fails to meet this target, it will incur an 8-basis point NRA.
(3) 95% of all gas leak and odor calls within 60 minutes each calendar year. If NYSEG or RG&E fails to meet this target, it will incur a 5-basis point NRA.

Gas leak and odor calls resulting from mass area odor complaints, major weather-related occurrences and major equipment failure can be excluded from this performance measure provided the exclusions are approved by the Commission.

Gas Safety Violations Performance Measure

NYSEG and RG&E will incur an NRA for instances of noncompliance (occurrences) of certain pipeline safety regulations, set forth in 16 NYCRR Parts 255 and 261 (see Schedule 1 of this Appendix), as identified during Staff's annual field and record audits. This Appendix sets forth a list of identified "High Risk" and "Other Risk" pipeline safety regulations pertaining to this metric. Each Company will be assessed an NRA for High Risk or Other Risk occurrences up to a combined maximum of 75 basis points per CY as set forth below:

Compliance				
		CY 2020	CY 2021	CY 2022
High Risk	Target	6 to 20 (Record) > 20 (Record) 1 to 20 (Field) > 20 (Field)	6 to 20 (Record) > 20 (Record) 1 to 20 (Field) > 20 (Field)	6 to 20 (Record) > 20 (Record) 1 to 20 (Field) > 20 (Field)
	NRA	0.5 1 0.5 1	0.5 1 0.5 1	0.5 1 0.5 1
Other Risk	Target	> 15 (Record) > 0 (Field)	> 15 (Record) > 0 (Field)	> 15 (Record) > 0 (Field)
	NRA	0.25 0.25	0.25 0.25	0.25 0.25

The NRA described above will be capped at 10 violations per section of the Commission's pipeline safety regulations subject to this performance measure as listed in this Appendix. 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 Proposal will constitute an occurrence under the metric.

Should either NYSEG or RG&E incur more than 10 violations of a single code section, the Company will be required to file a remediation plan that explains how it will address and resolve the compliance issues, including the dates by which all cited violations will be brought into compliance or, where appropriate, when remedial actions will be taken to mitigate recurrence. A remediation plan in this context may consist of identified corrective actions as part of the Companies' written response to an audit finding report, a formalized plan developed in conjunction with Staff or equivalent. The filing will be made within 90 days of Staff's audit letter discussed below. Should either NYSEG or RG&E fail to comply with their implementation plan, those violations of a given code section in excess of 10 will be included with the remainder of the violations being considered for the compliance measure.

This metric will be measured on a calendar year basis and will become effective January 1, 2020 (meaning, therefore, the 2021 audit of CY 2020 will be the first applicable audit for these targets). At the conclusion of each audit, Staff will conduct a compliance meeting with the Companies where Staff will present its findings to the Companies. The Companies will have ten business days from the date the audit findings are presented to cure any identified document deficiency. Only official NYSEG and / or RG&E records, as defined in the Companies' Operating and Maintenance plan, will be considered by Staff as a cure to a document deficiency.

Staff will submit its final audit report to the Secretary to the Commission. If the Companies dispute any of Staff's final audit results including, but not limited to, the counting of violations that encompass more than one code section towards this metric or violations of common procedures, construction standards, or practices, the Companies may appeal Staff's finding[s] to the Commission. The Companies will not incur an NRA on the contested finding[s] until such time as the Commission has issued a final decision on the contested finding[s]. The Companies do not waive their right to seek an appeal of any Commission determination regarding a violation or penalty under applicable law.

If an alleged High Risk or Other Risk violation set forth in this appendix is the subject of a separate penalty proceeding by the Commission under PSL Section 25 or 25-a, that instance will not constitute an occurrence under this performance metric.

Damage Prevention

Beginning in CY 2020, NYSEG and RG&E will be subject to the following damage prevention targets and associated NRAs:

Damage Prevention				
		CY 2020	CY 2021	CY 2022
Total	Target (Rate)	> 2.50 2.26 to 2.50 2.01 to 2.25	> 2.50 2.26 to 2.50 2.01 to 2.25	> 2.50 2.26 to 2.50 2.01 to 2.25
	NRA	20 10 5	20 10 5	20 10 5

All damages will be tracked, measured and counted following the guidelines for the data reported for the annual gas safety performance measures report.

Events Outside of the Companies' Control

Factors beyond the control of the Companies could adversely affect the ability of each Company to meet the gas safety performance measure targets established in this Appendix. Examples of such factors could include but are not limited to: weather; contractor damage to pipelines; or disruptions in neighboring utility systems; and epidemics/pandemics. Accordingly, the Companies do not waive and expressly retain their right to petition the Commission for a waiver, release, or other relief related to a Company's failure to meet the targets set forth in this

Appendix as a result of factors beyond the Company's control. The Companies may petition the Commission for relief within 45 days after such an event occurs.[3]

Reporting Requirements

Within sixty (60) days of the end of each calendar year, each Company shall file with the Secretary to the Commission a report on gas safety performance for the prior calendar year period. With respect to leak prone main projects, these reports will include material type, mileage, project location, rank of the segments addressed at the time of replacement, removal or retirement in place (e.g., due to NPA solution) using the risk-based model, project cost, and a forecast of the scheduled leak prone main removal projects and their rank on the risk-based model for the upcoming calendar year. The report will also include a reconciliation of proposed versus actual leak prone mains.

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3 As an example, on April 8, 2020, in Case 20-G-0140, Joseph Suich, Director of the Office of Investigations and Enforcement, granted in part and with certain conditions, the New York LDC's proposal for enforcement discretion and the Companies submitted a letter on May 1, 2020 outlining the plan and indicating the relief sought.

HIGH RISK SECTIONS PART 255		
ACTIVITY TITLE	CODE SECTION	RISK FACTOR
Material - General	255.53(a),(b),(c)	HIGH
Transportation of Pipe	255.65	HIGH
Pipe Design - General	255.103	HIGH
Design of Components - General Requirements	255.143	HIGH
Design of Components - Flexibility	255.159	HIGH
Design of Components - Supports and anchors	255.161	HIGH
Compressor Stations: Emergency shutdown	255.167	HIGH
Compressor Stations: Pressure limiting devices	255.169	HIGH
Compressor Stations: Ventilation	255.173	HIGH
Valves on pipelines to operate at 125 psig or more	255.179	HIGH
Distribution line valves	255.181	HIGH
Vaults: Structural Design requirements	255.183	HIGH
Vaults: Drainage and waterproofing	255.189	HIGH
Protection against accidental overpressuring	255.195	HIGH
Control of the pressure of gas delivered from high pressure distribution systems	255.197	HIGH
Requirements for design of pressure relief and limiting devices	255.199	HIGH
Required capacity of pressure relieving and limiting stations	255.201	HIGH
Qualification of welding procedures	255.225	HIGH
Qualification of Welders	255.227	HIGH
Protection from weather	255.231	HIGH
Miter Joints	255.233	HIGH
Preparation for welding	255.235	HIGH
Inspection and test of welds	255.241(a),(b)	HIGH
Nondestructive testing-Pipeline to operate at 125 PSIG or more	255.243(a)-(e)	HIGH
Welding inspector	255.244(a),(b),(c)	HIGH
Repair or removal of defects	255.245	HIGH
Joining Of Materials Other Than By Welding - General	255.273	HIGH
Joining Of Materials Other Than By Welding - Copper Pipe	255.279	HIGH
Joining Of Materials Other Than By Welding - Plastic Pipe	255.281	HIGH
Plastic pipe: Qualifying persons to make joints	255.285(a),(b),(d)	HIGH
Notification requirements	255.302	HIGH
Compliance with construction standards	255.303	HIGH
Inspection: General	255.305	HIGH
Inspection of materials	255.307	HIGH
Repair of steel pipe	255.309	HIGH
Repair of plastic pipe	255.311	HIGH
Bends and elbows	255.313(a),(b),(c)	HIGH
Wrinkle bends in steel pipe	255.315	HIGH
Installation of plastic pipe	255.321	HIGH
Underground clearance	255.325	HIGH
Customer meters and service regulators: Installation	255.357(d)	HIGH
Service lines: Installation	255.361(e),(f),(g),(h),(i)	HIGH
Service lines: Location of valves	255.365(b)	HIGH
External corrosion control: Buried or submerged pipelines installed after July 31, 1971	255.455(d),(e)	HIGH
External corrosion control: Buried or submerged pipelines installed before August 1, 1971	255.457	HIGH
External corrosion control: Protective coating	255.461(c)	HIGH
External corrosion control: Cathodic protection	255.463	HIGH
External corrosion control: Monitoring	255.465(a),(e)	HIGH
Internal corrosion control: Design and construction of transmission line	255.476(a),(c)	HIGH
Remedial measures: General	255.483	HIGH
Remedial measures: transmission lines	255.485(a),(b)	HIGH
Strength test requirements for steel pipelines to operate at 125 PSIG or more	255.505(a),(b),(c),(d)	HIGH
General requirements (UPGRADES)	255.553 (a),(b),(c),(f)	HIGH
Upgrading to a pressure of 125 PSIG or more in steel pipelines	255.555	HIGH
Upgrading to a pressure less than 125 PSIG	255.557	HIGH
Conversion to service subject to this Part	255.559(a)	HIGH
General provisions	255.603	HIGH
Operator Qualification	255.604	HIGH
Essentials of operating and maintenance plan	255.605	HIGH
Change in class location: Required study	255.609	HIGH
Damage prevention program	255.614	HIGH
Emergency Plans	255.615	HIGH

Customer education and information program	255.616	HIGH
Maximum allowable operating pressure: Steel or plastic pipelines	255.619	HIGH
Maximum allowable operating pressure: High pressure distribution systems	255.621	HIGH
Maximum and minimum allowable operating pressure: Low pressure distribution systems	255.623	HIGH
Odorization of gas	255.625(a),(b)	HIGH
Tapping pipelines under pressure	255.627	HIGH
Purging of pipelines	255.629	HIGH
Control Room Management	255.631(a)	HIGH
Transmission lines: Patrolling	255.705	HIGH
Leakage Surveys - Transmission	255.706	HIGH
Transmission lines: General requirements for repair procedures	255.711	HIGH
Transmission lines: Permanent field repair of imperfections and damages	255.713	HIGH
Transmission lines: Permanent field repair of welds	255.715	HIGH
Transmission lines: Permanent field repair of leaks	255.717	HIGH
Transmission lines: Testing of repairs	255.719	HIGH
Distribution systems: Leak surveys and procedures	255.723	HIGH
Compressor stations: procedures	255.729	HIGH
Compressor stations: Inspection and testing relief devices	255.731	HIGH
Compressor stations: Additional inspections	255.732	HIGH
Compressor stations: Gas detection	255.736	HIGH
Pressure limiting and regulating stations: Inspection and testing	255.739(a),(b)	HIGH
Regulator Station Overpressure Protection	255.743(a),(b)	HIGH
Transmission Line Valves	255.745	HIGH
Prevention of accidental ignition	255.751	HIGH
Protecting cast iron pipelines	255.755	HIGH
Replacement of exposed or undermined cast iron piping	255.756	HIGH
Replacement of cast iron mains paralleling excavations	255.757	HIGH
Leaks: Records	255.807(d)	HIGH
Leaks: Instrument sensitivity verification	255.809	HIGH
Leaks: Type 1	255.811(b),(c),(d),(e)	HIGH
Leaks: Type 2A	255.813(b),(c),(d)	HIGH
Leaks: Type 2	255.815(b),(c),(d)	HIGH
Leak Follow-up	255.819(a)	HIGH
High Consequence Areas	255.905	HIGH
Required Elements (IMP)	255.911	HIGH
Knowledge and Training (IMP)	255.915	HIGH
Identification of Potential Threats to Pipeline Integrity and Use of the Threat Identification in an Integrity Program (IMP)	255.917	HIGH
Baseline Assessment Plan(IMP)	255.919	HIGH
Conducting a Baseline Assessment (IMP)	255.921	HIGH
Direct Assessment (IMP)	255.923	HIGH
External Corrosion Direct Assessment (ECDA) (IMP)	255.925	HIGH
Internal Corrosion Direct Assessment (ICDA) (IMP)	255.927	HIGH
Confirmatory Direct Assessment (CDA) (IMP)	255.931	HIGH
Addressing Integrity Issues (IMP)	255.933	HIGH
Preventive and Mitigative Measures to Protect the High Consequence Areas (IMP)	255.935	HIGH
Continual Process of Evaluation and Assessment (IMP)	255.937	HIGH
Reassessment Intervals (IMP)	255.939	HIGH
General requirements of a GDPIM plan	255.1003	HIGH
Implementation requirements of a GDPIM plan.	255.1005	HIGH
Required elements of a GDPIM plan.	255.1007	HIGH
Required report when compression couplings fail.	255.1009	HIGH
Requirements a small liquefied petroleum gas (LPG) operator must satisfy to implement a GDPIM plan	255.1015	HIGH

HIGH RISK SECTIONS PART 261		
Operation and maintenance plan	261.15	HIGH
Leakage Survey	261.17(a),(c)	HIGH
Carbon monoxide prevention	261.21	HIGH
Warning tag procedures	261.51	HIGH
HEFPA Liaison	261.53	HIGH
Warning Tag Inspection	261.55	HIGH
Warning tag: Class A condition	261.57	HIGH
Warning tag: Class B condition	261.59	HIGH

OTHER RISK SECTIONS PART 255		
ACTIVITY TITLE	CODE SECTION	RISK FACTOR
Preservation of records	255.17	OTH
Compressor station: Design and construction	255.163	OTH
Compressor station: Liquid removal	255.165	OTH
Compressor stations: Additional safety equipment	255.171	OTH
Vaults: Accessibility	255.185	OTH
Vaults: Sealing, venting, and ventilation	255.187	OTH
Calorimeter or calorimeter structures	255.190	OTH
Design pressure of plastic fittings	255.191	OTH
Valve installtion in plastic pipe	255.193	OTH
Instrument, control, and sampling piping and components	255.203	OTH
Limitations On Welders	255.229	OTH
Quality assurance program	255.230	OTH
Preheating	255.237	OTH
Stress relieving	255.239	OTH
Inspection and test of welds	255.241(c)	OTH
Nondestructive testing-Pipeline to operate at 125 PSIG or more	255.243(f)	OTH
Plastic pipe: Qualifying joining procedures	255.283	OTH
Plastic pipe: Qualifying persons to make joints	255.285(c)(e)	OTH
Plastic pipe: Inspection of joints	255.287	OTH
Bends and elbows	255.313(d)	OTH
Protection from hazards	255.317	OTH
Installation of pipe in a ditch	255.319	OTH
Casing	255.323	OTH
Cover	255.327	OTH
Customer meters and regulators: Location	255.353	OTH
Customer meters and regulators: Protection from damage	255.355	OTH
Customer meters and service regulators: Installation	255.357(a)-(c)	OTH
Customer meter installations: Operating pressure	255.359	OTH
Service lines: Installation	255.361(a), (b), (c), (d)	OTH
Service lines: valve requirements	255.363	OTH
Service lines: Location of valves	255.365(a), (c)	OTH
Service lines: General requirements for connections to main piping	255.367	OTH
Service lines: Connections to cast iron or ductile iron mains	255.369	OTH
Service lines: Steel	255.371	OTH
Service lines: Cast iron and ductile iron	255.373	OTH
Service lines: Plastic	255.375	OTH
Service lines: Copper	255.377	OTH
New service lines not in use	255.379	OTH
Service lines: excess flow valve performance standards	255.381	OTH
External corrosion control: Buried or submerged pipelines installed after July 31, 1971	255.455 (a)	OTH
External corrosion control: Examination of buried pipeline when exposed	255.459	OTH
External corrosion control: Protective coating	255.461(a), (b), (d), (e), (f), (g)	OTH
External corrosion control: Monitoring	255.465 (b)(c)(d)(f)	OTH
External corrosion control: Electrical isolation	255.467	OTH
External corrosion control: Test stations	255.469	OTH
External corrosion control: Test lead	255.471	OTH
External corrosion control: Interference currents	255.473	OTH
Internal corrosion control: General	255.475(a)(b)	OTH
Atmospheric corrosion control: General	255.479	OTH
Atmospheric corrosion control: Monitoring	255.481	OTH
Remedial measures: transmission lines	255.485(c)	OTH
Remedial measures: Pipelines lines other than cast iron or ductile iron lines	255.487	OTH
Remedial measures: Cast iron and ductile iron pipelines	255.489	OTH
Direct Assessment	255.490	OTH
Corrosion control records	255.491	OTH
General requirements (TESTING)	255.503	OTH
Strength test requirements for steel pipelines to operate at 125 PSIG or more	255.505 (e),(h), (i)	OTH
Test requirements for pipelines to operate at less than 125 PSIG	255.507	OTH
Test requirements for service lines	255.511	OTH
Environmental protection and safety requirements	255.515	OTH
Records (TESTING)	255.517	OTH
Notification requirements (UPGRADES)	255.552	OTH
General requirements (UPGRADES)	255.553 (d)(e)	OTH
Conversion to service subject to this Part	255.559(b)	OTH

Change in class location: Confirmation or revision of maximum allowable operating pressure	255.611(a), (d)	OTH
Continuing surveillance	255.613	OTH
Odorization	255.625 (e)(f)	OTH
Pipeline Markers	255.707(a),(c),(d),(e)	OTH
Transmission lines: Record keeping	255.709	OTH
Distribution systems: Patrolling	255.721(b)	OTH
Test requirements for reinstating service lines	255.725	OTH
Inactive Services	255.726	OTH
Abandonment or inactivation of facilities	255.727(b)-(g)	OTH
Compressor stations: storage of combustible materials	255.735	OTH
Pressure limiting and regulating stations: Inspection and testing	255.739 (c), (d)	OTH
Pressure limiting and regulating stations: Telemetering or recording gauges	255.741	OTH
Regulator Station MAOP	255.743 (c)	OTH
Service Regulator - Min.& Oper. Load, Vents	255.744	OTH
Distribution Line Valves	255.747	OTH
Valve maintenance: Service line valves	255.748	OTH
Regulator Station Vaults	255.749	OTH
Caulked bell and spigot joints	255.753	OTH
Reports of accidents	255.801	OTH
Emergency lists of operator personnel	255.803	OTH
Leaks General	255.805 (a), (b), (e), (g), (h)	OTH
Leaks: Records	255.807(a)-(c)	OTH
Type 3	255.817	OTH
Interruptions of service	255.823 (a)-(b)	OTH
Logging and analysis of gas emergency reports	255.825	OTH
Annual Report	255.829	OTH
Reporting safety-related conditions	255.831	OTH
General (IMP)	255.907	OTH
Changes to an Integrity Management Program (IMP)	255.909	OTH
Low Stress Reassessment (IMP)	255.941	OTH
Measuring Program Effectiveness (IMP)	255.945	OTH
Records (IMP)	255.947	OTH
Records an operator must keep	255.1011	OTH

OTHER RISK SECTIONS PART 261		
High Pressure Piping - Annual Notice	261.19	OTH
Warning tag: Class C condition	261.61	OTH
Warning tag: Action and follow-up	261.63(a)-(h)	OTH
Warning Tag Records	261.65	OTH

Natural Gas Matters

New York State Electric & Gas Corporation – Gas
Rochester Gas and Electric Corporation – Gas

The following represents a listing of the Companies' commitments regarding their natural gas business and related to climate change.

1. The Companies will structure their gas planning with the objective of achieving a zero-net increase in billed gas use, normalized for temperature, in their service territories over the three-year term of these rate proceedings. For the purpose of this Joint Proposal, achieving a zero-net increase in billed gas use shall mean that the weather-normalized levels of billed gas use for NYSEG and RG&E each in RY2 and in RY3 do not exceed the forecasted levels of gas use in RY1 (56,037,087 Dths for NYSEG and 58,545,147 Dths for RG&E). The Companies shall calculate BTU's of savings required to offset forecasted increases in gas use within RY2 and RY3, and will pursue targeted heat pump programs, district heating projects, building efficiency upgrades, non-gas NPA projects, and other initiatives as needed to offset those increases.

   In addition, NYSEG will structure its gas planning with the objective of achieving a zero-net increase in gas use, normalized for temperature, for customers served by the DeRuyter pipeline over the three-year term of this rate case. NYSEG will identify areas served by the DeRuyter pipeline and its distribution network that are most likely to request load growth or expansion and will also identify areas of the DeRuyter pipeline and its distribution network that may be considered for replacement. The Companies will seek out and pursue opportunities for reducing gas demand in the identified areas through projects that may include targeted heat pump programs, district heating projects, building efficiency upgrades, non-gas NPA projects , and other initiatives. For the purpose of this Joint Proposal, achieving a zero-net increase in gas use for the DeRuyter pipeline shall mean that the weather-normalized volume of gas flow to the DeRuyter pipeline from Dominion Transmission, Inc. ("Dominion") for each May through April twelve-month period during the term of the rate plan does not exceed the weather-normalized volume of gas flow to the DeRuyter pipeline from Dominion for the twelve-month period of May 2018 through April 2019 (2,187,969 Dths).

2. The Companies agree to provide quarterly reports (on a calendar quarter basis) starting with the first full calendar quarter following approval of the Joint Proposal to measure progress on the objectives set forth above. These reports will be provided within thirty (30) days after the end of each calendar quarter and will include volumes of actual billed gas use, and volumes of billed gas use normalized for temperature. The reports will identify monthly billed use by sector (residential, commercial and industrial) for each Company, and will track natural gas customer counts and include net change in natural gas customers by month and will also report billed gas use and customer counts associated with the DeRuyter pipeline. To the extent the information is available, on a monthly basis, the reports will also track customer use of heat pump and building efficiency incentives by replaced fuel type as applicable (new construction or oil, natural gas, propane, etc), as well as BTU's of energy saved with heat pump and building efficiency incentives by replaced fuel type as applicable. For reference,

the first issuance of these reports shall also provide data for 2019.
Finally, NYSEG and RG&E will be tracking and reporting heat pump information in the Statewide Heat Pump Program Annual Report filed each April 1st, as required by Case 18-M-0084 - In the Matter of a Comprehensive Energy Efficiency Initiative.

3. Several Parties to this Rate Case have expressed that with the passage of the Climate Leadership and Community Protection Act (CLCPA) it is important to proactively evaluate issues and potential strategies for reducing natural gas usage and increasing electricity usage as an alternative. In response, the Companies agree that within eighteen months of a Commission Order approving the Joint Proposal in these rate cases, the Companies will prepare a report that evaluates how the Companies' businesses may evolve in the decades ahead and which identifies the potential issues and strategies related to reducing natural gas usage and increasing electricity usage as an alternative and the modernization and expansion of the electric grid needed to support the widespread deployment of renewables and beneficial electrification. The report shall be developed in light of the renewable energy and greenhouse gas reductions goals set forth by the CLCPA. The report shall provide a meaningful analysis of the scale, timing, and costs of achieving significant, quantifiable reductions in gas use, grid improvements necessary to achieve various levels of renewables deployment and beneficial electrification, and potential financing mechanisms. Interested parties to the rate case proceeding shall be invited to provide input to the scope of the study.

   The Parties recognize that duplication of efforts in this area is not in anyone's interest. If the Commission requires the Companies to participate in a similar statewide study or initiative within eighteen months from the date of the Order, the Companies will not prepare or provide a separate report. The Companies will continue to produce their own report for any items not included in the statewide study or initiative, with funding reduced proportionally. The Companies anticipate that the studies identified in paragraphs 3 and 11 will utilize the majority ($400k-$500k) of the total of funds to be used for Studies ($750k) as identified elsewhere in the Joint Proposal.

4. No future funding for building the Lansing Pipeline is provided within the capital budget for the term of the rate plan. This includes capital funding for planning, engineering, permitting, or construction. Prior expenditures made on the Lansing Project will be included in the Companies' rate base and will be recovered through an amortization over the same period as any NPA done in the area.

5. No future funding for the replacement or expansion of the DeRuyter Pipeline is provided within the capital budget for the term of the rate plan. This includes capital funding for planning, engineering, permitting, or construction.[1] Prior expenditures made on the DeRuyter Project will be included in the Companies' rate base and will be recovered through an amortization over the same period as any NPA done in the area.

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[1] The Commitments herein with respect to the Lansing and DeRuyter pipelines will not restrict or limit the Companies from taking measures, including making capital investments, necessary to comply with all laws, rules, regulations or Orders of the Commission or other applicable agency or to protect the integrity of the pipelines or in the event of an emergency as determined by the Companies.

NYSEG will not file an Article VII Application related to the DeRuyter Pipeline or the Lansing Pipeline during the term of the rate plan.

6. In direct response to notification from one of the parties regarding a natural gas promotional video on the Companies' websites, the Companies agreed to remove the video. The video was removed in December 2019.

7. No later than twelve months from receiving a Commission Order adopting the Joint Proposal, the Companies will modify their websites, customer mailings, emails, and marketing material to remove promotion of natural gas. Modifications shall include replacement of the "convert to gas" link with a link that describes programs and incentives available to customers for opportunities to reduce gas use or consider alternate forms of energy consumption and as soon as can be achieved, discontinuation of the use of the phrase "heat smart" in connection with the promotion of natural gas use. The Companies will also provide information about NYSERDA sponsored on-bill financing when providing information about energy efficiency programs and heat pumps.

   The Companies commit to develop programs that better inform and encourage customers to consult with organizations such as HeatSmart to make more informed energy choices. The Companies will meet during RY1 with NYSERDA and its HeatSmart partners within the Companies' service territories to discuss advancement of heat pumps and building efficiency efforts. These meetings will include:

   - Discussion with relevant non-profits and information sharing;
   - How best to include on the Companies' websites appropriate links to HeatSmart campaigns, as well as links to HeatSmart event information and schedules;
   - Inclusion on the Companies' websites of information for customers to understand the process of converting to heat pump use;
   - Discussion about available energy use data, including Energy Star and Source EUI; and
   - Discussion of specific measures to facilitate customer decision making in choosing to convert to heat pumps and/or invest in building efficiencies.

8. NYSEG's Tariff will be amended to make gas interruptible rates available to all eligible gas customers in its entire service territory.

9. The Companies will increase the number of electric and hybrid vehicles in the Companies' fleet. NYSEG and RG&E would each add five fully electric vehicles to their fleet per year for the period 2020 through 2023. In addition, RG&E will begin a program to increase the number of hybrid bucket trucks and plans to add the first of these during the first rate year and will evaluate future additions.

10. The Companies will complete and file a study with the Commission by December 31, 2021, on the potential depreciation impacts of climate change policies and laws on its gas, electric and common assets. The Companies will use calendar 2020 information for the study and it

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 to help inform the Companies' next base rate filing.

11. Within RY1, the Companies 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 Companies' service territory, and to develop plans for subsequent pilot projects where feasible, including but not limited to those areas with existing leak prone pipe. The study will include, but not be limited to, sites in Monroe, Tompkins, Chenango, and Otsego counties. At the conclusion of the study, the Companies will make a filing to the Commission, including recommendations for advancing pilot projects of various types and sizes, along with related cost recovery approaches.

12. The Companies will modify their natural gas tariffs to provide only the required allowances for mains, service lines and appurtenant facilities (the 100-foot rule) consistent with NYPSC Regulations (16 NYCRR Part 230).

13. NYSEG will end the Rebate Program set forth in Matter 15-01252 effective with the Commission Order approving a Joint Proposal in this Proceeding. Any pending applications for rebates as of the date of the Order, will be honored if verified for completeness and eligibility for the rebate. Two Hundred and Fifty Thousand Dollars ($250,000) of the remaining funds after pending applications for rebates have been paid under the rebate program (estimated at $1 million) will be applied by NYSEG to the incremental costs incurred by NYSEG to perform the seven studies identified in Appendix N. The remaining NYSEG funds will be used for an enhanced heat pump rebate program to be developed by NYSEG. The enhanced heat pump rebate program will be available for households with income of 120% of state median income or less, low income housing providers, and nonprofits. Eligibility criteria, incentive levels and application processes will be developed in partnership with NYSERDA Clean Heating and Cooling Community programs that are operating in the NYSEG service territory. With respect to RG&E customers, RG&E commits up to $750,000 in previously unspent economic development funds for a comparable enhanced heat pump rebate program to be deployed in RG&E's territory.

14. To the extent not already completed or terminated, upon approval of the Joint Proposal, the Companies will terminate all gas expansion pilot programs and conversion rebate programs, including all oil-to-gas conversion programs, and those required by Appendix CC of the Joint Proposal in Cases 15-E-0283 et al. and to limit natural gas marketing activities to the provision of information to customers to assure they understand their options for energy choices. References to the terminated programs on the Companies' websites will, accordingly, be removed.

15. The Companies agree that gas projects involving the construction of a new pipeline or the replacement or expansion of an existing pipeline may be potentially suitable for a NPA, except where conditions pose an immediate threat to public safety or where construction is

imminent (within 12 months). Following approval of the Joint Proposal, the Companies agree that for other future projects, a two-prong approach to NPA evaluation would be used. The first would be expedited for smaller projects (less than or equal to $2 million) and would utilize a standardized review approach, including an economic and technical analysis ("streamlined BCA"), to determine the potential economic and technical feasibility of an NPA that may or may not include a full-scale solicitation of NPA alternatives. The second would be a more comprehensive review for larger projects which would require a full-scale solicitation of NPA alternatives followed by a BCA analysis of potential solutions, which would be performed prior to detailed engineering, permitting, and construction, and before more than five percent of the total project cost has been spent. The Companies agree to involve DPS Staff in the application of both the streamlined and the more comprehensive NPA approaches.[2]

The Companies agree to work with Staff and interested parties to develop a BCA Handbook for NPAs consistent with the BCA Framework Order which will be submitted as a Report to the Secretary to the Commission in these proceedings within six months of the Commission's approval of the Joint Proposal. This effort will be coordinated with the Department of Public Service Staff in cooperation with interested parties. The BCA Handbook for NPAs will be subsequently updated subject to the requirements of the Climate Leadership and Community Protection Act.

The Signatory Parties recommend to the NYPSC that it institute a Statewide Proceeding to develop BCA Handbooks for NPAs statewide. In the event the Commission implements such a Statewide Proceeding, the Statewide Proceeding will take precedence over the NYSEG and RG&E specific effort.

The Companies agree that the social cost of carbon, the global warming potential of methane over 20 years, and methane lifecycle emission from extraction to consumption should be part of whatever NPA BCA methodology is developed.

NPA projects shall be amortized over the anticipated "used and useful" life of installed assets and equipment. (For example, this may be 20 years for a heat pump and several decades for a ground loop.) NPA projects without a clearly measurable period for amortization shall use a 20-year default amortization period.

The Companies would get a credit toward the overall leak-prone pipe replacement mileage targets if a NPA or other economically viable solution was implemented. For example, if in lieu of replacing one mile of leak prone pipe, a NPA was completed, the Company would get credit for one mile of leak prone pipe replacement.

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[2] The Companies are committed to making NPA evaluation the new norm. In this new environment, safety, reliability and adherence to law cannot be compromised. Therefore, for all gas projects, (just as for DeRuyter and Lansing) the Companies will not be restricted from taking measures, including making capital investments, that are necessary to comply with all laws, rules, regulations or Orders of the Commission or other applicable agency or to protect the integrity of the pipelines or in the event of an emergency as determined by the Companies.

The Companies agree to continue to "stack" customer and vendor incentives from the Energy Efficiency order with NPA-based incentives where allowed by applicable Commission Order, law or regulation.

16. The Companies agree to minimize the incremental costs associated with the proposed Renewable Natural Gas (RNG) study to develop mapping of favorable RNG locations.

17. The Companies, within six months of the approval of the Joint Proposal, will submit a petition to the NYPSC regarding the potential preferential reallocation of natural gas made available in the Lansing Moratorium area. This reallocation would be to commercial and industrial customers for reasons of economic development.

Special Studies

New York State Electric & Gas Corporation – Electric
New York State Electric & Gas Corporation – Gas
Rochester Gas and Electric Corporation – Electric
Rochester Gas and Electric Corporation – Gas

New/Special Studies

The Companies will conduct the following studies during the term of the Rate Plan:

1) Senior Customer Study for Customer Service;
2) Natural Gas System Resiliency Study;
3) Renewable Natural Gas Study;
4) Geothermal – District Energy Study;
5) Overall Natural Gas and Grid Modernization Report;
6) Depreciation Study Reflecting the Climate Leadership and Community Protection Act ("CLCPA"); and
7) Street Light Replacement Cost Study.

During the term of this Rate Plan, the total budget for the studies identified above shall be capped at $750,000 across both NYSEG and RG&E. As indicated in Appendix M, Gas Matters, $250,000 of funds associated with the termination of NYSEG's Rebate Program set forth in Matter 15-01252 will be applied by NYSEG to the incremental costs incurred by NYSEG to perform the seven studies identified above. The remaining total Rate Plan budget of $500,000 will be allocated between NYSEG and RG&E using the Common Allocation Factors contained in Appendix GG, Common Allocation Factors. Such allocated budget amounts are reflected in the revenue requirement schedules included in Appendices B through E of this Rate Plan. The Companies anticipate that between $400,000 and $500,000, in total, will be spent on items 5 and 6 above. The table below provides additional details concerning the allocation of these costs.

Table 1: Special Studies Cost Allocation

	NY Company Allocation	Allocation of costs to Company	Allocation of Costs to Electric	Allocation of Costs to Gas
RG&E – Revenue Requirements	34.77%	$260,753	$176,139	$84,614
NYSEG	65.23%	$489,247	$393,305	$95,941
Less: NYSEG Shareholder Portion		$250,000	$200,975	$49,025
NYSEG Residual to Revenue Requirements		$239,247	$192,330	$46,916
	100%	$750,000	$569,444	$180,556

To the extent the Commission institutes a statewide proceeding or initiative to study any of the subjects covered by the above-identified studies, NYSEG or RG&E will not necessarily prepare or provide a separate report or study. The Companies will continue to produce their own report or study for any items not included in a statewide study or initiative.

The Companies will provide interested parties with the proposed scope of the above-identified studies in advance of NYSEG or RG&E performing any such study. Interested parties to these rate proceedings including New York State Energy Research and Development Authority and New York State Department of Public Service Staff ("Staff") will be provided the opportunity to provide input on the scope of each study sufficiently in advance of the Companies performing any study. Additional information concerning the anticipated scope of certain studies is provided below. The Companies will provide the results of each study to interested parties to these rate proceedings and Staff upon completion of a study by NYSEG or RG&E, and in some cases, will file the study results with the Secretary of the Commission (noted below).

<u>Senior Customer Study for Customer Service</u> - The Companies agree to conduct a study to identify potential partnerships for senior customer outreach concerning energy efficiency opportunities, low income discounts and other senior customer-related opportunities. The Companies will coordinate such study with Staff. The scope of the study will include the identification of potential partnerships and associated activities. As part of the study, the Companies will research best practices of utilities in states/service territories that have higher-than-average percentages of seniors as customers.

<u>Natural Gas System Resiliency Study</u> - The Companies will conduct an analysis to address areas of engineering concern related to the Companies' ability to maintain resiliency of the gas distribution system during a gas curtailment scenario. The Companies will retain a third party to conduct the analysis. Upon completion, the Companies will provide the analysis to Staff pursuant to the Commission's regulations governing confidential and trade secret information. The Companies will target the analysis for completion with the submission of the Companies' winter preparedness review filing in 2021.

<u>Renewable Natural Gas ("RNG") Study</u> - The Companies will review their service territories to identify all feed stock sources and map potential locations for RNG.

<u>Geothermal – District Energy Study</u> - As discussed in Appendix M, during RY1, the Companies 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 Companies' service territory and to develop plans for subsequent pilot projects where feasible, including but not limited to those areas with existing leak prone pipe. The study will include, but not be limited to, sites in Monroe, Tompkins, Chenango, and Otsego counties. At the conclusion of the study, the Companies will make a filing to the Commission, including recommendations for advancing pilot projects of various types and sizes, along with related cost recovery approaches.

Overall Natural Gas and Grid Modernization Report - The Companies agree that within 18 months of a Commission order approving the Joint Proposal in these rate cases, the Companies will complete and file with the Commission a report that evaluates how the Companies' businesses may evolve in the decades ahead. The study will identify the potential issues and strategies related to reducing natural gas usage and increasing electricity usage as an alternative and the modernization and expansion of the electric grid needed to support the widespread deployment of renewables and beneficial electrification. The report shall be developed in light of the renewable energy and greenhouse gas reduction goals set forth by the CLCPA. The report shall provide a meaningful analysis of the scale, timing, and costs of achieving significant, quantifiable reductions in gas use, grid improvements necessary to achieve various levels of renewables deployment and beneficial electrification, and potential financing mechanisms. Interested parties, to the rate case proceedings shall be invited to provide input to the scope of the study.

The Companies intend to include the following parameters when designing the study:

a. Identify future energy scenarios consistent with achievement of CLCPA goals (Greenhouse Gas reduction: 40% by 2030, 85% by 2050; electricity: 70% renewable by 2030, zero-emission by 2040). The Companies will:

    i. Model various future scenarios for 2030, 2040, and 2050 in which gas use is substantially reduced, demand for electricity increases to accommodate alternatives to combustion (e.g., heat pumps, electric vehicles, electrification of industrial processes), and significant renewable electricity generation is deployed within the service territories of both Companies.

    ii. Explain how each scenario supports the statewide goals, noting the potential for significant increases in generation which must be carbon free by 2040, to support widespread beneficial electrification and addresses applicable power quality, system stability, and reliability during both high and low load periods.

b. For each scenario, the Companies should analyze physical changes to NYSEG's and RG&E's electric and gas systems, including the need for new and upgraded electricity infrastructure/assets, decommissioning of gas infrastructure/assets, related costs, and resulting greenhouse gas reduction.

    i. The Companies should evaluate the scale and type of changes to the electric grid associated with the identified changes, including consideration of quality of service and reliability associated with the various scenarios. This should include various renewable deployment scenarios, analyzing optimal deployment patters, interconnection to transmission and distribution networks, storage, and improvements needed to support long-distance electricity transmission. The Companies also should evaluate existing constraints and improvements needed to the electric grid in each scenario to support beneficial electrification, considering demand and peak load impacts.

ii. The Companies should evaluate strategies for achieving significant, quantifiable reductions in natural gas use and related infrastructure, examining various gas reduction profiles for both Companies over time, including opportunities for eliminating gas use where possible. NYSEG and RG&E should also evaluate system-wide strategies, as well as those targeted within particular pipeline service areas. This should include, but not be limited to, expansion of heat pumps, electric appliances, building efficiency, and district geothermal systems, considering ownership and management.

c. The study should identify technical, logistic, legal, regulatory, and financial challenges associated with implementation of the various scenarios and make recommendations regarding evolution of the Companies' businesses, funding mechanism and state law/regulations to facilitate attainment of CLCPA goals.

Depreciation Study Reflecting the CLCPA - As discussed in Appendix M, the Companies will complete and file a study with the Commission by December 31, 2021, on the potential impacts of climate change policies and laws on the depreciation of their gas, electric, and common assets. The Companies will use calendar 2020 information for the study and it 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 to help inform the Companies' next base rate filing.

No later than 60 days after the issuance of a final Commission order adopting this Rate Plan, the Companies will hold a meeting with Staff and interested parties to discuss the scope of this depreciation study and specific study requests, including the potential study parameters identified above. The Companies shall notify all parties in these proceedings of the meeting date at least two weeks prior to the meeting. The Companies 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 Staff and interested parties to provide feedback. The Companies 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 Companies shall notify all parties in these proceedings of the meeting date at least two weeks prior to the meeting.

Street Light Replacement Cost Study - The Companies will conduct a street light luminaires replacement cost study and present the results in their next rate filings.

Appendix O (AMI-1)

Benefit-Cost Analysis of AMI

Table of Contents

1. Introduction and Summary

This Appendix documents the data and assumptions used to generate estimates of the benefits and costs associated with full deployment of advanced metering infrastructure (AMI) at New York State Electric & Gas and Rochester Gas and Electric (hereafter referred to as the Companies). The document includes the changes to certain data and assumptions that have resulted from interactions with New York State Department of Public Service staff and other settlement that have taken place since the May 2019 filing of the original version of this Appendix, which was Exhibit 2 to the Companies' AMI Panel testimony filed in May 2019. Specifically, changes made since May 2019 are as follows:

- Meter installation start date of April 2022 rather than April 2021;
- Begin development of the IT infrastructure and software platform, starting in 3rd quarter 2020 rather than April, 2020;
- Updated the avoided carbon costs associated with reductions in electricity use to be consistent with the most recent Tier 1 REC value;
- Updated the projected cost of natural gas;
- Increased the cost of Home Energy Fair Practices Act (HEFPA) compliance compared to the prior BCA analysis (leading to a reduction in net benefits of roughly $13m) so that all payment related disconnections meet current HEFPA compliance rules ;
- Reduced the contingency included in the AMI deployment capital costs by $17.2 million;
- Increased the capital cost of meter installation to cover the cost of load side cable during meter panel replacement work (leading to an increase in cost of $4.5m);
- Increased IT platform costs to support residential 15-minute and commercial 5-minute interval data delivered at 15-minute intervals to the operations center for presentation on the web portal (a cost increase of $4.3 million);
- Updated the pre- and post-tax discount and inflation rates used to produce present value calculations to be consistent with the overall rate case proposed cost of capital and general inflation adjustment.

AMI is a foundational system for realizing REV goals to empower customers through new tools and information to effectively manage and reduce usage, establish and animate new markets to promote the implementation of DER's, and minimize environmental impacts of power generation and energy consumption. The AMI project will include installation of intelligent meters (both electric and gas), a supporting telecommunications network, IT infrastructure, and software applications to process data and interact with field devices.

AMI implementation will generate a wide variety of benefits, many of which can be reasonably quantified while others are less tangible. Although the less tangible benefits, such as market animation, may ultimately be quite large, the benefit-cost analysis (BCA) documented here focuses on the tangible, quantifiable benefits and compares those with the cost of obtaining them through AMI deployment and implementation of customer programs that are enabled by AMI. The BCA incorporates the benefits and costs stemming from AMI-driven changes in day-to-day operations and required capital investments (e.g., meter replacements) associated with normal business operations. The BCA also examines costs and benefits from different AMI-driven programs as outlined below.

- **Time-varying Pricing (TVP):** Examination of the benefits (e.g. avoided capacity and energy costs, among others) of an illustrative time-of-use-critical-peak-pricing (TOU-CPP) tariff;
- **Behavioral Conservation:** A comparison of the costs and benefits, primarily in the form of avoided energy consumption and carbon emissions, from an illustrative program that would begin sending weekly usage alerts to roughly a third[1] of the Companies' residential customers on an opt-out basis—these alerts would show customers their usage and energy costs over the prior week and cumulatively since the start of the billing period;
- **AMI-OMS Integration:** Estimation of the benefits, in the form of reduced customer outage costs, resulting from the fact that AMI can provide quicker visibility into exactly where outages occur and also reduce outage restoration times; and
- **CVR/VVO:** The incremental reduction in energy use associated with conservation voltage-reduction/volt-var-optimization (CVR/VVO) when implemented in conjunction with full deployment of AMI.

1.1 Benefit-Cost Analysis

The primary methodology used to assess the AMI investment and related programs is benefit-cost analysis. BCA compares the costs of an investment with the benefits it produces. BCA is applied on a forward-looking basis to investments that typically have large upfront costs but have benefits that accrue over multiple years. BCA requires a pre-specified perspective, since different parties can view the same outcome differently. The BCA Handbook[2] specifies that benefit-cost estimates be developed based on three perspectives:

- **Societal:** Do the benefits, including externalities, exceed the costs?
- **Utility Cost Test (UCT):** Is the investment or program self-funding or are additional funds needed?
- **Ratepayer Impact Measure (RIM)**: How does the investment affect rates? Note that this perspective is not focused on whether customers' bills will increase or decrease (which may depend upon their participation in the program), but rather whether the volumetric rate increases or decreases.

The societal test not only counts operational benefits within the utility, but also includes benefits experienced by customers (e.g. reduced outage costs), reductions in resource requirements (e.g. generation capacity, energy use) and reductions in externalities such as carbon emissions. It does not treat transfers between parties as costs. On the other hand, the UCT does not include benefits experienced by customers or externalities but counts as costs things such as customer incentives, since money to fund programs and incentive payments must be collected. The RIM test focusses exclusively on rates. In some cases, resources that reduce energy

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[1] Customers in the top two usage quartiles for which the Companies have email addresses, which is about 60% of customers.

[2] Benefit Cost Analysis (BCA) Handbook, Version 2.0. Submitted July 26, 2018.

consumption, such as energy efficiency and conservation voltage reduction, can lead to lower bills but higher rates because the revenue for capital infrastructure investments is collected from fewer energy sales. Of these three perspectives, the societal test is the most important from a public policy perspective and is the primary focus in this Appendix although results for the other two tests are also presented.

In addition to the societal benefits summarized above, several benefits were also quantified that can be categorized as fairness benefits – that is, equitable redistributions of costs among various stakeholders. These include reductions in theft and write offs, fewer meter malfunctions and slow meters, and less consumption on inactive meters. These benefits are included in the RIM test perspective summarized in the following section. As seen later, these additional benefits are substantial and are important considerations even if they are not incorporated into the societal BCA. Tables 1-1 and 1-2 summarize the benefits and costs that are included in each test perspective.

TABLE 1-1: BENEFITS INCLUDED IN EACH BCA TEST PERSPECTIVE

	Benefit Type	Benefit Category	Societal	Utility	Ratepayer
AMI	Avoided Capital	Avoided meter purchases	X	X	X
		Avoided solar meters	X	X	X
		Avoided sensors	X	X	X
	Avoided O&M	Billing	X	X	X
		Call center	X	X	X
		Field work	X	X	X
		Improved cash flow	X	X	
		Meter reading	X	X	X
		Reduced field costs through voltage monitoring	X	X	X
		Reduced storm costs	X	X	X
		Avoided network O&M	X	X	X
		Reduced non-storm restoration costs	X	X	X
	Avoided Fleet Capital	Field work	X	X	X
		Meter reading	X	X	X
	Societal Benefits	Avoided carbon due to fewer truck rolls	X		
		Avoided customer outage costs	X		
	Fairness Benefits	Meter Accuracy Improvement			X
		Energy theft reduction			X
		Delivery write offs			X
		Energy write offs			X
AMI Enabled Programs	Avoided Capital	Avoided transmission capacity	X	X	X
		Avoided distribution capacity	X	X	X
	Customer Energy	Avoided generation capacity	X	X	X

	Benefit Type	Benefit Category	Societal	Utility	Ratepayer
	Supply Savings	Avoided wholesale energy costs	X	X	X
		Avoided wholesale natural gas costs	X	X	X
	Societal Benefits	Avoided carbon due to reduced energy use	X		
		Avoided carbon due to reduced natural gas use	X		

TABLE 1-2: COSTS INCLUDED IN EACH BCA TEST PERSPECTIVE

	Benefit Type	Cost Category	Societal	Utility	Ratepayer
AMI	Deployment Capital	IT hardware	X	X	X
		IT software	X	X	X
		Meters	X	X	X
		Network	X	X	X
		PMO	X	X	X
	Refresh Capital	IT hardware	X	X	X
		Meters	X	X	X
		Network	X	X	X
	O&M	O&M	X	X	X
AMI Enabled Programs	O&M	Marketing acquisition costs	X	X	X
		Other variable costs	X	X	X
		Fixed overhead costs	X	X	X
		Participant sign up incentives		X	X
	Lost Revenue	T&D revenue losses /customer savings			X
	AMI/ OMS Capital	Software	X	X	X

All of the separate analyses summarized below are based on a common set of inputs and assumptions. Among the most basic are:

- The meters are assumed to be deployed over a three-year period starting in 2022 and ending in early 2025. The Companies' AMI deployment schedule is illustrated in Table 1-3.

TABLE 1-3: METER DEPLOYMENT SCHEDULE

	2022	2023	2024	2025
NYSEG/RG&E	25%	33.3%	33.3%	8.4%

- Each meter is assumed to have a 20-year life. As such, meters deployed in 2022 are assumed to produce benefits tied to meter deployment through 2042, meters deployed in 2023 are assumed to deliver benefits through 2043, and so on. Thus, the overall AMI life cycle goes from 2021 through the first quarter of 2045. In this analysis the benefits are measured for all but the last three months, so that the net benefits of approximately 8.4% of all meters are excluded from the analysis. This exclusion, for practicality reasons, results in an analysis that very slightly understates the net benefits of AMI and the AMI benefit/cost ratio.
- The present value of costs and benefits are discounted back to 2019 using the NYSEG and RG&E weighted average cost of capital (WACC) as the discount rates. Since taxes are considered income transfers, which are excluded from the societal test, the after-tax WACC is used for the societal test (6.16% for NYSEG; 6.46% for RG&E) whereas the pre-tax WACC is used for the UCT and RIM tests (7.65% for NYSEG; 7.96% for RG&E). As directed by the BCA Order, carbon reductions are discounted using a societal discount rate of 3%. These differences in discount rates have a very substantial impact on the net benefits and should be kept in mind when comparing the societal, UCT and RIM tests.
- All present value calculations are reported in 2019 dollars. Annual labor inflation rates are assumed to equal 3% and all other costs are assumed to inflate by 1.9% annually unless stated otherwise in the discussion below. The general annual escalation of 1.9% is equivalent to the Blue Chip forecast which has lower rates of escalation for the recovery years of the COVID-19 pandemic and then 2.0% escalation after the recovery years.
- The annual growth in the NYSEG/RG&E customer population is assumed to equal 0.21% for NYSEG and 0.36% for RGE.

1.2 Summary of Results

Figure 1-1 summarizes the quantifiable societal costs and benefits associated with AMI deployment. All values in the figure are presented in present value terms in 2019 dollars for ease of comparison with the original BCA from May 2019. The analysis recognizes that some pre-deployment expenditures occurred in the 2017 – 2020 time period and assumes that meter deployment occurs from April 1, 2022 through March 31, 2025. Benefits and costs are included for the period from 2019[3] through the end of 2044.[4]

[3] NYSEG and RG&E have incurred costs of roughly $2.5 million over the 2017-2019 period for planning work. These costs were inflated to 2019 dollars and also included in the BCA.

[4] As discussed above, for practical reasons, benefits accrued in the first three months of 2045 are not included in the BCA, resulting in a very small underestimate of net benefits.

The Companies have approximately 1.9 million gas and electric meters that would be replaced during AMI deployment. Of these, roughly 1.3 million are electric meters and the rest are gas meters. In order to achieve some of the primary operational benefits associated with AMI deployment, especially avoided meter reading costs, electric meters must be replaced and gas meters must be retrofitted with communications modules, or replaced if retrofitting is not feasible because of meter condition.

FIGURE 1-1: PRESENT VALUE OF SOCIETAL BENEFITS AND COSTS

As seen in Figure 1-1, AMI operational costs are broken down into five primary categories:

- Meter and network hardware and installation;
- IT hardware and software;
- Other deployment period costs, including project management, testing, exception handling, customer engagement and outreach, and legal;
- Ongoing operations and maintenance of the system over the life of the AMI investment; and
- Refresh capital (e.g. annual replacement of failed meters plus replacement of IT hardware and network devices at several intervals).

In addition to the above cost categories, costs are also incurred in conjunction with several programs that are enabled by AMI: time-varying pricing, usage alerts, and the integration of AMI with the Companies' outage management system (OMS) to reduce outage duration and, therefore, outage costs. These costs include marketing and program administration for TVP and usage alerts, for example, and IT related costs associated with integrating the AMI and OMS systems.

Roughly 44% of the $549.2 million in costs over the life of the investment are comprised of meter and network hardware and installation. The $126.5 million associated with investment in and operation of IT systems and equipment includes costs for AMI head-end hosting, meter data management hosting, and a new billing and customer relationship management system. Another $0.8 million in IT related costs, shown at the top of the cost column, has to do with AMI-OMS integration. Roughly 6% of the present value of costs is associated with project management, testing, exception handling, customer outreach, legal, and deployment support services during the deployment phase and 18% is associated with ongoing operations and maintenance. Refresh capital accounts for about 7% of the present value of costs and the remaining 3% of costs stem from implementation of the TVP and usage alert programs.

During the period leading up to and through the end of meter deployment (covering the years from 2017 through 2025), the Companies estimate that cash outlays (non-discounted) will equal approximately $489 million for meter and network hardware and installation, project management, testing, exceptions handling, customer outreach, legal, and IT hardware and software. This is roughly $272 for each installed electric meter and $227 for each gas meter.

The present value of operational benefits from AMI deployment is estimated to equal $565.3 million, or 106% of total operational costs (e.g., capital and O&M) over the life of the investment, which are projected to equal approximately $534.2 million in present value dollars. Of these total operational benefits, 36% ($201.5 million) come from avoided meter reading costs (including roughly $7 million for avoided fleet capital) and 15% ($84.4 million) comes from reductions in field service costs (including about $3 million in avoided field service fleet capital) stemming from meter features such as remote connect/disconnect. Savings of approximately $23.4 million are estimated to come from reduced billing and call center costs and another $38.5 million in cost reductions stem from reductions in storm restoration costs due to more efficient management of crews through greater visibility into where outages occur and when they are restored. Estimated savings in field service restoration costs for non-storm outages equal $18.5 million over the life of the AMI investment. Savings of $80.8 million are estimated to come from reduced meter purchases from the Companies' existing replacement program. Savings of $95.3 million result from the avoidance of distribution line sensors since AMI meters will provide appropriate monitoring information. There are $9.6 million in savings from avoided purchases of bi-directional meters for roof-top solar installations, and $10.5 million from improved cash flow through shorter meter-to-bill times.

The operational benefits of AMI by themselves more than offset the costs of AMI over its product life cycle for the combined Companies. In addition, the net benefits from AMI enabled pricing and other programs such as usage alerts, improvements in reliability from AMI-OMS integration and conservation savings from CVR/VVO, further increase the surplus of benefits over costs. The TVP benefits are based on an opt-in tariff in which 15% of the top three quartiles of residential and small and medium business ("SMB") customers are enrolled on a TOU-CPP tariff. This stylized program generates benefits totaling $30.0 million over the life of the investment and net benefits equaling $17.5 million. An alternative scenario that assumes residential customers are enrolled on TVP using opt-out enrollment, which is currently being deployed in California, would generate net benefits equal to $82.5 million. The usage alert program provides weekly updates on usage and costs via email on a default basis to roughly

33% of the Companies' residential consumers (e.g., the top two usage quartiles for the roughly 60% of customers for whom the Companies have email addresses). The net benefits, which total $54.8 million, primarily arise from avoided energy and natural gas costs and avoided carbon emissions for both electricity and gas behavioral conservation.

The integration of AMI with OMS will reduce the average outage duration for a subset of outage types due to the ability to detect outages more quickly and through more effective management of outage restoration due to greater visibility into outage locations. Shorter average outage duration will reduce customer outage costs. The cost of AMI-OMS integration is estimated to equal $0.8 million in present value terms and the outage cost reduction benefits are estimated to equal $93.5 million for a net benefit of $92.6 million.

The final AMI-related, societal benefit stream that is quantified has to do with the incremental reduction in energy use that can be obtained from CVR/VVO when AMI is fully deployed. The Companies estimate that AMI combined with CVR/VVO will reduce energy use by an additional 0.5% on average across all customer usage compared with CVR/VVO in the absence of AMI. This reduction would produce benefits with a present value equal to approximately $84.7 million, of which 79% is attributable to avoided energy costs and carbon reductions (with the remainder due to avoided capacity costs).

Combined, the quantifiable societal benefits of full deployment of AMI by the Companies are estimated to exceed the present value of costs by $280.7 million over the assumed life of the investment. Of this total net benefit, only $72.4 million, or 26%, stems from programs designed to change usage behavior (e.g., TVP and usage alerts). The remainder comes from operational savings, CVR/VVO and reductions in outage costs due to AMI-OMS integration.

With a societal benefit-cost ratio of 1.51 and the fact that many intangible and hard-to-forecast benefits such as market animation and increased penetration of DER are not included in the analysis, the AMI deployment will have a substantial positive impact on the Companies' customers. AMI also helps the Companies more fairly align an estimated $154.6 million in costs with customers that cause them. Finally, the full deployment of AMI by the Companies is consistent with recently approved AMI projects in New York at Long Island Power Authority, Consolidated Edison and Orange and Rockland.

Figures 1-2 and 1-3 show the societal benefits and costs by category and the overall net benefits for NYSEG and RG&E separately. This separate analysis could be considered artificial since the costs for each Company would increase significantly if only one Company deployed AMI rather than both companies. However, the separate analysis does show that net benefits for each Company in isolation are positive, so that customers in each Company are better off with AMI in place. Customers at NYSEG benefit more than customers at RG&E because there are proportionately more gas customers at RG&E than at NYSEG. The ratio of electric customers to gas customers is roughly one to one at RG&E and roughly three to one at NYSEG. Electric customers generate greater societal benefits from AMI than gas customers because of AMI's ability to improve outage restoration (an electric service issue) and because of AMI's ability to support a CVR program and a TVP program, which are both electric service issues. Accentuating the difference in net benefits between RG&E and NYSEG is the fact that there are fewer outages at RG&E than at NYSEG because RG&E is a much more urban and compact service territory and, therefore, is less subject to outages. Still another reason is that RG&E's average cost per meter read is currently lower than NYSEG's primarily due, once again, to the more compact service territory.

FIGURE 1-2: PRESENT VALUE OF SOCIETAL BENEFITS AND COSTS FOR NYSEG

FIGURE 1-3: PRESENT VALUE OF SOCIETAL BENEFITS AND COSTS FOR RG&E

1.3 Appendix Organization

The remainder of this Appendix is organized as follows. Section 2 summarizes the analysis for the operational business case, which compares the Companies' costs of AMI deployment with the operational savings that the Companies will achieve once AMI is fully deployed. Section 3 summarizes the outage cost reduction benefits that can be achieved through the integration of AMI and OMS. Section 4 summarizes the net benefits associated with implementation of TVP. Section 5 analyzes the net benefits that can be obtained from information feedback programs that are enabled by AMI. Section 6 presents estimates of the benefits stemming from CVR/VVO implementation in conjunction with AMI. Section 7 provides a summary of all quantified costs and benefits associated with AMI deployment.

2. Operational Business Case

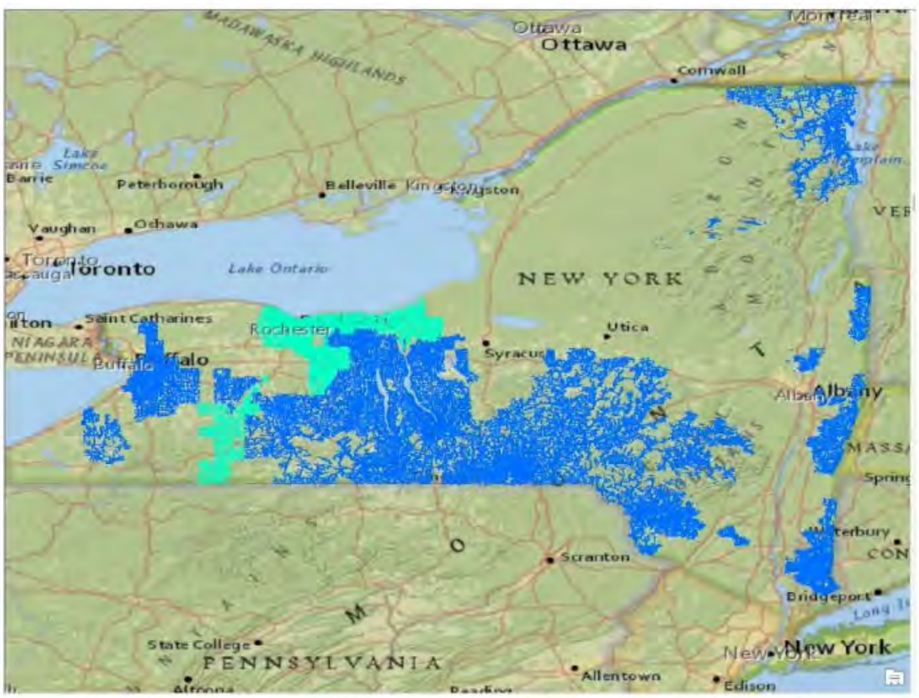
This section describes the costs and savings from AMI deployment that translate directly to changes in the Companies' spending or impact how costs are distributed across the customer base. This operational business case includes changes in both O&M and capital spending. It provides a perspective on AMI's impact from the Companies' and ratepayer's perspectives.

As seen in Table 2-1, the Companies have approximately 1.9 million electric and gas meters in New York, located in the RG&E and NYSEG service areas. Roughly 46% of RG&E's meters are gas meters whereas only 23% of NYSEG's meters are gas meters. Figures 2-1 and 2-2 provide maps of these meter locations within the state.

TABLE 2-1: ELECTRIC AND GAS METERS

Meter Type	RG&E	NYSEG	Total
Gas meters	324,746	281,270	606,016
Electric meters	387,673	902,788	1,290,461
Total	712,419	1,227,534	1,896,477

FIGURE 2-1: THE COMPANIES' 1,290,461 ELECTRIC METER LOCATIONS



Note: Dark blue dots are NYSEG meters, and light blue dots are RG&E meters

FIGURE 2-2: THE COMPANIES' 606,016 GAS METER LOCATIONS

Note: Dark blue dots are NYSEG meters, and light blue dots are RG&E meters

The Companies have evaluated the costs and benefits of AMI technology that can provide the following capabilities:

- Deliver daily reads with a success rate of 99.5% for both electric and gas meters;
- Deliver electric interval consumption data (15-minute intervals for residential customers and 5-minute intervals for commercial customers) with a success rate of 99.0% and delivery to the operations center every 15 minutes;
- Execute service connects and disconnects for electric residential and network meters with a 98% success rate (and execution within 30 minutes after the required premise visit for HEFPA compliance for all disconnections related to nonpayment);
- Execute on-demand reads for gas and electric meters with a 98% success rate within 60 seconds;
- Support Home Area Networking ("HAN") to facilitate customer interaction and management of their gas and electric service usage;
- Deliver electric meter power-off and power-on requests to the AMI operations center within 15 minutes;
- Allow reprogramming of meters over-the-air to adapt to new demand response rates that might evolve;
- Monitor voltage for electric meters;
- Include meter communication capability that can be upgraded within existing meters if necessary;

- Monitor attempts at power diversion including magnetic theft detection;
- Monitor micro-arcing conditions in electric meters;
- Have multi-day network power backup capability;
- Have AMI software and firmware that accommodates interoperability of network interface cards and network collector equipment from multiple manufacturers; and
- Gas modules that that meet Commission and national standards.

The Companies will observe the following guidelines during the deployment of the AMI technology:

- Acceptance testing will be performed at the Companies' facilities with representatives from the Companies, and the testing will be completed in New York independently from the AMI technology provider;
- The Companies will continue testing of existing meter populations throughout the AMI deployment period;
- The Companies will perform safety inspections at the time of electric meter replacement and make repairs to the meter panel and load side cable if determined necessary by the inspection.

Specific Electric and Gas Meter Requirements are described in the following paragraphs.

Electric

Prior to installation of AMI, all electric meters used by NYSEG and RG&E must be Commission approved for use in New York State and must comply with Public Service Law § 67, 16 NYCRR Part 92 and 16 NYCRR § 92 Operating Manual, 16 NYCRR § 93, and the applicable Federal Communications Commission (FCC) regulations.

All electric meters and ancillary equipment shall be tested within the New York service territory of NYSEG and RG&E. The meter test facility shall be approved annually by Department of Public Service Staff and must meet the performance standards mentioned in the latest American National Standards Institute C12.1 and C12.20 "Code for Electric Metering", as well as all Commission regulations.

The accuracy of electric meters under test shall comply with 16 NYCRR §92, Operating Manual. The test load points shall be determined by the Test Ampere ("TA") located on the meter badge or at other load points allowed under the 16 NYCRR Operating Manual. The final accuracy of the meter will be determined by multiplying the heavy load by four and adding the light load and dividing the total by five. The Commission will not accept test results from meter manufacturers, nor will Staff accept test results from one load test point.

All new shipments of meters and ancillary equipment shall be tested for accuracy and functionality prior to installation using test equipment that maintains an accuracy level in compliance with the National Institute of Standards Technology ("NIST"). The accuracy criteria for new meters shall have a weighted average from 99.2% to 100.8%. New meters under test shall endure a functionality test schedule to ensure the proper meter electronic program is installed, the LCD display, the AMI communication module, and the service connect/disconnect switch is operational. To determine if meter shipments meet the minimum criteria the Companies shall use a statistical sampling method as mentioned in ANSI Z1.4 "Sampling Procedures and Tables for Inspection by Attributes". The method of sampling will be determined by using the General Inspection Level II at the normal sampling rate, with an Acceptable Quality Level ("AQL") of 1.0. When meter samples are found not meeting the ANSI Z1.4 criteria, the shipment will be rejected and sent back to the manufacturer or the entire shipment must be tested.

To ensure the performance of new AMI meters and ancillary products the Companies will select, in the first year, 200 meters from each meter type for testing. The test schedule shall be conducted under actual in-service conditions.

During the AMI roll-out the Companies should continue with their annual meter statistical test program for their existing electric meter population, unless an exemption is requested and granted by the Commission. Meters for testing will be selected by meter classification, type, and serial number. The number of meters selected for testing shall be determined using the ANSI Z1.4 General Inspection Level II at the normal sampling rate, with an Acceptable Quality Level (AQL) of 2.5 for each meter type. The accuracy criteria for in-service meters shall have a weighted average from 98.0% to 102.0%; meters found outside this criterion are to be considered as failing products. The Companies will be responsible to submit annual meter test results consistent with 16 NYCRR Part 92, Operating Manual, for each meter type to Staff and will provide a remediation schedule regarding failing meter types within six calendar months after submittal.

<u>Gas</u>

Prior to installation of AMI, gas communication modules used by NYSEG and RG&E must be Commission approved for use and comply with Public Service Law §67, 16 NYCRR Parts 226 and 227, and the applicable Federal Communications Commission (FCC) regulations.

NYSEG/RG&E intend to retrofit existing gas meters with ancillary equipment, an encoder, receiver and transmitter (the "AMI Communication Module") that is used to monitor gas consumption. This equipment will be physically compatible with the meter and will monitor consumption in cubic feet. The AMI Communication Module will be able to store at least 45 days of gas consumption data in nonvolatile memory and transmit this data at regular intervals. The AMI Communication Module will be equipped with a visual gas consumption index for customers to monitor their gas usage over time and compare this usage to utility data. The visual index will be equipped with a test hand to monitor consumption in real time and provide an indicator to check the service for leaks.

All new shipments of AMI Communication Modules will be acceptance inspected and tested prior to installation to ensure the products can properly monitor gas consumption over time and successfully transmit and collect data. AMI Communication Modules under test shall endure a functionality test schedule to ensure the proper AMI Communication

Module electronic program, parameters, and serial number/endpoint ID are installed. To determine if AMI Communication Module shipments meet the minimum criteria the Companies shall use a statistical sampling method as mentioned in ANSI Z1.4 “Sampling Procedures and Tables for Inspection by Attributes”. The method of sampling will be determined by using the General Inspection Level II at the normal sampling rate, with an Acceptable Quality Level (AQL) of 2.5. When AMI Communications Module samples are found not meeting the ANSI Z1.4 criteria, the shipment will be rejected and sent back to the manufacturer or the entire shipment must be tested.

Additionally, the Companies will continue to work with Staff throughout deployment to ensure meter regulatory compliance.

This section has five subsections that describe the operational costs and benefits of AMI in more detail. Section 2.1 discusses the capital and O&M costs expected to be incurred by the Companies’ from 2017 through 2025 as AMI meters are deployed across the service territory. Section 2.2 describes the O&M savings projected by the company over the entire AMI system life-cycle. Section 2.3 describes the capital savings projected by the company over the entire AMI system life-cycle. Section 2.4 presents an economic analysis that combines and compares the costs and savings described in Sections 2.1 through 2.3. Finally, Section 2.5 discusses impacts of AMI that improve equity or bill fairness by reducing the socialization of costs incurred by a few customers across the entire customer population. These impacts represent $154.6 million (20-year NPV) of cost redistribution to improve fairness.

2.1 Initial AMI Deployment Expenditures

Table 2-2 summarizes the projected expenditures required to deploy AMI to all of the Companies’ customers. The total cost of $488.1 (exclusive of $0.9 million OMS integration expenditures) million dollars over the nine-year period from 2017 to 2025 represents estimated cash flows, adjusted for inflation where appropriate, not the present value of expenditures. Approximately seventy percent of the total costs in Table 2-2 have total or unit pricing supported by firm RFP bid responses. The table does not include $0.9 million of integration expenditures that are discussed in Section 3. The remainder of this subsection discusses each of the entries in Table 2-2.

TABLE 2-2: PROJECTED AMI DEPLOYMENT EXPENDITURES (Capital)
($ Millions, unless otherwise identified)

Cost Category	Electric	Gas	Total
Meters and installation	[redacted]		
Network			
IT			
PMO, legal, customer outreach, testing, vendor management fees			
Total	**$361.1**	**$127.0**	**$488.1**
Meters to be upgraded	1,290,461	606,016	1,896,477
Cost per meter	$280	$210	$257

2.1.1 Meter Equipment and Direct Installation

The meter equipment and direct installation costs summarized in Table 2-2 and detailed in Tables 2-3 and 2-4 account for 55% of total deployment costs. It should be noted that single-phase and poly-phase meter unit costs reflect the weighted average of different single and poly-phase models. The standard residential meter is single phase but is projected to cost significantly less than the average single-phase meter.

Electric meters include disconnect switches for residential and network meters and also Home Area Networking to permit broadcasting of information from meters to customer devices. In the description of customer service benefits below, the role of the disconnect switch in producing customer benefits is described more fully. For gas customers, ordinarily a telecommunications module is installed on existing meters and no meter change-out is required. However, the Companies have identified 31,589 gas meters where the age and design of the meter indicated that replacement was prudent to avoid rework during the life of the AMI system. The $42.7 million differential between the $270.4 million in meter and installation costs in Table 2-2 and the $227.7 million in Table 2-3 includes make-ready work and inventory replacement as explained in the subsection below on "other" meter deployment costs.

TABLE 2-3: METER EQUIPMENT AND DIRECT INSTALLATION COSTS
($ Millions, unless otherwise identified)

Equipment or Installation Service	Quantity	Unit Price ($)	Sales Tax per Unit ($)	Contingency per Unit ($)	Total
Single phase electric meters	[redacted]				
Network electric meters					
Self-contained three phase meters					
Transformer-rated three phase meters					
Gas meters					
Gas telecommunication modules					
Single phase electric meter installation					
Network electric meter installation					
Self-contained three phase meter installation					
Transformer-rated three phase meter installation					
Gas meter with integrated module installation					
Gas module installation					
Total Expenditure					$227.7

2.1.2 Other Meter Deployment Costs

Beyond meter equipment and the meter installation visit, there are other costs included in the meter deployment cost category. Approximately 9% of the overall deployment costs, or $42.7 million, result from support that is needed for the direct meter installation effort, including replacement of the current meter inventory with smart meters. Table 2-4 summarizes these costs. These cumulative costs are not discounted but do reflect inflation expected over the project time period. The AMI deployment cost estimates in Table 2-4 that are labor-related are escalated at 3% over the deployment period. Meter panel repairs are anticipated [redacted]. Although meter panel repairs are typically charged to customers when meters are replaced during the normal course of business, having customers own this responsibility during AMI deployment would increase costs by holding up meter replacement while waiting for customers to take remedial action. That is, it is more efficient to proactively repair the meter panels to maintain installation efficiency. In addition, it is estimated that 10% of direct installations will require a revisit for trouble-shooting purposes that will cost an average of $25 per visit.[5]

TABLE 2-4: OTHER METER DEPLOYMENT COSTS
($ Millions, unless otherwise identified)

Cost Category	Expenditure
Meter panel repair	[redacted]
Meter revisits	
Meter installation support	
Meter engineering support	
Meter inventory	
Seals and adaptors	
Total other meter deployment costs	$42.7

Meter installation support and meter engineering support are two areas that proved essential for successful deployment at CMP. Over the 2022-2025 period, five installation support workers and four engineering support workers are projected to be required, with an expected loaded cost of $64 per hour. The meter installation support individuals will track and audit daily installation results from the AMI installation vendor and help schedule troubleshooting and meter panel repair efforts. The meter engineering support individuals will help with meter testing, meter inventory auditing, and meter programming. Costs for meter installation and engineering support are escalated at 3% over the four-year deployment period.

[5] It is prudent to include some revisit expenses, and this estimate is based on CMP experience, taking into account the mix of indoor and outdoor meters in New York, and advancements in field tools and remote trouble shooting that have occurred since CMP installed its system.

Other meter deployment costs include replacement of the current meter inventory, which is assumed to equal 3% of the cost of meters for deployment. Finally, other meter deployment costs include an estimate of [redacted] per meter for seals and locking rings and a provision for A- and C-based adaptors for 2.4% of the meters at a cost of [redacted] per adaptor. No fees will be charged to customers for replacement of seals or adaptors.

2.1.3 Network Equipment and Direct Installation Costs

The telecommunications network sends and receives information from the meters to the AMI operations center. The Companies' AMI design includes 20% increased equipment density to improve network resiliency during storm restoration events, and multi-day power backup for all network devices. The network installation prices include costs for a site visit prior to installation and "make-ready work" that might be needed.

The AMI network underlying the total cost estimate of [redacted] million includes equipment costs of [redacted] million for network collectors and repeaters and [redacted] million for associated installation, including make-ready work. Make-ready work often includes tasks such as site surveying, running secondary lines to network devices, and adding pole-top extensions for device mounting purposes. In the development of these cost estimates, the installation costs have been escalated by 3% annually. The network equipment requirements on a dollars-per-customer basis are significantly less than they were for CMP's AMI system. This decrease reflects network design and technology advancements that have taken place over the last seven years.[6]

The direct costs of the network are a relatively small part (approximately 4%) of overall deployment costs. However, additional network deployment costs, which are described in the next subsection, are slightly higher than the direct equipment acquisition and installation costs of [redacted] million.

2.1.4 Other Network Deployment Costs

Table 2-5 summarizes network deployment costs of $19.9 million that are in addition to the direct equipment acquisition and installation costs discussed above. These cumulative costs are not discounted but do reflect inflation over the project period. These costs are roughly equivalent to the direct network equipment and installation costs. Table 2-5 includes transformers for 9% of network collector devices to support the installation when a location is required where a transformer is not already installed on the distribution system (based on CMP experience). Four FTE-years of an external network troubleshooter are included to help identify performance problems with the network and coordinate with the AMI system provider to develop solutions. Twelve FTE-years of internal installation support individuals are included to help with equipment inventory management, to set up network devices and get them ready for installation, and to assist with inspections in the field and with installation issues that might arise with customers located near the installation sites. The resources in Table 2-5 reflect experience gained during deployment at CMP, adjusted for the network performance improvements that have taken place throughout the AMI industry since 2012.

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[6] CMP deployed 625,000 AMI meters between 2010 and 2012, with an AMI system similar to the one used as a reference system in this estimate.

Table 2-5 also includes [redacted] million (contingency included) for build-out of the Companies' telecommunications backhaul system to allow all network collectors to tie into it, so that backhaul telecommunications costs can be avoided.

TABLE 2-5: OTHER NETWORK DEPLOYMENT COSTS
($ Millions, unless otherwise identified)

Cost Category	Expenditure
Transformers	[redacted]
Network installation support	
Network troubleshooting	
Tier I telecommunications network improvements	
Total other network deployment costs	$19.9

2.1.5 Other Deployment Expenditures

Cost estimates for the project management office and miscellaneous expenditures represent 9% of total deployment costs. The aggregate costs in Table 2-6 are not discounted and reflect both 3% escalation per year and contingency. Total cost is comprised of the following components:

- Customer engagement costs include costs for a customer engagement specialist firm to manage a community outreach effort, two internal staff members to coordinate outreach, a specialist in identifying and resolving RF interference issues, and the cost of mail and email contacts during deployment.
- The AMI vendor services fee covers the AMI technology vendor's staffing to support deployment.
- Legal expenses are for contract negotiations, dispute resolutions, and contract amendments, and real estate support includes assistance in locating network devices where company facilities are not available.
- Testing costs cover interface testing and process reengineering testing.
- Exception management covers the work necessary to resolve discrepancies between company databases and actual configurations encountered in the field during deployment.
- The project management team includes 20 internal FTE's and 5 external FTE's during the 2021-2025 period based on assessment of how to cover all the elements of the AMI deployment in New York. This team represents the project management office (PMO).

  As a result of the 12-month delay in the start of meter deployment, there will be more time to plan and integrate project elements. To represent the efficiencies that this increased planning time can generate, the cost estimate includes a reduction of $3.6 million in total across all the line items in the project management cost estimate.

TABLE 2-6: AGGREGATE PROJECT MANAGEMENT OFFICE AND MISCELLANEOUS COSTS
($ Millions, unless otherwise identified)

Cost Category	Total Cost
Customer engagement	[redacted]
Legal and real estate	
Vendor services	
Exceptions	
Testing	
Internal staff	
External staff	
Efficiency adjustment	
Total	$39.2

2.1.6 IT Hardware, Software, and Integration

Table 2-7 shows the breakdown of IT expenditures associated with AMI deployment, which totals $139.8 million over the deployment period, including contingency, 8.5% sales tax on hardware and software licenses, and 3% escalation on integration costs. This cost estimate includes AMI head-end hosting, meter data management hosting, implementation of a new customer billing system and provision and support for a customer web portal. The IT integration effort links the MDM to the new customer billing system, and the AMI head-end to the MDM and the OMS. The IT budget was developed internally with a team that included IT staff members who had implemented the CMP AMI project. It reflects experience gained at CMP, the particulars of the New York IT environment, and changes in hardware costs that have occurred since 2010 when CMP IT changes were implemented.

TABLE 2-7: IT HARDWARE SOFTWARE AND INTEGRATION COSTS
($ Millions, unless otherwise identified)

Cost Category	Hardware	Software	Services	Total
AMI head-end system	[redacted]			
Meter data management system				
GIS integration				
Web portal				
Customer billing system				
Total	$41.8	$33.8	$64.2	$139.8

Note: Project Management Office cost allocations are not included in the table above and are discussed separately above.

2.1.7 Annual AMI Operations and Maintenance Costs ("O&M")

Table 2-8 summarizes the cost of operating and maintaining the new AMI system, which is estimated to equal roughly $8.5 million annually (in 2026$, the first full year of operation after deployment is completed). The estimated budget includes costs for 24 staff members (12 for the AMI system, 9 for the MDM system, and 3 for data analytics support), and includes budget for field maintenance and troubleshooting. These costs represent about [redacted] of the O&M budget. IT software maintenance charges represent [redacted] of the budget.

TABLE 2-8: ANNUAL OPERATIONS AND MAINTENANCE COSTS
(2026, the first full year of operation after system deployment is completed)
($ Millions, unless otherwise identified)

Cost Category	Annual Cost	Comment
Operations staff expense	[redacted]	12 FTE's
MDM staff expense		9 FTE's
Analytics staff expense		3 FTE's
IT software maintenance		
Field maintenance and trouble shooting		
Total annual expenditures	$8.3	

2.1.8 System Refresh Costs

The total life-cycle cost estimate for AMI includes three kinds of capital investments over the life of the system. First, it is expected that each year, 0.5% of electric meters and gas modules will fail due to electronic problems and will need to be replaced. This annual failure rate would also be expected with existing electric meters, but existing meters cost about [redacted] less than AMI meters (assumed not to escalate over the AMI life-cycle). As such, the annual meter refresh cost that occurs with AMI will be incrementally more expensive by [redacted] per electric meter than without AMI. The incremental cost of replacing failed gas modules, including installation, is [redacted] per meter, representing the full cost of the module and the full cost of the trip to exchange the module. These incremental costs account for the [redacted] million in annual expenditures shown in Table 2-9.

The system network refresh costs include annual expenditures of about [redacted] to address an anticipated annual 2% equipment failure rate, with a major refresh of all network equipment in 2032. The costs of both the annual equipment replacements and the major equipment refreshes are assumed to be the full cost of the equipment and 10% of the original installation cost.

The system refresh costs include an average of [redacted] million for 100% replacement of IT hardware each year in 2026, 2031, 2038, and 2041. This hardware supports four environments (Production, Test, Development, and Disaster Recovery).

TABLE 2-9: AMI SYSTEM REFRESH COSTS

Cost Category	Refresh Cost	Comment
Annual electric meter and gas module failures	[redacted]m per year	Covers incremental costs of .5% electric meter and gas module failure rate each year
Periodic network refresh	[redacted]m annual refresh and major refresh in 2031 of $13.7m	Covers revisits to all network devices in 2031, and 2% of network devices in all other years between 2025 and 2044
Periodic IT hardware refresh	[redacted]m per average refresh	Covers IT hardware replacement in 2026, 2031, and 2036 and 2041

2.2 O&M Savings

Offsetting the costs detailed in Section 2.1 are reductions in operational capital and O&M costs. Capital cost reductions are discussed in Section 2.3. O&M cost reductions are detailed in this section.

Full deployment of AMI for both gas and electric meters will produce substantial operational savings. Table 2-10 summarizes the annual operational benefits in 2026, the first year after AMI deployment is complete, and totals $34.4 million. These benefits are described in more detail in the subsections below

TABLE 2-10: SUMMARY OF ANNUAL OPERATIONAL BENEFITS IN 2026
($ Millions, unless otherwise identified)

Benefit Category	Annual Benefits
Reduced meter reading costs	[redacted]
Reduced field service costs	
Reduced storm restoration costs	
Avoided costs of patrolling for faults before service restoration and patrolling for nested outages after restoration	
Reduced call center costs	
Reduced billing costs	
Avoided costs of addressing customer voltage issues	
Total	$34.4

2.2.1 Savings in Meter Reading, Field Customer Service, Billing and Call Center

To estimate direct customer service savings, expenditures were first estimated assuming that AMI was not in place. Next, a review of how work would change with full deployment of AMI was conducted, utilizing interviews with call center and billing supervisors and detailed review of all field work orders in 2018. Projected position savings were proportioned to projected work reduction in all areas except field customer service, where the expectation is less than a proportional reduction in staff because of the decline in efficiency for remaining work due to the reduced density of jobs. This analysis of all customer service O&M benefits (meter reading, field services, billing, and call center) produced an annual savings estimate of [redacted] million in 2026, the first year after deployment of AMI is complete.

Table 2-11 summarizes the position reductions resulting from AMI. These estimates are based on the following assumptions and analysis:

- The new AMI system will read 99.5% of meters accurately each day. In rare instances where reads are missing for an entire billing cycle, manual reads can be obtained with the remaining field service staff so that the entire meter reading staff can be released. The analysis assumes that severance payments equal to two weeks of compensation for every year of service are made to all 198 staff members that lose their positions.
- A review of field work completed in 2018 suggests that [redacted] of the current work would be eliminated after deploying AMI. The estimated reduction in field staff is less than proportional to this expected work reduction because it is anticipated that the work not eliminated by AMI will involve more drive time per job and thus require more time to complete.
- Savings in billing and call center activities occur because customer questions about billed usage, estimated bills and billing rework to address anomalies will drop dramatically after AMI implementation. Currently, customers receive bills monthly but meters are typically only read every other month so the percent of total bills that are estimated is quite high. In addition, the manual meter reading process sometimes produces misreads, which can lead to call center inquiries as well as manual bill adjustments. In estimating call center savings, it was assumed that future staffing of the call center would reflect a greater number of call center representatives than are in place today, to address projected needs in fulfilling customer service expectations. The projected position savings in Table 2-11 have been reviewed and compared to experience at CMP, where AMI has been fully deployed for seven years.

TABLE 2-11: NUMBER OF CUSTOMER SERVICE LABOR POSITIONS REDUCED BY AMI

Work Area	Projected Positions without AMI	Projected Reductions in Positions Resulting from AMI	% of Positions Reduced
Meter reading and support	[redacted]		100%
Field customer service			42%
Billing/call center			12%
All work areas			42%

2.2.2 Reduced Major Storm Restoration Costs

The granular visibility into outage locations provided through AMI can reduce field service time required to resolve major outages by ensuring that crews are not pulled out of the field prior to full restoration and then re-dispatched to restore service to any trailing outage locations. This improvement in the efficiency of full restoration can significantly reduce major storm restoration costs associated with paying external crews, overtime, meal and lodging. From 2016 through 2018, average costs in these categories for storm restoration equaled $29 million per year for the combined companies ($25.6 million for NYSEG and $3.4 million for RG&E), excluding costs associated with storms that triggered a NYPSC Part 105 filing. Assuming a 3% annual inflation rate, these costs equal $36.7 million in 2026, the first year after full deployment of AMI. Assuming that 10%[7] of this work can be reduced by using the AMI system to "ping" meters and direct the outage restoration crews more efficiently, annual projected savings would equal $3.7 million in 2026, as summarized in Table 2-12.

TABLE 2-12: ANNUAL REDUCED STORM RESTORATION COSTS IN 2025
($ Millions, unless otherwise identified)

Statistic Description	Value
Projected storm restoration costs in 2025	$36.7
Expected % reduction in incremental costs due to AMI	10%
Expected avoided incremental storm restoration costs	$3.7

2.2.3 Savings in Patrol Time to Locate Faults and Nested Outages

The Companies estimate an annual savings of $1.8 million in 2026 for crew time and vehicle costs from using AMI power off and power on messaging to identify faults with less patrol time and to reduce patrol time for nested outages after faults have been resolved. This estimate relies on judgmental assumptions made by Avangrid's operational experts that AMI would reduce initial patrol time to identify faults by 12 minutes per outage at NYSEG and 8 minutes per outage at RG&E. An additional 12 minutes at NYSEG and 8 minutes at RG&E would be saved per outage

[7] A 10% reduction was also assumed in the CMP AMI application filing and a subsequent audit of the business case by the Maine PUC concluded that this assumption was reasonable. (See "Audit of Central Maine Power Company's Management of its Advanced Metering Infrastructure Program," February, 5, 2014, page 27.)

in avoiding patrol time needed to search for nested outages after the fault has been corrected and patrol time would also be saved for outages that activated an automated protection device. These benefits are for outages that don't occur in major outage situations so they don't overlap with the patrol time savings highlighted in Section 2.2.2 above.

TABLE 2-13: ANNUAL PATROL AND NESTED OUTAGE TIME SAVINGS FOR OUTAGES NOT DURING MAJOR STORMS IN 2026

Statistic	NYSEG	RG&E	RG&E + NYSEG
Number of patrols to find faults and number of patrols to find nested outages	28,946	7,868	36,814
Minutes per event	12	8	11
Savings per hour for labor and vehicle costs in 2019$	[redacted]		
Savings per year in millions of 2019$			
Escalation from 2019 to 2026			
Total annual savings in millions of 2026	$1.5	$0.3	$1.8

2.2.4 Savings Resulting from Voltage Monitoring

AMI meters provide voltage measurements and alerts for high and low voltage situations. The companies can use this information to proactively address customer voltage problems and issues with transformer loads. The proactive actions will reduce the number of calls into the customer service center. In addition, proactive action will reduce the costs of upgrading or replacing transformers, since that work can be completed on a scheduled basis rather than an emergency overtime basis. The Companies estimate the savings from voltage monitoring will total $250,000 per year in 2026, the first year after AMI deployment is completed, as will continue at the same level over the life of the AMI investment.

2.3 Capital Savings

The prior section summarized the reductions in O&M costs resulting from AMI deployment. This section summarizes reductions in capital costs.

2.3.1 Avoided Meter Purchases

By the end of the projected AMI life cycle, without AMI in place the Companies would have replaced 1.3 million electric meters and 31,000 gas meters due to obsolescence and performance. With AMI deployment, this replacement work will no longer be necessary. The 31,000 gas meters will be replaced as part of the AMI deployment, and the new AMI meters effectively pre-empt the replacement that would otherwise be needed over time. Table 2-15 summarizes the expected savings of $7.8 million in 2026, the first year after AMI deployment is completed. This estimate assumes that installation labor costs escalate 3% annually while equipment costs remain constant.

TABLE 2-14: ANNUAL AVOIDED METER COSTS IN 2026
($ Millions, unless otherwise identified)

Avoided Cost Category	Value
Annual gas meter replacements avoided (9 years)	[redacted]
Annual electric meter replacements avoided (20 years)	
Annual gas replacement installation labor avoided ($ per Meter)	
Annual gas meter expenditure avoided ($ per meter)	
Annual electric replacement installation labor avoided ($ per meter)	
Annual electric meter expenditure avoided ($ per meter)	
Annual avoided costs ($ millions)	$7.8

2.3.2 Avoided Fleet Capital Costs

Changes in the Customer Service Organization that are described above generate a significant reduction in operational expenses. In addition, the reduction of 170 positions in meter reading and field customer service generate capital savings related to the vehicles that are no longer needed. These capital savings amount to $1.0 million per year by 2026 or about $6,000 per vehicle per year by 2026.

2.3.3 Avoided Sensor Costs

In the December 2016 Petition for AMI, the Companies included a societal benefit cost analysis (BCA) to demonstrate the value of AMI deployment. That analysis was filed in conjunction with the Companies' DSIP filing which included cost estimates for foundational investments required to support REV as a Distribution System Platform Provider. The DSIP filing assumed that AMI was a foundational investment required for REV and that the deployment of AMI would provide the enhanced line sensing capability required to support REV. As such, the benefits of line sensing were not included in the 2016 BCA analysis of AMI. If AMI were not deployed, in order to support REV, the Companies would have to install voltage and load sensors at key points on the distribution circuits to meet the REV objectives and replace the functionality that would have been provided by AMI. Deploying AMI will result in the avoidance of the sensor installations and, consequently, represent a benefit resulting from AMI deployment.

Table 2-15 outlines the assumptions and calculations that support an estimated benefit (undiscounted) of $126 million resulting from not having to install sensors to meet REV objectives. Based on recent experience at Central Maine Power, an affiliated company, installed sensor costs equal [redacted] each. With three sensors per regulator, and an additional 9 sensors for key points along distribution circuits with more than 100 customers, it is projected that [redacted] sensors may be avoided with AMI in place. These sensor requirements were identified in a recent effort to deploy sensors on circuits at Central Maine Power. The $126 million estimated benefit results from multiplying the [redacted] cost per sensor by the [redacted] projected sensors that will not be needed when AMI is deployed.

Table 2-15: CALCULATION OF THE $126M IN LINE SENSORS AVOIDED AS A RESULT OF AMI DEPLOYMENT

#	Line Item Description	RG&E	NYSEG	Combined	Source
1	Sensor equipment unit cost	[redacted]	[redacted]	[redacted]	
2	Equipment costs per sensor for connection to backhaul communications	[redacted]	[redacted]	[redacted]	Based on costs observed in CMP CVR/VVO pilot
3	Site planning, installation, and verification per sensor	[redacted]	[redacted]	[redacted]	
4	Total cost per installed sensor	[redacted]	[redacted]	[redacted]	Line 1 + Line 2 + Line 3
5	Total # of regulators	[redacted]	[redacted]	[redacted]	Based on current regulator counts at RG&E and NYSEG
6	Sensors per regulator	[redacted]	[redacted]	[redacted]	Based on CMP/VVO pilot
7	Total sensors for regulators	[redacted]	[redacted]	[redacted]	Line 5 * Line 6
10	Total circuits with 100 or more meters	[redacted]	[redacted]	[redacted]	Based on current circuit counts at RG&E and NYSEG
11	Sensors per circuit	[redacted]	[redacted]	[redacted]	Based on CMP/VVO pilot
12	Total sensors for circuits	[redacted]	[redacted]	[redacted]	Line 10 * Line 11
13	Total sensors	[redacted]	[redacted]	[redacted]	Line 12 + Line 7
14	Total avoided sensor costs ($ millions)	[redacted]	[redacted]	$126.3	Line 13 * Line 4

2.3.4 Avoided DER Meters

In the December 2016 Petition the Companies did not include an AMI benefit related to the avoidance of installation of net meters to support DER as it is deployed across the distribution network. AMI meters have the functionality to support DER through their two-way capability, so if AMI meters were in place, then installation of net meters to support DER would not be necessary.

The avoided DER meter benefit estimate is based on a Navigant Research Report entitled "U.S. Distributed Renewables Deployment Forecast (q2, 2016)." That report estimates the annual number of new megawatts of installed solar PV capacity by state for both new residential and new commercial customers. In New York, projections for residential PV capacity increase from 88 MW in 2020 to 134 MW in 2025. Projections for commercial PV capacity increase from 82 MW in 2020 to 148 MW in 2025.

To use the Navigant forecast to estimate an AMI benefit related to avoided meter installation, the forecasts of new installed residential and commercial capacity from 2020 to 2025 need to be converted from capacity units (MW) to the number of new installations, and the forecast needs to be extended to 2044, the last year of the AMI benefit assessment period. In addition, the forecasts for New York State need to be disaggregated to focus on RG&E and NYSEG only.

The following steps accomplish the adjustments of the Navigant forecast necessary to estimate the AMI benefit for RG&E and NYSEG.

- The forecasts of residential and commercial capacity were extrapolated out from 2025 to 2044 using the growth rate from 2024 to 2025 that Navigant projected.
- The capacity forecasts were converted to installations using system sizes of 7.3 kW for residential installations and 25.9 kW for commercial installations. The residential size estimate is from a report on installed and pending capacity that NYSEG and RG&E submitted to the Public Service Commission. The commercial size estimate is an average of system sizes reported in two NYSERDA reports, "New York State Photovoltaic Market Trends" (2010) and "New York Solar Study" (2012).
- To identify the proportion of New York State installations that are associated with NYSEG and RG&E, 4.5% of the statewide forecast was assumed to represent the RG&E share and 10.6% of the statewide forecast was assumed to represent the NYSEG share. These percentages are calculated from the most recent EIA report on electric meters from the U.S. Department of Energy, which provides electric meter counts for individual utilities within the state of New York.

The steps outlined above result in estimates of installations of solar PV for 11% of NYSEG and RG&E customers from 2020 to 2044.

One final assumption in the calculation of the AMI benefit related to avoiding installation of solar meters is the savings from each avoided installation. The analysis assumes that $150 is the average savings per PV installation. The $150 savings represents both equipment and installation costs, and scales to an aggregate annual savings of $590,000 in 2026.

2.3.5 Improved Cash Flow

AMI offers the opportunity to reduce the time between meter reading and bill mailing for non-industrial revenue by 1.5 days. Effectively, this reduction will result in payments consistently being received 1.5 days earlier than before AMI. Table 2-16 shows the $1 million annual savings provided by this improvement.[8]

TABLE 2-16: ANNUAL REDUCED CASH REQUIREMENTS IN 2026
($ Millions, unless otherwise identified)

Statistic	Value
Annual non-industrial revenue projected in 2026 (Millions)	$2,639
Annual cost of capital	10%
Daily cost of capital	0.03%
Days from read-to-bill reduced with AMI	1.5
Annual cash flow savings ($ millions)	$1.10

[8] This is not a one-time benefit. One way to describe it is that the payment terms for customers, including the delay from the meter read to the bill send out, are being reduced from 33-34 days to 31.5-32.5 days.

2.4 Economic Analysis of AMI Operational Costs and Benefits

The sum of AMI system costs (Deployment Capital, System Refresh Capital, and Operations and Maintenance Annual Costs) can be directly compared to the expected capital and O&M savings described above by discounting the costs and benefits over time to provide point estimates of lifetime costs and benefits, using the after-tax cost of capital that is appropriate for the societal cost test. Table 2-17 shows the present value of costs for AMI deployment and Table 2-18 shows the present value of benefits covered in this operational business case. Net benefits and the benefit/cost ratio are shown in Table 2-19.

The present value of operational costs over the forecast horizon equals $534.2 million and the present value of operational benefits equals $565.8 million. The operational benefits more than offset the life cycle deployment and operational costs, including system refresh, over the assumed life of the investment. As discussed in subsequent sections in this appendix, additional benefits can be derived from AMI enabled programs and services, such as time-varying pricing, information feedback programs, integration of AMI with OMS and the incremental benefits of CVR/VVO attributable to AMI. The aggregate net benefits associated with these additional programs and investments add significant value to the already positive business case based on the Companies' cost and savings.

TABLE 2-17: PRESENT VALUE OF AMI IMPLEMENTATION AND OPERATIONAL COSTS

Expenditure Type	Cost Category	Life Cycle Costs ($ Millions)
Deployment capital	IT hardware	[redacted]
	IT software	
	Meter capital	
	Network capital	
	PMO, legal, testing, exceptions handling, customer engagement	
Refresh capital over AMI life cycle	IT hardware	
	Meter capital	
	Network capital	
Incremental O&M over AMI life cycle	Labor and software maintenance fees	
All types	All expenditures	

TABLE 2-18: PRESENT VALUE OF AMI OPERATIONAL BENEFITS
($ Millions, unless otherwise identified)

Benefit Type	Benefit Category	Life Cycle Savings ($ Millions)
Capital	Avoided meter purchases	[redacted]
	Avoided solar meters	
	Avoided sensors	
	Improved cash flow (reduced working capital)	
	Reduced fleet cost for field work	
	Reduced fleet cost for meter reading	
O&M	Reduced billing costs	
	Reduced call center costs	
	Reduced field work costs	
	Reduced meter reading costs	
	Reduced incremental major storm costs	
	Reduced T&D operational costs for non-storm restoration events	
	Avoided service costs from voltage monitoring	
All	All savings	$565.3

TABLE 2-19: SUMMARY OF OPERATIONAL BCA

	NYSEG	RG&E	Total
Benefits	$403.4	$161.9	$565.3
Costs	$350.5	$183.7	$534.2
Net Benefits	$52.9	$(21.8)	$31.1
B/C Ratio	1.15	0.88	1.06

Table 2-19 indicates that overall, the benefit-cost ratio for the operational business case for the combined Companies equals 1.06. The operational benefit-cost ratio equals 1.15 and 0.88 for NYSEG and RG&E, respectively. Clearly, the calculation of these ratios at the individual Company level depends heavily on the allocation of project fixed costs, such as the [redacted] million investment in IT hardware and software, which for investments like IT is somewhat subjective. Slightly different assumptions about this allocation could result in a more balanced set of benefit cost ratios for the individual Companies.

Using the allocation rules for fixed costs that we have used, the differences between the two companies reflect the lower cost of meter reading at RG&E relative to NYSEG (which reduces the benefit of avoided meter reading cost at RG&E compared with NYSEG), the much greater avoided storm restoration costs estimated for NYSEG relative to RG&E, and the higher ratio of electric to gas meters at NYSEG.[9]

2.5 Customer Benefits Not Reflected in the BCA

In addition to the operational benefits described above, deployment of AMI can also address fairness issues by reducing or eliminating revenue losses from various sources that are currently socialized to all ratepayers. AMI helps direct costs to customers who are responsible for those costs, thus reducing the socialization of certain kinds of costs from customers that generate them to the overall customer population. There are three kinds of socialized costs that AMI can address:

- **Theft of Service:** While it is difficult to quantify, there is undoubtedly some theft of service in the Companies' service area, and the revenue that would have been collected from individuals responsible for the theft is effectively socialized and collected from customers who pay for the service they receive. AMI provides tamper alarms and produces granular usage data at the customer level that can be analyzed for reasonableness in order to identify unusual patterns that may reflect theft of service. Note that theft of service reduction could be considered a societal benefit if it was assumed that consumption related to the theft of service ceased as soon as the theft of service was detected. With that assumption, less energy would need to be supplied after the identification of theft of service, which would reduce the use of societal resources.
- **Meter Inaccuracy:** While meters perform within tolerance ranges specified by the Public Service Commission, not all meters are 100% accurate and some of the existing electromechanical meters in the service territory don't measure all the electricity that is delivered to customers. Typically, electromechanical meters slow down with age and meters that are 20 years old might be under-registering usage by up to 1%. Customers with these "slow" meters do not pay for all the service they receive and the revenue shortfall from these customers is socialized to the rest of the customer base. In addition to slow electro-mechanical meters, revenue losses can occur from certain types of meter failures. For example, a three-phase meter might not measure all three phases correctly and, as a result, may under-charge a customer for the service they receive. Finally, it is well-known that new electronic meters have the ability to measure lower starting loads than electromechanical meters. As a result, customers that use proportionately more electricity at lower load levels may not be charged for all the electricity they use.[10] Again, the extent to which this under-registration of low-load demand results in the socialization of usage costs to the rest of the customer population is uncertain but with a new population of AMI meters, the accuracy and meter malfunction problems would be reduced.
- **Write-offs and Consumption on Inactive Meters:** Finally, the Companies currently write off bills that customers should have paid and also write off some consumption on inactive meters where deliveries occur but there is no customer of record to charge for

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[9] Electric AMI meters produce greater benefits per meter than gas AMI meter modules.

[10] An electronic meter can sense lower loads than an electromechanical meter, and thus register usage that an electro-mechanical meter would not notice.

the service. In both cases, the Companies socialize the revenue that would have been collected if the customer of record had paid their bills or if there had been no consumption on the inactive meter. With AMI meters, customers that do not pay can be shut off faster, reducing write-offs, and inactive meter consumption can be reduced because of the remote disconnect capability of AMI meters.

In this analysis, we have addressed these fairness issues by working to quantify how socialization of costs might be reduced through implementation of AMI and quantifying the extent of that socialization reduction as a rate reduction impact rather than a societal benefit. Basically, customers who today have accurate meters, who pay their bills, and who pay for all the electricity they receive will see their bills go down.

Assuming the existing meter population is under-registering consumption relative to AMI meters by 0.33% and that theft of service can be reduced by 0.25%, and applying those percentages to $2.2 billion of annual revenue (netting out revenues on large commercial and industrial customers where metering is already sophisticated), results in a $9.0 million reduction of costs annually that are socialized across the customer base. Projected write-off reductions of $6 million per year are expected from AMI deployment. The present value of the revenue associated with the reduction in socialization of all of these impacts is $154.6 million. However, we characterize the $154.6 million as a rate impact, which reduces the socialized costs that customers see, rather than as a societal benefit of AMI. The clearer benefit is the value of improving the fairness of customer bills by $154.6 million and by reducing the kWh generated to some extent. Table 2-20 summarizes the impacts discussed in this subsection.

TABLE 2-20: AMI IMPACTS THAT IMPROVE RATE FAIRNESS
($ Millions)

Fairness Impact	20-Year NPV
Meter accuracy	$ 19.2
Theft of service	$ 39.9
Write offs	$95.5
Total fairness impacts	$154.6

3. AMI-OMS Integration

As discussed in the main body of the DSIP filing in June 2016, the Companies plan to implement an advanced OMS. The cost and functionality of the OMS are discussed in the DSIP filing. Enhanced visibility into outages provided by full deployment of AMI and integration of AMI with OMS provides substantial incremental benefits that are quantified in this section. These benefits far exceed the minimal cost of developing the software needed for AMI-OMS integration, which equals only $0.8 million.

The Companies assessed how the integration of AMI with the Companies' OMS would reduce outage duration. Outages impose costs on consumers in the form of lost retail sales and lost service and production output for commercial and industrial customers. For residential consumers, outage costs take the form of inconvenience, lost wages, extra expenditures due to food spoilage, dining out and others. In addition to reducing customer outage costs, reducing the duration of outages will produce savings in the form of fewer hours of field crew time required to detect and solve the outage. These cost reductions were covered in Section 2 since they fall into the category of operational savings.

The assessment of historical outages found that AMI-OMS integration would reduce customer outage minutes in cases where an outage is evidenced by meters (as opposed to cases where the outage is evidenced by telemetry of the breaker tripping). When a non-telemetered component of the system fails and a utility does not have AMI integrated with OMS, the outage would typically not be identified until a customer calls. For these types of outages, AMI-OMS integration reduces outage duration in two ways. First, smart meters send a last gasp message to the OMS system and that message is typically received more quickly than a call from a customer. Second, by analyzing the set of last gasp messages that are received, the outage can be located using prior knowledge of connectivity of the network to identify the open device. This reduces the time associated with a crew traveling to a circuit to locate the open device. These operational efficiencies reduce outage duration and, therefore, reduce customer outage costs.

To quantify the benefits of the reduction in outage duration, the following two assumptions were made based on Avangrid's system operations experience:

- The time saved before an outage is confirmed is 3 minutes, the average time for a customer to call to report an outage; and
- The time saved identifying an open device is 12 minutes at NYSEG and 8 minutes at RG&E (NYSEG tends to have longer circuits).

Nexant identified the outages of non-telemetered fuses and breakers for which AMI-OMS integration would provide a reduction in outage duration based on the device codes in the 2016-2018 historical outage data for NYSEG and RG&E. Of the 26 device codes that NYSEG and RG&E assigned to outages during the three-year period, the specific device codes for non-telemetered fuses and breakers were a subset of 15 device codes (0, 3, 5, 17 or 20 through 30). Nexant also removed outages shorter than 20 minutes because AMI-OMS integration is not expected to provide a duration reduction for outages that the utility has historically resolved quickly without AMI.

The resulting dataset of 2016-2018 outages for the AMI-OMS integration analysis included 84% and 82% of all outage events for NYSEG and RG&E, respectively. However, the dataset accounted for a significantly lower percentage of total customer minutes interrupted (50% for NYSEG and 57% for RG&E), even though shorter outages of less than 20 minutes were removed. This results from the fact that outages of non-telemetered fuses and breakers affect far fewer customers on average. The outages that Nexant removed from the 2016-2018 database typically affected hundreds of customers (443 and 323 customers on average for NYSEG and RG&E, respectively), whereas the outages in the AMI-OMS integration analysis affected fewer than 40 customers on average for both utilities. Given that Nexant estimates AMI-OMS integration benefits specifically for those outages and scales the results based on the number of customers affected by those outages historically, the methodology described below ensures that the avoided interruption costs are not overstated.

3.1 Interruption Cost Estimation

Nexant estimated the value of avoided outage minutes using the Interruption Cost Estimation (ICE) Models, which are the econometric equations that serve as the basis for the ICE Calculator (available at icecalculator.com). The ICE Calculator is a DOE-sponsored tool developed by Nexant through a partnership with Lawrence Berkeley National Laboratory (LBNL) spanning more than a decade. It is designed for electric reliability planners at utilities, government organizations or other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements. The initial ICE Calculator version was an Excel-based tool that was BETA tested with dozens of members of the IEEE Distribution Reliability Working Group. In 2011, Nexant and LBNL released the first online version of the DOE-sponsored tool. In 2018, Nexant and LBNL released version 2.0 of the ICE Calculator.[11] Since the version 2.0 release, website usage at icecalculator.com has increased by 67% year-over-year. The tool now receives around 550 unique users per month, including utilities, regulators, think tanks, consultants and academic/government institutions throughout the country.

3.1.1 Source of Interruption Cost Estimates

In conjunction with the ICE Calculator 2.0 update, DOE also announced the release of a Nexant-LBNL report called "Estimating Power System Interruption Costs - A Guidebook for Electric Utilities."[12] The Guidebook details how to conduct customer interruption cost studies and summarizes why surveys of utility customers are the preferred method for estimating customer outage costs. These surveys describe several hypothetical outage scenarios and ask customers to detail the costs they would experience under those conditions. Various parties have proposed other approaches for estimating customer outage costs. The strengths and weaknesses of each approach are described in a literature review for the National Association of Regulatory Utility Commissioners.[13] As discussed in the literature review, customer surveys are the preferred method for estimating customer outage costs, as they directly measure the costs that customers

[11] See here: https://www.energy.gov/oe/articles/valuing-benefits-utility-investments-power-system-reliability-and-resilience

[12] Available here: https://emp.lbl.gov/publications/estimating-power-system-interruption

[13] Sullivan, M.J., and J. Schellenberg (2011). *Evaluating Smart Grid Reliability Benefits for Illinois*. National Association of Regulatory Utility Commissioners Report.

experience under a variety of outage scenarios without relying on the relatively weak assumptions that alternative methods use.

The primary drawback of survey-based outage cost estimation is that it requires collecting detailed information from large, representative samples of residential, commercial and industrial (C&I) customers. Therefore, only a few of the largest utilities in the U.S. have conducted customer outage cost surveys. To address this barrier to estimating customer outage costs, DOE, LBNL and Nexant have also worked together for over a decade to make reasonable outage cost estimates readily available for utilities that have not conducted their own surveys, both through the ICE Calculator and through reports that document the underlying ICE Models for use in custom applications, such as the one described below that Nexant developed for this AMI BCA. The ICE Models are based on results from all of the outage cost surveys that were conducted using the methods outlined in the Guidebook. This aggregated statistical study, called a meta-analysis, was first undertaken in 2003 (with results from 24 surveys) and then updated in 2009 and 2015 (with results from 34 surveys, including the original 24).

3.1.2 Overview of Approach for Estimating Avoided Customer Interuption Costs

Figure 3-1 provides an overview of the approach for estimating the benefits associated with avoided customer interruption costs from AMI-OMS integration. As shown on the left of the figure, the ICE Models are based on a meta-database of customer surveys, which contains 105,000 survey responses from 34 different studies conducted by 10 utilities between 1989 and 2012. The models themselves are sets of equations that relate characteristics of outages, characteristics of customers, and geography to interruption costs. Nexant applied a rigorous statistical learning process for selecting these models for each customer class (residential, small C&I and medium/large C&I). As detailed in the 2015 meta-analysis report,[14] Nexant finalized the ICE Models for each customer class (residential, small C&I and medium/large C&I). Using these ICE Models for the AMI BCA, Nexant applied the 2016-2018 NYSEG and RG&E outage history and current customer data to estimate interruption costs with and without the duration reduction from AMI-OMS integration. This analysis is applied to specific outage types for which AMI-OMS integration provides the duration reduction. Based on a comparison of the ICE Model estimates with and without AMI-OMS integration, Nexant estimated annual avoided customer interruption costs, which were then phased in over the BCA time period based on the proposed rollout and prioritization of AMI. The present value of this benefit stream is calculated to produce the overall benefit associated with AMI-OMS integration.

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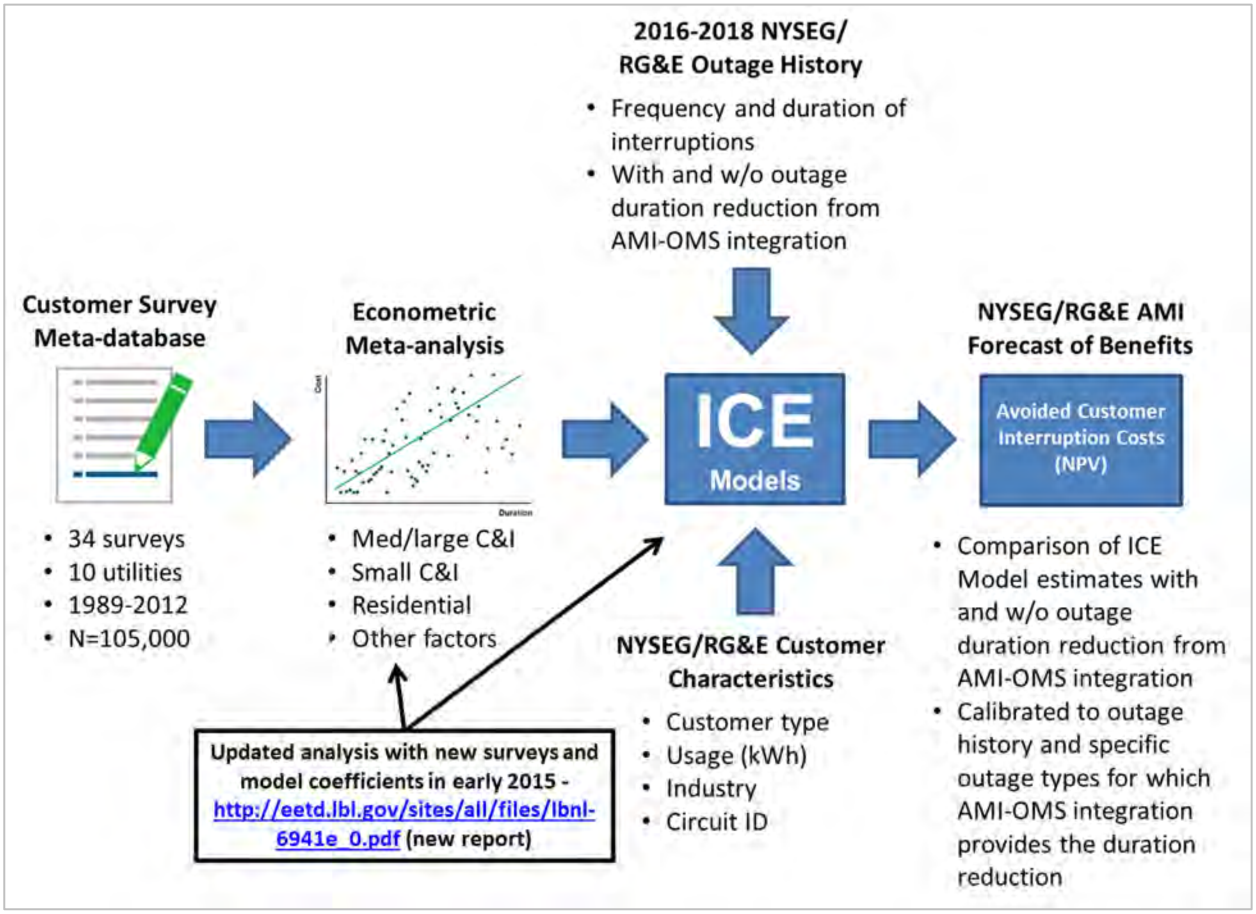
[14] Sullivan, M.J., J. Schellenberg and M. Blundell (2015). *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States*. Lawrence Berkeley National Laboratory Report No. LBNL-6941E.

FIGURE 3-1: APPROACH OVERVIEW FOR ESTIMATING OUTAGE COST REDUCTION BENEFITS



3.1.3 Generating Predictor Variables for ICE Models

The ICE Models are comprised of two-part econometric equations, which is the most appropriate model type given the nature of customer interruption cost data, as described in detail in the 2009 meta-analysis report.[15] The first equation for each customer class estimates the probability that an outage cost is greater than zero using a probit regression model. The second equation estimates the outage cost (in $) assuming that it is greater than zero using a Generalized Linear Model (GLM) with a logarithmic link function. Therefore, the outage cost for a given customer and outage scenario is a product of:

- **Part 1:** Predicted probability that an outage cost is greater than zero; and
- **Part 2:** Predicted outage cost assuming that it is greater than zero.

[15] Sullivan, M.J., M. Mercurio and J. Schellenberg (2009). *Estimated Value of Service Reliability for Electric Utility Customers in the United States*. Lawrence Berkeley National Laboratory Report No. LBNL-2132E.

The predictor variables for each customer class are the same in both equations, but the coefficients are different, given that the first equation predicts a probability between 0 and 1 and the second equation predicts a cost amount in dollars.

Each of the three customer classes has separate equations for each part, totaling six econometric equations. Appendix A provides summary tables of the coefficients for each of the six equations. As described in the 2015 meta-analysis report, Nexant aimed to improve upon the 2009 ICE Models by estimating a more parsimonious model that only included key predictor variables. This facilitates interruption cost estimation by reducing the burden that users face in providing numerous, accurate customer characteristics information. Table 3-1 summarizes the resulting predictor variables for the ICE Models by customer class. All three customer classes include the most important variables for any interruption cost estimation, which are outage duration and annual usage (including interactions and squared terms of those variables as appropriate). In the AMI-OMS integration analysis, these variables are based on the duration of a given historical outage and NYSEG and RG&E annual usage data for customers on the circuit impacted by the outage. After factoring in the other predictor variables as outlined in Table 3-1, the ICE Models estimate interruption costs for each outage, depending on the duration, season and time of day, specifically for the customer mix on the circuit impacted by each outage. Nexant then applied the assumed outage duration reduction from AMI-OMS integration (15 minutes for NYSEG and 11 minutes for RG&E) to estimate the interruption cost with the proposed investment. This reduction in outage costs that result from the duration reduction provides the avoided customer interruption costs.

TABLE 3-1: PREDICTOR VARIABLES FOR 2015 ICE MODELS BY CUSTOMER CLASS

Variable Name	Variable Definition in AMI BCA	Customer Class		
		Residential	Small C&I	M/L C&I
Annual Usage	NYSEG and RG&E annual usage data (in MWh) for customers on a given circuit	X	X	X
Duration	Duration (in minutes) of a given outage	X	X	X
Summer	Season of outage - Summer = 1, Non-summer = 0	X	X	X
Time of Day	Time of day of outage - morning (6 am to 12 pm), afternoon (12 pm to 5 pm), evening (5 pm to 10 pm) or night (10 pm to 6 am)	X	X	
Household Income	Median household income for Thompkins County (NYSEG) and Monroe County (RG&E)	X		
Manufacturing	Customer business type, based on NAICS/SIC code		X	X
Construction	Customer business type, based on NAICS/SIC code		X	
Backup Equipment	None or unknown; backup gen OR power conditioning; backup gen AND power conditioning		X	

The robust, disaggregated analysis summarized above is notable because it applies the ICE Models in a manner that fully leverages granular customer information and historical reliability data. This is a significant improvement over how these models are applied in the ICE Calculator itself, which is primarily designed to estimate the value associated with high level changes in system average sustained interruption indices (SAIFI, SAIDI and CAIDI). As described above, AMI-OMS integration provides a duration reduction for specific types of outages that impact relatively few customers on average, so an analysis based on system average sustained interruption indices would not be sufficient and could significantly overstate the benefits.

3.1.4 Accounting for Regional Variation for Medium & Large C&I Customers

As noted above, Nexant and LBNL released version 2.0 of the ICE Calculator in 2018. In this release, there was an important change to the ICE Models that significantly improved predictive accuracy across regions of varying economic productivity. Economic productivity per unit of electricity usage varies widely throughout the country, as measured by 2016 state-level data on Gross Domestic Product (GDP) from the U.S. Bureau of Economic Analysis (BEA) and non-residential electricity usage (kWh) from the U.S. Energy Information Administration (EIA). Based on these data sources, GDP/kWh varies from $2.8/kWh in Wyoming to $16/kWh in Connecticut. Significantly larger states such as Mississippi ($3.5/kWh), Alabama ($3.7/kWh), New York ($15.5/kWh) and California ($15.6/kWh) are also near the minimum and maximum values, indicating that this wide range of economic productivity per unit of electricity usage is not driven by a couple of small outlier states.

The 2015 ICE Models accounted for some regional variation in non-residential interruption costs with variables on customer size and industry, as summarized in Table 3-1 above. However, these few variables may not account for a substantial portion of the regional variation in interruption costs for C&I customers. Therefore, as part of the version 2.0 update of the ICE Calculator, Nexant re-ran the meta-analysis for the two C&I segments with GDP/kWh included as a predictor variable, based on the year of each survey response and location (state) of the respondent. This analysis found that the GDP/kWh variable significantly improved the predictive accuracy of the ICE Models across states for the medium and large C&I segment. As a result, Nexant and LBNL incorporated this improvement into the medium and large C&I model for the ICE Calculator. The small C&I segment did not show a similar improvement in predictive accuracy with the GDP/kWh variable included, so those econometric models remained the same as in 2015.

Given that this BCA applied the improved ICE Model for medium and large C&I customers, Nexant developed an estimate of GDP per kWh specifically for each utility using the following information:

- Non-residential kWh data by New York county from NYSERDA for 2013,[16] which is the most recent year available; and
- GDP data for 2013 by Metropolitan Statistical Area (MSA), which is the most granular level for which GDP information is available.

[16] Obtained from Appendix C in the following document: https://www.nyserda.ny.gov/-/media/Files/Publications/Energy-Analysis/2001-2015-patterns-and-trends.pdf

Based on this data, the Ithaca MSA (Tompkins County) had a GDP of $4,778 million in 2013 and 415 GWh of non-residential electricity usage. This resulted in a GDP/kWh value of $11.51, which was used in this BCA for NYSEG customers. The Rochester MSA, which includes the counties of Livingston, Monroe, Ontario, Orleans, Wayne and Yates, had a GDP of $53,141 in 2013 and those counties totaled 4,204 GWh of non-residential electricity usage. This resulted in a GDP/kWh value of $12.64, which was used in the BCA for RG&E customers. These results show that the $15.5/kWh value for New York as a whole would have overestimated benefits. As such, the values used for each utility will ensure that the medium and large C&I interruption cost estimates are more appropriate for Upstate New York, even though the MSAs do not directly overlap with either utility's service territory.

3.1.5 Estimating Long Duration Interruption Costs

A limitation of the ICE Models is that they cannot reliably estimate interruption costs for outages longer than 15 hours at this point, given the lack of survey data on long duration outages. Roughly 15% of the outages included in the AMI-OMS integration analysis were longer than 15 hours, with some lasting up to 7.5 days. Therefore, this BCA required a reasonable solution for estimating AMI-OMS integration benefits for long duration interruptions. Given that AMI-OMS integration provides a duration reduction (as opposed to a frequency reduction that completely eliminates outages), Nexant focused on obtaining a reasonable estimate of the benefit associated with the reduction as opposed to precisely estimating the specific cost of an outage longer than 15 hours. Therefore, Nexant limited the long duration outages in the historical database to have a duration of 15 hours before running the analysis. Nexant then estimated the benefit of AMI-OMS integration by applying the duration reduction to the 15-hour outage. This approach assumes that the change in outage costs leading up to 15 hours is similar to the rate of change at long durations. This approach results in a conservative estimate because outage costs increase *at an increasing rate* as outages go well beyond 15 hours, due to the damage and health hazards that occur under those circumstances, such as pipes freezing in the winter and heat exhaustion in the summer. In addition, as has been reported in many studies,[17] long duration outages are likely to produce substantial indirect (or "spillover") costs that spread to the greater economy. These indirect costs, which are not included in the AMI-OMS integration avoided cost estimates, are typically a 0.5x to 1.5x multiplier of the direct costs that the ICE Model estimates.

3.2 Analysis of Historical Outages

Table 3-2 summarizes the annual benefit (in 2019 dollars) of AMI-OMS integration for each year of historical outages from 2016 through 2018 for each utility, assuming that AMI is fully deployed. Over this three-year historical period, on average, NYSEG benefits from avoided customer outage costs equal $7.6 million per year, and RG&E benefits equal nearly $1.2 million per year. The average avoided cost per reduced customer outage minute is $0.92 for NYSEG and $0.69 for RG&E.

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[17] For a literature review on direct and indirect cost estimation for long duration outages, see Appendix B of this report: Sullivan, M.J. and J. Schellenberg (2013). *Downtown San Francisco Long Duration Outage Cost Study.* Prepared for Pacific Gas & Electric Co.

TABLE 3-2: AGGREGATE BENEFIT OF AMI-OMS AVOIDED OUTAGE COSTS
($ Millions, unless otherwise identified)

Utility	Year	Outages of Non-telemetered Fuses and Breakers	Average Number of Customers per Outage	Reduced Customer Outage Minutes	Avoided Customer Outage Costs (2019$ Millions)	Avoided Cost per Reduced Customer Minute (2019$)
NYSEG	2016	11,759	34.7	6,126,675	$5.89	$0.96
	2017	12,993	42.6	8,311,800	$7.85	$0.94
	2018	17,287	40.0	10,370,071	$8.97	$0.87
	Average	**14,013**	**39.3**	**8,269,515**	**$7.57**	**$0.92**
RG&E	2016	3,036	35.2	1,176,593	$0.84	$0.71
	2017	5,040	44.3	2,454,298	$1.63	$0.66
	2018	3,725	37.8	1,549,955	$1.10	$0.71
	Average	**3,934**	**39.9**	**1,726,949**	**$1.19**	**$0.69**

Using the three-year averages shown above as the basis for estimating the benefits that can be derived through the reduction in outage duration resulting from AMI-OMS integration implicitly assumes that outages due to storms would be similar in the future compared with what occurred between 2016 and 2018. Storms that hit RG&E in 2017 and NYSEG in 2018 were unusual by historical standards (although not as strong as super storm Sandy in 2012). Although there is widespread agreement that the frequency of significant storms is likely to increase in the future, assuming that the large storms that occurred over the last three years would repeat every three years may overstate the benefits from AMI-OMS integration. To be conservative, we have adjusted downward the average avoided customer outage costs from AMI-OMS integration shown in the second to last column in Table 3-2 for each Company based on an assumption that the avoided outage costs shown in 2017 for RG&E and 2018 for NYSEG would occur once every ten years rather than once every three years, which is what a simple average of the prior three-year values implicitly assumes. This is done by calculating a weighted average of the three years for each utility, with a weight of 45% assigned to each of 2016 and 2017 and a weight of 10% assigned to 2018 for NYSEG. For RG&E, the 45% weights are assigned to each of the years 2016 and 2018 and a 10% weight is assigned to 2017. The revised weighted average value for NYSEG is $7.08 million and for RG&E it is $1.03 million. These values represent roughly a 6% reduction in outage benefits for NYSEG and a 13% reduction in outage benefits for RG&E compared to what the benefits would be if the frequency of large storms was the same over the forecast horizon as it was over the last three years.

To estimate the present value of the benefit over the lifetime of the AMI-OMS integration investment as it rolls out, the avoided customer outage costs of $7.08 million per year for NYSEG customers and $1.03 million per year for RG&E are scaled by the percent of AMI deployment in each year. The benefit over time is also scaled by the same population growth rate, inflation rate and discount rates that apply to other investments. This results in a present value of the avoided customer outage cost benefit due to AMI-OMS integration of roughly $81.7 million for NYSEG and $11.7 million for RG&E, for a total benefit of $93.5 million across the two companies. After subtracting out the cost of AMI-OMS integration, the net benefits equal $81.2 million, $11.5 million and $92.6 million, respectively.

4. Time Varying Pricing

The Companies' plan to fully deploy AMI provides opportunities to improve economic efficiency and support the goals and objectives of REV by offering TVP to consumers. More than four decades of empirical research has shown that many consumers can and will enroll on TVP tariffs and will reduce usage during higher-priced periods relative to usage under traditional tariffs in which prices do not vary across the hours of the day, days of the week and seasons. TVP can lead to significant reductions in societal costs over time by reducing the need for high-cost peaking generation or reducing or delaying transmission and distribution capacity investments. It also gives consumers greater opportunities to reduce their energy bills by shifting from higher to lower cost time periods.

The remainder of this subsection provides a high level summary of the assumptions and analysis associated with estimating the net benefits of an illustrative TVP program involving the offer of a critical-peak-pricing/TOU tariff (CPP-TOU). Estimates are provided assuming both opt-in and opt-out enrollment. The opt-in scenario is incorporated in the net benefit estimates reported in Sections 1 and 7. These scenarios are meant to be illustrative of what could be achieved from TVP and do not represent all of the potential options that would be enabled by AMI. Neither are they meant to suggest what the Companies should or would do in terms of pricing strategies once AMI is fully deployed. The data and assumptions used here are based on evidence from pricing pilots and programs implemented by other utilities combined with usage data and other key inputs that are specific to the Companies' customer populations.

4.1 Conceptual Framework

The benefits of TVP pricing derive from the fact that prices more accurately reflect costs and customers respond to TVP price differentials across rate periods. Economic efficiency is improved when customers shift from high price/cost time periods to lower price/cost time periods. The aggregate benefits are primarily a function of the number of enrolled customers, the load shapes of customers prior to enrollment, the price responsiveness (or price elasticity of demand) of enrolled customers, and the structure of the TVP tariff (e.g. prices by rate period) being examined. These factors drive the change in usage by rate period which, in turn, drive the benefits that can be achieved in the form of avoided generation, transmission and distribution capacity investments, reductions in fuel costs and reduced carbon emissions. Figure 4-1 summarizes the main drivers of capacity benefits. A similar figure can be shown for energy benefits associated with TVP.

FIGURE 4-1: KEY DRIVERS OF CAPACITY BENEFITS FROM TVP

One variable in the figure not mentioned above is the % of capacity risk covered. In brief, this factor recognizes that TVP impacts do not necessarily produce demand reductions during all hours when generation or distribution capacity relief may be needed. Load reductions that occur when system (or an individual distribution network) load is at or near its maximum will be more valuable than reductions that occur when there is plenty of available capacity. As an extreme example, reducing load during summer afternoon hours when peaking risk is high will have substantially higher benefits than shedding load on winter nights. Conceptually, the benefits of time-varying pricing should be based on the contribution of load reductions in the hours when such reductions are most needed by the system. Factoring peaking risk into the calculation of benefits requires estimating the likelihood of peaks occurring for each hour throughout the year, which was done using historical data for NYSEG/RG&E.

4.2 Rate Design

The primary analysis presented here estimates the net benefits associated with an opt-in, TVP program for residential and small and medium (SMB) customers. Benefits stemming from the implementation of TVP for large commercial and industrial customers are not included because many of these customers already have interval meters and because TVP benefits from these customers could be cost-effectively obtained without full scale deployment of AMI.

A variety of TVP structures have been tested in pilot programs and deployed by utilities around the country, including:

- **Time of use ("TOU")** – prices vary by time of day every weekday (and perhaps on weekends and holidays);
- **Critical peak pricing ("CPP")** – prices vary by time of day only on high demand days (consumers are notified, typically the day before, when a high demand day occurs);
- **TOU-CPP** – combines the two options above, with prices varying on all days but where peak period prices are higher on CPP days than on the typical weekday;

- **Day-type variable pricing** – a set of TOU prices are established and communicated to consumers upon enrollment where prices by rate period vary across three or four different day types (e.g. low price days, moderate price days, high price days, critical price days) and consumers are told prior to each day what price schedule will be in effect on the following day;
- **Real time pricing** – prices change hourly in response to market conditions.

In this analysis, for both the opt-in and default enrollment scenarios, we estimate the impact associated with a hypothetical TOU-CPP rate in which time-varying prices are in effect for all non-holiday summer weekdays and higher prices are in effect for 12 critical peak pricing days on average each year. Nexant sought to design a reasonable rate that followed general principles of cost recovery, economic efficiency, customer equity, and rate simplicity. To meet these objectives, the rates were designed with the following features:

- The **TOU peak period** portion of the tariff is based on marginal generation and energy related costs;
- The **critical peak period** portion of the tariff is based on incorporating avoided capacity costs into the relatively few hours that drive capacity needs, which occur on high demand days;
- **Revenue neutrality** for the average customer by discounting the base energy prices to offset the higher peak period pricing.

It is important to note that the rates presented here are intended to be illustrative, yet plausible based on Nexant's experience with TVP at other utilities. They are designed to show the potential benefits that can be achieved by passing price signals through to consumers that more accurately reflect the cost of energy and avoided future capacity costs.

4.2.1 Rate Periods

TOU-CPP rates consist of a set of rate periods for two distinct days: normal weekdays (non-event days) and event days. On non-event days, we assume that a TOU pricing structure is in effect consisting of two rate periods: peak and off-peak. On an event day, a CPP adder is layered on top of the TOU price for all hours that fall inside the CPP window. An effective TOU-CPP rate will have peak periods that are well-aligned with the hours when system capacity is likely to peak.

To determine the hours for each TOU-CPP rate period, Nexant assessed the concentration of peaking risk associated with all hours of the year and then examined how much of the risk would be covered by various peak periods. A peak period from 11 AM to 6 PM would capture 94.4% of the historical generation peaking risk at RG&E and a peak period from noon to 9 PM would capture 89.3% of the peaking risk for NYSEG.

4.2.2 Prices

After the rate periods were defined based on peaking risk, it was necessary to set prices that would be in effect during each rate period. The analysis assumed that both bundled and retail access consumers would have the same rate options. To develop these prices, we first determined market-based generation and energy-related costs for the TOU peak period during summer weekdays. We used NYISO day-ahead prices from summer, non-holiday weekdays to determine the economically efficient price signal (peak-to-off-peak price ratio) during the TOU peak period. The ratio of average peak to off-peak prices yielded a price ratio of 1.5.

After establishing the TOU peak-to-off-peak price ratio, CPP adders[18] were then determined assuming that 12 CPP events would be called on average during each summer. A key initial input to determining CPP adders is the avoided capacity cost values; we used a value of \$68.48/kW-year. This represents the average avoided generation capacity cost for RG&E and NYSEG (SC1) for 2021 from Table 4-2 in Section 4.6 below (\$43.84/kW-year) plus the average avoided transmission cost (\$3.72/kW-year) and avoided distribution cost (\$20.92/kW-year) as also discussed in Section 4.6. Equation 1 shows the calculation of the CPP price adder based on the total avoided capacity costs, the number of CPP events, the length of the CPP period, and the percent of peaking risk captured.

$$\text{CPPadder\_gen} = \frac{\text{Avoided Generation Capacity Cost}}{\text{\# CPP days} \times \text{Length CPP Period}} \times \%\ \text{System Risk Captured} \qquad \textbf{(1)}$$

To determine the new TOU-CPP prices, we first took the TOU price signal and CPP adders as fixed and then discounted the off-peak price by a commensurate amount to reach a new rate that is revenue neutral.[19] This step necessitated calculating revenue under the current rate structure as well as revenue under the new, TVP structure, which required data on usage by time of day for the average customer within each customer class. We used a representative sample of 25% of residential customers within each IOU to calculate current revenue and solved for new prices that did not increase or decrease revenue, on average. In summary, the rates were calculated using the following steps:

- Calculate current revenue for the average customer using the variable portion of current prices;[20]
- Calculate the average customer's usage in CPP, TOU and off-peak periods; and
- Solve for the TOU off-peak variable price that equates current revenue with revenue under the new prices.

The outcome of the steps summarized above produced a peak to off-peak price ratio of 1.7 on average weekdays. On CPP days, the estimated peak to off-peak price ratio is 12 to 1 at NYSEG and 14 to 1 at RG&E. This is within range of the maximum CPP peak to off-peak price ratio of 14:1 for which pilot studies of load impacts in the region exist. This rate gives residential

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[18] By "adder," we mean an amount that is added to the TOU price in each period within the CPP window on an event day.

[19] The TOU-CPP rate is revenue neutral compared to the standard flat rate if the revenue collected under both tariffs is the same, holding the consumption pattern for the average customer constant for both rates.

[20] Only the variable portion of current prices is used as the customer has no incentive to change consumption when fixed prices change.

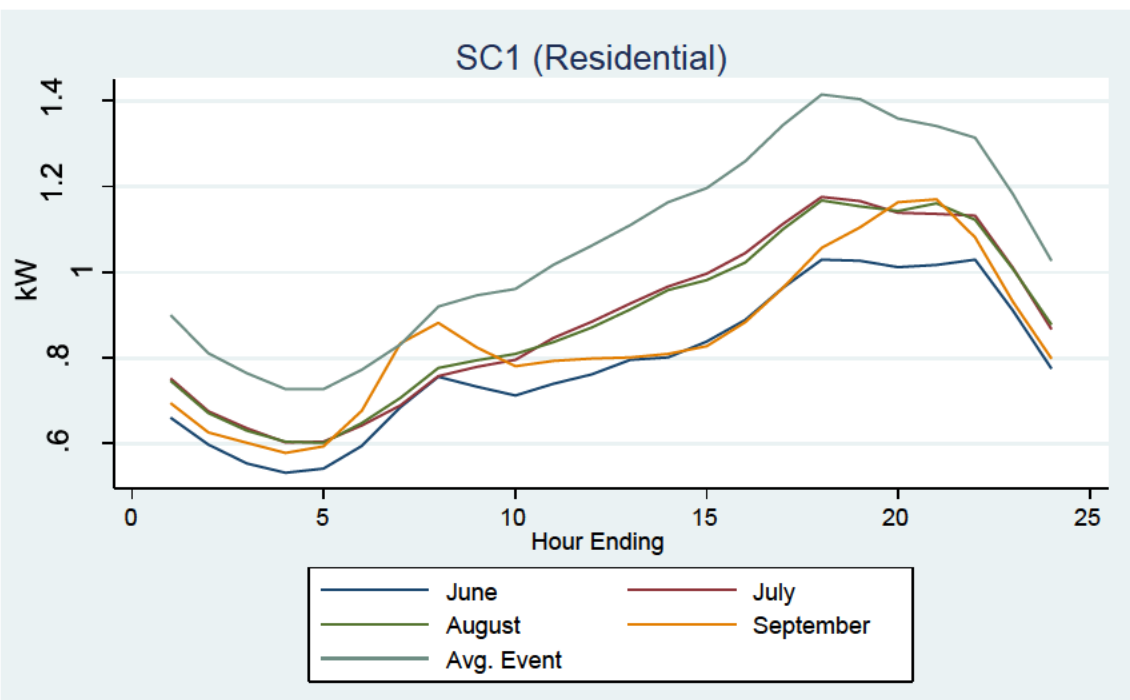
consumers a strong incentive to reduce peak period energy use on CPP days and a modest incentive to reduce it on average weekdays.

4.3 Price Responsiveness and Load Impacts

After deriving a revenue-neutral TOU-CPP rate, the next step in the methodology is to predict how customers would adjust their energy usage behavior in response to that rate. This is a two-step process involving the estimation of reference loads and the use of a demand model to estimate how usage in each pricing period changes. The analysis assumes that both bundled and direct access customers face the same rates.

A key input to predicting demand reductions in response to TVP tariffs is the current load shape for customers who enroll on the rate. Electricity usage varies throughout the year as seasons/temperatures change and it is important to capture these differences in the reference loads because it has a direct impact on the magnitude of load reductions that can be achieved using TVP at different points in time. Unfortunately, the Companies do not have a dynamic load research sample that could be used to develop reference loads. A neighboring utility, NGrid, does, however, and NGrid gave permission to use their load shapes for this analysis. NGrid's load data was combined with the Companies' annual usage data to develop proxy load shapes for each customer segment. Figure 4-2 shows the hybrid reference loads for the average weekday for each summer month and for the average CPP day for NYSEG's SC1 rate. As seen, loads on CPP days are much higher than on non-CPP days and reducing demand during peak periods on these days is a key driver of benefits from TVP rates. Similar profiles occur for the SC8 tariff and for the RG&E SC1 tariff.

FIGURE 4-2: REFERENCE LOADS FOR NYSEG SC1 NON-ESCO CUSTOMERS



The second step in estimating load reductions from TOU-CPP rates is predicting how customers would respond to time-varying rates in each rate period. Estimating changes in demand that result from a change in price is a fundamental issue in economics and a large amount of research has been done to develop structural models of demand that capture customer preferences for goods and services based on their own price and the prices of any complementary/substitutable goods and services. Empirically, these preferences can be represented by elasticities, which relate changes in consumer demand to changes in explanatory variables such as prices and income.

The Companies are currently conducting a TVP pilot in the Energy Smart Community (ESC) demonstration project but load impact estimates are not yet available from that study. Fortunately, numerous other utilities have conducted pilots and program evaluations that can be used to predict load reductions for the TVP tariffs summarized above.[21]. The analysis presented here relied on elasticity estimates from Connecticut Light and Power's ("CL&P") Plan-It Wise Energy Pilot[22] for residential opt-in customers. The demand response for small business customers was based on analysis of TOU pricing in California and was assumed to equal a conservative 2%.

The reference loads and price elasticities discussed above combined with the assumed price ratios discussed in Section 4.2.2 produce the average load reductions per customer shown in Table 4-1.

TABLE 4-1: AVERAGE LOAD IMPACTS BY CUSTOMER SEGMENT AND DAY TYPE

Utility	Customer Class	Rate	Supply	Type	Reference Load (kW)	Impact (kW)	Percent Impact
NYSEG	Residential	SC 1	Utility	Avg. Event	1.27	0.18	14.2%
				July Weekday	1.07	0.02	1.5%
			ESCO	Avg. Event	1.43	0.20	14.2%
				July Weekday	1.20	0.02	1.5%
		SC 8	Utility	Avg. Event	1.59	0.22	14.2%
				July Weekday	1.30	0.02	1.4%
			ESCO	Avg. Event	1.76	0.25	14.2%
				July Weekday	1.45	0.02	1.4%
	SMB	SC 2	Utility	Avg. Event	5.95	0.12	2.0%

[21] A useful bibliography on the topic can be found at http://files.brattle.com/system/publications/pdfs/000/005/266/original/dynamic_pricing_bibliography_4-15.pdf?1454955084

[22] See http://nuwnotes1.nu.com/apps/clp/clpwebcontent.nsf/AR/PlanItWise/$File/Planhttp://nuwnotes1.nu.com/apps/clp/clpwebcontent.nsf/AR/PlanItWise/$File/Plan-it Wise Pilot Results.pdfit%20Wise%20Pilot%20Results.pdf and http://papers.ssrn.com/sol3/papers.cfm?abstract_id=2028178

				July Weekday	5.61	0.11	2.0%
			ESCO	Avg. Event	14.04	0.28	2.0%
				July Weekday	13.00	0.26	2.0%
RG&E	Residential	SC 1	Utility	Avg. Event	1.27	0.21	16.2%
				July Weekday	1.07	0.02	1.5%
			ESCO	Avg. Event	1.50	0.24	16.2%
				July Weekday	1.26	0.02	1.5%
	SMB	SC 2	Utility	Avg. Event	1.39	0.03	2.0%
				July Weekday	1.25	0.02	2.0%
			ESCO	Avg. Event	1.59	0.03	2.0%
				July Weekday	1.41	0.03	2.0%
		SC 7	Utility	Avg. Event	11.64	0.23	2.0%
				July Weekday	10.82	0.22	2.0%
			ESCO	Avg. Event	18.65	0.37	2.0%
				July Weekday	17.32	0.35	2.0%

4.4 Enrollment Rates

Customer enrollment on TVP tariffs is influenced by a number of factors, including customer characteristics, enrollment strategy (e.g. opt-in versus default), rate characteristics and the marketing strategies and tactics used to encourage participation. Enrollment rates from the Sacramento Municipal Utility District's SmartPricing Options pilot[23] were used as input to the assumed enrollment rate of 15% for the opt-in and 90% for the default tariff. While SMUD's population differs from the Companies' and enrollment rates may differ, we believe that 15% enrollment is achievable if driven by extensive customer research (this effort is factored into the cost analysis) that informs the development of plans for communicating with customers and educating them about the rate. However, in the interest of having estimates that are conservative, we also included a $25 signup incentive to overcome inertia and encourage enrollment. Market studies done at PG&E indicate that a modest sign-up incentive can double enrollment rates for CPP tariffs compared with marketing campaigns that do not pay incentives. There are also well known examples of much higher enrollment rates for TOU tariffs. Salt River Project and Arizona Public Service have roughly 25% and 50% of their customers currently enrolled on TOU rates after several decades of concerted marketing. Over roughly a three-year marketing campaign, Oklahoma Gas and Electric ("OG&E") has enrolled roughly 15% of their target population onto their SmartHours Rewards program. Given these observed enrollment rates from actual TVP tariffs offered by utilities, we believe that the assumption of a 15% enrollment rate based on extensive customer research and the significant marketing expenditures (including a signup incentive) incorporated into the BCA is reasonable.[24]

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[23] Stephen George, Jennifer Potter and Lupe Jimenez. *SmartPricing Options Final Evaluation*. September 5, 2014. See also SmartPricing Options Interim Evaluation. October 23, 2013

[24] In 2017, NYSEG marketed a number of pilot rates to customers in the Energy Smart Community (ESC). Enrollment rates were quite low, which prompted an audit by two consultants to determine

The TVP rate program is assumed to ramp up according to the AMI meter deployment schedule but with a one-year lag based on the expected percentage of meters deployed by the beginning of each summer. Using the meter deployment schedule discussed in Section 2, enrollment on the TVP rate would begin in 2023 and ramp up over a three year period. The opt-in scenario also assumes that the 15% steady state enrollment rate is not reached until the third year in which the rate is offered and that only the top three quartiles of consumers, based on annual usage, are recruited. This is an increasingly common practice with opt-in rates since low use consumers may not deliver benefits large enough to overcome the marketing costs associated with enrolling them. Once the steady state enrollment of 15% is obtained in the opt-in scenario, this is assumed to be maintained in all subsequent years by recruiting enough consumers to replace those who leave the program. There are two types of consumers who may leave a rate program, those who drop out because they don’t want to be on the rate and those who close their account for any of a variety of reasons, including due to moving out of the service territory. In the analysis conducted here, we assume that customers who close their accounts but open a new account within the same service territory will be defaulted onto the TVP rate that they were on before they closed the account. That is, once a customer enrolls on the TVP rate, we assume the rate follows them as long as they stay inside the service territory. As such, no recruitment costs are incurred from replacing them. Data from the Companies on customer churn combined with census data concerning the number of customers who move outside the territory and an assumed dropout rate of 2% per year were combined to produce estimates of replacement customers equal to 8.8% for NYSEG and 11.1% for RG&E.

4.5 Costs

Costs associated with the illustrative TVP program are meant to be indicative of what might be needed to support each enrollment scenario. Wherever possible, they are based on evidence from pricing pilots or programs that have been implemented by other utilities or on the Companies’ costs for marketing campaigns for other programs. Costs are assumed to vary over time according to three implementation stages. Stage 1 is the prelaunch period during which program design, launch preparation and development of all marketing materials would occur. Stage 2 is the ramp up period during which primary program recruitment would occur and stage 3 is the steady state period. Stage 1 is assumed to last one year, stage 2 is assumed to last two years following the prelaunch period, and stage 3 covers the remaining years of the forecast period. Costs incorporated into the analysis include: program design and administration; general marketing; customer specific acquisition costs; recurring engagement costs; and program evaluation. The cost assumptions for each category are detailed below.

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why enrollment rates were less than expected. Several significant impediments were identified, including requiring that all customers enroll online rather than using simpler channels such as a business reply or calling into the Company’s call center, the fact that the online enrollment process involved numerous steps and many customers who wanted to enroll were not successful, the fact that all customers had to enroll in Energy Manager to enroll on the rate, and the fact that the marketing collateral was complicated and not compelling..

4.5.1 Program Design and Administration

This category covers the cost of in-house staff assigned to manage the TOU-CPP program during the analysis period, including program development, the intensive ramp up period and the long term steady state period. It also includes costs for outside consulting services during the prelaunch period.

During the prelaunch phase, we assume that a project manager and an assistant project manager will be needed half time for a year to get ready for program launch. The cost of an FTE project manager, fully loaded, is assumed to equal $162,000 per year ($81,000 for half a year), which is comprised of a base salary of $90,000 per year and 80% overhead rates.[25] The cost of an assistant is assumed to be $117,000 per year ($58,500 for half a year), with a base salary of $65,000 plus 80% overheads. We also assume that the Companies would require outside consulting services for design and implementation planning for both scenarios, at a cost of $200,000. Combined, the prelaunch costs for both scenarios are assumed to equal $339,500.

During the two-year ramp up period, we assume that program administration will require one fulltime project manager and a full time assistant project manager for both scenarios, at a cost of $279,000 per year. During the steady state period, we assume the program can be operated by a half-time project manager and a full-time assistant project manager, at an annual cost of $198,000.

4.5.2 General Marketing

The general marketing cost category covers all marketing costs other than direct mail and other forms of customer-specific communication. During the prelaunch phase, this category covers development of all marketing materials, including customer-specific outreach materials such as direct mail letters and brochures. Mass media advertising is assumed to not be used since this example involves targeting customers in the top three usage quartiles (since lower usage customers are less cost effective) and mass media advertising would invite inquiries from the lowest quartile customers. Mass media advertising is also inappropriate during the ramp up phase when not all customers are eligible because they don't yet have meters.

General marketing costs during the prelaunch period are assumed to cover development of all marketing materials and strategies. This would likely include focus groups to develop sound messaging strategies for marketing and educational materials. During the buildup to its very successful SmartPricing Options pilot, SMUD obtained input from roughly 2,500 customers through 20 focus groups and four surveys to develop successful names for each rate plan, preferred messaging and channels of communication for various customer segments and educational materials in the form of welcome kits and other ongoing communication.[26] This extensive research was one of the key reasons why SMUD was able to achieve enrollment rates between 15% and 20% for their opt-in pricing plans. At a cost of roughly $15,000 per focus group and $50,000 per survey, this level of effort would cost approximately $500,000.

[25] Based on input from the Companies. All estimates are assumed to be in 2019 dollars.
[26] SmartPricing Options Interim Evaluation. October 23, 2013.

Since the pricing scenarios analyzed here involve a single rate, we assume that the Companies would conduct 10 focus groups (covering different customer segments) and two surveys in support of development of marketing materials during the prelaunch period, at a total cost of $250,000.

SMUD's development of marketing materials for the SPO pilot involved outside service costs of more than $600,000 for seven different pricing plans. Development of direct mail marketing materials and welcome kits for a single rate is assumed to require expenditures of $200,000. In total, prelaunch expenditures for this illustrative program are assumed to total $450,000.

4.5.3 Customer Specific Acquisition Costs

This category covers costs associated with customer acquisition. Four subcategories of costs are included here: customer-specific communication costs for materials such as direct mail; an enrollment incentive; welcome kits that explain how the rate works and that educates consumers about the kinds of behavioral changes that could lead to lower bills; and the cost of processing a tariff change. Acquisition costs differ significantly during the ramp up and steady state periods.

Customer-specific communication costs are based on a direct-mail/email marketing campaign. Even though the Companies currently have email addresses on 45% to 50% of their customers and this percent is growing each year, we assume conservatively that the Companies would use email outreach for only 25% of the population and would use direct mail for the remaining 75% of the population. We also assume that each DM customer would receive 3 mailings over the course of the two-year ramp up period. The cost per mailing, $1.36, is based on inputs from the Companies from a recent direct mail campaign for an arrears management program.[27] In this recent campaign, the Companies paid $1.10 for printing and mailing for each direct mail piece, plus $0.26 for postage, bringing the total to $1.36. The Companies also recently paid $0.006 for each email in a recent marketing campaign.

The average cost per acquired customer for the DM/email campaign is a function of the enrollment rate. For example, if each customer targeted for enrollment received 3 direct mail pieces on average, and the enrollment rate was 5%, the average cost per enrolled customer would equal $81.60 (($1.36x3)/0.05). On the other hand, if the enrollment rate was 15%, the average cost per enrolled customer would be $27.20 (($1.36x3)/0.15). Based on the above costs and a 15% enrollment rate, the average cost per enrolled customer is $20.46 (= ((3x$1.36x0.75) + (6x$.006x.25))/0.15)).

The next subcategory of costs is for marketing incentives. Research by Nexant in conjunction with PG&E's SmartRate tariff [28] indicated that relatively modest sign up incentives in the range of $25 to $50 can significantly improve enrollment rates. Although SMUD obtained high enrollment rates for all pricing plans without using incentives, and Arizona Public Service and

[27] Email from Leona Michelson, dated 5/11/16.

[28] SmartRate is a critical peak pricing tariff with no TOU component. See Pacific Gas and Electric Company Rate Design Window 2012. Appendix A, Volume 1. Report in Compliance with D.11-11-008 OP3. Report on SmartRate™ and TOU Tariffs. February 29, 2012.

Salt River Project have obtained enrollment rates in the 25% to 50% range over a long period of time without using incentives, we nevertheless assumed that a signup incentive of $25 would be needed to achieve an enrollment rate of 15%.

The third cost element tied to initial recruitment onto each rate is a welcome kit that explains the details of the rate and provides education and tips concerning how changes in the timing of electricity use can reduce bills. In SMUD's SPO pilot, the cost for welcome kits equaled $2.50 per enrolled customer. We use this value here.

The final customer acquisition cost is associated with processing tariff changes in the Companies' CIS and billing systems as customers begin transitioning to the new rate. This cost is difficult to estimate as it is tied to the business processes that each utility uses to make such changes, the percent of changes that are made by call center representatives ("CSR") versus business reply cards ("BRC") and other factors. Costs could also vary depending on whether they are handled one at a time or in bulk through overnight batch processing. Once again, we turn to the SMUD pilot for data on this activity. SMUD estimated that, for the opt-in pricing plans, each rate change would cost $29 in terms of CSR labor costs and administrative costs for BRC processing. We use this estimate here although we believe it could be quite high if many changes can be made through a self-service web portal.

In summary, the total cost per enrolled customer for the opt-in scenario is $77.10, which equals $20.60 per enrolled customer for marketing, $25 for incentives, $2.50 for the welcome kit and $29 for CSR and related costs associated with the rate transfer.

In order to maintain a steady-state enrollment of 15%, customers who leave the tariff either because they close their account or wish to drop out, must be replaced. As discussed previously, we assume that customers who close their accounts but open a new account elsewhere within the Companies' service area would be defaulted onto the TVP rate that they were on before they closed the account. That is, once a customer enrolls on the TVP rate, we assume the rate follows them as long as they stay inside the service territory. As such, there are no customer acquisition costs associated with replacing these customers. On the other hand, customers who close their accounts and move outside the service territory must be replaced with someone who moves into the premise they vacated. For these replacement customers, we assume that they will be recruited onto the tariff at the time they open their account. Acquisition costs for these customers for the opt-in scenario would involve the cost of a welcome kit plus the sign-up incentive, for a total cost of $27.50 each. Data from the Companies on customer churn combined with census data concerning the number of customers who move outside the territory and an assumed dropout rate of 2% per year were combined to produce estimates of replacement customers equal to 8.8% for NYSEG and 11.1% for RG&E.

4.5.4 Recurring Engagement Costs

This category covers annual costs per enrolled customer. Costs for programming and operating a notification system are included in the IT cost category for AMI so no additional notification costs are included here. In analyzing costs for SMUD's SPO pilot, this cost category included $1.50 per customer per year for additional CSR support associated with customer inquiries around CPP events and $1.20 per customer per year for additional mailings to remind customers about the upcoming event season and to provide tips about how to manage energy costs. While we believe that there may be additional calls associated with events or high summer bills in the early years of the program, we would expect these calls to dissipate after customers have been on the rates for several years. We also don't believe that reminders would need to be provided every year but would be useful periodically. We have included a cost of $1.50 per year per enrolled customer for the entire duration of the analysis to cover these additional costs, while recognizing that they might be higher in the early years and less in subsequent years.

4.5.5 Measurement and Evaluation Costs

The final assumed cost is meant to cover estimation of load impacts and process evaluations for the tariff programs. We assume these evaluations would be contracted out to an independent evaluator at a cost of $250,000 and each would be done every other year. They are entered into the model as an average cost of $125,000 each year.

4.6 Avoided Costs

The final input variables used in the TVP benefit-cost analysis are the avoided generation, transmission, distribution, energy, and carbon costs used to value reductions in peak period energy use and load shifting behavior induced by the more accurate price signals incorporated in the TOU-CPP rates. Avoided generation capacity costs were based on an installed capacity ("ICAP") forecast produced by the 2018 Congestion Assessment and Resource Integration Study ("CARIS")[29] model, which is refreshed by NYISO annually. This model produces ICAP values for several regions, including the Lower Hudson Valley ("LHV") and Rest of State ("ROS"). The value used for each customer segment of this study was a weighted average between the LHV and ROS forecasts, based on the percentage of the segment's summer usage in the Brewster division (which is in LHV) versus outside of Brewster. For RG&E, the avoided generation forecast was equal to the ROS forecast since Brewster is not a part of RG&E's service territory. Table 4-2 shows the avoided capacity cost inputs used in the analysis in real 2019 dollars.

TABLE 4-2: AVOIDED GENERATION CAPACITY VALUES (2019$/kW-YEAR)

Year	Avoided Generation Capacity Value at Distribution Level ($/kW-yr)			
	RG&E	NYSEG SC1	NYSEG SC8	NYSEG SC2
2018	28.79	39.21	44.82	37.04
2019	40.54	48.57	52.89	46.90
2020	18.24	23.06	25.65	22.05
2021	37.55	51.97	59.73	48.97

[29] 2018 forecast provided to Nexant by Caitlyn Edmundson, NYPSC staff, in email dated November 13, 2018.

Year	Avoided Generation Capacity Value at Distribution Level ($/kW-yr)			
	RG&E	NYSEG SC1	NYSEG SC8	NYSEG SC2
2022	27.00	41.97	50.04	38.87
2023	25.75	40.61	48.61	37.52
2024	25.56	40.47	48.49	37.37
2025	26.09	41.12	49.21	38.00
2026	27.19	42.40	50.59	39.24
2027	30.06	45.35	53.58	42.18
2028	33.20	48.60	56.89	45.40
2029	36.45	51.93	60.26	48.71
2030	39.26	54.79	63.15	51.56
2031	41.72	57.30	65.70	54.07
2032	44.12	59.76	68.19	56.51
2033	46.32	62.03	70.49	58.76
2034	49.00	64.77	73.26	61.50
2035	51.85	67.71	76.25	64.42
2036	54.75	70.67	79.25	67.37
2037	56.46	72.21	80.69	68.94
2038 and Beyond	58.31	73.87	82.24	70.64

Avoided transmission capacity values were based on the value provided in the BCA Handbook (Version 2.0, 7/26/2018; p. 94), and came out to $3.45/kW-year for RG&E and $4.44/kW-year for NYSEG. Avoided distribution capacity values were also taken from the BCA Handbook, and were held constant in real 2019 dollars throughout the analysis period. The assumed value is $19.54/kW-year for NYSEG and $24.85/kW-year for RG&E.

Avoided energy costs were based on the 2018 CARIS location based marginal prices ("LBMP"). These costs include environmental compliance costs including Regional Greenhouse Gas Initiative ("RGGI") compliance, which captures a portion of the cost of carbon. The forecast used in this study was a weighted average of the zonal LBMP values, based on the aggregate annual usage in each zone. Table 4-3 summarizes the input values used for avoided wholesale energy costs in real 2019 dollars.

TABLE 4-3: AVOIDED WHOLESALE ENERGY COSTS (2019$/MWH)

Year	Weighted Average Avoided Wholesale Energy Cost ($/MWh)
2018	20.67
2019	22.22
2020	26.37
2021	28.10
2022	29.82
2023	33.45
2024	32.73
2025	36.22
2026	35.93
2027	38.62
2028	38.64
2029	39.14
2030	39.52
2031	39.84
2032	39.65
2033	39.39
2034	40.00
2035	39.85
2036 and beyond	41.07

Finally, avoided carbon values were based on Staff guidance to use the most recent NY REC value of $21.71/MWh in 2018 dollars, held constant on a nominal basis ($22.43/MWh in 2019 dollars).

4.7 Net Benefits for Opt-in TVP

The benefit-cost analysis presented here compares the cost of implementing TVP pricing assuming meters are in place with the benefits achieved in the form of avoided capacity and energy costs and reductions in carbon emissions. Table 4-4 shows the present value of societal costs, benefits and net benefits for the illustrative opt-in program summarized above. The present value of societal benefits in the form of reduced capacity and energy costs and lower carbon emissions exceed the cost of implementation by $18.2 million over the 20+ year forecast horizon. The benefit-cost ratio is a very robust 2.5.

TABLE 4-4: BCA ANALYSIS RESULTS FOR Opt-IN TVP
(PV over the life of the AMI meters $Millions)

Benefit/Cost Category	$ millions
Avoided generation capacity	$18.0

Avoided transmission capacity	$1.4
Avoided distribution capacity	$7.0
Avoided wholesale energy costs	$3.0
Avoided carbon due to reduced energy use	$0.7
PV of Total Benefits	$30.0
Marketing and acquisition costs	$6.2
Other variable costs	$2.3
Fixed overhead costs	$4.0
PV of Total Costs	$12.4
Net PV of TVP program over meter life	$17.5

4.8 Net Benefits for Opt-out TVP

Increasingly, utilities are considering enrolling customers on TVP using opt-out enrollment. With opt-out enrollment, customers are notified that they will be moved to a TVP rate on a certain date unless they choose to remain on their otherwise applicable tariff (OAT) or choose some other available rate besides the one that they would be defaulted onto if they take no action. In the aforementioned SMUD pilot, both opt-in and opt-out enrollment was tested. This pilot found that, although average load reductions per enrolled customer are smaller in opt-out than in opt-in programs, enrollment rates are much higher in opt-out programs and aggregate load reductions are significantly higher than in opt-in programs. In addition, the average cost per enrolled customer is much lower in opt-out programs. Over the next few years, the vast majority of residential customers in California will be enrolled on TVP using opt-out enrollment.

For comparative purposes, net benefits were estimated for an opt-out scenario. Key assumptions are that roughly 10% of customers will opt out prior to enrolling on the TVP rate, and the average load reduction per enrolled customer is 62% of the average for opt-in enrollment. This value was taken from the SMUD pilot. Opt-out program costs were also patterned after the SMUD pilot. The net benefits from this stylized opt-out program equal $82.5 million, or nearly five times larger than for the opt-in TVP program.

5. Information Feedback Programs

A wide variety of research has been done in the last decade concerning the potential impact on energy use resulting from more frequent and more granular access to information about energy use and the behavioral changes than can be made to reduce energy use and bills. For example, numerous empirical evaluations of Home Energy Reports ("HERs"), which typically provide normative comparisons of usage and energy savings tips through monthly delivery of paper reports on a default basis, show that sustainable annual energy savings of 1% to 3% are achievable.[30] However, these products were developed and have primarily been implemented using conventional, monthly billing data, not the more granular and near real time AMI interval data.

In the last several years, a number of utilities, including CMP, have conducted well designed pilots studying whether weekly provision of usage data (with or without goal setting) reduces energy use. CMPs usage alert pilot offered weekly delivery of usage and cost data to consumers on an opt-in basis and showed that participants reduced annual usage by around 2.5%. However, this pilot also found that it was relatively difficult and costly to attract customers into the program.[31]

Starting in 2013, Nexant began working with Southern California Gas Company ("SoCalGas"), to test a wide variety of information feedback programs, including a variety of weekly usage alert options that have been delivered via email on a default basis to gas only customers for whom SoCalGas already had email addresses. Table 5-1 summarizes winter savings from different usage alert variations over multiple years. All of these options have included email only communications except for the first year of the option that was initially offered in 2013, which included paper communications. Also, except for the first year for the 2013 option, all usage alerts have typically been targeted at the top two usage quartiles of customers. As seen, the average savings vary across years and options. Excluding the first year for the 2013 option, on average, the savings for the default usage alert options tested equals roughly 0.9%. With savings being higher in the second and third year for two of the three options shown in the table, we round this value to 1.0% to represent the assumed savings for the stylized usage alert program incorporated into the BCA.

[30] Reuven Sussman and Maxine Chikumbo. *Behavior Change Programs: Status and Impact.* Amercian Council for an Energy-Efficient Economy (ACEEE). October 2016. http://aceee.org/research-report/b1601

[31] Stephen George, Michael Sullivan, Josh Schellenberg and Taylor Smart. *Central Maine Power Bill Alert Pilot Evaluation.* November 20, 2013.

TABLE 5-1: PERCENT SAVINGS FROM SOCAL GAS USGAE ALERT OPTIONS[32]

First Year Usage Alert Option Offered	Initial Customer Count	Launch Year	% Gas Usage Reduction (Winter)		
			Year 1	Year 2	Year 3
2013	25,000	2013	0.70%[33]	1.20%	1.28%
2015	20,000	2015	0.49%	0.43%	
2015	20,000	2015	0.86%	1.18%	

Some may question whether it is appropriate to use savings from gas usage alert programs to represent electricity savings, or to use savings from a program offered in Southern California for a program offered in upstate New York. Default usage alert programs are not yet widespread and, as such, it is not possible to find empirical estimates that are potentially more representative of the NYSEG/RG&E electricity customers. However, we do note that in the ACEEE report cited above, which summarizes estimated impacts from a wide variety of behavioral conservation options, mostly in the form of paper home energy reports sent out to customers on a default basis, electricity savings were almost always equal to or larger than gas savings. This report also showed that savings at utilities in colder regions (e.g., Commonwealth Edison, Northeast Utilities, Central Hudson, National Grid, and others) differed little from savings estimates in warmer climates (e.g., San Diego Gas & Electric, Pacific Gas and Electric, CenterPoint, Southern California Gas and others). As such, we feel confident in applying this average savings of 1% from the rigorously tested SoCal Gas default usage alerts to the analysis here and submit that it may even be conservative given the evidence from other types of behavioral programs that electricity savings are typically larger than gas savings.

With this background in mind, we estimate the benefits and costs associated with a usage alert program that would be implemented on a default basis for gas and electric customers for whom the Companies have email addresses. This analysis is meant to be indicative of the type of societal benefits that could be obtained through the more granular and timely data that will be available once AMI is fully deployed. The Companies currently have email addresses on between 45% and 50% of residential customers and this percent is growing each year. For this analysis, we assumed that the availability of email addresses will reach 60% of residential customers by the time meters are deployed and will remain at this level over the forecast horizon. We also assume that 5% of customers will opt-out of the default program, which is conservative given that the SoCal Gas usage alerts have had opt-out rates around 1%. Similar to the TVP program, enrollment is predicted to begin in 2022 and ramp up evenly over a three year period until reaching a steady state percentage of the eligible population. For this analysis, the usage alerts are assumed to be offered to the top two usage quartiles of residential

[32] Southern California Gas Company Advanced Meter Semiannual Report, August 31, 2017. Tables 5-3 and 5-7.

[33] In year 1, customers were also sent paper materials in addition to the email alerts. As such, we did not include this year's estimate in the calculation of the average reduction since the objective was to only include usage alerts that were email only.

customers and the average savings for both gas and electricity is assumed to be 1%. Tables 5-2 and 5-3 summarize the average usage and savings for the average customer in the top two quartiles and, for reference, for the average customer in all usage quartiles. As seen, usage in the top two quartiles is much larger than for all customers for both electricity and gas.

TABLE 5-2: AVERAGE USAGE AND ESTIMATED IMPACTS FOR ELECTRICITY CUSTOMERS

Utility	Rate	Supply	Customer Subset	Average Annual Usage (kWh)	Average Annual Savings (kWh)	Average Effective Peak Demand (kW)	Average Effective Peak Demand Savings (kW)
NYSEG	SC 1	Utility	All Customers	7,751.0		1.12	
			Top 2 Quartiles	11,838.8	118.4	1.74	0.017
		ESCO	All Customers	8,725.2		1.28	
			Top 2 Quartiles	12,779.2	127.8	1.91	0.019
	SC 8	Utility	All Customers	13,006.9		1.44	
			Top 2 Quartiles	18,814.8	188.1	2.17	0.022
		ESCO	All Customers	13,654.4		1.60	
			Top 2 Quartiles	19,647.8	196.5	2.39	0.024
RG&E	SC 1	Utility	All Customers	7,845.5		1.10	
			Top 2 Quartiles	11,698.0	117.0	1.68	0.017
		ESCO	All Customers	8,939.4		1.27	
			Top 2 Quartiles	12,960.9	129.6	1.89	0.019

TABLE 5-3: AVERAGE USAGE AND ESTIMATED IMPACTS FOR GAS CUSTOMERS

Utility	Customer Subset	Average Annual Gas Usage (MMBTU)	Average Annual Savings (MMBTU)
NYSEG	All Customers	129.1	
	Top 2 Quartiles	207.8	2.08
RG&E	All Customers	89.2	
	Top 2 Quartiles	125.6	1.26

The analysis assumes there are three types of usage alerts that customers may receive – electricity only, gas-only or both. Both current ESCO and non-ESCO customers are included in this analysis. The annual electricity usage for these specific customers is aggregated and applied to this conservation analysis for usage alerts.

The assumed cost of setting up the usage alert program is $500,000 and the ongoing program management cost is assumed to equal $50,000 per year. In addition, it is assumed to cost $0.0216 per customer per year to send the weekly emails (equals $0.006 per email times 3 emails per month times 12 months). The cost estimates were based on the number of electric only, dual fuel and gas only customers in the NYSEG/RG&E service area.

The benefits associated with this program include avoided energy costs, avoided capacity costs and reduced carbon emissions. In addition to the avoided costs associated with electricity usage that were summarized in Section 4, the analysis for this program required assumptions around natural gas prices and avoided carbon costs associated with reduced gas usage.

Natural gas prices were taken from the 2018 CARIS forecast, which includes price forecasts for zones A-E, F-I, and J-K. RG&E prices were assumed to be equal to the zones A-E forecast, while the NYSEG prices were assumed to be a weighted average of the A-E and F-I forecasts with an 83/17 split, respectively. This was based on the percentage of natural gas sales in each zone for each company. Table 5-4 shows the natural gas price forecasts used in the analysis on a nominal basis.

TABLE 5-4: NATURAL GAS PRICE FORECAST BY COMPANY
(nominal $/MMBTU)

Year	Natural Gas Price (nominal $/MMBTU)	
	RG&E	NYSEG
2018	$2.35	$2.41
2019	$2.43	$2.49
2020	$2.83	$2.90
2021	$2.99	$3.07
2022	$3.13	$3.21
2023	$3.29	$3.38
2024	$3.45	$3.54
2025	$3.64	$3.73
2026	$3.75	$3.85
2027	$3.87	$3.97
2028	$3.96	$4.06
2029	$4.10	$4.21
2030	$4.19	$4.30
2031	$4.27	$4.38
2032	$4.38	$4.49
2033	$4.46	$4.58
2034	$4.57	$4.69
2035	$4.66	$4.79
2036	$4.88	$4.89
2037	$4.99	$4.99

Year	Natural Gas Price (nominal $/MMBTU)	
	RG&E	NYSEG
2038	$5.10	$5.09
2039	$5.21	$5.20
2040	$5.32	$5.31
2041	$5.43	$5.42
2042	$5.54	$5.54
2043	$5.66	$5.65
2044	$5.78	$5.77

Avoided carbon costs associated with reduced natural gas usage are taken from the 2018 CARIS forecast. They are presented in Table 5-5 in nominal dollars per pound of carbon reduction.

TABLE 5-5: AVOIDED CARBON COST ASSCOIATED WITH REDUCED NATURAL GAS USAGE

Year	Nominal $/lb
2017	$0.024
2018	$0.024
2019	$0.025
2020	$0.026
2021	$0.026
2022	$0.026
2023	$0.027
2024	$0.028
2025	$0.028
2026	$0.029
2027	$0.030
2028	$0.030
2029	$0.030
2030	$0.031
2031	$0.031

Year	Nominal $/lb
2032	$0.032
2033	$0.033
2034	$0.037
2035	$0.037
2036	$0.037
2037	$0.037
2038	$0.037
2039	$0.037
2040	$0.037
2041	$0.037
2042	$0.037
2043	$0.037
2044	$0.037

Table 5-6 shows the present value of societal benefits, costs and net benefits associated with usage alerts, based on the societal cost test. As seen, the present value of net benefits for the two operating companies combined over the 20+ year forecast horizon equal roughly $54.8 million. Roughly 40% of the total benefits come from reductions in gas usage and gas related carbon emissions. The benefit/cost ratio on this program is roughly 32.4, indicating that even if costs were much higher or benefits much lower, this program would still be very cost effective from a societal perspective.

TABLE 5-6: SOCIETAL BENEFITS FROM WEEKLY USAGE ALERTS FOR GAS AND ELECTRICITY CUSTOMERS
($Millions, unless otherwise identified)

Benefit/Cost Category	Present Value Over 20 Year Meter Life
Avoided generation capacity	$3.8
Avoided transmission capacity	$0.3
Avoided distribution capacity	$1.5
Avoided wholesale energy costs	$19.5
Avoided carbon due to reduced energy use	$8.8
Avoided wholesale gas costs	$10.9
Avoided carbon due to reduced natural gas use	$11.8
PV of Total Benefits	$56.6
PV of Costs	$1.7
PV of net benefits over 20 year meter life	$54.8

6. CVR/VVO Benefits

One vital role of electric utilities is to ensure that electricity supply remains reliable, which requires maintaining customer voltages between 114 and 126 volts (120 volts ±5%). In most distribution systems, however, voltage levels vary across a circuit due to line losses. Customers located close to the source of a circuit usually receive voltage at levels higher than 120V while voltages are lower at the end of a circuit. Voltage set points flowing into circuits are often set manually based on summer peaking conditions when temperatures are hotter and line losses are higher. Stabilizing and reducing voltage levels within the tolerance range reduces power consumption without requiring any changes in behavior or equipment by customers.

Advances in sensors, telecommunications, optimization models, and control technologies have made it possible to monitor voltages and adjust voltage regulating equipment and capacitor banks in near real time, while ensuring that voltage levels remain within the desired range for all customers. Volt and var optimization (VVO) systems make quick adjustments to voltage and reactive power levels within distribution circuits to address real-time system needs. Because of their real time monitoring and response, they enable delivery of power at lower voltage levels, thus saving power – a concept known as conservation voltage reduction (CVR). A key advantage of CVR/VVO technology is that it can deliver energy savings and demand reductions without changes in customer behavior, without customer purchases, and without utility incentive payments.

The magnitude of demand reductions and energy savings that can be achieved through CVR/VVO depend on whether AMI is in place. Without AMI, a VVO system needs to be operated more conservatively – voltage levels cannot be lowered as much because of the lack of visibility of voltage for end use customers. With AMI, smart meters can communicate voltage levels to the VVO system, thus enabling incremental decreases in voltage levels while ensuring customer voltages remain within the desired range. VVO technology has wide reaching potential and implications. Not only can it help achieve precise customer voltage control and provide substantial energy and demand savings, it can also enhance overall grid efficiency (by reducing line losses), improve power quality, and facilitate the integration of DER and electric vehicles.

Table 6-1 summarizes the key inputs used to estimate the incremental CVR/VVO benefits attributable to AMI due to having voltage reads for individual meters. The incremental reduction of 0.5% for all hours of the year was included in the Companies' 2016 DSIP filing. Consistent with the approach advocated by Staff and adopted by Niagara Mohawk Power Corporation d/b/a National Grid in Cases in Cases 17-E-0238 et al., the Companies recommend use of 0.5 percent for estimating the incremental benefits of CVR/VVO attributable to AMI. This is the same approach the Companies proposed in the AMI Business Plan Panel testimony and supporting exhibits filed in Cases 17-E-0058 et al."

Because the technology reduces energy use across nearly all customers for all hours it delivers a substantial amount of energy, peak demand, and carbon reductions, even though the percentage reduction is quite small. In aggregate, once AMI is fully deployed, the incremental CVR/VVO savings due to AMI is estimated to equal nearly 104 GWh of energy, 19.5 MW of demand reductions, and 56,000 tons of avoided carbon per year, prior to accounting for population and load growth. The present value of these societal benefits over the life of the investment is estimated to equal $86.4 million (in 2019 dollars) across the Companies two jurisdictions. The present value of benefits for NYSEG equal $61.3 million and for RG&E, the estimate equals $25.1 million.

TABLE 6-1: ESTIMATED MONETIZED SOCIETAL BENEFITS FROM CVR/VVO ATTRIBUTABLE TO AMI
($ Millions, unless otherwise identified)

Type of Metric	Metric	NYSEG	RG&E	Total
Inputs	Annual energy consumption (MWh)	14,545,749	6,160,417	
	Peak demand (MW)	2,644	1,265	n/a
Assumptions	% Reduction due to voltage reduction	0.50%	0.50%	0.5%
Benefits per Year	Energy savings (MWh)	72,729	30,802	103,531
	Reduced peak demand (MW)	13.2	6.3	n/a
	Reduced CO2 emissions(tons)	39,359	16,641	56,000
Present Value of Economic Benefits	Avoided gen capacity benefits	$9.0	$3.1	$12.1
	Avoided trans capacity benefits	$0.7	$0.3	$0.9
	Avoided distribution capacity benefits	$3.0	$1.8	$4.8
	Avoided energy benefits (2018 $)	$32.7	$113.7	$46.4
	Carbon benefits due to reduced energy use	$14.7	$5.7	$20.5
	Total Societal Benefits	**$60.0**	**$24.6**	**$84.7**

7. Summary of Benefits and Costs

Table 7-1 summarizes the present value of benefits, costs, net benefits, and the benefit/cost ratio, for five sources of benefits that are enabled by AMI: operational savings; reduction in outage duration and customer outage costs associated with AMI-OMS integration; and reduction in capacity and energy costs and carbon emissions from implementation of opt-in TVP, usage alerts and CVR/VVO. Overall, implementation of AMI and AMI-enabled programs and services is estimated to generate net societal benefits of roughly $281 million. The operational cost savings associated with implementing AMI exceed the AMI system operational costs by $31.1 million. The overall benefit-cost ratio of 1.51 means that even fairly significant changes in assumptions and input values would still produce a positive case for full deployment of AMI. These results, combined with the fact that many intangible and hard-to-forecast benefits such as market animation are not included in the analysis, makes it clear that full deployment of AMI at the Companies' New York service area is a very sound policy decision from a societal perspective. As seen in Table 7-1, the net benefits are positive and the benefit-cost ratio is greater than 1.0 for both NYSEG and RG&E.

TABLE 7-1: 20-YEAR NPV OF AMI SOCIETAL BENEFITS AND COSTS

	Analysis Metric		Societal	
		NYSEG	RG&E	TOTAL
AMI Operational Business Case	Benefits	$403.4	$161.9	$565.3
	Costs	$(350.5)	$(183.7)	$(534.2)
	Net Benefits	$52.9	$(21.8)	$31.1
	B/C Ratio	1.15	0.88	1.06
AMI/OMS Integration	Benefits	$81.7	$11.7	$93.5
	Costs	$(0.6)	$(0.2)	$(0.8)
	Net Benefits	$81.2	$11.5	$92.6
	B/C Ratio	144.94	48.81	116.21
Incremental VVO/CVR (Due to AMI)	Benefits	$60.1	$24.6	$84.7
	Costs	$-	$-	$-
	Net Benefits	$60.1	$24.6	$84.7
	B/C Ratio	n/a	n/a	n/a
Opt-in Time Varying Pricing	Benefits	$21.1	$8.9	$30.0
	Costs	$(8.6)	$(3.9)	$(12.4)
	Net Benefits	$12.5	$5.0	$17.5
	B/C Ratio	2.46	2.30	2.41
Usage Alerts	Benefits	$37.9	$18.7	$56.6
	Costs	$(1.2)	$(0.5)	$(1.7)
	Net Benefits	$36.7	$18.1	$54.8
	B/C Ratio	30.98	35.85	32.43
All AMI	**Benefits**	$604.2	$225.7	$829.9
	Costs	$(360.8)	$(188.4)	$(549.2)
	Net Benefits	$243.4	$37.4	$280.7
	B/C Ratio	1.67	1.20	1.51

Figures 7-1 and 7-2 show how the societal net benefits and benefit-cost ratio varies with changes in key inputs and assumptions for the combined companies. Each row in the figure represents either a benefit or a cost associated with AMI deployment and the values in the graph for each row show the net benefits or B/C ratio associated with an increase and decrease of 20% in the variable. For example, the first row in Figure 7-1 shows how the net benefits vary with a 20% decrease in the cost of sensors required for support of REV if AMI is deployed (which would reduce overall net benefits to $260.0 million compared with the base case of $280.7) and a 20% increase in the avoided cost of sensors (which would increase overall net benefits to $301.3 million). The larger the spread in the graph for a +/-20% change in a variable, the more sensitive are the results given a change in that variable. As seen in Figure 7-1, changes in the avoided cost of sensors, outage cost reductions due to the integration of AMI-OMS, average savings from CVR and avoided wholesale energy costs are the four most impactful variables on the benefit side of the equation. Increases or decreases in operational O&M costs are the most impactful variable on the cost side of the benefit-cost analysis. Variation in the avoided generation, transmission and distribution costs and TVP enrollment and price elasticities have relatively small impacts on overall net benefits.

FIGURE 7-1: VARIATION IN NET BENEFITS GIVEN VARIATION IN KEY INPUT VALUES (COMBINED COMPANIES)

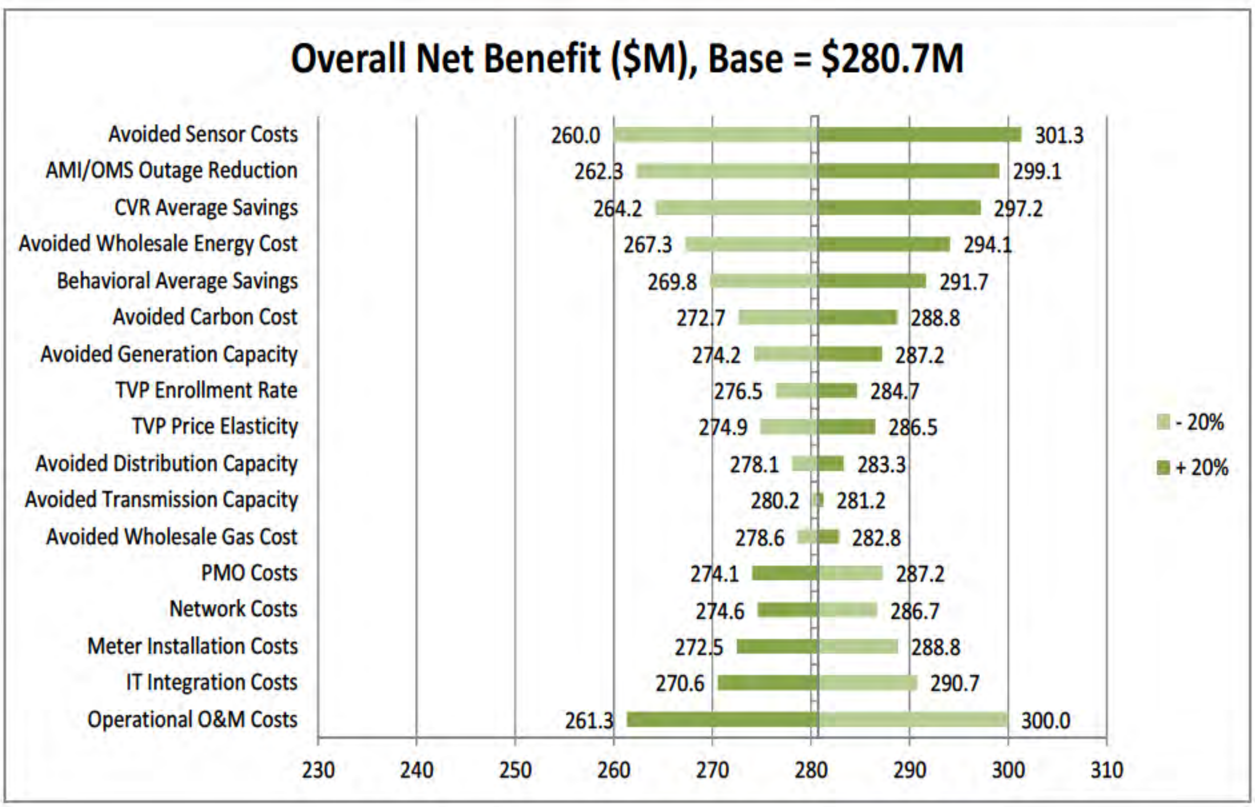
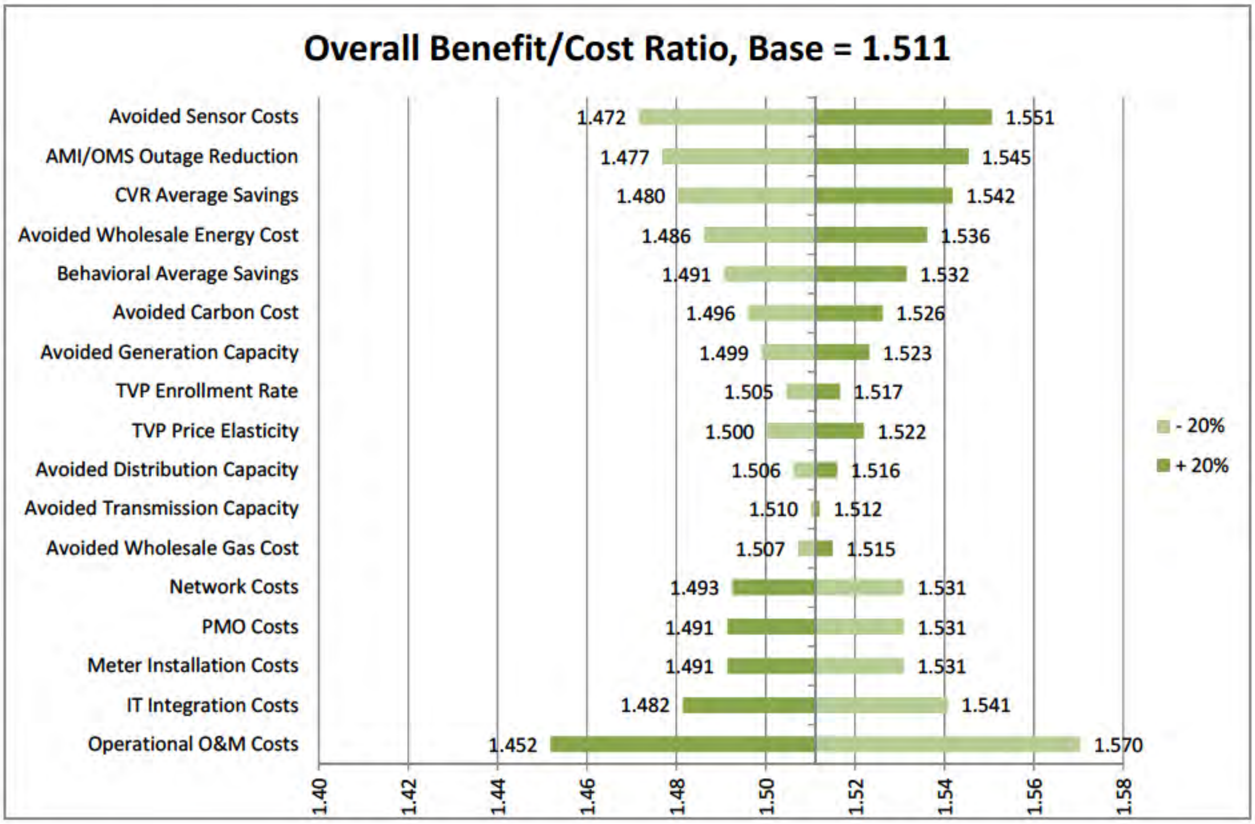


FIGURE 7-2: VARIATION IN B/C RATIO GIVEN VARIATION IN KEY INPUT VALUES (COMBINED COMPANIES)



The sensitivity analysis summarized in Figures 7-1 and 7-2 show that the net benefits from AMI deployment for the combined Companies is very robust across relatively large changes in any single input variable. Indeed, for the most significant input variable (avoided sensor costs), a +/-20% change in the assumed cost only changes the overall net benefits by roughly +/-7%. In fact, in a worst case scenario where all benefits were reduced by 20% from those estimated in the base case and all costs were increased by 20%, the net benefits for the combined Companies would still equal a very significant $120.7 million.[34]

Figures 7-3 and 7-4 show the net benefits and B/C ratio sensitivities for NYSEG and Figures 7-5 and 7-6 show the net benefits and B/C ratio sensitivities for RG&E. As seen in Figures 7-3 and 7-4, the net benefits and B/C ratios for NYSEG are even more robust than they are for the combined Companies. For reasons discussed in Section 1.2, the net benefits and B/C ratio for RG&E on a standalone basis are smaller than they are for NYSEG. Nevertheless, net benefits remain positive and the B/C ratio remains greater than 1.0 across variation of +/-20% in all input variables analyzed. For RG&E, only under a worst case scenario in which the 10 most impactful variables out of the 16 examined were 20% lower in terms of benefits or higher in terms of costs

[34] This worst case scenario was calculated by taking the difference in the net benefits given a change in each variable and the net benefits for the base case for each row in the figure and then subtracting the total for all rows from the base case net benefit estimate.

do the net benefits turn negative. Put differently, while the net benefits are not as large for RG&E as they are for NYSEG, only a very pessimistic set of assumptions regarding costs and benefits would show that deploying AMI at RG&E would not produce positive net benefits.

FIGURE 7-3: VARIATION IN NET BENEFITS GIVEN VARIATION IN KEY INPUT VALUES (NYSEG)

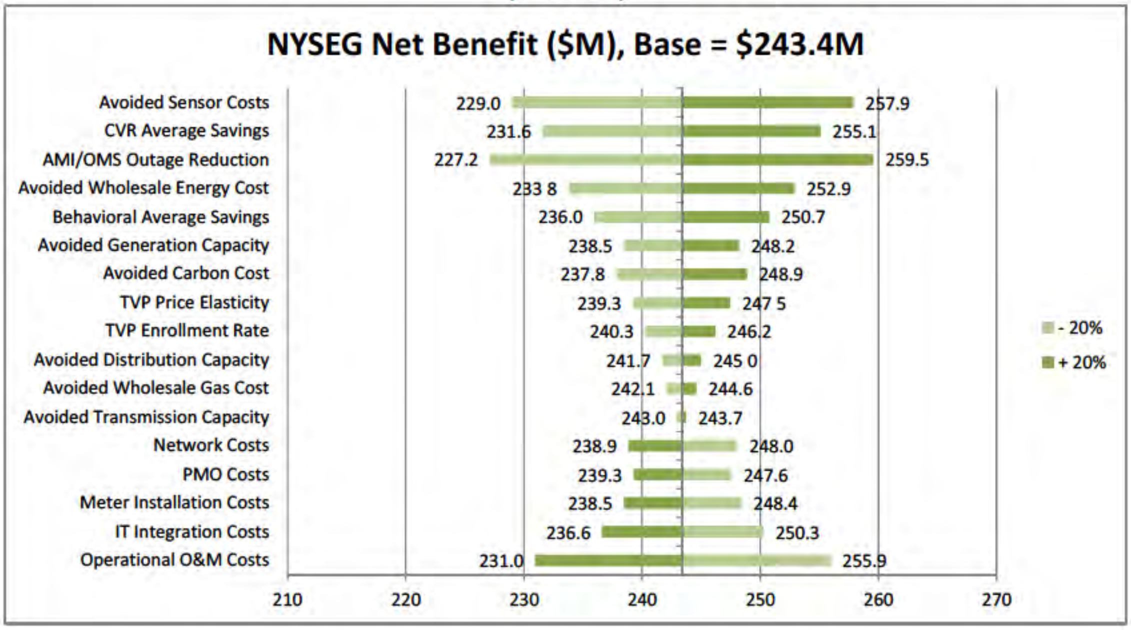


FIGURE 7-4: VARIATION IN B/C RATIO GIVEN VARIATION IN KEY INPUT VALUES (NYSEG)

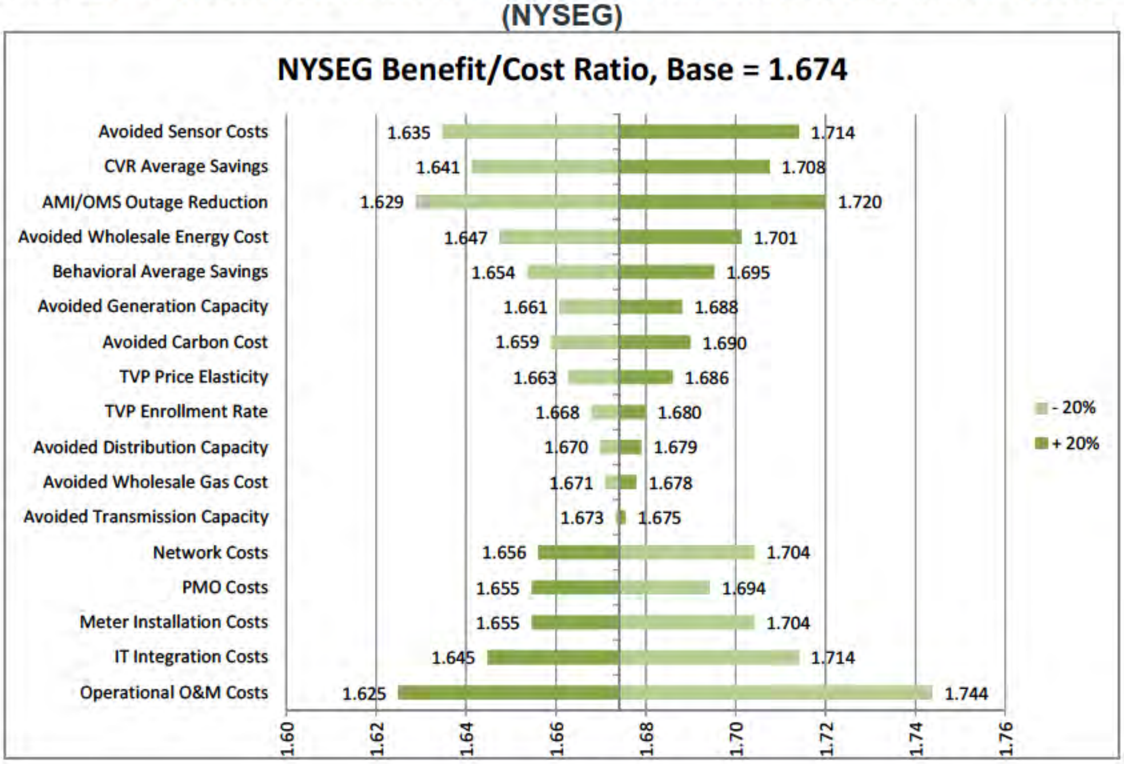


FIGURE 7-5: VARIATION IN NET BENEFITS GIVEN VARIATION IN KEY INPUT VALUES (RG&E)

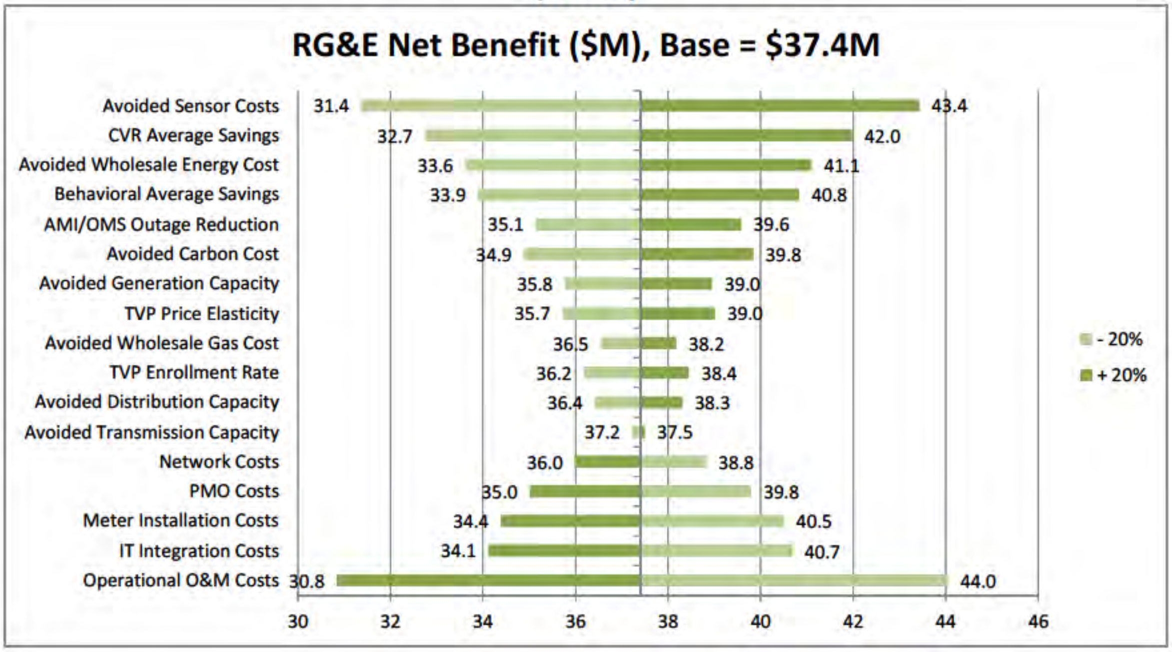


FIGURE 7-6: VARIATION IN B/C RATIO GIVEN VARIATION IN KEY INPUT VALUES (RG&E)

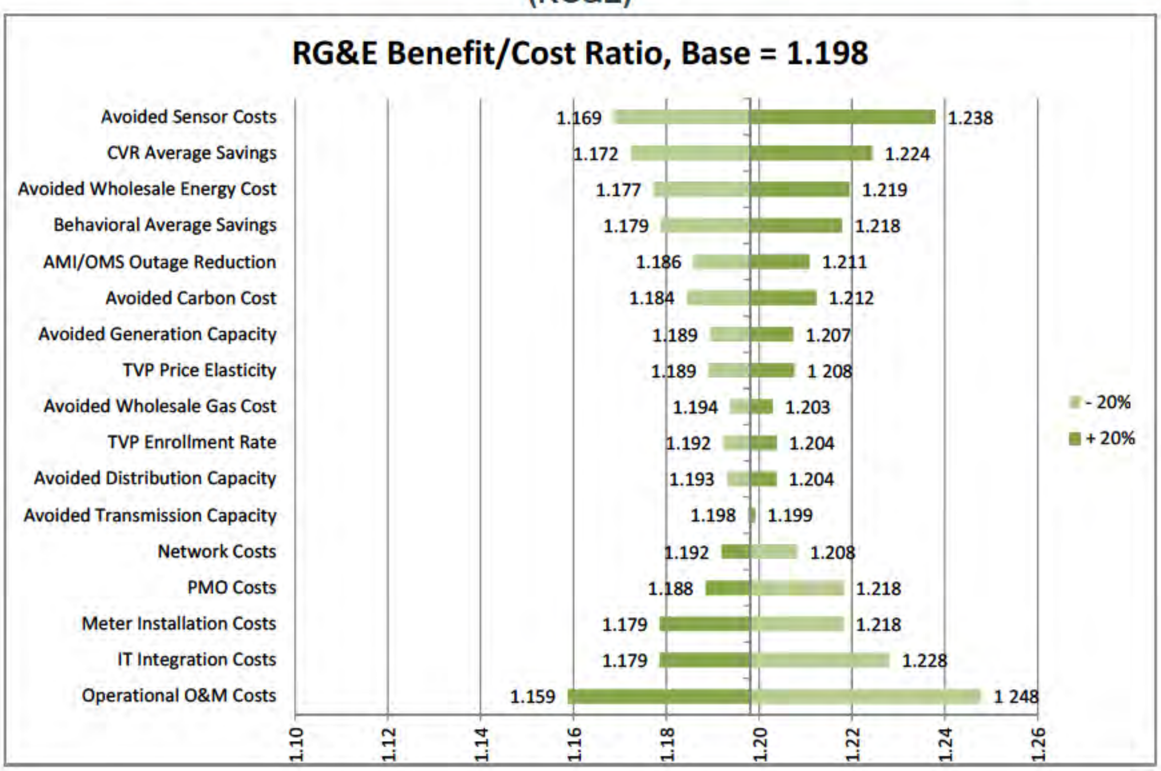


Table 7-2 shows the benefits, costs and net benefits associated with the UTC and RIM test perspectives. Recall from Tables 1-1 and 1-2 in Section 1 that each test includes or excludes certain costs and benefits. For example, both tests exclude carbon and avoided outage benefits and include customer incentives as costs, while the RIM test also counts lost revenue as a cost. It is also very important to note, as previously discussed, that the present value calculations for these two metrics use a significantly higher discount rate than the societal test perspective. This reduces the net benefit values relative to the societal test since many costs (especially the AMI deployment costs) are front loaded over the forecast horizon relative to the benefits, which tend to occur over a longer period of time. As such, the costs have a greater weight in the present value calculations than do the benefits when a higher discount rate is used. The impact of the different discount rates can be seen clearly in Table 7-3 and Table 7-4, which show the PV of benefits and costs side by side for each quantified benefit and cost category based on the post-tax (societal) and pretax discount rates. The tables also show how each quantified benefit and cost category discussed in this exhibit map into each cost test perspective. In spite of these differences across the test perspectives, as seen in Table 7-2, the net benefits are positive for both the Utility Cost Test and the Ratepayer Impact Test.

TABLE 7-2: NPV OF AMI BENEFITS AND COSTS USING UCT AND RIM TESTS

	Analysis Metric	Societal Test	Utility Cost Test	Ratepayer Impact Test
AMI Operational Business Case	Benefits	$565.3	$483.0	$600.9
	Costs	$(534.2)	$(497.6)	$(497.6)
	Net Benefits	$31.1	$(14.5)	$103.3
	B/C Ratio	1.06	0.97	1.21
AMI/OMS Integration	Benefits	$93.5	$-	$-
	Costs	$(0.8)	$(0.8)	$(0.8)
	Net Benefits	$92.6	$(0.8)	$(0.8)
	B/C Ratio	116.21	-	-
Incremental VVO/CVR (Due to AMI	Benefits	$84.7	$52.9	$52.9
	Costs	$-	$-	$(38.1)
	Net Benefits	$84.7	$52.9	$14.9
	B/C Ratio	n/a	n/a	1.39
Opt-in Time Varying Pricing	Benefits	$30.0	$24.2	$24.2
	Costs	$(12.4)	$(16.5)	$(17.7)
	Net Benefits	$17.5	$7.6	$6.5
	B/C Ratio	2.41	1.46	1.37
Usage Alerts	Benefits	$56.6	$29.9	$29.9
	Costs	$(1.7)	$(1.5)	$(13.4)
	Net Benefits	$54.8	$28.4	$16.5
	B/C Ratio	32.43	19.74	$2.21
All AMI	**Benefits**	**$829.9**	**$590.1**	**$707.9**
	Costs	**$(549.2)**	**$(516.4)**	**$(567.4)**
	Net Benefits	**$280.7**	**$73.7**	**$140.5**
	B/C Ratio	**1.51**	**1.14**	**1.31**

TABLE 7-3: BENEFIT ESTIMATES FOR EACH COST TEST PERSPECTIVE
($ million, unless otherwise identified)

	Benefit Type	Benefit Category	Societal	Utility	Ratepayer	NPV (Post Tax)	NPV (Pre-tax)
AMI	Avoided Capital	Avoided meter purchases	X	X	X	$80.8	$70.9
		Avoided solar meters	X	X	X	$9.6	$7.9
		Avoided sensors	X	X	X	$95.3	$89.4
	Avoided O&M	Billing	X	X	X	$9.3	$7.7
		Call center	X	X	X	$14.1	$11.7
		Field work	X	X	X	$81.8	$67.9
		Improved cash flow	X	X		$10.5	$8.8
		Meter reading	X	X	X	$194.3	$161.1
		Reduced field costs through voltage monitoring	X	X	X	$2.6	$2.2
		Reduced storm costs	X	X	X	$38.5	$32.0
		Avoided network O&M	X	X	X	$-	$-
		Reduced non-storm restoration costs	X	X	X	$18.5	$15.4
	Avoided Fleet Capital	Field work	X	X	X	$2.6	$2.2
		Meter reading	X	X	X	$7.2	$6.0
	Societal Benefits	Avoided carbon due to fewer truck rolls	X			$0.0	$0.0
		Avoided customer outage costs	X			$93.4	$77.7
	Fairness Benefits	Meter accuracy improvement			X	$19.2	$16.3
		Energy theft reduction			X	$39.9	$32.5
		Delivery write offs			X	$51.8	$42.2
		Energy write offs			X	$43.7	$35.6
AMI Enabled Rates/ Options	Avoided Capital	Avoided transmission capacity	X	X	X	$2.6	$2.2
		Avoided distribution capacity	X	X	X	$13.2	$11.0
	Customer Energy Supply	Avoided generation capacity	X	X	X	$33.9	$27.7

	Benefit Type	Benefit Category	Societal	Utility	Ratepayer	NPV (Post Tax)	NPV (Pre-tax)
	Savings	Avoided wholesale energy costs	X	X	X	$68.9	$57.1
		Avoided wholesale natural gas costs	X	X	X	$10.9	$9.1
	Societal Benefits	Avoided carbon due to reduced energy use	X			$29.9	$25.1
		Avoided carbon due to reduced natural gas use	X			$11.8	$9.7
Total	Total		$829.9	$590.1	$707.9		

TABLE 7-4: COST ESTIMATES FOR EACH COST TEST PERSPECTIVE
($Millions, unless otherwise identified)

	Benefit Type	Benefit Category	Societal	Utility	Ratepayer	NPV (Post Tax)	NPV (Pre Tax)
AMI	Deployment Capital	IT hardware	X	X	X	$38.6	$37.9
		IT software	X	X	X	$87.9	$85.7
		Meters	X	X	X	$209.2	$197.3
		Network	X	X	X	$31.3	$29.8
		PMO	X	X	X	$31.6	$30.1
	Refresh Capital	IT hardware	X	X	X	$19.1	$16.9
		Meters	X	X	X	$7.0	$6.0
		Network	X	X	X	$10.0	$8.6
	O&M	O&M	X	X	X	$99.6	$85.1
AMI Enabled Options	O&M	Marketing acquisition costs	X	X	X	$6.2	$5.7
		Other variable costs	X	X	X	$3.1	$2.6
		Fixed overhead costs	X	X	X	$4.9	$4.3
		Participant sign up incentives		X	X	$6.3	$5.5
	Lost Revenue	T&D revenue losses /customer savings			X	$61.3	$51.0
	AMI/ OMS Capital	Software	X	X	X	$0.8	$0.8
Total	Total		$549.2	$516.4	$567.4		

AMI Appendix A: Equations Underlying Estimation of Outage Cost Reduction Benefits

Section 3.1 summarized the methodology underlying the estimation of outage cost reduction benefits attributable to AMI-OMS integration. As discussed there, each of the three customer classes included in the analysis has two equations, one modeling the likelihood that the outage cost is greater than zero and the other estimating the outage cost associated with an interruption. This appendix provides the coefficients for each of the six equations used in the analysis. Table A-1 provides the Medium and Large C&I ICE Model coefficients for the probit (Part 1) and GLM (Part 2) equations. Table A-2 provides the Small C&I ICE Model coefficients and Table A-3 provides the residential coefficients.

Table A-1: MEDIUM AND LARGE C&I ICE MODEL COEFFICIENTS

Variable	Part 1: Probit	Part 2: GLM
Interruption Characteristics		
duration	0.005	0.005
duration^2	-2.689E-06	-2.912E-06
summer	0.380	0.032
Customer Characteristics		
ln(annual MWh)	0.118	0.489
Interactions		
duration x ln(annual MWh)	-3.183E-04	-1.270E-04
duration^2 *x ln(annual MWh)*	1.481E-07	1.071E-07
Industry		
manufacturing	0.203	0.818
Regional Characteristics		
GDP / kWh (Non-residential)	0.024	0.073
Constant	-1.082	4.916

Table A-2: SMALL C&I ICE MODEL COEFFICIENTS

Variable	Part 1: Probit	Part 2: GLM
Interruption Characteristics		
duration	0.003	0.004
duration^2	-1.783E-06	-2.155E-06
summer	0.215	-0.384
morning	0.537	-0.057
afternoon	0.664	-0.032
Customer Characteristics		
ln(annual MWh)	0.124	0.069
backupgen or power conditioning	0.082	0.308
backupgen and power conditioning	0.272	0.538
Industry		
construction	0.261	0.786
manufacturing	0.176	0.587
Constant	-1.332	7.000

Table A-3: RESIDENTIAL ICE MODEL COEFFICIENTS

Variable	Part 1: Probit	Part 2: GLM
Interruption Characteristics		
duration	0.002	0.002
duration^2	-6.735E-07	-9.474E-07
summer	0.224	0.237
afternoon	-0.255	-0.291
evening	-0.083	-0.096
Customer Characteristics		
ln(annual MWh)	0.130	0.262
household income	2.340E-07	1.653E-06
Constant	-0.053	1.299

Appendix O(AMI-2)

Customer Outreach and Engagement Plan
(AMI O&E Plan)

Table of Contents

1. Introduction

New York State Electric & Gas Corporation (NYSEG) and Rochester Gas and Electric Corporation (RG&E) (collectively, the Companies and individually, the Company) are excited about the opportunity to engage and educate customers on the benefits of Advanced Metering Infrastructure (AMI). We will execute our Customer O&E Plan through engagement with employees, customers, community resources, and other interested stakeholders. This approach will enable customers to understand and take advantage of the benefits of AMI.

A robust customer engagement plan is a key element in attracting and educating customers. This initiative will transform the Companies' relationship with customers by providing a foundation for future innovation and change. NYSEG and RG&E customers will have the opportunity to:

- Better understand and manage their energy use;
- Shop for renewable energy;
- Enroll in energy efficiency programs; and
- Compare energy products and services.

As part of the approved 2016 rate plan (Cases 15-E-0283 et al.[1]), the State of New York Public Service Commission ("Commission") approved the Companies' Energy Smart Community ("ESC") project in a portion of NYSEG's Tompkins County service area. Implementation began in 2016. NYSEG's ESC demonstration (12,451 electric meters and 7,590 gas meters) in Ithaca, New York, is designed to demonstrate and validate initiatives to implement New York State's Reforming the Energy Vision initiative ("REV"). While the ESC is completely separate from the full-scale deployment of AMI, there are helpful lessons learned that can be applied to full-scale deployment. While this experience is instructive, the selection of service providers to establish the Energy Smart Community is determinative to the selection vendors for the full-scale deployment of AMI through the Companies' service areas. There is no presumption that the service providers for the ESC will be the vendors and service providers for the full-scale deployment.

The implementation of AMI, pending regulatory approval, is expected to be completed over a four-year period ranging from the second quarter of 2020 through the first quarter of 2024.

- Immediately following regulatory approval, IT integration work will begin. Most key IT systems, including the customer web portal, will be in place prior to the installation of the first meter, in April 2021. The new customer information system will take longer to deploy but will be in place by the end of 2021.
- The AMI communications network, linking the customer meters to the AMI operations center, will be deployed over a two-year period from January 2021 through the end of 2022.

The 1.3 million AMI electric meters and 600,000 gas communications modules for existing gas meters will be deployed over a three-year period commencing in April 2021 through March of 2024. The Companies expect to commence work simultaneously in the eastern and western

[1] Cases 15-E-0283 et al. – Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of New York State Electric & Gas Corporation, Order Approving Electric and Gas Rate Plans in Accord with Joint Proposal (June 15, 2016 and Cases 15-E-0283 et al. – Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of New York State Electric & Gas Corporation, Joint Proposal)

parts of the New York service area, but a specific schedule will not be finalized until a contract with an installation vendor is executed.

2. Lessons Learned From the Energy Smart Community

NYSEG and RG&E have gathered valuable information from the Energy Smart Community project underway in Tompkins County. This project provided specific insights with regard to outreach and communications -- what works, what does not work, what was missing and what can be improved on for a full-scale roll out of AMI in our service areas. Where applicable, examples of communications and lessons learned used in that project are referenced in this Plan.

In developing this Plan, the Companies have considered the value proposition to customers, which is discussed in later in this document. This information is then used to develop specific customer messaging and communication.

A self-initiated, independent third party audit of the communications has been performed and the information collected will assist in developing more effective communication for the full-scale AMI project. Where feasible, recommendations from these findings, as well as all lessons learned from the ESC, are incorporated throughout this Plan. Any visuals and illustrations presented in this Plan are examples and may be modified to reflect lessons learned and additional research collected.

In the following sections, we discuss some of the specific recommendations related to the ESC Outreach and Stakeholder Engagement work plan that will be addressed in the broader AMI roll out.

2.1 Engagement with Stakeholders

The Companies understand the ESC is a demonstration project with specific investments to comprehensively evaluate innovative programs and apply lessons learned to larger regional initiatives. The AMI implementation will cover 52 counties in New York with diverse populations with varying levels of engagement with their energy use. Therefore collaboration initiatives will be evaluated and executed accordingly. Having the advantage of a demonstration project as robust as the Energy Smart Community, we are able to leverage the ESC to identify areas of collaboration because it is a concentrated test bed of AMI and other foundational platform technologies. These include programs to identify new methods for creating value for customers and engaging the market. In order to generate the widespread support necessary to meet REV goals, the Energy Smart Community has shown that stakeholder collaboration with AMI deployment needs to be a broad, comprehensive initiative. This will necessitate engaging with local stakeholders to facilitate community participation. Collaboration initiatives will be executed depending on each region’s population characteristics. **We define collaboration and its key elements as the following**:

- Developing a partnership with community organizations to help facilitate communication and interaction among local stakeholders;
- Establishing realistic goals for collaboration;
- Creating the relationships necessary to understand how to work together effectively;
- Establishing areas of shared goals among NYSEG/RG&E and stakeholders;
- Creating a clear plan of work to advance these goals;

- Following through and communicating promptly and openly;
- Establishing how engaged stakeholders can provide feedback and NYSEG/RG&E's process for addressing feedback; and
- Increasing awareness internally of project goals, scope, and communications so that NYSEG and RG&E are "speaking with one voice" when communicating to a community.

With this definition of collaboration in mind, the Companies will connect with local municipal officials and local sustainable energy organizations and take measures to protect low income and vulnerable populations.

Connect with local elected and municipal officials:

- Provide an opportunity for municipalities to share their energy goals and concerns;
- Consider ways to collaborate with municipalities on local goals;
- Maintain consistent communication with municipalities regarding changes, possible delays, and additions to the project; and
- Leverage municipalities as a communication channel to their residents.

Connect with local sustainable energy organizations:

- To the extent reasonable, identify and engage community champions who know their communities and understand REV and AMI; and
- Provide an opportunity for local sustainability and energy activists and organizations to share their energy goals and look for potential synergies.

Take measures to protect low-income and vulnerable populations:

- Leverage the Companies' internal and community efforts to support low to moderate income ("LMI") customers' energy efficiency programs;
- Educate and inform low income and other vulnerable members of the communities by providing additional communications regarding time-varying rates and other programs to help support informed energy choices;
- Deliver outreach for programs that will benefit low income and vulnerable populations
- Implement ESC Energy Navigator Program, where feasible. This program educates LMI customers on how their households use energy and the best ways to decrease energy use by providing them with tools through collaboration with locally trained individuals. The program won the Smart Energy Consumer Collaborative's 2019 Underserved Market Award; and
- Offer the Energy Manager tool to provide analysis of time-varying rates and annual savings. With 12 months of AMI data captured, we can proactively communication and inform residents if they would have saved money if they were on a specific TOU rate.

2.2 Customer Education

The level of community participation required to make the necessary shifts to energy-related goals will require an enhanced focus on educating the public on energy issues. The implementation of AMI technology will provide products, technology, and incentives for customers to actively participate in energy markets and control their individual energy use. With the appropriate data systems in place, customers will be able to leverage meter data to efficiently scale their energy use patterns. Creatively educating people concerning this initiative and the opportunities it affords will allow the utility the opportunity to maintain their role as the trusted source of energy information for customers. To achieve this goal, NYSEG and RG&E will place a focus on energy education.

2.2.1 Increase Energy Literacy

Customers benefit from understanding not just how the grid works, but that we are all part of the grid. Communicating grid issues as if electricity is a community need rather than a commodity helps customers appreciate how grid upgrades will ultimately ensure a reliable grid for all. Communications that focus more on "this is what **we** need to do together" will convey the type of collective action needed to achieve energy goals. To support this, NYSEG and RG&E will focus on customer education by:

- Providing information about where energy comes from and opportunities related to distributed energy resources;
- Explaining the challenges of aging infrastructure;
- Highlighting the environmental benefit of grid upgrades;
- Giving details on the energy market – supply and delivery charges, rate structures and energy service companies;
- Defining terms and continuing the shift to avoid industry jargon and overly technical terms;
- Where practical, the Companies will leverage community organizations for organizational purposes; and
- Once AMI is deployed in a community, we will also give customers ways to assess their energy use through a robust Energy Manager tool.

2.3 The Energy Environment and the Role of the Utility

AMI is a foundational platform that will facilitate reaching the goals outlined in REV by providing a greater level of detail and information to our stakeholders. Through AMI, individuals, businesses, and the Companies can truly understand actual and near real time energy use. AMI not only records and provides consumption of electricity in short-interval time periods and data on power outages; it also enables a two-way communication with the Companies, creating a system to encourage proactive end-user energy management and encourages the creation and delivery of new products and services. Through AMI, customers can use their meter data to make informed decisions on energy use, potentially leading to lower overall energy usage. AMI also enhances programs including Demand Response and Time of Use ("TOU") rates to encourage reduced usage during peak demand which results in lower carbon emissions through less reliance on power plants.

3. Customer Outreach and Engagement

We are committed to a robust Plan that maintains customer satisfaction and engages the customer in the products and services enabled by the smart meter and AMI platform. The Plan will prepare customers for smart meter installation and will encourage them to access the immediate AMI-enabled benefits and future benefits as new opportunities are presented.

Driven by our Voice of the Customer Program ("VOC") and our Energy Smart Community project, the Plan will be customized to various market segments and will employ multiple and varied communication channels to optimize audience reach.

Our Voice of the Customer Program is a comprehensive and robust listening program consisting of in-person focus groups, customer surveys, and various other research tools. We listen to our customers through a number of venues designed to meet a specific purpose. We are customer-centric in our planning, design, and delivery of customer services and experiences. The data collected through the Voice of the Customer touches nearly every aspect of our business. From the setting and measuring of targets to identifying transformative business projects, this data is critical to ensuring that we are anticipating and meeting customer needs.

Similar research strategies as conducted in the ESC project will be applied statewide. The customer experience in the ESC has provided us with guidance on how to proceed with our communication strategy for AMI.

Figure 3-1 Voice of the Customer Program

Example of Key Findings that Informed Plan	
Customer Perceptions	***Communication Strategy***
47% of customer are concerned with increased costs associated with Smart Meters	Opportunity to provide customers information about Energy Manager to help manage their energy use.
44% of customers are worried about data security	Leverage our brand trust by stating our security policies and procedures and how we treat customer data with confidentially.
44% of customers are unaware of Smart Meters	Build awareness and articulate the benefits to the individual and community at large.

Our VOC helps us design effective communications for customers by using language that is common and understandable to them. We use focus groups to test concepts and usability testing to test digital tools and communications before delivering to the market so they may be enhanced based on customer feedback. For example, our deployment of the online portal for hourly data Energy Manager by our affiliate in Maine, included customer testing of the information and presentation before launch. Other data from our VOC combined with information learned from our ESC project will be used to guide us in our communication strategy with AMI.

As noted earlier, NYSEG has been implementing the ESC Project as part of its participation in the Commission's REV Proceeding (Case 14-M-0101) and serves as a test-bed for implementation and deployment of REV initiatives. The ESC Project is intended to address the three main functions of NYSEG's role as the Distributed System Platform Provider ("DSP") operator:

1. Implement new processes and tools for integrated distribution system planning;
2. Support customer and third-party engagement, as appropriate; and
3. Operate the grid as a DSP operator efficiently and reliably.

These goals are supported by the rollout of Distribution Automation and AMI to customers in the Ithaca region and include collaboration with municipal and institutional partners, including Tompkins County and Cornell University.

Some specific customer outreach and engagement lessons learned from the ESC include:

1. A proactive public communications approach is effective in addressing and reducing opposition to smart meter deployment;
2. Planned opt-out mitigation activities will help to minimize opposition to smart meters;
3. Establishment of trust, transparency, and open communications with local elected officials and community influencers helps to provide support for AMI; and
4. Traditional and non-traditional communication methods are required to maximize customer awareness (for example, broader use of social media).

Through our AMI-enabled systems, we will provide customers with personalized benefits centered on control, choice, and convenience. Customers will be able to better manage their energy use through products and services enabling them to participate in innovative rate programs and to share data with third parties. We will offer customers enhancements in digital services, including online usage information and management and proactive billing notifications and alerts.

As part of general awareness, messaging will encompass an area-wide communication to give customers, media, elected officials and other stakeholders a broad context for upcoming changes in the energy landscape and new technologies that will create excitement and interest throughout the AMI deployment and beyond.

During this time, research will be conducted to determine and develop meaningful customer messaging in each community as well as establish a third-party stakeholder matrix. This will provide an opportunity to properly fine-tune our communications strategy based on community needs.

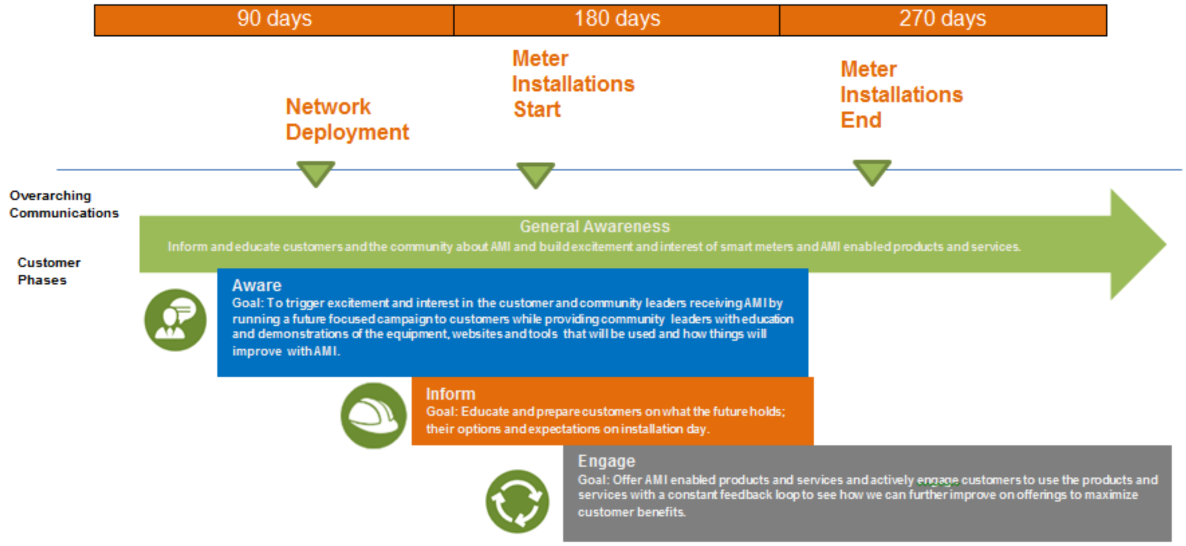
This ongoing campaign will alert customers that smart meters will be installed in the Companies' service territories and will touch broadly on the benefits of smart meters and the technology that will upgrade the grid and enable customers to make more informed energy decisions.

Each Phase compliments the general awareness phase of messaging and working together, these four education phases have distinct objectives and are coordinated with specific AMI program milestones:

- **Aware:** A series of communication campaigns designed to create excitement and interest, while educating customers and the community about smart meter benefits and the general scope and timing of the deployment.

- **Informed:** A series of communication campaigns designed to prepare customers for deployment, reiterate meter benefits, and provide information on available program opportunities for each customer.

- **Engaged:** Ongoing communications, starting from the day of meter installation, to provide individual customers with the knowledge and insight to participate in smart meter opportunities.



Approximate Customer Outreach and Education Timeline

Each Phase includes campaigns with defined targets, messages, audiences, and communication channels. Metrics are being developed to track participation and behavioral changes. Through the duration of the Plan, we will develop and adjust communication messages as necessary and select appropriate communication channels.

Throughout all Phases on the Plan, outreach and engagement to customer segments will be done in various ways. For example, in the Rochester area where there is a high percentage of Spanish-speaking customers, bilingual community advocates will assist with targeted forums. As with all customer interactions, both NYSEG and RG&E Customer Care Centers (and installation vendor Contact Centers) are fully equipped with translation services that allow for customer translation of more than 350 languages. Throughout all service areas, the Companies will partner with Senior Centers to ensure those customers receive all messages, particularly because they may not utilize digital forums as frequently as other customer groups. During all Phases of the Plan, the Companies will take into account the needs of the community to develop the appropriate channel for communications.

The Aware Phase will consist of general customer and community messaging and will begin immediately upon Commission's approval of AMI. This will take place in local area(s), and will include meetings and communications with local and community leaders along with regional messaging. The Aware Phase will begin approximately 75 days prior to the deployment of the AMI communications network in a local area. Messaging during the Aware phase will build upon our general awareness phase and continue to emphasize smart meter benefits and opportunities to give customers more control, choice and convenience. Other messages will provide inquiring customers with safety, privacy and security information. There will be two touch points prior to installation with the customer which will be dependent on the deployment schedule. The O&E Plan will be developed based upon feedback from the ESC and VOC data.

The Informed Phase will consist of direct customer communications regarding meter installation and Smart Meter benefits. The Inform Phase begins before meters are deployed for individual customers and will include administration of the Opt-Out program and coordination of access for installations.

The Engaged Phase starts as customers receive their smart meter and provides customers with knowledge to participate in smart meter opportunities. The Engaged Phase will help customers achieve the benefits of AMI-enabled products and services to manage energy use.

These activities will be repeated throughout the Companies' service areas.

3.1 Development of the Customer O&E Plan

To develop our Plan, we have taken into account the Voice of the Customer, our Energy Smart Community project, experience from other New York utility AMI plans, and our own experiences to anticipate the needs, priorities, and expectations of our customers. The Plan will be refined and updated based on market response, market research, customer analytics and segmentation as necessary.

As a trusted source of information for customers, the Companies will develop and implement education plans after an order is received and a contract with a vendor is secured. These education plans will encourage an understanding, interest, and participation in AMI-enabled products and services. We will also use information to tailor our approach to identified market segments for customized messaging across a variety of channels.

3.2 Communicating Customer Benefits Enabled by AMI

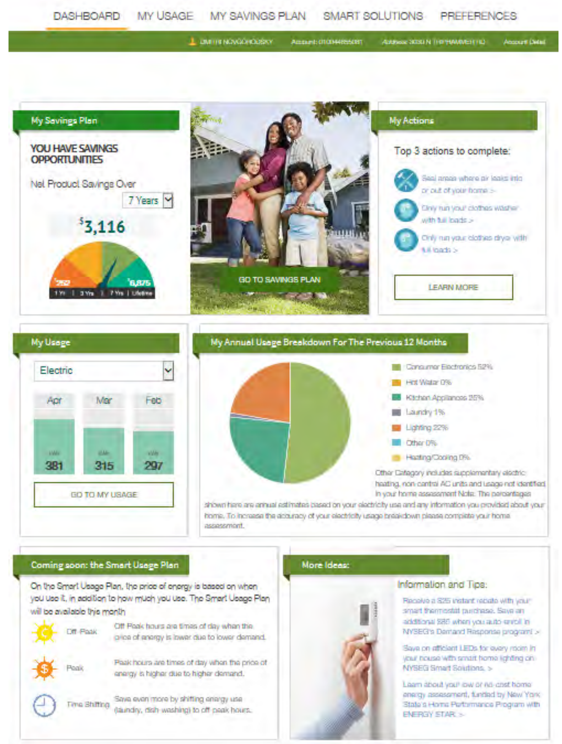
With the integration of the AMI, customers will have an enhanced multi-channel experience that provides greater **choice, control and customization**. The Companies will have a greater opportunity to expand consumer engagement in energy by offering more customer facing products and services, as well as additional options and information. The addition of Smart Meters will provide customer benefits in the following areas:

Account Management:

- Usage Alerts associated with billing, energy use and customized thresholds;
- Efficient monitoring and management of energy use;
- Time varying pricing options to better control periods of peak demand;
- Eliminating estimated meter reads, allowing for more accurate bills and customer convenience; and
- Customers opening a new account or closing an existing account will see a faster turnaround in making changes to their account.

Energy Management:

The Companies have long offered access to energy efficiency products and services to our customers. To coincide with our online energy marketplace, AMI will allow for behavior change and offer customers new abilities to help them engage in proactively managing their energy use and costs. Customer engagement will occur in all customer segments, particularly ensuring that low-income customers are able to access tools and realize the benefits of behavioral changes. Within the ESC and proposed for the Engagement Phase of AMI, the Energy Manager online portal will provide customers with the following innovative features:



- Access to hourly usage data and energy efficiency tips to see how they can save energy and improve comfort by installing energy efficient products and/or changing their behavior.
- Opportunity to download usage data and create an action plan by selecting from a checklist of ways to save money and reduce their carbon footprint.
- Access to Green Button Connect, an online platform that gives customers the ability to share usage data with third parties who will increase opportunities for customers to make smarter energy choices and investment decisions. (Further described in section 4).
- Facilitate greater customer participation in the Companies' demand response (DR) programs, increasing access to energy efficiency tools, and provide for other energy management opportunities.

The Companies continue to test customer segmentation strategies and messages that will further enhance our communication efforts as we implement our "Your Energy Smart YES" campaign. The YES campaign provides customers with a host of energy information including energy efficiency programs. This campaign also highlights the benefits of AMI-enabled products and services.

Outage Management:
In the event of an outage, customers expect prompt restoration. Incorporating AMI will enhance our response to customers by:

- Instantly providing automatic wireless signals of power outage locations;
- Identifying system issues accurately, allowing for faster diagnosis and response; and
- Improving system performance and reducing the duration of outages.

3.3 Aware Phase

As part of the Aware Phase, upon receiving approval, regional awareness to the general population will begin and will be carried out until approximately 75 days prior to the first installation of meters.

This will consist of broad market reach tactics utilized statewide. This campaign will inform and educate customers and the community about AMI, while building excitement and interest of smart meters and AMI enabled products and services. To achieve a comprehensive and effective communications campaign, the following mass media channels will be considered:

- Television;
- Radio;
- Traditional print; and
- Outdoor
- Social media

In addition to the regional campaign and as we approach deployment, messaging in the Aware Phase will be specific to areas of deployment and specific touch points with the customer and the community will be established. We will use lessons learned from the ESC, encompassing traditional and non-traditional communications methods to maximize customer and community awareness. To achieve optimal awareness and engagement, messaging will be considered using the following channels identified below.

Table 3-1 Aware Phase Campaign

Channel	Audience	Messages
• Phone calls • Emails/direct mail • Meetings • Social media • Company websites • Community fact sheets • Video demonstrations	• Public officials and community leaders • Customers	• Deployment overview (map) • Benefits of smart meters, AMI network • FAQs – safety, privacy & security

Campaigns around awareness will inform customers of the benefits of the smart meter and AMI-enabled services, as well as provide community leaders with education supporting the changes and improvements associated with AMI. In addition, the Aware Phase will also serve to prepare communities and customers for the installation of the smart meters. We will begin briefing community leaders on AMI infrastructure deployment to prepare them to answer questions and to support the AMI deployment efforts. Customers in the local area will be notified of smart meter benefits to increase customer acceptance and facilitate implementation of the AMI deployment. These steps will be repeated throughout the Companies' service areas.

Prior to installation, there will be two touch points with the customer based on feedback from the ESC and VOC data. Messaging during this Phase will build upon our experience with other AMI installations and will focus on smart meter benefits. We will develop responses to customer inquiries regarding safety, privacy, and security of information. A proactive approach will be taken to address key concerns of Radio Frequency ("RF") potential health anxieties, cyber security and privacy, and meter accuracy, while also articulating the benefits of Smart Meters not only to the customer, but to the community at large. A defined timeline will be provided after an order is received and a contract with a vendor is secured. The Aware Phase is organized into three campaigns: (1) Involve Local and Community Leadership; (2) Deliver Regional Messaging; and (3) Respond to Non-Adopter Concerns.

3.3.1 Involve Local and Community Leadership Campaign

Community leaders are important partners in our customer education effort. The goal of the local and community leadership campaign is to gain support from community leaders for the meter and installation process in the community. With insight from the ESC, it is necessary to establish trust, transparency and open communications with local elected officials and community influencers in order to gain significant support for AMI. We will request their assistance with projects and provide supporting tools and other mechanisms to assist with information sharing. The Companies will meet with Community leaders to develop effective communication methods and share information concerning:

- Deployment overview and schedule;
- Impact to the homeowner or business;
- Benefits of smart meters and the AMI network; and
- Answers to questions about safety, privacy, and the security of information.

Our outreach resources and chosen stakeholders will complete face-to-face meetings with community leaders and provide supporting communication materials. Specific materials will be developed for community groups and municipalities which will provide information on benefits, impacts, opt-out and timetables so that these organizations can assist in disseminating information and be able to answer questions from customers who contact them directly. Additionally, health and safety information will be provided as part of our materials.

Table 3-2 Local and Community Leadership

Involve Local Community Leadership	Deliver Regional Messaging	Respond to Non-Adopter Concerns
Involve local and community leaders in the deployment areas	Deliver messages to customers within the deployment areas to foster an awareness of smart meter benefits and address typical concerns	Prepare Companies and their Customer Care Center representatives to respond with current science and industry knowledge

3.3.2 Deliver Regional Messaging Campaign

The goals of the regional messaging campaign are to maintain customer satisfaction, increase acceptance of smart meters, provide information so customers can make informed choices, and facilitate meter and communication network deployment.

3.3.3 Respond to Non-Adopter Concerns

Some customers have concerns about safety, privacy, security, and cost and may be reluctant to have the smart meter installed. Our websites will have a section devoted to these concerns with information that includes AMI-enabled benefits and current science and industry knowledge. We will also prepare our Customer Care Center Representatives to respond to customer concerns.

To specifically address potential customer and community concerns, NYSEG and RG&E will be prepared to hold forums to address concerns. Based on local feedback and input, we would hold subject-specific meetings if there is a need. These forums may include experts to address specific topics such as customer data security, smart grid security, RF exposure and potential health risks. During the Informed Phase, customers will be offered information about the opt-out program option.

3.3.4 Aware Phase Example Outreach Material

All communications during the Awareness Phase will build on best practices from across the industry. The communications will be clear and simple to understand and will maintain Company branding so that customers will recognize the source of the information.

**Energy Smart Community Fact Sheet
Example**

NYSEG

Energy Smart Community FAQ's

Information about smart meters

What is a smart meter?

A smart meter is a natural gas and/or electric meter with two way communications between the meter and our systems. The smart meter will transmit usage and meter status data to NYSEG. This will ensure your monthly bills are based on actual usage. More than 65 million smart meters have been installed across the U.S.

What are the benefits of smart meters?

Smart meters provide many benefits. Once the meters are integrated with our back end system, they allow us to pinpoint outages and respond more quickly, which means better service to you. You can access up-to-date usage information to track, manage, and control your own energy use. We will use actual electronic meter reads to determine usage every month – no more estimates. If you are moving to a new location or starting or stopping your electric service, you will see faster turnaround in making changes to your account. There are environmental benefits, too! We're reducing the number of vehicles on the road by thousands of miles per year, reducing fossil fuels and carbon dioxide emissions.

Will a smart meter save me money?

Recent research demonstrates that giving consumers better information about their energy use in combination with tips on conservation, and energy efficiency can help them reduce their consumption.

A smart meter records your energy usage in smaller time increments (typically one hour); you will be able to monitor your consumption more precisely so you can make more informed energy choices. Based on your usage, you can then choose an innovative electric pricing plan that works best for your household, which could lower your monthly cost. New pricing plans are currently being developed.

Who will receive smart meters?

We plan to install approximately 12,400 electric and 7,300 natural gas smart meters in Tompkins County as part of the Energy Smart Community Program. We expect to expand this program to all customers in our service territory over the next few years.

Once the meters are installed, how long will it be before I start to see the benefits?

Once all meters are installed, we can begin working to integrate the technology with our back end billing and outage management system. We expect that process to take several months.

Understanding Usage

How do I access information regarding energy usage online?

Powered by your smart meter, our online Energy Manager is a tool that will allow you to see how you use electricity hour by hour, day by day. This will assist you in understanding when you use energy, and tracking your usage. Once all smart meters are installed, we can begin the work on integrating smart meter enabled products such as Energy Manager.

Are there different rate plans for customers who want to manage their energy use to lower cost "off-peak" periods?

NYSEG is developing new pricing options such as "off-peak" discounts for customers. New pricing plans are currently being developed.

NYSEG

Energy Smart Community

Cyber Security FAQ's

Will any of my data be shared with anyone?

We do not share such information unless required by regulatory or law-enforcement agencies, as required or permitted by law, or as necessary to obtain assistance or direct referrals for customers eligible for special programs such as low-income assistance or energy-efficiency improvements.

How can I share my data?

Once available, you can use our Energy Manager Platform or the Yes Home Solutions Portal to download and share your personal usage data with approved providers.

How does NYSEG protect AMI data and the Smart Grid from security breaches?

We have implemented strong encryption methodologies from the meter to the back end systems.

How was it decided who would and would not receive smart meters?

We plan to install approximately 12,400 electric and 7,300 natural gas smart meters in Tompkins County as part of the Energy Smart Community Program. We expect to expand this program to all customers in our service territory over the next few years.

Does NYSEG know when I'm home or not home based on my energy use?

The AMI meters read data/energy usage in real time. However, we do not try to determine if you are home or not. The only information collected is from the meter to the backend systems for billing purposes.

Could someone get into the AMI data to know when I'm away from my home?

We have implemented strong physical and technical controls, including strong encryption methodologies from the meter to the back end systems to secure the data.*

Is NYSEG going to know when I use my individual appliances within my household, or whatever I'm doing within my household?

The meters read overall energy usage in real time. We can not determine what specific appliances are running in your household.

Does NYSEG sell any of my data?

We do not sell customer data.

* No safeguards are completely secure and any system can be breached, thus, we cannot guarantee the security of the data.

Energy Smart Community Letter Example

NYSEG

************AUTO**SCH 5-DIGIT 13045 1 ###
[redacted]

[redacted],

Welcome to the Energy Smart Community!

The future of energy is changing, and we're changing with it, starting with the energy grid.

Thanks to new technological innovations, we're building a smarter energy infrastructure... one that will allow us to respond to outages more quickly, to seamlessly connect with cleaner energy sources, and keep our energy grid secure.

A smart grid means you get more control, greater flexibility, and more choice. And it is just one of the innovations we will introduce as we work to become your next generation energy company.

Smart meters are coming to parts of Tompkins County

A smart meter is a natural gas or electric meter that can digitally send meter readings to us. They enable a secure, two-way communication between the meter and our system. As part of the Energy Smart Community, approximately 12,400 homes and businesses in Tompkins County will be joining the more that 65 million others in the U.S. that have smart meters today.

We will begin installing smart meters in June. We anticipate it will take approximately three months to complete the process. Once all smart meters are installed, we can begin the process of connecting them to our system. This process is also expected to take several months.

Once connected, what will this mean for you?

- No more estimated bills! We will be able to use this data to bill you based on your actual use each month.
- You will also be able to use the information to monitor your electricity use, make more informed decisions on how you use energy and choose an innovative electric pricing option that may help you save money.
- If there is a power outage, we will automatically be informed right away, allowing us to send repair crews faster and restore your power quicker.

Installation of your smart meter is easy

Wellington Energy, our certified contractor, will install your smart meter. All Wellington Energy vehicles are marked with a sign for easy identification. Wellington Energy employees also carry photo identification that verifies they are an authorized contractor for NYSEG.

Telephone 800.925.1559
www.nyseg.com/energysmartcommunity

An equal opportunity employer

AVANGRID

You will not have to do any preparation for the installation. Approximately one week before installation, you will receive a post card to give you a closer timeframe. The installation process will take approximately 15 minutes and your power may be briefly interrupted. If access to your meters can be obtained, you do not need to be present to have your meter installed. If unable to access the meters, contact information will be left at the time of the visit so you can call and schedule a convenient appointment. Please note our contractor will not enter a home without an adult present, even if a key was provided to us in the past.

If you have any questions, or would like more information about our smart meter program, please visit our website at www.nyseg.com/energysmartcommunity or call us at 800.925.1559. Our community partner, Cornell Cooperative Extension of Tompkins County, is also offering information sessions. Please visit their website at www.ccetompkins.org/esc to locate an event near you.

Thank you

Sincerely,

NYSEG Customer Service

Energy Smart Community Facebook Ad & Fact Sheet Example

NYSEG

Energy Smart Community

WHAT IS THE ENERGY SMART COMMUNITY?

The future of energy is changing, and we're changing with it, starting with the energy grid.

Thanks to new technological innovations, we're building a smarter energy infrastructure... one that will allow us to respond to outages more quickly, to seamlessly connect with cleaner energy sources, and keep our energy grid secure.

A smart grid means you get more control, greater flexibility, and more choice. And it is just one of the innovations we will introduce as we work to become your next generation energy company.

COMING TO THE ENERGY SMART COMMUNITY IN 2017

YES Home Solutions // Offers our residential customers in Tompkins County an easy way to connect online with local service providers who offer energy efficiency, residential solar and community shared solar installations throughout the county. YES Home Solutions will also include rebates on product offerings like LED light bulbs and programmable thermostats. Service provider information is now available. Product offerings will be available this summer.

Smart Meters // Approximately 12,400 homes and businesses within the upgrade area in Tompkins County will join the more than 65 million others in the U.S. that have smart meters today! Smart meters eliminate estimated meter readings and will provide us with a more timely notification when power goes out, allowing us to restore service faster. Installations are scheduled to begin this spring.

Energy Manager // Enabled by the smart meter, this online tool provides users access to their personal energy data, usage alerts, tools, and tips to help better manage their energy use. Energy Manager will be available this fall.

Innovative Pricing Options // After logging into Energy Manager and becoming familiar with their energy usage patterns, customers can determine if one of our innovative pricing options would be beneficial. Innovative pricing options will be available this fall.

FOR MORE INFORMATION

- NYSEG | nyseg.com/energysmartcommunity
  Email: energysmartcommunity@nyseg.com | Telephone: 1.800.925.1559
- Cooperative Extension of Tompkins County
  ccetompkins.org/esc | Telephone: 607.220.3563

3.4 Informed Phase

The Informed Phase occurs approximately 1 month prior to the first smart meter installation in each deployment area. This timeframe was used in Maine's AMI rollout as well as the ESC, and was proven to be successful. It is designed to communicate smart meter deployment to customers while informing them of smart meter benefits and reiterate opt-out options. The Informed Phase uses the Voice of the Customer and other utility benchmarking such as Con Edison and National Grid to design and deliver effective messaging to the audience.

The Informed Phase overlaps with, and builds on, the Aware Phase, adding to the benefits message with details of installation and the opt-out process. The key difference in this Phase surrounds the detailed area-specific information regarding installation and timing. The primary channels of this campaign are direct mail and email notifications with supporting information available online and through Customer Care Centers who are trained in the smart meter implementation and typical customer concerns. The notifications will point customers to online resources, while the AMI outreach resources and Care Centers are available to discuss concerns directly with the customers. We will design communications for this Phase based on our experience and successful examples employed throughout the industry.

During the Informed Phase, the Companies will ensure an outreach presence in the areas where meters are being deployed. Each deployment area will receive multiple messages through three campaigns as follows: (1) Schedule and Deploy; (2) Opt-out Coordination; and (3) Schedule/Access. Table 3-4 summarizes the Informed Phase activities.

Table 3-4 Informed Phase Campaigns

Schedule and Deploy	Opt-Out Coordination	Access for Inside Meters
• Inform customers of smart meter installation process • Continued education on the benefits of smart meters • Inform customers of opt-out process	• Address customer concerns with facts • Continued education on the benefits of smart meters • Inform customers of opt-out process	• Address difficult access installations

3.4.1 Schedule and Deploy Campaign

The goal of the Schedule and Deploy campaign is to facilitate the smart meter benefits and deployment by preparing customers for AMI. Information about smart meter deployment will begin approximately two and three months prior to deployment in a region and will be provided to community leaders and through the Company's website. Direct notification will also occur approximately one month before a customer's smart meter installation. The messages of the schedule and deploy campaign include:

- Meter replacement timing and what the customer may expect;
- Customer benefits;
- Opt-out information; and
- Resources for more information.

The Companies have identified customer segments with special communication needs and preferences, including for example: low-income customers, non-English speaking customers, and senior and non-digital customers. Communications will be tailored and delivered to these segments. As needed, the Companies will rely on the expertise of its multi-lingual language line in the Customer Care Centers providing translations in multiple languages, and our internal customer advocates to best serve customers who require additional assistance.

The table below illustrates various resources that will potentially be used to better educate customers on expectations and installation routes, as well as provide individual communications and customer support as needed.

Table 3-5 Schedule and Deploy Campaign

Audience Customers in local deployment area	
Channel	Messages
• Direct mail/email (approximately 2 month notification) • Company Care Center • Vehicle signs • Social media • Company websites (deployment map, FAQs, customer data access)	• Notification of install, options • Smart meter benefits • Program opportunities as appropriate
• Door hangers	• Installation status – complete, sorry we missed you

3.4.2 Opt-Out Coordination Campaign

This campaign will focus on addressing barriers to participation by providing information in response to customers' concerns, with the ultimate goal to reduce opt-outs. For those customers who choose to opt-out, even after reviewing the information, the Companies will provide a clear opt-out process.

The Companies recognize that there may be some customers that chose to opt-out of having an AMI meter installed for any number of reasons. The Companies project that 1% of residential customers will choose to opt out. This assumption is based on experience with AMI meter opt-outs at Central Maine Power which has had provisions in place for customers to opt out of AMI since 2011.

The Companies will develop communication materials that clearly educate customers on the benefits of a smart meter and the cost of an "opt-out" decision. Only electric and gas residential customers have the ability to opt-out of receiving an AMI electric meter or an AMI gas module, and there will be a recurring monthly charge to recover costs of regular meter reads.
Projected monthly opt out charges are shown below:

Figure 3-1 Proposed Monthly Opt Out Fees

Bill Line Item	NYSEG	RG&E
Meter Reading Fee	$13.47	$11.56

The monthly meter reading charges are based on the assumption that all opt-out customer meters are read manually on a bi-monthly basis. Recurring costs associated with customer opt-out include:

- Field costs for monthly meter reading;
- Meter visits to connect or disconnect service or to read meters between billing read dates; and
- Maintenance and management of the hand-held devices to support monthly meter reading.

The option to opt-out will be communicated to customers throughout all Phases of outreach and engagement. Customers will have the ability to opt-out through multiple channels including online and through our Care Center. Any customer who opts out will be billed for the incremental operational costs as indicated above. The customer will have the ability to opt-in at any point in time avoiding future monthly opt-out charges.

Opt-out information is included in the letter the Companies will send to customers regarding the implementation of the smart meters, including general installation information and installation schedule. The letter will include a description of the process customers would follow to opt-out. More information on opt-out is included in Section 5 of this Plan. Opt-out coordination will be handled by employees trained to provide customers with accurate and up-to-date information regarding smart meters and the available opt-out process. The messages of this campaign will include customer choice and will reiterate:

- The benefits of smart meters;
- Safety, security, and privacy facts; and
- Opt-out processes and charges.

Table 3-6 Opt-Out Coordination Campaign Details

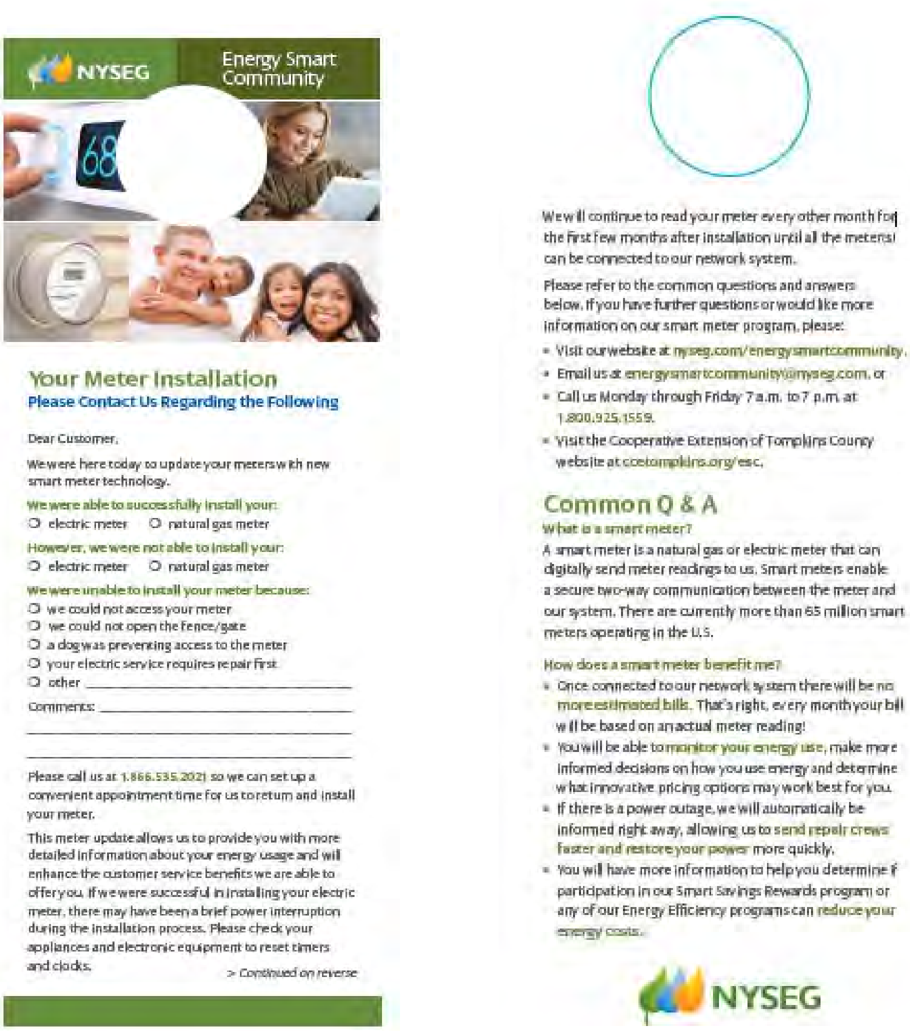
Channel	Audience	Messages
• Direct mail/email • Company websites (opt out information) • Customer Care Centers • Talking points, factsheet for meter installers on-site	• Concerned customers	• Benefits of smart meters • Safety, security and privacy facts (including scientific studies, white papers) • Opt-out process and associated fees

3.4.3 Access/Scheduling

The access/scheduling campaign is to accommodate customers for whom the smart meter installation poses a challenge, such as the need to be home to allow access, scheduling appointments, or difficulty installing meters, which can lead to potential delays.

Within the ESC, 21% of customer meters were inside, so it was critical that we developed a strong process for working with customers for access as conveniently and easy for the customer as possible.

Energy Smart Community Appointment Door Hanger Example


NYSEG Energy Smart Community

Your Meter Installation

Please Contact Us Regarding the Following

Dear Customer,

We were here today to update your meters with new smart meter technology.

We were able to successfully install your:

- ❍ electric meter ❍ natural gas meter

However, we were not able to install your:

- ❍ electric meter ❍ natural gas meter

We were unable to install your meter because:

- ❍ we could not access your meter
- ❍ we could not open the fence/gate
- ❍ a dog was preventing access to the meter
- ❍ your electric service requires repair first
- ❍ other ________________

Comments: ________________

____

____

Please call us at 1.866.535.2021 so we can set up a convenient appointment time for us to return and install your meter.

This meter update allows us to provide you with more detailed information about your energy usage and will enhance the customer service benefits we are able to offer you. If we were successful in installing your electric meter, there may have been a brief power interruption during the installation process. Please check your appliances and electronic equipment to reset timers and clocks.

> Continued on reverse

We will continue to read your meter every other month for the first few months after installation until all the meters can be connected to our network system.

Please refer to the common questions and answers below. If you have further questions or would like more information on our smart meter program, please:

- Visit our website at nyseg.com/energysmartcommunity,
- Email us at energysmartcommunity@nyseg.com, or
- Call us Monday through Friday 7 a.m. to 7 p.m. at 1.800.925.1559.
- Visit the Cooperative Extension of Tompkins County website at ccetompkins.org/esc.

Common Q & A

What is a smart meter?

A smart meter is a natural gas or electric meter that can digitally send meter readings to us. Smart meters enable a secure two-way communication between the meter and our system. There are currently more than 65 million smart meters operating in the U.S.

How does a smart meter benefit me?

- Once connected to our network system there will be no more estimated bills. That's right, every month your bill will be based on an actual meter reading!
- You will be able to monitor your energy use, make more informed decisions on how you use energy and determine what innovative pricing options may work best for you.
- If there is a power outage, we will automatically be informed right away, allowing us to send repair crews faster and restore your power more quickly.
- You will have more information to help you determine if participation in our Smart Savings Rewards program or any of our Energy Efficiency programs can reduce your energy costs.

NYSEG

As shown in the table below, while the percentages of inside gas and electric meters are low, with the full roll out of AMI, NYSEG and RG&E recognize the need to work with our customers to arrange access to inside meters. Creating a seamless transition while scheduling appointments that are accommodating for customers will be well thought out and coordinated in conjunction with our awarded installation vendor.

Table 3-7 Inside Meters

	NYSEG				RG&E			
	In	Out	Total	**% In**	In	Out	Total	**% In**
Elec.	96,561	821,163	917,724	**10.5%**	222,312	1,083,433	1,305,745	**17.0%**
Gas	71,288	211,256	282,544	**25.2%**	208,054	399,997	608,051	**34.2%**
Total	167,849	1,032,419	1,200,268	**14.0%**	430,366	1,483,430	1,913,796	**22.5%**

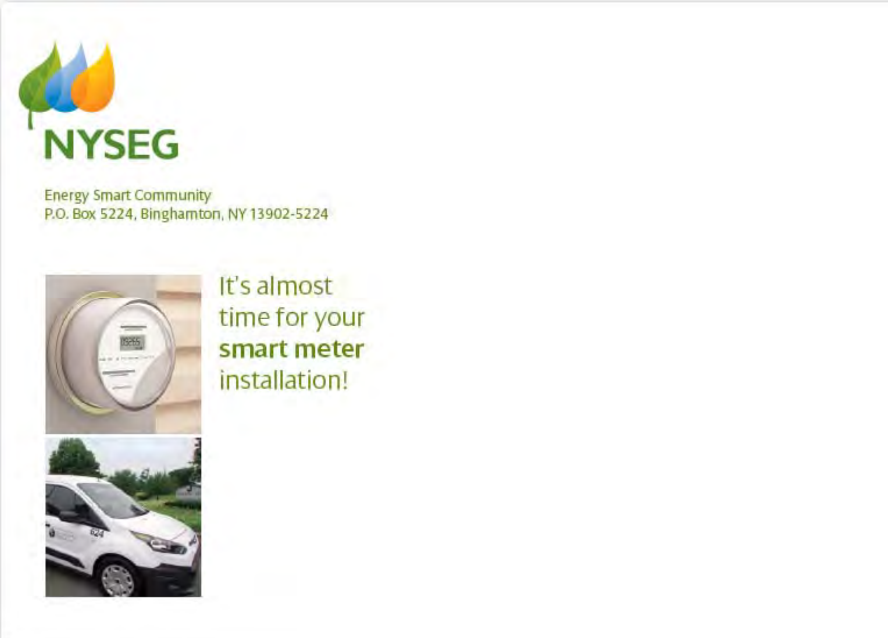
The messages of this campaign will address appointment scheduling. The activities for schedule/access are responsive to customer concerns and will be handled by the Customer Care Centers and Key Account Managers. Table 3-8 summarizes inconvenience mitigation for the Informed Phase.

Table 3-8 Inconvenience Mitigation

Channel	Audience	Messages

• Company Care Centers and Key Account Managers
• Installers
	• Pre-identified customer groups including:
	  o Difficult to access
	  o Businesses
	  o Vulnerable customers
	• Impacted customers
		• Information to schedule an installation appointment

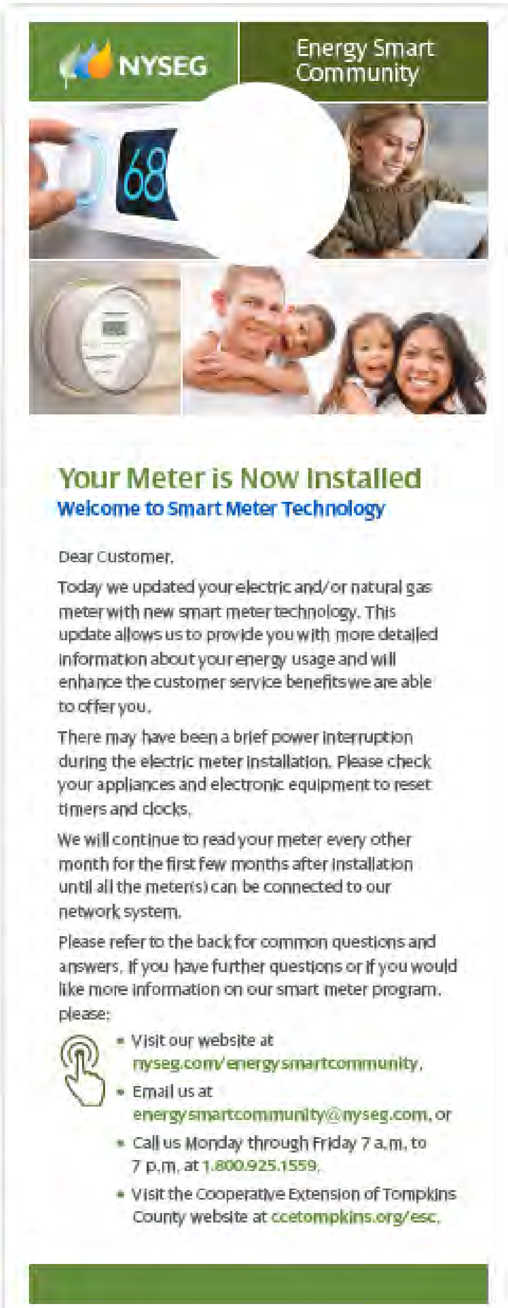
3.4.4 Informed Phase Example Outreach Material



Energy Smart Community Vehicle Magnet Example

Energy Smart Community Smart Meter Installation Postcard Example

Smart Meter Installation Door Hanger Example



NYSEG

Energy Smart Community

68

Your Meter is Now Installed

Welcome to Smart Meter Technology

Dear Customer,

Today we updated your electric and/or natural gas meter with new smart meter technology. This update allows us to provide you with more detailed information about your energy usage and will enhance the customer service benefits we are able to offer you.

There may have been a brief power interruption during the electric meter installation. Please check your appliances and electronic equipment to reset timers and clocks.

We will continue to read your meter every other month for the first few months after installation until all the meter(s) can be connected to our network system.

Please refer to the back for common questions and answers. If you have further questions or if you would like more information on our smart meter program, please:

- Visit our website at nyseg.com/energysmartcommunity,
- Email us at energysmartcommunity@nyseg.com, or
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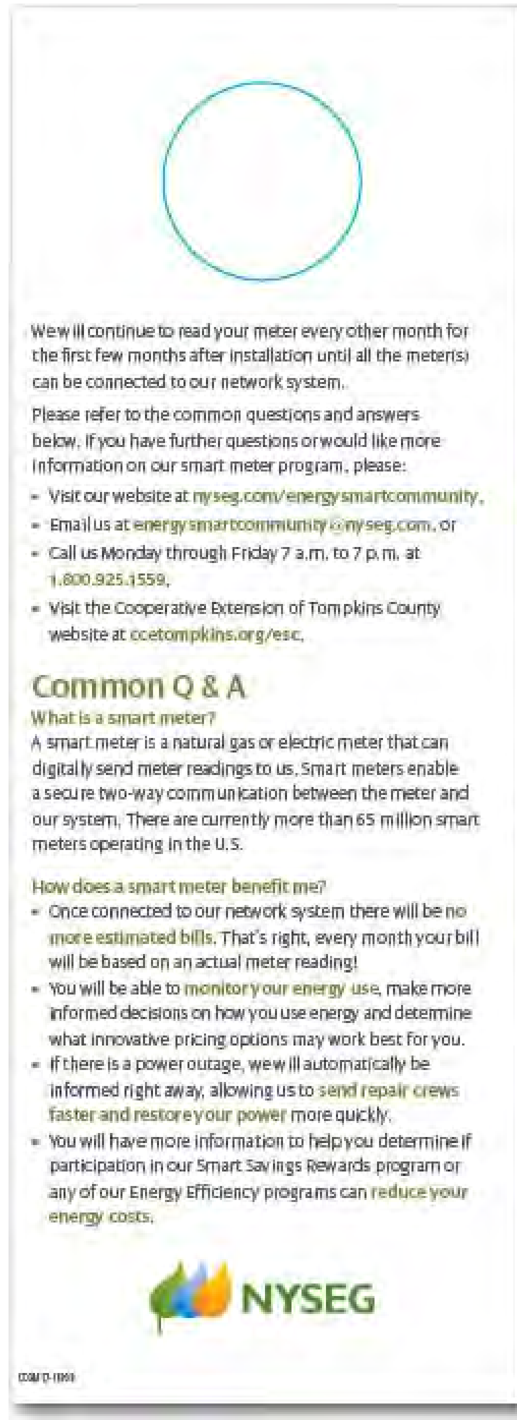
- Visit the Cooperative Extension of Tompkins County website at ccetompkins.org/esc.



We will continue to read your meter every other month for the first few months after installation until all the meter(s) can be connected to our network system.

Please refer to the common questions and answers below. If you have further questions or would like more information on our smart meter program, please:

- Visit our website at nyseg.com/energysmartcommunity,
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What is a smart meter?

A smart meter is a natural gas or electric meter that can digitally send meter readings to us. Smart meters enable a secure two-way communication between the meter and our system. There are currently more than 65 million smart meters operating in the U.S.

How does a smart meter benefit me?

- Once connected to our network system there will be no more estimated bills. That's right, every month your bill will be based on an actual meter reading!
- You will be able to monitor your energy use, make more informed decisions on how you use energy and determine what innovative pricing options may work best for you.
- If there is a power outage, we will automatically be informed right away, allowing us to send repair crews faster and restore your power more quickly.
- You will have more information to help you determine if participation in our Smart Savings Rewards program or any of our Energy Efficiency programs can reduce your energy costs.

NYSEG

3.5 Engaged Phase

The Engaged Phase starts once the smart meter is installed and provides customers with information on how to participate in smart meter opportunities. The objective of the Engaged Phase is to help customers achieve benefits of AMI-enabled products and services to manage energy use.

During this Phase, the Companies will assess and use insights gathered from our Voice of the Customer, our Energy Smart Community, and our outreach experience to refine and promote new customer opportunities. The ESC has taught us that the customer experience will establish the foundation for a comprehensive digital solution. The quality of leads generated and the use of customer behavioral data is critical to effectively targeting customers to increase conversion rates. Focusing on these activities will facilitate greater customer participation in the Companies' demand response programs, increase access to energy efficiency tools, and provide for other energy management opportunities offered through innovative third-party vendor value-added products and services.

Energy Smart Community Engaged Phase Examples – Customer Mailing

Figure 3-9 Customer Engagement Tools

Our experience confirms that awareness of Smart Meters drops in the years following initial installation. For example, during our Maine deployment, awareness peaked at 90% during the 2011-2012 installation periods and dropped to 65% by the end of 2014. Ongoing awareness of the smart meter and AMI-enabled products and services will be achieved through constant communication of customer benefits.

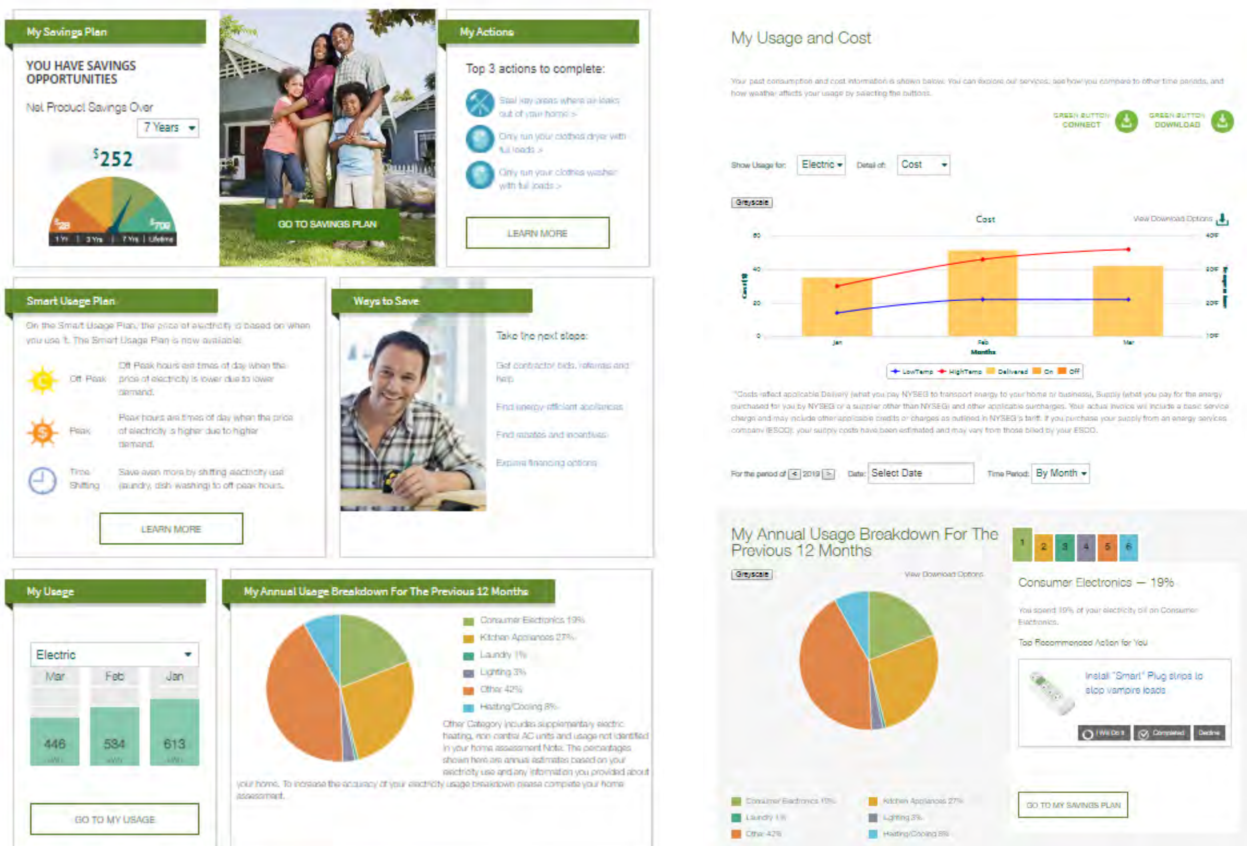
The Engaged Phase is a long-term, holistic approach, leveraging many digital and non-digital channels to engage and educate customers.

During this Phase, customers will have access to our enhanced web portal, Energy Manager. The Energy Manager application will engage customers in an online portal that will use AMI and metering data to help customers understand and manage their usage. The portal will allow customers to set energy-saving goals and provide personalized tips and actions that will help them meet their goals. Specifically, Energy Manager will:

- Provide customers with a simple, intuitive method to view their current and historical energy use in graphical form as measured by their smart meter;
- Provide customers the ability to download usage data in various forms, including Green Button format, the national standard;
- Provide improved analytical capabilities to better understand usage by providing additional information including weather, price, and bill cost data;

- Use AMI data to provide the customer with insights and energy savings tips as well as personalized action plans to conserve and save;
- Provide the ability for the customer to disaggregate their usage (i.e., understand what is driving their usage patterns) to determine how their energy is being used; and
- Provide customers with proactive alerts associated with projected billing, home energy use, and customized thresholds set by customers (energy use or projected costs).

Energy Smart Community Energy Manager Online Example



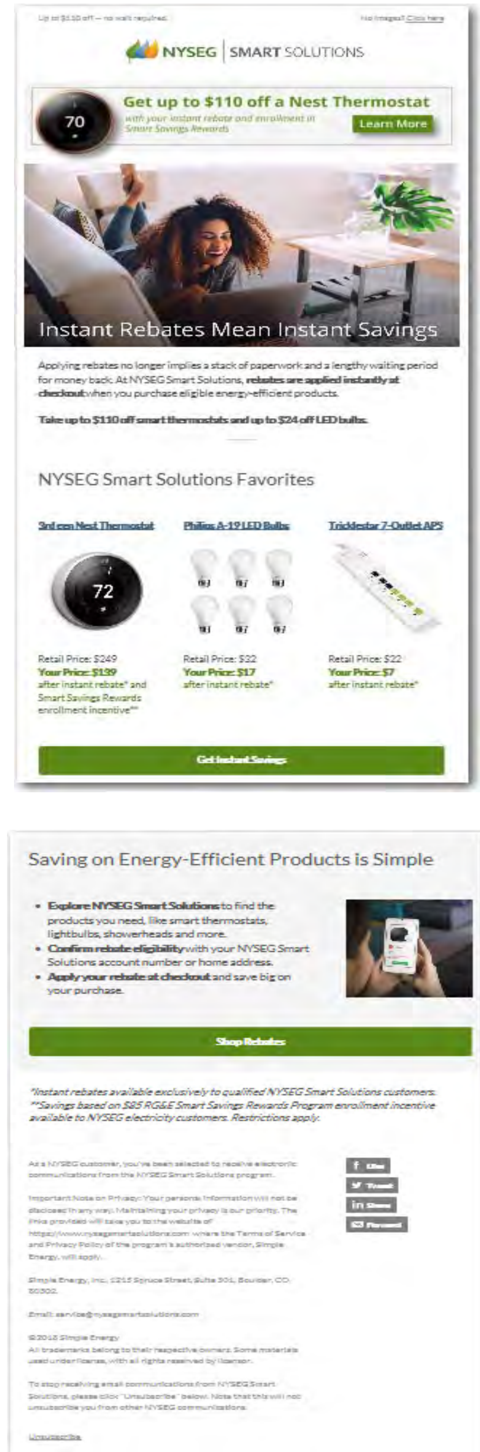
Energy Manager will be tailored to specific customer segments, such as residential and business. Energy Manager will be integrated with the Companies' websites, providing customers with seamless access. The Customer Care Center will have access to the same data screens as the customer.

Energy Manager will deliver a high-satisfaction digital customer experience that will drive increased customer adoption of AMI-enabled benefits. Customer engagement will occur in all customer segments, particularly ensuring that low-income customers are able to access tools and realize the benefits of behavioral changes.

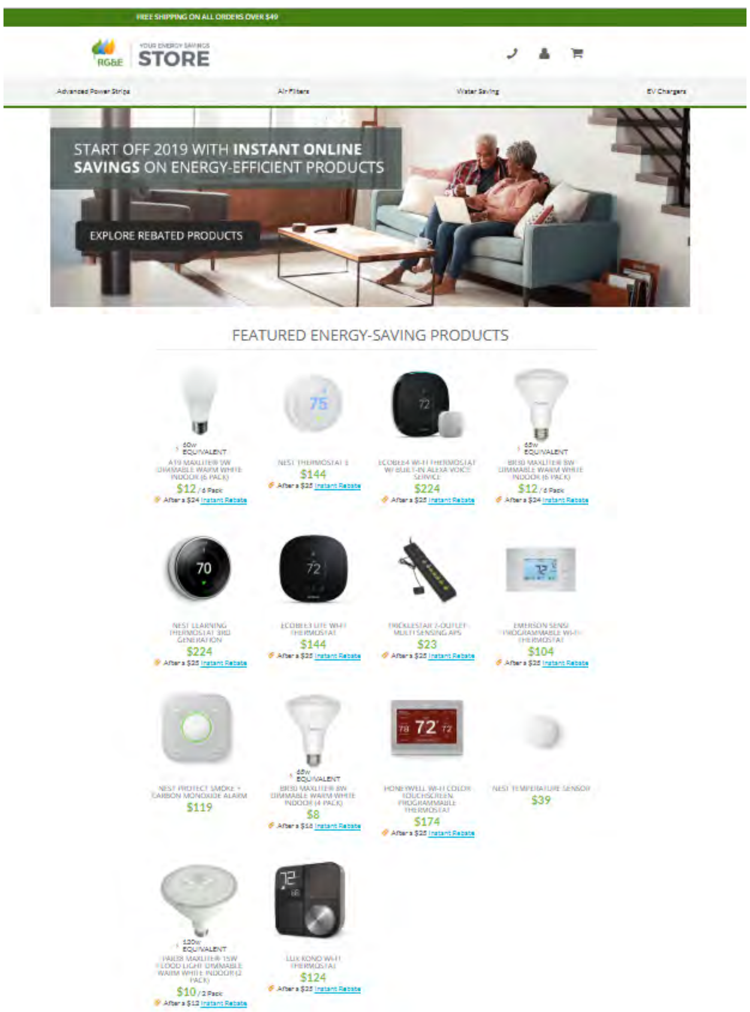
3.5.1 Electricity Supply Marketplace

NYSEG Smart Solutions and RG&E's Your Energy Saving Store are secure online sources where customers access information on instant rebate eligibility and savings for energy-saving products, such as LED lighting, smart thermostats and advanced power strips. Customers can also explore solar energy options, get free quotes, or connect with contractors who will assess their home and make recommendations on how to improve the home's energy efficiency.

NYSEG Smart Solutions Email Example



RG&E Your Energy Savings Store Webpage Example



3.5.2 Engaging All Customer Segments

There are customer segments throughout our service areas that require special engagement efforts (for example low-income, non-English speaking, and senior customers). Customer engagement will occur in all customer segments, particularly ensuring that low-income customers are able to access tools and realize the benefits of behavioral changes. Using our low income and advocacy groups, a range of channels will be used to engage these customers. Our Voice of the Customer will assist in identifying these segments and developing customized messaging to meet their specific needs.

The messages provided to special needs customers are consistent with the Engaged Phase and include:

- Current smart meter benefits available to customers;
- How to engage with smart meter benefits;
- How to engage with third-party opportunities; and
- Customer communication channel preferences.

The Companies also acknowledge that there are customer segments (such as high usage customers and solar customers) within the service area that may be able to take part in additional opportunities. The Companies will provide targeted messaging to these customers that will revolve around additional opportunities to become involved in energy efficiency, third-party offerings, or other ways to save.

Customer engagement will evolve over the course of the AMI deployment through lessons learned, Voice of the Customer, and a building of awareness across the Companies' respective service areas.

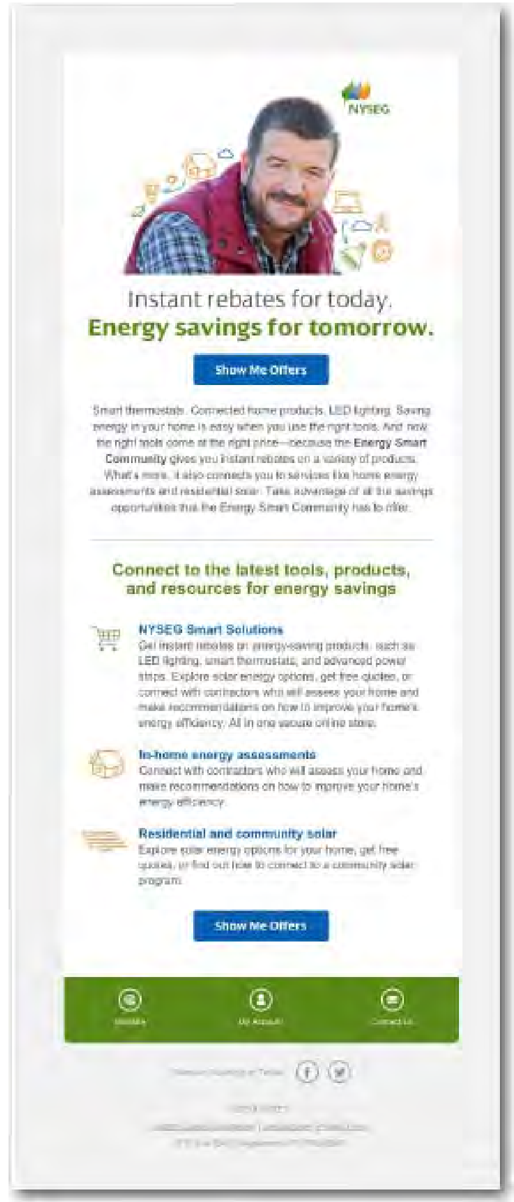
3.5.3 Engaged Phase Communications

Figure 3-10 Engaged Phase Communications

Channel	Audience	Messages
• Bill inserts and bill messages • Direct mail/email (example below) • Company websites, including Energy Manager • Social media • Notifications and alerts • Stakeholder websites, communications • Community events & forum • Employee talking points: Customer Care Center, Key Account Managers	• All customers including: • Special needs • Early adopters	• Understand and manage energy usage • How to access to AMI-enabled products and services • Convenience of digital tools

The Engaged Phase continues to build upon the Aware and Informed Phases, and provides customers with knowledge to participate in smart meter opportunities. Table 3-9 above summarizes the range of activities for this Phase.

NYSEG Energy Smart Community Program Snapshot Email Example



NYSEG Energy Smart Community Program Snapshot Brochure Example

Energy Manager

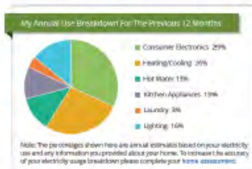
Build a customized energy savings plan—based on your data.

Energy Manager

Energy Manager is a robust online tool that provides insight into your energy use and the ability to create a personal energy savings plan based on the way you use energy.

Gain greater visibility into your energy use

+ Track your energy use and costs over the past 12 months—filtered by month, day, or hour
+ Set alerts for your energy use, bill amount, and day-ahead supply price
+ Get a percentage breakdown of your energy use by category, including heating and cooling, appliances, lighting, and more
+ View monthly bill projections based on what you've spent to date and how much you're expected to spend over the remainder of the month
+ Compare your monthly bills, broken down by electric and gas



Smart Usage Plan

A new pricing option that lets you shift your electricity use and save.

EnergyTrack Usage Reports

EnergyTrack is a free quarterly report that gives you a detailed analysis of your energy use, along with simple energy savings tips and recommended savings tools from the Energy Smart Community.

Detailed analysis of your energy use, including:

+ An estimation of where you use energy, broken down by different areas of your home
+ Hourly charting of your average daily energy use
+ Customized analysis of your energy use when you complete a quick and easy online home assessment

Additional energy-saving resources, including:

+ Seasonal energy-saving tips and do-it-yourself projects you can complete in minutes
+ Recommended savings tools from the Energy Smart Community
+ New products and programs coming soon in the Energy Smart Community

Look for EnergyTrack reports quarterly, and take advantage of more Energy Smart Community offers at www.nyseg.com/MyEnergy.

Smart Usage Plan

On the Smart Usage Plan, the price of electricity is based on when you use it, enabling you to shift some of your electricity use to lower-cost times of day to save on electricity bills.

How it works

Pricing is broken down into two periods of the day:

Off-peak hours are considered the time of day when the price of electricity is lower due to lower demand.

+ All hours except 4-6 p.m. on weekdays (Monday through Friday)
+ 24 hours per day on weekends (Saturday and Sunday) and holidays (New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day)

Peak hours are considered the time of day when the price of electricity is higher due to higher demand.

+ 4-6 p.m. on weekdays (Monday through Friday)

Easy Ways to Shift and Save

Set your thermostat for savings. If your thermostat is programmable, set it to heat or cool your home during lower-priced times of the day.

Load now, wash later. It's only natural to want to clean up after dinner so you can relax for the night. Simply load the dishwasher after dinner, and wait until after 6 p.m. or the next morning to run it.

Switch to the Smart Usage Plan and start saving today. Visit www.nyseg.com/MyEnergy to get started.

Energy Manager

Create a customized energy savings plan

+ View a detailed analysis of your energy use—hourly, weekly, or monthly
+ Complete a quick and easy online home assessment that will create your personal savings plan
+ Get a recommended actions list, including projected savings over the life of your plan
+ Set an energy target and check your progress anytime. Track your savings by dollar amount, CO_2 emissions, or kilowatt hours

Choose a pricing option that makes the most sense for you

+ Compare your pricing plan against the Smart Usage Plan
+ Get a recommendation based on the plan that will save you the most

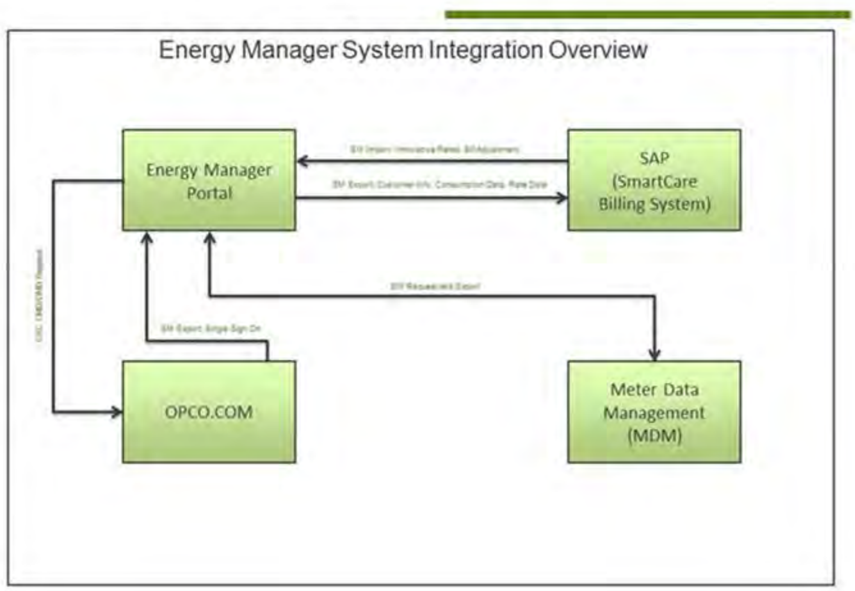
Take control of your energy use. Create your energy savings plan at www.nyseg.com/MyEnergy.

4.0 Green Button Connect

4.1 Overview

Energy Manager will host and support Green Button Connect to give customers the ability to allow third parties to view their AMI data and link usage data with multiple accounts.

The Green Button initiative is an industry-led effort to provide utility customers with easy and secure access to energy usage information in a consumer-friendly and computer-friendly format. Green Button Connect allows the customer to automate the secure transfer of its energy usage data to authorized third parties based on affirmative customer consent (opt-in). On the other side of the transaction, third parties are able download data, manage customer lists, and send each customer personalized services that are available to him/her.



The Green Button Alliance has created a standard, secure process for providing this functionality. The Companies intend to implement this standard process to facilitate customer engagement and are actively participating in the Green Button Connect collaborative (Case 18-M00084).

Sharing customer usage data aligns with the goals of New York State's REV initiatives. Providing customers the ability to share usage data with third parties will increase opportunities for customers to make smarter energy use and investment decisions. This can result in better controlled costs and, as a result, will provide environmental benefits. The accuracy and granularity of data available with AMI heightens the demand for data sharing capabilities. The Companies will be mindful of ensuring appropriate protections are in place so that no customer personal identifying or other confidential information is disclosed. This will be addressed briefly in this Plan and more thoroughly in our Cyber Security and Data Privacy plan.

Figure 4-1 shows the value created for each of the parties in the Green Button Connect ("GBC") transaction. By utilizing this standard, customers and third-parties are securely connected to data through the utility.

Figure 4-1 Green Button Connect Value Proposition

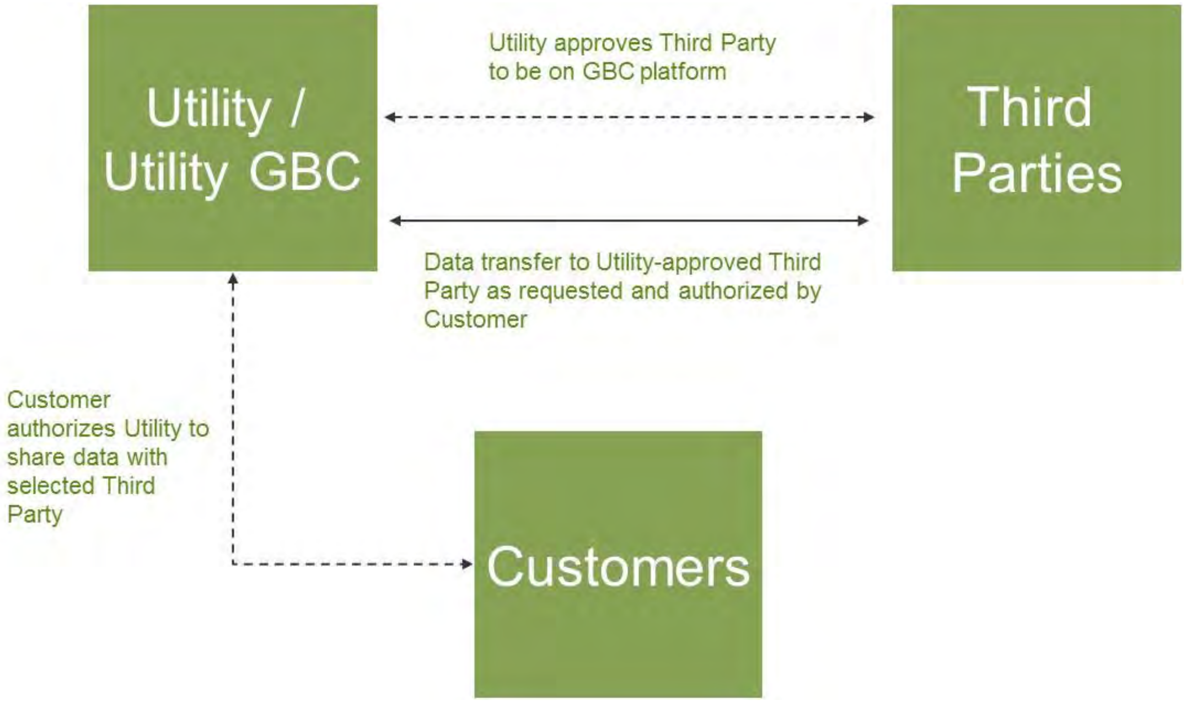
From a customer perspective, GBC will be a seamless transition through the Energy Manager portal and will provide the following benefits:

- A **user-friendly** and **easy** way for customers to download and share their electricity usage data in a standardized format (Connect My Data) with third party providers of their choice;
- An **informational hub** that will allow customers **choice** and **control** in obtaining information about energy savings directly from third party providers; and
- An analysis package of electricity data with the ability to **reduce consumption** and **increase efficiency**. Customers will have the means to make informed decisions to use less electricity and ultimately save money.

4.2 Green Button Enrollment Process for Customers and Third Parties

The Companies' GBC implementation will provide functionality that allows customers the flexibility to control their data. Third parties will be approved by the utility. As a result, customers will be able to authorize the utility to share data with their selected third parties.

Figure 4-2 Green Button Connect - How it Works



By utilizing Green Button Connect, a customer can choose an authorized third-party vendor (or vendors) and share past, current, and/or future data. The customer will also be able to select a category of data to share (consumption, demographics).

4.3 ESC Customer Experience

The Companies intend to use Green Button to facilitate data sharing with customers and third parties. Since GBC was recently deployed in the ESC, there are limited best practices to deliver. Major hurdles focus on relaying and receiving updates to and from the vendor specifically on branding and messaging, as well as having a solid testing process. The Companies expect to determine the most effective and efficient way for both customers and the market to realize the value of AMI data. The Companies will utilize a third party to develop a sole solution for each platform across operating companies.

The following are key points related to the Companies' implementation of Energy Manager and Green Button Connect in the ESC:

- ESC is using the Energy Manager vendor to implement and provide GBC functionality;
- Residential and small commercial customers are eligible and can authorize the utility to share information with third party vendors on an ongoing basis. All other service customers will use the Companies stand-alone Energy Profiler Online, our energy management interface for large Commercial and Industrial customers;
- Customers can set permissions for types of data and frequency of delivery;
- The use of GBC will facilitate DER adoption, support market animation, and support AMI value for customers, market and state policy goals;
- Usage of Energy Manager and GBC will only require customers to sign on to nyseg.com and/or rge.com and navigate to Energy Manager to access GBC. There is no registration required;

- Customers will validate by utilizing their existing nyseg.com or rge.com credentials. They can then access Energy Manager; and
- All third parties will be validated utilizing established protocols.

Figures 4-3 and 4-4 illustrate the paths an ESC customer can use to access GBC. The first is through the Company's website (Energy Manager to GBC). Customers will be able to access Energy Manager through nyseg.com and rge.com from a computer or on a mobile device. GBC is a button on Energy Manager. The second is through NYSEG Smart Solutions which provides Distributed Energy Services for customers.

Figure 4-3 Green Button Connect - Customer Access through nyseg.com

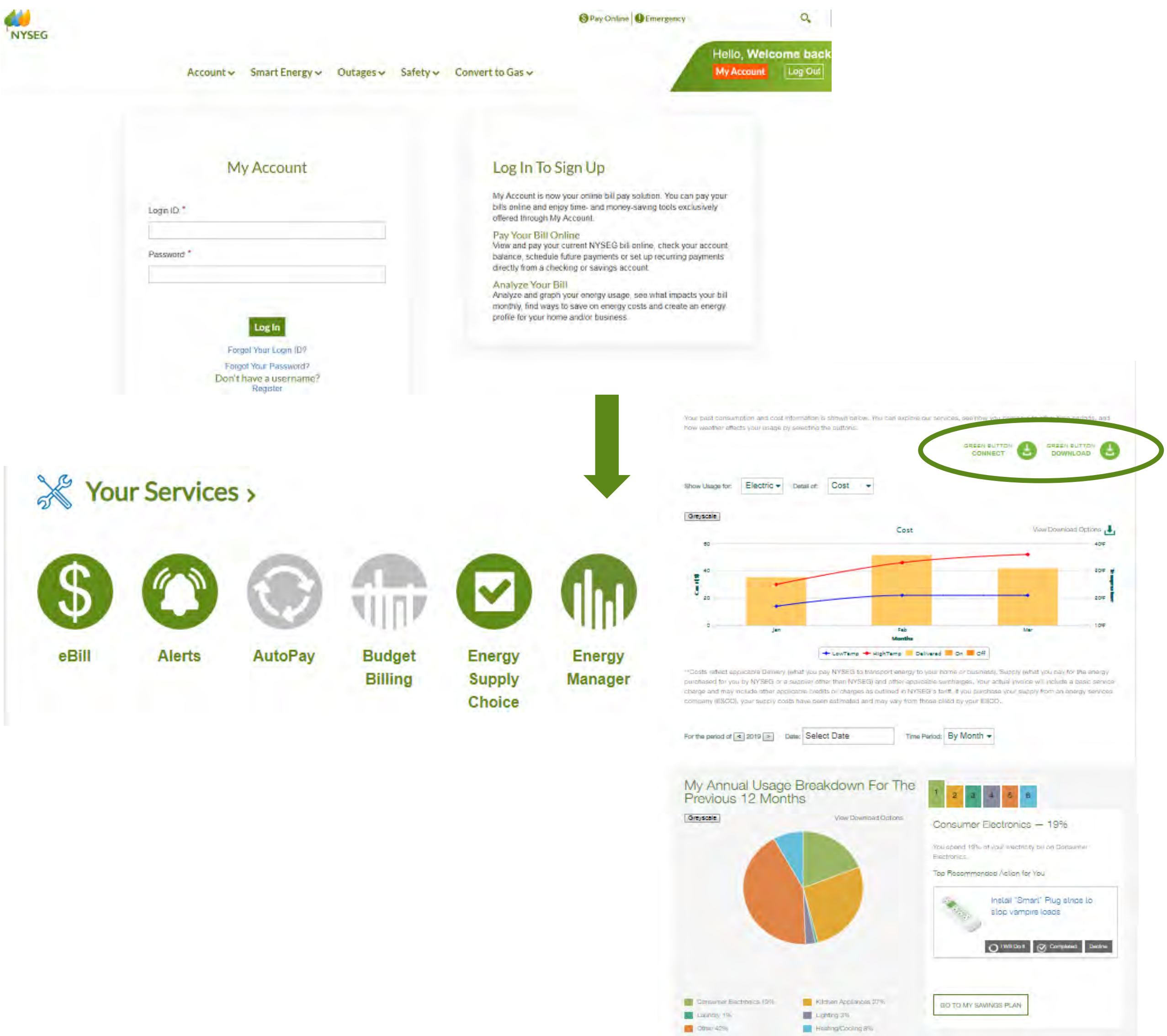
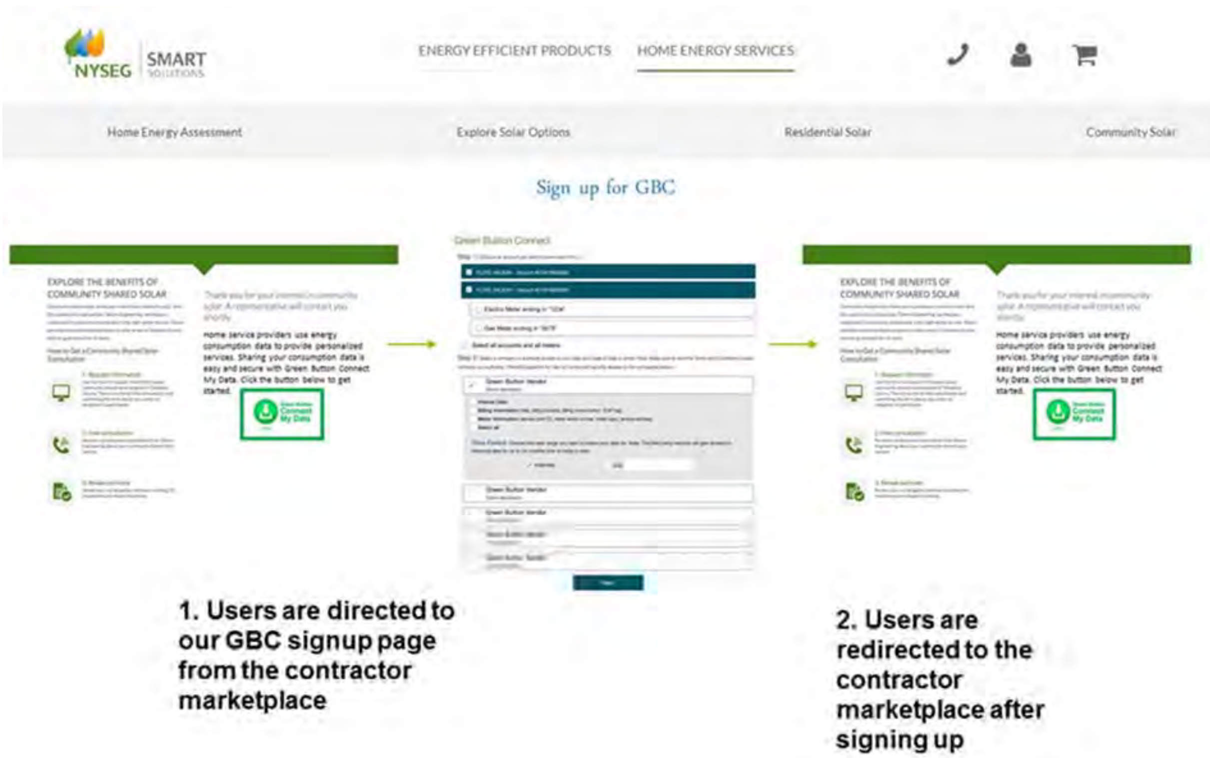


Figure 4-4 Green Button Connect - Customer Access through NYSEG Smart Solutions



4.4 Green Button Connect – Data Management

The Companies recognize that while providing value through GBC, customer data security is paramount in the implementation. Data requests and responses are made using the secure HTTPS protocol and authenticated via a two-way certificate exchange (OAuth 2.0 authorization).

Each customer who uses GBC will have the ability to personalize their self-service experience. Applications are being developed for both residential and commercial customers.
With GBC the customer can:

- Share only the data they want to share;
- Limit the availability of the data to specific third parties; and
- Limit the amount of time a third party has access to the data.

From a third party perspective, GBC allows access to customer data through the portal being used for the ESC. This portal and its access to GBC meet third party expectations in the following ways:

- Provides data in CSV or XML file formats;
- Optimizes resources (like file sizes, etc.);

- Offers customer-provided contact information;
- Allows automatic transfer of data from utility to third party based on customer authorization;
- Handles different types of energy data and time interval usage;
- Offers the availability of interval data; and
- Provides that all customer data will be available in the same place - billing and interval data will be integrated with a meter data management (MDM) system.

Implementation of GBC in the ESC meets the requirements of the Green Button Standard through the following:

- XML and CSV file formats for energy usage information;
- A data exchange protocol which allows for the automatic transfer of data from a utility to a third party based on customer authorization;
- Flexible enough to handle different types of energy data and time interval usage;
- Applications are being developed for both residential and commercial customers;
- The data can be provided in 5-minute, 15-minute, hourly, daily, or monthly intervals depending on what a utility decides to make available and what level of detail they are able to provide;
- The Energy Manager application shall present AMI interval data in hourly increments:
    - Current ESC data availability:
        - Residential Data – hourly data
        - C&I data – 5 minute data;
- Data requests and responses are made using the secure HTTPS protocol and authenticated via a two-way certificate exchange; and
- As per the ESPI standard, we will maintain unexpired, unrevoked RSA certificates with a public key length of at least 2048 bits.

4.5 Green Button Connect – Security Considerations

The NYSEG and RG&E third party risk management process includes a standardized procedure for identifying, assessing, and mitigating security risks that can be introduced at the vendor level. All third parties are assessed for cyber and information security controls, based on the NYSEG and RG&E cyber security controls framework, including operational, technical and administrative controls. The third party risk management process includes the addition of a data security rider/data services agreement, which includes the right to audit any third party processing, handling, transmitting, etc., of non-public information.

In the ESC, a Phased provisioning process has been used. These Phases are shown below:

Phase 1 (until April 30, 2019): Two-agreement approach:

- Energy Manager: Existing data security requirements. Avangrid Third Party Risk Assessment Process (third party assessment and signed data security rider).
- NYSEG Smart Solutions marketplace: RFP process, vetted and approved by the business, signed initial terms including Uniform Business Practices and Data Security Agreement. Additional terms of service (see next paragraph) to be signed for GBC upon development.

The only precedence for terms and conditions of GBC is the two-way approach used in other states. Example: Terms and Conditions used in the ESC GBC roll out were from Texas, California, and Illinois utilities.

The two agreements of this approach are:

- Agreement 1 is between the third party and utility during the registration process. The third party agrees that NYSEG does not have liability after the data is made available to the third party. In turn, NYSEG agrees to its usual protections, such that the data is secured and encrypted before and during transmission to the third party.
- Agreement 2 is between the customer and the utility. During its selection and approval of third parties to access its data, the customer sees a notice that asks it to agree that the utility has no liability due to sharing their data with these third parties. The customer must click a checkbox acknowledging its understanding.

Phase II (May 1, 2019 – forward)

Phase II of the provisioning process is a joint vendor risk assessment plus a data security agreement. The Companies require all GBC third parties to enter into a data security agreement as well as executing a Terms and Conditions, which includes uniform business practices obligation (including UBP). The Companies continue to participate in the Commission's ongoing proceedings concerning cyber protocols and will reflect any changes as appropriate. In this Phase, the NYSEG/RG&E administrator moves third parties through the processes.

4.6 Green Button Connect – Full Deployment Planning

The Companies intend to continue learning through the deployment of GBC in the ESC. This learning and experience will inform NYSEG and RG&E customers of the role of GBC as part of the full deployment of AMI.

5. Innovative Rate Design

5.1 Introduction

Full deployment of AMI will provide opportunities to offer time varying pricing ("TVP") to customers, which can improve economic efficiency by sending more appropriate price signals to customers regarding their consumption decisions. The Companies' plan to fully deploy AMI and offer TVP supports the goals and objectives of REV.

More than four decades of empirical research has shown that many consumers can and will enroll in TVP tariffs and reduce usage during higher-priced periods relative to usage under traditional tariffs in which prices do not vary across the hours of the day, days of the week and seasons. TVP can lead to significant reductions in societal costs over time by reducing the need for high-cost peaking generation or reducing or delaying transmission and distribution capacity investments. It also gives consumers greater opportunities to reduce their energy bills by shifting from higher to lower cost time periods.

Historically, a major impediment to customer participation in TVP has been the high cost of metering on an individual customer basis. This is especially true for mass market consumers such as residential households and small commercial businesses. Full deployment of AMI will provide low cost opportunities for consumers to better manage their energy costs and, in the process, improve the economic efficiency of the electricity system by choosing and responding to prices that more accurately reflect the cost of electricity supply. In the Commission's Order Adopting Regulatory Policy Framework and Implementation Plan issued in Case 14-M-0101 (February 26, 2015), the Commission stated that "REV will establish markets so that customers and third parties can be active participants, to achieve dynamic load management on a system-wide scale. Customers, by exercising choices within an improved electricity pricing structure and vibrant market, will create new value opportunities and at the same time drive system efficiencies and help to create a more cost-effective and secure integrated grid."

In its Order issued April 23, 2018 in Case 17-E-0370 ("Project Order"), the Commission approved the Companies' proposal to implement a rate project for the Energy Smart Community (Smart Usage Plan). The experience gained from the Project will provide insight and serve as the basis for lessons learned for potential future innovative rates once AMI is deployed to all customers. The Companies can also learn from the results of other rate projects implemented throughout the State by other New York utilities and determine their applicability in the Companies' respective service areas.[2]

5.2 Smart Usage Plan

Tariffs for the Smart Rate Option Project became effective May 1, 2018. Customers in the ESC project area may elect to enroll in the Project on an opt-in basis. Rate options are available to customers in all service classifications that have an AMI installed. The make-up of customers with AMI in the ESC is: 84% Residential, 10% Non-residential, Non-demand, and 6% Non-residential, Demand.

Collaborative meetings were held in 2017 to develop the rates for the Project. During the meetings, the objectives of the Project were discussed, which include: (1) providing customers with time-varying rate options; (2) measuring customer adoption and impacts of time-varying rates that focus on system efficiency; (3) empowering customers with more capability to influence their bills; and (4) assessing needs for data access and customer communications. Through discussions in various forums, to the following rate design objectives have been identified: (1) providing customers with the opportunity to respond to prices and make decisions on their energy usage; (2) conveying a strong price signal that focuses on the Company's system peak; (3) developing rates that reflect cost; and (4) ensuring that rates are designed to be revenue neutral by class.

Customers that enroll in the Project will be subject to time-differentiated delivery rates, and for customers that choose NYSEG as their electricity supplier, they will be subject to hourly supply rates. Alternatively, an ESC customer may choose an Energy Service Company for its electricity supply.

NYSEG has developed time-differentiated delivery rates on a revenue neutral basis for each service classification. For the residential and non-residential classes, the on-peak hours are from 4:00 PM to 6:00 PM on weekdays, excluding holidays. For the non-residential classes, the

[2] For example, Consolidated Edison and Orange and Rockland propose to test demand-based delivery rates for mass market customers. See Advanced Metering Infrastructure Customer Engagement Plan filed July 29, 2016 in Case 15-E-0050 *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.*

on peak hours are from 2:00 PM to 6:00 PM on weekdays, excluding holidays. All other hours are off-peak. The price differential between on-peak and off-peak will provide customers with a clear signal to shift or reduce their usage. For each service classification, on-peak rates are at least 2.5 times greater than off-peak rates. For Service Classification No. 1 (Residential), the differential is more pronounced: the on-peak delivery rate is 5.9 times the off-peak delivery rate. The development of the delivery rates was largely based on NYSEG's system peak hours and was influenced by the collaborative.

Customers that choose NYSEG for their supply are subject to hourly prices based on the New York Independent System Operator (NYISO) day-ahead locational based marginal price (LBMP). Capacity charges will be recovered through an individual capacity tag, with the price based on the NYISO monthly and spot capacity auctions. Hourly pricing for customers choosing NYSEG supply is similar to how the Company provides supply service to customers under mandatory hourly pricing (MHP). Hourly supply pricing provides an accurate, cost-based price signal to customers. Customers will have the ability to enroll in pricing alerts based on the day-ahead pricing. In addition, the Company will provide a link and instructions for customers to access the NYISO where they will be able to view the day-ahead prices.

Research within the Energy Smart Community has identified that residential customers show interest in time varying prices. These same customers also expect to see savings and are hesitant to make a change based on current lifestyle. This is mirrored in participation rates. Information that makes it easy for customers to understand the impacts and manage a different rate is key to success, but not necessarily a motivating factor to participate.

Tools implemented within the Project to aid in this understanding include the "what-if scenario," providing an interactive experience that allows interested customers to make assumptions on electricity use changes they are able to make, and the impact of those changes on their current rate and the time varying rate. In addition, a day-ahead supply alert provides a price signal when supply prices are above $.12/kwh. This amount was set based on historical analysis and is intended to provide a meaningful responsiveness without over alerting customers to ensure it is a useful tool.

Education and familiarity with the rate is also imperative for participation. Providing information that explains impacts, recommendations for shifts and impacts of actions to the community through multiple touch points familiarizes potential participants with the goal of implementation as well as personal advantages of participation. NYSEG has developed multiple communications to familiarize customers with the new rate option, as well as a welcome communication to introduce new participants.

Smart Usage Plan Customer Email Example and Fact Sheet

View in browser
Account number: 10012222333
10023333444
10034444555

NYSEG

Welcome to the Smart Usage Plan!

Our new time-of-use pricing option available to Tompkins County customers with a smart meter

Making some small changes to when you're using electricity can create a more efficient and resilient grid and make a big difference to your community and New York.

Understanding your new pricing option

The Smart Usage Plan has two components - **delivery and supply** - that allow you to contribute to reducing NY's peak energy use and potentially reduce your electricity costs. We've partnered with **Cornell Cooperative Extension of Tompkins County (CCE-TC)** to educate residents about the **Energy Smart Community** and the benefits of saving energy. Learn more about peak use and other resources available through CCE-TC.

Delivery Pricing: What you pay NYSEG to transport electricity to your home or business

How is delivery pricing different on the Smart Usage Plan?
With a standard pricing option, your delivery price is the same regardless of the hour or day of the week.
With the Smart Usage Plan, your delivery price is higher during a small window of peak hours and lower during a large window of off-peak hours. Pricing is based on your service classification (SC) and current delivery prices are outlined in the chart below.

Not sure which SC you're billed?
Log in to your nyseg.com account and view page 3 of your bill. You can identify your service and rate classification in the top left hand corner, similar to the example below. Your service classification is the last two numbers of the rate listed. For example, the sample below lists Residential 120001 NYSEG Supply Service. This represents a residential service classification no 1.

***Electricity Service** - Residential*
***Electricity Rate** - 12001 NYSEG Supply Service*

Delivery Charge (Per kWh)	SC No. 1	SC No. 6	SC No. 8	SC No. 12
Standard Pricing Option	$0.04256	$0.04746	$0.03790	$0.03951
Smart Usage Plan On-peak	$0.18769	$0.09645	$0.20233	$0.15706
Smart Usage Plan Off-peak	$0.03164	$0.03839	$0.02870	$0.03231

- **Residential** (SC No. 1, 8 and 12) **peak hours** are 4 p.m. - 6 p.m., Monday through Friday, excluding major holidays.*
- **Non-Residential** (SC No. 6) **peak hours** are 2 p.m. - 6 p.m., Monday through Friday, excluding major holidays.*
- All other hours are considered **off-peak hours**, and include weekends and major holidays.*
- By shifting some of your electricity use to off-peak times, you can help to reduce overall demand on the grid and save on your own electricity costs.

*Holidays include New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day.

Expert Tip: When possible, shift your electricity use to off-peak hours. Consider adjusting your thermostat a few degrees during peak hours. Doing a load of laundry or dishes during off-peak hours can also help you save. By shifting energy-consuming activities to off-peak hours, you can help contribute to a more efficient, resilient grid.

Welcome to the
Energy Smart Community

NYSEG

Smart Usage Plan

A new pricing option that lets you shift your electricity use and save.

On the Smart Usage Plan, the price of electricity is based on when you use it, enabling you to shift some of your electricity use to lower-cost times of day to save on electricity bills.

How it works

Pricing is broken down into two periods of the day:

Off-peak hours are considered the time of day when the price of electricity is lower due to lower demand.
- All hours except 4-6 p.m. on weekdays (Monday through Friday)
- 24 hours per day on weekends (Saturday and Sunday) and holidays (New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day)

Peak hours are considered the time of day when the price of electricity is higher due to higher demand.
- 4-6 p.m. on weekdays (Monday through Friday)

Easy Ways to Shift and Save

Set your thermostat for savings.
If your thermostat is programmable, set it to heat or cool your home during lower-priced times of the day.

Load now, wash later.
It's only natural to want to clean up after dinner so you can relax for the night. Simply load the dishwasher after dinner, and wait until after 6 p.m. or the next morning to run it.

Switch to the Smart Usage Plan and start saving today. Get started at:
nyseg.com/SmartUsagePlan

Supply Pricing: What you pay for the energy purchased for you by NYSEG or a supplier other than NYSEG

You can purchase your supply from **NYSEG** or an **energy services company (ESCO or supplier)**. If you purchase from an **ESCO**, your supply rate will be based on the prices charged by your supplier. If you purchase from **NYSEG**, your supply rate is based on several market-based components including energy, capacity and NYISO (New York Independent System Operator) charges. Energy charges are typically the largest component of the supply price.

How is supply pricing different on the Smart Usage Plan?
If you purchase from an ESCO, your supply pricing will be based on the prices charged by your supplier. If you purchase your supply from NYSEG, our supply prices are based on market demand for energy and set by NYISO. This means when electricity is in higher demand (think hot summer days and cold winter evenings) the cost is also higher. With a standard supply price, market price fluctuations are often balanced and you'll see an overall cost during your billing period, but not the daily highs and lows of the energy market. On the Smart Usage Plan you can take advantage of market fluctuations throughout the day and shift your electricity usage to avoid higher priced times of day. Your smart meter data can provide insight on the times of day when you tend to use more electricity and Day-Ahead Supply Alerts provide a reminder when supply prices are expected to be higher.

How will I know when supply prices are higher?
It's simple. Enroll in our Day-Ahead Supply Alerts. Anytime supply prices are forecasted to be $0.12/kWh or more the following day, we'll send you a reminder.

Setting up Alerts is easy, here's how:
1. Log in to your nyseg.com account
2. Select "Energy Manager"
3. Choose "Set Up Alerts" from the Preferences menu

Set Up Alerts

Want to learn more about day-ahead supply prices? You can visit NYISO for an hourly breakdown of forecasted hourly prices. Select "Zonal" under the Day Ahead Market LBMP section, then choose the "CENTRL" zone. To determine hourly $/kWh supply prices, divide the prices in the Day Ahead Market Zonal Location Based Marginal Prices (DAM Zonal LBMP) by 1,000. Day-ahead hourly prices are available for viewing after 5 p.m. the previous day.

Expert Tip: Enroll in Day-Ahead Supply Alerts. We'll send you a reminder so you can shift your electricity use during any hours the following day with forecasted high supply prices. Making changes to shift your electricity use during these hours may help you save and help reduce the overall demand on the electricity grid.

When will your new pricing option begin?

After you enroll, the Smart Usage Plan will begin with your next billing cycle. Once enrolled and billed on this option, you will find adjustments outlined in the Miscellaneous Charges/Detailed Adjustments section of your bill, similar to the sample below.*

*Sample is for illustrative purposes only and does not represent your actual charges. Adjustments may be a credit or debit. If you are enrolled in the Budget Billing plan, future monthly costs may fluctuate based on the Miscellaneous Charges adjustments included in this pricing option.

For more information on the Energy Smart Community, visit our website or Cornell Cooperative Extension of Tompkins County and learn why saving energy is important to you, your community, New York and the world. You can also contact us at 1.800.925.1559 or email us.

Website | My Account | Contact Us

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5.3 Evaluation Plan for Smart Rate Option Project

The Project Order approving the Smart Rate Option Project directs NYSEG to submit a report to the Commission's Secretary detailing the NYSEG's finding by July 1, 2019, and annually thereafter. The Company expects that the project evaluation will include the following:

Load impact analysis: This task will involve estimation of average load impacts (e.g., maximum demand, monthly usage) by rate period for each rate tested. This will require developing a pseudo-control group based on statistically matching loads for participants and non-participants using pre-treatment usage data.

Billing analysis: Estimating bill impacts for participants can provide useful insight on customer response to the rate structure and identify customers that might be experiencing large positive or negative bill impacts. Changes in participants' bills can result from three factors: (1) structural bill impacts (the difference in bills due to differences in the rates holding usage constant); (2) impacts due to behavioral change; and (3) impacts due to exogenous factors (e.g., differences in weather, the economy, etc.). The evaluation will involve isolating each of these determinants of bill impacts so that only impacts attributable to the project rates are reported.

Choice analysis: This analysis involves quantifying the impact of various customer characteristics on the likelihood of enrolling. This can be done by a model that predicts the likelihood of enrollment as a function of characteristics such as pretreatment load shapes, annual or summer usage, structural bill impacts, customer personas (e.g., "convinced and committed" vs. "unconvinced traditionalists", etc.) and others.

The evaluation conducted for the Smart Rate Plan will provide the Companies with valuable information regarding: (1) customer adoption of TVP; (2) the impacts such rates have on peak load; and (3) the resulting changes in participants' bills. The findings will be used to inform future TVP rate designs that can be developed for all customers as AMI is installed throughout the Companies' service territories.

6. Outreach and Engagement – Measurement

The Companies will track and document customer awareness and participation using defined measures. These measures will help determine whether customer education has been sufficiently clear and effective. Tracking will help refine communication approaches as we seek to drive customer engagement.

Table 6-1 Measuring Outreach and Engagement Effectiveness
NYSEG and RG&E Engagement Metrics

#	NYSEG/RG&E Category	NYSEG/RG&E Metric	NYSEG/RG&E Metric Description	NYSEG/RG&E Target	NYSEG/RG&E Frequency
1	Customer Outreach & Engagement	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. Subsequent progress (check in surveys) measured semi- annually beginning at least six (6) months after beginning of deployment, through the end of roll-out in each region. Check in surveys will draw from customers with AMI meters only. The Companies will measure low-income awareness.	80% of customers with Awareness of AMI at six (6) months post deployment for each specific region.	Semi-Annually (Before/During/After Implementation)
2	Customer Outreach & Engagement	Targeted Energy Briefings	Company-hosted forums providing information on the AMI plan, features, and benefits. Two events per region.	Two events per region during deployment in that region.	Annually (Before/During Implementation)
3	Customer Outreach & Engagement	Community Outreach	Organizational events attended by the Companies where information on the AMI plan, features, and benefits are presented. Four events will be attended during deployment for each region.	Four events will be attended during deployment for each region.	Semi-Annually (Before/During Implementation)
4	Customer Outreach & Engagement	Percentage of deployments completed	The number and percentage of AMI meters installed and working by region, measured based on adherence to planned deployment schedule.	Target TBD - contingent upon vendor selection and deployment plan finalized upon consultation and review with Staff.	Quarterly (During Implementation)

#	NYSEG/RG&E Category	NYSEG/RG&E Metric	NYSEG/RG&E Metric Description	NYSEG/RG&E Target	NYSEG/RG&E Frequency
5	Customer Outreach & Engagement	Appointments Kept	Number of appointments kept as compared to appointments scheduled by region.	Target: 90%	Quarterly (During Implementation)
6	Customer Outreach & Engagement	Customers utilizing Energy Manager	Percentage of customers in each region with AMI meters that log on to usage/analytics page 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 first six (6) months of deployment in each region. Improvement measured against regional baselines in each reporting period. Additional reporting (no targets): Percentage of customers that logged on more than once during each reporting period.	1.6% for region at 12 months after full deployment for region Annual targets after year 1: 50% improvement over actual results for each division	Semi-Annually (During/After Implementation)
7	Customer Outreach & Engagement	Green Button Connect ("GBC") 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 2018 data. In addition, track third parties that provide GBC services. Ensure that Avangrid is certified and meets GBC Alliance Standards.	Target TBD; baseline set 12 months after full deployment Annual target after year 1: 50% improvement over actual results # of applied vs. # onboarded/ certified Avangrid GBC Certification	Semi-Annually (During/After Implementation)
8	Customer Outreach & Engagement	Usage alerts	Percentage of customers enrolled for usage alerts.	Target TBD - to be set once baseline information is available for each region.	Quarterly (During/After Implementation)

#	NYSEG/RG&E Category	NYSEG/RG&E Metric	NYSEG/RG&E Metric Description	NYSEG/RG&E Target	NYSEG/RG&E Frequency
9	Customer Outreach & Engagement	Adoption of Time-Varying Rates	Customer Adoption of Time-Variant Rates: Number of customers with AMI meters that adopt a Time of Use ("TOU") or Time Varying Pricing ("TVP") tariff, expressed as a number and percentage of each by rate. The Companies will document the number of customers on existing TOU or TVP rates prior to the start of AMI roll-out, for comparison purposes.	This information will be provided for tracking purposes only.	Semi-Annually (After Implementation)
10	Customer Outreach & Engagement	Targeted 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). 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.	98% of customers with targeted messages at least twice per year.	Semi-Annually (After Implementation)
11	Customer Outreach & Engagement	Estimated Bills	Estimated Bills: Percentage of bills that were estimated for accounts with AMI meters during the reporting period.	<1.0% of meters estimated for customers with AMI meters.	Monthly (After Implementation)
12	Customer Outreach & Engagement	Real Time Data	Real Time Data: Percent of customers with an AMI meter that have access to data via the web, mobile web, tablet or apps (i.e., Home Area Network or HAN).	99% of customers with AMI meters have access to electric usage data at agreed upon frequencies. Residential - 15 minute data every 15 minutes Commercial - 5 minute data every 15 minutes Gas (Residential & Commercial) - data will be recorded at hourly intervals and collected once per day.	Semi-Annually (After Implementation)
13	Customer Outreach & Engagement	Opt-Out	Customers who have chosen to opt out as a percent of AMI deployment in a region	≤ 1%	Quarterly

7. Data Privacy

NYSEG and RG&E recognize the need to develop and document formal data access and privacy policies in advance of the implementation of AMI. AVANGRID has implemented a formal Cyber Security Program (Program) and a Controls Framework based on industry standards of best practice to protect the confidentiality, integrity, availability and reliability of our cyber-infrastructure and its associated cyber-assets. The Program is governed by a BOD (Board of Directors) approved Cybersecurity Risk Policy, a BOD approved Personal Data Protection Policy, a Unified Incident Response plan and process, as well as various risk-based rules, procedures and processes. The Controls Framework creates a common language for identifying and implementing cybersecurity and privacy standards of best practice. Industry standards and best practice guidance used in the development and maintenance of the Controls Framework include, but are not limited to:

- NIST Cybersecurity Framework;
- NIST 800- 53: Security and Privacy Controls for Federal Information Systems and Organizations;
- NIST 800-171: Protecting Controlled Unclassified Information (CUI) in Non-federal Systems and Organizations;
- NISTIR 7628: Guidelines for Smart Grid Security;
- NIST 800-30: Guide for Conducting Risk Assessments;
- NIST 800-161: Supply Chain Risk Management Practices for Federal Information Systems and Organizations; and
- NIST 800-144: Guidelines on Security and Privacy in Public Cloud Computing.

The Companies have technical, physical and administrative controls in place to protect customers Personally Identifiable Information (“PII”) that is collected, maintained or in transit against loss, unauthorized access, or disclosure. Planning and response to privacy incidents complies with New York State law as appropriate.

8. Summary

The Companies are committed to implementing the three phases of this robust plan to provide a solid platform for future innovation and change. By making stakeholders aware, and providing education and engagement opportunities that are tested through lessons learned and collaboration, the benefits of AMI can be fully realized by our customers.

Appendix O (AMI-3)

AMI Metrics

Appendix O (AMI-3): Advanced Metering Infrastructure ("AMI") Metrics

#	NYSEG/RG&E Category	NYSEG/RG&E Metric	NYSEG/RG&E Metric Description	NYSEG/RG&E Target	NYSEG/RG&E Frequency
1	Customer Outreach & Engagement	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. Subsequent progress (check in surveys) measured semi-annually beginning at least six (6) months after beginning of deployment, through the end of roll-out in each region. Check in surveys will draw from customers with AMI meters only. The Companies will measure low-income awareness.	80% of customers with Awareness of AMI at six (6) months post deployment for each specific region.	Semi-Annually (Before/During/After Implementation)
2	Customer Outreach & Engagement	Targeted Energy Briefings	Company-hosted forums providing information on the AMI plan, features, and benefits. Two events per region.	Two events per region during deployment in that region.	Annually (Before/During Implementation)
3	Customer Outreach & Engagement	Community Outreach	Organizational events attended by the Companies where information on the AMI plan, features, and benefits are presented. Four events will be attended during deployment for each region.	Four events will be attended during deployment for each region.	Semi-Annually (Before/During Implementation)
4	Customer Outreach & Engagement	Percentage of deployments completed	The number and percentage of AMI meters installed and working by region, measured based on adherence to planned deployment schedule.	Target TBD - contingent upon vendor selection and deployment plan finalized upon consultation and review with Staff.	Quarterly (During Implementation)
5	Customer Outreach & Engagement	Appointments Kept	Number of appointments kept as compared to appointments scheduled by region.	Target: 90%	Quarterly (During Implementation)

#	NYSEG/RG&E Category	NYSEG/RG&E Metric	NYSEG/RG&E Metric Description	NYSEG/RG&E Target	NYSEG/RG&E Frequency
6	Customer Outreach & Engagement	Customers utilizing Energy Manager	Percentage of customers in each region with AMI meters that log on to usage/analytics page 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 first six (6) months of deployment in each region. Improvement measured against regional baselines in each reporting period. Additional reporting (no targets): Percentage of customers that logged on more than once during each reporting period.	1.6% for region at 12 months after full deployment for region Annual targets after year 1: 50% improvement over actual results for each division	Semi-Annually (During/After Implementation)
7	Customer Outreach & Engagement	Green Button Connect ("GBC") 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 2018 data. In addition, track third parties that provide GBC services. Ensure that Avangrid is certified and meets GBC Alliance Standards.	Target TBD; baseline set 12 months after full deployment Annual target after year 1: 50% improvement over actual results # of applied vs. # onboarded/certified Avangrid GBC Certification	Semi-Annually (During/After Implementation)
8	Customer Outreach & Engagement	Usage alerts	Percentage of customers enrolled for usage alerts.	Target TBD - to be set once baseline information is available for each region.	Quarterly (During/After Implementation)
9	Customer Outreach & Engagement	Adoption of Time-Varying Rates	Customer Adoption of Time-Variant Rates: Number of customers with AMI meters that adopt a Time of Use ("TOU") or Time Varying Pricing ("TVP") tariff, expressed as a number and percentage of each by rate. The Companies will document the number of customers on existing TOU or TVP rates prior to the start of AMI roll-out, for comparison purposes.	This information will be provided for tracking purposes only.	Semi-Annually (After Implementation)

#	NYSEG/RG&E Category	NYSEG/RG&E Metric	NYSEG/RG&E Metric Description	NYSEG/RG&E Target	NYSEG/RG&E Frequency
10	Customer Outreach & Engagement	Targeted 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). 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.	98% of customers with targeted messages at least twice per year.	Semi-Annually (After Implementation)
11	Customer Outreach & Engagement	Estimated Bills	Estimated Bills: Percentage of bills that were estimated for accounts with AMI meters during the reporting period.	<1.0% of meters estimated for customers with AMI meters.	Monthly (After Implementation)
12	Customer Outreach & Engagement	Real Time Data	Real Time Data: Percent of customers with an AMI meter that have access to data via the web, mobile web, tablet or apps (i.e., Home Area Network or HAN).	99% of customers with AMI meters have access to electric usage data at agreed upon frequencies. Residential - 15 minute data every 15 minutes Commercial - 5 minute data every 15 minutes Gas (Residential & Commercial) - data will be recorded at hourly intervals and collected once per day	Semi-Annually (After Implementation)
13	Customer Outreach & Engagement	Opt Out	Customers who have chosen to opt out as a percent of AMI deployment in a region	≤ 1%	Quarterly
14	Meter Reading Labor	Labor Cost Reductions	Cost reductions associated with Meter Reading functions will be reported.	Achieve Reductions in final Benefit Cost Analysis	Annually
15	Field Service Labor	Labor Cost Reductions	Cost reductions associated with Field Service functions will be reported.	Achieve Reductions in final Benefit Cost Analysis	Annually

#	NYSEG/RG&E Category	NYSEG/RG&E Metric	NYSEG/RG&E Metric Description	NYSEG/RG&E Target	NYSEG/RG&E Frequency
16	Call Center Labor	Labor Cost Reductions	Cost reductions associated with Call Center functions will be reported.	Achieve Reductions in final Benefit Cost Analysis	Annually
17	Billing Labor	Labor Cost Reductions	Cost reductions associated with Billing Labor functions will be reported.	Achieve Reductions in final Benefit Cost Analysis	Annually
18	CO_2 Emissions	Reduce CO_2 Emissions	Reduction in vehicle fuel consumption and vehicle emissions due to reduction in manual meter reading costs and conservation voltage reduction ("CVR") savings.	≥ 72k tons # of Truck Rolls, CVR	Annually (After Implementation)
19	Conservation Voltage Reduction	kWh Reductions	Quantify kWh savings attributed to CVR.	1/2% incremental savings as indicated in Benefit Cost Analysis	Annually (After Implementation)
20	System Operation and Environmental Benefits	CVR Enabled Feeders	Number of feeders with AMI deployed and have implemented CVR.	In accordance with Final Benefit Cost Analysis	Semi-Annually (During Implementation)
21	Capital Expenditure Spend	Capital Expenditure Reporting	Capital Expenditure spend according to Plan	In accordance with Final Benefit Cost Analysis	Quarterly (Before/During Implementation)

#	NYSEG/RG&E Category	NYSEG/RG&E Metric	NYSEG/RG&E Metric Description	NYSEG/RG&E Target	NYSEG/RG&E Frequency
22	Improved Cash Flow	Cash Flow	Based on cash flows actually experienced	Reduce Read to Bill Time by 1.5 days	Annually (After Implementation)
23	Revenue Protection	Loss factor	Reporting of gas and electric supply loss.	In accordance with Final Benefit Cost Analysis	Annually (After Implementation)
24	Meter Accuracy/ Irregular Meter Conditions	Loss factor	Assumes a 30% savings from slow meter reduction, the benefit is reduced by 3.3% annually as meters are replaced in the normal course of business.	In accordance with Final Benefit Cost Analysis	Annually (After Implementation)
25	Bad Debt	Bad debt	Reporting of bad debt.	In accordance with Final Benefit Cost Analysis	Annually

Appendix O (AMI-4)

Security Plan

1. Introduction

This Exhibit documents the current and planned Security Program initiatives supporting the deployment of advanced metering infrastructure ("AMI") at New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation (herein referred to as the "Companies"). The Companies are committed to implementing a secure and reliable AMI system and infrastructure. Strategies, tools, processes and procedures for protecting the privacy of AMI data and for securing the computing and communication networks are being designed and implemented early in the process and are continuously evolving in concert with advances in technology, threat detection and intelligence gathering and the changing risk landscape.

1.1 Corporate Security Program(s)

The Companies have a formally implemented Corporate Security Organization and Program(s), governed by a Board of Directors-approved Corporate Security Policy, a Cyber Risk Policy, Personal Data Protection Policy and a Unified Incident Response Plan. The Corporate Security Organization's focus is on cybersecurity, data protection, physical security, NERC-CIP compliance and threat and incident management. A Controls Framework, based on industry standards of best practice, protects the confidentiality, integrity, availability and reliability of the Companies' infrastructure. Corporate Security Program(s) are designed based on an established controls framework.

2.0 The Security Plan

The Security Plan expands the AMI scope and support model to specifically address AMI physical and cybersecurity risks by identifying and integrating AMI-specific controls into the planning, design and implementation processes. This approach enforces the Companies' commitment to protecting information/data related to customers, employees, and the Companies' transmission and distribution infrastructure.

2.1 The Controls Framework

The Controls Framework is based on industry standards of best practice. Industry standards and best practice guidance used in the development and maintenance of the Controls Framework, include, but are not limited to:

- NIST Cybersecurity Framework
- NISTIR 7628: Guidelines for Smart Grid Security
- NIST SP 800-53: Security and Privacy Controls for Federal Information Systems and
- Organizations
- NIST SP 800-30: Guide for Conducting Risk Assessments
- NIST SP 800-161: Supply Chain Risk Management Practices for Federal Information
- Systems and Organizations
- NIST 800-144: Guidelines on Security and Privacy in Public Cloud Computing
- NIST SP 800-171: Protecting Controlled Unclassified Information
- NIST IR 8062: Privacy Risk Management for Federal Information Systems
- Fair Information Practice Principles (FIPPs)
- Electric Sector Cybersecurity Capability Maturity Model (C2M2)
- DOEDataguard Energy Data Privacy Program
- AICPA Generally Accepted Privacy Principles
- ISO/IEC 27001 Information Security Management
- ISO/IEC 27002 Code of Practice for Information Security Controls
- ISO/IEC 27005 Information Security Risk Management
- ISO/IEC 27018 Code of Practice for Protection of PII in Public Cloud
- ISO/IEC 29100 Privacy Framework
- ISO/IEC 29101 Privacy Architecture Framework
- ISO/IEC 29134 Privacy Impact Assessment
- Information Security Forum General Information Security Practices

2.2 Collaboration

The Security Program includes on-going collaboration with security industry authoritative organizations and working groups providing vital information for the continued development and implementation of security controls. The Corporate Security Organization actively participates in:

- The Electricity Information Sharing and Analysis Center
- The Edison Institute
- Electricity Subsector Coordinating Council
- Electric Power Research Institute
- The Industrial Control Systems Cyber Energy Response Team
- InfraGard (a partnership between the Federal Bureau of Investigation and the private sector)
- The United States Computer Emergency Readiness Team
- NYS Joint Utilities working groups

2.3 Protection of Customer Personally Identifiable Information (PII)

The Companies have implemented technical, physical, and administrative controls to protect customer personally identifiable information (PII) that is collected or maintained against loss, unauthorized access or disclosure in compliance with New York State law. The Companies follow a set of principles based on the Organization for Economic Cooperation and Development and General Acceptable Privacy Principles framework which is geared towards the utility industry. These principles are:

- **Collection Limitation Principle:** Unless a customer opts out, the Companies will collect AMI smart meter data for the purposes of servicing customers' accounts.
- **Data Quality Principle:** The Companies will collect accurate, complete and up-to-date customer information. Disposal of customer data will be performed in accordance with record retention and disposal policies.
- **Purpose Specification Principle**: Use AMI smart meter data to administer the customer account, inform the customer about energy usage and utility programs and services available to them, and provide quality service.
    - Customer billing statements and allowing customers to see and track energy usage data using web based applications to improve the overall customer experience.
    - Changes and updates to data collection and use will be provided in the Companies' online Privacy Statements.
- **Use Limitation Principle**: Commitment to safeguarding the security and confidentiality of AMI collected customer information and to only disclose and/or share that data as stated in the Companies' privacy statement.
    - Support and comply with state laws and any regulatory orders that bar third-party access to individual customer data unless it is necessary for the legitimate business needs of the utility or the customer explicitly requests or approves sharing of their data with designated third-parties.
- **Security Safeguards Principle**: Provide appropriate measures and security technologies to safeguard customer information.
- **Openness Principle**: The Companies will provide updated privacy information to customers regarding any changes to data access, data privacy practices or policies associated with collected AMI smart meter data.
- **Individual Participation Principle:** The Companies shall provide to customers via web based applications secure access to their covered information and the following:
    - Acknowledgment that the Companies are in custody of customer data collected via AMI smart meters. Information/data will be presented in an easily understood format and terminology,
    - A dispute and resolution process for issues relating to customer data and access.

- **Accountability Principle:** The Companies will make every reasonable effort to comply with these Principles. The Companies shall take legal and business exceptions into consideration, including:
  - Compliance with applicable legal process or orders from governing regulatory agencies including, among others, the New York State Public Service Commission;
  - Response to requests from government or legal authorities;
  - Enforcement of the Companies' terms and conditions of service;
  - Protection of the Companies' operations;
  - Protection of rights, privacy, safety or property; and
  - Allowing the Companies to pursue available remedies or limit the damages that may be sustained

2.4 Third-Party/Vendor Risk Management

The Companies have implemented a standardized procedure for identifying, assessing, and mitigating security risks introduced at the vendor level. This process has been integrated into the AMI bidding process, including with all AMI potential vendors.

Company business resources engaging with third-parties (i.e., vendors) initiate the process during the Request for Information or Request for Proposals ("RFP") stage. The process is multi-departmental with areas of responsibility identified for the engaging business, procurement, security and legal services. The Companies' AMI RFPs must include an AMI Security Requirements section. The Security Requirements section specifically requests that the bidder develop and propose a comprehensive AMI-specific Cyber Security Plan that describes and documents its plans to address physical and cyber risks.

In addition, all RFPs must include a Data Security Rider ("DSR"). The DSR includes a requirement for cyber insurance, a non-disclosure/confidentiality agreement and a Security Controls questionnaire which must be completed by each bidder.

Built into the Third-Party/Vendor Risk Management process specific to AMI architecture design and deployment is the integration and implementation of a controls effectiveness assessment and reporting process. Cybersecurity subject matter experts actively monitor and report, on a monthly basis, progress towards implementing security deliverables defined by NIST SP 800-171 (Protecting Controlled Unclassified Information in Nonfederal Systems and Organizations). NIST 800-171 controls are mapped to NIST 800-53 and ISO 27001 controls, aligning with the Controls Framework. This process addresses the security plan for each network segment of the AMI architecture, including, the Head End System ("HES"), Meter Data Management System ("MDMS"), vendor remote access, physical security network, and customer facing applications, i.e., a best practice approach to delivering a secure set of solutions. As designed, the HES is responsible for managing connections to the smart meters, pulling the reads at some pre-scheduled interval and passing the read data onto the MDMS. The MDMS interfaces with SAP for customer billing. Security controls are built into each interface through which AMI data transverses.

Example of NIST 800-171 Adoption Report for Management:

AVANGRID Projects		NIST 800-171 Adoption Plan			Implemented Progress to Date (2018)												Implementation Status
Project	Environment	Planned Alignment	Exceptions	Not Applicable	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
NY AMI	Secure Network Infrastructure	95%	0%	5%										0%	0%		Project Awaiting PSC Approval
	Head End System	95%	0%	5%										0%	0%		
	Interactive Remote Access	95%	0%	5%										0%	0%		
	IT Infrastructure		In Process											0%	0%		
	Vendor/Application		In Process											0%	0%		
Physical Security	Production	93%	0%	7%										0%	0%		Production Deployment starts in December

Examples of Security Scope Deliverables Report

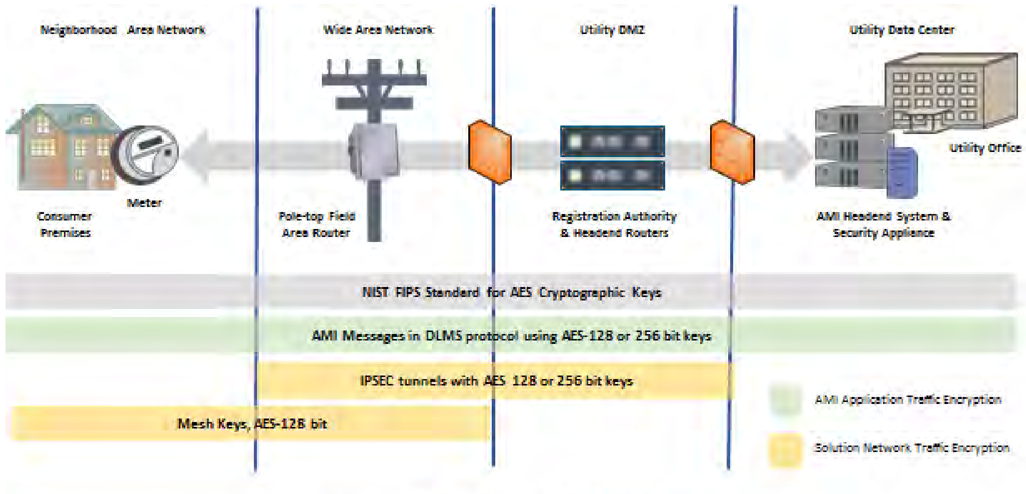
AVANGRID Projects		NIST 800-171 Adoption Plan					Calculations			Percent of Planned Actually Implemented to date (2018)											
Project	Environment	Total 800-171	To Do	Standard Solution	Not Aligned	Not Applicable	Percent Aligned	Exceptions	NA	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
NY AMI	Secure Network Infrastructure	227	149	66	0	12	95%	0%	5%										0%	0%	
	Head End System	227	149	66	0	12	95%	0%	5%										0%	0%	
	Interactive Remote Access	227	55	160	0	12	95%	0%	5%										0%	0%	
	IT Infrastructure	227		In Process				In Process													
	Vendor/Application	227																			
Physical Security	Production	227	2	210	0	15	93%	0%	7%										0%	0%	

2.5 Meter Data Transfer Protections Design Requirements

Multiple layers of encryption shall be implemented to protect meter data. The network and application security layers shall support and provide confidentiality through encryption and authentication, data integrity and non‐repudiation using unique key implementation and intrusion detection.

Communications and messages from the meter to the HES shall be secured through end to end encryption by implementing 128‐bit AES encryption at the application layer.

128-bit AES encryption shall be implemented at multiple layers; from meter to the field area routers and the first wall of the demilitarized zone ("DMZ") and from the field area routers to the head end routers/second router of the DMZ. The network layer security shall employ Active Directory, Certificate Authority Server, RADIUS Server (using Microsoft NPS), and Head End Router (Cisco ISR 4331) to provide tunnels to the routers. The security manager application shall secure the signing of messages from the HES to the endpoints.



End-to-end Protection of AMI Messages

2.6 Training and Awareness

The Security program supports a robust cybersecurity training and awareness program for all of the Companies' personnel. The program is designed to ensure that managers, system administrators and users of the Companies' systems are aware of the security risks associated with their activities and of the applicable policies, rules and procedures related to the security of those systems. A Companies-wide phishing program runs monthly and includes reporting and trend analysis. The Companies are recognized champions of National Cyber Security Awareness Month ("NCSAM") and National Critical Infrastructure Security and Resiliency Month ("NCISRM"). NCSAM was launched by the National Cyber Security Alliance and the Department of Homeland Security in October of 2004. As NCSAM champions, the Companies are committed to promoting a safer, more secure and more trusted internet. NCISRM, observed in November, builds awareness and appreciation of the importance of critical infrastructure and re-affirms a nationwide commitment to keep our critical infrastructure and communities safe and secure. Company personnel receive role-based cybersecurity training addressing specific areas of increased risk or concern, e.g., Human Resources privacy training. PII training is available to all of the Companies' personnel. Successful completion of PII training is monitored and reported to the management team. Annual NERC-CIP training is required of all Companies' personnel with NERC-CIP access.

Specific to the Companies' AMI deployment, managers, system administrators and users shall be made aware of the security risks associated with their activities and of the applicable Company policies, rules and controls related to the security of each network segment of the AMI architecture.

AMI-specific RFPs require bidders to include specific security training in their bids. Adherence to this requirement is included in and tracked using the NIST 800-171 reports sited in Section 2.4 – Third-Party/Vendor Risk Management.

Customer Service Provisions

New York State Electric & Gas Corporation – Electric
New York State Electric & Gas Corporation – Gas
Rochester Gas and Electric Corporation – Electric
Rochester Gas and Electric Corporation – Gas

The Customer Service provisions set forth in this Appendix will be in effect for the term of the Rate Plan and thereafter unless and until changed by the State of New York Public Service Commission ("Commission").

Customer Bill Credits

Customer Bill Credits with an overall cap of $30.0 million which will directly benefit some of the Companies' most vulnerable residential and small commercial customers facing negative economic impacts as a result of the COVID-19 Pandemic. NYSEG will have an overall Company cap of $16.5 million and RG&E will have an overall Company cap of $13.5 million Relief in the form of bill credits will begin in 2020 and occur over three phases.

When the bill credits are provided to customers, the Companies will create regulatory assets that will be recovered over five years beginning in July 2021 with carrying charges applied on the unrecovered balance using the Commission's Other Customer Capital rate. The recovery will be through the Rate Adjustment Mechanism ("RAM") for each business until the balance is fully recovered. The Companies expect that the bill credits will be applied to customer accounts in Phase 1 starting with the billing cycle that starts about 30 days following a Commission order approving the Proposal. Phase 2 and Phase 3 bill credits are expected to begin with bill cycles during the months of October 2020 and January 2021, respectively.

The three phases of bill credits will be:

Phase 1 (through May 31, 2020):

a. The first phase will provide customer relief through a one-time $100 maximum bill credit to approximately 133,000 customers[1] who meet the following criteria as of May 31, 2020:
   - Residential
     - Low Income Programs participants
     - Customers on minimum payment agreements, but not enrolled in the Low Income Programs
   - Small Commercial
     - Customers on payment agreements
     - Customers in arrears

[1] Eligible customer counts as of April 2020 are: NYSEG Residential = 60,717; RG&E Residential = 47,041. NYSEG small commercial = 17,311; RG&E small commercial = 7,906.

Phase 2 (June 1, 2020 through August 31, 2020):

a. The Companies recognize that there will be customers who do not currently meet Phase 1 criteria who will be economically impacted by this Pandemic but would become eligible under the criteria noted below between June 1, 2020 and August 31, 2020. In an effort to assist these newly payment-challenged customers, one-time bill credits will be provided to these customers. These credits will be a maximum of $100 per customer. If sufficient funding under the total Company caps noted above is not available to provide $100 to each newly qualifying customer, then a reduced amount will be provided to each newly qualifying customer using the formula "Total Company Cap less Company Bill Credits provided in Phase 1" divided by the number of newly qualified customers. Credits will be provided in Phase 2 only to customers who did not receive a bill credit in Phase 1.

b. Phase 2 credits will be provided to customers who meet the following criteria between June 1, 2020 and August 31, 2020:
    - Residential:
        - New Home Energy Assistance Program ("HEAP") recipients (and therefore new Low Income participants)
        - New minimum payment agreement
    - Small commercial
        - New payment agreement

Phase 3 (September 1, 2020 through November 30, 2020)

a. The Companies recognize that there will be customers who do not currently meet Phase 1 or Phase 2 criteria who will be economically impacted by this Pandemic, and would become eligible under the criteria noted below between September 1, 2020 and November 30, 2020. In an effort to assist these newly payment-challenged customers, one-time bill credits will be provided to these customers. These credits will be a maximum of $100 per customer. If sufficient funding under the total Company caps noted above is not available to provide $100 to each newly qualifying customer, then a reduced amount will be provided to each newly qualifying customer using the formula "Total Company Cap less Company Bill Credits provided in Phases 1 and 2" divided by the number of newly qualified customers. Credits will be provided in Phase 3 only to customers who did not receive a bill credit in either Phase 1 or Phase 2.

b. Phase 3 credits will be provided to customers who meet the following criteria between September 1, 2020 and November 30, 2020:
    - Residential:
        - New HEAP recipients (and therefore new Low Income Program participants)
        - New minimum payment agreement
    - Small commercial
        - New payment agreement.

The Customer Bill Credit program will end with Phase 3, even if a Company has not reached the previously indicated cap level.

Any modifications to this program could be determined in any future generic proceeding addressing the COVID-19 Pandemic.

Customer Service Performance Indicator Metrics and Targets

This Appendix establishes threshold performance levels for designated aspects of customer service. The specific service quality metrics and targets and negative revenue adjustments for New York State Electric & Gas Corporation ("NYSEG") and Rochester Gas and Electric Corporation ("RG&E" and together with NYSEG, the "Companies" and individually, the "Company") are set forth in this Appendix. The following metrics will be in effect beginning with calendar year 2021. Specific calculations and targets for each metric are shown in the table below:

Service Quality Performance Measures			
Measure	**Monthly Calcualtion**	**Annual Calculation**	**Threshold**
PSC Complaints per 100,000 customers	Monthly Escalated Complaint Total / Number of active residential and commercial premises (minus inactive) at year end [12/31/20xx] x 100,000	12 Month Escalated Complaint Total / 12) x (1 / Number of active residential and commercial premises (minus inactive) at year end [12/31/20xx]) * 100,000	NYSEG: ≥1.0; RG&E: ≥1.0
Contact Satisfaction	Number of Customers who have responded satisfied or somewhat satisfied Divided By Total Number of Customers who have answered the overall satisfaction question	(same calculation as monthly using cumulative January through December inputs): January through December Number of Customers who have responded satisfied or somewhat satisfied Divided By Sum of January through December Number of Customers who have answered the overall satisfaction question	NYSEG: ≤89.5%; RG&E: ≤ 88%.

Percent of Calls Answered in 30 Seconds	Number of Total Calls Answered within 30 Seconds Divided By (Number of Total Calls Requesting a Representative minus All Calls Abandoned within 30 Seconds) x 100	(same calculation as monthly using cumulative January through December inputs) Sum of January through December Number of Total Calls Answered within 30 Seconds Divided by (Sum of January through December Number of Total Calls Requesting a Representative minus All Calls Abandoned within 30 Seconds) x 100	NYSEG ≤70%; RG&E: ≤ 70%.
Percent of Estimated Bills	Number of Estimated Bills Divided By Number of Scheduled Bills x 100	(same calculation as monthly using cumulative January through December inputs) Sum of January through December Estimated Bills Divided by Sum of January through December Scheduled Bills x100	NYSEG: ≥6.76% RG&E: ≥15.65%

Specific negative revenue adjustments for Company and each metric are shown in the tables below:

Customer Service Performance Indicator Thresholds for Revenue Adjustments and Amounts at Risk

	Performance Measures	Threshold for Revenue Adjustment	Maximum Revenue Amount at Risk
NYSEG	PSC Complaints Per 100,000 Customers	< 1.00	N/A
		≥ 1.00	$800,000
		≥ 1.20	$1,600,000
		≥ 1.40	$2,400,000
		≥ 1.70	$3,200,000
	Contact Satisfaction	> 89.50%	N/A
		≤ 89.50%	$800,000
		≤ 88.00%	$1,600,000
		≤87.00%	$2,400,000
		≤ 86.00%	$3,200,000
	Percent of Calls Answered in 30 Seconds	> 70.00%	N/A
		≤ 70.00%	$330,000
		≤ 69.00%	$660,000
		≤ 68.00%	$990,000
		≤ 67.00%	$1,720,000
	Percent of Estimated Bills	< 6.76%	N/A
		≥ 6.76%	$250,000
		≥ 7.76%	$500,000
		≥ 8.76%	$750,000
		≥ 9.76%	$1,400,000
	Total Amount at Risk		$9,520,000
	Electric		$7,330,400
	Gas		$2,189,600

Customer Service Performance Indicator Thresholds for Revenue Adjustments and Amounts at Risk

	Performance Measures	Threshold for Revenue Adjustment	Maximum Revenue Amount at Risk
RGE	PSC Complaints Per 100,000 Customers	< 1.00	N/A
		≥ 1.00	$500,000
		≥ 1.20	$1,000,000
		≥ 1.40	$1,500,000
		≥ 1.70	$2,000,000
	Contact Satisfaction	> 88.00%	N/A
		≤ 88.00%	$500,000
		≤ 84.00%	$1,000,000
		≤ 83.00%	$1,500,000
		≤ 82.00%	$2,000,000
	Percent of Calls Answered in 30 Seconds	> 70.00%	N/A
		≤ 70.00%	$175,000
		≤ 69.00%	$350,000
		≤ 68.00%	$525,000
		≤ 67.00%	$1,000,000
	Percent of Estimated Bills	< 15.65%	N/A
		≥ 15.65%	$175,000
		≥ 16.65%	$350,000
		≥ 17.65%	$525,000
		≥ 18.65%	$900,000
	Total Amount at Risk		$5,900,000
	Electric		$3,245,000
	Gas		$2,655,000

Reporting Requirements

Each Company will submit the results of its Customer Service Performance Indicators in compliance with Order 15-M-0566. A final report will be submitted for each calendar year within 30 days of the end of the calendar year. The final report will also state whether a revenue adjustment is applicable, and if so, the amount of the revenue adjustment. The Companies will provide all supporting workpapers related to reported performance when the final report is submitted.

Doubling Provision

The negative revenue adjustment for an individual measure will double if the Company misses any of the target levels for that particular measure for two consecutive calendar years. Any doubling of the negative revenue adjustment would apply to the calendar year encompassing the second miss of the target. The negative revenue adjustment would continue to double for each consecutive miss of the target. If doubling takes place and the Company subsequently meets the previously missed target, the negative revenue adjustment for that target will revert to the original (i.e., non-doubled) amounts.

Missed Appointments

In the event of a Company missing a scheduled appointment with a residential customer, the Company will provide a credit of $35.00 to the customer. The Companies will include in their respective annual Customer Service Performance Indicator reports the total number of credits provided in the calendar year and total dollar amount of the credits given to residential customers. The Companies will send to Staff, confidentially, a list of the customers who received a credit, total number of all missed appointments , and information on any customers who did not receive a credit, yet qualified, in the information reported.

Negative Revenue Adjustment (NRA) Audit and Reconciliation

In the 2016 Rate Plan, the following calendar year customer service metrics were established based on the Companies' annual Service Quality Performance Mechanism (SQPM) reports: (1) PSC Complaint Rate; (2) Contact Satisfaction; (3) Calls Answered in 30 Seconds; and, (4) Estimated Meter Reads.

In RG&E's 2017 annual customer service filing it reported two NRAs: $175,000 for failure to meet the Calls Answered in 30 Seconds metric target, and $350,000 for failure to meet the Estimated Meter Reads metric target. Staff conducted an audit of the Companies' 2016, 2017, and 2018 data provided in the quarterly and annual SQPM reports and confirmed that NYSEG did not incur any customer service NRAs and RG&E incurred the two reported NRAs.[2]

The Signatory Parties agree that RG&E deferred $525,000, which will be used in RY1, RY2 and RY 3Rate Years 1, 2, and 3 for the benefit of customers as shown in Appendix AA (RG&E Electric and RG&E Gas, "Service Quality Performance" line items). As set forth in the 2016 Rate Plan, the deferred amount accrued interest utilizing the pre-tax rate of return of 10.26% for the rate year ending April 30, 2018.[3]

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2 Staff also audited the Companies' monthly Customer Service Performance Indicators (CSPI) reports which were required to be filed based on Case 15-M-0566, In the Matter of Revisions to Customer Service Performance Indicators Applicable to Gas and Electric Corporations, Order Adopting Revisions to Customer Service Reporting Metrics (the Order) (Approved August 4, 2017).

3 2016 Rate Plan at Appendix A.

Uncollectibles/Terminations/Arrears Measure

The Companies will add an arrears component to the existing uncollectible/termination measure set forth below. These measures will be in effect beginning with calendar year 2021.

Specific components of the Uncollectibles/Termination/Arrears measure are listed below:

1) Arrears will be based on residential > 60 day arrears as reported on PSC collection reports submitted by each Company;

2) The three-year average of each component (Uncollectibles, Terminations and Arrears) will be used for target setting;

3) The upper target will be set at the three-year average plus one standard deviation; and

4) The lower target will be set using two standard deviations from average;

Each Company will be eligible for full positive revenue adjustment (NYSEG: $855,000 and RG&E: $560,000) if the results for all three components (Uncollectibles, Terminations and Arrears) are below the lower targets identified in the table below. Each Company will be eligible for a partial (three-quarter) positive revenue adjustment (NYSEG: $641,250 and RG&E: $420,000) if two components (one of which must be Terminations) are below the lower targets and one is below the upper target identified in the table below. Each Company will be eligible for a partial positive revenue adjustment (NYSEG: $427,500 and RG&E: $280,000) if the Terminations component is below the lower target and two components are below the upper targets identified in the table below.

Targets for each component of the measure are set forth below:

	Residential Uncollectible Expense		Residential Termination		Residential Arrears	
	NYSEG	RGE	NYSEG	RGE	NYSEG	RGE
3-Year AVG	$11,958,896	$12,493,091	17,669	11,962	$33,341,097	$35,475,607
Higher Target(Based on 1 STD)	$10,853,127	$11,706,225	11,430	9,373	$30,354,081	$34,164,831
Lower Target(Based on 2 STD)	$9,747,358	$10,919,358	5,192	6,784	$27,367,064	$32,854,054
Range	$1,105,769	$786,867	6,239	2,589	$2,987,017	$1,310,777

Same-Day Reconnection Report – Quarterly Report

The Companies will continue to file a report on same-day reconnections for each calendar quarter ("Reconnection Reporting Period"). Each report will be filed with the Secretary to the Commission with copies by electronic mail to interested parties within 30 days after the end of each Reconnection Reporting Period.

Credit and Debit Card Fees

Customers will continue to be permitted to pay their NYSEG or RG&E bill by use of a credit or debit card without incurring a fee from either the Companies or a third-party agent processing such payments. The Companies will not assess on customers a convenience payment or other fee for use of a credit or debit card for payment.

Upon expiration of the current third-party vendor processing agreement, the Companies will pursue a competitive bidding process for credit card merchant services.

Each Company shall reconcile actual expenditures to the rate allowance for credit and debit card fees as included in Appendix T.

The Companies will report to the Secretary, on a quarterly basis, the monthly totals as well as monthly total dollar amounts of credit card transactions.

Third Party Agent Fees

The Companies will eliminate per-transactions fees for customers who pay their bill at authorized payment locations with an authorized third party pay agent. Any third-party pay agent fees associated with customer payments using third-party pay agents will be charged by the third-party pay agent direct to NYSEG or RG&E. Each Company shall reconcile actual expenditures associated with any third-party pay agent fees to the rate allowance for such fees as included in Appendix T.

The Companies will file an annual report to the Secretary evaluating expenditures related to the transaction fees associated with the elimination of Third Part Payment Agent Fees. The annual report will include the quantity of payments processed, fee cost, and dollar of total payments processed

Electronic Deferred Payment Agreements

The Home Energy Fair Practices Act and the implementing regulations set forth in 16 NYCRR § 11.10 Deferred Payment Agreements, govern deferred payment agreements between the residential customer and the Companies. Within three months of the issuance of a final Commission Order in these proceedings, the Companies will file a plan to implement an electronic deferred payment agreement ("e-dpa") process for residential customers.

The Companies will file reports to the Secretary detailing: a comparison of e-DPAs and conventional DPAs by type; total dollar amount of all e-DPAs; number of e-DPAs created; number of active e-DPAs; number of e-DPAs completed; number of canceled e-DPAs; and a summary of any customer inquiries and complaints regarding the program that the Companies have received.

Walk-In Offices

Beginning June 1, 2021, the Companies shall be permitted to close designated walk-in office locations based upon the following phased office closure schedule. As agreed below, the Companies will provide reports of customer traffic in each customer office. Any material increase in traffic in an office will be reviewed with Department of Public Service Staff and other parties to determine if the closure is still appropriate. A material increase is defined as a 25% increase in representative-assisted transactions (from baseline provided in testimony) sustained consistently for at least a 3-month period.

(1) RG&E Office located at 256 Waring Road, Rochester, New York 14609 – 2021 closure.

(2) RG&E Office located at 32 Main Street, Fillmore, New York 14735 – 2021 closure.

(3) RG&E Office located at 79 Clark Street, Canandaigua, New York 14424 – 2021 closure.

(4) NYSEG Office located at 150 Erie Street, Lancaster, New York 14086 – 2021 closure.

(5) NYSEG Office located at 7760 Industrial Park Road, Hornell, New York 14843 – 2021 closure.

(6) NYSEG Office located at 26 Wierk Avenue, Liberty, New York 12754 – 2022 closure.

All current employees assigned to a walk-in office that will be closed will continue with a job assignment at their same level and pay-grade to be located in that same Company division/region.

The Companies shall be permitted to modify the hours of the following walk-in office locations based upon the following office hours-change schedule:

(1) NYSEG Office located at 73 Wright Circle, Auburn, New York 13021 ("Auburn Office"). The new walk-in hours for the Auburn office will be modified to be two days per week - one day from 8 a.m to 3 p.m and one day from 9 a.m. to 4 p.m.

(2) NYSEG Office located at 65 Country Club Road, Oneonta, New York 13820 ("Oneonta Office"). The new walk-in hours for the Oneonta Office will be modified to be two days per week - one day from 8 a.m to 3 p.m and one day from 9 a.m. to 4 p.m.

(3) NYSEG Office located at 1387 Dryden Road, Ithaca, New York 14850 ("Ithaca Office"). The new walk-in hours for the Ithaca Office will be modified to be two days per week - one day from 8 a.m to 3 p.m and one day from 9 a.m. to 4 p.m.

(4) RG&E Office located at 14 State Street, Sodus, New York 14551 ("Sodus Office"). The new walk-in hours for the Sodus Office will be modified to be two days per week - one day from 8 a.m to 3 p.m and one day from 9 a.m. to 4 p.m.

NYSEG and RG&E shall provide a customer outreach implementation plan to Staff and interested parties to these proceedings a minimum of two months prior to the closure of each walk-in office identified above. In the event NYSEG or RG&E proposes to close any additional walk-in office(s), the applicable Company must first file a petition with the Commission and obtain Commission approval for such office closure.

In those service areas in which the Companies will be closing a walk-in office as identified above, the Companies agree to implement a process for a customer to request a meeting with a Customer Service employee. A Customer Service employee will schedule meetings with customers on an as-needed/as-requested basis. The Companies will assign two positions (FTEs) to assist with this workload.

The Companies will coordinate with the following counties to provide scheduled dates and times to have a NYSEG or RG&E Customer Advocate on site at the New York State Department of Social Services office for a minimum of two times per month per location subject to the approval and schedule of the particular New York State Department of Social services location: Monroe, Chenango, Erie, Ontario, Steuben, Sullivan. These offices have been selected to correspond with those walk-in office locations identified above that the Companies will close. The Companies will make reasonable efforts to coordinate with the Department of Social Services offices so that Company representatives are located in a prominent and easily accessible area for customers. The Companies will coordinate with the New York State Office of Temporary and Disability Assistance/Department of Social Services ("OTDA") to expand periodic location of Customer Advocates in additional counties subject to the approval and schedule of the particular New York State Department of Human Services location.

The Companies agree to provide outreach and communications regarding options for completing transactions as well as meeting with a Company representative in person. These communications will be made through multiple channels, including but not limited to, Third Party Payment locations, Customer Contact Centers, Company websites, bill inserts and remaining open offices.

The Companies will provide quarterly reporting of customer usage of open offices, number of individual customer appointments requested (individually reported for appointments with a Customer Service employee and for those at NYS Department of Social Services offices), number of appointments made and other relevant information.

Voluntary Protections During Periods of Extreme Cold and Heat

The Companies will implement the following excessive cold weather moratorium pledges and heat provisions.

Cold Weather Protections:

NYSEG and RG&E will commit to additional winter protections for residential customers during the Cold Weather Period of November 1 through April 15 ("Cold Weather Period"). These protections include:

- The Companies will provide the customer with continued or restored service regardless of the amount due and/or the customer's payment status when a Home Energy Assistance Program ("HEAP") payment has been accepted by the Company during the period from November 1 through April 15. This excludes "Heat Included" benefits for households that pay for heat as a portion of their rental cost as explained in the OTDA HEAP Program information outline.

- During the Cold Weather Period, the Companies will consider any Regular and Emergency HEAP payment as entitling the applicant to a fair and reasonable Deferred Payment Agreement, regardless of any previous DPA or e-DPA defaults.

- The Companies will refrain from scheduling residential service terminations on days when the local weather forecast predicts below-freezing (32 degrees) temperatures.

- NYSEG and RG&E will establish a voluntary moratorium on winter terminations for customers who are elderly, blind or disabled.

Excessive Heat Protections:

NYSEG and RG&E will suspend residential terminations during a heat advisory. A heat advisory is in place when the heat index is forecasted at 95 degrees for two or more consecutive days and/or when the heat index is forecasted at 100 degrees for 1 or more consecutive days. The Companies will use the forecasts provided by the United States National Weather Service.

Senior Study

The Companies agree to conduct a study to identify potential partnerships for senior customer outreach concerning energy efficiency opportunities, low income discounts and other senior customer-related opportunities. The Companies will coordinate such study with Staff of the Department of Public Service. The scope of the study will be to identify such potential partnerships and associated activities. As part of the study, the Companies will research best practices of utilities in states/service territories that have higher-than-average percentages of seniors as customers.

Events Outside of the Companies' Control

Factors beyond the control of the Companies could adversely affect the ability of each Company to meet the customer service targets established in this Appendix. Examples of such factors could include but are not limited to: weather; and epidemics/pandemics. Accordingly, the Companies do not waive and expressly retain their right to petition the Commission for a waiver, release, or other relief related to a Company's failure to meet the targets set forth in this Appendix as a result of factors beyond the Company's control. The Companies may petition the Commission for relief.

Low Income Programs

New York State Electric & Gas Corporation – Electric
New York State Electric & Gas Corporation – Gas
Rochester Gas and Electric Corporation – Electric
Rochester Gas and Electric Corporation – Gas

The Companies agree to the following related to Low Income Programs:

1) Low Income Program budgets will be set at \$20.7 million for NYSEG and \$17.3 million for RG&E. Below is a chart that breaks out the annual program budget per Rate Year. All home energy assistance program ("HEAP") recipients will be eligible for the program, with discounts to be provided to monthly bills. Self-enrollment in the Companies' Low Income Program will be expanded to include any customer who is denied a HEAP grant, but who can provide confirmation via a denial letter that he or she is HEAP eligible.

2) Average bill amounts used to set discounts were derived by utilizing bill impacts as shown in Appendix CC (electric) and Appendix EE (gas).

3) Low Income Participant numbers used for setting program budgets reflect actual participants as of March 1, 2020.

4) The Low Income Program discounts for Year 1 will become effective coincident with the effective date of new tariffs for this Rate Plan. The Low Income Program discounts for Year 2 will be effective for the period November 2021 and will be in effect for the period November 1, 2021 through October 31, 2021. The Low Income Program discounts for Year 3 will become effective November 1, 2022 and will be in effect for the period November 1, 2022 through October 31, 2023.

5) The Arrears Forgiveness portion of the Low Income Program will be maintained at existing levels of funding (\$1.5 million for NYSEG and \$1.13 million for RG&E).

6) Average bills will be recalculated annually and bill discounts will be reviewed to determine if there is a need to change discount amounts to maintain the two percent cap and to be in line with six percent energy burden for customers consistent with the parameters established by the Commission in Case 14-M-0565 – Proceeding in Motion of the Commission to Examine Programs to Address Energy Affordability for Low Income Customers (the "Low Income Proceeding").

7) All Low Income Program participants will be referred to the New York Energy Research and Development Authority's ("NYSERDA") Empower program for energy efficiency and/or budget counseling or a similar program.

8) Companies will provide quarterly reports on a number of low income program-related topics utilizing the existing template and methodology. The Companies will provide quarterly reports to the Secretary on the following Low Income Program components:
   a) Number of customers enrolled in the Bill Reduction program;
   b) Number of customers enrolled in the Arrears Forgiveness program;
   c) Total amount held in arrears for the program;
   d) Average amount in arrears;
   e) Aggregate amounts of low income bill discounts;
   f) Aggregate amount of arrears forgiven; and
   g) Number of customers who have defaulted off the program.

9) There is a Low Income Proceeding (Case 14-M0565) pending before the Commission that may modify the Companies' Low Income Programs. To the extent the Commission orders modification(s) to the Companies' Low Income Programs, the Companies will be held harmless from any increase in expenses associated with the revised or new Low Income Programs and will be authorized to defer the difference between the rate allowance during each Rate Year and the actual costs for Low Income Programs for future recovery with carrying charges at the Companies' pre-tax rate of return.

10) Parties have agreed that the low income discounts will remain equal or greater to current discounts unless the Commission directs the Companies to modify the discount levels in the Low Income or other statewide proceeding.

11) Funding and Reconciliation: The Bill Reduction Program will continue to be subject to symmetrical reconciliation. Any unspent Arrears Forgiveness funding will first be utilized to offset any actual spending which is over the planned (budgeted) amount in the Bill Reduction Program. If there are additional unspent Low Income Program funds at the end of Rate Year 3, these funds will be used to offset the remaining regulatory assets associated with the Customer Relief Bill Credits.

The following table shows low income discounts for Rate Years 1 through 3. These amounts may be adjusted based on any subsequent Commission action related to the Low Income Proceeding or other statewide initiative or proceeding.

Total Low Income Program Annual Budget

	NYSEG				RG&E		
	Year 1	Year 2	Year 3		Year 1	Year 2	Year 3
Bill Reduction	$19,206,108	$19,206,108	$19,206,108		$16,163,556	$16,163,556	$16,163,556
Arrears Forgiveness	$1,500,000	$1,500,000	$1,500,000		$1,130,000	$1,130,000	$1,130,000
Total Funding	**$20,706,108**	**$20,706,108**	**$20,706,108**		**$17,293,556**	**$17,293,556**	**$17,293,556**

Bill Reduction

Eligible customers will receive the following discount on their monthly bill.

NYSEG				
Utility Type	**Tier**	**Year 1 Discount**	**Year 2 Discount**	**Year 3 Discount**
Gas Heat	Tier 1	$3.00	$3.00	$3.00
Gas Heat	Tier 2	$5.00	$5.00	$5.00
Gas Heat	Tier 3	$26.00	$26.00	$26.00
Gas Heat	Tier 4	$8.00	$9.00	$11.00
Gas Non Heat	Tier 1	$3.00	$3.00	$3.00
Gas Non Heat	Tier 2	$3.00	$3.00	$3.00
Gas Non Heat	Tier 3	$3.00	$3.00	$3.00
Gas Non Heat	Tier 4	$3.00	$3.00	$3.00
Electric Heat	Tier 1	$4.00	$4.00	$4.00
Electric Heat	Tier 2	$20.00	$20.00	$20.00
Electric Heat	Tier 3	$36.00	$36.00	$36.00
Electric Heat	Tier 4	$22.00	$22.00	$22.00
Electric Non Heat	Tier 1	$4.00	$4.00	$4.00
Electric Non Heat	Tier 2	$20.00	$20.00	$20.00
Electric Non Heat	Tier 3	$36.00	$36.00	$36.00
Electric Non Heat	Tier 4	$22.00	$22.00	$22.00

RG&E				
Heat Type	**Tier**	**Year 1 Discount**	**Year 2 Discount**	**Year 3 Discount**
Gas Heat	Tier 1	$3.00	$3.00	$3.00
Gas Heat	Tier 2	$3.00	$3.00	$3.00
Gas Heat	Tier 3	$20.00	$20.00	$20.00
Gas Heat	Tier 4	$3.00	$3.00	$3.00
Gas Non Heat	Tier 1	$3.00	$3.00	$3.00
Gas Non Heat	Tier 2	$3.00	$3.00	$3.00
Gas Non Heat	Tier 3	$3.00	$3.00	$3.00
Gas Non Heat	Tier 4	$3.00	$3.00	$3.00
Electric Heat	Tier 1	$4.00	$4.00	$4.00
Electric Heat	Tier 2	$20.00	$20.00	$20.00
Electric Heat	Tier 3	$35.00	$35.00	$35.00
Electric Heat	Tier 4	$21.00	$21.00	$21.00
Electric Non Heat	Tier 1	$4.00	$4.00	$4.00
Electric Non Heat	Tier 2	$20.00	$20.00	$20.00
Electric Non Heat	Tier 3	$35.00	$35.00	$35.00
Electric Non Heat	Tier 4	$21.00	$21.00	21.00

Bill discount amounts will run from November 1 through October 31. Program costs are based on the 2020 level of HEAP recipients.

Listing of NYSEG Electric Capital Expenditures by Project and Category
(in thousands of dollars)

	Capital Project or Category	2020 PLAN	2021 PLAN	2022 PLAN	2023 PLAN
	ELECTRIC: Asset Condition Replacement				
1	Substation Modernization	5,000	10,000	10,000	10,000
2	Distribution Line	21,469	22,113	22,777	23,460
3	Substation Circuit Breaker Replacement Program	17,316	17,664	18,019	18,381
4	Transmission Line	15,914	16,391	16,883	17,389
5	Betterments	10,115	10,328	10,545	10,766
6	Line 968 - 115 kV	1,400	2,799	27,993	27,993
7	Line 879 Rebuild - Ausable Town Line to Rainbow Falls	7,127	-	-	-
8	Subst Minor Capital	7,147	7,252	3,749	3,451
9	Mobile Replacements	6,283	-	-	-
10	Line 880 Rebuild	6,948	6,987	3,535	-
11	Line 810 Brewster - 46 kV	687	1,031	6,870	10,305
12	Homer City Capital Breakers	6,257	3,639	5,310	-
13	All Other	14,787	12,386	23,300	49,756
14	Total Asset Condition Replacement	120,449	110,589	148,979	171,501
	ELECTRIC: Efficiency				
15	Substation Automation Program	10,916	11,609	11,841	12,023
16	All Other	1,700	1,703	1,706	1,709
17	Total Efficiency	12,616	13,312	13,547	13,732
	ELECTRIC: System Capacity				
18	Dingle Ridge - 2nd Bank and 13.2kV Conversion	3,501	3,500	-	-
19	Sloan - Add a Second Transformer Bank and Fourth Circuit Position	-	685	4,111	12,332
20	Hilldale - 115 kV Source, Transformer Bank Upgrade and Second 12 kV Distribution Circ	787	4,723	14,168	11,806
21	Java NWA - Microgrid	1,000	15,800	10,000	-
22	All Other	5,737	2,352	4,857	13,689
23	Total System Capacity	11,025	27,060	33,135	37,827
	ELECTRIC: Mandatory				
24	NYSEG BES Program	52,132	97,339	85,246	49,301
25	NERC Alert Priority III	9,108	9,108	9,108	9,108
26	Non-AMI DSIP Grid Automation	31,551	32,873	33,176	36,720
27	Distribution Line Inspection	12,731	13,113	13,506	13,911
28	New Gardenville Rebuild	735	12,757	20,444	8,532
29	Major Government Highway	4,081	4,203	4,329	4,459
30	North Brewster Reinforcement	3,337	3,337	-	-
31	Residential Line Extensions	8,430	8,683	8,943	9,212
32	Service Connects	5,357	5,518	5,684	5,854
33	Industrial Commercial	5,495	5,660	5,830	6,005
34	Street Lighting	6,306	6,495	1,625	1,674
35	All Other	7,290	9,124	7,914	8,271
36	Total Mandatory	146,553	208,209	195,805	153,045
37	**ELECTRIC: AMI**	28,900	47,857	50,546	62,035
	ELECTRIC: Reliability				
38	Resiliency Plan	19,895	24,640	30,600	31,960
39	Coopers Corners, Add 3rd 345/115kV Trfmr	5,395	11,097	15,462	28,653
40	Wood Street, Add 3rd 345/115 kV Trfmr	1,250	12,255	8,481	-
41	Carmel New 2nd 115/46 kV Transformer	1,249	3,747	4,997	8,744
42	Roll Road New 2nd 115/34.5kV Transformer	950	2,849	3,799	6,648
43	Lyon Mountain New 2nd 115/34.5kV Transformer	908	2,725	3,634	6,359
44	All Other	10,713	2,664	7,008	9,759
45	Total Reliability	40,361	59,978	73,981	92,123
	ELECTRIC: Strategic				
46	Electric Vehicle Infrastructure	4,717	5,617	5,617	-
47	All Other	524	152	-	-
48	Total Strategic	5,240	5,768	5,617	-
49	**TOTAL - ELECTRIC (BEFORE COMMON ALLOCATION)**	365,144	472,773	521,610	530,264
50	Common Allocation - Electric Portion	55,320	71,759	68,374	44,299
51	**TOTAL - ELECTRIC**	420,463	544,533	589,983	574,564

Listing of NYSEG Gas Capital Expenditures by Project and Category
(in thousands of dollars)

	Capital Project or Category	2020 PLAN	2021 PLAN	2022 PLAN	2023 PLAN
	GAS: Asset Condition Replacement				
1	Hornby Station Rebuild	3,000	-	-	-
2	Post Creek, Gas Main Replacements	500	-	-	-
3	Chambers Road Gas Main Replacements	500	500	500	500
4	Slaterville Rd	-	1,000	15,000	-
5	All Other	820	838	855	873
6	Total Asset Condition Replacement	4,820	2,338	16,355	1,373
7	**GAS: AMI**	7,144	11,749	13,467	16,273
	GAS: Efficiency				
8	Gas RTU/Telemetry Upgrades and Zeck 9000 Odorizer Upgrades	5,800	5,325	2,500	2,000
9	Other completed in 2019	-	-	-	-
10	Total Efficiency	5,800	5,325	2,500	2,000
	GAS: Growth				
11	Town of Maine	1,450	-	-	-
12	North Country	-	-	-	-
13	Total Growth	1,450	-	-	-
	GAS: Mandatory				
14	Leak Prone Services Replacement Program	4,514	6,134	6,258	6,384
15	Leak Prone Main Replacement Program	19,076	22,458	22,951	22,954
16	West Genesee Street Leak Prone Main Replacement	1,400	1,000	1,000	1,500
17	Gas Regulators	317	323	330	337
18	Gas Meters	2,500	2,000	2,400	2,800
19	Gas Distribution Mains - Replacements	2,690	2,744	2,799	2,856
20	Gas Distribution Mains - Installations	3,380	1,830	1,868	1,908
21	Install Gas Services	3,777	3,853	3,930	4,009
22	Minor Government Jobs, Replace Gas Mains	1,563	1,594	1,626	1,659
23	Large Government Jobs	-	2,493	2,545	2,599
24	Non-Leak Prone Services Replacement Program	5,881	4,500	4,595	4,692
25	Critical Valve Installations, Binghamton	150	153	156	160
26	All Other	500	-	-	-
27	Total Mandatory	45,746	49,083	50,459	51,856
	GAS: Reliability				
28	Gas Regulator Modernization & Automation Program, Replace Regulator Stations	3,024	3,024	3,024	3,024
29	Phelps (South) Transmission Replacement	132	-	-	-
30	DeRuyter Transmission Replacement	-	-	-	-
31	Low Pressure Relief Valve Program	500	500	500	500
32	Homer System	910	-	-	-
33	Vienna Rd-Macedon Feeder Main Replacement	19,000	1,000	-	-
34	Pendleton - South West System improvement project	-	-	2,000	-
35	Canandaigua Feeder Main (124-psig) Reinforcement Project	-	-	100	900
36	Albion - Eastern system improvement and reliability project	-	-	500	2,000
37	All Other	65	500	400	1,000
38	Lansing / Freeville Distribution	-	-	-	-
39	Total Reliability	23,631	5,024	6,524	7,424
40	**TOTAL - GAS (BEFORE COMMON ALLOCATION)**	88,592	73,519	89,305	78,927
41	Common Allocation - Gas Portion	13,564	17,616	16,782	10,860
40	**TOTAL - GAS**	102,156	91,135	106,087	89,787

Listing of RG&E Electric Capital Expenditures by Project and Category
(in thousands of dollars)

	Capital Project or Category	2020 PLAN	2021 PLAN	2022 PLAN	2023 PLAN
	ELECTRIC: Asset Condition Replacement				
1	Station 43 Modernization Project	9,139	6,651	6,338	13,174
2	Station 5 - Modernization Project	7,868	7,868	8,337	40
3	Station 127 - 115 kV System Upgrade	6,694	6,694	4,928	-
4	Distribution Line	8,710	8,971	9,240	9,517
5	Betterments	4,153	4,278	4,406	4,538
6	Substation Circuit Breaker Replacement Program	3,974	4,076	4,178	4,284
7	Station 204 Upgrade	602	645	2,450	6,353
8	Station 82 Upgrades	15,899	11,701	28,433	14,193
9	All Other	18,725	13,491	13,112	35,377
10	Total Asset Condition Replacement	75,764	64,375	81,422	87,477
	ELECTRIC: Efficiency				
11	Pilot Wire Replacement Project	3,418	2,286	6,638	2,509
12	Total Efficiency	3,418	2,286	6,638	2,509
	ELECTRIC: Group Initiatives				
13	Fossil Hydro Operations Minor projects	1,500	1,500	1,500	1,500
14	All Other	-	25	250	1,000
15	Total Group Initiatives	1,500	1,525	1,750	2,500
	ELECTRIC: Growth/System Capacity				
16	RARP	104,378	5,877	-	-
17	Station 156 transformer/facilities upgrade	4,140	7,944	10,154	3,279
18	Station 46 - Replace #1 and #3 Transformer Banks	3,428	6,546	9,043	14,455
19	Station 192 Upgrades	2,148	5,832	4,412	1,448
20	Station 117 - Replace #1 Transformer Bank and convert 3 circuits to 12kV operation.	5,450	8,370	4,916	1,327
21	Station 2 Modernization (Penstock, Intake, Reg Mndates, New Unit)	6,348	15,113	10,953	7,600
22	All Other	-	-	-	-
23	Total Growth/System Capacity	125,891	49,682	39,478	28,108
24	**ELECTRIC: AMI**	12,948	21,384	19,628	24,613
	ELECTRIC: Mandatory				
25	BES Program	12,210	20,171	14,433	8,097
26	NERC Alert Priority III	1,000	1,000	1,000	1,000
27	Industrial Commercial	3,433	3,535	3,642	3,751
28	Residential Service Installation	3,508	3,614	3,722	3,834
29	Service Connects	2,268	2,336	2,407	2,479
30	Non AMI DSIP ADMS	1,490	1,400	1,400	1,000
31	All Other	4,298	4,444	5,286	4,102
32	Total Mandatory	28,208	36,500	31,889	24,262
	ELECTRIC: Reliability				
33	Resiliency Plan	6,670	8,260	10,200	10,540
34	Station 168 - Service area reinforcements	9,479	3,822	-	-
35	Cable Replacement C759-740	11,335	806	-	-
36	All Other	41,834	52,869	71,681	34,356
37	Total Reliability	69,319	65,757	81,881	44,896
	ELECTRIC: Strategic				
38	Electric Vehicle Infrastructure	2,156	2,516	2,516	-
39	All Other	99	151	-	-
40	Total Strategic	2,256	2,667	2,516	-
41	**TOTAL - ELECTRIC (BEFORE COMMON ALLOCATION)**	319,303	244,177	265,202	214,367
42	Common Allocation - Electric Portion	24,698	26,914	26,030	22,547
43	**TOTAL - ELECTRIC**	344,001	271,091	291,231	236,914

Listing of RG&E Gas Capital Expenditures by Project and Category
(in thousands of dollars)

	Capital Project or Category	2020 PLAN	2021 PLAN	2022 PLAN	2023 PLAN
	GAS: Asset Condition Replacement				
1	Mendon Gate Station	182	-	-	1,000
2	Caledonia Station Rebuild	182	-	-	1,000
3	All Other	273	278	284	290
4	Total Asset Condition Replacement	637	278	284	2,290
5	**GAS: AMI**	5,336	8,885	13,052	16,084
	GAS: Reliability				
6	CM-1 Transmission Gas Main Replacement Project	5,097	20,000	20,000	500
7	CM-1 Transmission Pipeline: Chili GS to Ballantyne Rd, Transmission Gas Main Replacement Project	279	-	-	1,000
8	CM-1A Transmission Pipeline: CM-1 to Brockport, Replace Gas Mains	-	1,000	1,500	-
9	Gas Regulator Modernization & Automation Program, Replace Regulator Station	2,820	3,998	4,079	4,161
10	CM-1 Transmission Pipeline: Paul Rd to Buffalo Rd, Transmission Gas Main Replacement Project	-	-	2,000	3,000
11	CM3D Transmission Pipeline - Rte 441 to Whitney Rd, Install Gas Main	1,500	-	-	-
12	MF120 Eastern Monroe, State Road, Install Gas Main	-	-	250	6,000
13	MF60 Southeast (Mendon Gate - Simmons Rd, Rte 64, Willis Hill Rd., Malone Rd\), Install Gas Main	310	815	3,200	-
14	RG&E Transmission Short Segments, Install Gas Mains	200	200	200	200
15	MF120 Western Monroe: FM reinforcement project, sections 1-4	-	-	1,000	5,000
16	Mt Read SF115 psi, Replace Gas Mains	-	-	150	2,650
17	MF42 Henrietta: Brighton Henrietta Town Line Rd Improvement, Install Gas Mains	-	1,100	-	-
18	MF14 Greece: Ridge Rd and Mt Read Blvd, Install Gas Mains	-	-	-	-
19	MF35 Walworth System Improvement, Install Pipe and Regulator Stations	-	-	-	-
20	Various Projects Completed in 2019	-	-	-	-
21	All Other	-	-	-	50
22	Total Reliability	10,207	27,113	32,379	22,561
23	**GAS: Efficiency**				
	GAS: Growth				
24	MF14 Greece: Lake Avenue (Port of Rochester), Install Gas Mains	-	-	-	-
25	Total Growth	-	-	-	-
	GAS: Mandatory				
26	Gas Meters	2,100	2,144	2,300	2,600
27	Gas Regulators	50	55	60	65
28	Large Government Jobs	-	2,493	2,543	2,594
29	LPM - Cabot Line	500	500	-	-
30	Leak Prone Main Replacement Program	19,014	19,396	19,786	20,183
31	Leak Prone Services Replacement Program	3,341	3,408	3,476	3,546
32	Gas Distribution Mains - Installations	1,753	2,672	2,726	2,781
33	Gas Distribution Mains - Replacements	976	996	1,016	1,036
34	Install Gas Services	2,562	2,614	2,666	2,720
35	Customer - Gas Related Projects	-	-	-	-
36	Minor Government Jobs, Replace Gas Mains	640	653	667	680
37	Non-Leak Prone Services Replacement Program	1,648	3,374	3,442	3,511
38	All Other Mandatory	-	-	-	-
39	Total Mandatory	32,584	38,305	38,682	39,717
40	**TOTAL - GAS (BEFORE COMMON ALLOCATION)**	48,765	74,582	84,397	80,652
41	Common Allocation - Gas Portion	9,898	10,786	10,432	9,036
40	**TOTAL - GAS**	58,663	85,368	94,829	89,688

NYSEG and RG&E
Net Plant Reconciliation
Index

Schedule I - NYSEG

Schedule II - RG&E

Note: Net Plant Targets are the average balances for the applicable rate year.

NYSEG
Net Plant and Depreciation Targets
Electric: Substation Modernization
($ 000)

	Rate Year 1 2020-2021	Rate Year 2 2021-2022	Rate Year 3 2022-2023
Net Plant Targets			
Plant in Service	$ -	$ 1,154	$ 7,308
Accumulated Reserve	-	(3)	(79)
Net Plant Targets	$ -	$ 1,151	$ 7,229
Depreciation Targets	$ -	$ 21	$ 146

Notes:

1) Values do not reflect the impact of any Retirements associated with Substation Modernization.

NYSEG
Net Plant and Depreciation Targets
Electric: Resiliency
($ 000)

	Rate Year 1 2020-2021	Rate Year 2 2021-2022	Rate Year 3 2022-2023
Net Plant Targets			
Plant in Service	$ 19,801	$ 43,474	$ 72,603
Accumulated Reserve	(251)	(893)	(2,077)
Net Plant Targets	$ 19,550	$ 42,581	$ 70,526
Depreciation Targets	$ 406	$ 892	$ 1,492

Notes:

1) Values do not reflect the impact of any Retirements associated with Resiliency.

NYSEG
Net Plant and Depreciation Targets
Electric & Gas: Advanced Meter Infrastructure (AMI)
($ 000)

	Electric			Gas		
	Rate Year 1 2020-2021	Rate Year 2 2021-2022	Rate Year 3 2022-2023	Rate Year 1 2020-2021	Rate Year 2 2021-2022	Rate Year 3 2022-2023
Net Plant Targets						
Plant in Service	$ -	$ 14,265	$ 112,987	$ -	$ 3,542	$ 28,594
Accumulated Reserve	-	(217)	(5,439)	-	(47)	(1,444)
Net Plant Targets	$ -	$ 14,048	$ 107,548	$ -	$ 3,495	$ 27,150
Depreciation Targets	$ -	$ 1,236	$ 8,946	$ -	$ 268	$ 2,514

NYSEG
Net Plant and Depreciation Targets
Electric & Gas: Residual
($ 000)

	Electric			Gas		
	Rate Year 1 2020-2021	Rate Year 2 2021-2022	Rate Year 3 2022-2023	Rate Year 1 2020-2021	Rate Year 2 2021-2022	Rate Year 3 2022-2023
Net Plant Targets						
Plant in Service, CCNC, NIBCWIP, Capital Leases	$ 5,272,058	$ 5,546,420	$ 5,824,911	$ 1,292,140	$ 1,379,702	$ 1,454,464
Accumulated Reserve	(2,367,419)	(2,468,051)	(2,580,397)	(474,394)	(503,404)	(536,632)
Amortization of Excess Depreciation Reserve	44,488	77,388	114,413	n.a.	n.a.	n.a.
EDR Used to Recover Make-Whole	10,303	11,774	11,774	n.a.	n.a.	n.a.
Net Plant Targets	$ 2,959,430	$ 3,167,531	$ 3,370,701	$ 817,746	$ 876,298	$ 917,832
Depreciation Targets						
Depreciation Expense	$ 137,881	$ 145,991	$ 154,136	$ 38,574	$ 41,112	$ 43,372
Exclude Transportation Depreciation	(5,667)	(6,421)	(7,025)	(856)	(1,042)	(1,190)
Depreciation Targets	$ 132,214	$ 139,570	$ 147,111	$ 37,718	$ 40,070	$ 42,182

Notes:

1) Electric values reflect Total NYSEG Electric, including Electric's allocation of Common, less Electric Substation Modernization, Electric Resiliency and Electric AMI; values reflect the impact of all projected Retirements.
2) Gas values reflect Total NYSEG Gas, including Gas' allocation of Common, less Gas AMI; values reflect the impact of all projected Retirements.
3) Net Plant and Depreciation targets will be adjusted for: 1) any asset sales requiring New York State Public Service Law ("PSL") § 70 approval that occur prior to or during the Rate Plan period; and 2) any electric or gas projects deferred or avoided through an NWA or NPA.

NYSEG
Illustration of the Net Plant Reconciliation
Electric & Gas: Residual
($ 000)

	Electric				Gas			
	Rate Year 1 2020-2021	**Rate Year 2 2021-2022**	**Rate Year 3 2022-2023**	**Cumulative**	**Rate Year 1 2020-2021**	**Rate Year 2 2021-2022**	**Rate Year 3 2022-2023**	**Cumulative**
Net Plant								
Actual (for illustrative purposes only)	$ 2,941,000	$ 3,147,000	$ 3,345,000		$ 820,000	$ 879,000	$ 920,000	
Target	2,959,430	3,167,531	3,370,701		817,746	876,298	917,832	
Difference	(18,430)	(20,531)	(25,701)		2,254	2,702	2,168	
Pre-Tax Cost of Capital	7.60%	7.54%	7.49%		7.60%	7.54%	7.49%	
Return Component	$ (1,401)	$ (1,548)	$ (1,925)		$ 171	$ 204	$ 162	
Depreciation Expense								
Actual (for illustrative purposes only)	$ 131,000	$ 139,000	$ 146,000		$ 37,600	$ 40,000	$ 42,100	
Target	132,214	139,570	147,111		37,718	40,070	42,182	
Difference	(1,214)	(570)	(1,111)		(118)	(70)	(82)	
Revenue Requirement Impact - Before Tax	$ (2,615)	$ (2,118)	$ (3,036)	$ (7,769)	$ 53	$ 134	$ 80	$ 267
Amount Deferred for Customer Benefit -								
Smaller of Cumulative Amount at End of RY 3 or $0				$ (7,769)				$ -

RG&E
Net Plant and Depreciation Targets
Electric: Rochester Area Reliability Program (RARP)
($ 000)

	Rate Year 1 2020-2021	Rate Year 2 2021-2022	Rate Year 3 2022-2023
Net Plant Targets			
Plant in Service	$ 114,620	$ 354,870	$ 357,308
Accumulated Reserve	(480)	(5,487)	(12,271)
Net Plant Targets	$ 114,140	$ 349,383	$ 345,037
Depreciation Targets	$ 2,075	$ 6,748	$ 6,792

Notes:
1) Values do not reflect the impact of any Retirements associated with RARP.

RG&E
Net Plant and Depreciation Targets
Electric: Resiliency
($ 000)

	Rate Year 1 2020-2021	Rate Year 2 2021-2022	Rate Year 3 2022-2023
Net Plant Targets			
Plant in Service	$ 5,971	$ 13,814	$ 23,437
Accumulated Reserve	(65)	(256)	(618)
Net Plant Targets	$ 5,906	$ 13,558	$ 22,819
Depreciation Targets	$ 117	$ 270	$ 459

Notes:
1) Values do not reflect the impact of any Retirements associated with Resiliency.

RG&E
Net Plant and Depreciation Targets
Electric & Gas: Advanced Meter Infrastructure (AMI)
($ 000)

	Electric			Gas		
	Rate Year 1 2020-2021	**Rate Year 2 2021-2022**	**Rate Year 3 2022-2023**	**Rate Year 1 2020-2021**	**Rate Year 2 2021-2022**	**Rate Year 3 2022-2023**
Net Plant Targets						
Plant in Service	$ -	$ 6,389	$ 48,363	$ -	$ 1,804	$ 17,735
Accumulated Reserve	-	(152)	(3,541)	-	(43)	(1,094)
Net Plant Targets	$ -	$ 6,237	$ 44,822	$ -	$ 1,761	$ 16,641
Depreciation Targets	$ -	$ 865	$ 5,581	$ -	$ 244	$ 1,812

RG&E
Net Plant and Depreciation Targets
Electric & Gas: Residual
($ 000)

	Electric			Gas		
	Rate Year 1 2020-2021	Rate Year 2 2021-2022	Rate Year 3 2022-2023	Rate Year 1 2020-2021	Rate Year 2 2021-2022	Rate Year 3 2022-2023
Net Plant Targets						
Plant in Service, CCNC, NIBCWIP, Capital Leases	$ 2,839,055	$ 2,935,127	$ 3,101,918	$ 1,113,128	$ 1,162,863	$ 1,238,928
Accumulated Reserve	(867,113)	(924,138)	(977,586)	(438,880)	(462,349)	(483,900)
EDR Used to Recover Make-Whole	3,121	3,567	3,567	n.a.	n.a.	n.a.
Net Plant Targets	$ 1,975,063	$ 2,014,556	$ 2,127,899	$ 674,248	$ 700,514	$ 755,028
Depreciation Targets						
Depreciation Expense	$ 73,846	$ 76,679	$ 81,282	$ 32,119	$ 33,518	$ 35,580
Exclude Transportation Depreciation	(1,857)	(1,958)	(2,061)	(744)	(785)	(826)
Depreciation Targets	$ 71,989	$ 74,721	$ 79,221	$ 31,375	$ 32,733	$ 34,754

Notes:
1) Electric values reflect Total RG&E Electric, including Electric's allocation of Common, less Electric RARP, Electric Resiliency and Electric AMI; values reflect the impact of all projected Retirements.
2) Gas values reflect Total RG&E Gas, including Gas' allocation of Common, less Gas AMI; values reflect the impact of all projected Retirements.

RG&E
Illustration of the Net Plant Reconciliation
Electric & Gas: Residual
($ 000)

	Electric				Gas			
	Rate Year 1 2020-2021	**Rate Year 2 2021-2022**	**Rate Year 3 2022-2023**	**Cumulative**	**Rate Year 1 2020-2021**	**Rate Year 2 2021-2022**	**Rate Year 3 2022-2023**	**Cumulative**
Net Plant								
Actual (for illustrative purposes only)	$ 1,967,000	$ 2,006,000	$ 2,120,000		$ 675,000	$ 702,000	$ 756,000	
Target	1,975,063	2,014,556	2,127,899		674,248	700,514	755,028	
Difference	(8,063)	(8,556)	(7,899)		752	1,486	972	
Pre-Tax Cost of Capital	8.11%	7.98%	7.87%		8.11%	7.98%	7.87%	
Return Component	$ (654)	$ (683)	$ (622)		$ 61	$ 119	$ 76	
Depreciation Expense								
Actual (for illustrative purposes only)	$ 71,900	$ 74,500	$ 78,900		$ 32,000	$ 32,800	$ 35,600	
Target	71,989	74,721	79,221		31,375	32,733	34,754	
Difference	(89)	(221)	(321)		625	67	846	
Revenue Requirement Impact - Before Tax	$ (743)	$ (904)	$ (943)	$ (2,590)	$ 686	$ 186	$ 922	$ 1,794
Amount Deferred for Customer Benefit -								
Smaller of Cumulative Amount at End of RY 3 or $0				$ (2,590)				$ -

New York State Electric & Gas Corporation
Electric Business
Reconciliation Targets
'($000)

		Reconciliation	RAM Eligible	Notes	Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023	Ongoing Annual Targets Effective 5/1/2023
1	Labor	Downward with carryover		(1)	113,630	121,821	128,702	128,702
2	Pensions	Symmetrical		(2)	17,854	17,854	17,854	17,854
3	OPEBs	Symmetrical		(2)	(1,646)	(233)	20	20
4	Property Taxes	Symmetrical - subject to sharing	X	(3)	100,367	101,680	103,010	103,010
5	Electric Distribution Vegetation Management							
5a	Routine Distribution VM	Downward with carryover			30,000	30,000	30,000	30,000
5b	Reclamation	Downward with carryover			17,203	17,203	17,203	17,203
5c	Danger Tree	Downward with carryover				See Danger Tree Schedule - page 11		
6	Management Audit Implementation Costs	Symmetrical - Upward CAP		(4)	22	22	22	22
6a	Management Audit Consultant	Deferred Cost		(4)	-	-	-	-
6b	Operational Audit Expenses	Symmetrical		(4)	-	-	-	-
7	REV Incremental Costs and Fees	Symmetrical	X	(5)	9,330	9,575	10,086	10,086
7a	COVID-19 Pandemic			(5)	(5,700)	-	-	-
8	Incremental Maintenance	Downward with carryover		(6)	616	1,460	1,033	1,033
9	Energy Efficiency	Symmetrical - carryover		(7)	12,578	22,017	28,458	46,245
9a	Heat Pumps	Symmetrical - carryover		(7)	6,137	9,742	12,292	14,964
10	Environmental Costs, Reserve Accounting	Symmetrical		(8)	15,000	15,000	15,000	15,000
11	Economic Development	Symmetrical - carryover			5,052	5,052	5,052	5,052
12	Low Income Program	Symmetrical - Per Appendix Q			14,408	14,408	14,408	14,408
13	Credit and Debit Card Fees	Symmetrical			2,040	2,773	3,251	3,251
14	Third Party Agent Fees	Symmetrical			388	371	355	355

New York State Electric & Gas Corporation
Electric Business
Reconciliation Targets
'($000)

		Reconciliation	RAM Eligible	Notes	Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023	Ongoing Annual Targets Effective 5/1/2023
15	Net Plant (excluding Substation Modernization, Resiliency, and AMI)	Downward Only				See Appendix S		
15a	Net Plant - Substation Modernization	Downward Only				See Appendix S		
15b	Net Plant - Resiliency Projects	Downward Only				See Appendix S		
15c	Net Plant - AMI	Downward Only				See Appendix S		
16	Legislative, Actg, Regulatory, Tax and Related	Symmetrical				Subject to Rate Year threshold of $2M pretax		
17	Exogenous Costs	Deferred Cost			-	-	-	-
18	Debt Cost Reconciliation	Symmetrical				See Debt Reconciliation Schedules page 9		
19	Electric Vehicle Program Costs	Symmetrical - carryover	X		290	287	287	287
20	Major Storm Costs, Reserve Accounting	Symmetrical	X	(9)	25,582	25,582	25,582	25,582
20a	Prestaging Storm Costs	Deferred Cost		(10)	-	-	-	-
21	NEIL Credits	Symmetrical			(352)	(352)	(352)	(352)
22	Energy Smart Community	Downward Only			1,000	1,021	1,042	1,042

Notes - See page 3

New York State Electric & Gas Corporation
Gas Business
Reconciliation Targets
'($000)

		Reconciliation	RAM Eligible	Notes	Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023	Ongoing Annual Targets Effective 5/1/2023
1	Labor	Downward with carryover		(1)	31,991	33,315	34,202	34,202
2	Pensions	Symmetrical		(2)	5,474	5,474	5,474	5,474
3	OPEBs	Symmetrical		(2)	(486)	(61)	12	12
4	Property Taxes	Symmetrical - subject to sharing	X	(3)	20,337	20,604	20,874	20,874
5	Gas Vegetation Management	Downward Only			600	613	625	625
6	Management Audit Implementation Costs	Symmetrical - Upward CAP		(4)	75	75	75	75
6a	Management Audit Consultant	Deferred Cost		(4)	-	-	-	-
6b	Operational Audit Expenses	Symmetrical		(4)	-	-	-	-
7	REV Incremental Costs and Fees	Symmetrical	X	(5)	-	-	-	-
8	Incremental Maintenance	Downward with carryover		(6)	2,800	4,048	4,133	4,133
9	Energy Efficiency	Symmetrical - carryover		(7)	966	2,858	4,751	8,427
10	Environmental Costs, Reserve Accounting	Symmetrical		(8)	4,300	4,300	4,300	4,300
11	Economic Development	Symmetrical – Upward Cap		(13)	200	200	200	200
12	Low Income Program	Symmetrical - Per Appendix Q			6,298	6,298	6,298	6,298
13	Credit and Debit Card Fees	Symmetrical			609	828	971	971
14	Third Party Agent Fees	Symmetrical			116	111	106	106
15	Net Plant (excluding AMI)	Downward Only				See Appendix S		
15a	Net Plant - AMI	Downward Only				See Appendix S		
16	Legislative, Actg, Regulatory, Tax and Related Actions	Symmetrical				Subject to Rate Year threshold of $1M pretax		
17	Exogenous Costs	Deferred Cost			-	-	-	-
18	Debt Cost Reconciliation	Symmetrical				See Debt Reconciliation Schedules page 9		
19	Gas R&D	Symmetrical			1,703	1,715	1,728	1,728
20	Pipeline Integrity Costs	Downward with carryover			1,434	1,434	1,434	1,434
21	Pipeline Safety Management Systems	Symmetrical - carryover			128	-	-	-
22	Leak Prone Pipe Replacement Incentive	Symmetrical	X	(11)		Mileage above target - See Appendix L		
23	Gas Interruptible Revenues	Symmetrical		(12)	2,004	2,120	2,225	2,225

Notes - See page 3

NOTES: See also Joint Proposal language / other appendices for specific conditions.

(1) Labor reconciliation with modifications for attrition, productivity; includes carryover, See Appendix U - Labor Reconciliation.

(2) Excludes non-qualified plan costs

(3) 90% of the variation above or below the target will be deferred. The Company's 10% share of property tax expense above or below the target will be limited to 10 basis points on the amount of common equity supporting Rate Base. 100% of additional variances are deferred. Deferral recovery subject to the provisions of Appendix W - Rate Adjustment Mechanism (RAM) Process and Procedures.

(4) Costs associated with implementation of last management audit recommendations capped at 25% above the amount included in delivery rates. Consultants retained to conduct management, operational, staffing and other audits are fully deferrable.

(5) The Company shall defer certain REV costs and fees not otherwise included in base delivery rates. The amounts on line 7 and COVID-19 Pandemic reduction (delaying start of GMEP) on line 7a represent the total REV target. Line 7a is not independently reconciled. Deferral recovery subject to the provisions of Appendix W - RAM Process and Procedures.

(6) Refer to page 7 for Incremental Maintenance Initiatives. New Initiatives can be considered after consultation with DPS Staff.

(7) The Companies' revenue requirement reflects amounts for Energy Efficiency program and Heat Pump program generally consistent with the January 2020 EE Order and the proposed utilization of unspent funds through 2019. Any difference between actual energy efficiency costs and the level embedded in delivery rates (including the amounts being collected in a surcharge prior to their inclusion in delivery rates) is fully reconciled. To moderate revenue requirements in Rate Years 1 and 2, for NYSEG Gas, RG&E Electric, and RG&E Gas, the amounts included in the January 2020 EE Order have been reduced by 15%, and at NYSEG Electric the RY1 amount has been reduced by 20%, the RY2 amount by 15%, and the RY3 amount by 10%. These changes do not impact the total 2020 – 2025 EE and Heat Pump budget amounts noted in the January 2020 EE Order. To the extent required, delivery rates would be adjusted in Rate Years 4 and 5 accordingly. Ongoing target amounts represent a 3 year average.

(8) The Companies shall continue to utilize reserve accounting for Environmental Costs.

(9) The Companies shall continue to utilize reserve accounting for Major Storm Costs, per Appendix H. Major Storm deferral recovery subject to the provisions of Appendix W - RAM Process and Procedures.

(10) Prestaging Storm costs - lower threshold of $250k, upper threshold at $1.5m, with 85/15 sharing (Reserve/Company) if incremental costs exceeds upper threshold.

(11) Leak Prone Pipe Replacement Incentive, deferral recovery subject to the provisions of Appendix W - RAM Process and Procedures.

(12) Gas Interruptible Revenues included in Revenue Forecast.

(13) Gas Economic Development spending is treated as symmetrical with carryover on an annual basis, but it is subject to an overall RY1 - RY3 cap of $600,000 in total.

Rochester Gas and Electric Corporation
Electric Business
Reconciliation Targets
'($000)

		Reconciliation	RAM Eligible	Notes	Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023	Ongoing Annual Targets Effective 5/1/2023
1	Labor	Downward with carryover		(1)	39,404	41,319	42,730	42,730
2	Pensions	Symmetrical		(2)	5,805	5,805	5,805	5,805
3	OPEBs	Symmetrical		(2)	990	1,068	838	838
4	Property Taxes	Symmetrical - subject to sharing	X	(3)	88,443	93,255	98,328	98,328
5	Electric Distribution Vegetation Management							
5a	Routine Distribution VM	Downward with carryover			8,270	8,443	8,621	8,621
5b	Danger Tree	Downward with carryover			See Danger Tree Schedule - page 11			
6	Management Audit Implementation Costs	Symmetrical - Upward CAP		(4)	21	21	21	21
6a	Management Audit Consultant	Deferred Cost		(4)	-	-	-	-
6b	Operational Audit Expenses	Symmetrical		(4)	-	-	-	-
7	REV Incremental Costs and Fees	Symmetrical	X	(5)	4,741	4,721	4,980	4,980
7a	COVID-19 Pandemic			(5)	(2,950)	-	-	-
8	Incremental Maintenance (excludes Manhole Maint Prog)	Downward with carryover		(6)	992	2,298	875	875
8a	Manhole Maintenance Program (City of Rochester)	Downward with carryover		(6a)	1,095	3,000	5,000	5,000
9	Energy Efficiency	Symmetrical - carryover		(7)	8,546	13,182	17,910	22,925
9a	Heat Pumps	Symmetrical - carryover		(7)	786	1,181	1,674	1,786
10	Environmental Costs, Reserve Accounting	Symmetrical		(8)	988	988	988	988
11	Economic Development	Symmetrical - carryover			7,000	7,000	7,000	7,000
12	Low Income Program	Symmetrical - Per Appendix Q			11,837	11,837	11,837	11,837
13	Credit and Debit Card Fees	Symmetrical			884	1,121	1,345	1,345
14	Third Party Agent Fees	Symmetrical			101	94	88	88

Rochester Gas and Electric Corporation
Electric Business
Reconciliation Targets
'($000)

		Reconciliation	RAM Eligible	Notes	Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023	Ongoing Annual Targets Effective 5/1/2023
15	Net Plant (excluding RARP, Resiliency, and AMI)	Downward Only			See Appendix S			
15a	Net Plant - RARP	Downward Only			See Appendix S			
15b	Net Plant - Resiliency Projects	Downward Only			See Appendix S			
15c	Net Plant - AMI	Downward Only			See Appendix S			
16	Legislative, Actg, Regulatory, Tax and Related Actions	Symmetrical			Subject to Rate Year threshold of $1.5M pretax			
17	Exogenous Costs	Deferred Cost			-	-	-	-
18	Debt Cost Reconciliation	Symmetrical			See Debt Reconciliation Schedules page 10			
19	Electric Vehicle Program Costs	Symmetrical - carryover	X		125	123	123	123
20	Major Storm Costs, Reserve Accounting	Symmetrical	X	(9)	3,400	3,400	3,400	3,400
20a	Prestaging Storm Costs	Deferred Cost		(10)	-	-	-	-
21	NEIL Credits	Symmetrical			(3,613)	(3,688)	(3,766)	(3,766)
22	DOE Liability Carrying Costs	Symmetrical		(11)	-	-	-	-

Notes - See page 6

Rochester Gas and Electric Corporation
Gas Business
Reconciliation Targets
'($000)

		Reconciliation	RAM Eligible	Notes	Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023	Ongoing Annual Targets Effective 5/1/2023
1	Labor	Downward with carryover		(1)	20,650	21,584	22,263	22,263
2	Pensions	Symmetrical		(2)	3,244	3,244	3,244	3,244
3	OPEBs	Symmetrical		(2)	541	584	458	458
4	Property Taxes	Symmetrical - subject to sharing	X	(3)	29,394	30,993	32,679	32,679
5	Gas Vegetation Management	Downward Only			361	369	376	376
6	Management Audit Implementation Costs	Symmetrical - Upward CAP		(4)	74	74	74	74
6a	Management Audit Consultant	Deferred Cost		(4)	-	-	-	-
6b	Operational Audit Expenses	Symmetrical		(4)	-	-	-	-
7	REV Incremental Costs and Fees	Symmetrical	X	(5)	-	-	-	-
8	Incremental Maintenance	Downward with carryover		(6)	6,151	7,497	7,585	7,585
9	Energy Efficiency	Symmetrical - carryover		(7)	1,574	2,554	3,991	6,509
10	Environmental Costs, Reserve Accounting	Symmetrical		(8)	370	370	370	370
11	Economic Development	Symmetrical – Upward Cap		(14)	200	200	200	200
12	Low Income Program	Symmetrical - Per Appendix Q			5,457	5,457	5,457	5,457
13	Credit and Debit Card Fees	Symmetrical			723	917	1,100	1,100
14	Third Party Agent Fees	Symmetrical			82	77	72	72
15	Net Plant (excluding AMI)	Downward Only			See Appendix S			
15a	Net Plant - AMI	Downward Only			See Appendix S			
16	Legislative, Actg, Regulatory, Tax and Related Actions	Symmetrical			Subject to Rate Year threshold of $1M pretax			
17	Exogenous Costs	Deferred Cost			-	-	-	-
18	Debt Cost Reconciliation	Symmetrical			See Debt Reconciliation Schedules page 10			
19	Gas R&D	Symmetrical			1,244	1,255	1,266	1,266
20	Pipeline Integrity Costs	Downward with carryover			2,720	2,720	2,720	2,720
21	Pipeline Safety Management Systems	Symmetrical - carryover			128	-	-	-
22	Leak Prone Pipe Replacement Incentive	Symmetrical	X	(12)	Mileage above target - See Appendix L			
23	Gas Interruptible Revenues	Symmetrical		(13)	-	-	-	-

Notes - See page 6

NOTES: See also Joint Proposal language / other appendices for specific conditions.

(1) Labor reconciliation with modifications for attrition, productivity; includes carryover, See Appendix U - Labor Reconciliation

(2) Excludes non-qualified plan costs.

(3) 90% of the variation above or below the target will be deferred. The Company's 10% share of property tax expense above or below the target will be limited to 10 basis points on the amount of common equity supporting Rate Base. 100% of additional variances are deferred. Deferral recovery subject to the provisions of Appendix W - Rate Adjustment Mechanism (RAM) Process and Procedures.

(4) Costs associated with implementation of last management audit recommendations capped at 25% above the amount included in delivery rates. Consultants retained to conduct management, operational, staffing and other audits are fully deferrable.

(5) The Company shall defer certain REV costs and fees not otherwise included in base delivery rates. The amounts on line 7 and COVID-19 Pandemic reduction (delaying start of GMEP) on line 7a represent the total REV target. Line 7a is not independently reconciled. Deferral recovery subject to the provisions of Appendix W - RAM Process and Procedures.

(6) Refer to page 8 for Incremental Maintenance Initiatives. New Initiatives can be considered after consultation with DPS Staff.

(6a) Manhole Maintenance Program - City of Rochester amounts at 100% downward reconciliation and upward reconciliation of 100% of first 25% spending above amount allowed in rates with 50/50 sharing (deferral/Company) of any amount above the 125% level.

(7) The Companies' revenue requirement reflects amounts for Energy Efficiency program and Heat Pump program generally consistent with the January 2020 EE Order and the proposed utilization of unspent funds through 2019. Any difference between actual energy efficiency costs and the level embedded in delivery rates (including the amounts being collected in a surcharge prior to their inclusion in delivery rates) is fully reconciled. To moderate revenue requirements in Rate Years 1 and 2, for NYSEG Gas, RG&E Electric, and RG&E Gas, the amounts included in the January 2020 EE Order have been reduced by 15%, and at NYSEG Electric the RY1 amount has been reduced by 20%, the RY2 amount by 15%, and the RY3 amount by 10%. These changes do not impact the total 2020 – 2025 EE and Heat Pump budget amounts noted in the January 2020 EE Order. To the extent required, delivery rates would be adjusted in Rate Years 4 and 5 accordingly. Ongoing target amounts represent a 3 year average.

(8) The Companies shall continue to utilize reserve accounting for Environmental Costs

(9) The Companies shall continue to utilize reserve accounting Major Storms per Appendix H. Major Storms deferral recovery subject to the provisions of Appendix W - RAM Process and Procedures.

(10) Prestaging Storm costs - lower threshold of $250k, upper threshold at $1.25m, with a 85/15 sharing (Reserve/Company) if incremental costs exceeds upper

(11) DOE Liability Carrying Costs - The actual annual amounts identified by DOE will be deferred

(12) Leak Prone Pipe Replacement Incentive, deferral recovery subject to the provisions of Appendix W - RAM Process and Procedures

(13) Gas Interruptible Revenues included in Revenue Forecast.

(14) Gas Economic Development spending is treated as symmetrical with carryover on an annual basis, but it is subject to an overall RY1 - RY3 cap of $600,000 in total.

Incremental Maintenance Initiatives - NYSEG

		($000's)		
		Rate Year 1 TME 4/30/2021	**Rate Year 2 TME 4/30/2022**	**Rate Year 3 TME 4/30/2023**
	NYSEG Electric			
1	Tranformer LTC RMV Monitoring	$ 132	$ 132	$ 110
2	Innovative Maintenance Technologies	75	400	400
3	Long Lake Distributed Generator Fuel and Maintenance	141	141	141
4	Keuka Canal & Bradford Dam Dredging	95	455	50
5	Hydro Facility Interior Structures/Building Maintenance	159	318	318
6	Mill C Rackraker and Rack Maintenance	14	14	14
7	**Total Rate Year Allowance**	**$ 616**	**$ 1,460**	**$ 1,033**
	NYSEG Gas			
8	Public Awareness	$ 86	$ 88	$ 90
9	Public Awareness (Fire Department Outreach)	154	157	161
10	Damage Prevention (Enhanced DPV)	1,033	2,244	2,291
11	Exposed Piping on Bridges	354	361	369
12	Distribution Integrity Management (Data Automation & electronic records)	129	132	135
13	Distribution Integrity Management (Leak Survey)	342	349	357
14	Corrosion Control (Outside Res. Meter Atmospheric Corrosion Inspections)	78	80	81
15	Corrosion Control (Meter & Regulator Station inspections)	81	83	84
16	Corrosion Control (Incremental Anode Installations)	120	123	125
17	Corrosion Control (Inside Res. Meter Atmospheric Corrosion inspections)	676	690	704
18	Methane Detection Program	389	397	406
19	Net of Previously Deferred NRA'sMethane Detection Program	(389)	(397)	(406)
20	Less: Offset due to New Hires	(415)	(424)	(433)
21	QA/QC Excavations and Field Support	162	165	169
22	**Total Rate Year Allowance**	**$ 2,800**	**$ 4,048**	**$ 4,133**

Note: Electric and Gas Incremental Maintenance costs will be reconciled in total by business.

Incremental Maintenance Initiatives - RG&E

		($000's) Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
	RG&E Electric			
1	Transformer Bushings	$ 80	$ 80	$ 79
2	Transformer LTC RMV Monitoring	88	88	88
3	Innovation Maintenance Technologies	40	200	200
4	Station 70 - Wiscoy Spillway Maintenance and Dredging	202	464	60
5	Hydro Plant Structures/Building Maintenance	328	328	328
6	Station 5 Tunnel Inspection	92	520	-
7	Station 2 Penstock Repairs	62	362	62
8	Station 2 Intake House Maintenance	58	108	58
9	Station 5 Road Repair (Powerhouse to Seth Green Drive)	42	148	-
10	**Subtotal**	**992**	**2,298**	**875**
11	Manhole Maintenance Program	1,095	3,000	5,000
12	**Total Rate Year Allowance**	**$ 2,087**	**$ 5,298**	**$ 5,875**
	RG&E Gas			
13	Public awareness	$ 80	$ 82	$ 83
14	Public Awareness (Fire Department Outreach	135	138	141
15	Damage Prevention (Enhanced DPV)	1,083	2,382	2,433
16	Exposed piping on bridges	332	339	346
17	Distribution Integrity Management (Data automation & electronic records)	129	132	135
18	Distribution Integrity Management (Leak Survey)	404	412	421
19	Corrosion Control (Outside Res. Meter Atmospheric Corrosion Inspections)	55	56	57
20	Corrosion Control (Meter & Regulator Station inspections)	78	80	81
21	Corrosion Control (Incremental Anode Installation)	81	83	84
22	Corrosion Control (Inside Res. Meter Atmospheric Corrosion Inspections)	676	690	704
23	Upgrade GIS mapping to version 10.2.1	-	-	-
24	RGE GIS Gas Services Conversion Project	1,328	1,339	1,339
25	RGE SAP Gas Service Record Project	2,023	2,023	2,024
26	Methane Detection Program	389	397	406
27	Net of Previously Deferred NRA's	(389)	(397)	(406)
28	QA/QC Excavations and Field Support	162	165	169
29	Less: Offset due to New Hires	(415)	(424)	(433)
30	**Total Rate Year Allowance**	**$ 6,151**	**$ 7,497**	**$ 7,585**

Note: Electric and Gas Incremental Maintenance costs will be reconciled in total by business, excluding Manhole Maintenance Program.

NYSEG Fixed and Variable Rate Debt Reconciliation*
($000)

	NYSEG EXAMPLE:	Rate Year 1	Rate Year 2	Rate Year 3
1	Long-Term Debt Capitalization Ratios	51.61%	51.67%	51.71%
2	Electric Rate Base for Ratesetting from Joint Proposal	$ 2,437,398	$ 2,696,647	$ 3,037,309
3	Gas Rate Base for Ratesetting from Joint Proposal	662,114	726,225	796,905
4	NYSEG Rate Base for Ratesetting from Joint Proposal	$ 3,099,512	$ 3,422,872	$ 3,834,214
5	Weighted Average Cost of Debt for Ratesetting	3.63%	3.52%	3.42%
6	Actual Weighted Average Cost of Debt (Example)	3.72%	3.45%	3.34%
7	Annual Rate Allowance	$ 58,068	$ 62,255	$ 67,807
8	Actual Cost of Debt (Example)	$ 59,507	$ 61,017	$ 66,221
9	Amount Deferred to (from) customers	$ (1,440)	$ 1,238	$ 1,586

Notes:
1 LTD Capitalization Ratios from Joint Proposal
2 NYSEG Electric Rate Base from Joint Proposal
3 NYSEG Gas Rate Base from Joint Proposal
4 Total NYSEG Rate Base from Joint Proposal
5 NYSEG Forecasted Cost of Long-Term Debt from Joint Proposal
6 Actual Cost of Long-Term Debt (Example)
7 Line 1 x Line 4 x Line 5
8 Line 1 x Line 4 x Line 6
9 Line 7 less Line 8

*NYSEG businesses are also subject to a Net Plant Reconciliation (see Appendix S) in addition to the Debt Reconciliation

RG&E Fixed and Variable Rate Debt Reconciliation*
($000)

	RG&E EXAMPLE:	Rate Year 1	Rate Year 2	Rate Year 3
1	Long-Term Debt Capitalization Ratios	51.79%	51.82%	51.84%
2	Electric Rate Base for Ratesetting from Joint Proposal	$ 1,500,899	$ 1,818,579	$ 2,008,301
3	Gas Rate Base for Ratesetting from Joint Proposal	509,465	550,697	633,677
4	RG&E Rate Base for Ratesetting from Joint Proposal	$ 2,010,364	$ 2,369,276	$ 2,641,978
5	Weighted Average Cost of Debt for Ratesetting	4.62%	4.35%	4.14%
6	Actual Weighted Average Cost of Debt (Example)	4.72%	4.25%	4.01%
7	Annual Rate Allowance	$ 48,102	$ 53,408	$ 56,701
8	Actual Cost of Debt (Example)	$ 49,143	$ 52,180	$ 54,921
9	Amount Deferred to (from) customers	$ (1,041)	$ 1,228	$ 1,780

Notes:
1 LTD Capitalization Ratios from Joint Proposal
2 RG&E Electric Rate Base from Joint Proposal
3 RG&E Gas Rate Base from Joint Proposal
4 Total RG&E Rate Base from Joint Proposal
5 RG&E Forecasted Cost of Long-Term Debt from Joint Proposal
6 Actual Cost of Long-Term Debt (Example)
7 Line 1 x Line 4 x Line 5
8 Line 1 x Line 4 x Line 6
9 Line 7 less Line 8

*RG&E businesses are also subject to a Net Plant Reconciliation (see Appendix S) in addition to the Debt Reconciliation

NYSEG and RG&E
Danger Tree - Rate Year Spending Targets and Deferral Example
Downward Only Reconciliation with Carryover
($000's)

Note: The Danger Tree downward only with carryover reconciliation needs to compare to the amounts collected in rates each Rate Year, which increase year over year. The amount deferred on a Company's books at the end of each rate year under this reconciliation item would be the difference in total amount spent on the program to date and the total amount of targeted spend to date, divided by 5 to correspond to the 5 year amortization period.

NYSEG Electric

		Rate Year Targets			Deferral Example			
	Rate Year TME	A Target Spend	B Cumulative Target	C [B / 5] Collected Over 5 Years	D Actual Spend	E Cumulative Spend	F [E - B] Cumulative Variance	G [F / 5] Deferral Balance
1	4/30/2021	$ 10,000	$ 10,000	$ 2,000	$ 6,500	$ 6,500	$ (3,500)	$ (700)
2	4/30/2022	10,000	20,000	4,000	9,500	16,000	(4,000)	(800)
3	4/30/2023	10,000	30,000	6,000	14,000	30,000	-	-

RG&E Electric

		Rate Year Targets			Deferral Example			
	Rate Year TME	A Target Spend	B Cumulative Target	C Collected Over 5 Years	D Actual Spend	E Cumulative Spend	F [E - B] Cumulative Variance	G [F / 5] Deferral Balance
4	4/30/2021	$ 1,575	$ 1,575	$ 315	$ 1,300	$ 1,300	$ (275)	$ (55)
5	4/30/2022	1,575	3,150	630	1,400	2,700	(450)	(90)
6	4/30/2023	1,575	4,725	945	2,100	4,800	-	-

Labor Reconciliation

New York State Electric & Gas Corporation – Electric
New York State Electric & Gas Corporation – Gas
Rochester Gas and Electric Corporation – Electric
Rochester Gas and Electric Corporation – Gas

Overview

The Joint Proposal reflects the implementation of a downward-only reconciliation mechanism for Labor O&M Expenses. The calculation of any deferrals attributed to this mechanism will be determined by comparing the actual number of Full-Time Equivalent Positions ("FTEs") at each of the Companies versus the forecasts used to establish revenue requirements in this Joint Proposal, subject to the adjustments discussed below. NYSEG Electric and RG&E Electric will have two reconciliation mechanisms: one for positions in the Electric Line Workers area and another for all other functional areas. NYSEG Gas and RG&E Gas will have a single reconciliation mechanism for all functional areas.

Full-Time Equivalent Positions

The following table contains the average number of FTEs used to determine revenue requirements at the four Company businesses for each rate year. These values represent two-point averages, calculated by adding the FTEs at the start and end of each rate year and dividing by two.

	Average FTEs Rate Year 1 Ended 4/30/21	Average FTEs Rate Year 2 Ended 4/30/22	Average FTEs Rate Year 3 Ended 4/30/23
NYSEG Electric			
Line Workers	406	469	508
All Other Functional Areas	1,122	1,146	1,170
Total NYSEG Electric	1,528	1,614	1,678
NYSEG Gas	432	440	440
RG&E Electric			
Line Workers	113	114	113
All Other Functional Areas	408	423	430
Total RG&E Electric	521	537	543
RG&E Gas	279	285	286

Attrition Adjustment to Full-Time Equivalent Positions

The revenue requirement includes an adjustment for attrition that lowers forecasted labor expense, expressed as a percentage of overall staffing levels. This attrition percentage is 5.745% at NYSEG and 8.101% at RG&E. As labor expenses used to set rates reflected reductions based on these percentages, a similar adjustment will be made to the number of FTEs used in this reconciliation.

The following schedules identify the target FTEs for purposes of calculating the labor reconciliation.

FTE Targets

	Average FTEs Rate Year 1 Ended 4/30/21	Average FTEs Rate Year 2 Ended 4/30/22	Average FTEs Rate Year 3 Ended 4/30/23
NYSEG Line Workers			
Total FTEs before Attrition and Productivity	406	469	508
less: Attrition Adjustment (5.745%)	(23)	(27)	(29)
NYSEG Line Workers FTEs for Reconciliation	382	442	478
NYSEG Electric - All Other			
Total FTEs before Attrition and Productivity	1,122	1,146	1,170
less: Attrition Adjustment (5.745%)	(64)	(66)	(67)
NYSEG Electric All Other FTEs for Reconciliation	1,058	1,080	1,103
NYSEG Gas			
Total FTEs before Attrition and Productivity	432	440	440
less: Attrition Adjustment (5.745%)	(25)	(25)	(25)
NYSEG Gas FTEs for Reconciliation	407	415	415
RG&E Line Workers			
Total FTEs before Attrition and Productivity	113	114	113
less: Attrition Adjustment (8.101%)	(9)	(9)	(9)
RG&E Line Workers FTEs for Reconciliation	104	105	103
RG&E Electric - All Other			
Total FTEs before Attrition and Productivity	408	423	430
less: Attrition Adjustment (8.101%)	(33)	(34)	(35)
RG&E Electric Operations FTEs for Reconciliation	375	389	395
RG&E Gas			
Total FTEs before Attrition and Productivity	279	285	286
less: Attrition Adjustment (8.101%)	(23)	(23)	(23)
RG&E Gas FTEs for Reconciliation	256	262	263

Per FTE Labor Expense Deferral

At the end of each rate year, a comparison of actual average FTEs (based on a twelve-month rate year average) will be made to FTE Targets utilized to establish the revenue requirement (adjusted for attrition, as outlined above). Any deficit in actual FTEs relative to the target values used to establish rates will require the Company to book a deferred regulatory liability. The initial value of the deferral will equal the deficit in FTEs times the average labor expense, net of overtime and net of productivity.

Productivity Adjustment to Per FTE Labor Expense

The revenue requirement includes an adjustment for productivity that lowers the forecasted labor expense. This adjustment is expressed as a percentage and then applied to certain O&M expense categories, including labor. The productivity percentages are 1.25% in Rate Year 1 and 1.50% in Rate Years 2 and 3.

The schedules on the following page identify the calculation of the Average labor expense per FTE for each business, to be used in calculating any labor reconciliation deferred amount.

	Rate Year 1 Ended 4/30/21	Rate Year 2 Ended 4/30/22	Rate Year 3 Ended 4/30/23
NYSEG Electric ($K)			
Labor Expense per RRP-2	$ 113,630	$ 121,821	$ 128,702
less: Overtime	(20,686)	(21,244)	(21,831)
Labor Expense net of Overtime	$ 92,944	$ 100,577	$ 106,871
less: Productivity	(1,162)	(1,509)	(1,603)
Labor net of OT and Productivity	$ 91,782	$ 99,068	$ 105,268
divided by FTEs net ot attrtition	1,440	1,521	1,582
Average labor expense per FTE	$ 64	$ 65	$ 67
NYSEG Gas ($K)			
Labor Expense per RRP-2	$ 31,991	$ 33,315	$ 34,202
less: Overtime	(4,810)	(4,939)	(5,076)
Labor Expense net of Overtime	$ 27,181	$ 28,376	$ 29,126
less: Productivity	(340)	(426)	(437)
Labor net of OT and Productivity	$ 26,841	$ 27,950	$ 28,689
divided by FTEs net ot attrtition	407	415	415
Average labor expense per FTE	$ 66	$ 67	$ 69
RG&E Electric ($K)			
Labor Expense per RRP-2	$ 39,404	$ 41,319	$ 42,730
less: Overtime	(6,861)	(7,061)	(7,272)
Labor Expense net of Overtime	$ 32,543	$ 34,258	$ 35,458
less: Productivity	(407)	(514)	(532)
Labor net of OT and Productivity	$ 32,136	$ 33,744	$ 34,926
divided by FTEs net ot attrtition	478	494	499
Average labor expense per FTE	$ 67	$ 68	$ 70
RG&E Gas ($K)			
Labor Expense per RRP-2	$ 20,650	$ 21,584	$ 22,263
less: Overtime	(3,017)	(3,105)	(3,198)
Labor Expense net of Overtime	$ 17,633	$ 18,479	$ 19,065
less: Productivity	(220)	(277)	(286)
Labor net of OT and Productivity	$ 17,413	$ 18,202	$ 18,779
divided by FTEs net ot attrtition	256	262	263
Average labor expense per FTE	$ 68	$ 70	$ 72

Carry Over Provision

Deferral amounts created shall be carried over, with carrying charges, and would be offset in future periods to the extent that the relevant Company business exceeds FTE targets in those future periods during the term of the rate plan.

Average Actual FTEs

Rate Year 1

For the first rate year (May 1, 2020 – April, 2021), the calculation of the average actual FTEs to be used in the reconciliation will be the average of the applicable months starting with the first calendar month following a Commission Order approving the Joint Proposal.

Rate Years 2 and 3

The calculation of the average actual FTEs will be the twelve-month average during the second rate year (May 2021 – April 2022) and third rate year (May 2022 – April 2023).

Follow On Provision

For subsequent periods following the conclusion of the third rate year, the target FTE will remain at rate year 3 levels until a new rate plan takes effect.

Allocation of FTEs between Electric and Gas

Percentages utilized to allocate FTEs between Electric and Gas by functional location in this Joint Proposal will also be used to allocate actual FTEs for the purposes of this calculation.

	NYSEG		RG&E	
	Electric Allocation Percentage	Gas Allocation Percentage	Electric Allocation Percentage	Gas Allocation Percentage
Administration	78.24%	21.76%		
General Services	78.24%	21.76%	62.20%	37.80%
Health & Safety	78.24%	21.76%	62.20%	37.80%
Asset Management & Planning	72.36%	27.64%	92.18%	7.82%
Customer Service	77.57%	22.43%	62.05%	37.95%
Electric T&D Operations	100.00%	0.00%	100.00%	0.00%
Energy Supply	78.24%	21.76%	62.20%	37.80%
Gas Operations	0.00%	100.00%	0.00%	100.00%
NY President's Office	78.24%	21.76%	62.20%	37.80%
Process & Technology	96.78%	3.22%	95.39%	4.61%
Projects	100.00%	0.00%	100.00%	0.00%
Regulatory	78.24%	21.76%	62.20%	37.80%
Smart Grids	78.24%	21.76%	62.20%	37.80%

Calculation Examples

No Deferral Scenario – assumes August 2020 PSC Order

NYSEG Electric Operations - Rate Year 1

Actual FTEs		
Sep 2020		382.0
Oct 2020		384.0
Nov 2020		386.0
Dec 2020		388.0
Jan 2021		390.0
Feb 2021		392.0
Mar 2021		394.0
Apr 2021		396.0
Average Actual FTEs - Rate Year 1		389.0
FTE Target for Reconciliation		382.2
Deficiency - Actual vs. Target		-
times: Per FTE Labor Expense Deferral ($K)	$	63.7
Labor Expense Deferral ($K)	$	-

Deferral Scenario

NYSEG Electric Operations - Rate Year 2

Actual FTEs		
May 2021		425.0
Jun 2021		427.0
Jul 2021		429.0
Aug 2021		431.0
Sep 2021		433.0
Oct 2021		435.0
Nov 2021		437.0
Dec 2021		439.0
Jan 2022		441.0
Feb 2022		443.0
Mar 2022		445.0
Apr 2022		447.0
Average Actual FTEs - Rate Year 2		436.0
FTE Target for Reconciliation		441.6
Deficiency - Actual vs. Target		5.6
times: Per FTE Labor Expense Deferral ($K)	$	65.1
Labor Expense Deferral ($K)	$	363.7

New York State Electric & Gas Corporation – Electric and Natural Gas Non-Rate Assistance Programs
Rochester Gas and Electric Corporation – Electric and Natural Gas Non-Rate Assistance Programs

PROGRAM	*DESCRIPTION*	*MINIMUM ELIGIBILITY REQUIREMENTS*
Brownfield/Building Redevelopment Program	The Companies will provide assistance up to $500,000 per project / unique phase of project for electric-related infrastructure improvements on either the Company - owned or Company approved customer-owned equipment necessary for the redevelopment of a brownfield site or a vacant building. This program includes brownfield sites and redevelopment of historic / legacy buildings, waterfront developments, etc. that result in totally dedicated facilities or mixed-use facilities, contingent upon qualified business sectors, load, usage or square footage being more than 50% of the project. No minimum monthly demand threshold is required. In addition, as part of the maximum contribution of up to $500,000, the Companies will provide up to $20,000 toward a feasibility/assessment and/or remediation redevelopment efforts. The customer would have to invest at least 33.33% toward total investment.	➢ The funds may be utilized for up to 10% of the redevelopment costs. ➢ Funding cannot exceed the estimated cost of the electricity delivery-related infrastructure improvements. ➢ Project must hold the Companies harmless with regard to contaminant liability. ➢ Site/facility must be located within the Companies' service areas. ➢ Applicant must be the owner or leaseholder of facility and current on their account (existing customers). ➢ Project must demonstrate the ability to retain and/or attract new employment. ➢ Applicant must demonstrate efforts to obtain state and /or local economic development incentives. ➢ Business use must be classified under the following general categories: agriculture*, forestry, fishing, mining, manufacturing, wholesale trade durable goods, wholesale trade non-durable goods, finance, insurance, real estate, business services, clean technologies, regional warehouses and distribution centers, colleges/universities and hospitals/health care facilities**, and certain projects that are endorsed by one of the Empire State Development's (ESD) Regional Economic Development Councils and/or the Governor's office. *Agriculture includes the craft beverage industry supported by recent legislation for wineries, distilleries, micro-breweries, farm cideries, etc. **Colleges/universities and health care facilities must demonstrate that project for economic development assistance goes beyond typical educational facilities/dormitories/traditional health care occupancy and promotes research and development and/or state-of-the-art technologies/best practices, centers of excellence, that foster regional economic development benefits. ➢ Applicant must demonstrate a viable reuse strategy for the site, facility or company operation based on the following factors: – Physical condition of the building or site; – Demonstration of potential for land acquisition and site control; – Regional economic development impact; – Demonstration of efforts to qualify and obtain other federal, state, local, as well as private funding; – Demonstration of ability to market the site or building to attract economic investment ➢ Applicant must have the ability to sustain the reuse of site, facility or company operation a minimum of five years.

Note – funding associated with Appendix V programs will not be spent on gas-fired electric generating equipment, nor on integration of such equipment with other infrastructure

Capital Investment Incentive Program – Tier 1	The Companies will provide assistance up to $400,000 per project / unique phase of project for electric-related infrastructure improvements on either Company-owned or customer-owned equipment and other costs necessary for the construction of a new building or the addition to or redevelopment of an existing building. Funds are targeted for business projects that involve major capital investment in plant and equipment. Support will be considered based upon the project's overall economic impact to the community. Projects included may be either stand-alone buildings or those in a business or industrial park. Additionally, projects may include mixed-use facilities, including waterfront developments, contingent upon qualified business sectors, load, usage, or square footage being more than 50% of the project.	➢ Project must involve capital investment in facility and /or equipment purchases which total at least $1 million or more. ➢ The expected monthly incremental electric demand after capital investment must be at least 100 kilowatts ("kW"). ➢ Project must hold the Companies harmless with regard to contaminant liability. ➢ Site/facility must be located within the Companies' service areas. ➢ Applicant must be the owner or leaseholder of facility and current on their account (existing customers). ➢ Project must demonstrate the ability to retain and/or attract new employment. ➢ Applicant must demonstrate efforts to obtain state and /or local economic development incentives. ➢ Business use must be classified under the following general categories: agriculture*, forestry, fishing, mining, manufacturing, wholesale trade durable goods, wholesale trade non-durable goods, finance, insurance, real estate, business services, clean technologies, regional warehouses and distribution centers, colleges/universities and hospitals/health care facilities**, and certain projects that are endorsed by one of the ESD's Regional Economic Development Councils and/or the Governor's office. *Agriculture includes the craft beverage industry supported by recent legislation for wineries, distilleries, micro-breweries, farm cideries, etc. **Colleges/universities and health care facilities must demonstrate that project for economic development assistance goes beyond typical educational facilities/dormitories/traditional health care occupancy and promotes research and development and/or state-of-the-art technologies/best practices, centers of excellence, that foster regional economic development benefits.

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Capital Investment Incentive Program Tier 2	The Companies will provide assistance up to $200,000 per project / unique phase of project for electric-related infrastructure improvements on either Company-owned or customer-owned equipment and other costs necessary for the construction of a new building or the addition to or redevelopment of an existing building. Funds are targeted for business projects that involve major capital investment in plant and equipment. Support will be considered based upon the project's overall economic impact to the community. Projects included may be either stand-alone buildings or those in a business or industrial park. Additionally, projects may include mixed-use facilities, including waterfront developments, contingent upon qualified business sectors, load, usage, or square footage being more than 50% of the project.	➢ Project must involve capital investment in facility and /or equipment purchases which total at least $500,000 or more. ➢ The expected monthly incremental electric demand after capital investment must be at least 50 kW. ➢ Project must hold the Companies harmless with regard to contaminant liability. ➢ Site/facility must be located within the Companies' service areas. ➢ Applicant must be the owner or leaseholder of facility and current on their account (existing customers). ➢ Project must demonstrate the ability to retain and/or attract new employment. ➢ Applicant must demonstrate efforts to obtain state and /or local economic development incentives. ➢ Business use must be classified under the following general categories: agriculture*, forestry, fishing, mining, manufacturing, wholesale trade durable goods, wholesale trade non-durable goods, finance, insurance, real estate, business services, clean technologies, regional warehouses and distribution centers, colleges/universities and hospitals/health care facilities**, and certain projects that are endorsed by one of the ESD's Regional Economic Development Councils and/or the Governor's office. *Agriculture includes the craft beverage industry supported by recent legislation for wineries, distilleries, micro-breweries, farm cideries, etc. **Colleges/universities and health care facilities must demonstrate that project for economic development assistance goes beyond typical educational facilities/dormitories/traditional health care occupancy and promotes research and development and/or state-of-the-art technologies/best practices, centers of excellence, that foster regional economic development benefits.

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Business Energy Efficiency & Renewable Technologies Program **(Formerly named "Business Energy Efficiency Assistance Program)**	The Companies will provide supplemental assistance to eligible business customers participating in energy efficiency/ renewable/clean energy technologies programs offered by the Companies or the New York State Energy Research and Development Authority ("NYSERDA"). Supplemental assistance provided under this program will be over- and- above incentives, rebates, and other assistance provide to customers by the Companies or NYSERDA and will be used to fund energy efficiency/renewable technologies studies/analyses and/or implementation of energy efficiency/renewable technologies measures. Renewable technologies program assistance may include, but is not limited to: different forms of electrification, solar resources, energy storage, and electric vehicles. In addition, this program will provide supplemental assistance for workforce development/training associated with energy efficiency and renewable/clean energy technologies. Supplemental assistance provided under this program will be up to $20,000 toward a study/analysis and up to $50,000 toward implementation of a study/analysis. The customer will also be required to make a financial contribution of at least 33.33% toward total investment made.	➢ Facility must be within the Companies' service areas. ➢ Applicant must be current in payments to the Company or have a deferred payment agreement which is in place and current. ➢ Business use must be classified under the following general categories: agriculture*, forestry, fishing, mining, manufacturing, wholesale trade durable goods, wholesale trade non-durable goods, finance, insurance, real estate, business services, clean technologies, regional warehouses and distribution centers, colleges/universities and hospitals/health care facilities**, and certain projects that are endorsed by one of the ESD's Regional Economic Development Councils and/or the Governor's office. *Agriculture includes the craft beverage industry supported by recent legislation for wineries, distilleries, micro-breweries, farm cideries, etc. **Colleges/universities and health care facilities must demonstrate that project for economic development assistance goes beyond typical educational facilities/dormitories/traditional health care occupancy and promotes research and development and/or state-of-the-art technologies/best practices, centers of excellence, that foster regional economic development benefits.

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Power Quality/Reliability Program	The Companies will provide up to 50% of the equipment cost required for power reliability or power quality improvements to be installed behind the meter with a maximum contribution of up to $100,000. Under this program, the Companies, in consultation with the customer and/or its representatives, would make the final determination/assessment of the customer need for power quality equipment to address power quality issues behind the meter. In addition, as part of the maximum contribution of up to $100,000, the Companies will also provide up to $20,000 toward a feasibility study. The customer would have to invest at least 33.33% toward the total cost of a study.	➢ Facility must be within the Companies' service areas. ➢ Applicant must be current in payments to the Company or deferred payment agreement is in place and current. ➢ Applicant must be the owner of an eligible facility or prospective eligible facility. ➢ Business use must be classified under the following general categories: agriculture*, forestry, fishing, mining, manufacturing, wholesale trade durable goods, wholesale trade non-durable goods, finance, insurance, real estate, business services, clean technologies, regional warehouses and distribution centers, colleges/universities and hospitals/health care facilities**, and certain projects that are endorsed by one of the ESD's Regional Economic Development Councils and/or Governor's office. *Agriculture includes the craft beverage industry supported by recent legislation for wineries, distilleries, micro-breweries, farm cideries, etc. **Colleges/universities and health care facilities must demonstrate that project for economic development assistance goes beyond typical educational facilities/dormitories/traditional health care occupancy and promotes research and development and/or state-of-the-art technologies/best practices, centers of excellence, that foster regional economic development benefits.
Agriculture Capital Investment Incentive Program	The Companies will provide financial support toward electric-related infrastructure improvements on either Company-owned or customer-owned equipment up to $100,000. Decisions on actual awards will be commensurate with level of capital investment, load, and overall improvements. The overall intent in many instances is to help this industry convert from single phase to three phases to grow their business and install new technologies.	➢ Project must involve capital investment of at least $50,000 toward facility and/or equipment purchases. ➢ The monthly incremental electric demand after capital investment must be at least 25 kW. ➢ Project must hold the Company harmless in regard to any liability. ➢ Facility must be within the Companies' service areas. ➢ Recipient must be the owner or leaseholder of facility and current in any outstanding payments to the Company (existing customers). ➢ Business sectors to also include craft beverage industry which includes wineries, micro-breweries, distilleries, cideries, etc. to support recent legislation.

Note – funding associated with Appendix V programs will not be spent on gas-fired electric generating equipment, nor on integration of such equipment with other infrastructure

Economic Development Strategic Outreach Program **(Formerly named "Economic Development Outreach Program")**	The Companies will invest up to $150,000 per initiative on strategic economic development outreach projects primarily focusing on attracting new business investment into the Companies' service areas.	➢ Must be a 50 % matching fund from federal, state, local and/or private sources. ➢ Recipients must be a state, regional, or local economic development organization within the Companies' service areas. ➢ Initiative must promote a specific asset or group of assets that enhance the competitiveness of a specific Company service area or all of Upstate New York. ➢ Project must be targeted to decision makers who can influence the attraction of new jobs and new business investment within the Companies' service areas. ➢ Project must not duplicate or replace previously existing initiatives. ➢ Research initiatives must involve action items such as clearly defined industry targets, promotional messages, or other materials that facilitate recipient documentation. ➢ Limited to initiatives such as: – Trade show, professional trade/business meetings, tours, etc. – Sales missions – Advertising and direct mailings – Special events and promotions – Research and analysis – Ambassador programs – Reports to community leaders – Early stage planning for site preparation and/or feasibility studies that prepare assets to be marketed for both new and existing sites (may include the Build Now-NY Program and Shovel Ready Certification process) – Labor assessments and/or marketing activities associated with workforce/talent management from a regional perspective and to incorporate equity development, diversity, and inclusivity in the workforce and talent pool

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Commercial Corridor / Main Street Revitalization Assistance Program	The Companies will provide matching grants up to $200,000 per development annually to municipal economic development entities, non-profit development organizations and private developers involved in efforts to revitalize a municipality defined target area. The program is designed to assist the Companies' economic development partners in promoting private sector investment in distressed business corridors and districts. The program's goals include increasing jobs, property tax bases, and promoting sustainable investment in commercial corridors / neighborhoods. These sustainable investment opportunities may include designated districts or zones (i.e., eco-districts). This program will provide funding assistance for lighting installations and electric infrastructure associated with street improvements and revitalizing a designated / defined target area. In addition, the Companies will provide up to $20,000 with 50% matching funds toward the development of pre-construction drawings to advance an urban design plan associated with the proposed project.	➢ Initiative must promote a specific target area as identified and supported by the municipality. ➢ Prospective recipient must demonstrate efforts to obtain state and federal economic development incentives. ➢ Applicant must demonstrate the ability to retain and/or attract jobs and capital investment to the targeted area.

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Manufacturing Accelerator Program	The Companies will provide matching grants up to the lesser of $15,000 or 40% of the costs incurred by eligible applicants whose top management commits the time and resources to productivity improvement projects such as Lean manufacturing, Lean office procedures, waste reduction, ISO quality programs and other projects that lower costs, improve quality and reduce lead times. In addition, the MAP will provide matching grants the lesser of $15,000 or 50% to fund growth-targeted activities such as new product development, export initiatives, sales and marketing system improvements, and other projects designed to increase revenue. Customers who choose to commit time and resources to both productivity and growth initiatives will be eligible for grants of up to $40,000 or 60% (whichever is less) of the costs incurred to implement such transformative programs. The MAP will provide funding for companies willing to commit their efforts to growth projects that can combine improved productivity with innovations in products, processes and markets to increase revenue and help secure the firm's long term future.	➢ The project must be within the Companies' service areas. ➢ Applicant must be current in payments to the Company or have a deferred payment agreement which is in place and current. ➢ To be eligible for this program, the applicant must: – Be an SC-2, SC-3, SC-7, SC-8 customer in good standing within the NYSEG/RG&E service areas; – Be a business that is classified as Manufacturing (NAICS codes 31, 32 or 33); – Execute an agreement that commits top management to the productivity and/or growth improvement contemplated by the MAP; and, – Provide evidence of funding from the company and other sources that is sufficient to complete the proposed project. The company must provide a minimum of 25% of the total funding from its own capital.

Economic Development Innovation & Entrepreneurship Program **(Formerly named "Innovation Zone – Ignition Grant Program")**	The Companies will provide one-time financial support designed to spur development of high growth potential companies by selectively and competitively awarding funds to early stage startup companies that agree to locate in a recognized innovation zone/district or have a regional economic impact and/or footprint. The awards are determined based on the technical and commercial opportunity of the business and will typically be made to pre-revenue companies at a proof-of-concept stage, with funding awards up to $25,000 with 50% matching funds. It is anticipated that this program will help more early stage startups by providing the necessary early stage funding to help them move closer to commercial success. Funds could be utilized for market and/or customer research, business model or business plan development, prototype/product development and intellectual property/patent related activities.	➢ The program will be administered by the awarded high tech advocacy organization within a given region. ➢ The awarded organization will assemble an independent screening and selection committee that will review all applications for awards, and select the most promising companies for inclusion in the program. ➢ Startups that receive awards must locate their business in a recognized innovation zone/district or have a regional economic impact and/or footprint, and agree to receive coaching, mentoring, and connections to help them maximize their chance of success. ➢ Startups that receive awards must also agree to keep their businesses in New York and/or contribute to a regional economic impact in New York State for a period of at least three years. ➢ Startups and/or high tech advocacy organizations must hold the Companies harmless with regard to any liability. ➢ A startup facility may either be located in the Companies' service areas or may make a regional economic impact through existing businesses that are located in the Companies' service areas.
Targeted Financial Assistance	The Targeted Financial Assistance Program (TFA) will supplement the Companies' existing economic development assistance programs and enable the Companies to offer retention and attraction opportunities. These opportunities, which will retain or provide substantial economic development benefits to New York State that would otherwise be lost absent such financial assistance, will be addressed in conjunction with other rate and/or non-rate economic development incentives already offered by the Companies and its local and state economic development allies. With TFA, the Companies will provide financial assistance of up to $750,000* in any one (1) year and up to $1,750,000* over a three (3) year period for a project. Once a project receives TFA funding, regardless of the period for which it received such funding, that project will be ineligible for additional TFA funding.	Facility must be located within the Companies' service areas or be committed to locating within the Companies' service areas. <u>Retention and Attraction:</u> ➢ Business use must be classified under the following general categories: agriculture*, forestry, fishing, mining, manufacturing, wholesale trade durable goods, wholesale trade non-durable goods, finance, insurance, real estate, business services, clean technologies, regional warehouses and distribution centers, colleges/universities and hospitals/health care facilities**, and certain projects that are endorsed by one of the ESD's Regional Economic Development Councils and/or the Governor's office. *Agriculture includes the craft beverage industry supported by recent legislation for wineries, distilleries, micro-breweries, farm cideries, etc. **Colleges/universities and health care facilities must demonstrate that project for economic development assistance goes beyond typical educational facilities/dormitories/traditional health care occupancy and promotes research and development and/or state-of-the-art technologies/best practices, centers of excellence, that foster regional economic development benefits.

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Targeted Financial Assistance (cont.)	Applicants can include a customer facing severe competitive challenges from sources outside New York State that could lead to closure and the loss of jobs, payroll and benefits in a customer's location ("Retention"). Alternatively, an applicant can demonstrate a competitive development location outside the State of New York that will be pursued in lieu of such development in New York State absent the TFA supplemental funding ("Attraction"). Economic assistance under the TFA can be provided at the Companies' discretion in the situation where the package of economic development funding from the Companies, through other rate and non-rate program incentives, and from the Companies' economic development allies at the state and local levels is not adequate to retain or attract the project at risk or opportunity. TFA funding can be utilized to help offset electric-related infrastructure improvements on either the Company-owned or Company approved customer-owned equipment. As indicated under "Minimum Eligibility Requirements" TFA funds will be granted only in those situations where the customer has also secured complementary financial support from other sources, such as state or local economic development agencies equal to at least 50% of the Companies' TFA amount. Because the Companies have the obligation to allocate funds to those applicants that will provide the most benefit to the service area, the Companies reserve the right to refuse to pursue such economic development assistance for a customer that satisfies the eligibility criteria. * Funding assistance programs have annual limits. Availability of funds is contingent on firm commitments for qualified projects.	➢ Applicant/Customer must demonstrate the intention to retain and/or attract new employment: – In the event of corporate restructuring for a Retention facility, employment levels must either be a) maintained at 97.5% of expected employment levels after restructuring efforts have been completed or b) maintained at employment levels established under provisions of a Community Benefits Package offered by other economic development allies. ➢ Applicant/Customer must obtain complementary financial support from other sources, such as state or local economic development agencies. Such financial support shall not amount to less than 50% of the Company's TFA to the Applicant/Customer. – Sources of funding obtained for qualification for other Non-Rate Incentive components are not to be considered as complementary financial support for the TFA <u>Retention</u> ➢ Facility must have an annual peak demand of 1,000 kW; ➢ Facility must have an average annual load factor of at least 50 %; ➢ Facility must employ at least 50 full-time employees or have $1 million budgeted annually for payroll and employee benefits; ➢ Facility must demonstrate to the Companies' sole satisfaction, through a corporate officer's affidavit/financial documentation, at least one (1) of the following competitive challenges: – The facility's relocation from the Companies' service areas to another location outside of the Companies' service areas or New York State; – Facility closure due to competitive pressures from outside the Companies' service areas or New York State <u>Attraction</u> ➢ Facility must have an annual peak demand of 300 kW for manufacturing or 150 kW for other qualifying business sectors or projects ➢ Applicant must demonstrate to the Companies' sole satisfaction, through a corporate officer's affidavit/financial documentation, the following competitive challenge: – Facility would not locate in the Companies' service areas, absent the TFA Facility will invest a minimum of $10 million of capital in the project

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Natural Gas Efficiency Infrastructure Investment Program	The Companies will provide funding assistance up to $100,000 per project to fund natural gas related infrastructure improvements to facilitate more efficient use of gas on equipment either owned by the Companies or the customer (as directed by the Companies). These improvements can involve individual customers or be associated with a business/industrial park. For any new customers, assistance would be targeted to industrial or similar processes and shall not be used primarily for space heating. For each Company, this program will have a cap of $600,000 in total across the term of the Rate Plan. Actual grant awards would be commensurate with the magnitude of each project including capital investment and infrastructure improvements. The primary intent of this program is to retain and/or increase employment through more efficient utilization of natural gas.	➢ Project must involve capital investment in facility/equipment purchases of at least $100,000. ➢ Companies must have first offered and explained beneficial electrification options to the customer. ➢ Project must hold the Companies harmless in regard to any contaminant liability. ➢ Applicant must demonstrate that financial assistance from this program will be a benefit to attracting new investment activity. ➢ Facility must be located within the Companies' service areas. ➢ Recipient must be the owner or leaseholder of facility and current in payments to the Companies (existing customers). ➢ Project must demonstrate ability to retain and/or attract new employment. ➢ Recipient must demonstrate efforts to obtain state and local economic development incentives. ➢ Business use must be classified under the following general categories: agriculture*, forestry, fishing, mining, manufacturing, wholesale trade durable goods, wholesale trade non-durable goods, finance, insurance, real estate, business services, clean technologies, regional warehouses and distribution centers, colleges/universities and hospitals/health care facilities**, and certain projects that are endorsed by one of the ESD's Regional Economic Development Councils and/or the Governor's office. *Agriculture includes the craft beverage industry supported by recent legislation for wineries, distilleries, micro-breweries, farm cideries, etc. **Colleges/universities and health care facilities must demonstrate that project for economic development assistance goes beyond typical educational facilities/dormitories/traditional health care occupancy and promotes research and development and/or state-of-the-art technologies/best practices, centers of excellence, that foster regional economic development benefits.

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Non-Residential Geothermal and Air Source Heat Pump Pilot Program	The Companies will provide one-time grant assistance per project to install geothermal or air source heat pump systems in lieu of natural gas heating in customer-owned facilities to be owned by a customer who satisfies eligibility requirements. This economic development grant would provide funding to incentivize customers to utilize heat pump technology to meet their heating and/or cooling needs. Up to $3.155 million at NYSEG and up to $4.0 million at RG&E may be drawn from electric economic development reserved funds for this program over the term of the Rate Plan or until the electric economic development reserve funds are exhausted, whichever is earlier. Both geothermal and air source heat pump systems that meet or exceed applicable energy efficiency baseline and technical requirements could be funded through this program. The Companies will work with NYSERDA, the New York Power Authority (NYPA) and other organizations with subject matter expertise to specifically determine applicable energy efficiency baseline and technical requirements. Supplemental assistance provided under this program will be over-and-above incentives, rebates and other assistance provided to customers by the Companies, NYSERDA or NYPA. Customers participating in the Geothermal and Air Source Heat Pump Pilot Program must also participate fully in all available programs offered by NYSERDA, NYPA, and the Companies and satisfy program eligibility requirements. The applicant's simple payback on the heat pump system versus a reasonably defined baseline heating and cooling system including natural gas for heating, must be not less than one (1) year, net of energy efficiency incentives/ rebates for the heat pump system available from NYSERDA or NYPA, and the Companies.	➢ New or existing non-residential (commercial, industrial, or municipal/public authority) customers will be eligible. ➢ Non-residential NYSEG or RGE customers with a minimum peak electric demand of 350 kW and certain projects that are endorsed by one of the ESD's Regional Economic Development Councils and/or the Governor's office. ➢ Project must hold the Companies harmless with regard to contaminant liability. ➢ Site/facility must be located within the Companies' service areas and within an area where there are either natural gas system constraints or for business expansion/attraction projects, where incremental load requirements have determined a constraint in natural gas availability to meet their specific requirements. ➢ Applicant must be the owner or leaseholder of facility and current on their account (existing customers). ➢ Project must demonstrate the ability to retain and/or attract new employment. ➢ Applicant must demonstrate efforts to obtain state and /or local economic development incentives.

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Economic Development - COVID-19 Grant Assistance Programs

PROGRAM	*DESCRIPTION*	*MINIMUM ELIGIBILITY REQUIREMENTS*
Small Business Customer COVID-19 Relief Program – Electric Customers	A program to provide economic development grant assistance to existing small businesses as of March 16, 2020 (consistent with the Governor's Executive Orders). This program is available to all electric non-residential, demand billing customers that do not qualify under the Large Business Customer COVID - 19 Relief Program. The primary intent of this program is focused on economic recovery and retention efforts (e.g., retention of businesses, jobs and planned capital expenditures).	➢ Annual funding assistance up to $1 million from each Company's existing Economic Development allowance during the Rate Plan. ➢ One-time grant assistance per customer (business partner) ➢ Up to $15,000 per project/application, 100 % of eligible assistance. ➢ Program assistance shall be electric only and may include the following ; cybersecurity services for a remote workforce, consulting services to develop cybersecurity/incidence preparedness/strategic organizational/business continuity plans, workforce training/development, retention and recruitment, enhanced energy efficiency assistance, engineering redesign services, cleaning/disinfecting services for facilities and associated inspections prior to returning to the workplace, consulting services to assist with changes in business processes for more effective operation during pandemic (i.e., restaurant shift to take-out services), consulting services to help develop enhanced standards/procedures and new policies, educational services to help maintain employee habits in this new working environment, and additional electric infrastructure <u>only</u>, which may be required to change business processes. ➢ Applicant must demonstrate and certify that the request for funding assistance is associated with the COVID-19 pandemic. Examples could include receipt of payment under the federal government's Payment Protection Plan, loans, or other supplemental funding sources from governmental agencies to help support continued employment. ➢ Assistance is independent of other assistance either committed or already funded by local, state, or federal agencies. ➢ This program and application process will remain in place until a date determined by the Companies in consultation with Department of Public Service Staff or the New York State Public Service Commission. ➢ Utility payments to NYSEG/RG&E should be current, and if not, any grant amount will first be used to bring the payments current, and the remaining amount would be provided to the customer. ➢ Must be a NYSEG/RG&E <u>electric service customer</u> or leaseholder of landlord who is an electric service customer of NYSEG/RG&E.

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Large Business Customer COVID-19 Relief Program – Electric Customers	A program to provide economic development grant assistance to existing large businesses as of March 16, 2020 (consistent with the Governor's Executive Orders. This would apply to NYSEG SC-7 electric customers with a peak demand 500 kW or greater in the last 24 months and comparable SC-11 electric customers and RGE SC-8 electric customers with a peak demand of 300 kW or greater in the last 24 months and comparable SC-14 electric customers. The primary intent of this program is focused on economic recovery and retention efforts (e.g., retention of businesses, jobs and planned capital expenditures).	➢ Annual funding assistance up to $2 million from each Company's existing Economic Development allowance during the Rate Plan. ➢ Up to $50,000 per project/application, 100 % of eligible assistance. ➢ One-time grant assistance per customer (business partner) ➢ Program assistance shall be electric only and may include the following; cybersecurity services for a remote workforce, consulting services to develop cybersecurity/incidence preparedness/strategic organizational/business continuity plans, workforce training/development, retention and recruitment, enhanced energy efficiency assistance, engineering redesign services, cleaning/disinfecting services for facilities and associated inspections prior to returning to the workplace, consulting services to assist with changes in business processes for more effective operation during pandemic (i.e., retooling to change manufacturing production process), consulting services to help develop enhanced standards/procedures and new policies, educational services to help maintain employee habits in this new working environment, and additional electric infrastructure <u>only</u>, which may be required to change business processes. In addition, the Companies will evaluate specific projects submitted as part of the application process for evaluation and support of the COVID-19 pandemic. ➢ Applicant must demonstrate and certify that the request for funding assistance is associated with the COVID-19 pandemic. Examples could include receipt of payment under the federal government's Payment Protection Plan, loans, or other supplemental funding sources from governmental agencies to help support continued employment. ➢ Assistance is independent of any other assistance either committed or already funded by local, state, or federal agencies. ➢ This program and application process will remain in place until a date determined by the Companies in consultation with Department of Public Service Staff or the New York State Public Service Commission. ➢ Utility payments to NYSEG/RG&E must be current, and if not, any grant amount will first be used to bring the payments current, and the remaining amount would be provided to the customer. ➢ Must be a NYSEG/RG&E <u>electric service customer</u> or leaseholder of landlord who is an electric service customer of NYSEG/RG&E.

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In addition to the programs indicated in this Appendix, the Companies will also take the following steps to enhance the economic development process:

1. The Companies agree to use commercially reasonable efforts to improve response time to information requests from economic developers and/or companies attempting to assess the level or potential level of electric and/or gas service at a site, with a target to provide a response in ten (10) business days from the receipt of a request for information. When responding, the Companies will use commercially reasonable efforts to provide the best information the utility has available, including, where possible, estimates of the quantity and types of electric and/or gas service that may be provided at a development site and the costs and time required to provide service, recognizing that initial estimates provided will be high level and subject, in part, to the quality and level of detail of the load and other information provided to the Companies.
2. The Companies provide the maximum discount allowed under the Excelsior program.
3. The Companies will:
    a. Consider implementation of streamlined procedures for responding to both internal and external requests for information for economic development purposes;
    b. Work collaboratively to improve responsiveness to economic development representatives both within and outside the Companies; and
    c. Attend economic development Best Practices meetings that the Department of Public Service may convene from time to time with the utilities and consider adopting measures identified as best practices in this area.

Rate Adjustment Mechanism ("RAM") Process and Procedures

New York State Electric & Gas Corporation – Electric
New York State Electric & Gas Corporation – Gas
Rochester Gas and Electric Corporation – Electric
Rochester Gas and Electric Corporation – Gas

RAM Eligible Deferrals and Costs

The RAM will contain two types of eligible deferrals and costs:

Type 1: Customer Bill Credits: NYSEG electric and gas businesses and RG&E electric and gas businesses will collect the customer bill credits provided to customers as a result of Covid-19 over a five-year period beginning July 1, 2021. The annual collection will be determined by dividing the total amount to be collected by the number of years remaining in the five-year period.

Type 2: Other RAM Eligible Deferrals and Costs: These deferrals shall be the difference between actual costs and the amounts provided for in base rates. RAM Eligible Deferrals and Costs shall include:

1) Property Taxes;
2) Major Storm Deferral Balances;
3) Gas Leak Prone Pipe Replacement;
4) REV costs and fees which are not covered by other recovery mechanisms; and
5) Costs associated with the implementation of any Commission-ordered Electric Vehicle Program, which recovery is not provided for in respective Commission orders.

All RAM revenues and deferrals are subject to reconciliation.

Annual RAM Recovery / Return Limits

The annual RAM recovery / return shall be limited to: (1) $22.2 million for NYSEG Electric; (2) $5.3 million for NYSEG Gas; (3) $12.3 million for RG&E Electric; and (4) $4.5 million for RG&E Gas. The RAM will be implemented for each applicable Business beginning July 1, 2021 to collect Type 1 – Customer bill credits, and if applicable Type 2 – Other RAM Eligible deferrals and costs.

Type 1 – Customer bill credits will be collected annually beginning July 1, 2021 (over a five-year period). Type 2 – Other RAM Eligible deferrals and costs will only be implemented for each applicable Business once the limit is reached from netting the RAM Eligible Deferrals for that Business. The limit will take into account the Type 1 Customer bill credits.

Any net RAM Eligible Deferral value in excess of the specific Business limit will remain deferred and will be carried forward to the calculation of the RAM limits in the following year.

Any net regulatory asset or liability in excess of each Business' annual RAM recovery / return limit shall be carried forward to the calculation of the RAM in the following year.

Deferred Regulatory Asset and Liability Balances

For each Business, NYSEG and RG&E shall each measure the deferred regulatory asset and liability balances for the items specified as Type 2- Other RAM Eligible Deferrals and Costs (listed above) as of December 31 for each year. The RAM for each Business shall be identified in each Company's respective RAM Compliance Filings submitted on March 31 of each year and shall be implemented in rates on July 1 of each year for collection over the 12 months from July 1 to June 30. The RAM Compliance Filings will include proposed RAM rates by service classification. Annually, NYSEG and RG&E will submit RAM tariff statements effective on July 1.

RAM Annual Recovery / Return

The Electric RAM annual recovery / return amounts to service classifications will be based on the following:

(a) Type 1 – Customer Bill Credits: Shall be recovered from those service classes which were eligible to receive the customer bill credits. Specifically, residential classes will be charged for the recovery of the residential bill credits and applicable non-residential service classes will be charged for the recovery of the non-residential bill credits. The Companies will not recover customer bill credits from service classes that are not eligible for the bill credits. Recovery will occur on a per kwh basis for non-demand customers, on a per kw basis for demand billed customers and on an as-used demand basis for standby service customers.

(b) Type 2 – Other RAM Eligible Deferrals and Costs: Shall be allocated based on delivery service revenues to all service classes and recovered on a per kwh basis for non-demand customers, on a per kw basis for demand billed customers and on an as-used demand basis for standby service customers.

The Gas RAM annual recovery / return amounts to service classifications will be based on the following:

(a) Type 1 – Customer Bill Credits: Shall be recovered from those service classes which were eligible to receive the customer bill credits. Specifically, residential classes will be charged for the recovery of the residential bill credits and applicable non-residential service classes will be charged for the recovery of the non-residential bill credits. The Companies will not recover customer bill credits from service classes that are not eligible for the bill credits. Recovery from customers will occur on a per therm basis.

(b) Type 2 – Other RAM Eligible Deferrals and Costs: Shall be allocated based on delivery service revenues to all service classes and recovered from customers on a per therm basis.

Carrying Costs

The Companies will accrue carrying costs on Type 1 – Customer Bill Credits based on the Commission's authorized Other Customer Capital Rate.

The Companies will accrue carrying costs on Type 2 – Other RAM Eligible Deferrals and Costs as follows:

1) During the period that the RAM is in effect for those deferral balances being specifically collected or returned, carrying costs will be based on the Commission's authorized Other Customer Capital Rate.
2) Other RAM Eligible Deferral Balances not in the RAM tariff due to the annual dollar amount restrictions set forth above will accrue carrying charges as follows:
    a. Net Deferral amounts at or under the annual RAM recovery / return limits will accrue carrying charges at the Other Customer Capital Rate;
    b. Additional deferral amounts over the annual RAM recovery / return limits, up to one year's worth of value, will accrue carrying costs at the Other Customer Capital Rate; and
    c. Additional deferral amounts over the annual RAM recovery / return limits in (2)(a) and (2)(b) above, will accrue carrying costs at NYSEG's and RG&E's respective Pre-Tax Weighted Cost of Capital, applied to the after-tax balance.[1]

RAM Review Process

Concurrent with the submission of the RAM Compliance Filings, the Companies will provide to Staff and parties to these rate proceedings the Companies' workpapers underlying the calculation of the RAM.

Within 30 calendar days of filing the RAM Compliance Filings, the Companies will convene an informational meeting either in person or via teleconference of all interested parties to these proceedings to review the Companies' calculation of the RAM for each Business.

In the event Staff or any interested party to these proceedings objects to the calculation of the RAM, Staff or such party shall notify the Companies and the parties in writing within 21 calendar days after the informational meeting. The Companies will respond in writing within 21 calendar days addressing the objection. To the extent that Staff or other such party believes its concerns were not fully addressed by the Companies' response, Staff or such party may submit written comments to the Commission.

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1 Carrying Costs Example: If a NYSEG Electric RAM Eligible Deferral equals $50 million and the annual Customer Bill Credit value is $2.2 M, then the first $20.0 million ($22.2 M less $2.2M Customer Bill Credit) would be in the RAM and accrue carrying costs at the Commission's authorized Other Customer Capital Rate. The next $20.0 million would also accrue carrying costs at the Other Customer Capital Rate. The remaining $10.0 million ($50.0 million - $40.0 million) will accrue carrying costs at the Pre-Tax Weighted Cost of Capital.

In the event of a dispute regarding the calculation of the annual RAM, the parties will use their best efforts to resolve the dispute within 150 calendar days of the Companies' response. The parties agree to utilize the Commission's dispute resolution process to resolve any contested matters. To the extent the parties are unable to resolve any remaining differences, the parties agree to present such differences to the Commission for resolution. RAM amounts will be subject to true-up and reconciliation, including carrying costs as noted above.

The implementation of the RAM shall not limit Staff's right to audit the deferred costs included by each Company in their respective RAMs.

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Earnings Adjustment Mechanisms

New York State Electric & Gas Corporation – Electric
New York State Electric & Gas Corporation – Gas
Rochester Gas and Electric Corporation – Electric
Rochester Gas and Electric Corporation – Gas

INCENTIVE SUMMARY

Commencing with the term of the Rate Plan, the Companies will implement for the first time the following seven Earnings Adjustment Mechanisms ("EAMs") associated with their electric or gas business during the Rate Plan: (1) Electric Share the Savings ("ESTS"); (2) Heat Pump Share the Savings ("HPSTS"); (3) Beneficial Electrification ("BE"); (4) Distributed Energy Resources ("DER") Utilization; (5) Electric Peak Reduction ("EPR"); (6) Gas Share the Savings ("GSTS"); and (7) Gas Heating Load Peak Reduction ("GPR"). The EAMs will be measured on a rate year basis for RY1, RY2, and RY3. These EAMs will be in effect during the term of the Rate Plan and will remain in effect at the end of the term until extended or terminated by the Commission in a future rate proceeding. Table 1 and Table 2 below contain the EAMs and the incentives associated with each EAM's minimum, midpoint, and maximum values. Adjustments to Rate Year 1 incentive levels and targets related to the COVID-19 pandemic are described later in this Appendix X:

Table 1: NYSEG Summary

EAM	Description		Rate Year 1	Rate Year 2	Rate Year 3
			(EAMs in $)		
			NYSEG	NYSEG	NYSEG
Electric Share the Savings	Based on lifetime MWh savings' unit cost reductions.	Min	30% of $ / Lifetime MWh Savings applied to acquired EE Savings		
		Mid			
		Max			
Heat Pump Share the Savings	Based on lifetime MMBTU savings' unit cost reductions.	Min	30% of $ / Lifetime MMBtu Savings applied to acquired Heat Pump Savings		
		Mid			
		Max			
Beneficial Electrification	Based on GHG reductions provided by Heat Pumps and EVs.	Min	$ 402,648	$ 445,475	$ 501,751
		Mid	$ 805,296	$ 890,950	$ 1,003,502
		Max	$ 1,610,592	$ 1,781,900	$ 2,007,003
DER Utilization	Based on Solar and Storage installations (in MWh).	Min	$ 402,648	$ 445,475	$ 501,751
		Mid	$ 1,207,944	$ 1,336,425	$ 1,505,252
		Max	$ 2,415,888	$ 2,672,849	$ 3,010,505
Electric Peak Reduction	Based on electric peak reduction below NYISO ICAP forecast for Company service territories.	Min	$ 402,648	$ 445,475	$ 501,751
		Mid	$ 805,296	$ 890,950	$ 1,003,502
		Max	$ 1,610,592	$ 1,781,900	$ 2,007,003
Total Electric	Sum of all electric EAMs; includes the Share the Savings EAMs.	Min	$ 1,207,944	$ 1,336,425	$ 1,505,252
		Mid	$ 5,565,866	$ 6,240,879	$ 7,290,513
		Max	$10,021,984	$11,343,412	$13,218,024
Gas Share the Savings	Based on lifetime MMBTU savings' unit cost reductions.	Min	30% of $ / Lifetime MMBtu Savings applied to acquired EE Savings		
		Mid			
		Max			
Gas Heating Load Peak Reduction	Based on gas peak day per heating degree day usage reductions.	Min	$ 109,744	$ 120,370	$ 132,085
		Mid	$ 219,488	$ 240,740	$ 264,171
		Max	$ 438,976	$ 481,481	$ 528,341
Total Gas	Sum of all gas EAMs; includes the Share the Savings EAM.	Min	$ 109,744	$ 120,370	$ 132,085
		Mid	$ 505,056	$ 646,099	$ 767,822
		Max	$ 871,654	$ 1,095,661	$ 1,291,450

Table 2: RG&E Summary

EAM	Description		Rate Year 1	Rate Year 2	Rate Year 3
			(EAMs in $)		
			RG&E	RG&E	RG&E
Electric Share the Savings	Based on lifetime MWh savings' unit cost reductions.	Min	30% of $ / Lifetime MWh Savings applied to acquired EE Savings		
		Mid			
		Max			
Heat Pump Share the Savings	Based on lifetime MMBTU savings' unit cost reductions.	Min	30% of $ / Lifetime MMBtu Savings applied to acquired Heat Pump Savings		
		Mid			
		Max			
Beneficial Electrification	Based on GHG reductions provided by Heat Pumps and EVs.	Min	$ 249,214	$ 301,963	$ 333,465
		Mid	$ 498,429	$ 603,926	$ 666,930
		Max	$ 996,857	$ 1,207,852	$ 1,333,860
DER Utilization	Based on Solar and Storage installations (in MWh).	Min	$ 249,214	$ 301,963	$ 333,465
		Mid	$ 747,643	$ 905,889	$ 1,000,395
		Max	$ 1,495,286	$ 1,811,778	$ 2,000,791
Electric Peak Reduction	Based on electric peak reduction below NYISO ICAP forecast for Company service territories.	Min	$ 249,214	$ 301,963	$ 333,465
		Mid	$ 498,429	$ 603,926	$ 666,930
		Max	$ 996,857	$ 1,207,852	$ 1,333,860
Total Electric	Sum of all electric EAMs; includes the Share the Savings EAMs.	Min	$ 747,643	$ 905,889	$ 1,000,395
		Mid	$ 3,182,326	$ 3,583,848	$ 4,068,782
		Max	$ 5,694,389	$ 6,498,744	$ 7,353,091
Gas Share the Savings	Based on lifetime MMBTU savings' unit cost reductions.	Min	30% of $ / Lifetime MMBtu Savings applied to acquired EE Savings		
		Mid			
		Max			
Gas Heating Load Peak Reduction	Based on gas peak day per heating degree day reduction.	Min	$ 85,371	$ 92,280	$ 106,185
		Mid	$ 170,742	$ 184,560	$ 212,370
		Max	$ 341,483	$ 369,120	$ 424,739
Total Gas	Sum of all gas EAMs; includes the Share the Savings EAM.	Min	$ 85,371	$ 92,280	$ 106,185
		Mid	$ 462,887	$ 559,563	$ 651,750
		Max	$ 784,128	$ 937,307	$ 1,090,468

The following is a summary of the EAM basis point achievement levels; details regarding the EAMs, including metrics, associated achievement, and basis points are more fully described below.

NYSEG

Electric-Only EAMs

	Level	Rate Year 1	Rate Year 2	Rate Year 3
Electric EE Share the Savings	Minimum	0.0	0.0	0.0
	Midpoint	14.2	13.2	14.0
	Maximum	21.5	20.0	21.2
Heat Pump Share the Savings	Minimum	0.0	0.0	0.0
	Midpoint	2.8	4.3	4.8
	Maximum	5.7	8.7	9.6
Beneficial Electrification	Minimum	2.5	2.5	2.5
	Midpoint	5.0	5.0	5.0
	Maximum	10.0	10.0	10.0
DER Utilization	Minimum	2.5	2.5	2.5
	Midpoint	7.5	7.5	7.5
	Maximum	15.0	15.0	15.0
Electric Peak Reduction	Minimum	2.5	2.5	2.5
	Midpoint	5.0	5.0	5.0
	Maximum	10.0	10.0	10.0
Total	Minimum	7.5	7.5	7.5
	Midpoint	34.6	35.0	36.3
	Maximum	62.2	63.7	65.8

NYSEG

Gas-Only EAMs

	Level	Rate Year 1	Rate Year 2	Rate Year 3
Gas EE Share the Savings	Minimum	0.0	0.0	0.0
	Midpoint	6.5	8.4	9.5
	Maximum	9.9	12.8	14.4
Gas Heating Load Peak Reduction	Minimum	2.5	2.5	2.5
	Midpoint	5.0	5.0	5.0
	Maximum	10.0	10.0	10.0
Total	Minimum	2.5	2.5	2.5
	Midpoint	11.5	13.4	14.5
	Maximum	19.9	22.8	24.4

RG&E

Electric-Only EAMs

	Level	Rate Year 1	Rate Year 2	Rate Year 3
Electric EE Share the Savings	Minimum	0.0	0.0	0.0
	Midpoint	13.9	11.4	12.1
	Maximum	21.0	17.3	18.4
Heat Pump Share the Savings	Minimum	0.0	0.0	0.0
	Midpoint	0.6	0.7	0.9
	Maximum	1.1	1.5	1.7
Beneficial Electrification	Minimum	2.5	2.5	2.5
	Midpoint	5.0	5.0	5.0
	Maximum	10.0	10.0	10.0
DER Utilization	Minimum	2.5	2.5	2.5
	Midpoint	7.5	7.5	7.5
	Maximum	15.0	15.0	15.0
Electric Peak Reduction	Minimum	2.5	2.5	2.5
	Midpoint	5.0	5.0	5.0
	Maximum	10.0	10.0	10.0
Total	Minimum	7.5	7.5	7.5
	Midpoint	31.9	29.7	30.5
	Maximum	57.1	53.8	55.1

RG&E

Gas-Only EAMs

	Level	Rate Year 1	Rate Year 2	Rate Year 3
Gas EE Share the Savings	Minimum	0.0	0.0	0.0
	Midpoint	8.6	10.2	10.3
	Maximum	13.0	15.4	15.7
Gas Heating Load Peak Reduction	Minimum	2.5	2.5	2.5
	Midpoint	5.0	5.0	5.0
	Maximum	10.0	10.0	10.0
Total	Minimum	2.5	2.5	2.5
	Midpoint	13.6	15.2	15.3
	Maximum	23.0	25.4	25.7

The table below provides a summary of the value of a basis point for each rate year for each Company's electric and gas business.

NYSEG: Value of an EAM basis point	**Rate Year 1**	**Rate Year 2**	**Rate Year 3**
Electric ($) [$RY_x$ $ BP Electric]	$ 161,059	$ 178,190	$ 200,700
Gas ($) [$RY_x$ $ BP Gas]	$ 43,898	$ 48,148	$ 52,834

RG&E: Value of an EAM basis point	**Rate Year 1**	**Rate Year 2**	**Rate Year 3**
Electric ($) [$RY_x$ $ BP Electric]	$ 99,686	$ 120,785	$ 133,386
Gas ($) [$RY_x$ $ BP Gas]	$ 34,148	$ 36,912	$ 42,474

NYSEG TARGET SUMMARY: EARNINGS ADJUSTMENT MECHANISMS

EAM	Units	Level	Rate Year 1 NYSEG	Rate Year 2 NYSEG	Rate Year 3 NYSEG
Electric Share the Savings		Base (MWh)	89,262	96,572	120,287
		Budget ($)	$ 23,465,797	$ 24,348,006	$ 29,010,139
		EUL (years)	10.0	10.0	10.0
		Cost ($/Lifetime MWh)	$ 26.29	$ 25.21	$ 24.12
Gas Share the Savings		Base (MMBtu)	132,141	149,818	167,658
		Budget ($)	$ 2,897,761	$ 4,220,725	$ 5,221,802
		EUL (years)	15.4	15.4	15.4
		Cost ($/Lifetime MMBtu)	$ 1.42	$ 1.83	$ 2.02
Heat Pump Share the Savings		Base (MMBtu)	63,614	117,911	153,328
		Budget ($)	$ 6,204,522	$ 10,605,014	$ 13,173,160
		EUL (years)	19.0	19.0	19.0
		Cost ($/Lifetime MMBtu)	$ 5.12	$ 4.72	$ 4.51
Beneficial Electrification[1]	Lifetime CO_2e Savings	Min	335,853	517,894	664,720
		Mid	399,825	616,541	791,333
		Max	479,790	739,849	949,600
DER Utilization	Total Annual MWh	Min	99,307	70,662	102,420
		Mid	118,223	96,700	145,759
		Max	141,867	131,134	203,508
Electric Peak Reduction	NYISO Reported Peak (MW)	Forecasted Peak	3074.7		
		Min	3020.9		
		Mid	2994.3		
		Max	2967.8		
Gas Heating Load Peak Reduction[2]	% Reduction Below Prior Year Heat Factor	Prior Year HF	5,400		
		Min	0.4%		
		Mid	1.5%		
		Max	2.6%		

1 BE targets will be updated pursuant to the Companies' compliance filings ("Heat Pump Compliance Filings") filed pursuant to the Commission's Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025 issued January 16, 2020 in Case 18-M-0084 – In the Matter of a Comprehensive Energy Efficiency Initiative ("January 16, 2020 Order")..

2 Gas peak numbers given are for "Rate Year 0," (Winter 2019/2020) and will be calculated for RY1 to include actual performance in Rate Year 0 as further explained in this Appendix.

RG&E TARGET SUMMARY: EARNINGS ADJUSTMENT MECHANISMS

EAM	Units	Level	Rate Year 1 RG&E	Rate Year 2 RG&E	Rate Year 3 RG&E
Electric Share the Savings		Base (MWh)	52,961	58,155	69,591
		Budget ($)	$ 14,137,818	$ 14,788,092	$ 16,947,479
		EUL (years)	11.2	11.2	11.2
		Cost ($/Lifetime MWh)	$ 23.83	$ 22.70	$ 21.74
Gas Share the Savings		Base (MMBtu)	153,246	172,393	192,920
		Budget ($)	$ 2,965,890	$ 3,915,064	$ 4,612,178
		EUL (years)	14.6	14.6	14.6
		Cost ($/Lifetime MMBtu)	$ 1.33	$ 1.56	$ 1.64
Heat Pump Share the Savings		Base (MMBtu)	7,541	14,206	18,304
		Budget ($)	$ 747,986	$ 1,278,915	$ 1,611,466
		EUL (years)	19.7	19.7	19.7
		Cost ($/Lifetime MMBtu)	$ 5.05	$ 4.58	$ 4.48
Beneficial Electrification[3]	Lifetime CO_2e Savings	Min	104,814	149,794	190,782
		Mid	124,779	178,327	227,121
		Max	149,735	213,992	272,545
DER Utilization	Total Annual MWh	Min	45,360	34,352	45,385
		Mid	54,000	53,736	86,503
		Max	64,800	79,894	142,771
Electric Peak Reduction	NYISO Reported Peak (MW)	Forecasted Peak	1,531.6		
		Min	1,484.9		
		Mid	1,461.2		
		Max	1,437.6		
Gas Heating Load Peak Reduction[4]	% Reduction Below Prior Year Heat Factor	Forecasted Peak	5,366		
		Min	1.4%		
		Mid	5.7%		
		Max	9.9%		

3 BE targets will be updated pursuant to the Heat Pump Compliance Filings.

4 Gas peak numbers given are for “Rate Year 0,” (Winter 2019/2020) and will be calculated for RY1 to include actual performance in Rate Year 0 as further explained in this Appendix.

COVID-19 ADJUSTMENTS

The following adjustments will be made to Rate Year 1 targets and awards necessitated by the ongoing COVID-19 pandemic:

EAM	Target Adjustment or New Formula (Share the Savings EAMs)
	Rate Year 1
	NYSEG and RG&E
Electric Share the Savings	$= \left\{\left[\left(\frac{\$}{MWh_{lifetime}}\right)_{authorized} - \left(\frac{\$}{MWh_{lifetime}}\right)_{achieved}\right] * \left(MWh_{lifetime}\right)_{achieved} * (30\%)\right\} * \left(\frac{MWh_{achieved}}{MWh_{authorized}}\right)$ No minimum MWh threshold. Company share not to exceed 30% of savings.
Heat Pump Share the Savings	$= \left\{\left[\left(\frac{\$}{MMBtu_{lifetime}}\right)_{authorized} - \left(\frac{\$}{MMBtu_{lifetime}}\right)_{achieved}\right] * \left(MMBtu_{lifetime}\right)_{achieved} * (30\%)\right\} * \left(\frac{MMBtu_{achieved}}{MMBtu_{authorized}}\right)$ No minimum MMBtu threshold. Company share not to exceed 30% of savings.
Beneficial Electrification	EV Lifetime CO_2 Reductions: Adjusted by the change in new vehicle sales (from DMV data), in New York state. Sales of all vehicles in New York state during Rate Year 1 relative to sales during the 12 months preceding Rate Year 1. Heat Pumps Lifetime CO_2 Reductions: Adjusted by the $\left(\frac{MMBtu_{achieved}}{MMBtu_{authorized}}\right)$ adjustment ratio from Heat Pump STS EAM.
DER Utilization	Adjusted downward subject to number of days of NY on PAUSE Adjustment Factor = $\frac{365 - Number\ of\ Days\ of\ NY\ on\ PAUSE}{365}$ If NY on PAUSE is lifted at different times in different regions of NYSEG's territory, the average number of days will be used for all appropriate regions for NYSEG. For RG&E the region that encompasses Rochester will be used.
Electric Peak Reduction	Average of Hourly Load Deficit (versus expected use) from the hours of 2 PM to 6 PM from NYISO data available nearest July 1, 2020. NYSEG – Average of Zones A-G. RG&E – Zone B only.[5]
Gas Share the Savings	$= \left\{\left[\left(\frac{\$}{MMBtu_{lifetime}}\right)_{authorized} - \left(\frac{\$}{MMBtu_{lifetime}}\right)_{achieved}\right] * \left(MMBtu_{lifetime}\right)_{achieved} * (30\%)\right\} * \left(\frac{MMBtu_{achieved}}{MMBtu_{authorized}}\right)$ No minimum MMBtu threshold. Company share not to exceed 30% of savings.
Gas Heating Load Peak Reduction	No target adjustment.

[5] https://www.nyiso.com/documents/20142/12174395/NYISO-COVID-19-DemandImpactEstimates-20200505.pdf/f0867663-0b74-9724-38ab-8802f85b6a0d?t=1588787286990

EAM	Awards Rate Year 1 NYSEG and RG&E
Electric, Gas, and Heat Pump Share the Savings	Formula in prior table describes award levels.
Beneficial Electrification and DER Utilization	$Adjusted\ Incentive = Incentive\ * Adjustment\ Factor$
Electric Peak Reduction	$Adjusted\ Incentive = Incentive\ * (1 - Adjustment\ Factor)$
Gas Heating Load Peak Reduction	No award adjustment

For the Beneficial Electrification and DER Utilization EAMs, the Adjustment Factor is equal to the percentage of adjusted targets relative to the agreed upon targets (Pages 7 and 8 of the Appendix X). For example, if the original target is 100, and the adjusted target is 99, the adjustment factor is 99%, implying that the adjusted incentive is 99% of the original incentive.

For the Electric Peak Reduction EAMs, the Adjustment Factor is equal to the percentage reduction of adjusted targets relative to the agreed upon targets (Pages 7 and 8 of the Appendix X). For example, if the original target is 100, and the adjusted target is 99, the adjustment factor is 99%, implying that the adjusted incentive is 101% of the original incentive of the original incentive.

For any EAM that is adjusted downward, if NYSEG and/or RG&E achieves the original maximum target level (Pages 7 and 8 of this Appendix X) they shall be awarded the maximum incentive without adjustment. The EAMs subject to this clause are the Beneficial Electrification EAM and the DER Utilization EAM.

EAM CALCULATIONS

1.0 Electric EAMs

1.1 Electric Share the Savings EAM

1.1.1 Description

The ESTS EAM is designed to reduce unit costs for each Company's electric energy efficiency ("EE") portfolio by reducing the unit cost of lifetime energy savings (on a dollar per lifetime Megawatt-hour ("MWh") basis) below unit cost levels as approved in the Commission's Order Adopting Accelerated Energy Efficiency Targets, issued December 13, 2018 in Case 18-M-0084 and the January 16, 2020 Order, while increasing the overall achievement level of energy savings. Under the ESTS EAM, each Company will be awarded 30% of unit cost savings realized from the respective Company's acquired electric EE savings once the Company has met minimum electric 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 electric EE unit cost savings relative to the baseline unit cost; (ii) applying that to the acquired EE savings; and (iii) applying a percent share to the result, in this case 30%. The following formula represents this calculation.

$$Electric\ STS\ (\$) = \left[RY_x\ Base\ Cost\ \left(\frac{Lifetime\ \$}{MWh}\right) - RY_x\ Actual\ Cost\ \left(\frac{Lifetime\ \$}{MWh}\right)\right] \times\ RY_x\ Actual\ Lifetime\ MWhs\ \times 30\%$$

Where, X is equal to 1, 2 and 3 for RY_1, RY_2, and RY_3 respectively.

1.1.3 Measurement

The applicable Total Resource Measure ("TRM"), at the time savings are acquired, will be used for each EE measure in a particular RY. Each Company will file its applicable System Energy Efficiency Plan ("SEEP") in Cases 15-M-0252 and 18-M-0084 based on the reporting schedule as defined in Clean Energy Guidance Document CE-02 adopted July 15, 2015 in Case 15-M-0252 – In the Matter of Utility Energy Efficiency Programs.

1.1.4 Achievement

Achievement for this EAM is based on the formula detailed in section 1.1.2. A Company must achieve the base eligible installed MWh target levels to be eligible to receive a share of the savings under this EAM.

1.1.5 Targets

The following table provides the target levels for ESTS EAM. Savings can be achieved by either: (i) lowering unit cost (i.e., lowering costs relative to the budget); (ii) increasing MWh savings; or (iii) a combination of (i) and (ii).

EAM	Level	Rate Year 1	Rate Year 2	Rate Year 3
Electric Share the Savings		**NYSEG**	**NYSEG**	**NYSEG**
	Base (MWh)	89,262	96,572	120,287
	Budget ($)	$ 23,465,797	$ 24,348,006	$ 29,010,139
	EUL (years)	10.0	10.0	10.0
	Cost ($/Lifetime MWh)	$ 26.29	$ 25.21	$ 24.12
Electric Share the Savings		**RG&E**	**RG&E**	**RG&E**
	Base (MWh)	52,961	58,155	69,591
	Budget ($)	$ 14,137,818	$ 14,788,092	$ 16,947,479
	EUL (years)	11.2	11.2	11.2
	Cost ($/Lifetime MWh)	$ 23.83	$ 22.70	$ 21.74

1.1 <u>Heat Pump Share the Savings EAM</u>

1.1.1 Description

The HPSTS EAM is designed to reduce unit costs for each Company's heat pump portfolio by reducing the unit cost of lifetime energy savings (on a dollar per lifetime million British thermal units ("MMBtu")[6] basis) below unit cost levels as approved in the Commission's January 16, 2020 Order, while increasing the overall achievement level of energy savings. Under the HPSTS EAM, the Company will be awarded 30% of unit cost savings realized from the Company's acquired heat pump savings once the Company has met minimum heat pump MMBtu savings targets, as provided in the metric described below. In the event NYSEG or RG&E undertake non-pipes alternatives which include heat pumps as part of the solution, the Companies will not include those heat pumps associated with any such project in the calculation of the HPSTS EAM.

1.1.2 Metric

The EAM performance and associated Company incentive will be calculated by determining: (i) the heat pump unit cost savings relative to the baseline unit cost; (ii) applying that to the acquired heat pump savings; and (iii) applying a percent share to the result, in this case 30%. Mathematically,

$$Heat\ Pump\ STS\ (\$) = \left[RY_x\ Base\ Cost\ \left(\frac{Lifetime\ \$}{MMBtu}\right) - RY_x\ Actual\ Cost\ \left(\frac{Lifetime\ \$}{MMBtu}\right)\right] \times\ RY_x\ Actual\ Lifetime\ MMBtus\ \times 30\%$$

Where, X is equal to 1, 2 and 3 for RY_1, RY_2, and RY_3 respectively.

1.1.3 Measurement

At the time a customer is awarded an incentive for a heat pump, the heat pump will be considered as installed for the purposes of calculating this EAM. Typical residential installations will be counted based on 1) whether they are air-source heat pumps ("ASHPs") or ground source heat pumps ("GSHPs") and 2) whether the heat pump can provide water heating in addition to space heating, and then awarded an assumed level of lifetime MMBtu savings. If a heat pump can provide both water heating and space heating, it will be awarded the sum of the appropriate values found in the

6 BE targets will be updated pursuant to the Heat Pump Compliance Filings.

appropriate table in Section 1.1.5.

Multi-unit residential installations will be counted on a residential proxy basis, whereby a multi-unit installation will be counted as 50% of the number of individual residential units served by the heat pump(s). For example, an apartment building that installs a single, large air-source heat pump for 20 residential customers will be counted as 10 residential ASHP installations.

Commercial and industrial installations will be counted on a residential proxy basis, whereby the square footage of the non-residential installation will be divided by an expected residential square footage of 2,000 sq. ft / per housing unit and then awarded the appropriate number of corresponding residential installations. For example, a commercial installation of an air-source heat pump that serves 40,000 sq. ft. will be considered equivalent to 20 residential ASHP installations.

Mini-split heat pumps ("MSHPs") will be considered to be air-source heat pumps for the purposes of this EAM.

1.1.4 Achievement

Achievement for this EAM is based on the formula detailed in section 1.2.2 which provides the Companies' incentive. A Company must achieve the base eligible installed MMBtu target levels to be eligible to receive a share of the savings.

1.1.5 Targets

Target levels are given below. Savings can be achieved by either; (i) lowering unit cost (i.e., lowering costs relative to the budget); (ii) increasing MMBtu savings; or (iii) a combination of (i) and (ii).

EAM	Level	Rate Year 1	Rate Year 2	Rate Year 3
Heat Pump Share the Savings		**NYSEG**	**NYSEG**	**NYSEG**
	Base (MMBtu)	63,614	117,911	153,328
	Budget ($)	$ 6,204,522	$ 10,605,014	$ 13,173,160
	EUL (years)	19.0	19.0	19.0
	Base Cost ($/Lifetime MMBtu)	$ 5.12	$ 4.72	$ 4.51
Heat Pump Share the Savings		**RG&E**	**RG&E**	**RG&E**
	Base (MMBtu)	7,541	14,206	18,304
	Budget ($)	$ 747,986	$ 1,278,915	$ 1,611,466
	EUL (years)	19.7	19.7	19.7
	Base Cost ($/Lifetime MMBtu)	$ 5.05	$ 4.58	$ 4.48

Assumptions[7]	NYSEG + RG&E				
	ASHP Space Heat	**ASHP** Water Heat	**GSHP** Space Heat	**GSHP** Water Heat	**GSHP** Water Desuperheat[8]
Annual Savings (MMBtu)	54.0	11.2	66.1	13.6	11.2
EUL (years)	15.0	15.0	25.0	25.0	25.0
Lifetime Savings (MMBtu)	810.0	168.0	1,652.5	340.0	280.0

1.2 Beneficial Electrification EAM

1.2.1 Description

The BE EAM is designed to measure expected carbon savings over the life of two beneficially electrifying technologies: heat pumps and light-duty electric vehicles ("EVs").

1.2.2 Metric

The EAM performance and associated Company incentive will be calculated by determining the number of heat pumps installed and electric vehicles registered in a given Rate Year. The number of heat pumps and electric vehicles will be multiplied by the expected carbon savings over the life of the technology and measured against target levels set on a Lifetime Savings Tons CO_2e basis.

1.2.3 Measurement

Heat Pumps:

At the time a customer is awarded an incentive for a heat pump, the heat pump will be considered as installed for the purposes of calculating this EAM. Typical residential installations will be counted based on 1) whether they are space-heat only air-source heat pumps or ground source heat pumps, 2) whether they are heat pumps which provide water heating only, 3) whether the heat pumps are used for both space heating and water heating, and 4) whether a ground source heat pump includes a desuperheater, and then awarded an assumed level of lifetime CO_2e savings. If a heat pump can provide both water heating and space heating, it will be awarded the sum of the appropriate values found in the appropriate table in Section 1.2.5.

Multi-unit residential installations will be counted on a residential proxy basis, whereby a multi-unit installation will be counted as 50% of the number of individual residential units served by the heat pump(s). For example, an apartment building that installs an air-source heat pump for 20 residential customers will be counted as 10 residential ASHP installations.

Commercial and industrial installations will be counted on a residential proxy basis, whereby the square footage of the non-residential installation will be divided by an expected residential square footage of 2,000 sq. ft / per housing unit and then awarded

7 BE targets will be updated pursuant to the Heat Pump Compliance Filings.

8 Waste heat recovery systems such as those recovering heat from sewage lines will be credited as GSHP Desuperheaters.

the appropriate number of corresponding residential installations. For example, a commercial installation of an air-source heat pump that serves 40,000 sq. ft. will be considered equivalent to 20 residential ASHP installations.

MSHPs will be considered to be air-source heat pumps for the purposes of this EAM.

In the event NYSEG or RG&E undertake non-pipes alternatives which include heat pumps as part of the solution, the Companies will not include those heat pumps associated with any such project in the calculation of the BE EAM.

Electric Vehicles:
The Companies will determine the number and type of electric vehicles (battery or plug-in hybrid) by querying local municipality vehicle registration data over a given rate year. The number and type of EVs will then be multiplied by the appropriate number of lifetime tons CO_2e savings, as detailed in Section 1.3.5 in the Table "Electric Vehicle Assumptions."

1.2.4 Achievement

To determine achievement, lifetime tons of CO_2e savings from both heat pumps and electric vehicles will be added together and measured against the target levels identified above. The minimum, midpoint, and maximum will be set at 5%, 25%, and 50%, respectively, above the baseline target level.

1.2.5 Targets

Target levels are given below. The maximum target level will be 50% above the baseline target.

EAM	Level	Rate Year 1	Rate Year 2	Rate Year 3
Beneficial Electrification (Lifetime CO_2e Savings)		**NYSEG**	**NYSEG**	**NYSEG**
	Baseline	319,860	493,233	633,066
	Minimum	335,853	517,894	664,720
	Midpoint	399,825	616,541	791,333
	Maximum	479,790	739,849	949,600
Beneficial Electrification (Lifetime CO_2e Savings)		**RG&E**	**RG&E**	**RG&E**
	Baseline	99,823	142,661	181,697
	Minimum	104,814	149,794	190,782
	Midpoint	124,779	178,327	227,121
	Maximum	149,735	213,992	272,545

Heat Pump Assumptions[9]	**ASHP** Space Heat	**ASHP** Water Heat	**GSHP** Space Heat	**GSHP** Water Heat	**GSHP** Water Desuperheat[10]
(per residential HP)	**NYSEG**	**NYSEG**	**NYSEG**	**NYSEG**	**NYSEG**
Lifetime Savings (tons CO_2e)	78.8	11.2	146.1	21.4	18.7
	RG&E	**RG&E**	**RG&E**	**RG&E**	**RG&E**
Lifetime Savings (tons CO_2e)	61.8	11.2	117.7	21.4	18.7

Electric Vehicle Assumptions	**Battery Electric Vehicles**	**Plug-In Hybrid Electric Vehicles**
(per light-duty EV)	**NYSEG / RG&E**	**NYSEG / RG&E**
Annual Savings (tons CO_2e)	3.7	3.2
EUL (years)	10.0	10.0
Lifetime Savings (tons CO_2e)	37.4	31.7

1.3 DER Utilization EAM

1.3.1 Description

The DER Utilization EAM is designed to measure expected annual MWhs from two common Distributed Energy Resources: Solar and Energy Storage. These values will be measured as the amount of MWs interconnected by each Company over a given Rate Year.

1.3.2 Metric

The EAM performance and associated Company incentive will be calculated by determining the MWs of solar and energy storage successfully interconnected by each Company in a given Rate Year. The amount of MWs of solar and storage will then be multiplied by the expected annual output to be measured against target levels set on an annual MWh basis.

1.3.3 Measurement

Installations of solar and storage with an online date during a particular Rate Year will be counted towards achievement of the DER EAM. The Companies will measure and report the MWs of solar and storage interconnected, and then multiply that number by the appropriate conversion factors identified in Section 1.4.5.

1.3.4 Achievement

To determine achievement, annual MWhs from both solar and energy storage will be added together and measured against the target levels. The minimum, midpoint, and maximum will be set at 5%, 25%, and 50%, respectively, above the baseline target level.

1.3.5 Targets

Target levels are given below. The maximum target level will be 50% above the baseline target.

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9 BE targets will be updated pursuant to the Heat Pump Compliance Filings.

10 Waste heat recovery systems such as those recovering heat from sewage lines will be credited as GSHP Desuperheaters.

EAM	Level	Rate Year 1	Rate Year 2	Rate Year 3
DER Utilization (Annual MWh)		**NYSEG**	**NYSEG**	**NYSEG**
	Baseline	94,578	67,297	97,542
	Minimum	99,307	70,662	102,420
	Midpoint	118,223	96,700	145,759
	Maximum	141,867	131,134	203,508
DER Utilization (Annual MWh)		**RG&E**	**RG&E**	**RG&E**
	Baseline	43,200	32,716	43,224
	Minimum	45,360	34,352	45,385
	Midpoint	54,000	53,736	86,503
	Maximum	64,800	79,894	142,771

DER Assumptions	NYSEG / RG&E
Solar Capacity Factor (MW-AC)	17.7%
Annual Solar Output (MWh / MW-AC)	1,550.5
Storage Daily Operation (hours/day)	4
Annual Storage Output (MWh / MW installed)	1,460.0

1.4 Electric Peak Reduction EAM

1.4.1 Description

This EAM incentivizes NYSEG and RG&E 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 baseline level established for the EPR EAM, the Companies will receive an incentive under the EPR EAM.

1.4.2 Metric

The minimum, midpoint, and maximum levels of achievement are set below the adjusted NYISO Installed Capacity forecast Gold Book update issued in December prior to each rate year, with a downward revision of the lower bound of the 95% Confidence Interval ("CI"), based on the last five years of historical data (the difference between the New York Independent System Operator ("NYISO") Installed Capacity ("ICAP") forecast and actual peak contribution). The minimum, midpoint, and maximum targets will be 0.25, 1, and 1.75 Standard Deviations below the 95% CI lower interval.

The data used will be each Company's peak contribution, exclusive of co-ops and municipal loads (utility only data figures).
The EAM will always use the most recent five years of historical data. For example, Rate Year 1 (Summer 2020) will use the five-year historical period from 2015 through 2019. Rate Year 2 (Summer 2021) will use the five-year historical period from 2016 through 2020.

1.4.3 Measurement

All data used will come from the NYISO. Peak load forecasts and actuals will be reported by the NYISO and then used to determine EAM achievement.

1.4.4 Achievement

Achievement will be determined as the current Rate Year's coincident NYISO peak contribution relative to expected target levels.

1.4.5 Targets

EAM	Level	RY_1 (Summer 2020)	RY_1 (Summer 2020)
Electric Peak Reduction (MWs)		**NYSEG**	**RG&E**
	Baseline (NYISO Forecast)	3074.7	1,531.6
	Minimum	3020.9	1,484.9
	Midpoint	2994.3	1,461.2
	Maximum	2967.8	1,437.6

Note: 2021 and 2022 forecasts cannot be calculated until December of the year prior, based on NYISO's Gold Book forecast for peak load that upcoming year. The forecast will include the past five years of historical data. For example, the 2022 EPR target levels will be based on the historical forecast and actual peak data from 2017-2021.

2.0 Gas EAMs

1.1 <u>Gas Share the Savings EAM</u>

1.1.1 Description

The GSTS EAM is designed to reduce unit costs for each Company's gas energy efficiency portfolio by reducing the unit cost of lifetime energy savings (on a dollar per lifetime million British thermal units (MMBtu) basis) below unit cost levels as approved in the Commission's December 13, 2018 Order and January 16, 2020 Order, while increasing the overall achievement level of energy savings. Under the GSTS EAM, the Company will be awarded 30% of unit cost savings realized from the Company's acquired gas EE savings once the Company has met minimum gas 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 gas EE unit cost savings relative to the baseline unit cost; (ii) applying that to the acquired EE savings; and (iii) applying a percent share to the result, in this case 30%. Mathematically,

$$Gas\ STS\ (\$) = \left[RY_x\ Base\ Cost\ \left(\frac{Lifetime\ \$}{MMBtu}\right) - RY_x\ Actual\ Cost\ \left(\frac{Lifetime\ \$}{MMBtu}\right)\right] \times\ RY_x\ Actual\ Lifetime\ MMBtus\ \times 30\%$$

Where, X is equal to 1, 2 and 3 for RY_1, RY_2, and RY_3 respectively.

1.1.3 Measurement

The applicable TRM, at the time savings are acquired, will be used for each EE measure in a particular RY. The acquired savings will be determined on a gross verified savings basis. Each Company will file its applicable System Energy Efficiency Plan ("SEEP") in Cases 15-M-0252 and 18-M-0084 based on the reporting schedule as defined in Clean Energy Guidance Document CE-02 adopted July 15, 2015 in Case 15-M-0252 – In the Matter of Utility Energy Efficiency Programs.

1.1.4 Achievement

Achievement for this EAM is based on the formula detailed in section 2.1.2 which provides the Companies' incentive. A Company must achieve the base eligible installed MMBtu target levels to be eligible to receive a share of the savings.

1.1.5 Targets

Target levels are given below. Savings can be achieved by either: (i) lowering unit cost (i.e., lowering costs relative to the budget); (ii) increasing MMBtu savings; or (iii) a combination of (i) and (ii).

EAM	Level	Rate Year 1	Rate Year 2	Rate Year 3
Gas Share the Savings		**NYSEG**	**NYSEG**	**NYSEG**
	Base (MMBtu)	132,141	149,818	167,658
	Budget ($)	$ 2,897,761	$ 4,220,725	$ 5,221,802
	EUL (years)	15.4	15.4	15.4
	Base Cost ($/Lifetime MMBtu)	$ 1.42	$ 1.83	$ 2.02
Gas Share the Savings		**RG&E**	**RG&E**	**RG&E**
	Base (MMBtu)	153,246	172,393	192,920
	Budget ($)	$ 2,965,890	$ 3,915,064	$ 4,612,178
	EUL (years)	14.6	14.6	14.6
	Base Cost ($/Lifetime MMBtu)	$ 1.33	$ 1.56	$ 1.64

1.2 Gas Heating Load Peak Reduction ("GPR") EAM

1.2.1 Description

This EAM incentivizes NYSEG and RG&E to deliver gas 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 adjusted gas system peak below the prior rate year baseline level established for the GPR EAM, the Company will receive an incentive under the GPR EAM. The minimum, midpoint, and maximum levels of achievement are set below the prior year gas heat factor. The minimum, midpoint, and maximum targets will be 0.25, 1, and 1.75 Standard Deviations, respectively, below the prior year heat factor.

1.2.2 Metric

The minimum, midpoint, and maximum levels of achievement are set below the heating only load prior year's heat factor (heating load divided by heating degree days ("HDD") for each Company. The minimum, midpoint, and maximum targets will be 0.25, 1, and 1.75 Standard Deviations of the prior five years below the prior year heat factor for each Company.

NYSEG:

The "heat factor" for the peak day sendout is first calculated for the five years prior. Because NYSEG is a diverse territory with non-coincident peak day sendouts (different parts of the territory peak on different days), the weighted average sum of the various pooling areas' respective peak day sendouts and associated heating degree days will be used to calculate a single weighted-average figure for NYSEG to determine EAM achievement.

For the purposes of this metric, NYSEG's heat factor will be considered as the weighted average of seven pooling area components Dominion, Columbia, Tennessee, Orange & Rockland, Algonquin, North County, and Iroquois. For each pooling area component, the peak day winter sendout will be calculated as measured, then adjusted to remove the effects of: (i) interruptible customer usage; and (ii) baseline non-heating gas usage. Interruptible customer usage will be determined as the peak day usage for customers on an interruptible rate tariff. Baseline non-heating usage will be determined as the highest single day sendout during the preceding summer, less interruptible and daily-metered customer usage (on the summer peak day).

The weighted average sum of each pooling area peak day sendout less interruptible customer usage and baseline non-heating usage will be considered to be the aggregate peak day sendout for NYSEG. The weighted average sum of each pooling area's corresponding heating degree day (i.e., the HDD associated with each pooling area's peak day sendout) will be considered to be the aggregate HDDs for NYSEG.

For each of the prior five years, the aggregated peak day sendout for NYSEG will be divided by the aggregate peak day HDD's to determine a single annual heat factor. A simple linear regression is run on the prior five years of heat factors to determine a trendline and standard deviation.

The minimum, midpoint, and maximum targets are set as 0.25, 1, and 1.75 Standard Deviations (from the five-year regression), respectively, below the most recent year's heat factor.

RG&E:

The "heat factor" for the peak day sendout is first calculated for the five years prior. For the purposes of this metric, RG&E's heat factor will be considered as the measured peak day winter sendout, then adjusted to remove the effects of: (i) interruptible customer usage; (ii) baseline non-heating gas usage; and (iii) large customer usage. Interruptible customer usage will be determined as the peak day usage for customers on an interruptible rate tariff. Baseline non-heating usage will be determined as the highest single day sendout during the preceding summer, less interruptible, daily-metered, and large customer usage (on the summer peak day). The large customer peak day usage will be removed from RG&E's peak day sendout. The resulting adjusted peak day sendout value will be considered to be the adjusted peak day sendout for RG&E. The HDDs for the peak day will be used as measured.

For each of the prior five years, the adjusted peak day sendout for RG&E will be divided by the peak day HDD's to determine a single annual heat factor. A simple linear regression is run on the prior five years of heat factors to determine a trendline and standard deviation.

The minimum, midpoint, and maximum targets are set as 0.25, 1, and 1.75 Standard Deviations (from the five-year regression), respectively, below the most recent year's heat factor.

1.2.3 Measurement

The current year's heat factor will be determined as detailed above and measured against the target reduction levels to determine achievement. The current year's heat factor will then be used as next year's baseline level and included in a new regression model to determine next year's target levels as explained above. The standard deviation from the regression will always use the most recent five years of historical data.

For example, RY1 (Winter 2020/2021) will use the five-year historical period from Winter 2015/2016 through Winter 2019/2020. RY2 (Winter 2021/2022) will use the five-year historical period from Winter 2016/2017 through Winter 2020/2021.

1.2.4 Achievement

Achievement will be determined as the current year's aggregate heat factor as a percentage reduction below the prior year's heat factor relative to expected target levels.

1.2.5 Targets

EAM	Level	RY_0 (Winter 2019/2020)	RY_0 (Winter 2019/2020)
Gas Heating Load Peak Reduction		**NYSEG**	**RG&E**
	Baseline (Prior Year Heat Factor)	5,400	5,366
	Minimum	0.4%	1.4%
	Midpoint	1.5%	5.7%
	Maximum	2.6%	9.9%

Note: The numbers shown for Winter 2019/2020, Rate Year 0. For Rate Year 1 (Winter 2020/2021), Rate Year 2 (Winter 2021/2022), and Rate Year 3 (Winter 2022/2023) forecasts cannot be calculated until the prior year, based on the past 5 years of historical data. For example, the RY_1 (Winter 2020/2021) GPR target levels will be based on the actual peak data from Winter 2015/2016 through Winter 2019/2020.

EAM REPORTING REQUIREMENTS

On July 31, 2021, 2022, and 2023, NYSEG and RG&E will each make a compliance filing ("EAM Compliance Filing") to the Commission showing the calculation of incentives earned under each EAM for the Rate Year preceding the filing. Within 30 calendar days of filing the EAM Compliance Filing, the Companies will convene an informational meeting either in person or via teleconference of all interested parties to these proceedings to review the Companies' calculation of the EAM for each Business. The Companies will also file with the Secretary quarterly reports no later than 60 days after the end of each calendar quarter to describe the Companies' progress toward each EAM's metric's targets, the actions taken by the Companies to achieve target performance, and a forecast of whether the Companies expect to meet annual EAM targets.

RECOVERY OF EAM INCENTIVES

The Companies will be permitted to recover earned EAM incentives through a surcharge mechanism beginning 90 days after making its EAM Compliance Filing. NYSEG shall recover earned Electric EAMs through its Non-Bypassable Charge and earned Gas EAMs through a separate surcharge. RG&E shall recover earned Electric EAMs through its Non-Bypassable Charge and earned Gas EAMs through a separate surcharge. To determine responsibility for earned EAM awards amongst Service Classifications, the Companies will allocate the ESTS and HPSTS EAMs using the same allocation method to allocate Energy Efficiency-EE Tracker costs to service classes.

For NYSEG, the Energy Efficiency-EE Tracker cost allocation is as follows: (1) 83.81% is based on energy (i.e., kWh); (2) 5.84% is based on a 2 Coincident Peak ("CP") demand allocator; (3) 4.34% is based on a 12 CP demand allocator; (4) 2.42 is based on a primary non-coincident peak ("NCP") demand allocator; and (5) 3.59 % is based on a secondary NCP demand allocator.

For RG&E, the Energy Efficiency-EE Tracker cost allocation is as follows: (1) 83.43% is based on energy; (2) 6.53% is based on a 1CP demand allocator; (3) 3.38% is based on a 12 CP demand allocator; (4) 1.72% is based on a primary NCP demand allocator; and (5) 4.95% is based on a secondary NCP demand allocator.

The Companies will allocate EAM awards to Service Classifications for the BE EAM using transmission demand (12 CP), primary demand, secondary demand, and energy allocators with each carrying equal weight using the energy allocator. For the DER Utilization EAM, the Companies will allocate EAM awards to Service Classifications using transmission demand (12CP), primary demand, secondary demand, and energy allocators with each carrying equal weight. For the EPR EAM, the Companies will allocate EAM awards to Service Classification using the transmission demand allocator (12 CP). For the GSTS EAM, the Companies will allocate EAM awards to Service Classifications using the same allocation method to allocate Energy Efficiency-EE Tracker costs to service classes for both Companies, where the 83.81% is based on energy (i.e., therms) and 16.19% is based on peak day design demand allocator. For the Gas Heating Load Peak Demand EAM, the Companies will allocate EAM awards to Service Classifications using the gas peak day design demand allocator.

The calculation of the earned incentives is subject to review and adjustment by the Commission.

EAM SCORECARD METRICS

The Companies will track and report the progress of three Scorecard metrics: Locational System Relief Value ("LSRV") Load Factor, Residential Electric Energy Intensity, and Commercial Electric Energy Intensity. The Companies shall report progress on each of its Scorecard metrics as part of its annual EAM Compliance Filing. To facilitate possible development of new EAMs for proposal in a future rate proceeding, the Companies will track for a scorecard load factors at various LSRV areas on their respective distribution systems. The development of a Load Factor EAM at LSRV circuits/areas will require AMI for hourly usage data. Thus, the Companies' scorecard shall depend upon the installation of AMI at appropriate circuits. The Companies will also track Energy Intensity Data for a scorecard. The Residential Electric Energy Intensity metric will be calculated as the annual weather-normalized Residential MWh sales divided by the 12-month average of number of residential customers. For the purposes of this metric, residential customers are defined as customers taking service under Service Classifications 1, 8, and 12 for NYSEG, and Service Classifications 1, 4-I and 4-II for RG&E. The weather-normalized MWh sales used for this metric will be reduced by the aggregate MWh of electricity produced by Community Distributed Generation resources allocated to the relevant service classifications and adjusted to exclude the impacts of BE technologies such as incremental electric vehicle charging and heat pump usage.

The Commercial Electric Energy Intensity metric will be calculated as the annual weather-normalized Commercial MWh sales divided by the 12-month average of number of commercial customers. For the purposes of this metric, residential customers are defined as customers taking service under Service Classifications 2, 6, and 9 for NYSEG, and Service Classifications 2, 3, 7, and 9 for RG&E. The weather-normalized MWh sales used for this metric will be reduced by the aggregate MWh of electricity produced by Community Distributed Generation resources allocated to the relevant service classifications and adjusted to exclude the impacts of BE technologies such as incremental electric vehicle charging and heat pump usage.

Energy Efficiency

New York State Electric & Gas Corporation – Electric
New York State Electric & Gas Corporation – Gas
Rochester Gas and Electric Corporation – Electric
Rochester Gas and Electric Corporation – Gas

Energy Efficiency now recovered in Base Delivery Rates

Beginning with the start of RY1, the Companies' base electric and gas delivery rates reflect EE program costs for each Rate Year. These costs were previously collected through the "EE Tracker" portion of the SBC. On January 16, 2020, the Commission issued its Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025 ("January Order"). In the January Order, the Commission included utility specific electric and gas budgets and targets for years 2020-2025. The base delivery rates being implemented in this Joint Proposal reflect both EE programs and electric heat pump programs pursuant to the January Order. The revenue requirements established by this Joint Proposal generally reflect the budgets adopted in the January Order. In recognition of the Covid-19 pandemic, the budget amounts reflected in RY1 through RY3 have been reduced from the amounts reflected in the January Order, as described in Section V of the Joint Proposal. The Parties recognize that the adjustments to the RY1 through RY3 budgets do not reduce the overall budgets for years 2020-2025 established in the January 2020 Order.

Upon implementation of new delivery rates, the Companies will discontinue the SBC-EE Tracker component of the SBC surcharge currently applied to customer bills. The Companies will continue to collect, through the SBC surcharge, costs associated with EE programs not administered through the Companies (such as those administered by the New York State Energy Research and Development Authority ("NYSERDA"). Up to date details about each Company's respective EE and Heat Pump programs will be available on each Company's website.

In the event the Commission changes electric and gas EE budgets and targets during the term of this Rate Plan but does not adjust the Companies' revenue requirements or otherwise provide for recovery of such costs, the Companies will defer the revenue requirement impact of the cumulative difference between the amounts included in delivery rates in this Rate Plan and any increased budgets and targets established by the Commission.

The Companies will reconcile the revenue requirement effect of the actual level of costs incurred for the EE Programs to the cumulative electric and gas reconciliation targets and defer any cumulative over- or under-collection over the term of the Rate Plan for future charges to or credits to customers. Per the January 16, 2020 Order, the Companies are permitted to carry deferred overspent or underspent funds forward from year to year, through 2025, for offset or use in future year energy efficiency and/or heat pump programs. Per the January 16, 2020 Order, the total 2020-2025 budget is capped at $291,169,121 for NYSEG Electric, $38,721,068 for NYSEG Gas, $126,027,082 for RG&E Electric, and $31,794,046 for RG&E Gas. Contingent flexibility in this provision shall also mean that the Companies may: (1) shift any remaining funds from electric to gas when electric EE derived lifetime savings targets have been met in any Rate Year;

and (2) shift any remaining funds from gas to electric when gas EE derived lifetime savings targets have been met in any Rate Year.

Head Count

NYSEG is authorized to add six (6) full time equivalents ("FTEs") to its Conservation and Load Management ("CLM") group as shown in Table 1 below to support the increased targets in EE programs. Similarly, RG&E is authorized to add seven (7) FTEs to its CLM group as shown in Table 1 below.

Table 1: Additional EE FTE's by Company and Position

NYSEG - Position	RY1	RY2	RY3	Total
Supervisor				
Program Manager	1	1	1	**3**
Lead Analyst	1	1	1	**3**
Total	**2**	**2**	**2**	**6**
RG&E - Position	RY1	RY2	RY3	Total
Supervisor	1			**1**
Program Manager	1	1	1	**3**
Lead Analyst	1	1	1	**3**
Total	**3**	**2**	**2**	**7**
Grand total	**5**	**4**	**4**	**13**

Table 2: EE Job Functions by Job Title

Number of Positions	Job Title	Job Functions
1	Supervisor, Conservation and Load Management Program	• Oversee all delivery of NYSEG and RG&E EE and Demand Response ("DR") Programs • Manage all CLM regulatory requirements and compliance filings • Provide strategic guidance to EE and DR staff
6	Program Manager	• Develop and implement program plans and proposals • Develop and monitor program budgets • Oversee all aspects of third-party services including the procurement process, managing vendor activities, reporting, budgeting, program performance • Ensure quality assurance standards are met • Deliver customer service; ensure timely and successful resolution to issues • Meet regulatory and reporting requirements • Participate in working groups with NY Utilities, NYSERDA, and/or DPS Staff to support REV activities and regulatory initiatives
6	Lead Analyst	• Coordinate activities for program offerings to include processing vendor data files, compiling clean energy dashboards and reporting, and customer satisfaction • Validate and reconcile vendor invoices and vendor back up data files • Support a wide range of activities associated with program/product inquiries from customers, regulators, internal sources and vendors • Develop program level internal and external reports and associated documents

Demand Response

The Companies will eliminate the following two tariff programs: (1) the NYISO Emergency Demand Response Program ("EDRP"); and (2) the Day-Ahead Demand Response Program ("DADRP"). The elimination of these programs would be effective with the 2020 winter capability period, which begins November 1, 2020. These programs are eliminated in recognition of: (1) increased customer participation in utility distribution level DR programs; (2) increased saturation of Distributed Energy Resources ("DERs"); and (3) the fact that the NYISO has not requested curtailment under the EDRP program since August 2016.

Considering neither of the Companies has any participation through NYSEG or RG&E in the DADRP, there are no customers enrolled through RG&E in EDRP, and only four (4) customers with 0.5 MW enrolled through NYSEG in EDRP, any impact of ending the Companies' tariff programs for EDRP and DADRP would be minimal. Any end use locations currently participating in EDRP through NYSEG would be able to continue their participation through one of the many other NYISO DR Service Providers. NYSEG will advise participating EDRP customers that they intend to end participation in EDRP at the conclusion of the 2020 summer capability period (October 31, 2020) and will provide them with contact information for alternative NYISO Service Providers.

Case Nos. 19-E-0378, et al.
Joint Proposal

NYSEG ELECTRIC
DEPRECIATION RATES

	Account Number	Account Description	Depreciation Life (Yrs)	Salvage Rate	Depreciation Rate	
INTANGIBLE PLANT	303	Miscellaneous Intangible Plant	7	0%	9.14%	
STEAM PLANT	311	Structures and Improvements	35	0%	2.86%	
HYDRO	331	Structures and Improvements	75	-20%	1.60%	
	332	Reservoirs, Dams and Waterways	75	-25%	1.67%	
	333	Water Wheels, Turbines and Generators	75	-25%	1.67%	
	334	Accessory Electric Equipment	60	-20%	2.00%	
	335	Miscellaneous Power Equipment	55	-15%	2.09%	
	336	Roads, Railroads And Bridges	75	0%	1.33%	
OTHER PRODUCTION	341	Structures and Improvements	55	-5%	1.91%	
	342	Fuel Holders, Producers And Accessories	50	-10%	2.20%	
	343	Prime Movers	45	-5%	2.33%	
	344	Generators	50	-5%	2.10%	
	345	Accessory Electric Equipment	35	-5%	3.00%	
TRANSMISSION	352	Structures and Improvements	70	-25%	1.79%	
	353	Station Equipment	65	-10%	1.69%	
	354	Towers and Fixtures	80	-30%	1.63%	
	355	Poles and Fixtures	70	-45%	2.07%	
	356	Overhead Conductors and Devices	70	-55%	2.21%	
	357	Underground Conduit	65	0%	1.54%	
	358	Underground Conductors and Devices	60	-10%	1.83%	
DISTRIBUTION	361	Structures and Improvements	70	-30%	1.86%	
	362	Station Equipment	65	-25%	1.92%	
	363	Battery Storage Equipment	10	0%	10.00%	
	364	Poles, Towers and Fixtures	70	-50%	2.14%	
	365	Overhead Conductors and Devices	75	-60%	2.13%	
	365.02	Overhead Conductors and Devices - Reclosers	18	-30%	7.22%	
	366	Underground Conduit - Manholes	30	-25%	4.17%	
	366.1	Underground Conduit	75	-10%	1.47%	
	367	Underground Conductors and Devices	65	-20%	1.85%	
	368	Line Transformers	55	-20%	2.18%	
	369	Services	52	-70%	3.27%	
	370	Meters (electro-mechanical)	29	-20%	4.14%	
	370	Meters (AMI)	20	0%	5.00%	
	373	Street Lighting and Signal Systems	40	-20%	3.00%	
GENERAL	390	Structures and Improvements	65	-15%	1.77%	
	391	Office Furniture and Equipment	20	0%	5.00%	V
	391.2	Data Processing Equipment	7	0%	9.14%	V
	392.1	Transportation Equipment - Cars and Other Vehicles	10	5%	9.50%	T
	393	Stores Equipment	25	0%	2.56%	V
	394	Tools, Shop and Garage Equipment	25	0%	4.00%	V
	395	Laboratory Equipment	20	0%	3.66%	V
	396	Power Operated Equipment	11	10%	8.18%	V
	396.1	Power Operated Equipment - Vehicle	12	20%	6.67%	V
	397	Communication Equipment	15	0%	5.75%	
	397.1	Communication Equipment - Overhead	35	0%	2.86%	
	398	Miscellaneous Equipment	20	0%	2.95%	V

Notes:

(1) Accounts labeled as V are "Vintage" accounts and will amortize net plant using the above depreciation rates.
(2) Accounts labeled as T are Transportation accounts and are depreciated by asset.
(3) All other accounts are Group accounts and will be depreciated by applying depreciation rates to gross plant.
(4) Account 391.2 rates will also cover software, which is reflected in account 303 per FERC guidance.
(5) Accounts not covered above are considered non-depreciable.
(6) The EDR being amortized annually will be applied on a pro-rated basis to the following depreciation reserve accounts: 355, 358, 364, 365, 368 and 369

NYSEG GAS
DEPRECIATION RATES

	Account Number	Account Description	Depreciation Life (Yrs)	Salvage Rate	Depreciation Rate	
INTANGIBLE PLANT	303	Miscellaneous Intangible Plant	7	0%	14.29%	
DISTRIBUTION	374.1	Land and Land Rights - Rights of Way	60	0%	1.67%	
	375	Structures and Improvements	65	-15%	1.77%	
	376	Mains - Steel	75	-90%	2.53%	
	376.2	Mains - Plastic	75	-25%	1.67%	
	378	Measuring and Regulating Station Equipment	55	-55%	2.82%	
	380	Services - Other	53	-50%	2.83%	
	380.2	Services - Plastic	53	-50%	2.83%	
	381/382	Meters & Meter Installations (mechanical)	28	-15%	4.11%	
	381/382	Meters & Meter Installations (AMI)	20	0%	5.00%	
	383/384	House Regulators & Installations	60	-10%	1.83%	
	385	Industrial Measuring and Regulating Station Equipment	50	-10%	2.20%	
	387	Other Equipment	35	0%	2.86%	
GENERAL	390	Structures and Improvements	40	-10%	2.75%	
	390.3	Structures and Improvements - Leaseholds	20	0%	5.00%	
	391	Office Furniture and Equipment	20	0%	5.00%	V
	391.2	Data Processing Equipment	7	0%	14.29%	V
	392.22	Transportation Equipment - Cars	9	0%	11.11%	T
	392.23	Transportation Equipment - Other Vehicles	9	5%	10.56%	T
	393	Stores Equipment	34	0%	2.96%	V
	394	Tools, Shop and Garage Equipment	25	0%	4.00%	V
	395	Laboratory Equipment	37	0%	2.68%	V
	396	Power Operated Equipment	13	15%	6.54%	V
	397	Communication Equipment	15	0%	6.67%	
	398	Miscellaneous Equipment	20	0%	5.00%	V

Notes:

(1) Accounts labeled as V are "Vintage" accounts and will amortize net plant using the above depreciation rates.
(2) Accounts labeled as T are Transportation accounts and are depreciated by asset.
(3) All other accounts are Group accounts and will be depreciated by applying depreciation rates to gross plant.
(4) Account 391.2 rates will also cover software, which is reflected in account 303 per FERC guidance.
(5) Accounts not covered above are considered non-depreciable.

NYSEG COMMON
DEPRECIATION RATES

	Account Number	Account Description	Depreciation Life (Yrs)	Salvage Rate	Depreciation Rate	
INTANGIBLE PLANT	303	Miscellaneous Intangible Plant	7	0%	11.33%	
GENERAL	390	Structures and Improvements	70	-15%	1.64%	
	391	Office Furniture and Equipment	20	0%	4.32%	V
	391.2	Data Processing Equipment	7	0%	11.33%	V
	391.4	LANS/WANS	7	0%	14.29%	V
	392	Transportation Equipment - Cars	10	10%	9.00%	T
	392.1	Transportation Equipment - In Reserve	9	10%	10.00%	T
	393	Stores Equipment	25	0%	1.55%	V
	394	Tools, Shop and Garage Equipment	32	0%	3.09%	V
	395	Laboratory Equipment	20	0%	5.00%	V
	397	Communication Equipment	15	0%	6.67%	
	398	Miscellaneous Equipment	20	0%	4.91%	V

Notes:

(1) Accounts labeled as V are "Vintage" accounts and will amortize net plant using the above depreciation rates.
(2) Accounts labeled as T are Transportation accounts and are depreciated by asset.
(3) All other accounts are Group accounts and will be depreciated by applying depreciation rates to gross plant.
(4) Account 391.2 rates will also cover software, which is reflected in account 303 per FERC guidance.
(5) Accounts not covered above are considered non-depreciable.

RG&E ELECTRIC
DEPRECIATION RATES

	Account Number	Account Description	Depreciation Life (Yrs)	Salvage Rate	Depreciation Rate	
INTANGIBLE PLANT	303	Miscellaneous Intangible Plant	7	0%	14.29%	
HYDRO	331	Structures and Improvements	75	-20%	1.60%	
	332	Reservoirs, Dams and Waterways	45	-40%	3.11%	
	333	Water Wheels, Turbines and Generators	55	-50%	2.73%	
	334	Accessory Electric Equipment	85	-15%	1.35%	
	335	Miscellaneous Power Equipment	80	-65%	2.06%	
	336	Roads, Railroads And Bridges	90	0%	1.11%	
TRANSMISSION	350.4	Land Rights	75	0%	1.33%	
	352	Structures and Improvements	65	-10%	1.69%	
	353	Station Equipment	60	-15%	1.92%	
	354	Towers and Fixtures	60	-20%	2.00%	
	355	Poles and Fixtures	60	-30%	2.17%	
	356	Overhead Conductors and Devices	60	-15%	1.92%	
	357	Underground Conduit	70	-10%	1.57%	
	358	Underground Conductors and Devices	70	-25%	1.79%	
DISTRIBUTION	360.2	Land Rights	75	0%	1.33%	
	361	Structures and Improvements	70	-10%	1.57%	
	362	Station Equipment	65	-15%	1.77%	
	363	Battery Storage Equipment	10	0%	10.00%	
	364	Poles, Towers and Fixtures	55	-50%	2.73%	
	365	Overhead Conductors and Devices	60	-25%	2.08%	
	366	Underground Conduit	75	-35%	1.80%	
	367	Underground Conductors and Devices	56	-20%	2.14%	
	368	Line Transformers	65	-10%	1.69%	
	369	Services	70	-60%	2.29%	
	370	Meters (electro-mechanical)	29	-15%	3.97%	
	370	Meter (AMI)	20	0%	5.00%	
	373	Street Lighting and Signal Systems	30	-20%	4.00%	
GENERAL	390	Structures and Improvements	55	-20%	2.18%	
	391	Office Furniture	20	0%	3.57%	V
	391.2	Data Processing Equipment	7	0%	14.29%	V
	391.3	Office Equipment	15	0%	2.77%	V
	394	Tools, Shop and Garage Equipment	25	0%	3.43%	V
	395	Laboratory Equipment	20	0%	0.96%	V
	397	Communication Equipment	15	0%	3.63%	
	397.1	Communication Equipment - Overhead/Underground	35	0%	2.86%	
	398	Miscellaneous Equipment	15	0%	6.67%	V

Notes:
(1) Accounts labeled as V are "Vintage" accounts and will amortize net plant using the above depreciation rates.
(2) All other accounts are Group accounts and will be depreciated by applying depreciation rates to gross plant.
(3) Account 391.2 rates will also cover software, which is reflected in account 303 per FERC guidance.
(4) Accounts not covered above are considered non-depreciable.

RG&E GAS
DEPRECIATION RATES

	Account Number		Depreciation Life (Yrs)	Salvage Rate	Depreciation Rate	
INTANGIBLE PLANT	303	Miscellaneous Intangible Plant	7	0%	14.29%	
DISTRIBUTION	374.2	Land Rights	75	0%	1.33%	
	375	Structures and Improvements	45	-15%	2.56%	
	376	Mains - Steel	70	-50%	2.14%	
	376.2	Mains - Plastic	58	-40%	2.41%	
	376.3	Mains - Cast Iron	65	-90%	2.92%	
	378	Measuring and Regulating Station Equipment	46	-25%	2.72%	
	380	Services - Steel	45	-35%	3.00%	
	380.2	Services - Plastic	65	-35%	2.08%	
	381/382	Meters & Installations (mechanical)	35	-10%	3.14%	
	381/382	Meters & Installations (AMI)	20	0%	5.00%	
	383/384	House Regulators & Installations	40	-25%	3.13%	
GENERAL	390	Structures and Improvements	60	-5%	1.75%	
	394	Tools, Shop and Garage Equipment	25	0%	3.82%	V

Notes:
(1) Accounts labeled as V are "Vintage" accounts and will amortize net plant using the above depreciation rates.
(2) All other accounts are Group accounts and will be depreciated by applying depreciation rates to gross plant.
(3) Account 391.2 rates will also cover software, which is reflected in account 303 per FERC guidance.
(4) Accounts not covered above are considered non-depreciable.

RG&E COMMON
DEPRECIATION RATES

	Account Number		Depreciation Life (Yrs)	Salvage Rate	Depreciation Rate	
INTANGIBLE PLANT	303	Miscellaneous Intangible Plant	7	0%	13.09%	V
COMMON	390	Structures and Improvements	42	-25%	2.98%	
	391	Office Furniture	20	0%	3.42%	V
	391.2	Data Processing Equipment	7	0%	13.09%	V
	391.3	Office Equipment	15	0%	1.09%	V
	392.09	Mini Passenger Vans	9	10%	10.00%	T
	392.13	Passenger Cars	8	10%	11.25%	T
	392.32	Full Size Pickups	11	10%	8.18%	T
	392.33	Light Duty Gas Powered Utility Trucks	10	10%	9.00%	T
	392.34	Heavy Duty Gas Powered Utility Trucks	11	10%	8.18%	T
	392.36	Mini Cargo Vans	8	10%	11.25%	T
	392.37	Full Size Cargo Vans	9	10%	10.00%	T
	392.38	Mini Pickups	10	10%	9.00%	T
	392.39	Heavy Duty Diesel Powered Utility Trucks & Equip.	13	10%	6.92%	T
	392.42	Medium Duty Diesel Powered Utility Trucks	12	10%	7.50%	T
	392.43	Medium Duty Gas Powered Utility Trucks	11	10%	8.18%	T
	393	Stores Equipment	30	0%	2.87%	V
	394	Tools, Shop and Garage Equipment	25	0%	2.91%	V
	395	Laboratory Equipment	20	0%	2.83%	V
	396	Power Operated Equipment	13	0%	7.69%	V
	397	Communication Equipment	15	0%	5.38%	
	398	Miscellaneous Equipment	15	0%	6.25%	V

Notes:
(1) Accounts labeled as V are "Vintage" accounts and will amortize net plant using the above depreciation rates.
(2) Accounts labeled as T are Transportation accounts and are depreciated by asset.
(3) All other accounts are Group accounts and will be depreciated by applying depreciation rates to gross plant.
(4) Account 391.2 rates will also cover software, which is reflected in account 303 per FERC guidance.
(5) Accounts not covered above are considered non-depreciable.

NYSEG Electric
Schedule of Regulatory Amortizations
($000)

		A	B		C	D	E	F
		Starting Rate Year Asset / (Liab) Balance	Amortization Period (years)		Inc / (Exp) Rate Year 1 Amortization 4/30/2021	Inc / (Exp) Rate Year 2 Amortization 4/30/2022	Inc / (Exp) Rate Year 3 Amortization 4/30/2023	Projected Balance 4/30/2023
	3-Year Term Amortizations							
1	2018 Windstorm Settlement - Case 19-E-0105	$ (9,000)	3	Note 2	$ 3,000	$ 3,000	$ 3,000	$ -
2	2019 Order - Case 19-E-0302	(2,500)	3		833	833	833	-
3	NRA - SAIFI	(7,000)	3	Note 1	2,333	2,333	2,333	-
4	ACF ASGA - JP Stip 56	(1,300)	3		433	433	433	-
5	ASGA	2,185	3		(728)	(728)	(728)	-
6	Bonus Depreciation NCR	(8,485)	3		2,828	2,828	2,828	-
7	CAIDI/SAIFI Study	19	3		(6)	(6)	(6)	-
8	CapEx Customer Credit 07-M-0906 Merger Order	(1,473)	3		491	491	491	-
9	CapEx Shareholder Deferral	2,272	3		(757)	(757)	(757)	-
10	Cost to Achieve Efficiency Initiatives	139	3		(46)	(46)	(46)	-
11	Def Inc Tax Deferral - Book Depr Rate Change	(1,067)	3		356	356	356	-
12	Economic Development - Remaining Amort (15-E-0283 Appx. V)	1,612	3		(537)	(537)	(537)	-
13	Economic Development - New Amortization	(4,766)	3		1,589	1,589	1,589	-
14	EEPS	(108)	3		36	36	36	-
15	EE Tracker	(23,571)	3		7,857	7,857	7,857	-
16	ESM	(2,622)	3		874	874	874	-
17	Excess DIT - New York State Tax Rate change	73	3		(24)	(24)	(24)	-
18	Medicare Subsidy NCR	(1,802)	3		601	601	601	-
19	MHP Meter Costs	2	3		(1)	(1)	(1)	-
20	Mixed Use 263(a) NCR	(6,187)	3		2,062	2,062	2,062	-
21	NYPA Ancillaries	6	3		(2)	(2)	(2)	-
22	PBA Utilization	(2,958)	3		986	986	986	-
23	Stray Voltage	(4,967)	3		1,656	1,656	1,656	-
24	Theoretical Reserve Inc Tax Flow Through	(6,291)	3		2,097	2,097	2,097	-
25	Unit of Property CTA	21	3		(7)	(7)	(7)	-
26	Post Term Amortization Deferral - 2010 Joint Proposal	3,915	3		(1,305)	(1,305)	(1,305)	-
27	**Subtotal**	**$ (73,853)**			**$ 24,618**	**$ 24,618**	**$ 24,618**	**$ -**
	Other Than 3-Year Amortizations							
28	Credit & Debit Card Fees	$ 4,257	5		$ (851)	$ (851)	$ (851)	$ 1,703
29	Environmental - Remaining Amort (15-E-0283 Appx. V)	(11,112)	7		1,587	1,587	1,587	(6,350)
30	Environmental - New Amortization	5,519	7		(788)	(788)	(788)	3,154
31	Fixed Rate Debt	(27,510)	5		5,502	5,502	5,502	(11,004)
32	Incremental Maintenance	(2,560)	5		512	512	512	(1,024)
33	Low Income Program - Remaining Amort (15-E-0283 Appx. V)	(1,221)	5		244	244	244	(488)
34	Low Income Program - New Amortization	1,547	5		(309)	(309)	(309)	619
35	Management Audit - Remaining Amort (15-E-0283 Appx. V)	(25)	5		5	5	5	(10)
36	Management Audit - New Amortization	835	5		(167)	(167)	(167)	334
37	NEIL Credit	(600)	5		120	120	120	(240)
38	NRA - CAIDI	(3,722)	5		744	744	744	(1,489)
39	NY Transco	(2,745)	5		549	549	549	(1,098)
40	OPEB Deferral - Remaining Amort (15-E-0283 Appx. V)	(12,170)	5		2,434	2,434	2,434	(4,868)
41	OPEB Deferral - New Amortization	(7,597)	5		1,519	1,519	1,519	(3,039)
42	Pension Deferral - Remaining Amort (15-E-0283 Appx. V)	19,262	5		(3,852)	(3,852)	(3,852)	7,705
43	Pension Deferral - New Amortization	40,153	5		(8,031)	(8,031)	(8,031)	16,061
44	Pole Attachment Revenue Requirement	4,374	5		(875)	(875)	(875)	1,750
45	PRA - Terminations & Uncollectibles	778	5		(156)	(156)	(156)	311
46	Property Tax Deferral - Remaining Amort (15-E-0283 Appx. V)	8,469	5		(1,694)	(1,694)	(1,694)	3,388
47	Property Tax Deferral - New Amortization	(15,024)	5		3,005	3,005	3,005	(6,010)
48	PSC Assessment	(263)	5		53	53	53	(105)
49	Rate Increase Levelization Amortization	(6,526)	5		1,305	1,305	1,305	(2,611)
50	REV Incremental Costs	10,490	5		(2,098)	(2,098)	(2,098)	4,196
51	Reliability Support Services	(13)	5		3	3	3	(5)
52	Storm - Non-Superstorm - Remaining Amort (15-E-0283 Appx. V)	32,986	5		(6,597)	(6,597)	(6,597)	13,194
53	Storm - Non-Superstorm - New Amortization	119,194	10		(11,919)	(11,919)	(11,919)	83,436
54	Storm - Superstorm	74,754	10		(7,475)	(7,475)	(7,475)	52,328
55	Variable Rate Debt - Remaining Amort (15-E-0283 Appx. V)	(2,371)	5		474	474	474	(948)
56	Variable Rate Debt - New Amortization	(2,950)	5		590	590	590	(1,180)
57	Vegetation Management - Danger Tree Deferral $10M/yr beginning in RY2		5		(2,000)	(4,000)	(6,000)	(12,000)
58	**Subtotal**	**$ 226,211**			**$ (28,167)**	**$ (30,167)**	**$ (32,167)**	**$ 135,710**
	Income Tax Related Amortizations							
59	Excess DIT - TCJA - Protected Amortization	$ (296,621)	ARAM	See Note 3	$ 7,728	$ 7,380	$ 7,325	$ (274,187)
60	Excess DIT - TCJA - Protected Pre-RY1 Liability	(16,678)	1		16,678	-	-	-
61	Excess DIT - TCJA - Unprotected Amortization	(65,409)	3		21,803	21,803	21,803	-
62	Federal Tax Reform - Jan-Sep 2018 Savings Amortization	(19,433)	1		19,433	-	-	-
63	PowerTax Regulatory Asset	82,038	23	See Note 4	(3,567)	(3,567)	(3,567)	71,338
64	Unfunded Future Income Taxes	(36,274)	46	""	789	789	789	(33,908)
65	Unfunded Future Income Taxes - NCR	243	5		(49)	(49)	(49)	97
66	**Subtotal**	**$ (352,134)**			**$ 62,815**	**$ 26,356**	**$ 26,301**	**$ (236,661)**
67	**Excess Depreciation Reserve Amortization**				**$ 30,850**	**$ 34,950**	**$ 39,100**	
68	**Total - NYSEG Electric**	**$ (199,776)**			**$ 90,116**	**$ 55,757**	**$ 57,852**	**$ (100,951)**

Make Whole Provision:

69 NYSEG Electric will not compress Rate Year 1 rates and will amortize Excess Depreciation Reserve (EDR) balances to cover the revenue increase associated with the make whole period. The EDR amortization amounts will neither be included in rate base in setting revenue requirement, nor will these amounts accrue carrying costs during the rate plan term.

70 **Notes**: See Post Term Amortization Deferral and Notes schedule

NYSEG Gas
Schedule of Regulatory Amortizations
($000)

		A	B		C	D	E	F
		Starting Rate Year Asset / (Liab) Balance	Amortization Period (years)		Inc / (Exp) Rate Year 1 Amortization 4/30/2021	Inc / (Exp) Rate Year 2 Amortization 4/30/2022	Inc / (Exp) Rate Year 3 Amortization 4/30/2023	Projected Balance 4/30/2023
	3-Year Term Amortizations							
1	Bonus Depreciation NCR	$ (1,529)	3		$ 510	$ 510	$ 510	$ -
2	Cost to Achieve Efficiency Initiatives	(15)	3		5	5	5	-
3	EEPS	(25)	3		8	8	8	-
4	EEPS Loss Revenue Gas	4	3		(1)	(1)	(1)	-
5	EE Tracker	(4,846)	3		1,615	1,615	1,615	-
6	Excess DIT - NYS Tax Rate change	1,532	3		(511)	(511)	(511)	-
7	Gains/Losses on Surplus Sales - Gas	(9)	3		3	3	3	-
8	Gas Phase 2A/B	11	3		(4)	(4)	(4)	-
9	Gas R&D Tax Credit	(163)	3		54	54	54	-
10	IRS Audit	11	3		(4)	(4)	(4)	-
11	Medicare Subsidy NCR	(1,046)	3		349	349	349	-
12	Mixed Use 263(a) NCR	(1,811)	3		604	604	604	-
13	Net Plant Reconciliation	(30)	3		10	10	10	-
14	Outreach & Education	67	3		(22)	(22)	(22)	-
15	Pension Costs	(1,790)	3		597	597	597	-
16	PBA Utilization	51	3		(17)	(17)	(17)	-
17	Sarbanes-Oxley	40	3		(13)	(13)	(13)	-
18	Seneca Pipeline Integrity Initiative	(47)	3		16	16	16	-
19	Seneca Storage	(47)	3		16	16	16	-
20	Seneca Sale - ASGA Amort	(289)	3		96	96	96	-
21	Seneca Sale - Operational Savings	(133)	3		44	44	44	-
22	Unit of Property CTA	437	3		(146)	(146)	(146)	-
23	Post Term Amortization Deferral - 2010 Joint Proposal	(875)	3		292	292	292	-
24	**Subtotal**	**$ (10,503)**			**$ 3,501**	**$ 3,501**	**$ 3,501**	**$ -**
	Other Than 3-Year Amortizations							
25	Community Development Fund	$ (150)	5		$ 30	$ 30	$ 30	$ (60)
26	Credit & Debit Card Fees	1,266	5		(253)	(253)	(253)	506
27	Economic Development - Remaining Amort (15-E-0283 Appx. V)	(389)	0		-	-	-	(389)
28	Economic Development - New Amortization	(1,676)	0		-	-	-	(1,676)
29	Environmental - Remaining Amort (15-E-0283 Appx. V)	(3,705)	7		529	529	529	(2,117)
30	Environmental - New Amortization	143	7		(20)	(20)	(20)	82
31	ESM	(2,758)	5		552	552	552	(1,103)
32	Fixed Rate Debt	(9,307)	5		1,861	1,861	1,861	(3,723)
33	Gas R&D Deferral - Remaining Amort (15-E-0283 Appx. V)	(1,045)	5		209	209	209	(418)
34	Gas R&D Deferral - New Amortization	(558)	5		112	112	112	(223)
35	Incremental Maintenance - Remaining Amort (15-E-0283 Appx. V)	(7)	5		1	1	1	(3)
36	Incremental Maintenance - New Amortization	(155)	5		31	31	31	(62)
37	Low Income Program - Remaining Amort (15-E-0283 Appx. V)	3,199	5		(640)	(640)	(640)	1,279
38	Low Income Program - New Amortization	1,202	5		(240)	(240)	(240)	481
39	Management Audit - Remaining Amort (15-E-0283 Appx. V)	(96)	5		19	19	19	(38)
40	Management Audit - New Amortization	274	5		(55)	(55)	(55)	110
41	NRA - Gas Safety	-	0		-	-	-	-
42	OPEB Deferral - Remaining Amort (15-E-0283 Appx. V)	(2,564)	5		513	513	513	(1,025)
43	OPEB Deferral - New Amortization	(776)	5		155	155	155	(310)
44	Pension Deferral - Remaining Amort (15-E-0283 Appx. V)	5,843	5		(1,169)	(1,169)	(1,169)	2,337
45	Pension Deferral - New Amortization	11,167	5		(2,233)	(2,233)	(2,233)	4,467
46	Gas Pipeline Integrity Costs - Remaining Amort (15-E-0283 Appx. V)	(97)	5		19	19	19	(39)
47	Gas Pipeline Integrity Costs - New Amortization	(429)	5		86	86	86	(171)
48	PRA - Leak Prone Main	716	5		(143)	(143)	(143)	287
49	PRA - Gas Enhancement Performance Incentive	45	5		(9)	(9)	(9)	18
50	PRA - Terminations & Uncollectibles	164	5		(33)	(33)	(33)	66
51	Property Tax Deferral - Remaining Amort (15-E-0283 Appx. V)	2,110	5		(422)	(422)	(422)	844
52	Property Tax Deferral - New Amortization	(2,560)	5		512	512	512	(1,024)
53	PSC Assessment	(123)	5		25	25	25	(49)
54	Rate Increase Levelization Amortization	(7,055)	5		1,411	1,411	1,411	(2,822)
55	REV Incremental Costs	12	5		(2)	(2)	(2)	5
56	Variable Rate Debt - Remaining Amort (15-E-0283 Appx. V)	(690)	5		138	138	138	(276)
57	Variable Rate Debt - New Amortization	(876)	5		175	175	175	(350)
58	Vegetation Management - Remaining Amort (15-E-0283 Appx. V)	(23)	5		5	5	5	(9)
59	Vegetation Management - New Amortization	(91)	5		18	18	18	(37)
60	**Subtotal**	**$ (8,989)**			**$ 1,181**	**$ 1,181**	**$ 1,181**	**$ (5,445)**
	Income Tax Related Amortizations							
61	Excess DIT - TCJA - Protected Amortization	$ (71,752)	ARAM	See Note 3	$ 1,869	$ 1,785	$ 1,772	$ (66,326)
62	Excess DIT - TCJA - Protected Pre-RY1 Liability	(4,035)	3		1,345	1,345	1,345	-
63	Excess DIT - TCJA - Unprotected Amortization	(18,458)	10		1,846	1,846	1,846	(12,921)
64	Federal Tax Reform - Jan-Sep 2018 Savings Amortization	(3,048)	1.5		2,032	1,016	-	-
65	PowerTax Regulatory Asset	7,720	35	See Note 4	(221)	(221)	(221)	7,058
66	Unfunded Future Income Taxes	25,262	46	""	(549)	(549)	(549)	23,615
67	Unfunded Future Income Taxes - NCR	(6,035)	5		1,207	1,207	1,207	(2,414)
68	**Subtotal**	**$ (70,345)**			**$ 7,529**	**$ 6,429**	**$ 5,400**	**$ (50,987)**
69	**Total - NYSEG Gas**	**$ (89,838)**			**$ 12,212**	**$ 11,111**	**$ 10,082**	**(56,432)**

70 **Notes**: See Post Term Amortization Deferral and Notes schedule

RG&E Electric
Schedule of Regulatory Amortizations
($000)

		A	B		C	D	E	F
		Starting Rate Year Asset / (Liab) Balance	Amortization Period (years)		Inc / (Exp) Rate Year 1 Amortization 4/30/2021	Inc / (Exp) Rate Year 2 Amortization 4/30/2022	Inc / (Exp) Rate Year 3 Amortization 4/30/2023	Projected Balance 4/30/2023
	Specific or 3-Year Term Amortizations							
1	ASGA	$ (10,851)	Specific	See Note 1	$ 5,370	$ 5,481	$ -	$ -
2	Bonus Depreciation NCR	(18,974)	Specific	See Note 1	3,795	5,984	9,195	-
3	Fixed Rate Debt	(16,501)	Specific	See Note 1	3,300	3,300	7,820	(2,080)
4	2018 Windstorm Settlement - Case 19-E-0105	(1,500)	3	See Note 2	500	500	500	-
5	EEPS	(53)	3		18	18	18	-
6	EE Tracker	(14,624)	3		4,875	4,875	4,875	-
7	**Subtotal**	**$ (62,503)**			**$ 17,857**	**$ 20,157**	**$ 22,407**	**$ (2,080)**
	Other Than 3-Year Amortizations							
8	Allegheny Sale Loss and Savings	$ (5,121)	5		$ 1,024	$ 1,024	$ 1,024	$ (2,048)
9	Beebee Decommissioning	(764)	5		153	153	153	(306)
10	CAIDI/SAIFI Study	95	5		(19)	(19)	(19)	38
11	Cap Ex NCR 03-E-0765, et al	3,401	5		(680)	(680)	(680)	1,360
12	CapEx Customer Credit 07-M-0906 Merger Order	(10,000)	5		2,000	2,000	2,000	(4,000)
13	Cost to Achieve Efficiency Initiatives	105	5		(21)	(21)	(21)	42
14	Credit & Debit Card Fees	1,781	5		(356)	(356)	(356)	713
15	Economic Development - Remaining Amort (15-E-0283 Appx. V)	(17,052)	$3M/Yr		3,000	3,000	3,000	(8,052)
16	Economic Development - New Amortization	(571)	0		-	-	-	(571)
17	Electric Reliability Organization	304	5		(61)	(61)	(61)	121
18	Environmental - Remaining Amort (15-E-0283 Appx. V)	(21,617)	7		3,088	3,088	3,088	(12,352)
19	Environmental - New Amortization	(14,550)	7		2,079	2,079	2,079	(8,314)
20	ESM - Remaining Amort (15-E-0283 Appx. V)	(5,422)	5		1,084	1,084	1,084	(2,169)
21	ESM - New Amortization	(2,170)	5		434	434	434	(868)
22	Excess DIT - NYS Tax Rate	(2,898)	5		580	580	580	(1,159)
23	Incremental Maintenance - New Amortization	(167)	5		33	33	33	(67)
24	IRS Audit - 1998-2001	70	5		(14)	(14)	(14)	28
25	Low Income Program - Remaining Amort (15-E-0283 Appx. V)	(3,634)	5		727	727	727	(1,454)
26	Low Income Program - New Amortization	20,296	5		(4,059)	(4,059)	(4,059)	8,118
27	Management Audit - Remaining Amort (15-E-0283 Appx. V)	(217)	5		43	43	43	(87)
28	Management Audit - New Amortization	50	5		(10)	(10)	(10)	20
29	Medicare Part D	(241)	5		48	48	48	(96)
30	MHP Meter Costs	(4)	5		1	1	1	(2)
31	Mixed Use 263(a) NCR	(4,241)	5		848	848	848	(1,696)
32	NEIL Credit	(6,357)	5		1,271	1,271	1,271	(2,543)
33	Net Plant Reconciliation - Remaining Amort (15-E-0283 Appx. V)	(9,623)	5		1,925	1,925	1,925	(3,849)
34	Net Plant Reconciliation - New Amortization	(12,978)	5		2,596	2,596	2,596	(5,191)
35	Nine Mile II - TCCs - Remaining Amort (15-E-0283 Appx. V)	(11,472)	5		2,294	2,294	2,294	(4,589)
36	Nine Mile II - TCCs - New Amortization	(9,673)	5		1,935	1,935	1,935	(3,869)
37	Nuclear Fuel DOE Liability True-up - Remaining Amort (15-E-0283 Appx. V)	(12,188)	5		2,438	2,438	2,438	(4,875)
38	Nuclear Fuel DOE Liability True-up - New Amortization	2,888	5		(578)	(578)	(578)	1,155
39	NYS Tax Audit	228	5		(46)	(46)	(46)	91
40	NYS Tax Rate	(319)	5		64	64	64	(128)
41	OPEB Deferral - Remaining Amort (15-E-0283 Appx. V)	(1,559)	5		312	312	312	(623)
42	OPEB Deferral - New Amortization	(219)	5		44	44	44	(88)
43	PBA Utilization	(32,987)	5		6,597	6,597	6,597	(13,195)
44	Pension Deferral - Remaining Amort (15-E-0283 Appx. V)	21,403	5		(4,281)	(4,281)	(4,281)	8,561
45	Pension Deferral - New Amortization	8,101	5		(1,620)	(1,620)	(1,620)	3,240
46	PRA - Terminations & Uncollectibles	171	5		(34)	(34)	(34)	68
47	Property Tax Deferral - New Amortization	(12,105)	5		2,421	2,421	2,421	(4,842)
48	Rate Increase Levelization Amortization	364	5		(73)	(73)	(73)	146
49	Property Tax 481(a) - NCR	(346)	5		69	69	69	(138)
50	PSC Assessment	(126)	5		25	25	25	(50)
51	REV Incremental Costs	5,013	5		(1,003)	(1,003)	(1,003)	2,005
52	Russell Decommissioning	4,143	5		(829)	(829)	(829)	1,657
53	ROW Tree Trim	1,480	5		(296)	(296)	(296)	592
54	Sarbanes-Oxley	386	5		(77)	(77)	(77)	155
55	Service Quality Performance	(393)	5		79	79	79	(157)
56	SO2 Allowance	(829)	5		166	166	166	(332)
57	Storm - Non-Superstorm - Remaining Amort (15-E-0283 Appx. V)	(4,163)	5		833	833	833	(1,665)
58	Storm - Non-Superstorm - New Amortization	53,183	5		(10,637)	(10,637)	(10,637)	21,273
59	Stray Voltage	585	5		(117)	(117)	(117)	234
60	Theoretical Reserve Inc Tax Flow Through- Remaining Amort (15-E-0283 Appx. V)	(6,279)	5		1,256	1,256	1,256	(2,512)
61	Unit of Property CTA	76	5		(15)	(15)	(15)	30
62	Variable Rate Debt- Remaining Amort (15-E-0283 Appx. V)	(284)	5		57	57	57	(114)
63	Variable Rate Debt - New Amortization	1,447	5		(289)	(289)	(289)	579
64	Vegetation Management	(682)	5		136	136	136	(273)
65	Vegetation Management - Danger Tree Deferral $1.575M/yr		5		(315)	(630)	(945)	(1,890)
66	Post Term Amortization Deferral - 2010 Joint Proposal	(1,590)	5		318	318	318	(636)
67	**Subtotal**	**$ (87,269)**			**$ 14,548**	**$ 14,233**	**$ 13,918**	**$ (44,571)**
	Income Tax Related Amortizations							
68	Excess DIT - TCJA - Protected Amortization	$ (207,111)	ARAM	Note 3	$ 3,963	$ 4,119	$ 4,196	$ (194,833)
69	Excess DIT - TCJA - Protected Pre-RY1 Liability	(8,957)	3		2,986	2,986	2,986	-
70	Excess DIT - TCJA - Unprotected Amortization	(12,358)	3		4,119	4,119	4,119	-
71	Federal Tax Reform - Jan-Sep 2018 Savings Amortization	(6,934)	1.5		4,623	2,311	-	-
72	PowerTax Regulatory Asset	36,031	35	Note 4	(1,029)	(1,029)	(1,029)	32,943
73	Unfunded Future Income Taxes	132,082	46	""	(2,871)	(2,871)	(2,871)	123,468
74	Unfunded Future Income Taxes - NCR	(29,947)	5		5,989	5,989	5,989	(11,979)
75	**Subtotal**	**$ (97,195)**			**$ 17,780**	**$ 15,624**	**$ 13,390**	**$ (50,401)**
76	**Total - RG&E Electric**	**$ (246,967)**			**$ 50,185**	**$ 50,014**	**$ 49,715**	**$ (97,052)**

Make Whole Provision:

77 RG&E Electric will not compress Rate Year 1 rates and will amortize Excess Depreciation Reserve (EDR) balances to cover the revenue increase associated with the make whole period. The EDR amortization amounts will neither be included in rate base in setting revenue requirement, nor will these amounts accrue carrying costs during the rate plan term.

78 **Notes**: See Post Term Amortization Deferral and Notes schedule

RG&E Gas
Schedule of Regulatory Amortizations
($000)

		A	B		C	D	E	F
		Starting Rate Year Asset / (Liab) Balance	Amortization Period (years)		Inc / (Exp) Rate Year 1 Amortization 4/30/2021	Inc / (Exp) Rate Year 2 Amortization 4/30/2022	Inc / (Exp) Rate Year 3 Amortization 4/30/2023	Projected Balance 4/30/2023
	1 & 3-Year Term Amortizations							
1	NRA - Damage Prevention	$ (550)	1		$ 550	$ -	$ -	$ -
2	PRA - Leak Prone Main	579	1		(579)	-	-	-
3	EE Tracker	(1,006)	3		335	335	335	-
4	**Subtotal**	**$ (978)**			**$ 307**	**$ 335**	**$ 335**	**$ -**
	Other Than 1 & 3-Year Amortizations							
5	Bonus Depreciation NCR	$ (14,295)	5		$ 2,859	$ 2,859	$ 2,859	$ (5,718)
6	Cap Ex NCR 03-E-0765, et al	646	5		(129)	(129)	(129)	258
7	Cost to Achieve Efficiency Initiatives	114	5		(23)	(23)	(23)	45
8	Community Development Fund	(150)	5		30	30	30	(60)
9	Credit & Debit Card Fees	1,466	5		(293)	(293)	(293)	586
10	Economic Development - Remaining Amort (15-E-0283 Appx. V)	(1,127)	0		-	-	-	(1,127)
11	Economic Development - New Amortization	(669)	0		-	-	-	(669)
12	EEPS - Remaining Amort (15-E-0283 Appx. V)	35	5		(7)	(7)	(7)	14
13	EEPS - New Amortization	(12,394)	5		2,479	2,479	2,479	(4,957)
14	Environmental - Remaining Amort (15-E-0283 Appx. V)	(8,787)	7		1,255	1,255	1,255	(5,021)
15	Environmental - New Amortization	(7,610)	7		1,087	1,087	1,087	(4,349)
16	Excess DIT - NYS Tax Rate change	(840)	5		168	168	168	(336)
17	Fixed Rate Debt	(4,268)	5		854	854	854	(1,707)
18	ESM - Remaining Amort (15-E-0283 Appx. V)	(1,111)	5		222	222	222	(445)
19	ESM - New Amortization	(1,824)	5		365	365	365	(730)
20	Incremental Maintenance - Remaining Amort (15-E-0283 Appx. V)	(266)	5		53	53	53	(107)
21	Incremental Maintenance - New Amortization	(532)	5		106	106	106	(213)
22	IRS Audit - 1998-2001	(199)	5		40	40	40	(80)
23	Low Income Program - Remaining Amort (15-E-0283 Appx. V)	(855)	5		171	171	171	(342)
24	Low Income Program - New Amortization	(8,841)	5		1,768	1,768	1,768	(3,537)
25	Management Audit - Remaining Amort (15-E-0283 Appx. V)	(38)	5		8	8	8	(15)
26	Management Audit - New Amortization	37	5		(7)	(7)	(7)	15
27	Medicare Part D	(362)	5		72	72	72	(145)
28	Mixed Use 263(a) NCR	(1,585)	5		317	317	317	(634)
29	Net Plant Reconciliation	(67)	5		13	13	13	(27)
30	NRA - Gas Safety	-	0		-	-	-	-
31	NYS Tax Audit	624	5		(125)	(125)	(125)	249
32	NYS Tax Rate	(516)	5		103	103	103	(206)
33	OPEB Deferral - Remaining Amort (15-E-0283 Appx. V)	(1,070)	5		214	214	214	(428)
34	OPEB Deferral - New Amortization	(1,019)	5		204	204	204	(408)
35	PBA Utilization	348	5		(70)	(70)	(70)	139
36	Pension Deferral - Remaining Amort (15-E-0283 Appx. V)	12,971	5		(2,594)	(2,594)	(2,594)	5,188
37	Pension Deferral - New Amortization	(1,670)	5		334	334	334	(668)
38	Gas Pipeline Integrity Costs - Remaining Amort (15-E-0283 Appx. V)	677	5		(135)	(135)	(135)	271
39	Gas Pipeline Integrity Costs - New Amortization	(715)	5		143	143	143	(286)
40	PRA - Gas Enhancement Performance Incentive	391	5		(78)	(78)	(78)	157
41	PRA - Terminations & Uncollectibles	132	5		(26)	(26)	(26)	53
42	Property Tax Deferral - Remaining Amort (15-E-0283 Appx. V)	(18,324)	5		3,665	3,665	3,665	(7,330)
43	Property Tax Deferral - New Amortization	(4,267)	5		853	853	853	(1,707)
44	Property Tax 481(a) - NCR	(151)	5		30	30	30	(61)
45	PSC Assessment	(295)	5		59	59	59	(118)
46	Purchase of Receivables Discount	1,335	5		(267)	(267)	(267)	534
47	Gas R&D Deferral - Remaining Amort (15-E-0283 Appx. V)	(135)	5		27	27	27	(54)
48	Gas R&D Deferral - New Amortization	(252)	5		50	50	50	(101)
49	Gas R&D Tax Credit	(190)	5		38	38	38	(76)
50	REV Incremental Costs	3	5		(1)	(1)	(1)	1
51	Sarbanes-Oxley	194	5		(39)	(39)	(39)	78
52	Service Quality Performance Program - Remaining Amort (15-E-0283 Appx. V)	(415)	5		83	83	83	(166)
53	Service Quality Performance Program - New Amortization	(618)	5		124	124	124	(247)
54	Unit of Property CTA	232	5		(46)	(46)	(46)	93
55	Variable Rate Debt - Remaining Amort (15-E-0283 Appx. V)	14	5		(3)	(3)	(3)	6
56	Variable Rate Debt - New Amortization	543	5		(109)	(109)	(109)	217
57	Vegetation Management- Remaining Amort (15-E-0283 Appx. V)	(228)	5		46	46	46	(91)
58	Vegetation Management- New Amortization	(267)	5		53	53	53	(107)
59	Post Term Amortization Deferral - 2010 Joint Proposal	4,520	5		(904)	(904)	(904)	1,808
60	**Subtotal**	**$ (71,672)**			**$ 13,038**	**$ 13,038**	**$ 13,038**	**$ (32,557)**
	Income Tax Related Amortizations							
61	Excess DIT - TCJA - Protected Amortization	$ (67,341)	ARAM	Note 3	$ 1,289	$ 1,339	$ 1,364	$ (63,349)
62	Excess DIT - TCJA - Protected Pre-RY1 Liability	(2,912)	3		971	971	971	-
63	Excess DIT - TCJA - Unprotected Amortization	2,946	10		(295)	(295)	(295)	2,062
64	Federal Tax Reform - Jan-Sep 2018 Savings Amortization	(2,173)	1.5		1,449	724	-	-
65	PowerTax Regulatory Asset	11,510	30	Note 4	(384)	(384)	(384)	10,359
66	Unfunded Future Income Taxes	25,939	46	""	(564)	(564)	(564)	24,247
67	Unfunded Future Income Taxes - NCR	(2,848)	5		570	570	570	(1,139)
68	**Subtotal**	**$ (34,880)**			**$ 3,035**	**$ 2,362**	**$ 1,663**	**$ (27,820)**
69	**Total - RG&E Gas**	**$ (107,530)**			**$ 16,381**	**$ 15,736**	**$ 15,036**	**$ (60,377)**

NYSEG and RG&E
Post Term Amortization Deferral and Notes
($000)

All Companies
Rate Levelization Deferral: Beginning May 1, 2023 any rate levelized business will defer the Rate Year 3 revenue requirement impact of any rate levelization or rate shaping built into Rate Year 3 rates.

Post Term Amortization Deferral - Rate Years 4 & 5:
The Rate Year 3 Annual Amortization amounts listed below will cease on April 30, 2023. In the event that the Companies do not file for new rates effective May 1, 2023, the Companies will defer regulatory assets for the revenue requirement effect associated with expiring amortizations from Rate Year 3.

			A	B
	( ) Denotes an expense		**Post Term Amortization Deferral Rate Year 4**	**Post Term Amortization Deferral Rate Year 5**
	NYSEG Electric:			
1	Total - 3Yr Amortizations - pg. 1, line 27		$ 24,618	$ 24,618
2	Excess DIT - TCJA - Unprotected - pg. 1, line 61		21,803	21,803
3	**Total Post Term Deferral - NYSEG Electric**		**$ 46,421**	**$ 46,421**
	NYSEG Gas:			
4	Total - 3Yr Amortizations - pg. 2, line 24		$ 3,501	$ 3,501
5	Excess DIT - TCJA - Protected Pre-RY1 - pg. 2, line 62		1,345	1,345
6	**Total Post Term Deferral - NYSEG Gas**		**$ 4,846**	**$ 4,846**
	RG&E Electric:			
7	Fixed Rate Debt - pg. 3, line 3	Note 1	$ 5,740	$ 7,820
8	3 Yr term Amortizations - pg. 3, lines 2, 4 - 6		14,587	14,587
9	Excess DIT - TCJA - Protected Pre-RY1 - pg. 3, line 69		2,986	2,986
10	Excess DIT - TCJA - Unprotected - pg. 3, line 70		4,119	4,119
11	**Total Post Term Deferral - RG&E Electric**		**$ 27,432**	**$ 29,512**
	RG&E Gas:			
12	Total - 1 Yr & 3Yr Amortizations - pg. 4, line 4		$ 335	$ 335
13	Excess DIT - TCJA - Protected Pre-RY1 - pg. 4, line 62		971	971
14	**Total Post Term Deferral - RG&E Gas**		**$ 1,306**	**$ 1,306**
15	**NYSEG - Site Investigation Remediation (SIR)**	Note 2	$ 6,000	$ 6,000
16	**Grand Total**		**$ 86,005**	**$ 88,086**

Post Term Notes
Note 1: RG&E Electric Fixed Rate Debt - Rate Year 4 amortization deferral is net of the remaining balance at 4/30/23.
The Rate Year 5 amortization deferral is at the full Rate Year 3 amortization amount.

Note 2: NYSEG Electric SIR of $4.816m and NYSEG Gas SIR of $1.184m will not continue after Rate Year 3 and during any post-tern stayout this SIR adjustment will be included in the post-term deferral.

NYSEG Notes from NYSEG Electric and NYSEG Gas schedules
Note 1: Amortize over 3 years as a rate moderator.

Note 2: 2018 Windstorm Settlement is an amount of $9.0M to be amortized over 3 years as a rate moderator.

Note 3: The Excess DIT - Protected annual amortization amount reflects the Average Rate Assumption Method.
Therefore, the annual amortization amount will vary from year to year.

Note 4: PowerTax Regulatory Asset - Amortization period was determined using the original assigned life of 27 years and reduced by the approximate four years of amortization that have occurred between 5/1/16 and 3/31/20.
Unfunded Future Income Tax - Amortization period was determined using the original assigned life of 50 years and reduced by the approximate four years of amortization that have occurred between 5/1/16 and 3/31/20.

RG&E Notes from RG&E Electric and RG&E Gas schedules
Note 1: Amortizations shaped

Note 2: 2018 Windstorm Settlement is an amount of $1.5M to be amortized over 3 years as a rate moderator.

Note 3: The Excess DIT - Protected annual amortization amount reflects the Average Rate Assumption Method.
Therefore, the annual amortization amount will vary from year to year.

Note 4: PowerTax Regulatory Asset - Amortization period was determined using the original assigned life of 39 years and reduced by the approximate four years of amortization that have occurred between 5/1/16 and 3/31/20.
Unfunded Future Income Tax - Amortization period was determined using the original assigned life of 50 years and reduced by the approximate four years of amortization that have occurred between 5/1/16 and 3/31/20.

Electric Revenue Allocation and Rate Design

New York State Electric & Gas Corporation – Electric
Rochester Gas and Electric Corporation – Electric

Cost of Service

In their next electric rate cases, the Companies will develop a method to perform a zero-intercept or minimum system study, or some other equitable allocation, for classifying electric distribution plant (Accounts 364-368) between customer and demand. The Companies will provide Electric Embedded Cost of Service ("ECOS") studies based on the results of this analysis.

i. The Companies will convene a meeting to explain the methodology they plan to use for their study to classify electric distribution plant. The Companies will target the meeting to be held during the last six months of RY2.
ii. Within 30 days after filing their next rate cases, the Companies will convene a technical conference to explain the results of the electric distribution plant classification.

In their next electric rate cases, the Companies will file the results of the ECOS studies that classify electric distribution plant (Accounts 364-368) on a 100% demand basis (for illustrative purposes only).

Notwithstanding the foregoing, the Companies are free to recommend the use of any cost study they believe is appropriate.

Energy Efficiency Costs in Base Delivery Rates

The base delivery rates include Energy Efficiency ("EE") Tracker costs for energy efficiency programs that are administered by the Companies and are currently collected through the System Benefits Charge ("SBC") consistent with the Commission's Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025, issued January 16, 2020 in Case 18-M-0084 ("January 16, 2020 Order"), and the proposed utilization of unspent funds through 2019. The base delivery rates also include costs associated with Electric Heat Pump programs to be administered by the Companies as determined by the January 16, 2020 Order issued in Case 18-M-0084. Upon implementation of new delivery rates, the Companies will discontinue the EE Tracker component of the SBC surcharge currently applied to customer bills. Customers taking service from the Companies that are currently exempt from paying the SBC surcharge will continue to receive an exemption from costs associated with EE Tracker and Electric Heat Pump programs through a delivery rate credit that will be listed on those customers' bills.

The dollar amounts allocated to electric service classes for each Rate Year for these programs, as well as the per unit credits that will be applied to the bills of the SBC-exempt customers for each Rate Year, are set forth in Schedule A for NYSEG and Schedule B for RG&E to this Appendix. For SBC-exempt customers that take service under standby rates, the credit may be adjusted subject to modifications to standby rates under consideration in Case 15-E-0751 – In the Matter of the Value of Distributed Energy Resources.

Revenue Allocation

The Signatory Parties recognize that the revenue allocation determined in these proceedings does not use or otherwise reflect any one ECOS study sponsored by any party in these proceedings in reaching agreement on each Company's allocation of the revenue increases to service classifications.

The base delivery revenue increases begin with the total levelized/shaped delivery revenue increases as presented in Appendix A, net of Gross Receipts Taxes. The revenue allocation process consists first of separate allocations to service classes for: energy efficiency costs associated with EE Tracker, energy efficiency costs associated with Heat Pumps, Advanced Metering Infrastructure ("AMI") costs associated with Information Technology ("IT") infrastructure, AMI costs associated with all other investments and expenses, and incremental costs associated with Distribution Vegetation Management for NYSEG. The residual revenue requirement (i.e., the total base delivery revenue increase net of the increases associated with the aforementioned separate allocations) is allocated to service classes as shown in this Appendix. The delivery revenue increases also account for adjustments for standby rate changes.

The separate allocations to service classifications are summarized below.

- Energy Efficiency – EE Tracker costs are allocated to service classes as follows: for NYSEG, 83.81% based on energy (i.e., kWh); 5.84% based on a 2 Coincident Peak ("CP") demand allocator; 4.34% based on a 12 CP demand allocator; 2.42% based on a primary non-coincident peak ("NCP") demand allocator; and 3.59% based on a secondary NCP demand allocator. For RG&E, 83.43% based on energy (i.e., kWh); 6.53% based on a 1 CP demand allocator; 3.38% based on a 12 CP demand allocator; 1.72% based on a primary NCP demand allocator; and 4.95% based on a secondary NCP demand allocator.

- Energy Efficiency – Heat Pumps costs are split 85%/15% between residential and non-residential service classes. Costs are allocated to the respective service classes based on total energy (i.e., kWh).

- Incremental Distribution Vegetation Management costs for NYSEG are allocated to service classes based on the allocators per the ECOS study for distribution management costs (i.e., Account 593-Maintenance of Overhead Lines).

- AMI costs associated with IT infrastructure, such as IT hardware and software, are allocated to service classes based on the labor expense allocation factors per the ECOS study.

- AMI costs associated with all other investments and expenses, such as meters and communications network equipment, are allocated to service classes based on weighted average meter costs.

The overall resulting base delivery revenue increases by service class, and the delivery increases associated with the aforementioned separate revenue allocations and the residual revenue requirement by service class, are set forth in Schedule C to this Appendix.

Rate Design

Standard Service Classes

The delivery revenue requirement is recovered through customer charges ($/month), volumetric (per kWh) delivery charges and/or demand (per kW) delivery charges, and reactive (rKVa) charges. Customer charges for the NYSEG and RG&E electric service classes are increased as listed in the tables below. The revenue requirement, net of the customer charge revenue for each service class, is recovered through volumetric delivery charges for the non-demand classes, and through demand delivery charges for the demand classes. For service classes with both volumetric delivery charges and demand delivery charges, priority was given to collect the remaining delivery revenue requirement through demand charges first, and then through volumetric charges. Reactive charges remain unchanged from current levels.

NYSEG ELECTRIC SERVICE CLASS	Current Monthly Customer Charge	Monthly Customer Charge Rate Year 1	Monthly Customer Charge Rate Year 2	Monthly Customer Charge Rate Year 3
SC1 RESIDENTIAL SERVICE	$ 15.11	$ 15.11	$ 16.05	$ 17.00
SC8 RESIDENTIAL DAY-NIGHT SERVICE	$ 17.40	$ 17.40	$ 18.50	$ 19.60
SC12 RESIDENTIAL SERVICE TIME-OF-USE	$ 24.11	$ 24.11	$ 25.60	$ 27.15
SC2 GENERAL SERVICE DEMAND	$ 24.31	$ 24.31	$ 28.65	$ 33.00
SC3P GENERAL SERVICE DEMAND PRIMARY	$ 101.17	$ 101.17	$ 119.00	$ 137.00
SC3S GENERAL SERVICE DEMAND SUBTRANSMISSION	$ 333.06	$ 333.06	$ 391.55	$ 450.00
SC6 GENERAL SERVICE NON-DEMAND	$ 17.60	$ 17.60	$ 18.70	$ 19.80
SC7-1 LARGE GENERAL SERVICE SECONDARY	$ 160.65	$ 201.00	$ 209.00	$ 217.00
SC7-2 LARGE GENERAL SERVICE PRIMARY	$ 561.77	$ 702.00	$ 730.00	$ 758.00
SC7-3 LARGE GENERAL SERVICE SUBTRANSMISSION	$ 1,169.55	$ 1,462.00	$ 1,520.00	$ 1,579.00
SC7-4 LARGE GENERAL SERVICE TRANSMISSION	$ 2,641.63	$ 2,800.00	$ 3,000.00	$ 3,200.00
SC9 GENERAL SERVICE DAY-NIGHT SERVICE	$ 20.41	$ 20.41	$ 21.70	$ 23.00

RG&E ELECTRIC SERVICE CLASS	Current Monthly Customer Charge	Monthly Customer Charge Rate Year 1	Monthly Customer Charge Rate Year 2	Monthly Customer Charge Rate Year 3
SC1 RESIDENTIAL SERVICE	$ 21.38	$ 21.38	$ 21.70	$ 22.00
SC2 GENERAL SERVICE SMALL USE	$ 21.38	$ 21.38	$ 21.70	$ 22.00
SC3 GENERAL SERVICE 100 KW MINIMUM	$ 297.13	$ 297.13	$ 349.00	$ 401.00
SC4-I RESIDENTIAL SERVICE TIME-OF-USE - SCHEDULE I	$ 25.36	$ 25.36	$ 25.80	$ 26.10
SC4-II RESIDENTIAL SERVICE TIME-OF-USE - SCHEDULE II	$ 28.84	$ 28.84	$ 29.25	$ 29.70
SC7 GENERAL SERVICE 12 KW MINIMUM	$ 88.77	$ 88.77	$ 105.00	$ 120.00
SC 8 LARGE GENERAL SERVICE TRANSMISSION	$ 3,703.73	$ 4,000.00	$ 4,200.00	$ 4,400.00
SC 8 LARGE GENERAL SERVICE SUBTRANSMISSION-IND.	$ 2,116.77	$ 2,646.00	$ 2,752.00	$ 2,858.00
SC 8 LARGE GENERAL SERVICE SUBTRANSMISSION-COM.	$ 2,027.62	$ 2,535.00	$ 2,636.00	$ 2,737.00
SC 8 LARGE GENERAL SERVICE PRIMARY	$ 1,144.87	$ 1,431.00	$ 1,488.00	$ 1,546.00
SC 8 LARGE GENERAL SERVICE SECONDARY	$ 910.47	$ 1,138.00	$ 1,184.00	$ 1,229.00
SC 8LARGE GENERAL SERVICE SUBSTATION	$ 1,969.55	$ 2,462.00	$ 2,560.00	$ 2,659.00
SC 9 GENERAL SERVICE TIME-OF-USE	$ 95.50	$ 95.50	$ 112.25	$ 129.00

Area Lighting and Street Lighting Classes

The revenue increase allocated to the area and street lighting classes are applied on an equal percent basis to the unit rates of each class. No revenue increases are applied to newly added Light Emitting Diode ("LED") options for RY1. The new LED options will receive the overall average increases for RY2 and RY3.

Standby Rate Design

Standby customer charges are set at the same level as otherwise applicable service classifications. The remaining revenue requirement associated with standby rates for each service classification is recovered through contract demand charges and as-used demand charges in proportion to the revenues collected through current contract demand and as-used demand charges.

Optional Residential Plug-In EV ("PEV") Charging Rates

The optional residential PEV charging rates under NYSEG PSC No. 120, SC No. 8, Special Provision (p) are updated, on a revenue-neutral basis, to recover the total delivery revenues of SC No. 1, SC No. 8 and SC No. 12, for each Rate Year. The customer charge is set at the same level as the SC No. 1 customer charge. The remaining revenue requirement is recovered through peak and off-peak volumetric charges, in the same proportion as the current peak and off-peak volumetric charges.

The optional residential PEV charging rates under RG&E PSC No. 19, SC No. 4, Special Provision (11) are updated, on a revenue-neutral basis, to recover the total delivery revenues of SC No. 1 and SC No. 4, for each Rate Year. The customer charge is set at the same level as the SC No. 1 customer charge. The remaining delivery revenue requirement is recovered through peak and off-peak volumetric charges, in the same proportion as the current peak and off-peak volumetric charges.

Energy Smart Community ("ESC") Rate Option Pilot

The rates under the ESC Rate Option Pilot, NYSEG PSC No. 120 - General Information Section 41, are updated, on a revenue-neutral basis, to recover the total delivery revenues of the otherwise applicable service classes. The customer charges are set at the same level of the customer charges of the otherwise applicable service classes. For service classes with both volumetric delivery charges and demand delivery charges, the volumetric charges are set at the same rate as the otherwise applicable service classes. Reactive charges remain unchanged from current levels. The remaining delivery revenue requirement is recovered through peak and off-peak delivery charges of the respective service classes, in the same proportion as the current delivery charges.

Delivery rates by Company and Rate Year are set forth in Appendix CC.

Competitive Service Rates

Competitive service rates (i.e., the Bill Issuance and Payment Processing ("BIPP") Charge, the Credit and Collections/Call Center component of the Merchant Function Charge ("MFC") and Purchase of Receivables ("POR") discount, and the Administrative component of the MFC) are based on the ECOS studies filed as part of the Companies' rebuttal in these proceedings. The MFC and the POR Discount will continue to be calculated as stated in the respective Companies' currently-effective tariffs.

MFC and POR Rates

The Companies continue to follow the process outlined in the Amended Stipulation Regarding Purchase of Receivables Discount and Merchant Function Charge (included as Appendix W in the Joint Proposal approved in Cases 09-E-0715 et. al.) and updated in Appendix W of the Joint Proposal approved in the 2016 Rate Order (page 6) for calculating the MFC and POR discount. The fixed components are set by the ECOS study and can be found in Schedule D to this Appendix. The fixed percentage factor as discussed in Appendix W of the Joint Proposal approved in the 2016 Rate Order has been updated using current data.

Bill Issuance and Payment Processing Charges

NYSEG's BIPP charge will increase from the current charge of $0.81 per bill to $0.90 per bill. RG&E's BIPP charge will increase from the current charge of $0.72 per bill to $0.93 per bill.

A combination electric and gas customer will receive one BIPP charge applied to the bill. An electric-only or gas-only customer will receive one BIPP charge applied to each bill. The BIPP charge for a combination customer will be the same as that for an electric-only customer or a gas-only customer.

If an energy service company ("ESCO") is providing both the electric and gas service, it will be billed an amount equivalent to the BIPP charge for each consolidated bill. If the ESCO is only providing a consolidated bill for either gas or electric service, it will also be billed an amount equivalent to the BIPP charge per consolidated bill. If a customer has separate ESCOs for electric and gas, the charge for consolidated billing will be prorated between the ESCOs.

Competitive Metering Charges

Competitive metering charges, which consist of meter data service provider (meter reading), meter service provider (meter services), and meter ownership component charges, have been eliminated and recovery of metering costs are included in base delivery rates.

Economic Development Rates

Discounted rates offered under NYSEG's Economic Development Zone Incentive ("EDZI") Program, RG&E's Empire Zone Rates ("EZR") Program, and the Companies' Excelsior Jobs Programs are updated based on the results of the Companies' filed marginal cost of service studies in these proceedings.

Street Lighting

New street lights will no longer be available under Service Classification No. 2 – Street Lighting Service – Energy and Limited Maintenance, of NYSEG P.S.C. No 121 – Street Lighting. Municipalities will be able to request additions of customer-owned lights pursuant to Service Classification No. 4 – Street Lighting Service – Energy Only. The Companies are removing light fixtures or light types that are no longer available (e.g., Metal Halide or High-Pressure Sodium light fixtures).

The Companies will conduct a street light luminaires replacement cost study and present the results in their next rate filings.

Pricing Methodology for Street Light Sales:

1. Net Book Value ("NBV") plus 15% Customer Protection Overhead ("CPO") plus a 4.5% administrative and general ("A&G") expenses fee to develop a purchase price for street light sales transactions.

2. For any difference (X) in NBV between the time of establishing the purchase agreement price and the time of closing the transaction, apply either (a) or (b) below, as applicable:

   a) If X is ***equal to or less*** than the calculated CPO (purchase agreement NBV * 15%), then there will be no adjustments to the purchase agreement price. The final closing price will remain at the purchase agreement price (which included CPO and A&G).

   b) If X ***exceeds*** the calculated CPO (purchase agreement NBV * 15%), then the Companies will calculate the difference between the CPO and X, and will calculate additional CPO and A&G on that difference. The final closing price will therefore be re-calculated to include the purchase agreement price (which included CPO and A&G), plus the amount of NBV exceeding the CPO plus additional CPO and A&G applied to that difference. No fewer than 30 days before date of closing, the Companies will provide a detailed asset report to the municipality that supports an NBV change requiring an adjustment to the overall closing price.

3. Schedule E provides an illustrative example of this methodology.

<u>Tariffs</u>

The compliance filing submitted in these proceedings will include tariff changes to implement the rates and other provisions of this Proposal. The specific language will be set forth in the compliance tariff leaves filed with the Commission.

<u>Customer Bill Impacts</u>

The estimated total bill and delivery bill impacts resulting from the rates set forth in this Proposal are set forth in Appendix CC.

Electric Revenue Allocation and Rate Design
Index of Schedules

New York State Electric & Gas Corporation
Electric Department
Electric Allocation of EE Tracker, Unspent EE Funds and Heat Pump Costs

Allocation per Service Class	Rate Year 1				Rate Year 2 Inclusive of Rate Year 1				Rate Year 3 Inclusive of Rate Years 1 and 2			
Service Classifications (SC)	**SBC EE Tracker**	**Unspent Funds**	**Heat Pumps**	**Total**	**SBC EE Tracker**	**Unspent Funds**	**Heat Pumps**	**Total**	**SBC EE Tracker**	**Unspent Funds**	**Heat Pumps**	**Total**
SC1	$ 4,446,941	$ (2,790,652)	$ 4,048,938	$ 5,705,227	$ 7,781,579	$ (2,790,652)	$ 6,427,102	$ 11,418,029	$ 10,056,119	$ (2,790,652)	$ 8,109,674	$ 15,375,141
SC8	$ 1,502,794	$ (943,069)	$ 1,116,862	$ 1,676,586	$ 2,629,697	$ (943,069)	$ 1,772,856	$ 3,459,484	$ 3,398,353	$ (943,069)	$ 2,236,978	$ 4,692,261
SC12	$ 157,020	$ (98,537)	$ 98,571	$ 157,054	$ 274,765	$ (98,537)	$ 156,468	$ 332,695	$ 355,078	$ (98,537)	$ 197,430	$ 453,971
SC2	$ 2,648,394	$ (1,661,984)	$ 445,039	$ 1,431,449	$ 4,634,351	$ (1,661,984)	$ 706,435	$ 3,678,802	$ 5,988,963	$ (1,661,984)	$ 891,375	$ 5,218,354
SC3P	$ 164,334	$ (103,127)	$ 16,074	$ 77,281	$ 287,564	$ (103,127)	$ 25,515	$ 209,952	$ 371,618	$ (103,127)	$ 32,194	$ 300,685
SC3S	$ 3,717	$ (2,332)	$ 502	$ 1,887	$ 6,504	$ (2,332)	$ 797	$ 4,969	$ 8,405	$ (2,332)	$ 1,006	$ 7,079
SC6	$ 278,876	$ (175,007)	$ 110,757	$ 214,627	$ 487,998	$ (175,007)	$ 175,811	$ 488,802	$ 630,639	$ (175,007)	$ 221,838	$ 677,469
SC7-1	$ 1,162,098	$ (729,268)	$ 143,156	$ 575,986	$ 2,033,523	$ (729,268)	$ 227,239	$ 1,531,495	$ 2,627,918	$ (729,268)	$ 286,729	$ 2,185,379
SC7-2	$ 1,380,300	$ (866,199)	$ 112,516	$ 626,616	$ 2,415,349	$ (866,199)	$ 178,602	$ 1,727,752	$ 3,121,351	$ (866,199)	$ 225,359	$ 2,480,510
SC7-3	$ 976,392	$ (612,729)	$ 31,143	$ 394,806	$ 1,708,562	$ (612,729)	$ 49,435	$ 1,145,267	$ 2,207,971	$ (612,729)	$ 62,376	$ 1,657,618
SC7-4	$ 779,567	$ (489,212)	$ 10,297	$ 300,651	$ 1,364,142	$ (489,212)	$ 16,345	$ 891,275	$ 1,762,878	$ (489,212)	$ 20,624	$ 1,294,290
SC9	$ 20,840	$ (13,078)	$ 5,776	$ 13,538	$ 36,467	$ (13,078)	$ 9,169	$ 32,558	$ 47,126	$ (13,078)	$ 11,570	$ 45,618
Street Lighting	$ 63,055	$ (39,570)	$ 43,449	$ 66,934	$ 110,339	$ (39,570)	$ 68,969	$ 139,738	$ 142,590	$ (39,570)	$ 87,025	$ 190,045
SC5 - Area	$ 16,936	$ (10,628)	$ 10,297	$ 16,605	$ 29,636	$ (10,628)	$ 16,345	$ 35,353	$ 38,299	$ (10,628)	$ 20,624	$ 48,295
Total Base Revenue	$ 13,601,264	$ (8,535,394)	$ 6,193,378	$ 11,259,248	$ 23,800,476	$ (8,535,394)	$ 9,831,089	$ 25,096,171	$ 30,757,309	$ (8,535,394)	$ 12,404,802	$ 34,626,716

Per Unit Rate Embedded in Delivery	Rate Year 1		Rate Year 2		Rate Year 3	
Service Classifications (SC)	kwh	kw	kwh	kw	kwh	kw
SC1	$ 0.00113		$ 0.00223		$ 0.00297	
SC8	$ 0.00103		$ 0.00222		$ 0.00314	
SC12	$ 0.00095		$ 0.00211		$ 0.00300	
SC2*		$ 0.15		$ 0.38		$ 0.54
SC3P*		$ 0.15		$ 0.41		$ 0.59
SC3S*		$ 0.10		$ 0.26		$ 0.37
SC6	$ 0.00067		$ 0.00152		$ 0.00213	
SC7-1*		$ 0.16		$ 0.44		$ 0.62
SC7-2*		$ 0.17		$ 0.47		$ 0.68
SC7-3*		$ 0.15		$ 0.43		$ 0.62
SC7-4*		$ 0.13		$ 0.40		$ 0.57
SC9	$ 0.00057		$ 0.00138		$ 0.00195	
Street Lighting	$ 0.00097		$ 0.00202		$ 0.00275	
SC5 - Area	$ 0.00091		$ 0.00194		$ 0.00266	

* Indicate service classes with SBC exempt customers

New York State Electric & Gas Corporation
Electric Department
Electric Allocation of EE Tracker, Unspent EE Funds and Heat Pump Costs
Per kw Credit - SBC Exempt Customers

SBC Exempt Customers - Per kw Credit

Service Classifications (SC)	Rate Year 1	Rate Year 2	Rate Year 3
SC2	$ (0.15)	$ (0.38)	$ (0.54)
SC3P	$ (0.15)	$ (0.41)	$ (0.59)
SC3S	$ (0.10)	$ (0.26)	$ (0.37)
SC7-1	$ (0.16)	$ (0.44)	$ (0.62)
SC7-2	$ (0.17)	$ (0.47)	$ (0.68)
SC7-3	$ (0.15)	$ (0.43)	$ (0.62)
SC7-4	$ (0.13)	$ (0.40)	$ (0.57)

SBC Exempt Standby Customers - Contract Demand Per kw Credit

	Rate Year 1	Rate Year 2	Rate Year 3
SC2	$ (0.06)	$ (0.16)	$ (0.22)
SC3P	$ (0.07)	$ (0.18)	$ (0.26)
SC3S	$ (0.03)	$ (0.07)	$ (0.10)
SC7-1	$ (0.07)	$ (0.18)	$ (0.26)
SC7-2	$ (0.08)	$ (0.21)	$ (0.31)
SC7-3	$ (0.06)	$ (0.17)	$ (0.25)
SC7-4	$ (0.02)	$ (0.05)	$ (0.07)

SBC Exempt Standby Customers - As-Used Demand Per kw Credit

	Rate Year 1	Rate Year 2	Rate Year 3
SC2	$ (0.06141)	$ (0.00769)	$ (0.01091)
SC3P	$ (0.00353)	$ (0.00958)	$ (0.01372)
SC3S	$ (0.00299)	$ (0.00785)	$ (0.01117)
SC7-1	$ (0.00371)	$ (0.00986)	$ (0.01407)
SC7-2	$ (0.00371)	$ (0.01021)	$ (0.01465)
SC7-3	$ (0.00440)	$ (0.01272)	$ (0.01837)
SC7-4	$ (0.00744)	$ (0.02187)	$ (0.03165)

Rochester Gas and Electric Corporation
Electric Department
Electric Allocation of EE Tracker, Unspent EE Funds and Heat Pump Costs

Allocation per Service Class	Rate Year 1				Rate Year 2 Inclusive of Rate Year 1				Rate Year 3 Inclusive of Rate Years 1 and 2			
Service Classifications (SC)	**SBC EE Tracker**	**Unspent Funds**	**Heat Pumps**	**Total**	**SBC EE Tracker**	**Unspent Funds**	**Heat Pumps**	**Total**	**SBC EE Tracker**	**Unspent Funds**	**Heat Pumps**	**Total**
SC1	$ 3,258,563	$ (1,865,500)	$ 658,582	$ 2,051,646	$ 5,026,392	$ (1,865,500)	$ 989,528	$ 4,150,420	$ 6,794,958	$ (1,865,500)	$ 1,402,382	$ 6,331,840
SC2	$ 279,005	$ (159,728)	$ 9,242	$ 128,519	$ 430,370	$ (159,728)	$ 13,886	$ 284,528	$ 581,798	$ (159,728)	$ 19,680	$ 441,750
SC3	$ 764,192	$ (437,493)	$ 18,877	$ 345,576	$ 1,178,780	$ (437,493)	$ 28,363	$ 769,649	$ 1,593,540	$ (437,493)	$ 40,197	$ 1,196,244
SC4-I	$ 44,746	$ (25,617)	$ 7,823	$ 26,952	$ 69,022	$ (25,617)	$ 11,754	$ 55,159	$ 93,307	$ (25,617)	$ 16,658	$ 84,348
SC4-II	$ 47,378	$ (27,124)	$ 8,321	$ 28,575	$ 73,082	$ (27,124)	$ 12,502	$ 58,460	$ 98,796	$ (27,124)	$ 17,718	$ 89,390
SC7	$ 1,003,715	$ (574,618)	$ 33,772	$ 462,869	$ 1,548,248	$ (574,618)	$ 50,743	$ 1,024,373	$ 2,093,008	$ (574,618)	$ 71,915	$ 1,590,305
SC 8T	$ 34,218	$ (19,589)	$ 442	$ 15,071	$ 52,781	$ (19,589)	$ 665	$ 33,857	$ 71,353	$ (19,589)	$ 942	$ 52,705
SC 8STInd	$ 872,109	$ (499,275)	$ 10,004	$ 382,838	$ 1,345,243	$ (499,275)	$ 15,031	$ 861,000	$ 1,818,575	$ (499,275)	$ 21,302	$ 1,340,603
SC 8STComm	$ 603,633	$ (345,575)	$ 7,472	$ 265,530	$ 931,114	$ (345,575)	$ 11,227	$ 596,767	$ 1,258,732	$ (345,575)	$ 15,911	$ 929,069
SC 8P	$ 742,258	$ (424,936)	$ 13,593	$ 330,914	$ 1,144,946	$ (424,936)	$ 20,423	$ 740,432	$ 1,547,801	$ (424,936)	$ 28,944	$ 1,151,809
SC 8S	$ 875,618	$ (501,284)	$ 18,287	$ 392,621	$ 1,350,657	$ (501,284)	$ 27,477	$ 876,850	$ 1,825,893	$ (501,284)	$ 38,941	$ 1,363,550
SC 8SubS	$ 131,606	$ (75,343)	$ 2,114	$ 58,376	$ 203,005	$ (75,343)	$ 3,176	$ 130,837	$ 274,433	$ (75,343)	$ 4,501	$ 203,591
SC 9	$ 55,274	$ (31,644)	$ 1,721	$ 25,351	$ 85,262	$ (31,644)	$ 2,585	$ 56,203	$ 115,262	$ (31,644)	$ 3,664	$ 87,281
PSC18 St. Light - SC1	$ 14,915	$ (8,539)	$ 843	$ 7,220	$ 23,007	$ (8,539)	$ 1,267	$ 15,735	$ 31,102	$ (8,539)	$ 1,795	$ 24,359
PSC18 St. Light - SC2	$ 34,218	$ (19,589)	$ 1,933	$ 16,561	$ 52,781	$ (19,589)	$ 2,905	$ 36,097	$ 71,353	$ (19,589)	$ 4,117	$ 55,880
PSC18 St. Light - SC3	$ 3,509	$ (2,009)	$ 199	$ 1,699	$ 5,413	$ (2,009)	$ 299	$ 3,703	$ 7,318	$ (2,009)	$ 424	$ 5,733
SC6-Res	$ 877	$ (502)	$ 393	$ 768	$ 1,353	$ (502)	$ 591	$ 1,442	$ 1,830	$ (502)	$ 837	$ 2,164
SC6-NonRes	$ 7,896	$ (4,521)	$ 639	$ 4,015	$ 12,180	$ (4,521)	$ 960	$ 8,620	$ 16,466	$ (4,521)	$ 1,361	$ 13,306
Total Base Revenue	$ 8,773,730	$ (5,022,887)	$ 794,258	$ 4,540,318	$ 13,533,636	$ (5,022,887)	$ 1,193,382	$ 9,694,070	$ 18,295,525	$ (5,022,887)	$ 1,691,289	$ 14,948,456

Per Unit Rate Embedded in Delivery	Rate Year 1		Rate Year 2		Rate Year 3	
Service Classifications (SC)	kwh	kw	kwh	kw	kwh	kw
SC1	$ 0.00077		$ 0.00156		$ 0.00238	
SC2	$ 0.00058		$ 0.00129		$ 0.00200	
SC3*		$ 0.21		$ 0.48		$ 0.75
SC4-I	$ 0.00080		$ 0.00168		$ 0.00265	
SC4-II	$ 0.00082		$ 0.00173		$ 0.00272	
SC7*		$ 0.20		$ 0.44		$ 0.69
SC 8T*		$ 0.20		$ 0.44		$ 0.69
SC 8STInd*		$ 0.23		$ 0.51		$ 0.80
SC 8STComm*		$ 0.26		$ 0.58		$ 0.90
SC 8P*		$ 0.25		$ 0.55		$ 0.86
SC 8S*		$ 0.23		$ 0.51		$ 0.79
SC 8SubS*		$ 0.21		$ 0.48		$ 0.75
SC 9		$ 0.16		$ 0.35		$ 0.54
PSC18 St. Light - SC1	$ 0.00063		$ 0.00140		$ 0.00221	
PSC18 St. Light - SC2	$ 0.00064		$ 0.00141		$ 0.00223	
PSC18 St. Light - SC3	$ 0.00059		$ 0.00129		$ 0.00200	
SC6-Res	$ 0.00113		$ 0.00211		$ 0.00316	
SC6-NonRes	$ 0.00061		$ 0.00129		$ 0.00200	

* Indicate service classes with SBC exempt customers

Rochester Gas and Electric Corporation
Electric Department
Electric Allocation of EE Tracker, Unspent EE Funds and Heat Pump Costs
Per kw Credit - SBC Exempt Customers

SBC Exempt Customers - Per kw Credit

Service Classifications (SC)	Rate Year 1	Rate Year 2	Rate Year 3
SC3	$ (0.21)	$ (0.48)	$ (0.75)
SC7	$ (0.20)	$ (0.44)	$ (0.69)
SC 8T	$ (0.20)	$ (0.44)	$ (0.69)
SC 8STInd	$ (0.23)	$ (0.51)	$ (0.80)
SC 8STComm	$ (0.26)	$ (0.58)	$ (0.90)
SC 8P	$ (0.25)	$ (0.55)	$ (0.86)
SC 8S	$ (0.23)	$ (0.51)	$ (0.79)
SC 8SubS	$ (0.21)	$ (0.48)	$ (0.75)

SBC Exempt Standby Customers - Contract Demand Per kw Credit

	Rate Year 1	Rate Year 2	Rate Year 3
SC3	$ (0.09)	$ (0.21)	$ (0.32)
SC7	$ (0.12)	$ (0.26)	$ (0.40)
SC 8T	$ (0.15)	$ (0.34)	$ (0.53)
SC 8STInd	$ (0.03)	$ (0.07)	$ (0.10)
SC 8STComm	$ (0.03)	$ (0.06)	$ (0.10)
SC 8P	$ (0.09)	$ (0.20)	$ (0.31)
SC 8S	$ (0.09)	$ (0.21)	$ (0.32)
SC 8SubS	$ (0.10)	$ (0.22)	$ (0.34)

SBC Exempt Standby Customers - As-Used Demand Per kw Credit

	Rate Year 1	Rate Year 2	Rate Year 3
SC3	$ (0.00042)	$ (0.01097)	$ (0.01717)
SC7	$ (0.00165)	$ (0.00365)	$ (0.00571)
SC 8T	$ (0.00228)	$ (0.00512)	$ (0.00803)
SC 8STInd	$ (0.00988)	$ (0.02223)	$ (0.03491)
SC 8STComm	$ (0.00984)	$ (0.02211)	$ (0.03468)
SC 8P	$ (0.00725)	$ (0.01622)	$ (0.02543)
SC 8S	$ (0.00612)	$ (0.01367)	$ (0.02141)
SC 8SubS	$ (0.00457)	$ (0.01024)	$ (0.01605)

New York State Electric & Gas Corporation
Electric Department
Development of Delivery Revenues - SETTLEMENT
Rate Year May 1, 2020 - April 30, 2021

		A	B	C = B minus A	D = C divided by A
		Delivery Revenue Prior to EE Tracker Transfer and Delivery Rate Increase $	Rate Year Delivery Revenues $	Revenue Increase/(Decrease) $	Change %
1	PSC 120 Service Classifications (SC)				
2	SC # 1 - Residential Regular	319,750,071	344,647,557	24,897,486	7.8%
3	SC # 8 - Residential Day-Night	84,716,531	92,445,464	7,728,933	9.1%
4	SC #12 - Residential Time of Use	7,276,241	7,575,018	298,777	4.1%
5	SC #6 - General Service Regular	29,602,253	31,921,270	2,319,017	7.8%
				-	
6	SC # 9 - General Service Day-Night	1,471,138	1,587,111	115,973	7.9%
				-	
7	SC # 2 - General Service-w/Demand	112,596,151	117,790,856	5,194,705	4.6%
8	SC # 7-1 - General Service-Time of Use	34,904,610	36,136,107	1,231,497	3.5%
9	SC # 3P - Primary Service	3,806,597	4,207,866	401,269	10.5%
10	SC # 7-2 - Primary Service-Time of Use	27,585,061	29,610,859	2,025,798	7.3%
11	SC # 3S - Sub transmission Service	123,382	127,798	4,416	3.6%
12	SC # 7-3 - Sub transmission-Time of Use	7,439,574	7,702,352	262,778	3.5%
13	SC # 7-4 - Transmission-Time of Use	2,337,613	2,681,688	344,075	14.7%
14	SC #11 - Standby Service	1,620,841	1,688,798	67,957	4.2%
15	SC # 5 - Outdoor Lighting	2,453,669	2,639,602	185,934	7.6%
16	Total P.S.C. 120 Revenue	635,683,733	680,762,347	45,078,614	7.1%
17					
18	PSC 121 Service Classifications (SC)				
19	SC #1 - Street Lighting Service	41,922	43,397	1,475	3.5%
20	SC #2 - Street Lighting Service	270,351	279,863	9,512	3.5%
21	SC #1 - Street Lighting Service	9,559,045	9,895,355	336,310	3.5%
22	SC #4 - Street Lighting Service - Customer Owned Equip.	490,019	507,259	17,240	3.5%
23	Total P.S.C. 121 Revenue	10,361,338	10,725,874	364,537	3.5%
24	Subtotal PSC 120 and 121 Base Delivery Revenue	646,045,070	691,488,221	45,443,151	7.0%
25					
26	EE Tracker Exemptions		(409,049)	(409,049)	
27	Bill Issuance and Payment Processing Charge	8,211,183	8,211,183	0	
28	MFC/POR - Credit/Coll/Call Ctr/Admin	14,600,478	14,600,478	0	
29	Subtotal PSC 120 and 121 Base Delivery Revenue after Adjustments	668,856,731	713,890,833	45,034,102	6.7%
30	Other Delivery Revenue Adjustments				
31	Clean Energy Fund	68,091,295	68,091,295	-	
32	Dynamic Load Management Surcharge	4,556,056	4,556,056	-	
33	Gross Revenue Tax	10,694,223	11,343,720	649,497	
34	Total Tariff Delivery Revenue	752,198,305	797,881,903	45,683,599	6.1%

New York State Electric & Gas Corporation
Electric Department
Electric Revenue Allocation - SETTLEMENT
Rate Year May 1, 2020 - April 30, 2021

Rate Case Revenues

1	Current Delivery Revenues with forecasted billing determinants	$	646,045,070
2	Total Proposed Delivery Increase		45,034,102
3	Total Proposed Delivery Increase Adjusted for SBC Exempt EE Tracker		45,443,151
4	SBC EE Tracker moved to Delivery		5,065,869
5			
6	Heat Pump moved to Delivery		6,193,378
7	Distribution Vegetation Management Increase		19,253,846
8	AMI Investment in Delivery		0
9	AMI IT Costs		0
10	**Net Delivery Revenue Increase (Decrease)**		14,930,058
11	Less: Change in BIPP - Revenue	$	0
12	Less: Change in MFC - Delivery Revenue	$	0
13			
14	**Residual Delivery Revenue Increase (Decrease)**	$	14,930,057
15	Total Proposed Revenue (at overall increase or decrease)	$	691,488,221

							Detail of Revenue Increase Components					
	B	C	D	E	F	G	H	I	J	K	L	M
			Delivery Revenue Prior to Rate Increase $	Revenue Requirement Increase $	Rate Year Delivery Revenues $	Total Proposed Revenue Percent Change $	Total Proposed Revenue Percent Change Residual Only %	Percent of Total Change Attributed to SBC EE Tracker %	Percent of Total Change Attributed to Heat Pumps	Percent of Total Change Attributed to DVM %	Percent of Total Change Attributed to AMI Investment in Delivery %	Percent of Total Change Attributed to AMI IT Costs %
16	PSC 120 Service Classifications (SC)											
17	SC1	Residential Regular	319,750,071	24,897,486	344,647,557	7.8%	2.7%	0.5%	1.3%	3.3%	0.000%	0.000%
18	SC8	Residential Day-Night	84,716,531	7,728,933	92,445,464	9.1%	3.6%	0.7%	1.3%	3.5%	0.000%	0.000%
19	SC12	Residential Time of Use	7,276,241	298,777	7,575,018	4.1%	-0.9%	0.8%	1.4%	2.8%	0.000%	0.000%
20	SC2	General Service-w/Demand	112,596,151	5,194,705	117,790,856	4.6%	0.9%	0.9%	0.4%	2.4%	0.000%	0.000%
21	SC3P	Primary Service	3,806,597	401,269	4,207,866	10.5%	5.8%	1.6%	0.4%	2.7%	0.000%	0.000%
22	SC3S	Sub transmission Service	123,382	4,416	127,798	3.6%	2.2%	1.0%	0.4%	0.0%	0.000%	0.000%
23	SC6	General Service Regular	29,602,253	2,319,017	31,921,270	7.8%	3.8%	0.4%	0.4%	3.4%	0.000%	0.000%
24	SC7-1	General Service-Time of Use	34,904,610	1,231,497	36,136,107	3.5%	-0.2%	1.2%	0.4%	2.1%	0.000%	0.000%
25	SC7-2	Primary Service-Time of Use	27,585,061	2,025,798	29,610,859	7.3%	2.3%	1.8%	0.4%	2.9%	0.000%	0.000%
26	SC7-3	Sub transmission-Time of Use	7,439,574	262,778	7,702,352	3.5%	-1.8%	4.9%	0.4%	0.0%	0.000%	0.000%
27	SC7-4	Transmission-Time of Use	2,337,613	344,075	2,681,688	14.7%	3.0%	11.3%	0.4%	0.0%	0.000%	0.000%
28	SC9	General Service Day-Night	1,471,138	115,973	1,587,111	7.9%	4.0%	0.5%	0.4%	3.0%	0.000%	0.000%
29	Street Lighting	PSC 121 Street Lighting	10,361,338	364,537	10,725,874	3.5%	2.0%	0.2%	0.4%	0.9%	0.000%	0.000%
30	SC5 - Area	Outdoor Lighting	2,453,669	185,934	2,639,602	7.6%	2.6%	0.3%	0.4%	4.3%	0.000%	0.000%
31	SC 11 - Standby Service		1,620,841	67,957	1,688,798	4.2%	-1.2%	2.9%	0.4%	2.1%	0.000%	0.000%
32	Subtotal PSC 120 and 121		646,045,070	45,443,151	691,488,221	7.0%	2.3%	0.8%	1.0%	3.0%	0.0%	0.0%

New York State Electric & Gas Corporation
Electric Department
Development of Delivery Revenues - SETTLEMENT
Rate Year May 1, 2021 - April 30, 2022

		A	C	C = B minus A	D = C divided by A
		Delivery Revenue Prior to EE Tracker Transfer and Delivery Rate Increase $	Rate Year Delivery Revenues $	Revenue Increase/(Decrease) $	Change %
1	PSC 120 Service Classifications (SC)				
2	SC # 1 - Residential Regular	347,823,548	391,885,071	44,061,523	12.7%
3	SC # 8 - Residential Day-Night	89,477,076	101,969,728	12,492,652	14.0%
4	SC #12 - Residential Time of Use	7,287,430	7,935,379	647,948	8.9%
5	SC #6 - General Service Regular	31,994,252	36,160,764	4,166,511	13.0%
6	SC # 9 - General Service Day-Night	1,589,179	1,801,219	212,041	13.3%
7	SC # 2 - General Service-w/Demand	117,751,328	130,016,911	12,265,583	10.4%
8	SC # 7-1 - General Service-Time of Use	35,953,845	38,170,796	2,216,951	6.2%
9	SC # 3P - Primary Service	4,234,903	4,938,267	703,364	16.6%
10	SC # 7-2 - Primary Service-Time of Use	29,797,054	33,822,381	4,025,328	13.5%
11	SC # 3S - Sub transmission Service	128,546	136,299	7,753	6.0%
12	SC # 7-3 - Sub transmission-Time of Use	7,754,380	8,547,703	793,322	10.2%
13	SC # 7-4 - Transmission-Time of Use	2,704,647	3,573,593	868,946	32.1%
14	SC #11 - Standby Service	1,688,798	1,922,378	233,580	13.8%
15	SC # 5 - Outdoor Lighting	2,635,587	2,946,513	310,926	11.8%
16	Total P.S.C. 120 Revenue	680,820,573	763,827,001	83,006,428	12.2%
17					
18	PSC 121 Service Classifications (SC)				
19	SC #1 - Street Lighting Service	43,444	46,468	3,024	7.0%
20	SC #2 - Street Lighting Service	280,166	299,666	19,500	7.0%
21	SC #1 - Street Lighting Service	9,903,182	10,592,473	689,291	7.0%
22	SC #4 - Street Lighting Service - Customer Owned Equip.	508,678	544,083	35,405	7.0%
23	Total P.S.C. 121 Revenue	10,735,469	11,482,690	747,221	7.0%
24	Subtotal PSC 120 and 121 Base Delivery Revenue	691,556,042	775,309,691	83,753,649	12.1%
25	Adj to Match RR (Units & Rates Differences)	(347,379)		347,379	
26	EE Tracker Exemptions		(758,510)	(758,510)	
27	Bill Issuance and Payment Processing Charge	8,228,861	8,228,861	-	
28	MFC/POR - Credit/Coll/Call Ctr/Admin	14,600,478	14,600,478	-	
29	Subtotal PSC 120 and 121 Base Delivery Revenue after Adjustments	714,038,002	797,380,520	83,342,518	11.7%
30	Other Delivery Revenue Adjustments				
31	Clean Energy Fund	66,401,023	66,401,023	-	
32	Dynamic Load Management Surcharge	4,791,256	4,791,256	-	
33	Gross Revenue Tax	11,467,930	12,895,854	1,427,923	
34	Total Tariff Delivery Revenue	796,698,212	881,468,653	84,770,441	10.6%

New York State Electric & Gas Corporation
Electric Department
Electric Revenue Allocation - SETTLEMENT
Rate Year May 1, 2021 - April 30, 2022

Rate Case Revenues

1	Current Delivery Revenues with forecasted billing determinants	$	691,556,042
2	Total Proposed Delivery Increase		83,342,518
3	Total Proposed Delivery Increase Adjusted for SBC Exempt EE Tracker		84,101,028
4	SBC EE Tracker moved to Delivery		10,199,212
5			
6	Heat Pump moved to Delivery		3,637,711
7	Distribution Vegetation Management Increase		2,005,274
8	AMI Investment in Delivery		3,282,939
9	AMI IT Costs		5,249,920
10	**Net Delivery Revenue Increase (Decrease)**		59,725,972
11	Less: Change in BIPP - Revenue	$	-
12	Less: Change in MFC - Delivery Revenue	$	-
13	Plus: Adj to Match RR (Units & Rates Differences)	$	(347,379)
14	**Residual Delivery Revenue Increase (Decrease)**	$	59,378,592
15	Total Proposed Revenue (at overall increase or decrease)	$	775,309,691

							Detail of Revenue Increase Components					
	B	C	D	E	F	G	H	I	J	K	L	M
			Delivery Revenue Prior to Rate Increase $	Revenue Requirement Increase $	Rate Year Delivery Revenues $	Total Proposed Revenue Percent Change $	Total Proposed Revenue Percent Change Residual Only %	Percent of Total Change Attributed to SBC EE Tracker %	Percent of Total Change Attributed to Heat Pumps	Percent of Total Change Attributed to DVM %	Percent of Total Change Attributed to AMI Investment in Delivery %	Percent of Total Change Attributed to AMI IT Costs %
16	PSC 120 Service Classifications (SC)											
17	SC1	Residential Regular	347,823,548	44,061,523	391,885,071	12.7%	9.3%	1.0%	0.7%	0.3%	0.647%	0.780%
18	SC8	Residential Day-Night	89,477,076	12,492,652	101,969,728	14.0%	10.3%	1.3%	0.7%	0.3%	0.503%	0.864%
19	SC12	Residential Time of Use	7,287,430	647,948	7,935,379	8.9%	5.3%	1.6%	0.8%	0.3%	0.188%	0.692%
20	SC2	General Service-w/Demand	117,751,328	12,265,583	130,016,911	10.4%	7.4%	1.7%	0.2%	0.2%	0.221%	0.632%
21	SC3P	Primary Service	4,234,903	703,364	4,938,267	16.6%	12.3%	2.9%	0.2%	0.3%	0.058%	0.928%
22	SC3S	Sub transmission Service	128,546	7,753	136,299	6.0%	3.1%	2.0%	0.2%	0.0%	0.080%	0.649%
23	SC6	General Service Regular	31,994,252	4,166,511	36,160,764	13.0%	10.1%	0.7%	0.2%	0.3%	0.851%	0.853%
24	SC7-1	General Service-Time of Use	35,953,845	2,216,951	38,170,796	6.2%	2.7%	2.4%	0.2%	0.2%	0.053%	0.589%
25	SC7-2	Primary Service-Time of Use	29,797,054	4,025,328	33,822,381	13.5%	8.9%	3.4%	0.2%	0.3%	0.010%	0.781%
26	SC7-3	Sub transmission-Time of Use	7,754,380	793,322	8,547,703	10.2%	-0.1%	9.4%	0.2%	0.0%	0.014%	0.650%
27	SC7-4	Transmission-Time of Use	2,704,647	868,946	3,573,593	32.1%	10.7%	19.7%	0.2%	0.0%	0.007%	1.452%
28	SC9	General Service Day-Night	1,589,179	212,041	1,801,219	13.3%	10.6%	1.0%	0.2%	0.3%	0.499%	0.744%
29	Street Lighting	PSC 121 Street Lighting	10,735,469	747,221	11,482,690	7.0%	5.5%	0.4%	0.2%	0.1%	0.000%	0.661%
30	SC5 - Area	Outdoor Lighting	2,635,587	310,926	2,946,513	11.8%	9.6%	0.5%	0.2%	0.4%	0.000%	1.031%
31	SC 11 - Standby Service		1,688,798	233,580	1,922,378	13.8%	7.1%	5.5%	0.2%	0.2%	0.036%	0.829%
32	Subtotal PSC 120 and 121		691,556,042	83,753,649	775,309,691	12.1%	8.6%	1.5%	0.5%	0.3%	0.5%	0.8%

New York State Electric & Gas Corporation
Electric Department
Development of Delivery Revenues - SETTLEMENT
Rate Year May 1, 2022 - April 30, 2023

		A	C	C = B minus A	D = C divided by A
		Delivery Revenue Prior to EE Tracker Transfer and Delivery Rate Increase $	Rate Year Delivery Revenues $	Revenue Increase/(Decrease) $	Change %
1	PSC 120 Service Classifications (SC)				
2	SC # 1 - Residential Regular	395,629,826	442,559,448	46,929,621	11.9%
3	SC # 8 - Residential Day-Night	98,660,908	111,509,761	12,848,853	13.0%
4	SC #12 - Residential Time of Use	7,638,103	8,259,680	621,576	8.1%
5	SC #6 - General Service Regular	36,189,142	40,691,771	4,502,629	12.4%
				-	
6	SC # 9 - General Service Day-Night	1,799,486	2,027,360	227,874	12.7%
				-	
7	SC # 2 - General Service-w/Demand	129,751,905	142,468,892	12,716,986	9.8%
8	SC # 7-1 - General Service-Time of Use	37,873,826	40,046,915	2,173,089	5.7%
9	SC # 3P - Primary Service	4,958,168	5,685,801	727,633	14.7%
10	SC # 7-2 - Primary Service-Time of Use	33,883,887	37,939,364	4,055,477	12.0%
11	SC # 3S - Sub transmission Service	136,618	144,307	7,690	5.6%
12	SC # 7-3 - Sub transmission-Time of Use	8,563,636	9,192,146	628,510	7.3%
13	SC # 7-4 - Transmission-Time of Use	3,583,655	4,361,163	777,509	21.7%
14	SC #11 - Standby Service	1,922,378	2,149,322	226,944	11.8%
15	SC # 5 - Outdoor Lighting	2,933,965	3,267,650	333,686	11.4%
16	Total P.S.C. 120 Revenue	763,525,504	850,303,580	86,778,076	11.4%
17					
18	PSC 121 Service Classifications (SC)				
19	SC #1 - Street Lighting Service	46,509	49,713	3,204	6.9%
20	SC #2 - Street Lighting Service	299,934	320,598	20,664	6.9%
21	SC #1 - Street Lighting Service	10,601,948	11,332,369	730,420	6.9%
22	SC #4 - Street Lighting Service - Customer Owned Equip.	544,570	582,088	37,518	6.9%
23	Total P.S.C. 121 Revenue	11,492,961	12,284,768	791,807	6.9%
24	Subtotal PSC 120 and 121 Base Delivery Revenue	775,018,465	862,588,348	87,569,883	11.3%
25	Adj to Match RR (Units & Rates Differences)	(654,943)		654,943	
26	EE Tracker Exemptions		(515,323)	(515,323)	
27	Bill Issuance and Payment Processing Charge	8,251,241	8,251,241	-	
28	MFC/POR - Credit/Coll/Call Ctr/Admin	14,600,478	14,600,478	-	
29	Subtotal PSC 120 and 121 Base Delivery Revenue after Adjustments	797,215,240	884,924,744	87,709,503	11.0%
	Other Delivery Revenue Adjustments				
30	Less:Rate Increase Shaping Deferral	14,430,000	14,430,000		
31	Clean Energy Fund	64,581,302	64,581,302	-	
32	Dynamic Load Management Surcharge	5,026,456	5,026,456	-	
33	Gross Revenue Tax	12,948,081	13,803,320	855,239	
34	Total Tariff Delivery Revenue	894,201,079	982,765,822	88,564,742	9.9%

New York State Electric & Gas Corporation
Electric Department
Electric Revenue Allocation - SETTLEMENT
Rate Year May 1, 2022 - April 30, 2023

Rate Case Revenues

1	Current Delivery Revenues with forecasted billing determinants	$	775,018,465
2	Total Proposed Delivery Increase		87,709,503
3	Total Proposed Delivery Increase Adjusted for SBC Exempt EE Tracker		88,224,826
4	SBC EE Tracker moved to Delivery		6,956,832
5			
6	Heat Pump moved to Delivery		2,573,712
7	Distribution Vegetation Management Increase		2,005,274
8	AMI Investment in Delivery		3,687,095
9	AMI IT Costs		5,893,030
10	**Net Delivery Revenue Increase (Decrease)**		67,108,882
11	Less: Change in BIPP - Revenue	$	-
12	Less: Change in MFC - Delivery Revenue	$	-
13	Plus: Adj to Match RR (Units & Rates Differences)	$	(654,943)
14	**Residual Delivery Revenue Increase (Decrease)**	$	66,453,939
15	Total Proposed Revenue (at overall increase or decrease)	$	862,588,348

							Detail of Revenue Increase Components					
	B	C	D	E	F	G	H	I	J	K	L	M
			Delivery Revenue Prior to Rate Increase $	Revenue Requirement Increase $	Rate Year Delivery Revenues $	Total Proposed Revenue Percent Change $	Total Proposed Revenue Percent Change Residual Only %	Percent of Total Change Attributed to SBC EE Tracker %	Percent of Total Change Attributed to Heat Pumps	Percent of Total Change Attributed to DVM %	Percent of Total Change Attributed to AMI Investment in Delivery %	Percent of Total Change Attributed to AMI IT Costs %
16	PSC 120 Service Classifications (SC)											
17	SC1	Residential Regular	395,629,826	46,929,621	442,559,448	11.9%	9.2%	0.6%	0.4%	0.3%	0.639%	0.769%
18	SC8	Residential Day-Night	98,660,908	12,848,853	111,509,761	13.0%	10.1%	0.8%	0.5%	0.3%	0.513%	0.879%
19	SC12	Residential Time of Use	7,638,103	621,576	8,259,680	8.1%	5.3%	1.1%	0.5%	0.3%	0.201%	0.741%
20	SC2	General Service-w/Demand	129,751,905	12,716,986	142,468,892	9.8%	7.5%	1.0%	0.1%	0.2%	0.225%	0.643%
21	SC3P	Primary Service	4,958,168	727,633	5,685,801	14.7%	11.7%	1.7%	0.1%	0.2%	0.056%	0.890%
22	SC3S	Sub transmission Service	136,618	7,690	144,307	5.6%	3.4%	1.3%	0.1%	0.0%	0.085%	0.686%
23	SC6	General Service Regular	36,189,142	4,502,629	40,691,771	12.4%	9.9%	0.4%	0.1%	0.3%	0.845%	0.847%
24	SC7-1	General Service-Time of Use	37,873,826	2,173,089	40,046,915	5.7%	3.1%	1.6%	0.2%	0.2%	0.057%	0.627%
25	SC7-2	Primary Service-Time of Use	33,883,887	4,055,477	37,939,364	12.0%	8.8%	2.0%	0.1%	0.2%	0.010%	0.771%
26	SC7-3	Sub transmission-Time of Use	8,563,636	628,510	9,192,146	7.3%	0.7%	5.8%	0.2%	0.0%	0.015%	0.661%
27	SC7-4	Transmission-Time of Use	3,583,655	777,509	4,361,163	21.7%	10.2%	10.2%	0.1%	0.0%	0.006%	1.231%
28	SC9	General Service Day-Night	1,799,486	227,874	2,027,360	12.7%	10.4%	0.6%	0.1%	0.3%	0.495%	0.737%
29	Street Lighting	PSC 121 Street Lighting	11,492,961	791,807	12,284,768	6.9%	5.7%	0.3%	0.2%	0.1%	0.000%	0.693%
30	SC5 - Area	Outdoor Lighting	2,933,965	333,686	3,267,650	11.4%	9.5%	0.3%	0.1%	0.4%	0.000%	1.040%
31	SC 11 - Standby Service		1,922,378	226,944	2,149,322	11.8%	7.4%	3.3%	0.1%	0.2%	0.035%	0.815%
32	Subtotal PSC 120 and 121		775,018,465	87,569,883	862,588,348	11.3%	8.6%	0.9%	0.3%	0.3%	0.5%	0.8%

Rochester Gas and Electric Corporation
Electric Department
Development of Delivery Revenues - SETTLEMENT
Rate Year May 1, 2020 - April 30, 2021

		A	C	D = C minus B	E = D divided by B
		Delivery Revenue Prior to EE Tracker Transfer and Delivery Rate Increase $	Rate Year Delivery Revenues $	Revenue Increase/ (Decrease)	Change $
1	PSC 19 Service Classifications (SC)				
2	SC #1 - Residential Service	$ 198,715,985	$ 208,000,435	$ 9,284,450	4.7%
3	SC #4 -Residential Service TOU				
4	Schedule I	$ 2,164,449	$ 2,203,482	$ 39,032	1.8%
5	Schedule II	$ 2,262,877	$ 2,304,026	$ 41,149	1.8%
6	SC #2 - General Service - Small Use	$ 14,963,206	$ 15,540,981	$ 577,775	3.9%
7	SC #3 - General Service - 100 kW Minimum	$ 30,422,315	$ 31,507,149	$ 1,084,834	3.6%
				$ -	
8	SC #7 - General Service - 12 kW Minimum	$ 53,451,614	$ 54,624,318	$ 1,172,703	2.2%
9	SC #8 - Large General Service - Time-of-Use				
10	SC #8 - Primary	$ 20,778,380	$ 21,689,183	$ 910,802	4.4%
11	SC #8 - Secondary	$ 28,832,349	$ 29,887,226	$ 1,054,877	3.7%
12	SC #8 - Subtransmission - Commercial	$ 9,206,221	$ 9,431,020	$ 224,799	2.4%
13	SC #8 - Subtransmission - Industrial	$ 14,433,114	$ 14,766,451	$ 333,337	2.3%
14	SC #8 - Transmission	$ 742,617	$ 774,256	$ 31,639	4.3%
15	SC #8 - Substation	$ 2,851,527	$ 2,905,245	$ 53,719	1.9%
16	SC #9 - General Service - Time-of-Use	$ 2,719,519	$ 2,773,875	$ 54,356	2.0%
17	SC #14 - Standby Service	$ 4,410,049	$ 4,721,076	$ 311,027	7.1%
18	SC #6 - Area Lighting	$ 1,136,320	$ 1,175,009	$ 38,689	3.4%
19	Total P.S.C. 19 Revenue	$ 387,090,543	$ 402,303,732	$ 15,213,190	3.9%
20	PSC 18 Service Classifications (SC)				
21	SC #1 - Street Lighting Service	$ 2,738,948	$ 2,832,203	$ 93,255	3.4%
22	SC #2 - Street Lighting Service - Customer Owned Equip.	$ 1,495,247	$ 1,546,157	$ 50,910	3.4%
23	SC #3 - Traffic Signal Service	$ 100,014	$ 103,419	$ 3,405	3.4%
24	Total P.S.C. 18 Revenue	$ 4,334,209	$ 4,481,780	$ 147,571	3.4%
25	Subtotal PSC 18 and 19 Base Delivery Revenue	$ 391,424,752	$ 406,785,512	$ 15,360,760	3.9%
26	Less: Economic Development Discounts	$ (24,000)	$ (24,000)	$ -	
27	EE Tracker Exemptions		$ (73,800)	$ (73,800)	
28	Bill Issuance and Payment Processing Revenue	$ 2,675,680	$ 2,675,680	$ (0)	
29	MFC/POR - Credit/Coll/Call Ctr/Admin	$ 5,559,008	$ 5,559,008	$ (0)	
30	Subtotal PSC 18 and 19 Base Delivery Revenue After Adjustments	$ 399,635,440	$ 414,922,399	$ 15,286,960	3.8%
31	Other Delivery Revenue Adjustments:				
32	Clean Energy Fund	$ 36,979,669	$ 36,979,669	$ -	
33	Dynamic Load Management Surcharge	$ 2,821,104	$ 2,821,104	$ -	
34	Gross Revenue Tax	$ 6,593,936	$ 6,544,496	$ (49,440)	
				$ -	
				$ -	
35	Total Tariff Delivery Revenue	$ 446,030,149	$ 461,267,669	$ 15,237,520	3.4%

Rochester Gas and Electric Corporation
Electric Department
Electric Revenue Allocation - SETTLEMENT
Rate Year May 1, 2020 - April 30, 2021

Rate Case Revenues

1	Current Delivery Revenues with forecasted billing determinants	$	391,424,752
2	Total Proposed Delivery Increase		15,286,960
3	Total Proposed Delivery Increase Adjusted for SBC Exempt EE Tracker		15,360,759
4	SBC EE Tracker moved to Delivery		3,750,843
5			
6	Heat Pump moved to Delivery		794,258
7			
8	AMI Investment in Delivery		0
9	AMI IT Costs		0
10	**Net Delivery Revenue Increase (Decrease)**		**10,815,658**
11	Less: Change in BIPP - Revenue		(0)
12	Less: Change in MFC - Delivery Revenue		(0)
13			
14	**Residual Delivery Revenue Increase (Decrease)**	**$**	**10,815,659**
15	Total Proposed Revenue (at overall increase or decrease)	$	406,785,512

							Detail of Revenue Increase Components					
	B	C	D	E	F	G	H	I	J	K	L	M
			Delivery Revenue Prior to Rate Increase $	Revenue Requirement Increase $	Rate Year Delivery Revenues $	Total Proposed Revenue Percent Change $	Total Proposed Revenue Percent Change Residual Only %	Percent of Total Change Attributed to SBC EE Tracker %	Percent of Total Change Attributed to Heat Pumps	Percent of Total Change Attributed to DVM %	Percent of Total Change Attributed to AMI Investment in Delivery %	Percent of Total Change Attributed to AMI IT Costs %
16	PSC 18 & 19 Service Classifications (SC)											
17	SC1	Residential Service	198,715,985	9,284,450	208,000,435	4.7%	3.6%	0.7%	0.3%	0.0%	0.000%	0.000%
18	SC2	General Service - Small Use	14,963,206	577,775	15,540,981	3.9%	3.0%	0.8%	0.1%	0.0%	0.000%	0.000%
19	SC3	General Service - 100 kW Minimum	30,422,315	1,084,834	31,507,149	3.6%	2.4%	1.1%	0.1%	0.0%	0.000%	0.000%
20	SC4	Residential Service TOU	4,427,326	80,181	4,507,507	1.8%	0.6%	0.9%	0.4%	0.0%	0.000%	0.000%
21	SC7	General Service - 12 kW Minimum	53,451,614	1,172,703	54,624,318	2.2%	1.3%	0.8%	0.1%	0.0%	0.000%	0.000%
22	SC 8P	Large General Service - Primary	20,778,380	910,802	21,689,183	4.4%	2.8%	1.5%	0.1%	0.0%	0.000%	0.000%
23	SC 8S	Large General Service - Secondary	28,832,349	1,054,877	29,887,226	3.7%	2.3%	1.3%	0.1%	0.0%	0.000%	0.000%
24	SC 8STComm	Subtransmission - Commercial	9,206,221	224,799	9,431,020	2.4%	0.2%	2.1%	0.1%	0.0%	0.000%	0.000%
25	SC 8STInd	Subtransmission - Industrial	14,433,114	333,337	14,766,451	2.3%	0.1%	2.2%	0.1%	0.0%	0.000%	0.000%
26	SC 8T	Transmission	742,617	31,639	774,256	4.3%	2.2%	2.0%	0.1%	0.0%	0.000%	0.000%
27	SC 8SubS	Substation	2,851,527	53,719	2,905,245	1.9%	0.1%	1.7%	0.1%	0.0%	0.000%	0.000%
28	SC 9	General Service - Time-of-Use	2,719,519	54,356	2,773,875	2.0%	1.1%	0.9%	0.1%	0.0%	0.000%	0.000%
29	Lighting	Area Lighting & Street Lighting	5,470,529	186,260	5,656,789	3.4%	2.9%	0.5%	0.1%	0.0%	0.000%	0.000%
30	SC 14 - Standby Service		4,410,049	311,027	4,721,076	7.1%	3.9%	3.1%	0.1%	0.0%	0.000%	0.000%
31												
32	Subtotal PSC 18 and 19		391,424,752	15,360,760	406,785,512	3.9%	2.8%	1.0%	0.2%	0.0%	0.0%	0.0%

Rochester Gas and Electric Corporation
Electric Department
Development of Delivery Revenues - SETTLEMENT
Rate Year May 1, 2021 - April 30, 2022

		A	C	D = C minus B	E = D divided by B
		Delivery Revenue Prior to EE Tracker Transfer and Delivery Rate Increase $	Rate Year Delivery Revenues $	Revenue Increase/ (Decrease)	Change $
1	PSC 19 Service Classifications (SC)				
2	SC #1 - Residential Service	$ 208,504,089	$ 225,323,408	$ 16,819,319	8.1%
3	SC #4 -Residential Service TOU				
4	Schedule I	$ 2,143,135	$ 2,240,290	$ 97,156	4.5%
5	Schedule II	$ 2,243,290	$ 2,344,938	$ 101,648	4.5%
6	SC #2 - General Service - Small Use	$ 15,582,873	$ 16,772,208	$ 1,189,335	7.6%
7	SC #3 - General Service - 100 kW Minimum	$ 31,498,248	$ 33,500,092	$ 2,001,843	6.4%
				$ -	
8	SC #7 - General Service - 12 kW Minimum	$ 54,623,140	$ 56,458,526	$ 1,835,386	3.4%
9	SC #8 - Large General Service - Time-of-Use				
10	SC #8 - Primary	$ 21,664,895	$ 23,198,839	$ 1,533,944	7.1%
11	SC #8 - Secondary	$ 29,895,774	$ 31,842,618	$ 1,946,843	6.5%
12	SC #8 - Subtransmission - Commercial	$ 9,423,190	$ 9,903,637	$ 480,446	5.1%
13	SC #8 - Subtransmission - Industrial	$ 14,714,581	$ 15,213,050	$ 498,469	3.4%
14	SC #8 - Transmission	$ 774,720	$ 828,404	$ 53,683	6.9%
15	SC #8 - Substation	$ 2,903,023	$ 2,998,840	$ 95,817	3.3%
16	SC #9 - General Service - Time-of-Use	$ 2,775,057	$ 2,866,728	$ 91,671	3.3%
17	SC #14 - Standby Service	$ 4,721,076	$ 4,919,461	$ 198,385	4.2%
18	SC #6 - Area Lighting	$ 1,183,113	$ 1,251,965	$ 68,852	5.8%
19	Total P.S.C. 19 Revenue	$ 402,650,204	$ 429,663,003	$ 27,012,799	6.7%
20	PSC 18 Service Classifications (SC)				
21	SC #1 - Street Lighting Service	$ 2,771,103	$ 2,932,369	$ 161,266	5.8%
22	SC #2 - Street Lighting Service - Customer Owned Equip.	$ 1,516,708	$ 1,604,974	$ 88,266	5.8%
23	SC #3 - Traffic Signal Service	$ 103,422	$ 109,441	$ 6,019	5.8%
24	Total P.S.C. 18 Revenue	$ 4,391,233	$ 4,646,784	$ 255,551	5.8%
25	Subtotal PSC 18 and 19 Base Delivery Revenue	$ 407,041,437	$ 434,309,787	$ 27,268,350	6.7%
26	Adj to Match RR (Units & Rates Differences)	$ (85,647)		$ 85,647	
27	Less: Economic Development Discounts	$ -	$ -		
28	EE Tracker Exemptions		$ (91,917)	$ (91,917)	
29	Bill Issuance and Payment Processing Revenue	$ 2,681,904	$ 2,681,904	$ -	
30	MFC/POR - Credit/Coll/Call Ctr/Admin	$ 5,559,008	$ 5,559,008	$ -	
31	Subtotal PSC 18 and 19 Base Delivery Revenue After Adjustments	$ 415,196,703	$ 442,458,783	$ 27,262,080	6.6%
32	Other Delivery Revenue Adjustments:				
33	Less:Rate Increase Shaping Deferral	$ (18,581,731)	$ (18,581,731)		
34	Clean Energy Fund	$ 35,880,063	$ 35,880,063	$ -	
35	Dynamic Load Management Surcharge	$ 3,054,735	$ 3,054,735	$ -	
36	Gross Revenue Tax	$ 6,673,156	$ 7,475,331	$ 802,175	
37	Total Tariff Delivery Revenue	$ 442,222,926	$ 470,287,181	$ 28,064,255	6.3%

Rochester Gas and Electric Corporation
Electric Department
Electric Revenue Allocation - SETTLEMENT
Rate Year May 1, 2021 - April 30, 2022

Rate Case Revenues

1	Current Delivery Revenues with forecasted billing determinants	$	407,041,437
2	Total Proposed Delivery Increase		27,262,080
3	Total Proposed Delivery Increase Adjusted for SBC Exempt EE Tracker		27,353,997
4	SBC EE Tracker moved to Delivery		4,759,906
5			
6	Heat Pump moved to Delivery		399,124
7			
8	AMI Investment in Delivery		1,543,796
9	AMI IT Costs		3,085,719
10	**Net Delivery Revenue Increase (Decrease)**		**17,565,451**
11	Less: Change in BIPP - Revenue		-
12	Less: Change in MFC - Delivery Revenue		-
13	Plus: Adj to Match RR (Units & Rates Differences)		(85,647)
14	**Residual Delivery Revenue Increase (Decrease)**	**$**	**17,479,804**
15	Total Proposed Revenue (at overall increase or decrease)	$	434,309,787

							Detail of Revenue Increase Components					
	B	C	D	E	F	G	H	I	J	K	L	M
			Delivery Revenue Prior to Rate Increase	Revenue Requirement Increase	Rate Year Delivery Revenues	Total Proposed Revenue Percent Change	Total Proposed Revenue Percent Change Residual Only	Percent of Total Change Attributed to SBC EE Tracker	Percent of Total Change Attributed to Heat Pumps	Percent of Total Change Attributed to DVM	Percent of Total Change Attributed to AMI Investment in Delivery	Percent of Total Change Attributed to AMI IT Costs
			$	$	$	$	%	%		%	%	%
16	PSC 18 & 19 Service Classifications (SC)											
17	SC1	Residential Service	208,504,089	16,819,319	225,323,408	8.1%	5.6%	0.8%	0.16%	0.0%	0.626%	0.883%
18	SC2	General Service - Small Use	15,582,873	1,189,335	16,772,208	7.6%	4.7%	1.0%	0.03%	0.0%	0.898%	1.013%
19	SC3	General Service - 100 kW Minimum	31,498,248	2,001,843	33,500,092	6.4%	4.3%	1.3%	0.03%	0.0%	0.032%	0.643%
20	SC4	Residential Service TOU	4,386,424	198,804	4,585,228	4.5%	2.0%	1.1%	0.18%	0.0%	0.313%	0.855%
21	SC7	General Service - 12 kW Minimum	54,623,140	1,835,386	56,458,526	3.4%	1.7%	1.0%	0.03%	0.0%	0.120%	0.546%
22	SC 8P	Large General Service - Primary	21,664,895	1,533,944	23,198,839	7.1%	4.4%	1.8%	0.03%	0.0%	0.007%	0.773%
23	SC 8S	Large General Service - Secondary	29,895,774	1,946,843	31,842,618	6.5%	4.2%	1.6%	0.03%	0.0%	0.012%	0.710%
24	SC 8STComm	Subtransmission - Commercial	9,423,190	480,446	9,903,637	5.1%	2.0%	2.7%	0.03%	0.0%	0.005%	0.387%
25	SC 8STInd	Subtransmission - Industrial	14,714,581	498,469	15,213,050	3.4%	0.3%	2.7%	0.03%	0.0%	0.004%	0.331%
26	SC 8T	Transmission	774,720	53,683	828,404	6.9%	4.2%	2.4%	0.03%	0.0%	0.005%	0.330%
27	SC 8SubS	Substation	2,903,023	95,817	2,998,840	3.3%	0.8%	2.2%	0.03%	0.0%	0.009%	0.292%
28	SC 9	General Service - Time-of-Use	2,775,057	91,671	2,866,728	3.3%	1.5%	1.1%	0.03%	0.0%	0.083%	0.561%
29	Lighting	Area Lighting & Street Lighting	5,574,346	324,403	5,898,749	5.8%	4.6%	0.6%	0.04%	0.0%	0.000%	0.541%
30	SC 14 - Standby Service		4,721,076	198,385	4,919,461	4.2%	-0.1%	3.6%	0.04%	0.0%	0.008%	0.558%
31												
32	Subtotal PSC 18 and 19		407,041,437	27,268,350	434,309,787	6.7%	4.3%	1.2%	0.1%	0.0%	0.4%	0.8%

Rochester Gas and Electric Corporation
Electric Department
Development of Delivery Revenues - SETTLEMENT
Rate Year May 1, 2022 - April 30, 2023

		A	C	D = C minus B	E = D divided by B
		Delivery Revenue Prior to EE Tracker Transfer and Delivery Rate Increase $	Rate Year Delivery Revenues $	Revenue Increase/ (Decrease)	Change $
1	PSC 19 Service Classifications (SC)				
2	SC #1 - Residential Service	$ 225,668,334	$ 243,893,362	$ 18,225,029	8.1%
3	SC #4 -Residential Service TOU				
4	Schedule I	$ 2,174,359	$ 2,278,506	$ 104,147	4.8%
5	Schedule II	$ 2,278,472	$ 2,387,427	$ 108,956	4.8%
6	SC #2 - General Service - Small Use	$ 16,797,923	$ 18,119,471	$ 1,321,548	7.9%
7	SC #3 - General Service - 100 kW Minimum	$ 33,450,411	$ 35,629,781	$ 2,179,370	6.5%
				$ -	
8	SC #7 - General Service - 12 kW Minimum	$ 56,407,121	$ 58,358,441	$ 1,951,320	3.5%
9	SC #8 - Large General Service - Time-of-Use				
10	SC #8 - Primary	$ 23,128,183	$ 25,407,180	$ 2,278,997	9.9%
11	SC #8 - Secondary	$ 31,806,212	$ 33,904,991	$ 2,098,780	6.6%
12	SC #8 - Subtransmission - Commercial	$ 9,882,331	$ 10,407,026	$ 524,694	5.3%
13	SC #8 - Subtransmission - Industrial	$ 15,106,238	$ 15,635,603	$ 529,365	3.5%
14	SC #8 - Transmission	$ 822,801	$ 880,097	$ 57,296	7.0%
15	SC #8 - Substation	$ 2,991,206	$ 3,093,421	$ 102,215	3.4%
16	SC #9 - General Service - Time-of-Use	$ 2,864,868	$ 2,961,724	$ 96,857	3.4%
17	SC #14 - Standby Service	$ 4,919,461	$ 5,161,760	$ 242,299	4.9%
18	SC #6 - Area Lighting	$ 1,253,991	$ 1,328,846	$ 74,855	6.0%
19	Total P.S.C. 19 Revenue	$ 429,551,911	$ 459,447,636	$ 29,895,725	7.0%
20	PSC 18 Service Classifications (SC)				
21	SC #1 - Street Lighting Service	$ 2,867,764	$ 3,038,951	$ 171,187	6.0%
22	SC #2 - Street Lighting Service - Customer Owned Equip.	$ 1,573,838	$ 1,667,786	$ 93,948	6.0%
23	SC #3 - Traffic Signal Service	$ 109,438	$ 115,971	$ 6,533	6.0%
24	Total P.S.C. 18 Revenue	$ 4,551,040	$ 4,822,707	$ 271,667	6.0%
25	Subtotal PSC 18 and 19 Base Delivery Revenue	$ 434,102,951	$ 464,270,343	$ 30,167,392	6.9%
26	Adj to Match RR (Units & Rates Differences)	$ (72,709)		$ 72,709	
27	Less: Economic Development Discounts	$ -	$ -		
28	EE Tracker Exemptions		$ (94,402)	$ (94,402)	
29	Bill Issuance and Payment Processing Revenue	$ 2,687,822	$ 2,687,822	$ -	
30	MFC/POR - Credit/Coll/Call Ctr/Admin	$ 5,559,004	$ 5,559,004	$ -	
31	Subtotal PSC 18 and 19 Base Delivery Revenue After Adjustments	$ 442,277,069	$ 472,422,768	$ 30,145,699	6.8%
32	Other Delivery Revenue Adjustments:				
33	Less:Rate Increase Shaping Deferral	$ 6,513,269	$ 6,513,269		
34	Clean Energy Fund	$ 34,696,841	$ 34,696,841	$ -	
35	Dynamic Load Management Surcharge	$ 3,291,808	$ 3,291,808	$ -	
36	Gross Revenue Tax	$ 7,524,585	$ 8,099,870	$ 575,285	
37	Total Tariff Delivery Revenue	$ 494,303,572	$ 525,024,555	$ 30,720,984	6.2%

Rochester Gas and Electric Corporation
Electric Department
Electric Revenue Allocation - SETTLEMENT
Rate Year May 1, 2022 - April 30, 2023

Rate Case Revenues

1	Current Delivery Revenues with forecasted billing determinants	$	434,102,951
2	Total Proposed Delivery Increase		30,145,699
3	Total Proposed Delivery Increase Adjusted for SBC Exempt EE Tracker		30,240,101
4	SBC EE Tracker moved to Delivery		4,854,767
5			
6	Heat Pump moved to Delivery		497,907
7			
8	AMI Investment in Delivery		1,729,600
9	AMI IT Costs		3,439,247
10	**Net Delivery Revenue Increase (Decrease)**		**19,718,579**
11	Less: Change in BIPP - Revenue		-
12	Less: Change in MFC - Delivery Revenue		-
13	Plus: Adj to Match RR (Units & Rates Differences)		(72,709)
14	**Residual Delivery Revenue Increase (Decrease)**	**$**	**19,645,870**
15	Total Proposed Revenue (at overall increase or decrease)	$	464,270,343

							Detail of Revenue Increase Components					
	B	C	D	E	F	G	H	I	J	K	L	M
			Delivery Revenue Prior to Rate Increase	Revenue Requirement Increase	Rate Year Delivery Revenues	Total Proposed Revenue Percent Change	Total Proposed Revenue Percent Change Residual Only	Percent of Total Change Attributed to SBC EE Tracker	Percent of Total Change Attributed to Heat Pumps	Percent of Total Change Attributed to DVM	Percent of Total Change Attributed to AMI Investment in Delivery	Percent of Total Change Attributed to AMI IT Costs
			$	$	$	$	%	%		%	%	%
16	PSC 18 & 19 Service Classifications (SC)											
17	SC1	Residential Service	225,668,334	18,225,029	243,893,362	8.1%	5.5%	0.8%	0.2%	0.0%	0.648%	0.909%
18	SC2	General Service - Small Use	16,797,923	1,321,548	18,119,471	7.9%	4.9%	0.9%	0.0%	0.0%	0.933%	1.047%
19	SC3	General Service - 100 kW Minimum	33,450,411	2,179,370	35,629,781	6.5%	4.5%	1.3%	0.0%	0.0%	0.034%	0.675%
20	SC4	Residential Service TOU	4,452,831	213,102	4,665,934	4.8%	2.1%	1.1%	0.2%	0.0%	0.345%	0.939%
21	SC7	General Service - 12 kW Minimum	56,407,121	1,951,320	58,358,441	3.5%	1.7%	1.0%	0.0%	0.0%	0.130%	0.590%
22	SC 8P	Large General Service - Primary	23,128,183	2,278,997	25,407,180	9.9%	7.2%	1.8%	0.0%	0.0%	0.007%	0.807%
23	SC 8S	Large General Service - Secondary	31,806,212	2,098,780	33,904,991	6.6%	4.3%	1.5%	0.0%	0.0%	0.012%	0.744%
24	SC 8STComm	Subtransmission - Commercial	9,882,331	524,694	10,407,026	5.3%	2.3%	2.6%	0.0%	0.0%	0.006%	0.411%
25	SC 8STInd	Subtransmission - Industrial	15,106,238	529,365	15,635,603	3.5%	0.4%	2.7%	0.0%	0.0%	0.004%	0.359%
26	SC 8T	Transmission	822,801	57,296	880,097	7.0%	4.3%	2.3%	0.0%	0.0%	0.006%	0.346%
27	SC 8SubS	Substation	2,991,206	102,215	3,093,421	3.4%	0.9%	2.1%	0.0%	0.0%	0.010%	0.316%
28	SC 9	General Service - Time-of-Use	2,864,868	96,857	2,961,724	3.4%	1.6%	1.1%	0.0%	0.0%	0.091%	0.605%
29	Lighting	Area Lighting & Street Lighting	5,805,031	346,522	6,151,553	6.0%	4.8%	0.6%	0.0%	0.0%	0.000%	0.580%
30	SC 14 - Standby Service		4,919,461	242,299	5,161,760	4.9%	0.7%	3.6%	0.1%	0.0%	0.009%	0.598%
31												
32	Subtotal PSC 18 and 19		434,102,951	30,167,392	464,270,343	6.9%	4.5%	1.1%	0.1%	0.0%	0.4%	0.8%

New York State Electric & Gas Corporation
Rochester Gas and Electric Corporation
Embedded Cost of Service Information for Rate Development

Line					
1	**Information from ECOS Studies**	**Source**			
2					
3	New York State Electric & Gas Corporation BIPP	October 15, 2019 Exhibit RARD-R12			$0.90 Per bill
4					
5	Rochester Gas and Electric Corporation BIPP	October 15, 2019 Exhibit RARD-R12			$0.93 Per bill
6					
7					
8	NYSEG Electric CCCC Expenses	October 15, 2019 Exhibit RARD-R12			$5,788,841
9	NYSEG Gas CCCC Expenses	October 15, 2019 Exhibit RARD-R12			$1,688,215
10	RGE Electric CCCC Expenses	October 15, 2019 Exhibit RARD-R12			$1,887,365
11	RGE Gas CCCC Expenses	October 15, 2019 Exhibit RARD-R12			$2,126,991
12					
13	NYSEG Electric Admin Expenses	October 15, 2019 Exhibit RARD-R12			$8,811,637
14	NYSEG Gas Admin Expenses	October 15, 2019 Exhibit RARD-R12			$1,687,410
15	RGE Electric Admin Expenses	October 15, 2019 Exhibit RARD-R12			$3,671,643
16	RGE Gas Admin Expenses	October 15, 2019 Exhibit RARD-R12			$2,653,167
17					
18					
19	**CCCC Fixed Factor Percentage Based on Billed units from Twelve months ending 12/31/2019**				
20	**Determines how much of CCCC will be recovered through POR Discount Rate and how much recovered through MFC rate**				
21		Units			
22	NYSEG Electric MFC	7,239,263,171		91.9%	$5,317,693
23	NYSEG Electric POR	641,399,488		8.1%	$471,148
24		7,880,662,659			$5,788,841
25					
26	NYSEG Gas MFC	278,333,990		94.9%	$1,601,499
27	NYSEG Gas POR	15,070,845		5.1%	$86,716
28		293,404,835			$1,688,215
29					
30	RGE Electric MFC	2,959,521,617		92.8%	$1,751,910
31	RGE Electric POR	228,826,434		7.2%	$135,455
32		3,188,348,051			$1,887,365
33					
34	RGE Gas MFC	307,670,446		95.3%	$2,027,558
35	RGE Gas POR	15,088,406		4.7%	$99,433
		322,758,852			2,126,991

Note:
BIPP = Bill Issuance and Payment Processing Charge
CCCC = Credit and Collection and Call Center Expenses

Example of Street Light Price Pricing Methodology

Static Percentages	
Administrative and General Fee (A&G)	4.50%
Customer Protection Overhead (CPO)	15%

Purchase Agreement Price Applying A&G and CPO	
Net Book Value (NBV)	$100.00
A&G	$100.00*4.5% = $4.50
CPO	$100.00*15% = $15.00
Total Purchase Agreement Sale Price	**$119.50**

	Final Closing Price when NBV Adjustments Do NOT Exceed CPO	**Final Closing Price when NBV Adjustments Exceed CPO**
NBV at Purchase Agreement	$100.00	$100.00
NBV at Final Closing	$114.00	$116.00
NBV Adjustment	**$114.00-$100.00 = $14.00**	**$116.00-$100.00 = $16.00**
Δ between NBV Adjustment and CPO	$14.00-$15.00 = ($1.00)	$16.00-$15.00 = $1.00
NBV	$100.00	$100.00+$1.00 = $101.00
A&G	$100.00*4.5% = $4.50	($100.00*4.5%) + ($1.00*4.5%) = $4.55
CPO	$100.00*15% = $15.00	($100.00*15%) + ($1.00*15%) = $15.15
Final Closing Price	**$119.50**	**$120.70**

Electric Rate Plan Rates and Bill Impacts

Index of Schedules

New York State Electric & Gas Corporation
Electric Department
Retail Delivery Rates

P.S.C. No. 120 - Electric
Service Class No. 1
Residential Service

		Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:		$15.11	$15.11	$16.05	$17.00
Energy Charge:	All kWh per kWh:	$0.04030	$0.04523	$0.05244	$0.06009
Bill Issuance Payment Processing Charge:		$0.81	$0.90	$0.90	$0.90

P.S.C. No. 120 - Electric
Service Class No. 8
Residential Service - Day/Night

		Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:		$17.40	$17.40	$18.50	$19.60
Energy:	Day, per kWh:	$0.03595	$0.04072	$0.04769	$0.05521
	Night, per kWh:	$0.03595	$0.04072	$0.04769	$0.05521
Bill Issuance Payment Processing Charge:		$0.81	$0.90	$0.90	$0.90

P.S.C. No. 120 - Electric
Service Class No. 12
Residential Service - TOU

		Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:		$24.11	$24.11	$25.60	$27.15
Energy:	On-Peak, per kWh:	$0.03780	$0.03961	$0.04331	$0.04698
	Mid-Peak, per kWh:	$0.03780	$0.03961	$0.04331	$0.04698
	Off-Peak, per kWh:	$0.03780	$0.03961	$0.04331	$0.04698
Bill Issuance Payment Processing Charge:		$0.81	$0.90	$0.90	$0.90

New York State Electric & Gas Corporation
Electric Department

P.S.C. No. 120 - Electric
Service Class No. 6
Non Residential General Service

		Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:		$17.60	$17.60	$18.70	$19.80
Energy Charge:	All kWh per kWh:	$0.04446	$0.05166	$0.06165	$0.07272
Bill Issuance Payment Processing Charge:		$0.81	$0.90	$0.90	$0.90

P.S.C. No. 120 - Electric
Service Class No. 9
Non Residential General Service - Day/Night

		Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:		$20.41	$20.41	$21.70	$23.00
Energy:	Day, per kWh:	$0.03842	$0.04332	$0.05078	$0.05895
	Night, per kWh:	$0.03842	$0.04332	$0.05078	$0.05895
Bill Issuance Payment Processing Charge:		$0.81	$0.90	$0.90	$0.90

P.S.C. No. 120 - Electric
Service Class No. 3S
Non Residential Primary Service - Subtransmission

		Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:		$333.06	$333.06	$391.55	$450.00
Demand:	All kW:	$4.21	$4.47	$4.43	$4.39
Reactive Charge:	Per rkVah:	$0.00078	$0.00078	$0.00078	$0.00078
Bill Issuance Payment Processing Charge:		$0.81	$0.90	$0.90	$0.90

New York State Electric & Gas Corporation
Electric Department
Retail Delivery Rates

P.S.C. No. 120 - Electric
Service Class No. 2
Non Residential General Service - Secondary

		Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:		$24.31	$24.31	$28.65	$33.00
Demand:	All kW:	$9.43	$10.11	$11.25	$12.40
Energy Charge:	All kWh per kWh:	$0.00251	$0.00201	$0.00161	$0.00129
Reactive Charge:	Per rkVah:	$0.00078	$0.00078	$0.00078	$0.00078
Bill Issuance Payment Processing Charge:		$0.81	$0.90	$0.90	$0.90

P.S.C. No. 120 - Electric
Service Class No. 3P
Non Residential - Primary Service

		Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:		$101.17	$101.17	$119.00	$137.00
Demand:	All kW:	$5.93	$6.90	$8.30	$9.71
Energy Charge:	All kWh per kWh:	$0.00253	$0.00202	$0.00162	$0.00130
Reactive Charge:	Per rkVah:	$0.00078	$0.00078	$0.00078	$0.00078
Bill Issuance Payment Processing Charge:		$0.81	$0.90	$0.90	$0.90

New York State Electric & Gas Corporation
Electric Department
Retail Delivery Rates

P.S.C. No. 120 - Electric
Service Class No. 7-1
Non Residential Large General Service - Secondary

		Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:		$160.65	$201.00	$209.00	$217.00
Demand:	All kW:	$8.56	$8.57	$9.13	$9.69
Reactive Charge:	Per rkVah:	$0.00078	$0.00078	$0.00078	$0.00078
Bill Issuance Payment Processing Charge:		$0.81	$0.90	$0.90	$0.90

P.S.C. No. 120 - Electric
Service Class No. 7-2
Non Residential Large General Service - Primary

		Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:		$561.77	$702.00	$730.00	$758.00
Demand:	All kW:	$7.03	$7.43	$8.53	$9.64
Reactive Charge:	Per rkVah:	$0.00078	$0.00078	$0.00078	$0.00078
Bill Issuance Payment Processing Charge:		$0.81	$0.90	$0.90	$0.90

New York State Electric & Gas Corporation
Electric Department
Retail Delivery Rates

P.S.C. No. 120 - Electric
Service Class No. 7-3
Non Residential Large General Service - Subtransmission

		Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:		$1,169.55	$1,462.00	$1,520.00	$1,579.00
Demand:	All kW:	$2.03	$1.95	$2.22	$2.42
Reactive Charge:	Per rkVah:	$0.00078	$0.00078	$0.00078	$0.00078
Bill Issuance Payment Processing Charge:		$0.81	$0.90	$0.90	$0.90

P.S.C. No. 120 - Electric
Service Class No. 7-4
Non Residential Large General Service - Transmission

		Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:		$2,641.63	$2,800.00	$3,000.00	$3,200.00
Demand:	All kW:	$0.79	$0.94	$1.34	$1.70
Reactive Charge:	Per rkVah:	$0.00078	$0.00078	$0.00078	$0.00078
Bill Issuance Payment Processing Charge:		$0.81	$0.90	$0.90	$0.90

New York State Electric & Gas Corporation
Electric Department
Retail Delivery Rates

P.S.C. No. 120 - Electric
Service Class No. 11
Standby Service

	Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge (per month):				
S C 1	$ 15.11	$ 15.11	$ 16.05	$ 17.00
S C 8 Day/Night	$ 17.40	$ 17.40	$ 18.50	$ 19.60
S C 12 TOU	$ 24.11	$ 24.11	$ 25.60	$ 27.15
S C 6	$ 17.60	$ 17.60	$ 18.70	$ 19.80
S C 9 Day/Night	$ 20.41	$ 20.41	$ 21.70	$ 23.00
S C 2 - Secondary	$ 24.31	$ 24.31	$ 28.65	$ 33.00
S C 3P - Primary	$ 101.17	$ 101.17	$ 119.00	$ 137.00
S C 3S - SubTransmission	$ 333.06	$ 333.06	$ 391.55	$ 450.00
S C 7-1 - Secondary	$ 160.65	$ 201.00	$ 209.00	$ 217.00
S C 7-2 - Primary	$ 561.77	$ 702.00	$ 730.00	$ 758.00
S C 7-3 - Sub Transmission	$ 1,169.55	$ 1,462.00	$ 1,520.00	$ 1,579.00
S C 7-4 - Transmission	$ 2,641.63	$ 2,800.00	$ 3,000.00	$ 3,200.00
Contract Demand Charge (per kW):				
S C 2 - Secondary	$ 4.76	$ 4.48	$ 4.90	$ 5.33
S C 3P - Primary	$ 3.84	$ 3.32	$ 3.89	$ 4.47
S C 3S - SubTransmission	$ 1.43	$ 1.20	$ 1.19	$ 1.18
S C 7-1 - Secondary	$ 3.58	$ 3.55	$ 3.79	$ 4.02
S C 7-2 - Primary	$ 3.20	$ 3.33	$ 3.84	$ 4.35
S C 7-3 - Sub Transmission	$ 0.82	$ 0.77	$ 0.89	$ 0.97
S C 7-4 - Transmission	$ 0.09	$ 0.12	$ 0.17	$ 0.21
Contract Demand Charge (per month):				
S C 1	$ 13.35	$ 14.98	$ 17.43	$ 20.04
S C 8 Day/Night	$ 22.87	$ 25.19	$ 28.92	$ 32.80
S C 12 TOU	$ 87.55	$ 86.36	$ 93.03	$ 99.40
S C 6	$ 8.71	$ 10.66	$ 12.63	$ 14.77
S C 9 Day/Night	$ 18.61	$ 22.15	$ 25.76	$ 29.59
As-Used Demand Charge (per Daily kW):				
S C 2 - Secondary	$0.23174	$0.21826	$0.23860	$0.25941
S C 3P - Primary	$0.20417	$0.17669	$0.20677	$0.23755
S C 3S - SubTransmission	$0.15822	$0.13326	$0.13177	$0.13079
S C 7-1 - Secondary	$0.19549	$0.19378	$0.20684	$0.21929
S C 7-2 - Primary	$0.15357	$0.15987	$0.18433	$0.20857
S C 7-3 - Sub Transmission	$0.06052	$0.05718	$0.06538	$0.07152
S C 7-4 - Transmission	$0.03957	$0.05190	$0.07414	$0.09364
As-Used Demand Charge (per kWh):				
S C 1	$0.02020	$0.02267	$0.02638	$0.03033
S C 8 Day/Night	$0.01570	$0.01729	$0.01986	$0.02252
S C 12 TOU	$0.01710	$0.01687	$0.01817	$0.01941
S C 6	$0.01872	$0.02290	$0.02715	$0.03175
S C 9 Day/Night	$0.01479	$0.01760	$0.02047	$0.02351
Bill Issuance Payment Processing Charge:	$ 0.81	$ 0.90	$ 0.90	$ 0.90

New York State Electric & Gas Corporation
Electric Department
Retail Delivery Rates

P.S.C. No. 120 S.C.5 - Outdoor Lighting

		Current Monthly Delivery Charges	Rate Year 1	Rate Year 2	Rate Year 3
Delivery Charge					
Energy Charge (All kilowatt-hours, per kilowatt-hour)		$0.02480	$0.02668	$0.02983	$0.03322
Safeguard Luminaires (Post - 2/1/88)					
14,500	150 Watt	$6.09	$6.55	$7.32	$8.15
43,000	400 Watt	$8.94	$9.62	$10.75	$11.97
123,000	940 Watt	$7.41	$7.97	$8.91	$9.92
Lamp Charge: Area Lights					
3,300	50 H.P.S. (PACKLITE)***	$3.31	$3.56	$3.98	$4.43
5,200	70 H.P.S. (PACKLITE)***	$3.26	$3.51	$3.92	$4.37
8,500	100 H.P.S. (PACKLITE)***	$3.23	$3.47	$3.88	$4.32
3,200	100 Mercury (PACKLITE)	$3.13	$3.37	$3.77	$4.20
5,200	70 H.P.S. Power Brk.	$6.24	$6.71	$7.50	$8.35
8,500	100 H.P.S. Power Brk.	$6.79	$7.30	$8.16	$9.09
14,400	150 H.P.S.	$11.20	$12.05	$13.47	$15.00
24,700	250 H.P.S.	$10.98	$11.81	$13.20	$14.70
45,000	400 H.P.S.	$10.73	$11.54	$12.90	$14.37
126,000	1,000 H.P.S.	$10.01	$10.77	$12.04	$13.41
10,500	175 Metal Halide Power Brk.	$4.62	$4.97	$5.56	$6.19
16,000	250 Metal Halide	$11.90	$12.80	$14.31	$15.94
28,000	400 Metal Halide	$11.75	$12.64	$14.13	$15.74
Lamp Charge: Flood Lights					
14,400	150 H.P.S.	$11.94	$12.84	$14.35	$15.98
24,700	250 H.P.S.	$11.74	$12.63	$14.12	$15.73
45,000	400 H.P.S.	$11.53	$12.40	$13.86	$15.44
126,000	1,000 H.P.S.	$12.84	$13.81	$15.44	$17.20
16,000	250 Metal Halide	$11.13	$11.97	$13.38	$14.90
28,000	400 Metal Halide	$12.26	$13.19	$14.75	$16.43
88,000	1,000 Metal Halide	$12.79	$13.76	$15.38	$17.13
10,000	70 - 90 LED	N/A	$7.27	$8.13	$9.05
15,000	111 - 113 LED	N/A	$7.82	$8.74	$9.73
Lamp ("Shoebox") Luminaire					
14,400	150 H.P.S.	$12.61	$13.57	$15.17	$16.90
24,700	250 H.P.S.	$14.88	$16.01	$17.90	$19.94
45,000	400 H.P.S.	$15.78	$16.98	$18.98	$21.14
16,000	250 M. Halide	$11.92	$12.82	$14.33	$15.96
28,000	400 M. Halide	$11.76	$12.65	$14.14	$15.75
88,000	1,000 M. Halide	$16.93	$18.21	$20.36	$22.68
67,000	50 - 69 LED	N/A	$8.72	$9.75	$10.86
10,000	70 - 90 LED	N/A	$8.72	$9.75	$10.86
Lamp Charge: Post Tops					
3,300	50 H.P.S.	$9.17	$9.86	$11.02	$12.27
5,200	70 H.P.S.	$9.17	$9.86	$11.02	$12.27
8,500	100 H.P.S.	$9.15	$9.84	$11.00	$12.25
4,500	30 - 49 LED	N/A	$8.41	$9.40	$10.47
Lamp: High Pressure Sodium Cobra (non-residential)					
5,200	70 H.P.S.	$6.82	$7.34	$8.21	$9.14
8,500	100 H.P.S.	$6.82	$7.34	$8.21	$9.14
3,000	20 - 29 LED	N/A	$2.88	$3.22	$3.59
4,500	30 - 49 LED	N/A	$2.88	$3.22	$3.59
Bill Issuance Payment Processing Charge:		$ 0.81	$ 0.90	$ 0.90	$ 0.90

New York State Electric & Gas Corporation
Electric Department
Retail Delivery Rates

P.S.C. No. 120 S.C.5 - Outdoor Lighting

Brackets - Standard (up to 16')		$0.00	$0.00	$0.00	$0.00
Brackets - 16' and over		$2.24	$2.41	$2.69	$3.00
Additional Wood Pole Installed for Lamp		$11.46	$12.33	$13.78	$15.35
Wire Service (Overhead) Per circuit foot of extension		$0.032	$0.034	$0.038	$0.042
18' Fiberglass Pole - Direct Embedded		$11.83	$12.73	$14.23	$15.85
30' Metal Pole - Pedestal Mount		$41.08	$44.19	$49.40	$55.02
30' Fiberglass Pole - Direct Embedded		$17.99	$19.35	$21.63	$24.09
Installations prior to 2/1/88					
7,000		$9.63	$10.36	$11.58	$12.90
17,200		$12.44	$13.38	$14.96	$16.66
48,000		$13.37	$14.38	$16.08	$17.91
Additional Facilities					
Additional Wood Pole		$4.34	$4.67	$5.22	$5.81
Wire Service (per Circuit foot)		$0.012	$0.013	$0.015	$0.017
Monthly Operation, Maintenance and Energy Charges					
Mercury Vapor					
3,200	100 M.V.	$1.74	$1.87	$2.09	$2.33
High Pressure Sodium					
5200	70 H.P.S.	$2.23	$2.40	$2.68	$2.98
8,500	100 H.P.S.	$2.14	$2.30	$2.57	$2.86
14,400	150 H.P.S.	$1.96	$2.11	$2.36	$2.63
45,000	400 H.P.S.	$0.91	$0.98	$1.10	$1.23
Metal Halide					
5,800	100 M.H.	$1.73	$1.86	$2.08	$2.32
16,000	250 M.H.	$1.73	$1.86	$2.08	$2.32
28,000	400 M.H.	$1.28	$1.38	$1.54	$1.72
88,000	1,000 M.H.	$0.35	$0.38	$0.42	$0.47
Bill Issuance Payment Processing Charge:		$ 0.81	$ 0.90	$ 0.90	$ 0.90

New York State Electric & Gas Corporation

Electric Department
Retail Delivery Rates

P.S.C. No. 121 S.C. 1 - Street Lighting

	Current	Rate Year 1	Rate Year 2	Rate Year 3
	Monthly Delivery Rate	Monthly Delivery Rate	Monthly Delivery Rate	Monthly Delivery Rate
Delivery Charge				
Energy Charge (All kilowatthours, per kilowatthour)	$0.02508	$0.02596	$0.02777	$0.02968
High Pressure Sodium				
50 Watts - 3,300 Lumen	$3.18	$3.29	$3.52	$3.76
70 Watts - 5,200 Lumen	$3.23	$3.34	$3.57	$3.82
100 Watt - 8,500 Lumen	$3.23	$3.34	$3.57	$3.82
150 Watts - 14,400 Lumen	$3.23	$3.34	$3.57	$3.82
250 Watts - 24,700 Lumen	$3.23	$3.34	$3.57	$3.82
400 Watts - 45,000 Lumen	$3.23	$3.34	$3.57	$3.82
Bill Issuance Payment Processing Charge:	$ 0.81	$ 0.90	$ 0.90	$ 0.90

New York State Electric & Gas Corporation
Electric Department
Retail Delivery Rates

P.S.C. No. 121 S.C. 2 - Street Lighting

	Current	Rate Year 1	Rate Year 2	Rate Year 3
	Monthly Delivery Rate	Monthly Delivery Rate	Monthly Delivery Rate	Monthly Delivery Rate
Delivery Charge				
Energy Charge (All kilowatthours, per kilowatthour)	$0.02550	$0.02640	$0.02823	$0.03018
High Pressure Sodium				
50 Watts - 3,300 Lumen	$1.43	$1.48	$1.58	$1.69
70 Watts - 5,200 Lumen	$1.43	$1.48	$1.58	$1.69
100 Watts - 8,500 Lumen	$1.45	$1.50	$1.60	$1.71
150 Watts - 14,400 Lumen	$1.45	$1.50	$1.60	$1.71
250 Watts - 24,700 Lumen	$1.47	$1.52	$1.63	$1.74
400 Watts - 45,000 Lumen	$1.51	$1.56	$1.67	$1.79
1000 Watts - 126,000 Lumen	$2.84	$2.94	$3.14	$3.36
Mercury Vapor				
100 Watts+ - 3,200 Lumen	$0.99	$1.02	$1.09	$1.17
175 Watts+ - 7,000 Lumen	$1.02	$1.06	$1.13	$1.21
250 Watts+ - 9,400 Lumen	$1.04	$1.08	$1.16	$1.24
400 Watts+ - 17,200 Lumen	$1.09	$1.13	$1.21	$1.29
Metal Halide				
100 Watts - 5,800 Lumen	$2.93	$3.03	$3.24	$3.46
175 Watts - 12,000 Lumen	$2.93	$3.03	$3.24	$3.46
250 Watts - 16,000 Lumen	$2.95	$3.05	$3.26	$3.48
450 Watts - 28,000 Lumen	$3.01	$3.12	$3.34	$3.57
Other Facilities				
Group Controllers	$3.69	$3.82	$4.09	$4.37
Cable and Conduit	$0.09608	$0.09946	$0.10638	$0.11371
Direct Burial Cable	$0.08221	$0.08510	$0.09102	$0.09729
Cable Only	$0.04374	$0.04528	$0.04843	$0.05177
Undergroung Circuits	$0.05843	$0.06049	$0.06470	$0.06916
Bill Issuance Payment Processing Charge:	$ 0.81	$ 0.90	$ 0.90	$ 0.90

New York State Electric & Gas Corporation
Electric Department
Retail Delivery Rates

P.S.C. No. 121 S.C. 3 - Street Lighting

	Current	Rate Year 1	Rate Year 2	Rate Year 3
	Monthly Delivery Rate	Monthly Delivery Rate	Monthly Delivery Rate	Monthly Delivery Rate
Delivery Charge				
Energy Charge (All kilowatthours, per kilowatthour)	$0.02342	$0.02424	$0.02593	$0.02772
High Pressure Sodium				
Cobra				
50 Watts+ - 3,300 Lumen	$8.15	$8.44	$9.03	$9.65
70 Watts - 5,200 Lumen	$8.15	$8.44	$9.03	$9.65
100 Watts - 8,500 Lumen	$8.15	$8.44	$9.03	$9.65
150 Watts - 14,400 Lumen	$8.15	$8.44	$9.03	$9.65
250 Watts - 24,700 Lumen	$8.15	$8.44	$9.03	$9.65
400 Watts - 45,000 Lumen	$8.62	$8.92	$9.54	$10.20
1000 Watts - 126,000 Lumen	$12.77	$13.22	$14.14	$15.11
High Pressure Sodium				
Post Top				
50 Watts - 3,300 Lumen	$9.42	$9.75	$10.43	$11.15
70 Watts - 5,200 Lumen	$9.42	$9.75	$10.43	$11.15
100 Watts - 8,500 Lumen	$10.70	$11.08	$11.85	$12.67
150 Watts - 14,400 Lumen	$11.95	$12.37	$13.23	$14.14
250 Watts+ - 24,700 Lumen	$11.95	$12.37	$13.23	$14.14
High Pressure Sodium				
Cut Off ("Shoebox")				
70 Watts+ - 5,200 Lumen	$16.53	$17.11	$18.30	$19.56
100 Watts+ - 8,500 Lumen	$16.53	$17.11	$18.30	$19.56
150 Watts+ - 14,400 Lumen	$16.53	$17.11	$18.30	$19.56
250 Watts - 24,700 Lumen	$14.58	$15.09	$16.14	$17.25
400 Watts - 45,000 Lumen	$17.63	$18.25	$19.52	$20.86
Metal Halide				
Cobra				
70 Watts - 4,000 Lumen	$4.98	$5.16	$5.52	$5.90
100 Watts - 5,800 Lumen	$4.98	$5.16	$5.52	$5.90
175 Watts - 12,000 Lumen	$4.90	$5.07	$5.42	$5.79
Metal Halide				
Post Top				
100 Watts - 5,800 Lumen	$5.72	$5.92	$6.33	$6.77

New York State Electric & Gas Corporation
Electric Department
Retail Delivery Rates

P.S.C. No. 121 S.C. 3 - Street Lighting

		Current	Rate Year 1	Rate Year 2	Rate Year 3
		Monthly Delivery Rate	Monthly Delivery Rate	Monthly Delivery Rate	Monthly Delivery Rate
Delivery Charge					
Energy Charge (All kilowatthours, per kilowatthour)		$0.02342	$0.02424	$0.02593	$0.02772
Mercury Vapor					
Cobra					
100 Watts - 3,200 Lumen		$4.45	$4.61	$4.93	$5.27
175 Watts - 7,000 Lumen		$4.45	$4.61	$4.93	$5.27
250 Watts - 9,400 Lumen		$4.65	$4.81	$5.14	$5.49
400 Watts - 17,200 Lumen		$4.72	$4.89	$5.23	$5.59
1000 Watts - 48,000 Lumen		$6.93	$7.17	$7.67	$8.20
Mercury Vapor					
Post Top					
100 Watts - 3,200 Lumen		$5.76	$5.96	$6.37	$6.81
175 Watts - 7,000 Lumen		$5.81	$6.01	$6.43	$6.87
250 Watts - 9,400 Lumen		$5.87	$6.08	$6.50	$6.95
Incandescent					
Post Top					
103 Watts - 1,000 Lumen		$7.10	$7.35	$7.86	$8.40
High Pressure Sodium					
Special Luminaires					
250 Watts+ - 24,700 - Concourse - A		$14.58	$15.09	$16.14	$17.25
400 Watts+ - 45,000 - Concourse - A		$17.63	$18.25	$19.52	$20.86
250 Watts - 24,700 - Hiway Liter		$48.91	$50.63	$54.15	$57.88
400 Watts - 45,000 - Hiway Liter		$48.91	$50.63	$54.15	$57.88
150 Watts - 14,400 - Turnpike		$18.67	$19.33	$20.68	$22.10
250 Watts - 24,700 - Turnpike		$23.25	$24.07	$25.75	$27.52
400 Watts - 45,000 - Turnpike		$22.25	$23.03	$24.63	$26.33
150 Watts - 14,400 - Floodlight		$15.67	$16.22	$17.35	$18.55
250 Watts - 24,700 - Floodlight		$15.67	$16.22	$17.35	$18.55
400 Watts - 45,000 - Floodlight		$15.67	$16.22	$17.35	$18.55
Metal Halide - Floodlights					
250 Watts - 16,000 Lumen		$14.79	$15.31	$16.38	$17.51
400 Watts - 28,000 Lumen		$16.53	$17.11	$18.30	$19.56
Light Emitting Diode (LED)					
LED Cobrahead	Wattage				
2000 Lumen	12 - 19	3.95	$4.09	$4.37	$4.67
3000 Lumen	20 - 29	3.95	$4.09	$4.37	$4.67
4500 Lumen	30 - 49	3.95	$4.09	$4.37	$4.67
6700 Lumen	50 - 69	4.23	$4.38	$4.68	$5.01
10000 Lumen	70 - 90	5.23	$5.41	$5.79	$6.19
15000 Lumen	111 - 133	5.58	$5.78	$6.18	$6.60
Light Emitting Diode (LED)					
LED Flood	Wattage				
10000 Lumen	70 - 90	N/A	$7.03	$7.52	$8.04
15000 Lumen	111 - 133	N/A	$7.56	$8.09	$8.65
Light Emitting Diode (LED)					
LED Shoe Box					
6700 Lumen	50 - 69	N/A	$8.44	$9.02	$9.65
10000 Lumen	70 - 90	N/A	$8.44	$9.02	$9.65
Light Emitting Diode (LED)					
LED Post Top					
4500 Lumen	30 - 49	N/A	$8.13	$8.69	$9.29

New York State Electric & Gas Corporation
Electric Department
Retail Delivery Rates

P.S.C. No. 121 S.C. 3 - Street Lighting

	Current	Rate Year 1	Rate Year 2	Rate Year 3
Pole Installed by the Corporation Solely for Street Lighting Service	Monthly Delivery Rate	Monthly Delivery Rate	Monthly Delivery Rate	Monthly Delivery Rate
Standard Wood Pole	$11.18	$11.57	$12.38	$13.23
Wood Pole - High Mount	$30.58	$31.66	$33.86	$36.19
Steel Pole	$4.94	$5.11	$5.47	$5.85
Square Steel Pole	$17.97	$18.60	$19.89	$21.26
Aluminum Pole 16' and under	$6.73	$6.97	$7.46	$7.97
Alum. Pole over 16' installed prior to 08/1/87	$17.88	$18.51	$19.80	$21.16
Alum. Pole over 16' installed after 07/31/87	$17.88	$18.51	$19.80	$21.16
Alum. Pole over 16' Pedestal Mounted	$26.69	$27.63	$29.55	$31.59
Concrete Pole	$5.62	$5.82	$6.23	$6.66
Laminated Wood Pole	$4.49	$4.65	$4.97	$5.31
Fiberglass Pole Under 18'	$6.29	$6.51	$6.96	$7.44
Fiberglass Pole 18' to 22'	$8.54	$8.84	$9.46	$10.11
Center Bored Wood Pole - (no longer available)	$10.11	$10.47	$11.20	$11.97
Concrete Base for pedestal mounted poles	$23.72	$24.55	$26.26	$28.07
Screw Steel Base Lite	$14.70	$15.22	$16.28	$17.40
Screw Steel Base Heavy	$18.70	$19.36	$20.71	$22.14
Special Brackets				
Standard Bracket - 16' and over	$2.64	$2.73	$2.92	$3.12
Bracket Allowance	($0.70)	($0.72)	($0.77)	($0.82)
Bracket for post-top use on wood poles	$0.45	$0.47	$0.50	$0.53
Circuit Control				
Group Controllers	$3.37	$3.49	$3.73	$3.99
3000 Watt Photo Cell	$2.23	$2.31	$2.47	$2.64
Circuits (Per Trench Foot)				
Cable and Conduit	$0.08760	$0.09068	$0.09699	$0.10367
Direct Burial Cable	$0.07496	$0.07760	$0.08300	$0.08872
Cable Only (Conduit Supplied by Customer)	$0.03988	$0.04128	$0.04415	$0.04719
Underground Circuits	$0.05328	$0.05515	$0.05899	$0.06305
Bill Issuance Payment Processing Charge:	$ 0.81	$ 0.90	$ 0.90	$ 0.90

New York State Electric & Gas Corporation
Electric Department
Retail Delivery Rates

P.S.C. No. 121 S.C. 4 - Street Lighting

	Current	Rate Year 1	Rate Year 2	Rate Year 3
	Monthly Delivery Rate	Monthly Delivery Rate	Monthly Delivery Rate	Monthly Delivery Rate
Delivery Charge				
Energy Charge (All kilowatthours, per kilowatthour)	$0.02905	$0.03007	$0.03217	$0.03438
Bill Issuance Payment Processing Charge:	$ 0.81	$ 0.90	$ 0.90	$ 0.90

New York State Electric & Gas Corporation
Electric Department
Retail Delivery Rates
Electric Economic Development Rates

Service Class		Rate Components	Current EDZI/EJ Rate	RY1 Standard Rates	RY1 EZR/EJ Rates	RY2 Standard Rates	RY2 EZR/EJ Rates	RY3 Standard Rates	RY3 EZR/EJ Rates
SC 2	General Service - Small Use	Demand Charge	$9.43 [1]	$10.11	$10.11 [1]	$11.25	$11.25 [1]	$12.40	$12.40 [1]
SC 3P	General Service - Primary	Demand Charge	$5.93 [1]	$6.90	$6.51	$8.30	$6.54	$9.71	$6.60
SC 3S	General Service - Sub Transmission	Demand Charge	$4.21 [1]	$4.47	$4.47 [1]	$4.43	$4.43 [1]	$4.39	$4.39 [1]
SC 7-1	Large General Service - Time-of-Use Rate - Secondary	Demand Charge	$6.80	$8.57	$6.62	$9.13	$6.44	$9.69	$6.30
SC 7-2	Large General Service - Time-of-Use Rate - Primary	Demand Charge	$7.03 [1]	$7.43	$7.43 [1]	$8.53	$8.53 [1]	$9.64	$9.35
SC 7-3	Large General Service - Time-of-Use Rate - Sub Transmission	Demand Charge	$2.03 [1]	$1.95	$1.95 [1]	$2.22	$2.22 [1]	$2.42	$2.42 [1]
SC 7-4	Large General Service - Time-of-Use Rate - Transmission	Demand Charge	$0.79 [1]	$0.94	$0.94 [1]	$1.34	$1.34 [1]	$1.70	$1.58
SC 9	General Service Day-Night	Kilowatt Hour Charge	$0.03842 [1]	$0.04332	$0.04332 [1]	$0.05078	$0.04908	$0.05895	$0.04824

[1] The economic development rates and the standard rates are the same.

NYSEG Electric
Standby SC11 Meter Credits

Customers That Have Fully Paid for Meter and Instrument Transformation Costs:
Leaf 293 Meter Credits

	SC 2	**SC 3P**	**SC 3S**	**SC 7-1**	**SC 7-2**	**SC 7-3**	**SC 7-4**
Current	$ 1.23	$ 30.63	$ 38.54	$ 3.02	$ 25.48	$ 55.37	$ 284.89
Rate Year 1	$ 0.78	$ 19.34	$ 29.43	$ 1.75	$ 16.36	$ 32.97	$ 190.28
Rate Year 2	$ 0.78	$ 19.34	$ 29.43	$ 1.75	$ 16.36	$ 32.97	$ 190.28
Rate Year 3	$ 0.78	$ 19.34	$ 29.43	$ 1.75	$ 16.36	$ 32.97	$ 190.28

New York State Electric & Gas Corporation
Electric Department
Retail Delivery Rates

P.S.C. No. 120 - Electric
Energy Smart Community (ESC) Rate Option Pilot

ESC Service Class No. 1

	Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:	$15.11	$15.11	$16.05	$17.00
Energy: On-Peak, per kWh:	$0.17774	$0.19950	$0.23126	$0.26500
Off-Peak, per kWh:	$0.02996	$0.03363	$0.03898	$0.04467
Bill Issuance Payment Processing Charge:	$0.81	$0.90	$0.90	$0.90

ESC Service Class No. 8

	Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:	$17.40	$17.40	$18.50	$19.60
Energy: On-Peak, per kWh:	$0.19191	$0.21735	$0.25457	$0.29473
Off-Peak, per kWh:	$0.02722	$0.03083	$0.03611	$0.04180
Bill Issuance Payment Processing Charge:	$0.81	$0.90	$0.90	$0.90

ESC Service Class No. 12

	Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:	$24.11	$24.11	$25.60	$27.15
Energy: On-Peak, per kWh:	$0.15025	$0.15746	$0.17216	$0.18676
Off-Peak, per kWh:	$0.03091	$0.03239	$0.03542	$0.03842
Bill Issuance Payment Processing Charge:	$0.81	$0.90	$0.90	$0.90

ESC Service Class No. 6

	Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:	$17.60	$17.60	$18.70	$19.80
Energy: On-Peak, per kWh:	$0.09034	$0.10498	$0.12527	$0.14777
Off-Peak, per kWh:	$0.03596	$0.04179	$0.04986	$0.05882
Bill Issuance Payment Processing Charge:	$0.81	$0.90	$0.90	$0.90

ESC Service Class No. 2

	Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:	$24.31	$24.31	$28.65	$33.00
Energy: On-Peak, per kW:	$20.13	$21.59	$24.01	$26.48
Non-Summer On-Peak, per kW:	$12.85	$13.78	$15.33	$16.90
All Hours, per kWh:	$0.00251	$0.00201	$0.00161	$0.00129
Bill Issuance Payment Processing Charge:	$0.81	$0.90	$0.90	$0.90

ESC Service Class No. 3P

	Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:	$101.17	$101.17	$119.00	$137.00
Energy: On-Peak, per kW:	$14.30	$16.65	$20.02	$23.43
Off-Peak, per kW:	$7.86	$9.15	$11.01	$12.88
All Hours, per kWh:	$0.00253	$0.00202	$0.00162	$0.00130
Bill Issuance Payment Processing Charge:	$0.81	$0.90	$0.90	$0.90

ESC Service Class No. 7-1 Secondary

	Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:	$160.65	$201.00	$209.00	$217.00
Energy: On-Peak, per kW:	$26.03	$26.05	$27.77	$29.47
Off-Peak, per kW:	$9.35	$9.36	$9.98	$10.59
Bill Issuance Payment Processing Charge:	$0.81	$0.90	$0.90	$0.90

ESC Service Class No. 7-2 Primary

	Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:	$561.77	$702.00	$730.00	$758.00
Energy: On-Peak, per kW:	$20.25	$21.42	$24.59	$27.78
Off-Peak, per kW:	$7.85	$8.30	$9.52	$10.76
Bill Issuance Payment Processing Charge:	$0.81	$0.90	$0.90	$0.90

ESC Service Class No. 7-3 Subtransmission

	Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:	$1,169.55	$1,462.00	$1,520.00	$1,579.00
Energy: On-Peak, per kW:	$6.97	$6.71	$7.62	$8.31
Off-Peak, per kW:	$2.12	$2.05	$2.32	$2.53
Bill Issuance Payment Processing Charge:	$0.81	$0.90	$0.90	$0.90

New York State Electric & Gas Corporation
Electric Department
Retail Delivery Rates

P.S.C. No. 120 - Electric
Service Class No. 8 (SP p)
Residential Service - Day/Night
Plug-In Electric Vehicle

		Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:		$15.11	$15.11	$16.05	$17.00
Energy:	On-Peak, per kWh:	$0.04676	$0.05264	$0.06111	$0.07012
	Off-Peak, per kWh:	$0.01717	$0.01932	$0.02244	$0.02577
Bill Issuance Payment Processing Charge:		$0.81	$0.90	$0.90	$0.90

Rochester Gas and Electric Corporation
Electric Department
Retail Delivery Rates
P.S.C. No. 19 - Electric

Service Classification No. 1
Residential Service

		Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:		$21.38	$21.38	$21.70	$22.00
Energy Charge:	All kWh per kWh:	$0.04219	$0.04569	$0.05153	$0.05792
Bill Issuance Payment Processing Charge:		$0.72	$0.93	$0.93	$0.93

Service Classification No. 4
Residential Time-of-Use Service
Schedule I

		Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:		$25.36	$25.36	$25.80	$26.10
Energy Charge:	On-Peak, per kWh:	$0.04370	$0.04486	$0.04746	$0.05049
	Off-Peak, per kWh:	$0.04370	$0.04486	$0.04746	$0.05049
Bill Issuance Payment Processing Charge:		$0.72	$0.93	$0.93	$0.93

Service Classification No. 4
Residential Time-of-Use Service
Schedule II

		Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:		$28.84	$28.84	$29.25	$29.70
Energy Charge:	On-Peak, per kWh:	$0.05415	$0.05533	$0.05818	$0.06133
	Off-Peak, per kWh:	$0.05415	$0.05533	$0.05818	$0.06133
Bill Issuance Payment Processing Charge:		$0.72	$0.93	$0.93	$0.93

Rochester Gas and Electric Corporation
Electric Department
Retail Delivery Rates
P.S.C. No. 19 - Electric

Service Classification No. 2
General Service - Small Use

		Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:		$21.38	$21.38	$21.70	$22.00
Energy Charge:	All kWh per kWh:	$0.03331	$0.03592	$0.04078	$0.04627
Bill Issuance Payment Processing Charge:		$0.72	$0.93	$0.93	$0.93

Service Classification No. 3
General Service - 100 kW Minimum

		Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:		$297.13	$297.13	$349.00	$401.00
Demand:	All kW:	$16.46	$17.14	$17.94	$18.85
Bill Issuance Payment Processing Charge:		$0.72	$0.93	$0.93	$0.93

Service Classification No. 7
General Service - 12 kW Minimum

		Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:		$88.77	$88.77	$105.00	$120.00
Energy Charge:	First 200 hour use, per kWh:	$0.00831	$0.00665	$0.00532	$0.00425
	Over 200 hour use, per kWh:	$0.00831	$0.00665	$0.00532	$0.00425
Demand:	All kW:	$16.30	$17.37	$17.87	$18.38
Bill Issuance Payment Processing Charge:		$0.72	$0.93	$0.93	$0.93

Rochester Gas and Electric Corporation
Electric Department
Retail Delivery Rates
P.S.C. No. 19 - Electric

Service Classification No. 8
Large General Service - Time-of-Use
Secondary - 300 kW Minimum

		Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:		$910.47	$1,138.00	$1,184.00	$1,229.00
Demand:	All kW:	$14.16	$14.15	$15.16	$16.26
Reactive Charge:	Per rkVah:	$0.00127	$0.00127	$0.00127	$0.00127
Bill Issuance Payment Processing Charge:		$0.72	$0.93	$0.93	$0.93

Service Classification No. 8
Large General Service - Time-of-Use
Substation - 300 kW Minimum

		Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:		$1,969.55	$2,462.00	$2,560.00	$2,659.00
Demand:	All kW:	$8.88	$8.39	$8.65	$8.93
Reactive Charge:	Per rkVah:	$0.00127	$0.00127	$0.00127	$0.00127
Bill Issuance Payment Processing Charge:		$0.72	$0.93	$0.93	$0.93

Service Classification No. 9
General Service

		Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:		$95.50	$95.50	$112.25	$129.00
Energy Charge:	On-Peak, per kWh:	$0.01301	$0.01041	$0.00833	$0.00666
	Off-Peak, per kWh:	$0.01301	$0.01041	$0.00833	$0.00666
Demand:	All kW:	$11.34	$12.35	$13.07	$13.71
Bill Issuance Payment Processing Charge:		$0.72	$0.93	$0.93	$0.93

Rochester Gas and Electric Corporation
Electric Department
Retail Delivery Rates
P.S.C. No. 19 - Electric

Service Classification No. 8
Large General Service - Time-of-Use
Primary - 300 kW Minimum

		Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:		$1,144.87	$1,431.00	$1,488.00	$1,546.00
Demand:	All kW:	$13.79	$14.06	$15.13	$16.77
Reactive Charge:	Per rkVah:	$0.00127	$0.00127	$0.00127	$0.00127
Bill Issuance Payment	Processing Charge:	$0.72	$0.93	$0.93	$0.93

Service Classification No. 8
Large General Service - Time-of-Use
Sub Transmission Commercial - 300 kW Minimum

		Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:		$2,027.62	$2,535.00	$2,636.00	$2,737.00
Demand:	All kW:	$9.85	$9.73	$10.25	$10.84
Reactive Charge:	Per rkVah:	$0.00127	$0.00127	$0.00127	$0.00127
Bill Issuance Payment	Processing Charge:	$0.72	$0.93	$0.93	$0.93

Service Classification No. 8
Large General Service - Time-of-Use
Sub Transmission Industrial - 300 kW Minimum

		Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:		$2,116.77	$2,646.00	$2,752.00	$2,858.00
Demand:	All kW:	$9.16	$9.19	$9.50	$9.84
Reactive Charge:	Per rkVah:	$0.00127	$0.00127	$0.00127	$0.00127
Bill Issuance Payment	Processing Charge:	$0.72	$0.93	$0.93	$0.93

Service Classification No. 8
Large General Service - Time-of-Use
Transmission - 300 kW Minimum

		Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:		$3,703.73	$4,000.00	$4,200.00	$4,400.00
Demand:	All kW:	$8.74	$9.11	$9.78	$10.50
Reactive Charge:	Per rkVah:	$0.00127	$0.00127	$0.00127	$0.00127
Bill Issuance Payment	Processing Charge:	$0.72	$0.93	$0.93	$0.93

Rochester Gas and Electric Corporation
Electric Department
Retail Delivery Rates
P.S.C. No. 19 - Electricity

Service Classification No. 14
Standby Service

	Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge (per month):				
SC 1	$ 21.38	$ 21.38	$ 21.70	$ 22.00
SC 2	$ 21.38	$ 21.38	$ 21.70	$ 22.00
SC 3	$ 297.13	$ 297.13	$ 349.00	$ 401.00
SC 7	$ 88.77	$ 88.77	$ 105.00	$ 120.00
SC 8 - Secondary	$ 910.47	$ 1,138.00	$ 1,184.00	$ 1,229.00
SC 8 - Substation	$1,969.55	$ 2,462.00	$ 2,560.00	$ 2,659.00
SC 8 - Primary	$1,144.87	$ 1,431.00	$ 1,488.00	$ 1,546.00
SC 8 - Subtransmission - Industrial	$2,116.77	$ 2,646.00	$ 2,752.00	$ 2,858.00
SC 8 - Subtransmission - Commercial	$2,027.62	$ 2,535.00	$ 2,636.00	$ 2,737.00
SC 8 - Transmission	$3,703.73	$ 4,000.00	$ 4,200.00	$ 4,400.00
Contract Demand Charge (per kW):				
SC 3	$ 8.33	$ 7.42	$ 7.76	$ 8.14
SC 7	$ 12.07	$ 11.38	$ 11.39	$ 11.46
SC 8 - Secondary	$ 5.84	$ 5.77	$ 6.18	$ 6.62
SC 8 - Substation	$ 3.46	$ 3.83	$ 3.94	$ 4.06
SC 8 - Primary	$ 4.89	$ 5.03	$ 5.41	$ 5.99
SC 8 - Subtransmission - Industrial	$ 1.13	$ 1.19	$ 1.23	$ 1.27
SC 8 - Subtransmission - Commercial	$ 0.94	$ 1.03	$ 1.08	$ 1.14
SC 8 - Transmission	$ 7.50	$ 6.99	$ 7.51	$ 8.01
Contract Demand Charge (per month):				
SC 1	$ 12.90	$ 13.67	$ 15.40	$ 17.29
SC 2	$ 10.63	$ 11.26	$ 12.74	$ 14.41
As-Used Demand Charge (per Daily kW):				
SC 3	$0.44099	$0.39270	$0.41067	$0.43101
SC 7	$0.17112	$0.16136	$0.16154	$0.16250
SC 8 - Secondary	$0.38540	$0.38080	$0.40759	$0.43671
SC 8 - Substation	$0.16164	$0.17879	$0.18403	$0.18976
SC 8 - Primary	$0.40224	$0.41366	$0.44486	$0.49240
SC 8 - Subtransmission - Industrial	$0.37964	$0.40066	$0.41284	$0.42706
SC 8 - Subtransmission - Commercial	$0.34219	$0.37535	$0.39276	$0.41486
SC 8 - Transmission	$0.11301	$0.10533	$0.11309	$0.12075
As-Used Demand Charge (per kWh):				
SC 1	$0.02339	$0.02479	$0.02793	$0.03136
SC 2	$0.01688	$0.01788	$0.02023	$0.02289
Bill Issuance Payment Processing Charge:	0.72	0.93	0.93	0.93

Rochester Gas and Electric Corporation
Electric Department
Retail Delivery Rates

P.S.C. No. 19 - Electricity
Service Classification No. 6 Area Lighting

	Current Rates		Rate Year 1 Rates (per Month)		Rate Year 2 Rates (per Month)		Rate Year 3 Rates (per Month)	
	Residential	Non-Residential	Residential	Non-Residential	Residential	Non-Residential	Residential	Non-Residential
Wire Service For Luminaire	$0.01961	$0.01961	$0.02028	$0.02028	$0.02146	$0.02146	$0.02274	$0.02274
Additional Wood Pole	$4.64093	$4.64093	$4.79894	$4.79894	$5.07822	$5.07822	$5.38136	$5.38136
30" Bracket	$0.74357	$0.74357	$0.76889	$0.76889	$0.81364	$0.81364	$0.86221	$0.86221
8' Bracket	$0.99998	$0.99998	$1.03403	$1.03403	$1.09421	$1.09421	$1.15953	$1.15953
12' Bracket	$1.43587	$1.43587	$1.48476	$1.48476	$1.57117	$1.57117	$1.66496	$1.66496
16' Bracket	$1.98714	$1.98714	$2.05480	$2.05480	$2.17438	$2.17438	$2.30418	$2.30418
20' Bracket	$2.43585	$2.43585	$2.51879	$2.51879	$2.66537	$2.66537	$2.82447	$2.82447
Bracket, Single	$0.62819	$0.62819	$0.64958	$0.64958	$0.68738	$0.68738	$0.72841	$0.72841
Bracket, Twin	$1.25638	$1.25638	$1.29916	$1.29916	$1.37477	$1.37477	$1.45683	$1.45683
MV 175, Std Cobra	$8.26905	$8.34598	$8.55059	$8.63014	$9.04820	$9.13238	$9.58832	$9.67752
MV 400, Std Cobra	$14.47405	$14.70481	$14.96686	$15.20548	$15.83787	$16.09037	$16.78329	$17.05086
MV 1000, Std Cobra	$19.07651	$19.88419	$19.72602	$20.56120	$20.87399	$21.75777	$22.12003	$23.05656
HPS 70, Std Cobra	$7.58958	$7.53830	$7.84799	$7.79496	$8.30471	$8.24859	$8.80045	$8.74098
HPS 100, Std Cobra	$7.67932	$7.66650	$7.94078	$7.92753	$8.40290	$8.38888	$8.90450	$8.88964
HPS 150, Std Cobra	$13.70483	$13.60227	$14.17145	$14.06540	$14.99617	$14.88395	$15.89134	$15.77242
HPS 250, Std Cobra	$18.05090	$17.99961	$18.66549	$18.61246	$19.75174	$19.69563	$20.93079	$20.87133
HPS 400, Std Cobra	$19.43548	$19.53804	$20.09722	$20.20327	$21.26679	$21.37901	$22.53628	$22.65520
MH 250, Std Cobra	$18.35858	$18.32012	$18.98365	$18.94388	$20.08842	$20.04633	$21.28757	$21.24296
MH 400, Std Cobra	$19.35856	$19.46112	$20.01768	$20.12373	$21.18262	$21.29485	$22.44708	$22.56601
HPS 150, Flood	$13.35869	$13.26895	$13.81353	$13.72073	$14.61742	$14.51922	$15.48998	$15.38592
HPS 250, Flood	$14.75609	$14.71763	$15.25850	$15.21873	$16.14648	$16.10440	$17.11032	$17.06573
HPS 400, Flood	$16.03812	$16.11504	$16.58418	$16.66372	$17.54931	$17.63348	$18.59689	$18.68608
HPS 1000, Flood	$32.07624	$32.37110	$33.16837	$33.47327	$35.09863	$35.42127	$37.19379	$37.53569
MH 250, Flood	$17.12784	$17.05092	$17.71101	$17.63147	$18.74172	$18.65755	$19.86048	$19.77128
MH 400, Flood	$17.98679	$18.01244	$18.59920	$18.62573	$19.68159	$19.70967	$20.85645	$20.88621
MH 1000, Flood	$30.11474	$30.35832	$31.14008	$31.39196	$32.95230	$33.21884	$34.91933	$35.20178
HPS 250, Shoebox	$20.80725	$20.80725	$21.51569	$21.51569	$22.76781	$22.76781	$24.12690	$24.12690
HPS 400, Shoebox	$21.97389	$21.97389	$22.72205	$22.72205	$24.04438	$24.04438	$25.47967	$25.47967
LED 12-19, Cobra	N/A	N/A	$3.73797	$3.73797	$3.95550	$3.95550	$4.19162	$4.19162
LED 20-29, Cobra	N/A	N/A	$3.73797	$3.73797	$3.95550	$3.95550	$4.19162	$4.19162
LED 30-49, Cobra	N/A	N/A	$3.73797	$3.73797	$3.95550	$3.95550	$4.19162	$4.19162
LED 50-69, Cobra	N/A	N/A	$4.00245	$4.00245	$4.23538	$4.23538	$4.48820	$4.48820
LED 70-90, Cobra	N/A	N/A	$4.93170	$4.93170	$5.21870	$5.21870	$5.53022	$5.53022
LED 111-133, Cobra	N/A	N/A	$5.31184	$5.31184	$5.62097	$5.62097	$5.95650	$5.95650
LED 70-90, Flood	N/A	N/A	$8.52368	$8.52368	$9.01972	$9.01972	$9.55814	$9.55814
LED 111-133, Flood	N/A	N/A	$9.11274	$9.11274	$9.64306	$9.64306	$10.21869	$10.21869
Bill Issuance Payment Processing Charge:	$0.72	$0.72	$0.93	$0.93	$0.93	$0.93	$0.93	$0.93

Rochester Gas and Electric Corporation
Electric Department
Retail Delivery Rates

P.S.C. No. 18 - Electricity

Service Classification No. 1

Fixtures	LED Equivalent	Current Rates	Rate Year 1	Rate Year 2	Rate Year 3
Type 1		$9.03945	$9.34722	$9.89119	$10.48163
Type 1a		$9.03945	$9.34722	$9.89119	$10.48163
Type 1b		$9.03945	$9.34722	$9.89119	$10.48163
Type 2	Type 30	$12.58595	$13.01447	$13.77186	$14.59395
Type 2d		$15.48224	$16.00938	$16.94106	$17.95233
Type 2e		$20.23523	$20.92420	$22.14190	$23.46362
Type 2f		$14.61991	$15.11769	$15.99748	$16.95242
Type 2g	Type 30g	$14.24992	$14.73510	$15.59262	$16.52340
Type 3		$8.62232	$8.91589	$9.43476	$9.99795
Type 3a		$7.56190	$7.81937	$8.27442	$8.76835
Type 3a-2		$10.36286	$10.71569	$11.33930	$12.01618
Type 5		$3.65982	$3.78443	$4.00467	$4.24372
Type 5a		$1.93416	$2.00001	$2.11640	$2.24274
Type 6		$5.67003	$5.86308	$6.20429	$6.57465
Type 6a		$5.67003	$5.86308	$6.20429	$6.57465
Type 9	Type 31	$4.74803	$4.90969	$5.19541	$5.50554
Type 9b	Type 31b	$3.11472	$3.22077	$3.40821	$3.61166
Type 9c	Type 31c	$5.97624	$6.17972	$6.53935	$6.92971
Type 9d	Type 31d	$5.26787	$5.44723	$5.76424	$6.10833
Type 10	Type 32	$11.27533	$11.65923	$12.33775	$13.07423
Type 10a	Type 32a	$14.18804	$14.67111	$15.52491	$16.45164
Type 10c	Type 32c	$13.86679	$14.33892	$15.17338	$16.07913
Type 10c-2		$20.50828	$21.20654	$22.44067	$23.78023
Type 11	Type 33	$16.43045	$16.98987	$17.97861	$19.05181
Type 11a	Type 33a	$16.70179	$17.27045	$18.27552	$19.36645
Type 11b	Type 33b	$18.63667	$19.27121	$20.39271	$21.61002
Type 11b-2	Type 33b-2	$29.40464	$30.40581	$32.17530	$34.09595
Type 13	Type 34	$4.80859	$4.97231	$5.26168	$5.57577
Type13a	Type 34a	$8.15962	$8.43744	$8.92846	$9.46143
Type13b		$5.24329	$5.42181	$5.73734	$6.07982
Type 20	Type 35	$4.42434	$4.57498	$4.84122	$5.13021
Type 20b	Type 35b	$8.33339	$8.61712	$9.11860	$9.66292
Type 20g	Type 35g	$4.95952	$5.12838	$5.42683	$5.75078
Type 20i	Type 35i	$9.31833	$9.63560	$10.19635	$10.80500
Type 20j	Type 35j	$3.29982	$3.41217	$3.61074	$3.82628
Type 20k	Type 35k	$4.04954	$4.18742	$4.43111	$4.69562
Type 21	Type 36	$4.46208	$4.61400	$4.88252	$5.17397
Type 21a	Type 36a	$6.86687	$7.10067	$7.51390	$7.96243
Type 21b	Type 36b	$4.86322	$5.02880	$5.32145	$5.63911

Rochester Gas and Electric Corporation
Electric Department
Retail Delivery Rates

P.S.C. No. 18 - Electricity

Service Classification No. 1

	Current Rates	Rate Year 1	Rate Year 2	Rate Year 3
Circuit:				
Overhead Wire	$0.01477	$0.01527	$0.01616	$0.01712
Wood Pole Company Owned	$4.82945	$4.99388	$5.28450	$5.59995
Wood Pole Jointly Owned	$2.41476	$2.49698	$2.64229	$2.80002
Conduit & Cable	$0.10437	$0.10792	$0.11420	$0.12102
Buried Cable URD Subdivisions	$0.04841	$0.05006	$0.05297	$0.05613
Cable in Conduit owned by Others	$0.03721	$0.03848	$0.04072	$0.04315
Lamps:				
2500 Inc	$4.66546	$4.82431	$5.10506	$5.40980
2800 Inc	$4.92358	$5.09122	$5.38751	$5.70911
2800 Inc (C-5)	$14.68097	$15.18083	$16.06429	$17.02322
4400 MV	$2.96188	$3.06273	$3.24097	$3.43443
8500 MV	$4.28090	$4.42666	$4.68427	$4.96389
13000 MV	$5.69125	$5.88503	$6.22751	$6.59925
23000 MV	$8.63797	$8.93207	$9.45188	$10.01609
4000 HPS	$1.36086	$1.40719	$1.48908	$1.57797
5800 HPS	$1.75687	$1.81669	$1.92241	$2.03717
9500 HPS	$2.36129	$2.44169	$2.58379	$2.73803
16000 HPS	$3.31409	$3.42693	$3.62636	$3.84283
27500 HPS	$5.55217	$5.74121	$6.07532	$6.43798
50000 HPS	$8.30636	$8.58917	$9.08902	$9.63157
6950 Flor "Dusk-to-dawn"	$3.30544	$3.41798	$3.61689	$3.83279
6950 Flor "24-hour burning"	$5.33185	$5.51339	$5.83425	$6.18252
4000 MH	$3.05896	$3.16311	$3.34719	$3.54700
5850 MH	$3.02584	$3.12886	$3.31095	$3.50859
10500 MH	$2.91221	$3.01136	$3.18661	$3.37683
17000 MH	$2.91577	$3.01505	$3.19051	$3.38096
28800 MH	$2.91577	$3.01505	$3.19051	$3.38096
Light Emitting Diode (LED) – Cobra Head				
2000 Lumen	$2.09758	$2.16900	$2.29523	$2.43224
3000 Lumen	$2.09758	$2.16900	$2.29523	$2.43224
4500 Lumen	$2.09758	$2.16900	$2.29523	$2.43224
6700 Lumen	$4.14805	$4.28928	$4.53890	$4.80984
10000 Lumen	$5.19907	$5.37609	$5.68896	$6.02855
15000 Lumen	$5.55468	$5.74381	$6.07808	$6.44090
Light Emitting Diode (LED) – Shoe Box				
6700 Lumen	N/A	$10.09292	$10.68029	$11.30184
10000 Lumen	N/A	$10.09292	$10.68029	$11.30184
Light Emitting Diode (LED) – Post Top				
4500 Lumen	N/A	$9.74712	$10.31436	$10.91461
Bill Issuance Payment Processing Charge:	$0.72	$0.93	$0.93	$0.93

Rochester Gas and Electric Corporation
Electric Department
Retail Delivery Rates

P.S.C. No. 18 - Electricity

Service Classification No. 2
Customer Owned

	Current Rates	Rate Year 1	Rate Year 2	Rate Year 3
24-Hour Burning	$0.01572	$0.01626	$0.01721	$0.01824
Dusk-Dawn	$0.04953	$0.05122	$0.05420	$0.05744
Dusk-1:00 am	$0.14800	$0.15304	$0.16195	$0.17162
Bill Issuance Payment Processing Charge:	$0.72	$0.93	$0.93	$0.93

P.S.C. No. 18 - Electricity
Service Classification No. 3
Traffic Signal Service

	Current Rates	Rate Year 1	Rate Year 2	Rate Year 3
Rate, per billing face Per month	$1.74410	$1.80348	$1.90843	$2.01949
Bill Issuance Payment Processing Charge:	$0.72	$0.93	$0.93	$0.93

Rochester Gas and Electric Corporation
Electric Department
Retail Delivery Rates
Electric Economic Development Rates

Service Class		Rate Components	Current EZR/EJ Rates	RY1 Standard Rates	RY1 EZR/EJ Rates	RY2 Standard Rates	RY2 EZR/EJ Rates	RY3 Standard Rates	RY3 EZR/EJ Rates
SC No. 2	General Service - Small Use (1)	kWh Charge	$0.03331 [1]	$0.03592	$0.03592 [1]	$0.04078	$0.04078 [1]	$0.04627	$0.04627 [1]
SC No. 3	General Service - 100 kW Minimum	Demand Charge	$5.00	$17.14	$6.04	$17.94	$5.57	$18.85	$5.13
SC No. 7	General Service - 12 kW Minimum	Demand Charge	$12.48	$17.37	$14.51	$17.87	$14.27	$18.38	$14.02
SC No. 8	Large General Service - Time-of-Use Rate - Secondary	Demand Charge	$4.51	$14.15	$5.19	$15.16	$5.05	$16.26	$4.94
SC No. 8	Large General Service - Time-of-Use Rate - Primary	Demand Charge	$5.46	$14.06	$6.14	$15.13	$6.01	$16.77	$5.93
SC No. 8	Large General Service - Time-of-Use Rate - Substation (1)	Demand Charge	$8.88 [1]	$8.39	$8.39 [1]	$8.65	$8.65 [1]	$8.93	$8.93 [1]
SC No. 8	Large General Service - Time-of-Use Rate - Sub Transmission Industrial	Demand Charge	$3.78	$9.19	$4.29	$9.50	$4.01	$9.84	$3.97
SC No. 8	Large General Service - Time-of-Use Rate - Sub Transmission Commercial	Demand Charge	$3.96	$9.73	$5.25	$10.25	$4.07	$10.84	$4.00
SC No. 8	Large General Service - Time-of-Use Rate - Transmission	Demand Charge	$0.41	$9.11	$0.95	$9.78	$0.92	$10.50	$0.89
SC No. 9	General Service - Time-of-Use Rate	Demand Charge	$0.66	$12.35	$2.94	$13.07	$3.09	$13.71	$3.15

[1] The economic development rates and the standard rates are the same.

Rochester Gas and Electric Corporation
Electric Department
Retail Delivery Rates
Minimum Demand Charge

Rate Year 1 Delivery Demand		Current Demand Charge	Current Minimum Demand Charge	Rate Year 1 Demand Charge	Rate Year 1 Minimum Demand Charge	% Change
SC No. 3	General Service - 100 kW Minimum	$16.46	$ 3.47	$ 17.14	$ 3.62	4.13%
SC No. 8	Large General Service - Time-of-Use Rate - Secondary	$14.16	$ 4.57	$ 14.15	$ 4.57	-0.07%
SC No. 8	Large General Service - Time-of-Use Rate - Primary	$13.79	$ 4.91	$ 14.06	$ 5.01	1.95%
SC No. 8	Large General Service - Time-of-Use Rate - Substation	$8.88	$ 3.53	$ 8.39	$ 3.34	-5.56%
SC No. 8	Large General Service - Time-of-Use Rate - Sub Transmission Industrial	$9.16	$ 2.65	$ 9.19	$ 2.66	0.29%
SC No. 8	Large General Service - Time-of-Use Rate - Sub Transmission Commercial	$9.85	$ 2.85	$ 9.73	$ 2.82	-1.26%
SC No. 8	Large General Service - Time-of-Use Rate - Transmission	$8.74	$ 2.91	$ 9.11	$ 3.04	4.21%

Rate Year 2 Delivery Demand		Rate Year 1 Demand Charge	Rate Year 1 Minimum Demand Charge	Rate Year 2 Demand Charge	Rate Year 2 Minimum Demand Charge	% Change
SC No. 3	General Service - 100 kW Minimum	$ 17.14	$ 3.62	$ 17.94	$ 3.79	4.66%
SC No. 8	Large General Service - Time-of-Use Rate - Secondary	$ 14.15	$ 4.57	$ 15.16	$ 4.89	7.13%
SC No. 8	Large General Service - Time-of-Use Rate - Primary	$ 14.06	$ 5.01	$ 15.13	$ 5.39	7.63%
SC No. 8	Large General Service - Time-of-Use Rate - Substation	$ 8.39	$ 3.34	$ 8.65	$ 3.44	3.09%
SC No. 8	Large General Service - Time-of-Use Rate - Sub Transmission Industrial	$ 9.19	$ 2.66	$ 9.50	$ 2.75	3.40%
SC No. 8	Large General Service - Time-of-Use Rate - Sub Transmission Commercial	$ 9.73	$ 2.82	$ 10.25	$ 2.97	5.41%
SC No. 8	Large General Service - Time-of-Use Rate - Transmission	$ 9.11	$ 3.04	$ 9.78	$ 3.26	7.36%

Rate Year 3 Delivery Demand		Rate Year 2 Demand Charge	Rate Year 2 Minimum Demand Charge	Rate Year 3 Demand Charge	Rate Year 3 Minimum Demand Charge	% Change
SC No. 3	General Service - 100 kW Minimum	$ 17.94	$ 3.79	$ 18.85	$ 3.98	5.07%
SC No. 8	Large General Service - Time-of-Use Rate - Secondary	$ 15.16	$ 4.89	$ 16.26	$ 5.25	7.27%
SC No. 8	Large General Service - Time-of-Use Rate - Primary	$ 15.13	$ 5.39	$ 16.77	$ 5.97	10.83%
SC No. 8	Large General Service - Time-of-Use Rate - Substation	$ 8.65	$ 3.44	$ 8.93	$ 3.55	3.30%
SC No. 8	Large General Service - Time-of-Use Rate - Sub Transmission Industrial	$ 9.50	$ 2.75	$ 9.84	$ 2.85	3.55%
SC No. 8	Large General Service - Time-of-Use Rate - Sub Transmission Commercial	$ 10.25	$ 2.97	$ 10.84	$ 3.14	5.70%
SC No. 8	Large General Service - Time-of-Use Rate - Transmission	$ 9.78	$ 3.26	$ 10.50	$ 3.50	7.40%

Rate Year 1 Delivery Demand			Current Customer or Demand Charge	Current Minimum Demand Charge	Rate Year 1 Customer or Demand Charge	Rate Year 1 Minimum Demand Charge	% Change
SC No. 7	General Service - 12 kW Minimum	customer charge	$ 88.77	$ 88.77	$ 88.77	$ 88.77	
SC No. 7	General Service - 12 kW Minimum Special Capacity Charge	demand charge	$ 16.30	$ 5.58	$ 17.37	$ 5.95	6.56%
SC No. 9	General Service - Time-of-Use Rate	demand charge	$ 11.34	$ 4.84	$ 12.35	$ 5.27	8.92%

Rate Year 2 Delivery Demand			Rate Year 1 Customer or Demand Charge	Rate Year 1 Minimum Demand Charge	Rate Year 2 Customer or Demand Charge	Rate Year 2 Minimum Demand Charge	% Change
SC No. 7	General Service - 12 kW Minimum	customer charge	$ 88.77	$ 88.77	$ 105.00	$ 105.00	
SC No. 7	General Service - 12 kW Minimum Special Capacity Charge	demand charge	$ 17.37	$ 5.95	$ 17.87	$ 6.12	2.85%
SC No. 9	General Service - Time-of-Use Rate	demand charge	$ 12.35	$ 5.27	$ 13.07	$ 5.58	5.81%

Rate Year 3 Delivery Demand			Rate Year 2 Customer or Demand Charge	Rate Year 2 Minimum Demand Charge	Rate Year 3 Customer or Demand Charge	Rate Year 3 Minimum Demand Charge	% Change
SC No. 7	General Service - 12 kW Minimum	customer charge	$ 105.00	$ 105.00	$ 120.00	$ 120.00	
SC No. 7	General Service - 12 kW Minimum Special Capacity Charge	demand charge	$ 17.87	$ 6.12	$ 18.38	$ 6.29	2.86%
SC No. 9	General Service - Time-of-Use Rate	demand charge	$ 13.07	$ 5.58	$ 13.71	$ 5.85	4.91%

Rochester Gas and Electric Corporation
Electric Department
Retail Delivery Rates
High Voltage Discount

Demand with High Voltage Discount

Rate Year 1	High Voltage Discount	Current Demand Charge	Current Demand Charge with High Voltage Discount	Rate Year 1 Demand Charge	Rate Year 1 Demand Charge with High Voltage Discount
SC No. 3	$ 0.60	$16.46	$ 15.86	$ 17.14	$ 16.54
SC No. 9	$ 0.60	$ 11.34	$ 10.74	$ 12.35	$ 11.75

Rate Year 2	High Voltage Discount	Rate Year 1 Demand Charge	Rate Year 1 Demand Charge with High Voltage Discount	Rate Year 2 Demand Charge	Rate Year 2 Demand Charge with High Voltage Discount
SC No. 3	$ 0.60	$ 17.14	$ 16.54	$ 17.94	$ 17.34
SC No. 9	$ 0.60	$ 12.35	$ 11.75	$ 13.07	$ 12.47

Rate Year 3	High Voltage Discount	Rate Year 2 Demand Charge	Rate Year 2 Demand Charge with High Voltage Discount	Rate Year 3 Demand Charge	Rate Year 3 Demand Charge with High Voltage Discount
SC No. 3	$ 0.60	$ 17.94	$ 17.34	$ 18.85	$ 18.25
SC No. 9	$ 0.60	$ 13.07	$ 12.47	$ 13.71	$ 13.11

Minimum Demand with High Voltage Discount

Rate Year 1	High Voltage Discount	Current Minimum Demand Charge	Current Minimum Demand Charge with High Voltage Discount	Rate Year 1 Minimum Demand Charge	Rate Year 1 Minimum Demand Charge with High Voltage Discount
SC No. 3	$ 0.60	$ 3.47	$ 2.87	$ 3.62	$ 3.02
SC No. 9	$ 0.60	$ 4.84	$ 4.24	$ 5.27	$ 4.67

Rate Year 2	High Voltage Discount	Rate Year 1 Minimum Demand Charge	Rate Year 1 Minimum Demand Charge with High Voltage Discount	Rate Year 2 Minimum Demand Charge	Rate Year 2 Minimum Demand Charge with High Voltage Discount
SC No. 3	$ 0.60	$ 3.62	$ 3.02	$ 3.79	$ 3.19
SC No. 9	$ 0.60	$ 5.27	$ 4.67	$ 5.58	$ 4.98

Rate Year 3	High Voltage Discount	Rate Year 2 Minimum Demand Charge	Rate Year 2 Minimum Demand Charge with High Voltage Discount	Rate Year 3 Minimum Demand Charge	Rate Year 3 Minimum Demand Charge with High Voltage Discount
SC No. 3	$ 0.60	$ 3.79	$ 3.19	$ 3.98	$ 3.38
SC No. 9	$ 0.60	$ 5.58	$ 4.98	$ 5.85	$ 5.25

Rochester Gas and Electric Corporation
Electric Department
Retail Delivery Rates
P.S.C. No. 19 - Electric

Service Classification No. 4 (SP 11)
Residential Time-of-Use Service
Plug-In Electric Vehicle

		Current Rates	Rate Year 1 Rates	Rate Year 2 Rates	Rate Year 3 Rates
Customer Charge:		$21.38	$21.38	$21.70	$22.00
Energy Charge:	On-Peak, per kWh:	$0.06507	$0.07025	$0.07909	$0.08880
	Off-Peak, per kWh:	$0.02388	$0.02582	$0.02907	$0.03263
Bill Issuance Payment Processing Charge:		$0.72	$0.93	$0.93	$0.93

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2020 - April 30, 2021

Including Supply

PSC #120 - SC 1 - Residential

kWh	Current Rates	Rate Yr 1	increase / (decrease) Amount	Percent	# of Customers	# of Low Income Customers	Percent of Customers	Percent of Low Income Customers
100	$24.96	$25.45	$0.49	2.0%	34,023	683	5%	2%
200	$34.00	$34.89	$0.89	2.6%	48,276	2,803	8%	7%
300	$43.03	$44.33	$1.29	3.0%	61,295	4,359	10%	12%
400	$52.07	$53.77	$1.69	3.3%	67,881	4,939	11%	13%
500	$61.11	$63.20	$2.09	3.4%	67,787	4,476	11%	12%
600	$70.15	$72.64	$2.49	3.6%	63,739	3,926	10%	10%
700	$79.19	$82.08	$2.90	3.7%	55,914	3,162	9%	8%
800	$88.23	$91.52	$3.30	3.7%	47,727	2,751	8%	7%
900	$97.26	$100.96	$3.70	3.8%	39,223	2,184	6%	6%
1,000	$106.30	$110.40	$4.10	3.9%	31,407	1,698	5%	5%
1,100	$115.34	$119.84	$4.50	3.9%	25,132	1,395	4%	4%
1,200	$124.38	$129.28	$4.90	3.9%	19,685	1,124	3%	3%
1,500	$151.49	$157.60	$6.10	4.0%	36,425	2,110	6%	6%
2,000	$196.68	$204.79	$8.11	4.1%	23,598	1,396	4%	4%
3,000	$287.07	$299.18	$12.12	4.2%	12,884	710	2%	2%
					634,997	37,717		

Amount of EE Embedded in Delivery Rates*

Amount	Percent
$ 0.11	0.44%
$ 0.23	0.65%
$ 0.34	0.76%
$ 0.45	0.84%
$ 0.57	0.89%
$ 0.68	0.93%
$ 0.79	0.96%
$ 0.90	0.99%
$ 1.02	1.01%
$ 1.13	1.02%
$ 1.24	1.04%
$ 1.36	1.05%
$ 1.70	1.08%
$ 2.26	1.10%
$ 3.39	1.13%

	UOM	Current Rates SC1	Rate Yr 1 SC1	
Customer Charge	Monthly	$ 15.11	$ 15.11	
Delivery Charge All Hours kWh	kWh	$ 0.04256	$ 0.04523	Includes $ 0.00113 per kWh of EE Costs*
SBC (EEtr) per kWh	kWh	$ 0.00092	$ -	
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486	
RAM per kWh	kWh	$ 0.00189	$ 0.00189	
Tax Credit All Hours kWh	kWh	$ (0.00226)	$ -	
Transition Charge per kWh	kWh	$ 0.00078	$ 0.00078	
Billing Charge per Bill	Monthly	$ 0.81	$ 0.90	
Supply Charge All Hours kWh	kWh	$ 0.03897	$ 0.03897	
MFC per kWh	kWh	$ 0.00265	$ 0.00265	

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Low income customers represent customers who participated in the Company's low income program and received a credit on their bill each month during calendar year 2018.

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2020 - April 30, 2021

Including Supply

PSC #120 - SC 8 - Residential - Day/Night							
					increase / (decrease)		
kWh	Peak	Off Peak	Current Rates	Rate Yr 1	Amount	Percent	# of Customers
300	210	90	$42.55	$43.80	$1.24	2.9%	11,243
400	280	120	$50.67	$52.29	$1.63	3.2%	7,307
500	350	150	$58.78	$60.79	$2.01	3.4%	8,958
600	420	180	$66.90	$69.29	$2.39	3.6%	9,556
700	490	210	$75.01	$77.79	$2.78	3.7%	9,821
800	560	240	$83.13	$86.29	$3.16	3.8%	9,276
900	630	270	$91.24	$94.79	$3.55	3.9%	8,790
1,000	700	300	$99.36	$103.29	$3.93	4.0%	7,969
1,500	1,050	450	$139.93	$145.78	$5.85	4.2%	27,922
2,000	1,400	600	$180.50	$188.27	$7.77	4.3%	14,600
2,500	1,750	750	$221.07	$230.77	$9.69	4.4%	6,944
3,000	2,100	900	$261.65	$273.26	$11.62	4.4%	2,980
4,000	2,800	1,200	$342.79	$358.25	$15.46	4.5%	1,783
5,000	3,500	1,500	$423.94	$443.24	$19.30	4.6%	419
6,000	4,200	1,800	$505.08	$528.22	$23.14	4.6%	179
7,000	4,900	2,100	$586.23	$613.21	$26.98	4.6%	77

	UOM	Current Rates SC8	Rate Yr 1 SC8
Customer Charge	Monthly	$ 17.40	$ 17.40
Delivery Charge On Peak kWh	kWh-On	$ 0.03790	$ 0.04072
Delivery Charge Off Peak kWh	kWh-Off	$ 0.03790	$ 0.04072
SBC (EEtr) per kWh	kWh	$ 0.00092	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kWh	kWh	$ 0.00164	$ 0.00164
Tax Credit All Hours kWh	kWh	$ (0.00195)	$ -
Transition Charge per kWh	kWh	$ 0.00078	$ 0.00078
Billing Charge per Bill	Monthly	$ 0.81	$ 0.90
Supply Charge On Peak kWh	kWh-On	$ 0.03759	$ 0.03759
Supply Charge Off Peak kWh	kWh-Off	$ 0.02774	$ 0.02774
MFC per kWh	kWh	$ 0.00236	$ 0.00236

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates.
MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2020 - April 30, 2021

Including Supply

PSC #120 - SC 12 - Residential - TOU								
kWh	Peak	Mid Peak	Off Peak	Current Rates	Rate Yr 1	increase / (decrease) Amount	Percent	# of Customers
1,000	140	570	290	$107.78	$108.76	$0.98	0.9%	169
2,000	280	1,140	580	$190.63	$192.50	$1.87	1.0%	396
3,000	420	1,710	870	$273.49	$276.25	$2.76	1.0%	435
4,000	560	2,280	1,160	$356.35	$359.99	$3.64	1.0%	398
5,000	700	2,850	1,450	$439.21	$443.74	$4.53	1.0%	382
6,000	840	3,420	1,740	$522.06	$527.49	$5.42	1.0%	394
7,000	980	3,990	2,030	$604.92	$611.23	$6.31	1.0%	327
8,000	1,120	4,560	2,320	$687.78	$694.98	$7.20	1.0%	255
9,000	1,260	5,130	2,610	$770.63	$778.72	$8.09	1.0%	194
10,000	1,400	5,700	2,900	$853.49	$862.47	$8.98	1.1%	119
15,000	2,100	8,550	4,350	$1,267.78	$1,281.20	$13.42	1.1%	375
20,000	2,800	11,400	5,800	$1,682.06	$1,699.93	$17.87	1.1%	120
30,000	4,200	17,100	8,700	$2,510.63	$2,537.39	$26.76	1.1%	90
40,000	5,600	22,800	11,600	$3,339.21	$3,374.85	$35.64	1.1%	32
50,000	7,000	28,500	14,500	$4,167.78	$4,212.31	$44.53	1.1%	16

	UOM	Current Rates SC12	Rate Yr 1 SC12
Customer Charge	Monthly	$ 24.11	$ 24.11
Delivery Charge On Peak kWh	kWh-On	$ 0.03951	$ 0.03961
Delivery Charge Mid Peak kWh	kWh-Mid	$ 0.03951	$ 0.03961
Delivery Charge Off Peak kWh	kWh-Off	$ 0.03951	$ 0.03961
SBC (EEtr) per kWh	kWh	$ 0.00092	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kWh	kWh	$ 0.00144	$ 0.00144
Tax Credit All Hours kWh	kWh	$ (0.00171)	$ -
Transition Charge per kWh	kWh	$ 0.00078	$ 0.00078
Billing Charge per Bill	Monthly	$ 0.81	$ 0.90
Supply Charge On Peak kWh	kWh-On	$ 0.04489	$ 0.04489
Supply Charge Mid Peak kWh	kWh-Mid	$ 0.03591	$ 0.03591
Supply Charge Off Peak kWh	kWh-Off	$ 0.02738	$ 0.02738
MFC per kWh	kWh	$ 0.00236	$ 0.00236

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2020 - April 30, 2021

Including Supply

PSC #120 - SC 2 - Non Residential - Secondary							
					increase / (decrease)		
Kw	Load Factor	kWh	Current Rates	Rate Yr 1	Amount	Percent	# of Customers
5	20%	730	$107.94	$110.40	$2.46	2.3%	4,814
5	30%	1,095	$124.94	$126.88	$1.94	1.6%	1,783
5	40%	1,460	$141.94	$143.36	$1.42	1.0%	1,150
5	50%	1,825	$158.94	$159.84	$0.90	0.6%	737
5	60%	2,190	$175.94	$176.31	$0.38	0.2%	477
5	70%	2,555	$192.93	$192.79	($0.14)	-0.1%	276
5	80%	2,920	$209.93	$209.27	($0.66)	-0.3%	221
5	90%	3,285	$226.93	$225.75	($1.18)	-0.5%	493
25	20%	3,650	$439.24	$451.19	$11.95	2.7%	15,467
25	30%	5,475	$524.23	$533.57	$9.34	1.8%	5,392
25	40%	7,300	$609.22	$615.96	$6.74	1.1%	3,010
25	50%	9,125	$694.21	$698.35	$4.14	0.6%	1,577
25	60%	10,950	$779.20	$780.74	$1.54	0.2%	852
25	70%	12,775	$864.19	$863.12	($1.07)	-0.1%	448
25	80%	14,600	$949.18	$945.51	($3.67)	-0.4%	288
25	90%	16,425	$1,034.17	$1,027.90	($6.27)	-0.6%	371
100	20%	14,600	$1,681.60	$1,729.12	$47.52	2.8%	3,447
100	30%	21,900	$2,021.56	$2,058.66	$37.11	1.8%	1,541
100	40%	29,200	$2,361.51	$2,388.21	$26.70	1.1%	776
100	50%	36,500	$2,701.47	$2,717.76	$16.29	0.6%	343
100	60%	43,800	$3,041.43	$3,047.31	$5.88	0.2%	190
100	70%	51,100	$3,381.39	$3,376.86	($4.53)	-0.1%	80
100	80%	58,400	$3,721.35	$3,706.41	($14.94)	-0.4%	27
100	90%	65,700	$4,061.31	$4,035.96	($25.35)	-0.6%	45
300	20%	43,800	$4,994.55	$5,136.93	$142.38	2.9%	435
300	30%	65,700	$6,014.43	$6,125.58	$111.15	1.8%	412
300	40%	87,600	$7,034.30	$7,114.22	$79.92	1.1%	201
300	50%	109,500	$8,054.18	$8,102.87	$48.69	0.6%	101
300	60%	131,400	$9,074.06	$9,091.52	$17.46	0.2%	51
300	70%	153,300	$10,093.94	$10,080.17	($13.77)	-0.1%	29
300	80%	175,200	$11,113.82	$11,068.82	($45.00)	-0.4%	18
300	90%	197,100	$12,133.70	$12,057.47	($76.23)	-0.6%	28

	UOM	Current Rates SC2	Rate Yr 1 SC2
Customer Charge	Monthly	$ 24.31	$ 24.31
Demand Charge kW	kW	$ 9.79	$ 10.11
Delivery Charge All Hours kWh	kWh	$ 0.00261	$ 0.00201
SBC (EEtr) per kWh	kWh	$ 0.00092	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ 0.33000	$ 0.33000
Tax Credit per kW	kW	$ (0.36000)	$ -
Tax Credit All Hours kWh	kWh	$ (0.00010)	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00557	$ 0.00557
Billing Charge per Bill	Monthly	$ 0.81	$ 0.90
Supply Charge All Hours kWh	kWh	$ 0.03506	$ 0.03506
MFC per kWh	kWh	$ 0.00199	$ 0.00199

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2020 - April 30, 2021

Including Supply

PSC #120 - SC 3P - Non Residential - Primary

Kw	Load Factor	kWh	Current Rates	Rate Yr 1	increase / (decrease) Amount	Percent	# of Customers
5	20%	730	$165.87	$169.78	$3.91	2.4%	8
5	30%	1,095	$182.58	$185.97	$3.39	1.9%	4
5	40%	1,460	$199.29	$202.15	$2.86	1.4%	1
5	50%	1,825	$216.00	$218.34	$2.34	1.1%	2
5	60%	2,190	$232.70	$234.52	$1.82	0.8%	-
5	70%	2,555	$249.41	$250.71	$1.30	0.5%	-
5	80%	2,920	$266.12	$266.90	$0.78	0.3%	-
5	90%	3,285	$282.83	$283.08	$0.25	0.1%	-
25	20%	3,650	$421.44	$440.63	$19.18	4.6%	18
25	30%	5,475	$504.98	$521.56	$16.57	3.3%	9
25	40%	7,300	$588.52	$602.49	$13.96	2.4%	5
25	50%	9,125	$672.06	$683.41	$11.35	1.7%	8
25	60%	10,950	$755.60	$764.34	$8.74	1.2%	1
25	70%	12,775	$839.14	$845.27	$6.14	0.7%	1
25	80%	14,600	$922.68	$926.20	$3.53	0.4%	3
25	90%	16,425	$1,006.22	$1,007.13	$0.92	0.1%	-
100	20%	14,600	$1,379.83	$1,456.30	$76.47	5.5%	67
100	30%	21,900	$1,713.99	$1,780.02	$66.03	3.9%	-
100	40%	29,200	$2,048.14	$2,103.73	$55.59	2.7%	15
100	50%	36,500	$2,382.30	$2,427.45	$45.15	1.9%	11
100	60%	43,800	$2,716.46	$2,751.17	$34.71	1.3%	6
100	70%	51,100	$3,050.61	$3,074.89	$24.27	0.8%	3
100	80%	58,400	$3,384.77	$3,398.60	$13.83	0.4%	2
100	90%	65,700	$3,718.93	$3,722.32	$3.39	0.1%	-
300	20%	43,800	$3,935.54	$4,164.76	$229.22	5.8%	69
300	30%	65,700	$4,938.01	$5,135.91	$197.91	4.0%	-
300	40%	87,600	$5,940.47	$6,107.06	$166.59	2.8%	26
300	50%	109,500	$6,942.94	$7,078.21	$135.27	1.9%	22
300	60%	131,400	$7,945.41	$8,049.37	$103.95	1.3%	8
300	70%	153,300	$8,947.88	$9,020.52	$72.64	0.8%	4
300	80%	175,200	$9,950.35	$9,991.67	$41.32	0.4%	7
300	90%	197,100	$10,952.82	$10,962.82	$10.00	0.1%	8

	UOM	Current Rates SC3P	Rate Yr 1 SC3P
Customer Charge	Monthly	$ 101.17	$ 101.17
Demand Charge kW	kW	$ 6.12	$ 6.90
Delivery Charge All Hours kWh	kWh	$ 0.00261	$ 0.00202
SBC (EEtr) per kWh	kWh	$ 0.00092	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ 0.16000	$ 0.16000
Tax Credit per kW	kW	$ (0.19000)	$ -
Tax Credit All Hours kWh	kWh	$ (0.00008)	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00541	$ 0.00541
Billing Charge per Bill	Monthly	$ 0.81	$ 0.90
Supply Charge All Hours kWh	kWh	$ 0.03424	$ 0.03424
MFC per kWh	kWh	$ 0.00199	$ 0.00199

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2020 - April 30, 2021

Including Supply

PSC #120 - SC 3S - Non Residential - SubTransmission							
					increase / (decrease)		
Kw	Load Factor	kWh	Current Rates	Rate Yr 1	Amount	Percent	# of Customers
5	20%	730	$385.92	$386.62	$0.70	0.2%	1
5	30%	1,095	$400.82	$401.18	$0.36	0.1%	-
5	40%	1,460	$415.71	$415.74	$0.03	0.0%	-
5	50%	1,825	$430.61	$430.30	($0.31)	-0.1%	-
5	60%	2,190	$445.50	$444.85	($0.65)	-0.1%	-
5	70%	2,555	$460.40	$459.41	($0.98)	-0.2%	-
5	80%	2,920	$475.29	$473.97	($1.32)	-0.3%	-
5	90%	3,285	$490.19	$488.53	($1.66)	-0.3%	-
25	20%	3,650	$594.13	$597.28	$3.15	0.5%	2
25	30%	5,475	$668.60	$670.07	$1.46	0.2%	-
25	40%	7,300	$743.08	$742.85	($0.22)	0.0%	-
25	50%	9,125	$817.55	$815.64	($1.91)	-0.2%	-
25	60%	10,950	$892.02	$888.43	($3.60)	-0.4%	-
25	70%	12,775	$966.50	$961.22	($5.28)	-0.5%	-
25	80%	14,600	$1,040.97	$1,034.01	($6.97)	-0.7%	-
25	90%	16,425	$1,115.45	$1,106.79	($8.65)	-0.8%	-
100	20%	14,600	$1,374.90	$1,387.23	$12.33	0.9%	2
100	30%	21,900	$1,672.80	$1,678.38	$5.59	0.3%	-
100	40%	29,200	$1,970.69	$1,969.53	($1.16)	-0.1%	1
100	50%	36,500	$2,268.59	$2,260.69	($7.90)	-0.3%	1
100	60%	43,800	$2,566.49	$2,551.84	($14.65)	-0.6%	-
100	70%	51,100	$2,864.38	$2,842.99	($21.39)	-0.7%	-
100	80%	58,400	$3,162.28	$3,134.14	($28.14)	-0.9%	-
100	90%	65,700	$3,460.18	$3,425.29	($34.88)	-1.0%	-
300	20%	43,800	$3,456.96	$3,493.77	$36.82	1.1%	1
300	30%	65,700	$4,350.65	$4,367.23	$16.58	0.4%	-
300	40%	87,600	$5,244.34	$5,240.69	($3.66)	-0.1%	1
300	50%	109,500	$6,138.03	$6,114.14	($23.89)	-0.4%	-
300	60%	131,400	$7,031.72	$6,987.60	($44.13)	-0.6%	-
300	70%	153,300	$7,925.41	$7,861.05	($64.36)	-0.8%	2
300	80%	175,200	$8,819.10	$8,734.51	($84.60)	-1.0%	1
300	90%	197,100	$9,712.80	$9,607.96	($104.83)	-1.1%	-

	UOM	Current Rates SC3S	Rate Yr 1 SC3S
Customer Charge	Monthly	$ 333.06	$ 333.06
Demand Charge kW	kW	$ 4.50	$ 4.47
Delivery Charge All Hours kWh	kWh	$ -	$ -
SBC (EEtr) per kWh	kWh	$ 0.00092	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ 0.24000	$ 0.24000
Tax Credit per kW	kW	$ (0.29000)	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00236	$ 0.00236
Billing Charge per Bill	Monthly	$ 0.81	$ 0.90
Supply Charge All Hours kWh	kWh	$ 0.03181	$ 0.03181
MFC per kWh	kWh	$ 0.00199	$ 0.00199

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2020 - April 30, 2021

Including Supply

PSC #120 - SC 6 - Non Residential					
			increase / (decrease)		# of
kWh	Current Rates	Rate Yr 1	Amount	Percent	Customers
300	$47.36	$49.34	$1.97	4.2%	38,981
400	$57.02	$59.62	$2.60	4.6%	7,133
500	$66.67	$69.90	$3.23	4.8%	5,737
600	$76.32	$80.18	$3.86	5.1%	4,185
700	$85.97	$90.46	$4.49	5.2%	3,094
800	$95.62	$100.74	$5.11	5.3%	2,217
900	$105.27	$111.01	$5.74	5.5%	1,753
1,000	$114.92	$121.29	$6.37	5.5%	1,339
1,100	$124.58	$131.57	$7.00	5.6%	1,105
1,200	$134.23	$141.85	$7.63	5.7%	886
1,500	$163.18	$172.69	$9.51	5.8%	1,756
2,000	$211.44	$224.09	$12.65	6.0%	1,278
2,500	$259.70	$275.49	$15.79	6.1%	461
3,000	$307.95	$326.88	$18.93	6.1%	223
3,500	$356.21	$378.28	$22.07	6.2%	139
8,000	$790.53	$840.86	$50.33	6.4%	408

	UOM	Current Rates SC6	Rate Yr 1 SC6
Customer Charge	Monthly	$ 17.60	$ 17.60
Delivery Charge All Hours kWh	kWh	$ 0.04746	$ 0.05166
SBC (EEtr) per kWh	kWh	$ 0.00092	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kWh	kWh	$ 0.00253	$ 0.00253
Tax Credit All Hours kWh	kWh	$ (0.00300)	$ -
Transition Charge per kWh	kWh	$ 0.00124	$ 0.00124
Billing Charge per Bill	Monthly	$ 0.81	$ 0.90
Supply Charge All Hours kWh	kWh	$ 0.03985	$ 0.03985
MFC per kWh	kWh	$ 0.00265	$ 0.00265

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2020 - April 30, 2021

Including Supply

PSC #120 - SC 7-1 - Non Residential Large General Service - Secondary

Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Current Rates	Rate Yr 1	increase / (decrease) Amount	Percent	# of Customers
25	20%	3,650	1,898	1,752	$541.35	$578.58	$37.23	6.9%	558
25	30%	5,475	2,847	2,628	$620.20	$655.74	$35.54	5.7%	172
25	40%	7,300	3,796	3,504	$699.04	$732.90	$33.86	4.8%	139
25	50%	9,125	4,745	4,380	$777.89	$810.06	$32.17	4.1%	79
25	60%	10,950	5,694	5,256	$856.74	$887.22	$30.48	3.6%	50
25	70%	12,775	6,643	6,132	$935.59	$964.38	$28.80	3.1%	23
25	80%	14,600	7,592	7,008	$1,014.44	$1,041.55	$27.11	2.7%	13
25	90%	16,425	8,541	7,884	$1,093.28	$1,118.71	$25.42	2.3%	11
100	20%	14,600	7,592	7,008	$1,681.01	$1,708.60	$27.59	1.6%	585
100	30%	21,900	11,388	10,512	$1,996.40	$2,017.25	$20.85	1.0%	-
100	40%	29,200	15,184	14,016	$2,311.80	$2,325.90	$14.10	0.6%	109
100	50%	36,500	18,980	17,520	$2,627.19	$2,634.55	$7.36	0.3%	82
100	60%	43,800	22,776	21,024	$2,942.58	$2,943.19	$0.61	0.0%	44
100	70%	51,100	26,572	24,528	$3,257.97	$3,251.84	($6.13)	-0.2%	9
100	80%	58,400	30,368	28,032	$3,573.37	$3,560.49	($12.88)	-0.4%	4
100	90%	65,700	34,164	31,536	$3,888.76	$3,869.13	($19.62)	-0.5%	9
500	20%	73,000	37,960	35,040	$7,759.22	$7,735.43	($23.80)	-0.3%	275
500	30%	109,500	56,940	52,560	$9,336.18	$9,278.66	($57.52)	-0.6%	151
500	40%	146,000	75,920	70,080	$10,913.14	$10,821.89	($91.25)	-0.8%	100
500	50%	182,500	94,900	87,600	$12,490.10	$12,365.13	($124.98)	-1.0%	62
500	60%	219,000	113,880	105,120	$14,067.07	$13,908.36	($158.70)	-1.1%	27
500	70%	255,500	132,860	122,640	$15,644.03	$15,451.60	($192.43)	-1.2%	16
500	80%	292,000	151,840	140,160	$17,220.99	$16,994.83	($226.15)	-1.3%	7
500	90%	328,500	170,820	157,680	$18,797.95	$18,538.07	($259.88)	-1.4%	-
1,000	20%	146,000	75,920	70,080	$15,356.99	$15,268.95	($88.03)	-0.6%	32
1,000	30%	219,000	113,880	105,120	$18,510.91	$18,355.42	($155.49)	-0.8%	24
1,000	40%	292,000	151,840	140,160	$21,664.83	$21,441.89	($222.94)	-1.0%	21
1,000	50%	365,000	189,800	175,200	$24,818.75	$24,528.36	($290.39)	-1.2%	-
1,000	60%	438,000	227,760	210,240	$27,972.67	$27,614.83	($357.84)	-1.3%	16
1,000	70%	511,000	265,720	245,280	$31,126.59	$30,701.30	($425.29)	-1.4%	4
1,000	80%	584,000	303,680	280,320	$34,280.51	$33,787.77	($492.75)	-1.4%	5
1,000	90%	657,000	341,640	315,360	$37,434.43	$36,874.24	($560.20)	-1.5%	9

	UOM	Current Rates SC7-1	Rate Yr 1 SC7-1
Customer Charge	Monthly	$ 160.65	$ 201.00
Demand Charge kW	kW	$ 8.94	$ 8.57
SBC (EEtr) per kWh	kWh	$ 0.00092	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ 0.32000	$ 0.32000
Tax Credit per kW	kW	$ (0.38000)	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00768	$ 0.00768
Billing Charge per Bill	Monthly	$ 0.81	$ 0.90
Supply Charge On Peak kWh	kWh-On	$ 0.04008	$ 0.04008
Supply Charge Off Peak kWh	kWh-Off	$ 0.02783	$ 0.02783
MFC per kWh	kWh	$ 0.00199	$ 0.00199

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2020 - April 30, 2021

Including Supply

PSC #120 - SC 7-2 - Non Residential Large General Service - Primary							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Current Rates	Rate Yr 1	Amount	Percent	# of Customers
500	20%	73,000	37,960	35,040	$7,304.26	$7,578.80	$274.53	3.8%	90
500	30%	109,500	56,940	52,560	$8,855.46	$9,096.27	$240.81	2.7%	35
500	40%	146,000	75,920	70,080	$10,406.65	$10,613.74	$207.08	2.0%	32
500	50%	182,500	94,900	87,600	$11,957.85	$12,131.21	$173.36	1.4%	27
500	60%	219,000	113,880	105,120	$13,509.05	$13,648.68	$139.63	1.0%	12
500	70%	255,500	132,860	122,640	$15,060.24	$15,166.15	$105.90	0.7%	8
500	80%	292,000	151,840	140,160	$16,611.44	$16,683.62	$72.18	0.4%	-
500	90%	328,500	170,820	157,680	$18,162.63	$18,201.09	$38.45	0.2%	-
1,000	20%	146,000	75,920	70,080	$14,045.94	$14,454.69	$408.75	2.9%	21
1,000	30%	219,000	113,880	105,120	$17,148.34	$17,489.63	$341.30	2.0%	22
1,000	40%	292,000	151,840	140,160	$20,250.73	$20,524.57	$273.84	1.4%	23
1,000	50%	365,000	189,800	175,200	$23,353.12	$23,559.51	$206.39	0.9%	-
1,000	60%	438,000	227,760	210,240	$26,455.51	$26,594.45	$138.94	0.5%	14
1,000	70%	511,000	265,720	245,280	$29,557.90	$29,629.39	$71.49	0.2%	7
1,000	80%	584,000	303,680	280,320	$32,660.30	$32,664.33	$4.04	0.0%	2
1,000	90%	657,000	341,640	315,360	$35,762.69	$35,699.27	($63.42)	-0.2%	1
1,500	20%	219,000	113,880	105,120	$20,787.63	$21,330.59	$542.96	2.6%	4
1,500	30%	328,500	170,820	157,680	$25,441.21	$25,883.00	$441.78	1.7%	2
1,500	40%	438,000	227,760	210,240	$30,094.80	$30,435.41	$340.60	1.1%	8
1,500	50%	547,500	284,700	262,800	$34,748.39	$34,987.82	$239.43	0.7%	8
1,500	60%	657,000	341,640	315,360	$39,401.98	$39,540.23	$138.25	0.4%	-
1,500	70%	766,500	398,580	367,920	$44,055.57	$44,092.64	$37.07	0.1%	7
1,500	80%	876,000	455,520	420,480	$48,709.15	$48,645.05	($64.11)	-0.1%	2
1,500	90%	985,500	512,460	473,040	$53,362.74	$53,197.46	($165.29)	-0.3%	-
2,500	20%	365,000	189,800	175,200	$34,270.99	$35,082.38	$811.39	2.4%	5
2,500	30%	547,500	284,700	262,800	$42,026.97	$42,669.73	$642.76	1.5%	2
2,500	40%	730,000	379,600	350,400	$49,782.95	$50,257.08	$474.13	1.0%	11
2,500	50%	912,500	474,500	438,000	$57,538.93	$57,844.43	$305.50	0.5%	12
2,500	60%	1,095,000	569,400	525,600	$65,294.91	$65,431.78	$136.87	0.2%	-
2,500	70%	1,277,500	664,300	613,200	$73,050.89	$73,019.13	($31.76)	0.0%	1
2,500	80%	1,460,000	759,200	700,800	$80,806.87	$80,606.48	($200.39)	-0.2%	3
2,500	90%	1,642,500	854,100	788,400	$88,562.85	$88,193.83	($369.02)	-0.4%	5

	UOM	Current Rates SC7-2	Rate Yr 1 SC7-2
Customer Charge	Monthly	$ 561.77	$ 702.00
Demand Charge kW	kW	$ 7.30	$ 7.43
SBC (EEtr) per kWh	kWh	$ 0.00092	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ 0.24000	$ 0.24000
Tax Credit per kW	kW	$ (0.27000)	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00858	$ 0.00858
Billing Charge per Bill	Monthly	$ 0.81	$ 0.90
Supply Charge On Peak kWh	kWh-On	$ 0.03921	$ 0.03921
Supply Charge Off Peak kWh	kWh-Off	$ 0.02730	$ 0.02730
MFC per kWh	kWh	$ 0.00199	$ 0.00199

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2020 - April 30, 2021

Including Supply

PSC #120 - SC 7-3 - Non Residential Large General Service - SubTransmission									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Current Rates	Rate Yr 1	Amount	Percent	# of Customers
500	20%	73,000	37,960	35,040	$5,303.82	$5,491.29	$187.47	3.5%	18
500	30%	109,500	56,940	52,560	$6,839.21	$6,992.95	$153.74	2.2%	9
500	40%	146,000	75,920	70,080	$8,374.59	$8,494.61	$120.02	1.4%	7
500	50%	182,500	94,900	87,600	$9,909.98	$9,996.27	$86.29	0.9%	6
500	60%	219,000	113,880	105,120	$11,445.37	$11,497.94	$52.57	0.5%	2
500	70%	255,500	132,860	122,640	$12,980.76	$12,999.60	$18.84	0.1%	2
500	80%	292,000	151,840	140,160	$14,516.15	$14,501.26	($14.89)	-0.1%	-
500	90%	328,500	170,820	157,680	$16,051.54	$16,002.92	($48.61)	-0.3%	-
2,000	20%	292,000	151,840	140,160	$17,704.19	$17,576.45	($127.74)	-0.7%	32
2,000	30%	438,000	227,760	210,240	$23,845.74	$23,583.10	($262.64)	-1.1%	-
2,000	40%	584,000	303,680	280,320	$29,987.29	$29,589.75	($397.55)	-1.3%	11
2,000	50%	730,000	379,600	350,400	$36,128.85	$35,596.40	($532.45)	-1.5%	6
2,000	60%	876,000	455,520	420,480	$42,270.40	$41,603.05	($667.35)	-1.6%	4
2,000	70%	1,022,000	531,440	490,560	$48,411.96	$47,609.70	($802.26)	-1.7%	2
2,000	80%	1,168,000	607,360	560,640	$54,553.51	$53,616.35	($937.16)	-1.7%	-
2,000	90%	1,314,000	683,280	630,720	$60,695.07	$59,623.00	($1,072.07)	-1.8%	-
4,000	20%	584,000	303,680	280,320	$34,238.01	$33,690.00	($548.02)	-1.6%	2
4,000	30%	876,000	455,520	420,480	$46,521.12	$45,703.30	($817.83)	-1.8%	10
4,000	40%	1,168,000	607,360	560,640	$58,804.23	$57,716.60	($1,087.63)	-1.8%	4
4,000	50%	1,460,000	759,200	700,800	$71,087.34	$69,729.90	($1,357.44)	-1.9%	-
4,000	60%	1,752,000	911,040	840,960	$83,370.45	$81,743.20	($1,627.25)	-2.0%	6
4,000	70%	2,044,000	1,062,880	981,120	$95,653.56	$93,756.50	($1,897.06)	-2.0%	4
4,000	80%	2,336,000	1,214,720	1,121,280	$107,936.66	$105,769.80	($2,166.87)	-2.0%	-
4,000	90%	2,628,000	1,366,560	1,261,440	$120,219.77	$117,783.10	($2,436.67)	-2.0%	-
5,000	20%	730,000	379,600	350,400	$42,504.93	$41,746.77	($758.16)	-1.8%	-
5,000	30%	1,095,000	569,400	525,600	$57,858.81	$56,763.40	($1,095.42)	-1.9%	-
5,000	40%	1,460,000	759,200	700,800	$73,212.70	$71,780.02	($1,432.68)	-2.0%	-
5,000	50%	1,825,000	949,000	876,000	$88,566.58	$86,796.65	($1,769.94)	-2.0%	1
5,000	60%	2,190,000	1,138,800	1,051,200	$103,920.47	$101,813.27	($2,107.20)	-2.0%	1
5,000	70%	2,555,000	1,328,600	1,226,400	$119,274.35	$116,829.90	($2,444.46)	-2.0%	3
5,000	80%	2,920,000	1,518,400	1,401,600	$134,628.24	$131,846.52	($2,781.72)	-2.1%	-
5,000	90%	3,285,000	1,708,200	1,576,800	$149,982.13	$146,863.15	($3,118.98)	-2.1%	5

		Current Rates	Rate Yr 1
	UOM	SC7-3	SC7-3
Customer Charge	Monthly	$ 1,169.55	$ 1,462.00
Demand Charge kW	kW	$ 2.14	$ 1.95
SBC (EEtr) per kWh	kWh	$ 0.00092	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ 0.09000	$ 0.09000
Tax Credit per kW	kW	$ (0.11000)	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00536	$ 0.00536
Billing Charge per Bill	Monthly	$ 0.81	$ 0.90
Supply Charge On Peak kWh	kWh-On	$ 0.03873	$ 0.03873
Supply Charge Off Peak kWh	kWh-Off	$ 0.02692	$ 0.02692
MFC per kWh	kWh	$ 0.00199	$ 0.00199

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2020 - April 30, 2021

Including Supply

PSC #120 - SC 7-4 - Non Residential Large General Service - Transmission

Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Current Rates	Rate Yr 1	increase / (decrease) Amount	Percent	# of Customers
1,000	20%	146,000	75,920	70,080	$9,609.15	$9,784.66	$175.51	1.8%	1
1,000	30%	219,000	113,880	105,120	$12,679.93	$12,787.98	$108.06	0.9%	-
1,000	40%	292,000	151,840	140,160	$15,750.71	$15,791.31	$40.61	0.3%	2
1,000	50%	365,000	189,800	175,200	$18,821.49	$18,794.64	($26.85)	-0.1%	-
1,000	60%	438,000	227,760	210,240	$21,892.27	$21,797.97	($94.30)	-0.4%	-
1,000	70%	511,000	265,720	245,280	$24,963.05	$24,801.30	($161.75)	-0.6%	-
1,000	80%	584,000	303,680	280,320	$28,033.83	$27,804.63	($229.20)	-0.8%	-
1,000	90%	657,000	341,640	315,360	$31,104.61	$30,807.95	($296.65)	-1.0%	-
7,500	20%	1,095,000	569,400	525,600	$54,892.74	$55,179.08	$286.34	0.5%	5
7,500	30%	1,642,500	854,100	788,400	$77,923.59	$77,704.04	($219.55)	-0.3%	-
7,500	40%	2,190,000	1,138,800	1,051,200	$100,954.44	$100,229.00	($725.44)	-0.7%	1
7,500	50%	2,737,500	1,423,500	1,314,000	$123,985.29	$122,753.96	($1,231.33)	-1.0%	1
7,500	60%	3,285,000	1,708,200	1,576,800	$147,016.14	$145,278.92	($1,737.22)	-1.2%	-
7,500	70%	3,832,500	1,992,900	1,839,600	$170,046.99	$167,803.88	($2,243.11)	-1.3%	1
7,500	80%	4,380,000	2,277,600	2,102,400	$193,077.84	$190,328.84	($2,749.00)	-1.4%	-
7,500	90%	4,927,500	2,562,300	2,365,200	$216,108.70	$212,853.80	($3,254.89)	-1.5%	-
15,000	20%	2,190,000	1,138,800	1,051,200	$107,143.05	$107,557.26	$414.21	0.4%	1
15,000	30%	3,285,000	1,708,200	1,576,800	$153,204.75	$152,607.18	($597.57)	-0.4%	-
15,000	40%	4,380,000	2,277,600	2,102,400	$199,266.45	$197,657.10	($1,609.35)	-0.8%	1
15,000	50%	5,475,000	2,847,000	2,628,000	$245,328.15	$242,707.02	($2,621.13)	-1.1%	-
15,000	60%	6,570,000	3,416,400	3,153,600	$291,389.85	$287,756.94	($3,632.91)	-1.2%	-
15,000	70%	7,665,000	3,985,800	3,679,200	$337,451.55	$332,806.86	($4,644.69)	-1.4%	2
15,000	80%	8,760,000	4,555,200	4,204,800	$383,513.25	$377,856.78	($5,656.47)	-1.5%	1
15,000	90%	9,855,000	5,124,600	4,730,400	$429,574.95	$422,906.70	($6,668.25)	-1.6%	-
50,000	20%	7,300,000	3,796,000	3,504,000	$350,977.79	$351,988.76	$1,010.97	0.3%	-
50,000	30%	10,950,000	5,694,000	5,256,000	$504,516.80	$502,155.17	($2,361.63)	-0.5%	1
50,000	40%	14,600,000	7,592,000	7,008,000	$658,055.80	$652,321.57	($5,734.23)	-0.9%	-
50,000	50%	18,250,000	9,490,000	8,760,000	$811,594.80	$802,487.97	($9,106.83)	-1.1%	-
50,000	60%	21,900,000	11,388,000	10,512,000	$965,133.80	$952,654.37	($12,479.43)	-1.3%	-
50,000	70%	25,550,000	13,286,000	12,264,000	$1,118,672.80	$1,102,820.77	($15,852.03)	-1.4%	-
50,000	80%	29,200,000	15,184,000	14,016,000	$1,272,211.81	$1,252,987.18	($19,224.63)	-1.5%	1
50,000	90%	32,850,000	17,082,000	15,768,000	$1,425,750.81	$1,403,153.58	($22,597.23)	-1.6%	-

	UOM	Current Rates SC7-4	Rate Yr 1 SC7-4
Customer Charge	Monthly	$ 2,641.63	$ 2,800.00
Demand Charge kW	kW	$ 0.83	$ 0.94
SBC (EEtr) per kWh	kWh	$ 0.00092	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ 0.03000	$ 0.03000
Tax Credit per kW	kW	$ (0.04000)	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00515	$ 0.00515
Billing Charge per Bill	Monthly	$ 0.81	$ 0.90
Supply Charge On Peak kWh	kWh-On	$ 0.03926	$ 0.03926
Supply Charge Off Peak kWh	kWh-Off	$ 0.02635	$ 0.02635
MFC per kWh	kWh	$ 0.00199	$ 0.00199

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2020 - April 30, 2021

Including Supply

PSC #120 - SC 9 - Non Residential - Day/Night

kWh	Peak	Off Peak	Current Rates	Rate Yr 1	increase / (decrease) Amount	Percent	# of Customers
300	180	120	$47.48	$48.76	$1.28	2.7%	686
400	240	160	$56.23	$57.91	$1.68	3.0%	214
500	300	200	$64.98	$67.06	$2.08	3.2%	185
600	360	240	$73.73	$76.21	$2.47	3.4%	192
700	420	280	$82.49	$85.36	$2.87	3.5%	171
800	480	320	$91.24	$94.51	$3.27	3.6%	141
900	540	360	$99.99	$103.65	$3.66	3.7%	126
1,000	600	400	$108.74	$112.80	$4.06	3.7%	83
1,100	660	440	$117.49	$121.95	$4.46	3.8%	91
1,200	720	480	$126.25	$131.10	$4.86	3.8%	64
1,500	900	600	$152.50	$158.55	$6.05	4.0%	162
2,000	1,200	800	$196.26	$204.30	$8.03	4.1%	159
2,500	1,500	1,000	$240.03	$250.05	$10.02	4.2%	83
3,000	1,800	1,200	$283.79	$295.79	$12.01	4.2%	47
3,500	2,100	1,400	$327.55	$341.54	$13.99	4.3%	24
5,000	3,000	2,000	$458.83	$478.78	$19.95	4.3%	26

	UOM	Current Rates SC9	Rate Yr 1 SC9
Customer Charge	Monthly	$ 20.41	$ 20.41
Delivery Charge On Peak kWh	kWh-On	$ 0.04058	$ 0.04332
Delivery Charge Off Peak kWh	kWh-Off	$ 0.04058	$ 0.04332
SBC (EEtr) per kWh	kWh	$ 0.00092	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kWh	kWh	$ 0.00184	$ 0.00184
Tax Credit All Hours kWh	kWh	$ (0.00216)	$ -
Transition Charge per kWh	kWh	$ 0.00124	$ 0.00124
Billing Charge per Bill	Monthly	$ 0.81	$ 0.90
Supply Charge On Peak kWh	kWh-On	$ 0.04154	$ 0.04154
Supply Charge Off Peak kWh	kWh-Off	$ 0.03167	$ 0.03167
MFC per kWh	kWh	$ 0.00265	$ 0.00265

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation

Date Sources - NYSEG Electric Bill Impact Statements

Rate	Source of Rate in "Current" Rates	Source of Rate in Rate Years
Customer Charge	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
kW Charge	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
kWh Delivery Charge All Hours	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
kWh Delivery Charge On Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
kWh Delivery Charge Mid Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
kWh Delivery Charge Off Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
Reactive RkVah	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
Billing Charge per Bill	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
SBC (EEtr) per kWh	Current Tariff Rates in Effect 01/01/2020 - (SBC Statement #19)	Included in Delivery Rates
SBC (CEF) per kWh	Current Tariff Rates in Effect 01/01/2020 - (SBC Statement #19)	Current Tariff Rates in Effect 01/01/2020 - (SBC Statement #19)
RAM per kWh	Current Tariff Rates in Effect 07/19/2019 - (RAM Statement #1)	Current Tariff Rates in Effect 07/19/2019 - (RAM Statement #1)
RAM per kW	Current Tariff Rates in Effect 07/19/2019 - (RAM Statement #1)	Current Tariff Rates in Effect 07/19/2019 - (RAM Statement #1)
Tax Credit per kWh	Case No. 17-M-0815 dated August 9, 2018. Statement Number 1 Effective 10/01/2018	Included in Delivery Rates
Tax Credit per kW	Case No. 17-M-0815 dated August 9, 2018. Statement Number 1 Effective 10/01/2018	Included in Delivery Rates

Rate	Source of Rate in "Current" Rates and Rate Years
Transition Charge per kWh	NBC, Demand Response, and Value Stack: NBC is the Non-Weighted 2019 Average, Dmd Rsp is 05/01/2020 rate, Value Stack at $-0-. RAM is separate.
MFC per kWh	Current Tariff Rates in Effect 05/01/2020
kWh Supply Charge All Hours	2019 Annualized Supply Rates
kWh Supply Charge On Peak	2019 Annualized Supply Rates
kWh Supply Charge Mid Peak	2019 Annualized Supply Rates
kWh Supply Charge Off Peak	2019 Annualized Supply Rates
Customer Count	2018 monthly data - separate Low Income counts

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2020 - April 30, 2021

Delivery Bill Only

PSC #120 - SC 1 - Residential

kWh	Current Rates	Rate Yr 1	increase / (decrease) Amount	Percent	# of Customers	# of Low Income Customers	Percent of Customers	Percent of Low Income Customers	Amount of EE Embedded in Delivery Rates* Amount	Percent
100	$20.80	$21.29	$0.49	2.4%	34,023	683	5%	2%	$ 0.11	0.53%
200	$25.67	$26.56	$0.89	3.5%	48,276	2,803	8%	7%	$ 0.23	0.85%
300	$30.55	$31.84	$1.29	4.2%	61,295	4,359	10%	12%	$ 0.34	1.06%
400	$35.42	$37.12	$1.69	4.8%	67,881	4,939	11%	13%	$ 0.45	1.22%
500	$40.30	$42.39	$2.09	5.2%	67,787	4,476	11%	12%	$ 0.57	1.33%
600	$45.17	$47.67	$2.49	5.5%	63,739	3,926	10%	10%	$ 0.68	1.42%
700	$50.05	$52.95	$2.90	5.8%	55,914	3,162	9%	8%	$ 0.79	1.49%
800	$54.93	$58.22	$3.30	6.0%	47,727	2,751	8%	7%	$ 0.90	1.55%
900	$59.80	$63.50	$3.70	6.2%	39,223	2,184	6%	6%	$ 1.02	1.60%
1,000	$64.68	$68.78	$4.10	6.3%	31,407	1,698	5%	5%	$ 1.13	1.64%
1,100	$69.55	$74.05	$4.50	6.5%	25,132	1,395	4%	4%	$ 1.24	1.68%
1,200	$74.43	$79.33	$4.90	6.6%	19,685	1,124	3%	3%	$ 1.36	1.71%
1,500	$89.06	$95.16	$6.10	6.9%	36,425	2,110	6%	6%	$ 1.70	1.78%
2,000	$113.43	$121.54	$8.11	7.1%	23,598	1,396	4%	4%	$ 2.26	1.86%
3,000	$162.19	$174.31	$12.12	7.5%	12,884	710	2%	2%	$ 3.39	1.94%
					634,997	37,717				

	UOM	Current Rates SC1	Rate Yr 1 SC1
Customer Charge	Monthly	$ 15.11	$ 15.11
Delivery Charge All Hours kWh	kWh	$ 0.04256	$ 0.04523
SBC (EEtr) per kWh	kWh	$ 0.00092	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kWh	kWh	$ 0.00189	$ 0.00189
Tax Credit All Hours kWh	kWh	$ (0.00226)	$ -
Transition Charge per kWh	kWh	$ 0.00078	$ 0.00078
Billing Charge per Bill	Monthly	$ 0.81	$ 0.90

Includes $ 0.00113 per kWh of EE Costs*

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Low income customers represent customers who participated in the Company's low income program and received a credit on their bill each month during calendar year 2018.

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2020 - April 30, 2021

Delivery Bill Only

PSC #120 - SC 8 - Residential - Day/Night

kWh	Peak	Off Peak	Current Rates	Rate Yr 1	increase / (decrease) Amount	Percent	# of Customers
300	210	90	$31.46	$32.70	$1.24	3.9%	11,243
400	280	120	$35.87	$37.50	$1.63	4.5%	7,307
500	350	150	$40.29	$42.30	$2.01	5.0%	8,958
600	420	180	$44.70	$47.10	$2.39	5.4%	9,556
700	490	210	$49.12	$51.89	$2.78	5.7%	9,821
800	560	240	$53.53	$56.69	$3.16	5.9%	9,276
900	630	270	$57.95	$61.49	$3.55	6.1%	8,790
1,000	700	300	$62.36	$66.29	$3.93	6.3%	7,969
1,500	1,050	450	$84.44	$90.29	$5.85	6.9%	27,922
2,000	1,400	600	$106.51	$114.29	$7.77	7.3%	14,600
2,500	1,750	750	$128.59	$138.28	$9.69	7.5%	6,944
3,000	2,100	900	$150.66	$162.28	$11.62	7.7%	2,980
4,000	2,800	1,200	$194.81	$210.27	$15.46	7.9%	1,783
5,000	3,500	1,500	$238.97	$258.27	$19.30	8.1%	419
6,000	4,200	1,800	$283.12	$306.26	$23.14	8.2%	179
7,000	4,900	2,100	$327.27	$354.25	$26.98	8.2%	77

	UOM	Current Rates SC8	Rate Yr 1 SC8
Customer Charge	Monthly	$ 17.40	$ 17.40
Delivery Charge On Peak kWh	kWh-On	$ 0.03790	$ 0.04072
Delivery Charge Off Peak kWh	kWh-Off	$ 0.03790	$ 0.04072
SBC (EEtr) per kWh	kWh	$ 0.00092	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kWh	kWh	$ 0.00164	$ 0.00164
Tax Credit All Hours kWh	kWh	$ (0.00195)	$ -
Transition Charge per kWh	kWh	$ 0.00078	$ 0.00078
Billing Charge per Bill	Monthly	$ 0.81	$ 0.90

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2020 - April 30, 2021

Delivery Bill Only

PSC #120 - SC 12 - Residential - TOU								
						increase / (decrease)		
kWh	Peak	Mid Peak	Off Peak	Current Rates	Rate Yr 1	Amount	Percent	# of Customers
1,000	140	570	290	$70.73	$71.71	$0.98	1.4%	169
2,000	280	1,140	580	$116.54	$118.41	$1.87	1.6%	396
3,000	420	1,710	870	$162.35	$165.10	$2.76	1.7%	435
4,000	560	2,280	1,160	$208.16	$211.80	$3.64	1.8%	398
5,000	700	2,850	1,450	$253.97	$258.50	$4.53	1.8%	382
6,000	840	3,420	1,740	$299.78	$305.20	$5.42	1.8%	394
7,000	980	3,990	2,030	$345.58	$351.90	$6.31	1.8%	327
8,000	1,120	4,560	2,320	$391.39	$398.59	$7.20	1.8%	255
9,000	1,260	5,130	2,610	$437.20	$445.29	$8.09	1.9%	194
10,000	1,400	5,700	2,900	$483.01	$491.99	$8.98	1.9%	119
15,000	2,100	8,550	4,350	$712.06	$725.48	$13.42	1.9%	375
20,000	2,800	11,400	5,800	$941.10	$958.97	$17.87	1.9%	120
30,000	4,200	17,100	8,700	$1,399.20	$1,425.95	$26.76	1.9%	90
40,000	5,600	22,800	11,600	$1,857.29	$1,892.93	$35.64	1.9%	32
50,000	7,000	28,500	14,500	$2,315.38	$2,359.91	$44.53	1.9%	16

	UOM	Current Rates SC12	Rate Yr 1 SC12
Customer Charge	Monthly	$ 24.11	$ 24.11
Delivery Charge On Peak kWh	kWh-On	$ 0.03951	$ 0.03961
Delivery Charge Mid Peak kWh	kWh-Mid	$ 0.03951	$ 0.03961
Delivery Charge Off Peak kWh	kWh-Off	$ 0.03951	$ 0.03961
SBC (EEtr) per kWh	kWh	$ 0.00092	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kWh	kWh	$ 0.00144	$ 0.00144
Tax Credit All Hours kWh	kWh	$ (0.00171)	$ -
Transition Charge per kWh	kWh	$ 0.00078	$ 0.00078
Billing Charge per Bill	Monthly	$ 0.81	$ 0.90

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2020 - April 30, 2021

Delivery Bill Only

PSC #120 - SC 2 - Non Residential - Secondary							
					increase / (decrease)		
Kw	Load Factor	kWh	Current Rates	Rate Yr 1	Amount	Percent	# of Customers
5	20%	730	$80.90	$83.36	$2.46	3.0%	4,814
5	30%	1,095	$84.37	$86.31	$1.94	2.3%	1,783
5	40%	1,460	$87.85	$89.27	$1.42	1.6%	1,150
5	50%	1,825	$91.32	$92.22	$0.90	1.0%	737
5	60%	2,190	$94.80	$95.18	$0.38	0.4%	477
5	70%	2,555	$98.27	$98.13	($0.14)	-0.1%	276
5	80%	2,920	$101.75	$101.08	($0.66)	-0.7%	221
5	90%	3,285	$105.22	$104.04	($1.18)	-1.1%	493
25	20%	3,650	$304.01	$315.95	$11.95	3.9%	15,467
25	30%	5,475	$321.38	$330.72	$9.34	2.9%	5,392
25	40%	7,300	$338.75	$345.50	$6.74	2.0%	3,010
25	50%	9,125	$356.13	$360.27	$4.14	1.2%	1,577
25	60%	10,950	$373.50	$375.04	$1.54	0.4%	852
25	70%	12,775	$390.87	$389.81	($1.07)	-0.3%	448
25	80%	14,600	$408.25	$404.58	($3.67)	-0.9%	288
25	90%	16,425	$425.62	$419.35	($6.27)	-1.5%	371
100	20%	14,600	$1,140.67	$1,188.19	$47.52	4.2%	3,447
100	30%	21,900	$1,210.16	$1,247.27	$37.11	3.1%	1,541
100	40%	29,200	$1,279.65	$1,306.35	$26.70	2.1%	776
100	50%	36,500	$1,349.15	$1,365.44	$16.29	1.2%	343
100	60%	43,800	$1,418.64	$1,424.52	$5.88	0.4%	190
100	70%	51,100	$1,488.14	$1,483.61	($4.53)	-0.3%	80
100	80%	58,400	$1,557.63	$1,542.69	($14.94)	-1.0%	27
100	90%	65,700	$1,627.13	$1,601.78	($25.35)	-1.6%	45
300	20%	43,800	$3,371.76	$3,514.14	$142.38	4.2%	435
300	30%	65,700	$3,580.24	$3,691.39	$111.15	3.1%	412
300	40%	87,600	$3,788.72	$3,868.64	$79.92	2.1%	201
300	50%	109,500	$3,997.21	$4,045.90	$48.69	1.2%	101
300	60%	131,400	$4,205.69	$4,223.15	$17.46	0.4%	51
300	70%	153,300	$4,414.18	$4,400.41	($13.77)	-0.3%	29
300	80%	175,200	$4,622.66	$4,577.66	($45.00)	-1.0%	18
300	90%	197,100	$4,831.14	$4,754.92	($76.23)	-1.6%	28

		Current Rates	Rate Yr 1
	UOM	SC2	SC2
Customer Charge	Monthly	$ 24.31	$ 24.31
Demand Charge kW	kW	$ 9.79	$ 10.11
Delivery Charge All Hours kWh	kWh	$ 0.00261	$ 0.00201
SBC (EEtr) per kWh	kWh	$ 0.00092	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ 0.33000	$ 0.33000
Tax Credit per kW	kW	$ (0.36000)	$ -
Tax Credit All Hours kWh	kWh	$ (0.00010)	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00557	$ 0.00557
Billing Charge per Bill	Monthly	$ 0.81	$ 0.90

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2020 - April 30, 2021

Delivery Bill Only

PSC #120 - SC 3P - Non Residential - Primary							
					increase / (decrease)		
Kw	Load Factor	kWh	Current Rates	Rate Yr 1	Amount	Percent	# of Customers
5	20%	730	$139.42	$143.33	$3.91	2.8%	8
5	30%	1,095	$142.90	$146.29	$3.39	2.4%	4
5	40%	1,460	$146.39	$149.25	$2.86	2.0%	1
5	50%	1,825	$149.87	$152.21	$2.34	1.6%	2
5	60%	2,190	$153.35	$155.17	$1.82	1.2%	-
5	70%	2,555	$156.83	$158.13	$1.30	0.8%	-
5	80%	2,920	$160.31	$161.09	$0.78	0.5%	-
5	90%	3,285	$163.80	$164.05	$0.25	0.2%	-
25	20%	3,650	$289.19	$308.37	$19.18	6.6%	18
25	30%	5,475	$306.60	$323.17	$16.57	5.4%	9
25	40%	7,300	$324.01	$337.97	$13.96	4.3%	5
25	50%	9,125	$341.42	$352.77	$11.35	3.3%	8
25	60%	10,950	$358.83	$367.57	$8.74	2.4%	1
25	70%	12,775	$376.24	$382.37	$6.14	1.6%	1
25	80%	14,600	$393.65	$397.17	$3.53	0.9%	3
25	90%	16,425	$411.06	$411.97	$0.92	0.2%	-
100	20%	14,600	$850.80	$927.27	$76.47	9.0%	67
100	30%	21,900	$920.44	$986.47	$66.03	7.2%	-
100	40%	29,200	$990.08	$1,045.67	$55.59	5.6%	15
100	50%	36,500	$1,059.72	$1,104.87	$45.15	4.3%	11
100	60%	43,800	$1,129.36	$1,164.08	$34.71	3.1%	6
100	70%	51,100	$1,199.00	$1,223.28	$24.27	2.0%	3
100	80%	58,400	$1,268.65	$1,282.48	$13.83	1.1%	2
100	90%	65,700	$1,338.29	$1,341.68	$3.39	0.3%	-
300	20%	43,800	$2,348.45	$2,577.67	$229.22	9.8%	69
300	30%	65,700	$2,557.37	$2,755.27	$197.91	7.7%	-
300	40%	87,600	$2,766.29	$2,932.88	$166.59	6.0%	26
300	50%	109,500	$2,975.21	$3,110.48	$135.27	4.5%	22
300	60%	131,400	$3,184.13	$3,288.09	$103.95	3.3%	8
300	70%	153,300	$3,393.05	$3,465.69	$72.64	2.1%	4
300	80%	175,200	$3,601.98	$3,643.30	$41.32	1.1%	7
300	90%	197,100	$3,810.90	$3,820.90	$10.00	0.3%	8

	UOM	Current Rates SC3P	Rate Yr 1 SC3P
Customer Charge	Monthly	$ 101.17	$ 101.17
Demand Charge kW	kW	$ 6.12	$ 6.90
Delivery Charge All Hours kWh	kWh	$ 0.00261	$ 0.00202
SBC (EEtr) per kWh	kWh	$ 0.00092	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ 0.16000	$ 0.16000
Tax Credit per kW	kW	$ (0.19000)	$ -
Tax Credit All Hours kWh	kWh	$ (0.00008)	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00541	$ 0.00541
Billing Charge per Bill	Monthly	$ 0.81	$ 0.90

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2020 - April 30, 2021
Delivery Bill Only

PSC #120 - SC 3S - Non Residential - SubTransmission							
					increase / (decrease)		
Kw	Load Factor	kWh	Current Rates	Rate Yr 1	Amount	Percent	# of Customers
5	20%	730	$361.25	$361.95	$0.70	0.2%	1
5	30%	1,095	$363.81	$364.17	$0.36	0.1%	-
5	40%	1,460	$366.37	$366.39	$0.03	0.0%	-
5	50%	1,825	$368.92	$368.61	($0.31)	-0.1%	-
5	60%	2,190	$371.48	$370.84	($0.65)	-0.2%	-
5	70%	2,555	$374.04	$373.06	($0.98)	-0.3%	-
5	80%	2,920	$376.60	$375.28	($1.32)	-0.4%	-
5	90%	3,285	$379.16	$377.50	($1.66)	-0.4%	-
25	20%	3,650	$470.76	$473.91	$3.15	0.7%	2
25	30%	5,475	$483.56	$485.02	$1.46	0.3%	-
25	40%	7,300	$496.35	$496.13	($0.22)	0.0%	-
25	50%	9,125	$509.14	$507.23	($1.91)	-0.4%	-
25	60%	10,950	$521.94	$518.34	($3.60)	-0.7%	-
25	70%	12,775	$534.73	$529.45	($5.28)	-1.0%	-
25	80%	14,600	$547.52	$540.55	($6.97)	-1.3%	-
25	90%	16,425	$560.31	$551.66	($8.65)	-1.5%	-
100	20%	14,600	$881.45	$893.78	$12.33	1.4%	2
100	30%	21,900	$932.62	$938.21	$5.59	0.6%	-
100	40%	29,200	$983.79	$982.63	($1.16)	-0.1%	1
100	50%	36,500	$1,034.96	$1,027.06	($7.90)	-0.8%	1
100	60%	43,800	$1,086.14	$1,071.49	($14.65)	-1.3%	-
100	70%	51,100	$1,137.31	$1,115.91	($21.39)	-1.9%	-
100	80%	58,400	$1,188.48	$1,160.34	($28.14)	-2.4%	-
100	90%	65,700	$1,239.65	$1,204.76	($34.88)	-2.8%	-
300	20%	43,800	$1,976.61	$2,013.42	$36.82	1.9%	1
300	30%	65,700	$2,130.12	$2,146.70	$16.58	0.8%	-
300	40%	87,600	$2,283.64	$2,279.98	($3.66)	-0.2%	1
300	50%	109,500	$2,437.15	$2,413.26	($23.89)	-1.0%	-
300	60%	131,400	$2,590.67	$2,546.54	($44.13)	-1.7%	-
300	70%	153,300	$2,744.18	$2,679.82	($64.36)	-2.3%	2
300	80%	175,200	$2,897.69	$2,813.10	($84.60)	-2.9%	1
300	90%	197,100	$3,051.21	$2,946.38	($104.83)	-3.4%	-

	UOM	Current Rates SC3S	Rate Yr 1 SC3S
Customer Charge	Monthly	$ 333.06	$ 333.06
Demand Charge kW	kW	$ 4.50	$ 4.47
Delivery Charge All Hours kWh	kWh	$ -	$ -
SBC (EEtr) per kWh	kWh	$ 0.00092	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ 0.24000	$ 0.24000
Tax Credit per kW	kW	$ (0.29000)	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00236	$ 0.00236
Billing Charge per Bill	Monthly	$ 0.81	$ 0.90

Notes:
1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2020 - April 30, 2021

Delivery Bill Only

PSC #120 - SC 6 - Non Residential					
			increase / (decrease)		
kWh	Current Rates	Rate Yr 1	Amount	Percent	# of Customers
300	$34.61	$36.59	$1.97	5.7%	38,981
400	$40.02	$42.62	$2.60	6.5%	7,133
500	$45.42	$48.65	$3.23	7.1%	5,737
600	$50.82	$54.68	$3.86	7.6%	4,185
700	$56.22	$60.71	$4.49	8.0%	3,094
800	$61.62	$66.73	$5.11	8.3%	2,217
900	$67.02	$72.76	$5.74	8.6%	1,753
1,000	$72.42	$78.79	$6.37	8.8%	1,339
1,100	$77.83	$84.82	$7.00	9.0%	1,105
1,200	$83.23	$90.85	$7.63	9.2%	886
1,500	$99.43	$108.94	$9.51	9.6%	1,756
2,000	$126.44	$139.09	$12.65	10.0%	1,278
2,500	$153.44	$169.23	$15.79	10.3%	461
3,000	$180.45	$199.38	$18.93	10.5%	223
3,500	$207.46	$229.53	$22.07	10.6%	139
8,000	$450.52	$500.85	$50.33	11.2%	408

		Current Rates	Rate Yr 1
	UOM	SC6	SC6
Customer Charge	Monthly	$ 17.60	$ 17.60
Delivery Charge All Hours kWh	kWh	$ 0.04746	$ 0.05166
SBC (EEtr) per kWh	kWh	$ 0.00092	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kWh	kWh	$ 0.00253	$ 0.00253
Tax Credit All Hours kWh	kWh	$ (0.00300)	$ -
Transition Charge per kWh	kWh	$ 0.00124	$ 0.00124
Billing Charge per Bill	Monthly	$ 0.81	$ 0.90

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2020 - April 30, 2021

Delivery Bill Only

PSC #120 - SC 7-1 - Non Residential Large General Service - Secondary									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Current Rates	Rate Yr 1	Amount	Percent	# of Customers
25	20%	3,650	1,898	1,752	$409.24	$446.47	$37.23	9.1%	558
25	30%	5,475	2,847	2,628	$422.03	$457.57	$35.54	8.4%	172
25	40%	7,300	3,796	3,504	$434.82	$468.68	$33.86	7.8%	139
25	50%	9,125	4,745	4,380	$447.62	$479.79	$32.17	7.2%	79
25	60%	10,950	5,694	5,256	$460.41	$490.89	$30.48	6.6%	50
25	70%	12,775	6,643	6,132	$473.20	$502.00	$28.80	6.1%	23
25	80%	14,600	7,592	7,008	$486.00	$513.11	$27.11	5.6%	13
25	90%	16,425	8,541	7,884	$498.79	$524.21	$25.42	5.1%	11
100	20%	14,600	7,592	7,008	$1,152.57	$1,180.16	$27.59	2.4%	585
100	30%	21,900	11,388	10,512	$1,203.74	$1,224.59	$20.85	1.7%	-
100	40%	29,200	15,184	14,016	$1,254.91	$1,269.02	$14.10	1.1%	109
100	50%	36,500	18,980	17,520	$1,306.09	$1,313.44	$7.36	0.6%	82
100	60%	43,800	22,776	21,024	$1,357.26	$1,357.87	$0.61	0.0%	44
100	70%	51,100	26,572	24,528	$1,408.43	$1,402.30	($6.13)	-0.4%	9
100	80%	58,400	30,368	28,032	$1,459.60	$1,446.72	($12.88)	-0.9%	4
100	90%	65,700	34,164	31,536	$1,510.77	$1,491.15	($19.62)	-1.3%	9
500	20%	73,000	37,960	35,040	$5,117.02	$5,093.22	($23.80)	-0.5%	275
500	30%	109,500	56,940	52,560	$5,372.87	$5,315.35	($57.52)	-1.1%	151
500	40%	146,000	75,920	70,080	$5,628.73	$5,537.48	($91.25)	-1.6%	100
500	50%	182,500	94,900	87,600	$5,884.59	$5,759.61	($124.98)	-2.1%	62
500	60%	219,000	113,880	105,120	$6,140.45	$5,981.75	($158.70)	-2.6%	27
500	70%	255,500	132,860	122,640	$6,396.31	$6,203.88	($192.43)	-3.0%	16
500	80%	292,000	151,840	140,160	$6,652.16	$6,426.01	($226.15)	-3.4%	7
500	90%	328,500	170,820	157,680	$6,908.02	$6,648.14	($259.88)	-3.8%	-
1,000	20%	146,000	75,920	70,080	$10,072.57	$9,984.54	($88.03)	-0.9%	32
1,000	30%	219,000	113,880	105,120	$10,584.29	$10,428.80	($155.49)	-1.5%	24
1,000	40%	292,000	151,840	140,160	$11,096.00	$10,873.07	($222.94)	-2.0%	21
1,000	50%	365,000	189,800	175,200	$11,607.72	$11,317.33	($290.39)	-2.5%	-
1,000	60%	438,000	227,760	210,240	$12,119.44	$11,761.59	($357.84)	-3.0%	16
1,000	70%	511,000	265,720	245,280	$12,631.15	$12,205.86	($425.29)	-3.4%	4
1,000	80%	584,000	303,680	280,320	$13,142.87	$12,650.12	($492.75)	-3.7%	5
1,000	90%	657,000	341,640	315,360	$13,654.58	$13,094.38	($560.20)	-4.1%	9

	UOM	Current Rates SC7-1	Rate Yr 1 SC7-1
Customer Charge	Monthly	$ 160.65	$ 201.00
Demand Charge kW	kW	$ 8.94	$ 8.57
SBC (EEtr) per kWh	kWh	$ 0.00092	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ 0.32000	$ 0.32000
Tax Credit per kW	kW	$ (0.38000)	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00768	$ 0.00768
Billing Charge per Bill	Monthly	$ 0.81	$ 0.90

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2020 - April 30, 2021

Delivery Bill Only

PSC #120 - SC 7-2 - Non Residential Large General Service - Primary									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Current Rates	Rate Yr 1	Amount	Percent	# of Customers
500	20%	73,000	37,960	35,040	$4,713.59	$4,988.12	$274.53	5.8%	90
500	30%	109,500	56,940	52,560	$4,969.44	$5,210.25	$240.81	4.8%	35
500	40%	146,000	75,920	70,080	$5,225.30	$5,432.38	$207.08	4.0%	32
500	50%	182,500	94,900	87,600	$5,481.16	$5,654.51	$173.36	3.2%	27
500	60%	219,000	113,880	105,120	$5,737.02	$5,876.65	$139.63	2.4%	12
500	70%	255,500	132,860	122,640	$5,992.87	$6,098.78	$105.90	1.8%	8
500	80%	292,000	151,840	140,160	$6,248.73	$6,320.91	$72.18	1.2%	-
500	90%	328,500	170,820	157,680	$6,504.59	$6,543.04	$38.45	0.6%	-
1,000	20%	146,000	75,920	70,080	$8,864.59	$9,273.34	$408.75	4.6%	21
1,000	30%	219,000	113,880	105,120	$9,376.31	$9,717.60	$341.30	3.6%	22
1,000	40%	292,000	151,840	140,160	$9,888.02	$10,161.86	$273.84	2.8%	23
1,000	50%	365,000	189,800	175,200	$10,399.74	$10,606.13	$206.39	2.0%	-
1,000	60%	438,000	227,760	210,240	$10,911.45	$11,050.39	$138.94	1.3%	14
1,000	70%	511,000	265,720	245,280	$11,423.17	$11,494.65	$71.49	0.6%	7
1,000	80%	584,000	303,680	280,320	$11,934.88	$11,938.92	$4.04	0.0%	2
1,000	90%	657,000	341,640	315,360	$12,446.60	$12,383.18	($63.42)	-0.5%	1
1,500	20%	219,000	113,880	105,120	$13,015.60	$13,558.56	$542.96	4.2%	4
1,500	30%	328,500	170,820	157,680	$13,783.17	$14,224.95	$441.78	3.2%	2
1,500	40%	438,000	227,760	210,240	$14,550.74	$14,891.35	$340.60	2.3%	8
1,500	50%	547,500	284,700	262,800	$15,318.32	$15,557.74	$239.43	1.6%	8
1,500	60%	657,000	341,640	315,360	$16,085.89	$16,224.14	$138.25	0.9%	-
1,500	70%	766,500	398,580	367,920	$16,853.46	$16,890.53	$37.07	0.2%	7
1,500	80%	876,000	455,520	420,480	$17,621.03	$17,556.93	($64.11)	-0.4%	2
1,500	90%	985,500	512,460	473,040	$18,388.61	$18,223.32	($165.29)	-0.9%	-
2,500	20%	365,000	189,800	175,200	$21,317.61	$22,129.00	$811.39	3.8%	5
2,500	30%	547,500	284,700	262,800	$22,596.90	$23,239.65	$642.76	2.8%	2
2,500	40%	730,000	379,600	350,400	$23,876.18	$24,350.31	$474.13	2.0%	11
2,500	50%	912,500	474,500	438,000	$25,155.47	$25,460.97	$305.50	1.2%	12
2,500	60%	1,095,000	569,400	525,600	$26,434.76	$26,571.63	$136.87	0.5%	-
2,500	70%	1,277,500	664,300	613,200	$27,714.05	$27,682.29	($31.76)	-0.1%	1
2,500	80%	1,460,000	759,200	700,800	$28,993.34	$28,792.95	($200.39)	-0.7%	3
2,500	90%	1,642,500	854,100	788,400	$30,272.63	$29,903.61	($369.02)	-1.2%	5

	UOM	Current Rates SC7-2	Rate Yr 1 SC7-2
Customer Charge	Monthly	$ 561.77	$ 702.00
Demand Charge kW	kW	$ 7.30	$ 7.43
SBC (EEtr) per kWh	kWh	$ 0.00092	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ 0.24000	$ 0.24000
Tax Credit per kW	kW	$ (0.27000)	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00858	$ 0.00858
Billing Charge per Bill	Monthly	$ 0.81	$ 0.90

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2020 - April 30, 2021

Delivery Bill Only

PSC #120 - SC 7-3 - Non Residential Large General Service - SubTransmission									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Current Rates	Rate Yr 1	Amount	Percent	# of Customers
500	20%	73,000	37,960	35,040	$2,744.75	$2,932.22	$187.47	6.8%	18
500	30%	109,500	56,940	52,560	$3,000.61	$3,154.36	$153.74	5.1%	9
500	40%	146,000	75,920	70,080	$3,256.47	$3,376.49	$120.02	3.7%	7
500	50%	182,500	94,900	87,600	$3,512.33	$3,598.62	$86.29	2.5%	6
500	60%	219,000	113,880	105,120	$3,768.19	$3,820.75	$52.57	1.4%	2
500	70%	255,500	132,860	122,640	$4,024.04	$4,042.88	$18.84	0.5%	2
500	80%	292,000	151,840	140,160	$4,279.90	$4,265.02	($14.89)	-0.3%	-
500	90%	328,500	170,820	157,680	$4,535.76	$4,487.15	($48.61)	-1.1%	-
2,000	20%	292,000	151,840	140,160	$7,467.94	$7,340.20	($127.74)	-1.7%	32
2,000	30%	438,000	227,760	210,240	$8,491.37	$8,228.73	($262.64)	-3.1%	-
2,000	40%	584,000	303,680	280,320	$9,514.80	$9,117.25	($397.55)	-4.2%	11
2,000	50%	730,000	379,600	350,400	$10,538.23	$10,005.78	($532.45)	-5.1%	6
2,000	60%	876,000	455,520	420,480	$11,561.66	$10,894.31	($667.35)	-5.8%	4
2,000	70%	1,022,000	531,440	490,560	$12,585.09	$11,782.83	($802.26)	-6.4%	2
2,000	80%	1,168,000	607,360	560,640	$13,608.52	$12,671.36	($937.16)	-6.9%	-
2,000	90%	1,314,000	683,280	630,720	$14,631.96	$13,559.89	($1,072.07)	-7.3%	-
4,000	20%	584,000	303,680	280,320	$13,765.52	$13,217.50	($548.02)	-4.0%	2
4,000	30%	876,000	455,520	420,480	$15,812.38	$14,994.56	($817.83)	-5.2%	10
4,000	40%	1,168,000	607,360	560,640	$17,859.24	$16,771.61	($1,087.63)	-6.1%	4
4,000	50%	1,460,000	759,200	700,800	$19,906.10	$18,548.66	($1,357.44)	-6.8%	-
4,000	60%	1,752,000	911,040	840,960	$21,952.97	$20,325.72	($1,627.25)	-7.4%	6
4,000	70%	2,044,000	1,062,880	981,120	$23,999.83	$22,102.77	($1,897.06)	-7.9%	4
4,000	80%	2,336,000	1,214,720	1,121,280	$26,046.69	$23,879.82	($2,166.87)	-8.3%	-
4,000	90%	2,628,000	1,366,560	1,261,440	$28,093.55	$25,656.88	($2,436.67)	-8.7%	-
5,000	20%	730,000	379,600	350,400	$16,914.31	$16,156.15	($758.16)	-4.5%	-
5,000	30%	1,095,000	569,400	525,600	$19,472.89	$18,377.47	($1,095.42)	-5.6%	-
5,000	40%	1,460,000	759,200	700,800	$22,031.46	$20,598.79	($1,432.68)	-6.5%	-
5,000	50%	1,825,000	949,000	876,000	$24,590.04	$22,820.10	($1,769.94)	-7.2%	1
5,000	60%	2,190,000	1,138,800	1,051,200	$27,148.62	$25,041.42	($2,107.20)	-7.8%	1
5,000	70%	2,555,000	1,328,600	1,226,400	$29,707.19	$27,262.74	($2,444.46)	-8.2%	3
5,000	80%	2,920,000	1,518,400	1,401,600	$32,265.77	$29,484.05	($2,781.72)	-8.6%	-
5,000	90%	3,285,000	1,708,200	1,576,800	$34,824.35	$31,705.37	($3,118.98)	-9.0%	5

		Current Rates	Rate Yr 1
	UOM	SC7-3	SC7-3
Customer Charge	Monthly	$ 1,169.55	$ 1,462.00
Demand Charge kW	kW	$ 2.14	$ 1.95
SBC (EEtr) per kWh	kWh	$ 0.00092	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ 0.09000	$ 0.09000
Tax Credit per kW	kW	$ (0.11000)	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00536	$ 0.00536
Billing Charge per Bill	Monthly	$ 0.81	$ 0.90

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2020 - April 30, 2021

Delivery Bill Only

PSC #120 - SC 7-4 - Non Residential Large General Service - Transmission									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Current Rates	Rate Yr 1	Amount	Percent	# of Customers
1,000	20%	146,000	75,920	70,080	$4,491.02	$4,666.53	$175.51	3.9%	1
1,000	30%	219,000	113,880	105,120	$5,002.73	$5,110.79	$108.06	2.2%	-
1,000	40%	292,000	151,840	140,160	$5,514.45	$5,555.05	$40.61	0.7%	2
1,000	50%	365,000	189,800	175,200	$6,026.16	$5,999.32	($26.85)	-0.4%	-
1,000	60%	438,000	227,760	210,240	$6,537.88	$6,443.58	($94.30)	-1.4%	-
1,000	70%	511,000	265,720	245,280	$7,049.59	$6,887.84	($161.75)	-2.3%	-
1,000	80%	584,000	303,680	280,320	$7,561.31	$7,332.11	($229.20)	-3.0%	-
1,000	90%	657,000	341,640	315,360	$8,073.03	$7,776.37	($296.65)	-3.7%	-
7,500	20%	1,095,000	569,400	525,600	$16,506.77	$16,793.11	$286.34	1.7%	5
7,500	30%	1,642,500	854,100	788,400	$20,344.64	$20,125.09	($219.55)	-1.1%	-
7,500	40%	2,190,000	1,138,800	1,051,200	$24,182.50	$23,457.06	($725.44)	-3.0%	1
7,500	50%	2,737,500	1,423,500	1,314,000	$28,020.37	$26,789.04	($1,231.33)	-4.4%	1
7,500	60%	3,285,000	1,708,200	1,576,800	$31,858.24	$30,121.01	($1,737.22)	-5.5%	-
7,500	70%	3,832,500	1,992,900	1,839,600	$35,696.10	$33,452.99	($2,243.11)	-6.3%	1
7,500	80%	4,380,000	2,277,600	2,102,400	$39,533.97	$36,784.96	($2,749.00)	-7.0%	-
7,500	90%	4,927,500	2,562,300	2,365,200	$43,371.83	$40,116.94	($3,254.89)	-7.5%	-
15,000	20%	2,190,000	1,138,800	1,051,200	$30,371.11	$30,785.32	$414.21	1.4%	1
15,000	30%	3,285,000	1,708,200	1,576,800	$38,046.84	$37,449.27	($597.57)	-1.6%	-
15,000	40%	4,380,000	2,277,600	2,102,400	$45,722.57	$44,113.22	($1,609.35)	-3.5%	1
15,000	50%	5,475,000	2,847,000	2,628,000	$53,398.30	$50,777.17	($2,621.13)	-4.9%	-
15,000	60%	6,570,000	3,416,400	3,153,600	$61,074.03	$57,441.12	($3,632.91)	-5.9%	-
15,000	70%	7,665,000	3,985,800	3,679,200	$68,749.76	$64,105.07	($4,644.69)	-6.8%	2
15,000	80%	8,760,000	4,555,200	4,204,800	$76,425.49	$70,769.03	($5,656.47)	-7.4%	1
15,000	90%	9,855,000	5,124,600	4,730,400	$84,101.22	$77,432.98	($6,668.25)	-7.9%	-
50,000	20%	7,300,000	3,796,000	3,504,000	$95,071.33	$96,082.30	$1,010.97	1.1%	-
50,000	30%	10,950,000	5,694,000	5,256,000	$120,657.10	$118,295.47	($2,361.63)	-2.0%	1
50,000	40%	14,600,000	7,592,000	7,008,000	$146,242.87	$140,508.64	($5,734.23)	-3.9%	-
50,000	50%	18,250,000	9,490,000	8,760,000	$171,828.64	$162,721.81	($9,106.83)	-5.3%	-
50,000	60%	21,900,000	11,388,000	10,512,000	$197,414.41	$184,934.98	($12,479.43)	-6.3%	-
50,000	70%	25,550,000	13,286,000	12,264,000	$223,000.18	$207,148.15	($15,852.03)	-7.1%	-
50,000	80%	29,200,000	15,184,000	14,016,000	$248,585.95	$229,361.32	($19,224.63)	-7.7%	1
50,000	90%	32,850,000	17,082,000	15,768,000	$274,171.72	$251,574.49	($22,597.23)	-8.2%	-

		Current Rates	Rate Yr 1
	UOM	SC7-4	SC7-4
Customer Charge	Monthly	$ 2,641.63	$ 2,800.00
Demand Charge kW	kW	$ 0.83	$ 0.94
SBC (EEtr) per kWh	kWh	$ 0.00092	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ 0.03000	$ 0.03000
Tax Credit per kW	kW	$ (0.04000)	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00515	$ 0.00515
Billing Charge per Bill	Monthly	$ 0.81	$ 0.90

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2020 - April 30, 2021

Delivery Bill Only

PSC #120 - SC 9 - Non Residential - Day/Night

kWh	Peak	Off Peak	Current Rates	Rate Yr 1	increase / (decrease) Amount	Percent	# of Customers
300	180	120	$35.40	$36.69	$1.28	3.6%	686
400	240	160	$40.13	$41.81	$1.68	4.2%	214
500	300	200	$44.86	$46.94	$2.08	4.6%	185
600	360	240	$49.59	$52.06	$2.47	5.0%	192
700	420	280	$54.32	$57.19	$2.87	5.3%	171
800	480	320	$59.05	$62.31	$3.27	5.5%	141
900	540	360	$63.77	$67.44	$3.66	5.7%	126
1,000	600	400	$68.50	$72.56	$4.06	5.9%	83
1,100	660	440	$73.23	$77.69	$4.46	6.1%	91
1,200	720	480	$77.96	$82.81	$4.86	6.2%	64
1,500	900	600	$92.14	$98.19	$6.05	6.6%	162
2,000	1,200	800	$115.78	$123.82	$8.03	6.9%	159
2,500	1,500	1,000	$139.42	$149.45	$10.02	7.2%	83
3,000	1,800	1,200	$163.07	$175.07	$12.01	7.4%	47
3,500	2,100	1,400	$186.71	$200.70	$13.99	7.5%	24
5,000	3,000	2,000	$257.63	$277.58	$19.95	7.7%	26

	UOM	Current Rates SC9	Rate Yr 1 SC9
Customer Charge	Monthly	$ 20.41	$ 20.41
Delivery Charge On Peak kWh	kWh-On	$ 0.04058	$ 0.04332
Delivery Charge Off Peak kWh	kWh-Off	$ 0.04058	$ 0.04332
SBC (EEtr) per kWh	kWh	$ 0.00092	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kWh	kWh	$ 0.00184	$ 0.00184
Tax Credit All Hours kWh	kWh	$ (0.00216)	$ -
Transition Charge per kWh	kWh	$ 0.00124	$ 0.00124
Billing Charge per Bill	Monthly	$ 0.81	$ 0.90

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Standby Bill Impacts by SC
May 1, 2020 - April 30, 2021

	$(000) Revenue at Current Rates	$(000) Revenue at Rate Yr 1 Rates	$(000) Increase $(000)	% % Increase or Decrease
Customer Charge				
SC 2	$ 1.17	$ 1.17	$ -	0.00%
SC 3P	$ 7.28	$ 7.28	$ -	0.00%
SC 3S	$ 7.99	$ 7.99	$ -	0.00%
SC 7-1	$ 7.71	$ 9.65	$ 1.94	25.12%
SC 7-2	$ 53.93	$ 67.39	$ 13.46	24.96%
SC 7-3	$ 28.07	$ 35.09	$ 7.02	25.01%
SC 7-4	$ 126.80	$ 134.40	$ 7.60	6.00%
	$ 232.95	$ 262.97	$ 30.02	12.89%
Contract Demand				
SC 2	$ 86.5	$ 81.5	$ (5.0)	-5.82%
SC 3P	$ 62.7	$ 54.3	$ (8.4)	-13.46%
SC 3S	$ 4.3	$ 3.6	$ (0.7)	-15.77%
SC 7-1	$ 120.9	$ 119.9	$ (1.1)	-0.88%
SC 7-2	$ 569.5	$ 592.9	$ 23.4	4.10%
SC 7-3	$ 5.6	$ 5.3	$ (0.3)	-5.52%
SC 7-4	$ 40.3	$ 52.8	$ 12.5	31.15%
	$ 889.9	$ 910.3	$ 20.4	2.29%
Daily As-Used Demand				
SC 2	$ 48.6	$ 45.8	$ (2.8)	-5.82%
SC 3P	$ 14.8	$ 12.8	$ (2.0)	-13.46%
SC 3S	$ 0.4	$ 0.3	$ (0.1)	-15.77%
SC 7-1	$ 61.0	$ 60.5	$ (0.5)	-0.88%
SC 7-2	$ 300.7	$ 313.0	$ 12.3	4.10%
SC 7-3	$ 0.2	$ 0.2	$ (0.0)	-5.52%
SC 7-4	$ 34.1	$ 44.7	$ 10.6	31.15%
	$ 459.8	$ 477.3	$ 17.5	3.82%
Total				
SC 2	$ 136.3	$ 128.4	$ (7.9)	-5.77%
SC 3P	$ 84.8	$ 74.4	$ (10.4)	-12.30%
SC 3S	$ 12.6	$ 11.9	$ (0.7)	-5.79%
SC 7-1	$ 189.7	$ 190.0	$ 0.3	0.18%
SC 7-2	$ 924.1	$ 973.3	$ 49.2	5.32%
SC 7-3	$ 33.9	$ 40.6	$ 6.7	19.75%
SC 7-4	$ 201.2	$ 231.9	$ 30.8	15.30%
	$ 1,582.6	$ 1,650.6	$ 68.0	4.29%

New York State Electric & Gas Corporation		
Date Sources - NYSEG Electric Bill Impact Statements		
Rate	**Source of Rate in "Current" Rates**	**Source of Rate in Rate Years**
Customer Charge	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
kW Charge	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
kWh Delivery Charge All Hours	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
kWh Delivery Charge On Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
kWh Delivery Charge Mid Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
kWh Delivery Charge Off Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
Reactive RkVah	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
Billing Charge per Bill	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
SBC (EEtr) per kWh	Current Tariff Rates in Effect 01/01/2020 - (SBC Statement #19)	Included in Delivery Rates
SBC (CEF) per kWh	Current Tariff Rates in Effect 01/01/2020 - (SBC Statement #19)	Current Tariff Rates in Effect 01/01/2020 - (SBC Statement #19)
RAM per kWh	Current Tariff Rates in Effect 07/19/2019 - (RAM Statement #1)	Current Tariff Rates in Effect 07/19/2019 - (RAM Statement #1)
RAM per kW	Current Tariff Rates in Effect 07/19/2019 - (RAM Statement #1)	Current Tariff Rates in Effect 07/19/2019 - (RAM Statement #1)
Tax Credit per kWh	Case No. 17-M-0815 dated August 9, 2018. Statement Number 1 Effective 10/01/2018	Included in Delivery Rates
Tax Credit per kW	Case No. 17-M-0815 dated August 9, 2018. Statement Number 1 Effective 10/01/2018	Included in Delivery Rates
Rate	**Source of Rate in "Current" Rates and Rate Years**	
Transition Charge per kWh	NBC, Demand Response, and Value Stack: NBC is the Non-Weighted 2019 Average, Dmd Rsp is 05/01/2020 rate, Value Stack at $-0-. RAM is separate.	
MFC per kWh	Current Tariff Rates in Effect 05/01/2020	
kWh Supply Charge All Hours	2019 Annualized Supply Rates	
kWh Supply Charge On Peak	2019 Annualized Supply Rates	
kWh Supply Charge Mid Peak	2019 Annualized Supply Rates	
kWh Supply Charge Off Peak	2019 Annualized Supply Rates	
Customer Count	2018 monthly data - separate Low Income counts	

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2021 - April 30, 2022

Including Supply

PSC #120 - SC 1 - Residential

kWh	Rate Yr 1	Rate Yr 2	increase / (decrease) Amount	Percent	# of Customers	# of Low Income Customers	Percent of Customers	Percent of Low Income Customers
100	$25.45	$26.92	$1.47	5.8%	34,023	683	5%	2%
200	$34.89	$36.89	$2.00	5.7%	48,276	2,803	8%	7%
300	$44.33	$46.86	$2.53	5.7%	61,295	4,359	10%	12%
400	$53.77	$56.83	$3.06	5.7%	67,881	4,939	11%	13%
500	$63.20	$66.80	$3.59	5.7%	67,787	4,476	11%	12%
600	$72.64	$76.77	$4.13	5.7%	63,739	3,926	10%	10%
700	$82.08	$86.74	$4.66	5.7%	55,914	3,162	9%	8%
800	$91.52	$96.71	$5.19	5.7%	47,727	2,751	8%	7%
900	$100.96	$106.68	$5.72	5.7%	39,223	2,184	6%	6%
1,000	$110.40	$116.65	$6.25	5.7%	31,407	1,698	5%	5%
1,100	$119.84	$126.62	$6.78	5.7%	25,132	1,395	4%	4%
1,200	$129.28	$136.59	$7.31	5.7%	19,685	1,124	3%	3%
1,500	$157.60	$166.50	$8.90	5.7%	36,425	2,110	6%	6%
2,000	$204.79	$216.35	$11.56	5.6%	23,598	1,396	4%	4%
3,000	$299.18	$316.05	$16.87	5.6%	12,884	710	2%	2%
					634,997	37,717		

Amount of EE Embedded in Delivery Rates*

Amount	Percent
$ 0.22	0.83%
$ 0.45	1.21%
$ 0.67	1.43%
$ 0.89	1.57%
$ 1.12	1.67%
$ 1.34	1.74%
$ 1.56	1.80%
$ 1.78	1.85%
$ 2.01	1.88%
$ 2.23	1.91%
$ 2.45	1.94%
$ 2.68	1.96%
$ 3.35	2.01%
$ 4.46	2.06%
$ 6.69	2.12%

	UOM	Rate Yr 1 SC1	Rate Yr 2 SC1
Customer Charge	Monthly	$ 15.11	$ 16.05
Delivery Charge All Hours kWh	kWh	$ 0.04523	$ 0.05244
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kWh	kWh	$ 0.00189	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00078	$ 0.00078
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90
Supply Charge All Hours kWh	kWh	$ 0.03897	$ 0.03897
MFC per kWh	kWh	$ 0.00265	$ 0.00265

Includes $ 0.00223 per kWh of EE Costs*

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

4. Low income customers represent customers who participated in the Company's low income program and received a credit on their bill each month during calendar year 2018.

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2021 - April 30, 2022

Including Supply

PSC #120 - SC 8 - Residential - Day/Night

kWh	Peak	Off Peak	Rate Yr 1	Rate Yr 2	increase / (decrease) Amount	Percent	# of Customers
300	210	90	$43.80	$46.50	$2.70	6.2%	11,243
400	280	120	$52.29	$55.53	$3.23	6.2%	7,307
500	350	150	$60.79	$64.56	$3.77	6.2%	8,958
600	420	180	$69.29	$73.59	$4.30	6.2%	9,556
700	490	210	$77.79	$82.62	$4.83	6.2%	9,821
800	560	240	$86.29	$91.66	$5.37	6.2%	9,276
900	630	270	$94.79	$100.69	$5.90	6.2%	8,790
1,000	700	300	$103.29	$109.72	$6.43	6.2%	7,969
1,500	1,050	450	$145.78	$154.88	$9.10	6.2%	27,922
2,000	1,400	600	$188.27	$200.04	$11.77	6.3%	14,600
2,500	1,750	750	$230.77	$245.20	$14.43	6.3%	6,944
3,000	2,100	900	$273.26	$290.36	$17.10	6.3%	2,980
4,000	2,800	1,200	$358.25	$380.68	$22.44	6.3%	1,783
5,000	3,500	1,500	$443.24	$471.01	$27.77	6.3%	419
6,000	4,200	1,800	$528.22	$561.33	$33.10	6.3%	179
7,000	4,900	2,100	$613.21	$651.65	$38.44	6.3%	77

	UOM	Rate Yr 1 SC8	Rate Yr 2 SC8
Customer Charge	Monthly	$ 17.40	$ 18.50
Delivery Charge On Peak kWh	kWh-On	$ 0.04072	$ 0.04769
Delivery Charge Off Peak kWh	kWh-Off	$ 0.04072	$ 0.04769
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kWh	kWh	$ 0.00164	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00078	$ 0.00078
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90
Supply Charge On Peak kWh	kWh-On	$ 0.03759	$ 0.03759
Supply Charge Off Peak kWh	kWh-Off	$ 0.02774	$ 0.02774
MFC per kWh	kWh	$ 0.00236	$ 0.00236

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2021 - April 30, 2022

Including Supply

PSC #120 - SC 12 - Residential - TOU								
						increase / (decrease)		
kWh	Peak	Mid Peak	Off Peak	Rate Yr 1	Rate Yr 2	Amount	Percent	# of Customers
1,000	140	570	290	$108.76	$112.50	$3.74	3.4%	169
2,000	280	1,140	580	$192.50	$198.50	$6.00	3.1%	396
3,000	420	1,710	870	$276.25	$284.50	$8.25	3.0%	435
4,000	560	2,280	1,160	$359.99	$370.50	$10.51	2.9%	398
5,000	700	2,850	1,450	$443.74	$456.50	$12.76	2.9%	382
6,000	840	3,420	1,740	$527.49	$542.50	$15.02	2.8%	394
7,000	980	3,990	2,030	$611.23	$628.51	$17.27	2.8%	327
8,000	1,120	4,560	2,320	$694.98	$714.51	$19.53	2.8%	255
9,000	1,260	5,130	2,610	$778.72	$800.51	$21.78	2.8%	194
10,000	1,400	5,700	2,900	$862.47	$886.51	$24.04	2.8%	119
15,000	2,100	8,550	4,350	$1,281.20	$1,316.51	$35.31	2.8%	375
20,000	2,800	11,400	5,800	$1,699.93	$1,746.52	$46.59	2.7%	120
30,000	4,200	17,100	8,700	$2,537.39	$2,606.53	$69.13	2.7%	90
40,000	5,600	22,800	11,600	$3,374.85	$3,466.53	$91.68	2.7%	32
50,000	7,000	28,500	14,500	$4,212.31	$4,326.54	$114.23	2.7%	16

		Rate Yr 1	Rate Yr 2
	UOM	SC12	SC12
Customer Charge	Monthly	$ 24.11	$ 25.60
Delivery Charge On Peak kWh	kWh-On	$ 0.03961	$ 0.04331
Delivery Charge Mid Peak kWh	kWh-Mid	$ 0.03961	$ 0.04331
Delivery Charge Off Peak kWh	kWh-Off	$ 0.03961	$ 0.04331
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kWh	kWh	$ 0.00144	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00078	$ 0.00078
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90
Supply Charge On Peak kWh	kWh-On	$ 0.04489	$ 0.04489
Supply Charge Mid Peak kWh	kWh-Mid	$ 0.03591	$ 0.03591
Supply Charge Off Peak kWh	kWh-Off	$ 0.02738	$ 0.02738
MFC per kWh	kWh	$ 0.00236	$ 0.00236

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2021 - April 30, 2022

Including Supply

PSC #120 - SC 2 - Non Residential - Secondary							
					increase / (decrease)		
Kw	Load Factor	kWh	Rate Yr 1	Rate Yr 2	Amount	Percent	# of Customers
5	20%	730	$110.40	$118.47	$8.06	7.3%	4,814
5	30%	1,095	$126.88	$134.80	$7.91	6.2%	1,783
5	40%	1,460	$143.36	$151.13	$7.77	5.4%	1,150
5	50%	1,825	$159.84	$167.46	$7.62	4.8%	737
5	60%	2,190	$176.31	$183.79	$7.47	4.2%	477
5	70%	2,555	$192.79	$200.12	$7.33	3.8%	276
5	80%	2,920	$209.27	$216.45	$7.18	3.4%	221
5	90%	3,285	$225.75	$232.78	$7.03	3.1%	493
25	20%	3,650	$451.19	$474.13	$22.94	5.1%	15,467
25	30%	5,475	$533.57	$555.78	$22.21	4.2%	5,392
25	40%	7,300	$615.96	$637.44	$21.48	3.5%	3,010
25	50%	9,125	$698.35	$719.09	$20.74	3.0%	1,577
25	60%	10,950	$780.74	$800.75	$20.01	2.6%	852
25	70%	12,775	$863.12	$882.40	$19.28	2.2%	448
25	80%	14,600	$945.51	$964.05	$18.54	2.0%	288
25	90%	16,425	$1,027.90	$1,045.71	$17.81	1.7%	371
100	20%	14,600	$1,729.12	$1,807.86	$78.75	4.6%	3,447
100	30%	21,900	$2,058.66	$2,134.48	$75.82	3.7%	1,541
100	40%	29,200	$2,388.21	$2,461.10	$72.88	3.1%	776
100	50%	36,500	$2,717.76	$2,787.72	$69.95	2.6%	343
100	60%	43,800	$3,047.31	$3,114.33	$67.02	2.2%	190
100	70%	51,100	$3,376.86	$3,440.95	$64.09	1.9%	80
100	80%	58,400	$3,706.41	$3,767.57	$61.16	1.7%	27
100	90%	65,700	$4,035.96	$4,094.19	$58.23	1.4%	45
300	20%	43,800	$5,136.93	$5,364.49	$227.56	4.4%	435
300	30%	65,700	$6,125.58	$6,344.34	$218.77	3.6%	412
300	40%	87,600	$7,114.22	$7,324.20	$209.97	3.0%	201
300	50%	109,500	$8,102.87	$8,304.05	$201.18	2.5%	101
300	60%	131,400	$9,091.52	$9,283.91	$192.38	2.1%	51
300	70%	153,300	$10,080.17	$10,263.76	$183.59	1.8%	29
300	80%	175,200	$11,068.82	$11,243.61	$174.79	1.6%	18
300	90%	197,100	$12,057.47	$12,223.47	$166.00	1.4%	28

	UOM	Rate Yr 1 SC2	Rate Yr 2 SC2
Customer Charge	Monthly	$ 24.31	$ 28.65
Demand Charge kW	kW	$ 10.11	$ 11.25
Delivery Charge All Hours kWh	kWh	$ 0.00201	$ 0.00161
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ 0.33000	$ -
Tax Credit per kW	kW	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00557	$ 0.00557
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90
Supply Charge All Hours kWh	kWh	$ 0.03506	$ 0.03506
MFC per kWh	kWh	$ 0.00199	$ 0.00199

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2021 - April 30, 2022

Including Supply

PSC #120 - SC 3P - Non Residential - Primary

Kw	Factor	kWh	Rate Yr 1	Rate Yr 2	increase / (decrease) Amount	Percent	# of Customers
5	20%	730	$169.78	$193.51	$23.73	14.0%	8
5	30%	1,095	$185.97	$209.55	$23.58	12.7%	4
5	40%	1,460	$202.15	$225.58	$23.43	11.6%	1
5	50%	1,825	$218.34	$241.62	$23.28	10.7%	2
5	60%	2,190	$234.52	$257.66	$23.14	9.9%	-
5	70%	2,555	$250.71	$273.70	$22.99	9.2%	-
5	80%	2,920	$266.90	$289.74	$22.84	8.6%	-
5	90%	3,285	$283.08	$305.78	$22.69	8.0%	-
25	20%	3,650	$440.63	$487.94	$47.32	10.7%	18
25	30%	5,475	$521.56	$568.13	$46.58	8.9%	9
25	40%	7,300	$602.49	$648.33	$45.84	7.6%	5
25	50%	9,125	$683.41	$728.52	$45.10	6.6%	8
25	60%	10,950	$764.34	$808.71	$44.36	5.8%	1
25	70%	12,775	$845.27	$888.90	$43.62	5.2%	1
25	80%	14,600	$926.20	$969.09	$42.88	4.6%	3
25	90%	16,425	$1,007.13	$1,049.28	$42.15	4.2%	-
100	20%	14,600	$1,456.30	$1,592.08	$135.78	9.3%	67
100	30%	21,900	$1,780.02	$1,912.84	$132.82	7.5%	-
100	40%	29,200	$2,103.73	$2,233.60	$129.87	6.2%	15
100	50%	36,500	$2,427.45	$2,554.36	$126.91	5.2%	11
100	60%	43,800	$2,751.17	$2,875.13	$123.96	4.5%	6
100	70%	51,100	$3,074.89	$3,195.89	$121.00	3.9%	3
100	80%	58,400	$3,398.60	$3,516.65	$118.05	3.5%	2
100	90%	65,700	$3,722.32	$3,837.41	$115.09	3.1%	-
300	20%	43,800	$4,164.76	$4,536.44	$371.68	8.9%	69
300	30%	65,700	$5,135.91	$5,498.72	$362.81	7.1%	-
300	40%	87,600	$6,107.06	$6,461.01	$353.95	5.8%	26
300	50%	109,500	$7,078.21	$7,423.29	$345.08	4.9%	22
300	60%	131,400	$8,049.37	$8,385.58	$336.22	4.2%	8
300	70%	153,300	$9,020.52	$9,347.87	$327.35	3.6%	4
300	80%	175,200	$9,991.67	$10,310.15	$318.49	3.2%	7
300	90%	197,100	$10,962.82	$11,272.44	$309.62	2.8%	8

	UOM	Rate Yr 1 SC3P	Rate Yr 2 SC3P
Customer Charge	Monthly	$ 101.17	$ 119.00
Demand Charge kW	kW	$ 6.90	$ 8.30
Delivery Charge All Hours kWh	kWh	$ 0.00202	$ 0.00162
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ 0.16000	$ -
Tax Credit per kW	kW	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00541	$ 0.00541
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90
Supply Charge All Hours kWh	kWh	$ 0.03424	$ 0.03424
MFC per kWh	kWh	$ 0.00199	$ 0.00199

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2021 - April 30, 2022

Including Supply

PSC #120 - SC 3S - Non Residential - SubTransmission

Kw	Load Factor	kWh	Rate Yr 1	Rate Yr 2	increase / (decrease) Amount	Percent	# of Customers
5	20%	730	$386.62	$443.72	$57.10	14.8%	1
5	30%	1,095	$401.18	$458.28	$57.10	14.2%	-
5	40%	1,460	$415.74	$472.84	$57.10	13.7%	-
5	50%	1,825	$430.30	$487.39	$57.10	13.3%	-
5	60%	2,190	$444.85	$501.95	$57.10	12.8%	-
5	70%	2,555	$459.41	$516.51	$57.10	12.4%	-
5	80%	2,920	$473.97	$531.07	$57.10	12.0%	-
5	90%	3,285	$488.53	$545.62	$57.10	11.7%	-
25	20%	3,650	$597.28	$648.80	$51.52	8.6%	2
25	30%	5,475	$670.07	$721.59	$51.52	7.7%	-
25	40%	7,300	$742.85	$794.38	$51.52	6.9%	-
25	50%	9,125	$815.64	$867.17	$51.52	6.3%	-
25	60%	10,950	$888.43	$939.95	$51.52	5.8%	-
25	70%	12,775	$961.22	$1,012.74	$51.52	5.4%	-
25	80%	14,600	$1,034.01	$1,085.53	$51.52	5.0%	-
25	90%	16,425	$1,106.79	$1,158.32	$51.52	4.7%	-
100	20%	14,600	$1,387.23	$1,417.86	$30.63	2.2%	2
100	30%	21,900	$1,678.38	$1,709.01	$30.63	1.8%	-
100	40%	29,200	$1,969.53	$2,000.16	$30.63	1.6%	1
100	50%	36,500	$2,260.69	$2,291.31	$30.63	1.4%	1
100	60%	43,800	$2,551.84	$2,582.46	$30.63	1.2%	-
100	70%	51,100	$2,842.99	$2,873.62	$30.63	1.1%	-
100	80%	58,400	$3,134.14	$3,164.77	$30.63	1.0%	-
100	90%	65,700	$3,425.29	$3,455.92	$30.63	0.9%	-
300	20%	43,800	$3,493.77	$3,468.67	($25.10)	-0.7%	1
300	30%	65,700	$4,367.23	$4,342.13	($25.10)	-0.6%	-
300	40%	87,600	$5,240.69	$5,215.58	($25.10)	-0.5%	1
300	50%	109,500	$6,114.14	$6,089.04	($25.10)	-0.4%	-
300	60%	131,400	$6,987.60	$6,962.49	($25.10)	-0.4%	-
300	70%	153,300	$7,861.05	$7,835.95	($25.10)	-0.3%	2
300	80%	175,200	$8,734.51	$8,709.40	($25.10)	-0.3%	1
300	90%	197,100	$9,607.96	$9,582.86	($25.10)	-0.3%	-

	UOM	Rate Yr 1 SC3S	Rate Yr 2 SC3S
Customer Charge	Monthly	$ 333.06	$ 391.55
Demand Charge kW	kW	$ 4.47	$ 4.43
Delivery Charge All Hours kWh	kWh	$ -	$ -
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ 0.24000	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00236	$ 0.00236
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90
Supply Charge All Hours kWh	kWh	$ 0.03181	$ 0.03181
MFC per kWh	kWh	$ 0.00199	$ 0.00199

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2021 - April 30, 2022

Including Supply

PSC #120 - SC 6 - Non Residential					
			increase / (decrease)		
kWh	Rate Yr 1	Rate Yr 2	Amount	Percent	# of Customers
300	$49.34	$52.67	$3.34	6.8%	38,981
400	$59.62	$63.70	$4.08	6.8%	7,133
500	$69.90	$74.73	$4.83	6.9%	5,737
600	$80.18	$85.75	$5.57	7.0%	4,185
700	$90.46	$96.78	$6.32	7.0%	3,094
800	$100.74	$107.80	$7.07	7.0%	2,217
900	$111.01	$118.83	$7.81	7.0%	1,753
1,000	$121.29	$129.85	$8.56	7.1%	1,339
1,100	$131.57	$140.88	$9.30	7.1%	1,105
1,200	$141.85	$151.90	$10.05	7.1%	886
1,500	$172.69	$184.98	$12.28	7.1%	1,756
2,000	$224.09	$240.10	$16.01	7.1%	1,278
2,500	$275.49	$295.23	$19.74	7.2%	461
3,000	$326.88	$350.35	$23.47	7.2%	223
3,500	$378.28	$405.48	$27.20	7.2%	139
8,000	$840.86	$901.61	$60.75	7.2%	408

		Rate Yr 1	Rate Yr 2
	UOM	SC6	SC6
Customer Charge	Monthly	$ 17.60	$ 18.70
Delivery Charge All Hours kWh	kWh	$ 0.05166	$ 0.06165
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kWh	kWh	$ 0.00253	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00124	$ 0.00124
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90
Supply Charge All Hours kWh	kWh	$ 0.03985	$ 0.03985
MFC per kWh	kWh	$ 0.00265	$ 0.00265

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2021 - April 30, 2022

Including Supply

PSC #120 - SC 7-1 - Non Residential Large General Service - Secondary									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 1	Rate Yr 2	Amount	Percent	# of Customers
25	20%	3,650	1,898	1,752	$578.58	$592.78	$14.20	2.5%	558
25	30%	5,475	2,847	2,628	$655.74	$669.94	$14.20	2.2%	172
25	40%	7,300	3,796	3,504	$732.90	$747.10	$14.20	1.9%	139
25	50%	9,125	4,745	4,380	$810.06	$824.26	$14.20	1.8%	79
25	60%	10,950	5,694	5,256	$887.22	$901.42	$14.20	1.6%	50
25	70%	12,775	6,643	6,132	$964.38	$978.59	$14.20	1.5%	23
25	80%	14,600	7,592	7,008	$1,041.55	$1,055.75	$14.20	1.4%	13
25	90%	16,425	8,541	7,884	$1,118.71	$1,132.91	$14.20	1.3%	11
100	20%	14,600	7,592	7,008	$1,708.60	$1,741.41	$32.81	1.9%	585
100	30%	21,900	11,388	10,512	$2,017.25	$2,050.06	$32.81	1.6%	-
100	40%	29,200	15,184	14,016	$2,325.90	$2,358.70	$32.81	1.4%	109
100	50%	36,500	18,980	17,520	$2,634.55	$2,667.35	$32.81	1.2%	82
100	60%	43,800	22,776	21,024	$2,943.19	$2,976.00	$32.81	1.1%	44
100	70%	51,100	26,572	24,528	$3,251.84	$3,284.65	$32.81	1.0%	9
100	80%	58,400	30,368	28,032	$3,560.49	$3,593.29	$32.81	0.9%	4
100	90%	65,700	34,164	31,536	$3,869.13	$3,901.94	$32.81	0.8%	9
500	20%	73,000	37,960	35,040	$7,735.43	$7,867.45	$132.03	1.7%	275
500	30%	109,500	56,940	52,560	$9,278.66	$9,410.69	$132.03	1.4%	151
500	40%	146,000	75,920	70,080	$10,821.89	$10,953.92	$132.03	1.2%	100
500	50%	182,500	94,900	87,600	$12,365.13	$12,497.16	$132.03	1.1%	62
500	60%	219,000	113,880	105,120	$13,908.36	$14,040.39	$132.03	0.9%	27
500	70%	255,500	132,860	122,640	$15,451.60	$15,583.63	$132.03	0.9%	16
500	80%	292,000	151,840	140,160	$16,994.83	$17,126.86	$132.03	0.8%	7
500	90%	328,500	170,820	157,680	$18,538.07	$18,670.10	$132.03	0.7%	-
1,000	20%	146,000	75,920	70,080	$15,268.95	$15,525.01	$256.06	1.7%	32
1,000	30%	219,000	113,880	105,120	$18,355.42	$18,611.48	$256.06	1.4%	24
1,000	40%	292,000	151,840	140,160	$21,441.89	$21,697.95	$256.06	1.2%	21
1,000	50%	365,000	189,800	175,200	$24,528.36	$24,784.42	$256.06	1.0%	-
1,000	60%	438,000	227,760	210,240	$27,614.83	$27,870.89	$256.06	0.9%	16
1,000	70%	511,000	265,720	245,280	$30,701.30	$30,957.36	$256.06	0.8%	4
1,000	80%	584,000	303,680	280,320	$33,787.77	$34,043.83	$256.06	0.8%	5
1,000	90%	657,000	341,640	315,360	$36,874.24	$37,130.29	$256.06	0.7%	9

		Rate Yr 1	Rate Yr 2
	UOM	SC7-1	SC7-1
Customer Charge	Monthly	$ 201.00	$ 209.00
Demand Charge kW	kW	$ 8.57	$ 9.13
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ 0.32000	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00768	$ 0.00768
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90
Supply Charge On Peak kWh	kWh-On	$ 0.04008	$ 0.04008
Supply Charge Off Peak kWh	kWh-Off	$ 0.02783	$ 0.02783
MFC per kWh	kWh	$ 0.00199	$ 0.00199

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2021 - April 30, 2022

Including Supply

PSC #120 - SC 7-2 - Non Residential Large General Service - Primary									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 1	Rate Yr 2	Amount	Percent	# of Customers
500	20%	73,000	37,960	35,040	$7,578.80	$8,037.54	$458.74	6.1%	90
500	30%	109,500	56,940	52,560	$9,096.27	$9,555.01	$458.74	5.0%	35
500	40%	146,000	75,920	70,080	$10,613.74	$11,072.48	$458.74	4.3%	32
500	50%	182,500	94,900	87,600	$12,131.21	$12,589.95	$458.74	3.8%	27
500	60%	219,000	113,880	105,120	$13,648.68	$14,107.42	$458.74	3.4%	12
500	70%	255,500	132,860	122,640	$15,166.15	$15,624.89	$458.74	3.0%	8
500	80%	292,000	151,840	140,160	$16,683.62	$17,142.36	$458.74	2.7%	-
500	90%	328,500	170,820	157,680	$18,201.09	$18,659.83	$458.74	2.5%	-
1,000	20%	146,000	75,920	70,080	$14,454.69	$15,344.18	$889.49	6.2%	21
1,000	30%	219,000	113,880	105,120	$17,489.63	$18,379.12	$889.49	5.1%	22
1,000	40%	292,000	151,840	140,160	$20,524.57	$21,414.06	$889.49	4.3%	23
1,000	50%	365,000	189,800	175,200	$23,559.51	$24,449.00	$889.49	3.8%	-
1,000	60%	438,000	227,760	210,240	$26,594.45	$27,483.94	$889.49	3.3%	14
1,000	70%	511,000	265,720	245,280	$29,629.39	$30,518.88	$889.49	3.0%	7
1,000	80%	584,000	303,680	280,320	$32,664.33	$33,553.82	$889.49	2.7%	2
1,000	90%	657,000	341,640	315,360	$35,699.27	$36,588.76	$889.49	2.5%	1
1,500	20%	219,000	113,880	105,120	$21,330.59	$22,650.81	$1,320.23	6.2%	4
1,500	30%	328,500	170,820	157,680	$25,883.00	$27,203.22	$1,320.23	5.1%	2
1,500	40%	438,000	227,760	210,240	$30,435.41	$31,755.63	$1,320.23	4.3%	8
1,500	50%	547,500	284,700	262,800	$34,987.82	$36,308.04	$1,320.23	3.8%	8
1,500	60%	657,000	341,640	315,360	$39,540.23	$40,860.45	$1,320.23	3.3%	-
1,500	70%	766,500	398,580	367,920	$44,092.64	$45,412.86	$1,320.23	3.0%	7
1,500	80%	876,000	455,520	420,480	$48,645.05	$49,965.27	$1,320.23	2.7%	2
1,500	90%	985,500	512,460	473,040	$53,197.46	$54,517.68	$1,320.23	2.5%	-
2,500	20%	365,000	189,800	175,200	$35,082.38	$37,264.09	$2,181.71	6.2%	5
2,500	30%	547,500	284,700	262,800	$42,669.73	$44,851.44	$2,181.71	5.1%	2
2,500	40%	730,000	379,600	350,400	$50,257.08	$52,438.79	$2,181.71	4.3%	11
2,500	50%	912,500	474,500	438,000	$57,844.43	$60,026.14	$2,181.71	3.8%	12
2,500	60%	1,095,000	569,400	525,600	$65,431.78	$67,613.49	$2,181.71	3.3%	-
2,500	70%	1,277,500	664,300	613,200	$73,019.13	$75,200.84	$2,181.71	3.0%	1
2,500	80%	1,460,000	759,200	700,800	$80,606.48	$82,788.19	$2,181.71	2.7%	3
2,500	90%	1,642,500	854,100	788,400	$88,193.83	$90,375.54	$2,181.71	2.5%	5

	UOM	Rate Yr 1 SC7-2	Rate Yr 2 SC7-2
Customer Charge	Monthly	$ 702.00	$ 730.00
Demand Charge kW	kW	$ 7.43	$ 8.53
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ 0.24000	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00858	$ 0.00858
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90
Supply Charge On Peak kWh	kWh-On	$ 0.03921	$ 0.03921
Supply Charge Off Peak kWh	kWh-Off	$ 0.02730	$ 0.02730
MFC per kWh	kWh	$ 0.00199	$ 0.00199

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2021 - April 30, 2022

Including Supply

PSC #120 - SC 7-3 - Non Residential Large General Service - SubTransmission									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 1	Rate Yr 2	Amount	Percent	# of Customers
500	20%	73,000	37,960	35,040	$5,491.29	$5,636.43	$145.14	2.6%	18
500	30%	109,500	56,940	52,560	$6,992.95	$7,138.09	$145.14	2.1%	9
500	40%	146,000	75,920	70,080	$8,494.61	$8,639.75	$145.14	1.7%	7
500	50%	182,500	94,900	87,600	$9,996.27	$10,141.42	$145.14	1.5%	6
500	60%	219,000	113,880	105,120	$11,497.94	$11,643.08	$145.14	1.3%	2
500	70%	255,500	132,860	122,640	$12,999.60	$13,144.74	$145.14	1.1%	2
500	80%	292,000	151,840	140,160	$14,501.26	$14,646.40	$145.14	1.0%	-
500	90%	328,500	170,820	157,680	$16,002.92	$16,148.07	$145.14	0.9%	-
2,000	20%	292,000	151,840	140,160	$17,576.45	$17,983.01	$406.57	2.3%	32
2,000	30%	438,000	227,760	210,240	$23,583.10	$23,989.66	$406.57	1.7%	-
2,000	40%	584,000	303,680	280,320	$29,589.75	$29,996.31	$406.57	1.4%	11
2,000	50%	730,000	379,600	350,400	$35,596.40	$36,002.96	$406.57	1.1%	6
2,000	60%	876,000	455,520	420,480	$41,603.05	$42,009.62	$406.57	1.0%	4
2,000	70%	1,022,000	531,440	490,560	$47,609.70	$48,016.27	$406.57	0.9%	2
2,000	80%	1,168,000	607,360	560,640	$53,616.35	$54,022.92	$406.57	0.8%	-
2,000	90%	1,314,000	683,280	630,720	$59,623.00	$60,029.57	$406.57	0.7%	-
4,000	20%	584,000	303,680	280,320	$33,690.00	$34,445.13	$755.13	2.2%	2
4,000	30%	876,000	455,520	420,480	$45,703.30	$46,458.43	$755.13	1.7%	10
4,000	40%	1,168,000	607,360	560,640	$57,716.60	$58,471.73	$755.13	1.3%	4
4,000	50%	1,460,000	759,200	700,800	$69,729.90	$70,485.03	$755.13	1.1%	-
4,000	60%	1,752,000	911,040	840,960	$81,743.20	$82,498.33	$755.13	0.9%	6
4,000	70%	2,044,000	1,062,880	981,120	$93,756.50	$94,511.63	$755.13	0.8%	4
4,000	80%	2,336,000	1,214,720	1,121,280	$105,769.80	$106,524.93	$755.13	0.7%	-
4,000	90%	2,628,000	1,366,560	1,261,440	$117,783.10	$118,538.23	$755.13	0.6%	-
5,000	20%	730,000	379,600	350,400	$41,746.77	$42,676.19	$929.42	2.2%	-
5,000	30%	1,095,000	569,400	525,600	$56,763.40	$57,692.81	$929.42	1.6%	-
5,000	40%	1,460,000	759,200	700,800	$71,780.02	$72,709.44	$929.42	1.3%	-
5,000	50%	1,825,000	949,000	876,000	$86,796.65	$87,726.06	$929.42	1.1%	1
5,000	60%	2,190,000	1,138,800	1,051,200	$101,813.27	$102,742.69	$929.42	0.9%	1
5,000	70%	2,555,000	1,328,600	1,226,400	$116,829.90	$117,759.31	$929.42	0.8%	3
5,000	80%	2,920,000	1,518,400	1,401,600	$131,846.52	$132,775.94	$929.42	0.7%	-
5,000	90%	3,285,000	1,708,200	1,576,800	$146,863.15	$147,792.57	$929.42	0.6%	5

		Rate Yr 1	Rate Yr 2
	UOM	SC7-3	SC7-3
Customer Charge	Monthly	$ 1,462.00	$ 1,520.00
Demand Charge kW	kW	$ 1.95	$ 2.22
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ 0.09000	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00536	$ 0.00536
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90
Supply Charge On Peak kWh	kWh-On	$ 0.03873	$ 0.03873
Supply Charge Off Peak kWh	kWh-Off	$ 0.02692	$ 0.02692
MFC per kWh	kWh	$ 0.00199	$ 0.00199

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2021 - April 30, 2022

Including Supply

PSC #120 - SC 7-4 - Non Residential Large General Service - Transmission

Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 1	Rate Yr 2	increase / (decrease) Amount	Percent	# of Customers
1,000	20%	146,000	75,920	70,080	$9,784.66	$10,354.98	$570.33	5.8%	1
1,000	30%	219,000	113,880	105,120	$12,787.98	$13,358.31	$570.33	4.5%	-
1,000	40%	292,000	151,840	140,160	$15,791.31	$16,361.64	$570.33	3.6%	2
1,000	50%	365,000	189,800	175,200	$18,794.64	$19,364.97	$570.33	3.0%	-
1,000	60%	438,000	227,760	210,240	$21,797.97	$22,368.30	$570.33	2.6%	-
1,000	70%	511,000	265,720	245,280	$24,801.30	$25,371.62	$570.33	2.3%	-
1,000	80%	584,000	303,680	280,320	$27,804.63	$28,374.95	$570.33	2.1%	-
1,000	90%	657,000	341,640	315,360	$30,807.95	$31,378.28	$570.33	1.9%	-
7,500	20%	1,095,000	569,400	525,600	$55,179.08	$58,156.54	$2,977.46	5.4%	5
7,500	30%	1,642,500	854,100	788,400	$77,704.04	$80,681.50	$2,977.46	3.8%	-
7,500	40%	2,190,000	1,138,800	1,051,200	$100,229.00	$103,206.46	$2,977.46	3.0%	1
7,500	50%	2,737,500	1,423,500	1,314,000	$122,753.96	$125,731.42	$2,977.46	2.4%	1
7,500	60%	3,285,000	1,708,200	1,576,800	$145,278.92	$148,256.38	$2,977.46	2.0%	-
7,500	70%	3,832,500	1,992,900	1,839,600	$167,803.88	$170,781.34	$2,977.46	1.8%	1
7,500	80%	4,380,000	2,277,600	2,102,400	$190,328.84	$193,306.30	$2,977.46	1.6%	-
7,500	90%	4,927,500	2,562,300	2,365,200	$212,853.80	$215,831.26	$2,977.46	1.4%	-
15,000	20%	2,190,000	1,138,800	1,051,200	$107,557.26	$113,312.17	$5,754.92	5.4%	1
15,000	30%	3,285,000	1,708,200	1,576,800	$152,607.18	$158,362.09	$5,754.92	3.8%	-
15,000	40%	4,380,000	2,277,600	2,102,400	$197,657.10	$203,412.02	$5,754.92	2.9%	1
15,000	50%	5,475,000	2,847,000	2,628,000	$242,707.02	$248,461.94	$5,754.92	2.4%	-
15,000	60%	6,570,000	3,416,400	3,153,600	$287,756.94	$293,511.86	$5,754.92	2.0%	-
15,000	70%	7,665,000	3,985,800	3,679,200	$332,806.86	$338,561.78	$5,754.92	1.7%	2
15,000	80%	8,760,000	4,555,200	4,204,800	$377,856.78	$383,611.70	$5,754.92	1.5%	1
15,000	90%	9,855,000	5,124,600	4,730,400	$422,906.70	$428,661.62	$5,754.92	1.4%	-
50,000	20%	7,300,000	3,796,000	3,504,000	$351,988.76	$370,705.15	$18,716.38	5.3%	-
50,000	30%	10,950,000	5,694,000	5,256,000	$502,155.17	$520,871.55	$18,716.38	3.7%	1
50,000	40%	14,600,000	7,592,000	7,008,000	$652,321.57	$671,037.95	$18,716.38	2.9%	-
50,000	50%	18,250,000	9,490,000	8,760,000	$802,487.97	$821,204.35	$18,716.38	2.3%	-
50,000	60%	21,900,000	11,388,000	10,512,000	$952,654.37	$971,370.76	$18,716.38	2.0%	-
50,000	70%	25,550,000	13,286,000	12,264,000	$1,102,820.77	$1,121,537.16	$18,716.38	1.7%	-
50,000	80%	29,200,000	15,184,000	14,016,000	$1,252,987.18	$1,271,703.56	$18,716.38	1.5%	1
50,000	90%	32,850,000	17,082,000	15,768,000	$1,403,153.58	$1,421,869.96	$18,716.38	1.3%	-

	UOM	Rate Yr 1 SC7-4	Rate Yr 2 SC7-4
Customer Charge	Monthly	$ 2,800.00	$ 3,000.00
Demand Charge kW	kW	$ 0.94	$ 1.34
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ 0.03000	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00515	$ 0.00515
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90
Supply Charge On Peak kWh	kWh-On	$ 0.03926	$ 0.03926
Supply Charge Off Peak kWh	kWh-Off	$ 0.02635	$ 0.02635
MFC per kWh	kWh	$ 0.00199	$ 0.00199

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2021 - April 30, 2022

Including Supply

PSC #120 - SC 9 - Non Residential - Day/Night							
					increase / (decrease)		
kWh	Peak	Off Peak	Rate Yr 1	Rate Yr 2	Amount	Percent	# of Customers
300	180	120	$48.76	$51.74	$2.98	6.1%	686
400	240	160	$57.91	$61.45	$3.54	6.1%	214
500	300	200	$67.06	$71.16	$4.10	6.1%	185
600	360	240	$76.21	$80.87	$4.67	6.1%	192
700	420	280	$85.36	$90.59	$5.23	6.1%	171
800	480	320	$94.51	$100.30	$5.79	6.1%	141
900	540	360	$103.65	$110.01	$6.36	6.1%	126
1,000	600	400	$112.80	$119.72	$6.92	6.1%	83
1,100	660	440	$121.95	$129.44	$7.48	6.1%	91
1,200	720	480	$131.10	$139.15	$8.04	6.1%	64
1,500	900	600	$158.55	$168.28	$9.73	6.1%	162
2,000	1,200	800	$204.30	$216.85	$12.55	6.1%	159
2,500	1,500	1,000	$250.05	$265.41	$15.36	6.1%	83
3,000	1,800	1,200	$295.79	$313.97	$18.18	6.1%	47
3,500	2,100	1,400	$341.54	$362.53	$20.99	6.1%	24
5,000	3,000	2,000	$478.78	$508.22	$29.43	6.1%	26

		Rate Yr 1	Rate Yr 2
	UOM	SC9	SC9
Customer Charge	Monthly	$ 20.41	$ 21.70
Delivery Charge On Peak kWh	kWh-On	$ 0.04332	$ 0.05078
Delivery Charge Off Peak kWh	kWh-Off	$ 0.04332	$ 0.05078
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kWh	kWh	$ 0.00184	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00124	$ 0.00124
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90
Supply Charge On Peak kWh	kWh-On	$ 0.04154	$ 0.04154
Supply Charge Off Peak kWh	kWh-Off	$ 0.03167	$ 0.03167
MFC per kWh	kWh	$ 0.00265	$ 0.00265

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation

Date Sources - NYSEG Electric Bill Impact Statements

Rate	Source of Rate in "Current" Rates	Source of Rate in Rate Years
Customer Charge	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
kW Charge	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
kWh Delivery Charge All Hours	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
kWh Delivery Charge On Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
kWh Delivery Charge Mid Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
kWh Delivery Charge Off Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
Reactive RkVah	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
Billing Charge per Bill	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
SBC (EEtr) per kWh	Current Tariff Rates in Effect 01/01/2020 - (SBC Statement #19)	Included in Delivery Rates
SBC (CEF) per kWh	Current Tariff Rates in Effect 01/01/2020 - (SBC Statement #19)	Current Tariff Rates in Effect 01/01/2020 - (SBC Statement #19)
RAM per kWh	Current Tariff Rates in Effect 07/19/2019 - (RAM Statement #1)	No RAM forecasted for RY2. COVID Bill Credits begin 7/1/2021.
RAM per kW	Current Tariff Rates in Effect 07/19/2019 - (RAM Statement #1)	No RAM forecasted for RY2. COVID Bill Credits begin 7/1/2021.
Tax Credit per kWh	Case No. 17-M-0815 dated August 9, 2018. Statement Number 1 Effective 10/01/2018	Included in Delivery Rates
Tax Credit per kW	Case No. 17-M-0815 dated August 9, 2018. Statement Number 1 Effective 10/01/2018	Included in Delivery Rates

Rate	Source of Rate in "Current" Rates and Rate Years
Transition Charge per kWh	NBC, Demand Response, and Value Stack: NBC is the Non-Weighted 2019 Average, Dmd Rsp is 05/01/2020 rate, Value Stack at $-0-. RAM is separate.
MFC per kWh	Current Tariff Rates in Effect 05/01/2020
kWh Supply Charge All Hours	2019 Annualized Supply Rates
kWh Supply Charge On Peak	2019 Annualized Supply Rates
kWh Supply Charge Mid Peak	2019 Annualized Supply Rates
kWh Supply Charge Off Peak	2019 Annualized Supply Rates
Customer Count	2018 monthly data - separate Low Income counts

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2021 - April 30, 2022

Delivery Bill Only

PSC #120 - SC 1 - Residential								
			increase / (decrease)					
kWh	Rate Yr 1	Rate Yr 2	Amount	Percent	# of Customers	# of Low Income Customers	Percent of Customers	Percent of Low Income Customers
100	$21.29	$22.76	$1.47	6.9%	34,023	683	5%	2%
200	$26.56	$28.56	$2.00	7.5%	48,276	2,803	8%	7%
300	$31.84	$34.37	$2.53	8.0%	61,295	4,359	10%	12%
400	$37.12	$40.18	$3.06	8.3%	67,881	4,939	11%	13%
500	$42.39	$45.99	$3.59	8.5%	67,787	4,476	11%	12%
600	$47.67	$51.79	$4.13	8.7%	63,739	3,926	10%	10%
700	$52.95	$57.60	$4.66	8.8%	55,914	3,162	9%	8%
800	$58.22	$63.41	$5.19	8.9%	47,727	2,751	8%	7%
900	$63.50	$69.22	$5.72	9.0%	39,223	2,184	6%	6%
1,000	$68.78	$75.03	$6.25	9.1%	31,407	1,698	5%	5%
1,100	$74.05	$80.83	$6.78	9.2%	25,132	1,395	4%	4%
1,200	$79.33	$86.64	$7.31	9.2%	19,685	1,124	3%	3%
1,500	$95.16	$104.06	$8.90	9.4%	36,425	2,110	6%	6%
2,000	$121.54	$133.10	$11.56	9.5%	23,598	1,396	4%	4%
3,000	$174.31	$191.18	$16.87	9.7%	12,884	710	2%	2%
					634,997	37,717		

Amount of EE Embedded in Delivery Rates*	
Amount	Percent
$ 0.22	0.98%
$ 0.45	1.56%
$ 0.67	1.95%
$ 0.89	2.22%
$ 1.12	2.43%
$ 1.34	2.58%
$ 1.56	2.71%
$ 1.78	2.81%
$ 2.01	2.90%
$ 2.23	2.97%
$ 2.45	3.04%
$ 2.68	3.09%
$ 3.35	3.22%
$ 4.46	3.35%
$ 6.69	3.50%

		Rate Yr 1	Rate Yr 2
	UOM	SC1	SC1
Customer Charge	Monthly	$ 15.11	$ 16.05
Delivery Charge All Hours kWh	kWh	$ 0.04523	$ 0.05244
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kWh	kWh	$ 0.00189	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00078	$ 0.00078
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90

Includes $ 0.00223 per kWh of EE Costs*

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

4. Low income customers represent customers who participated in the Company's low income program and received a credit on their bill each month during calendar year 2018.

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2021 - April 30, 2022

Delivery Bill Only

PSC #120 - SC 8 - Residential - Day/Night							
					increase / (decrease)		
kWh	Peak	Off Peak	Rate Yr 1	Rate Yr 2	Amount	Percent	# of Customers
300	210	90	$32.70	$35.40	$2.70	8.3%	11,243
400	280	120	$37.50	$40.73	$3.23	8.6%	7,307
500	350	150	$42.30	$46.06	$3.77	8.9%	8,958
600	420	180	$47.10	$51.40	$4.30	9.1%	9,556
700	490	210	$51.89	$56.73	$4.83	9.3%	9,821
800	560	240	$56.69	$62.06	$5.37	9.5%	9,276
900	630	270	$61.49	$67.39	$5.90	9.6%	8,790
1,000	700	300	$66.29	$72.73	$6.43	9.7%	7,969
1,500	1,050	450	$90.29	$99.39	$9.10	10.1%	27,922
2,000	1,400	600	$114.29	$126.05	$11.77	10.3%	14,600
2,500	1,750	750	$138.28	$152.72	$14.43	10.4%	6,944
3,000	2,100	900	$162.28	$179.38	$17.10	10.5%	2,980
4,000	2,800	1,200	$210.27	$232.71	$22.44	10.7%	1,783
5,000	3,500	1,500	$258.27	$286.04	$27.77	10.8%	419
6,000	4,200	1,800	$306.26	$339.36	$33.10	10.8%	179
7,000	4,900	2,100	$354.25	$392.69	$38.44	10.9%	77

		Rate Yr 1	Rate Yr 2
	UOM	SC8	SC8
Customer Charge	Monthly	$ 17.40	$ 18.50
Delivery Charge On Peak kWh	kWh-On	$ 0.04072	$ 0.04769
Delivery Charge Off Peak kWh	kWh-Off	$ 0.04072	$ 0.04769
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kWh	kWh	$ 0.00164	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00078	$ 0.00078
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2021 - April 30, 2022

Delivery Bill Only

PSC #120 - SC 12 - Residential - TOU

kWh	Peak	Mid Peak	Off Peak	Rate Yr 1	Rate Yr 2	increase / (decrease) Amount	Percent	# of Customers
1,000	140	570	290	$71.71	$75.45	$3.74	5.2%	169
2,000	280	1,140	580	$118.41	$124.41	$6.00	5.1%	396
3,000	420	1,710	870	$165.10	$173.36	$8.25	5.0%	435
4,000	560	2,280	1,160	$211.80	$222.31	$10.51	5.0%	398
5,000	700	2,850	1,450	$258.50	$271.26	$12.76	4.9%	382
6,000	840	3,420	1,740	$305.20	$320.22	$15.02	4.9%	394
7,000	980	3,990	2,030	$351.90	$369.17	$17.27	4.9%	327
8,000	1,120	4,560	2,320	$398.59	$418.12	$19.53	4.9%	255
9,000	1,260	5,130	2,610	$445.29	$467.08	$21.78	4.9%	194
10,000	1,400	5,700	2,900	$491.99	$516.03	$24.04	4.9%	119
15,000	2,100	8,550	4,350	$725.48	$760.79	$35.31	4.9%	375
20,000	2,800	11,400	5,800	$958.97	$1,005.56	$46.59	4.9%	120
30,000	4,200	17,100	8,700	$1,425.95	$1,495.09	$69.13	4.8%	90
40,000	5,600	22,800	11,600	$1,892.93	$1,984.62	$91.68	4.8%	32
50,000	7,000	28,500	14,500	$2,359.91	$2,474.14	$114.23	4.8%	16

	UOM	Rate Yr 1 SC12	Rate Yr 2 SC12
Customer Charge	Monthly	$ 24.11	$ 25.60
Delivery Charge On Peak kWh	kWh-On	$ 0.03961	$ 0.04331
Delivery Charge Mid Peak kWh	kWh-Mid	$ 0.03961	$ 0.04331
Delivery Charge Off Peak kWh	kWh-Off	$ 0.03961	$ 0.04331
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kWh	kWh	$ 0.00144	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00078	$ 0.00078
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2021 - April 30, 2022

Delivery Bill Only

PSC #120 - SC 2 - Non Residential - Secondary

Kw	Load Factor	kWh	Rate Yr 1	Rate Yr 2	increase / (decrease) Amount	Percent	# of Customers
5	20%	730	$83.36	$91.42	$8.06	9.7%	4,814
5	30%	1,095	$86.31	$94.23	$7.91	9.2%	1,783
5	40%	1,460	$89.27	$97.03	$7.77	8.7%	1,150
5	50%	1,825	$92.22	$99.84	$7.62	8.3%	737
5	60%	2,190	$95.18	$102.65	$7.47	7.9%	477
5	70%	2,555	$98.13	$105.46	$7.33	7.5%	276
5	80%	2,920	$101.08	$108.26	$7.18	7.1%	221
5	90%	3,285	$104.04	$111.07	$7.03	6.8%	493
25	20%	3,650	$315.95	$338.90	$22.94	7.3%	15,467
25	30%	5,475	$330.72	$352.93	$22.21	6.7%	5,392
25	40%	7,300	$345.50	$366.97	$21.48	6.2%	3,010
25	50%	9,125	$360.27	$381.01	$20.74	5.8%	1,577
25	60%	10,950	$375.04	$395.05	$20.01	5.3%	852
25	70%	12,775	$389.81	$409.09	$19.28	4.9%	448
25	80%	14,600	$404.58	$423.12	$18.54	4.6%	288
25	90%	16,425	$419.35	$437.16	$17.81	4.2%	371
100	20%	14,600	$1,188.19	$1,266.93	$78.75	6.6%	3,447
100	30%	21,900	$1,247.27	$1,323.09	$75.82	6.1%	1,541
100	40%	29,200	$1,306.35	$1,379.24	$72.88	5.6%	776
100	50%	36,500	$1,365.44	$1,435.39	$69.95	5.1%	343
100	60%	43,800	$1,424.52	$1,491.54	$67.02	4.7%	190
100	70%	51,100	$1,483.61	$1,547.70	$64.09	4.3%	80
100	80%	58,400	$1,542.69	$1,603.85	$61.16	4.0%	27
100	90%	65,700	$1,601.78	$1,660.00	$58.23	3.6%	45
300	20%	43,800	$3,514.14	$3,741.70	$227.56	6.5%	435
300	30%	65,700	$3,691.39	$3,910.16	$218.77	5.9%	412
300	40%	87,600	$3,868.64	$4,078.62	$209.97	5.4%	201
300	50%	109,500	$4,045.90	$4,247.08	$201.18	5.0%	101
300	60%	131,400	$4,223.15	$4,415.54	$192.38	4.6%	51
300	70%	153,300	$4,400.41	$4,583.99	$183.59	4.2%	29
300	80%	175,200	$4,577.66	$4,752.45	$174.79	3.8%	18
300	90%	197,100	$4,754.92	$4,920.91	$166.00	3.5%	28

	UOM	Rate Yr 1 SC2	Rate Yr 2 SC2
Customer Charge	Monthly	$ 24.31	$ 28.65
Demand Charge kW	kW	$ 10.11	$ 11.25
Delivery Charge All Hours kWh	kWh	$ 0.00201	$ 0.00161
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ 0.33000	$ -
Tax Credit per kW	kW	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00557	$ 0.00557
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2021 - April 30, 2022

Delivery Bill Only

PSC #120 - SC 3P - Non Residential - Primary							
					increase / (decrease)		
Kw	Load Factor	kWh	Rate Yr 1	Rate Yr 2	Amount	Percent	# of Customers
5	20%	730	$143.33	$167.06	$23.73	16.6%	8
5	30%	1,095	$146.29	$169.87	$23.58	16.1%	4
5	40%	1,460	$149.25	$172.68	$23.43	15.7%	1
5	50%	1,825	$152.21	$175.49	$23.28	15.3%	2
5	60%	2,190	$155.17	$178.31	$23.14	14.9%	-
5	70%	2,555	$158.13	$181.12	$22.99	14.5%	-
5	80%	2,920	$161.09	$183.93	$22.84	14.2%	-
5	90%	3,285	$164.05	$186.74	$22.69	13.8%	-
25	20%	3,650	$308.37	$355.69	$47.32	15.3%	18
25	30%	5,475	$323.17	$369.75	$46.58	14.4%	9
25	40%	7,300	$337.97	$383.81	$45.84	13.6%	5
25	50%	9,125	$352.77	$397.87	$45.10	12.8%	8
25	60%	10,950	$367.57	$411.93	$44.36	12.1%	1
25	70%	12,775	$382.37	$425.99	$43.62	11.4%	1
25	80%	14,600	$397.17	$440.06	$42.88	10.8%	3
25	90%	16,425	$411.97	$454.12	$42.15	10.2%	-
100	20%	14,600	$927.27	$1,063.05	$135.78	14.6%	67
100	30%	21,900	$986.47	$1,119.29	$132.82	13.5%	-
100	40%	29,200	$1,045.67	$1,175.54	$129.87	12.4%	15
100	50%	36,500	$1,104.87	$1,231.79	$126.91	11.5%	11
100	60%	43,800	$1,164.08	$1,288.03	$123.96	10.6%	6
100	70%	51,100	$1,223.28	$1,344.28	$121.00	9.9%	3
100	80%	58,400	$1,282.48	$1,400.53	$118.05	9.2%	2
100	90%	65,700	$1,341.68	$1,456.77	$115.09	8.6%	-
300	20%	43,800	$2,577.67	$2,949.34	$371.68	14.4%	69
300	30%	65,700	$2,755.27	$3,118.08	$362.81	13.2%	-
300	40%	87,600	$2,932.88	$3,286.82	$353.95	12.1%	26
300	50%	109,500	$3,110.48	$3,455.56	$345.08	11.1%	22
300	60%	131,400	$3,288.09	$3,624.30	$336.22	10.2%	8
300	70%	153,300	$3,465.69	$3,793.04	$327.35	9.4%	4
300	80%	175,200	$3,643.30	$3,961.78	$318.49	8.7%	7
300	90%	197,100	$3,820.90	$4,130.52	$309.62	8.1%	8

		Rate Yr 1	Rate Yr 2
	UOM	SC3P	SC3P
Customer Charge	Monthly	$ 101.17	$ 119.00
Demand Charge kW	kW	$ 6.90	$ 8.30
Delivery Charge All Hours kWh	kWh	$ 0.00202	$ 0.00162
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ 0.16000	$ -
Tax Credit per kW	kW	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00541	$ 0.00541
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2021 - April 30, 2022

Delivery Bill Only

PSC #120 - SC 3S - Non Residential - SubTransmission							
					increase / (decrease)		
Kw	Load Factor	kWh	Rate Yr 1	Rate Yr 2	Amount	Percent	# of Customers
5	20%	730	$361.95	$419.05	$57.10	15.8%	1
5	30%	1,095	$364.17	$421.27	$57.10	15.7%	-
5	40%	1,460	$366.39	$423.49	$57.10	15.6%	-
5	50%	1,825	$368.61	$425.71	$57.10	15.5%	-
5	60%	2,190	$370.84	$427.93	$57.10	15.4%	-
5	70%	2,555	$373.06	$430.15	$57.10	15.3%	-
5	80%	2,920	$375.28	$432.38	$57.10	15.2%	-
5	90%	3,285	$377.50	$434.60	$57.10	15.1%	-
25	20%	3,650	$473.91	$525.44	$51.52	10.9%	2
25	30%	5,475	$485.02	$536.55	$51.52	10.6%	-
25	40%	7,300	$496.13	$547.65	$51.52	10.4%	-
25	50%	9,125	$507.23	$558.76	$51.52	10.2%	-
25	60%	10,950	$518.34	$569.86	$51.52	9.9%	-
25	70%	12,775	$529.45	$580.97	$51.52	9.7%	-
25	80%	14,600	$540.55	$592.08	$51.52	9.5%	-
25	90%	16,425	$551.66	$603.18	$51.52	9.3%	-
100	20%	14,600	$893.78	$924.41	$30.63	3.4%	2
100	30%	21,900	$938.21	$968.83	$30.63	3.3%	-
100	40%	29,200	$982.63	$1,013.26	$30.63	3.1%	1
100	50%	36,500	$1,027.06	$1,057.68	$30.63	3.0%	1
100	60%	43,800	$1,071.49	$1,102.11	$30.63	2.9%	-
100	70%	51,100	$1,115.91	$1,146.54	$30.63	2.7%	-
100	80%	58,400	$1,160.34	$1,190.96	$30.63	2.6%	-
100	90%	65,700	$1,204.76	$1,235.39	$30.63	2.5%	-
300	20%	43,800	$2,013.42	$1,988.32	($25.10)	-1.2%	1
300	30%	65,700	$2,146.70	$2,121.60	($25.10)	-1.2%	-
300	40%	87,600	$2,279.98	$2,254.88	($25.10)	-1.1%	1
300	50%	109,500	$2,413.26	$2,388.16	($25.10)	-1.0%	-
300	60%	131,400	$2,546.54	$2,521.43	($25.10)	-1.0%	-
300	70%	153,300	$2,679.82	$2,654.71	($25.10)	-0.9%	2
300	80%	175,200	$2,813.10	$2,787.99	($25.10)	-0.9%	1
300	90%	197,100	$2,946.38	$2,921.27	($25.10)	-0.9%	-

		Rate Yr 1	Rate Yr 2
	UOM	SC3S	SC3S
Customer Charge	Monthly	$ 333.06	$ 391.55
Demand Charge kW	kW	$ 4.47	$ 4.43
Delivery Charge All Hours kWh	kWh	$ -	$ -
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ 0.24000	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00236	$ 0.00236
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2021 - April 30, 2022

Delivery Bill Only

PSC #120 - SC 6 - Non Residential					
			increase / (decrease)		
kWh	Rate Yr 1	Rate Yr 2	Amount	Percent	# of Customers
300	$36.59	$39.92	$3.34	9.1%	38,981
400	$42.62	$46.70	$4.08	9.6%	7,133
500	$48.65	$53.47	$4.83	9.9%	5,737
600	$54.68	$60.25	$5.57	10.2%	4,185
700	$60.71	$67.02	$6.32	10.4%	3,094
800	$66.73	$73.80	$7.07	10.6%	2,217
900	$72.76	$80.57	$7.81	10.7%	1,753
1,000	$78.79	$87.35	$8.56	10.9%	1,339
1,100	$84.82	$94.12	$9.30	11.0%	1,105
1,200	$90.85	$100.90	$10.05	11.1%	886
1,500	$108.94	$121.22	$12.28	11.3%	1,756
2,000	$139.09	$155.10	$16.01	11.5%	1,278
2,500	$169.23	$188.97	$19.74	11.7%	461
3,000	$199.38	$222.85	$23.47	11.8%	223
3,500	$229.53	$256.73	$27.20	11.8%	139
8,000	$500.85	$561.60	$60.75	12.1%	408

		Rate Yr 1	Rate Yr 2
	UOM	SC6	SC6
Customer Charge	Monthly	$ 17.60	$ 18.70
Delivery Charge All Hours kWh	kWh	$ 0.05166	$ 0.06165
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kWh	kWh	$ 0.00253	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00124	$ 0.00124
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2021 - April 30, 2022

Delivery Bill Only

PSC #120 - SC 7-1 - Non Residential Large General Service - Secondary									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 1	Rate Yr 2	Amount	Percent	# of Customers
25	20%	3,650	1,898	1,752	$446.47	$460.67	$14.20	3.2%	558
25	30%	5,475	2,847	2,628	$457.57	$471.77	$14.20	3.1%	172
25	40%	7,300	3,796	3,504	$468.68	$482.88	$14.20	3.0%	139
25	50%	9,125	4,745	4,380	$479.79	$493.99	$14.20	3.0%	79
25	60%	10,950	5,694	5,256	$490.89	$505.09	$14.20	2.9%	50
25	70%	12,775	6,643	6,132	$502.00	$516.20	$14.20	2.8%	23
25	80%	14,600	7,592	7,008	$513.11	$527.31	$14.20	2.8%	13
25	90%	16,425	8,541	7,884	$524.21	$538.41	$14.20	2.7%	11
100	20%	14,600	7,592	7,008	$1,180.16	$1,212.97	$32.81	2.8%	585
100	30%	21,900	11,388	10,512	$1,224.59	$1,257.40	$32.81	2.7%	-
100	40%	29,200	15,184	14,016	$1,269.02	$1,301.82	$32.81	2.6%	109
100	50%	36,500	18,980	17,520	$1,313.44	$1,346.25	$32.81	2.5%	82
100	60%	43,800	22,776	21,024	$1,357.87	$1,390.67	$32.81	2.4%	44
100	70%	51,100	26,572	24,528	$1,402.30	$1,435.10	$32.81	2.3%	9
100	80%	58,400	30,368	28,032	$1,446.72	$1,479.53	$32.81	2.3%	4
100	90%	65,700	34,164	31,536	$1,491.15	$1,523.95	$32.81	2.2%	9
500	20%	73,000	37,960	35,040	$5,093.22	$5,225.25	$132.03	2.6%	275
500	30%	109,500	56,940	52,560	$5,315.35	$5,447.38	$132.03	2.5%	151
500	40%	146,000	75,920	70,080	$5,537.48	$5,669.51	$132.03	2.4%	100
500	50%	182,500	94,900	87,600	$5,759.61	$5,891.64	$132.03	2.3%	62
500	60%	219,000	113,880	105,120	$5,981.75	$6,113.78	$132.03	2.2%	27
500	70%	255,500	132,860	122,640	$6,203.88	$6,335.91	$132.03	2.1%	16
500	80%	292,000	151,840	140,160	$6,426.01	$6,558.04	$132.03	2.1%	7
500	90%	328,500	170,820	157,680	$6,648.14	$6,780.17	$132.03	2.0%	-
1,000	20%	146,000	75,920	70,080	$9,984.54	$10,240.60	$256.06	2.6%	32
1,000	30%	219,000	113,880	105,120	$10,428.80	$10,684.86	$256.06	2.5%	24
1,000	40%	292,000	151,840	140,160	$10,873.07	$11,129.13	$256.06	2.4%	21
1,000	50%	365,000	189,800	175,200	$11,317.33	$11,573.39	$256.06	2.3%	-
1,000	60%	438,000	227,760	210,240	$11,761.59	$12,017.65	$256.06	2.2%	16
1,000	70%	511,000	265,720	245,280	$12,205.86	$12,461.92	$256.06	2.1%	4
1,000	80%	584,000	303,680	280,320	$12,650.12	$12,906.18	$256.06	2.0%	5
1,000	90%	657,000	341,640	315,360	$13,094.38	$13,350.44	$256.06	2.0%	9

	UOM	Rate Yr 1 SC7-1	Rate Yr 2 SC7-1
Customer Charge	Monthly	$ 201.00	$ 209.00
Demand Charge kW	kW	$ 8.57	$ 9.13
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ 0.32000	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00768	$ 0.00768
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2021 - April 30, 2022

Delivery Bill Only

PSC #120 - SC 7-2 - Non Residential Large General Service - Primary									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 1	Rate Yr 2	Amount	Percent	# of Customers
500	20%	73,000	37,960	35,040	$4,988.12	$5,446.86	$458.74	9.2%	90
500	30%	109,500	56,940	52,560	$5,210.25	$5,668.99	$458.74	8.8%	35
500	40%	146,000	75,920	70,080	$5,432.38	$5,891.12	$458.74	8.4%	32
500	50%	182,500	94,900	87,600	$5,654.51	$6,113.26	$458.74	8.1%	27
500	60%	219,000	113,880	105,120	$5,876.65	$6,335.39	$458.74	7.8%	12
500	70%	255,500	132,860	122,640	$6,098.78	$6,557.52	$458.74	7.5%	8
500	80%	292,000	151,840	140,160	$6,320.91	$6,779.65	$458.74	7.3%	-
500	90%	328,500	170,820	157,680	$6,543.04	$7,001.78	$458.74	7.0%	-
1,000	20%	146,000	75,920	70,080	$9,273.34	$10,162.82	$889.49	9.6%	21
1,000	30%	219,000	113,880	105,120	$9,717.60	$10,607.09	$889.49	9.2%	22
1,000	40%	292,000	151,840	140,160	$10,161.86	$11,051.35	$889.49	8.8%	23
1,000	50%	365,000	189,800	175,200	$10,606.13	$11,495.61	$889.49	8.4%	-
1,000	60%	438,000	227,760	210,240	$11,050.39	$11,939.88	$889.49	8.0%	14
1,000	70%	511,000	265,720	245,280	$11,494.65	$12,384.14	$889.49	7.7%	7
1,000	80%	584,000	303,680	280,320	$11,938.92	$12,828.40	$889.49	7.5%	2
1,000	90%	657,000	341,640	315,360	$12,383.18	$13,272.67	$889.49	7.2%	1
1,500	20%	219,000	113,880	105,120	$13,558.56	$14,878.79	$1,320.23	9.7%	4
1,500	30%	328,500	170,820	157,680	$14,224.95	$15,545.18	$1,320.23	9.3%	2
1,500	40%	438,000	227,760	210,240	$14,891.35	$16,211.58	$1,320.23	8.9%	8
1,500	50%	547,500	284,700	262,800	$15,557.74	$16,877.97	$1,320.23	8.5%	8
1,500	60%	657,000	341,640	315,360	$16,224.14	$17,544.37	$1,320.23	8.1%	-
1,500	70%	766,500	398,580	367,920	$16,890.53	$18,210.76	$1,320.23	7.8%	7
1,500	80%	876,000	455,520	420,480	$17,556.93	$18,877.16	$1,320.23	7.5%	2
1,500	90%	985,500	512,460	473,040	$18,223.32	$19,543.55	$1,320.23	7.2%	-
2,500	20%	365,000	189,800	175,200	$22,129.00	$24,310.71	$2,181.71	9.9%	5
2,500	30%	547,500	284,700	262,800	$23,239.65	$25,421.37	$2,181.71	9.4%	2
2,500	40%	730,000	379,600	350,400	$24,350.31	$26,532.03	$2,181.71	9.0%	11
2,500	50%	912,500	474,500	438,000	$25,460.97	$27,642.68	$2,181.71	8.6%	12
2,500	60%	1,095,000	569,400	525,600	$26,571.63	$28,753.34	$2,181.71	8.2%	-
2,500	70%	1,277,500	664,300	613,200	$27,682.29	$29,864.00	$2,181.71	7.9%	1
2,500	80%	1,460,000	759,200	700,800	$28,792.95	$30,974.66	$2,181.71	7.6%	3
2,500	90%	1,642,500	854,100	788,400	$29,903.61	$32,085.32	$2,181.71	7.3%	5

		Rate Yr 1	Rate Yr 2
	UOM	SC7-2	SC7-2
Customer Charge	Monthly	$ 702.00	$ 730.00
Demand Charge kW	kW	$ 7.43	$ 8.53
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ 0.24000	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00858	$ 0.00858
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2021 - April 30, 2022

Delivery Bill Only

PSC #120 - SC 7-3 - Non Residential Large General Service - SubTransmission									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 1	Rate Yr 2	Amount	Percent	# of Customers
500	20%	73,000	37,960	35,040	$2,932.22	$3,077.37	$145.14	4.9%	18
500	30%	109,500	56,940	52,560	$3,154.36	$3,299.50	$145.14	4.6%	9
500	40%	146,000	75,920	70,080	$3,376.49	$3,521.63	$145.14	4.3%	7
500	50%	182,500	94,900	87,600	$3,598.62	$3,743.76	$145.14	4.0%	6
500	60%	219,000	113,880	105,120	$3,820.75	$3,965.89	$145.14	3.8%	2
500	70%	255,500	132,860	122,640	$4,042.88	$4,188.02	$145.14	3.6%	2
500	80%	292,000	151,840	140,160	$4,265.02	$4,410.16	$145.14	3.4%	-
500	90%	328,500	170,820	157,680	$4,487.15	$4,632.29	$145.14	3.2%	-
2,000	20%	292,000	151,840	140,160	$7,340.20	$7,746.77	$406.57	5.5%	32
2,000	30%	438,000	227,760	210,240	$8,228.73	$8,635.29	$406.57	4.9%	-
2,000	40%	584,000	303,680	280,320	$9,117.25	$9,523.82	$406.57	4.5%	11
2,000	50%	730,000	379,600	350,400	$10,005.78	$10,412.35	$406.57	4.1%	6
2,000	60%	876,000	455,520	420,480	$10,894.31	$11,300.87	$406.57	3.7%	4
2,000	70%	1,022,000	531,440	490,560	$11,782.83	$12,189.40	$406.57	3.5%	2
2,000	80%	1,168,000	607,360	560,640	$12,671.36	$13,077.93	$406.57	3.2%	-
2,000	90%	1,314,000	683,280	630,720	$13,559.89	$13,966.45	$406.57	3.0%	-
4,000	20%	584,000	303,680	280,320	$13,217.50	$13,972.63	$755.13	5.7%	2
4,000	30%	876,000	455,520	420,480	$14,994.56	$15,749.69	$755.13	5.0%	10
4,000	40%	1,168,000	607,360	560,640	$16,771.61	$17,526.74	$755.13	4.5%	4
4,000	50%	1,460,000	759,200	700,800	$18,548.66	$19,303.80	$755.13	4.1%	-
4,000	60%	1,752,000	911,040	840,960	$20,325.72	$21,080.85	$755.13	3.7%	6
4,000	70%	2,044,000	1,062,880	981,120	$22,102.77	$22,857.90	$755.13	3.4%	4
4,000	80%	2,336,000	1,214,720	1,121,280	$23,879.82	$24,634.96	$755.13	3.2%	-
4,000	90%	2,628,000	1,366,560	1,261,440	$25,656.88	$26,412.01	$755.13	2.9%	-
5,000	20%	730,000	379,600	350,400	$16,156.15	$17,085.57	$929.42	5.8%	-
5,000	30%	1,095,000	569,400	525,600	$18,377.47	$19,306.89	$929.42	5.1%	-
5,000	40%	1,460,000	759,200	700,800	$20,598.79	$21,528.20	$929.42	4.5%	-
5,000	50%	1,825,000	949,000	876,000	$22,820.10	$23,749.52	$929.42	4.1%	1
5,000	60%	2,190,000	1,138,800	1,051,200	$25,041.42	$25,970.84	$929.42	3.7%	1
5,000	70%	2,555,000	1,328,600	1,226,400	$27,262.74	$28,192.15	$929.42	3.4%	3
5,000	80%	2,920,000	1,518,400	1,401,600	$29,484.05	$30,413.47	$929.42	3.2%	-
5,000	90%	3,285,000	1,708,200	1,576,800	$31,705.37	$32,634.79	$929.42	2.9%	5

		Rate Yr 1	Rate Yr 2
	UOM	SC7-3	SC7-3
Customer Charge	Monthly	$ 1,462.00	$ 1,520.00
Demand Charge kW	kW	$ 1.95	$ 2.22
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ 0.09000	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00536	$ 0.00536
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2021 - April 30, 2022

Delivery Bill Only

PSC #120 - SC 7-4 - Non Residential Large General Service - Transmission									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 1	Rate Yr 2	Amount	Percent	# of Customers
1,000	20%	146,000	75,920	70,080	$4,666.53	$5,236.86	$570.33	12.2%	1
1,000	30%	219,000	113,880	105,120	$5,110.79	$5,681.12	$570.33	11.2%	-
1,000	40%	292,000	151,840	140,160	$5,555.05	$6,125.38	$570.33	10.3%	2
1,000	50%	365,000	189,800	175,200	$5,999.32	$6,569.65	$570.33	9.5%	-
1,000	60%	438,000	227,760	210,240	$6,443.58	$7,013.91	$570.33	8.9%	-
1,000	70%	511,000	265,720	245,280	$6,887.84	$7,458.17	$570.33	8.3%	-
1,000	80%	584,000	303,680	280,320	$7,332.11	$7,902.44	$570.33	7.8%	-
1,000	90%	657,000	341,640	315,360	$7,776.37	$8,346.70	$570.33	7.3%	-
7,500	20%	1,095,000	569,400	525,600	$16,793.11	$19,770.57	$2,977.46	17.7%	5
7,500	30%	1,642,500	854,100	788,400	$20,125.09	$23,102.54	$2,977.46	14.8%	-
7,500	40%	2,190,000	1,138,800	1,051,200	$23,457.06	$26,434.52	$2,977.46	12.7%	1
7,500	50%	2,737,500	1,423,500	1,314,000	$26,789.04	$29,766.49	$2,977.46	11.1%	1
7,500	60%	3,285,000	1,708,200	1,576,800	$30,121.01	$33,098.47	$2,977.46	9.9%	-
7,500	70%	3,832,500	1,992,900	1,839,600	$33,452.99	$36,430.44	$2,977.46	8.9%	1
7,500	80%	4,380,000	2,277,600	2,102,400	$36,784.96	$39,762.42	$2,977.46	8.1%	-
7,500	90%	4,927,500	2,562,300	2,365,200	$40,116.94	$43,094.40	$2,977.46	7.4%	-
15,000	20%	2,190,000	1,138,800	1,051,200	$30,785.32	$36,540.24	$5,754.92	18.7%	1
15,000	30%	3,285,000	1,708,200	1,576,800	$37,449.27	$43,204.19	$5,754.92	15.4%	-
15,000	40%	4,380,000	2,277,600	2,102,400	$44,113.22	$49,868.14	$5,754.92	13.0%	1
15,000	50%	5,475,000	2,847,000	2,628,000	$50,777.17	$56,532.09	$5,754.92	11.3%	-
15,000	60%	6,570,000	3,416,400	3,153,600	$57,441.12	$63,196.04	$5,754.92	10.0%	-
15,000	70%	7,665,000	3,985,800	3,679,200	$64,105.07	$69,859.99	$5,754.92	9.0%	2
15,000	80%	8,760,000	4,555,200	4,204,800	$70,769.03	$76,523.94	$5,754.92	8.1%	1
15,000	90%	9,855,000	5,124,600	4,730,400	$77,432.98	$83,187.89	$5,754.92	7.4%	-
50,000	20%	7,300,000	3,796,000	3,504,000	$96,082.30	$114,798.68	$18,716.38	19.5%	-
50,000	30%	10,950,000	5,694,000	5,256,000	$118,295.47	$137,011.85	$18,716.38	15.8%	1
50,000	40%	14,600,000	7,592,000	7,008,000	$140,508.64	$159,225.02	$18,716.38	13.3%	-
50,000	50%	18,250,000	9,490,000	8,760,000	$162,721.81	$181,438.19	$18,716.38	11.5%	-
50,000	60%	21,900,000	11,388,000	10,512,000	$184,934.98	$203,651.36	$18,716.38	10.1%	-
50,000	70%	25,550,000	13,286,000	12,264,000	$207,148.15	$225,864.53	$18,716.38	9.0%	-
50,000	80%	29,200,000	15,184,000	14,016,000	$229,361.32	$248,077.70	$18,716.38	8.2%	1
50,000	90%	32,850,000	17,082,000	15,768,000	$251,574.49	$270,290.87	$18,716.38	7.4%	-

		Rate Yr 1	Rate Yr 2
	UOM	SC7-4	SC7-4
Customer Charge	Monthly	$ 2,800.00	$ 3,000.00
Demand Charge kW	kW	$ 0.94	$ 1.34
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ 0.03000	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00515	$ 0.00515
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2021 - April 30, 2022

Delivery Bill Only

PSC #120 - SC 9 - Non Residential - Day/Night

kWh	Peak	Off Peak	Rate Yr 1	Rate Yr 2	increase / (decrease) Amount	Percent	# of Customers
300	180	120	$36.69	$39.66	$2.98	8.1%	686
400	240	160	$41.81	$45.35	$3.54	8.5%	214
500	300	200	$46.94	$51.04	$4.10	8.7%	185
600	360	240	$52.06	$56.73	$4.67	9.0%	192
700	420	280	$57.19	$62.42	$5.23	9.1%	171
800	480	320	$62.31	$68.11	$5.79	9.3%	141
900	540	360	$67.44	$73.79	$6.36	9.4%	126
1,000	600	400	$72.56	$79.48	$6.92	9.5%	83
1,100	660	440	$77.69	$85.17	$7.48	9.6%	91
1,200	720	480	$82.81	$90.86	$8.04	9.7%	64
1,500	900	600	$98.19	$107.92	$9.73	9.9%	162
2,000	1,200	800	$123.82	$136.37	$12.55	10.1%	159
2,500	1,500	1,000	$149.45	$164.81	$15.36	10.3%	83
3,000	1,800	1,200	$175.07	$193.25	$18.18	10.4%	47
3,500	2,100	1,400	$200.70	$221.69	$20.99	10.5%	24
5,000	3,000	2,000	$277.58	$307.02	$29.43	10.6%	26

	UOM	Rate Yr 1 SC9	Rate Yr 2 SC9
Customer Charge	Monthly	$ 20.41	$ 21.70
Delivery Charge On Peak kWh	kWh-On	$ 0.04332	$ 0.05078
Delivery Charge Off Peak kWh	kWh-Off	$ 0.04332	$ 0.05078
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kWh	kWh	$ 0.00184	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00124	$ 0.00124
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Electric Rates
Standby Bill Impacts by SC
May 1, 2021 - April 30, 2022

	Rate Yr 1	Rate Yr 2	Increase (000)	% Increase or Decrease
Customer Charge				
SC 2	$ 1.2	$ 1.4	$ 0.2	17.85%
SC 3P	$ 7.3	$ 8.6	$ 1.3	17.62%
SC 3S	$ 8.0	$ 9.4	$ 1.4	17.56%
SC 7-1	$ 9.6	$ 10.0	$ 0.4	3.98%
SC 7-2	$ 67.4	$ 70.1	$ 2.7	3.99%
SC 7-3	$ 35.1	$ 36.5	$ 1.4	3.97%
SC 7-4	$ 134.4	$ 144.0	$ 9.6	7.14%
	$ 263.0	$ 279.9	$ 17.0	6.45%
Contract Demand				
SC 2	$ 81.5	$ 89.1	$ 7.6	9.32%
SC 3P	$ 54.3	$ 63.5	$ 9.2	17.03%
SC 3S	$ 3.6	$ 3.6	$ (0.0)	-1.12%
SC 7-1	$ 119.9	$ 128.0	$ 8.1	6.74%
SC 7-2	$ 592.9	$ 683.6	$ 90.7	15.30%
SC 7-3	$ 5.3	$ 6.1	$ 0.8	14.35%
SC 7-4	$ 52.8	$ 75.4	$ 22.6	42.86%
	$ 910.3	$ 1,049.3	$ 139.0	15.27%
Daily As-Used Demand				
SC 2	$ 45.8	$ 50.0	$ 4.3	9.32%
SC 3P	$ 12.8	$ 15.0	$ 2.2	17.03%
SC 3S	$ 0.3	$ 0.3	$ (0.0)	-1.12%
SC 7-1	$ 60.5	$ 64.6	$ 4.1	6.74%
SC 7-2	$ 313.0	$ 360.9	$ 47.9	15.30%
SC 7-3	$ 0.2	$ 0.2	$ 0.0	14.35%
SC 7-4	$ 44.7	$ 63.9	$ 19.2	42.86%
	$ 477.3	$ 555.0	$ 77.6	16.26%
Total				
SC 2	$ 128.4	$ 140.5	$ 12.1	9.39%
SC 3P	$ 74.4	$ 87.1	$ 12.7	17.08%
SC 3S	$ 11.9	$ 13.3	$ 1.4	11.43%
SC 7-1	$ 190.0	$ 202.5	$ 12.5	6.60%
SC 7-2	$ 973.3	$ 1,114.6	$ 141.3	14.52%
SC 7-3	$ 40.6	$ 42.8	$ 2.2	5.38%
SC 7-4	$ 231.9	$ 283.4	$ 51.4	22.16%
	$ 1,650.6	$ 1,884.2	$ 233.6	14.15%

New York State Electric & Gas Corporation		
Date Sources - NYSEG Electric Bill Impact Statements		
Rate	**Source of Rate in "Current" Rates**	**Source of Rate in Rate Years**
Customer Charge	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
kW Charge	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
kWh Delivery Charge All Hours	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
kWh Delivery Charge On Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
kWh Delivery Charge Mid Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
kWh Delivery Charge Off Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
Reactive RkVah	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
Billing Charge per Bill	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
SBC (EEtr) per kWh	Current Tariff Rates in Effect 01/01/2020 - (SBC Statement #19)	Included in Delivery Rates
SBC (CEF) per kWh	Current Tariff Rates in Effect 01/01/2020 - (SBC Statement #19)	Current Tariff Rates in Effect 01/01/2020 - (SBC Statement #19)
RAM per kWh	Current Tariff Rates in Effect 07/19/2019 - (RAM Statement #1)	No RAM forecasted for RY2. COVID Bill Credits begin 7/1/2021.
RAM per kW	Current Tariff Rates in Effect 07/19/2019 - (RAM Statement #1)	No RAM forecasted for RY2. COVID Bill Credits begin 7/1/2021.
Tax Credit per kWh	Case No. 17-M-0815 dated August 9, 2018. Statement Number 1 Effective 10/01/2018	Included in Delivery Rates
Tax Credit per kW	Case No. 17-M-0815 dated August 9, 2018. Statement Number 1 Effective 10/01/2018	Included in Delivery Rates
Rate	**Source of Rate in "Current" Rates and Rate Years**	
Transition Charge per kWh	NBC, Demand Response, and Value Stack: NBC is the Non-Weighted 2019 Average, Dmd Rsp is 05/01/2020 rate, Value Stack at $-0-. RAM is separate.	
MFC per kWh	Current Tariff Rates in Effect 05/01/2020	
kWh Supply Charge All Hours	2019 Annualized Supply Rates	
kWh Supply Charge On Peak	2019 Annualized Supply Rates	
kWh Supply Charge Mid Peak	2019 Annualized Supply Rates	
kWh Supply Charge Off Peak	2019 Annualized Supply Rates	
Customer Count	2018 monthly data - separate Low Income counts	

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2022 - April 30, 2023

Including Supply

PSC #120 - SC 1 - Residential

kWh	Rate Yr 2	Rate Yr 3	increase / (decrease) Amount	Percent	# of Customers	# of Low Income Customers	Percent of Customers	Percent of Low Income Customers
100	$26.92	$28.63	$1.72	6.4%	34,023	683	5%	2%
200	$36.89	$39.37	$2.48	6.7%	48,276	2,803	8%	7%
300	$46.86	$50.10	$3.25	6.9%	61,295	4,359	10%	12%
400	$56.83	$60.84	$4.01	7.1%	67,881	4,939	11%	13%
500	$66.80	$71.57	$4.78	7.1%	67,787	4,476	11%	12%
600	$76.77	$82.31	$5.54	7.2%	63,739	3,926	10%	10%
700	$86.74	$93.05	$6.31	7.3%	55,914	3,162	9%	8%
800	$96.71	$103.78	$7.07	7.3%	47,727	2,751	8%	7%
900	$106.68	$114.52	$7.84	7.3%	39,223	2,184	6%	6%
1,000	$116.65	$125.25	$8.60	7.4%	31,407	1,698	5%	5%
1,100	$126.62	$135.99	$9.37	7.4%	25,132	1,395	4%	4%
1,200	$136.59	$146.72	$10.13	7.4%	19,685	1,124	3%	3%
1,500	$166.50	$178.93	$12.43	7.5%	36,425	2,110	6%	6%
2,000	$216.35	$232.60	$16.25	7.5%	23,598	1,396	4%	4%
3,000	$316.05	$339.95	$23.90	7.6%	12,884	710	2%	2%
					634,997	37,717		

Amount of EE Embedded in Delivery Rates*

Amount	Percent
$ 0.30	1.04%
$ 0.59	1.51%
$ 0.89	1.78%
$ 1.19	1.95%
$ 1.49	2.07%
$ 1.78	2.16%
$ 2.08	2.23%
$ 2.38	2.29%
$ 2.67	2.33%
$ 2.97	2.37%
$ 3.27	2.40%
$ 3.56	2.43%
$ 4.46	2.49%
$ 5.94	2.55%
$ 8.91	2.62%

	UOM	Rate Yr 2 SC1	Rate Yr 3 SC1
Customer Charge	Monthly	$ 16.05	$ 17.00
Delivery Charge All Hours kWh	kWh	$ 0.05244	$ 0.06009
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kWh	kWh	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00078	$ 0.00078
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90
Supply Charge All Hours kWh	kWh	$ 0.03897	$ 0.03897
MFC per kWh	kWh	$ 0.00265	$ 0.00265

Includes $ 0.00297 per kWh of EE Costs*

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

4. Low income customers represent customers who participated in the Company's low income program and received a credit on their bill each month during calendar year 2018.

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2022 - April 30, 2023

Including Supply

PSC #120 - SC 8 - Residential - Day/Night							
					increase / (decrease)		
kWh	Peak	Off Peak	Rate Yr 2	Rate Yr 3	Amount	Percent	# of Customers
300	210	90	$46.50	$49.85	$3.36	7.2%	11,243
400	280	120	$55.53	$59.64	$4.11	7.4%	7,307
500	350	150	$64.56	$69.42	$4.86	7.5%	8,958
600	420	180	$73.59	$79.21	$5.61	7.6%	9,556
700	490	210	$82.62	$88.99	$6.37	7.7%	9,821
800	560	240	$91.66	$98.77	$7.12	7.8%	9,276
900	630	270	$100.69	$108.56	$7.87	7.8%	8,790
1,000	700	300	$109.72	$118.34	$8.62	7.9%	7,969
1,500	1,050	450	$154.88	$167.27	$12.38	8.0%	27,922
2,000	1,400	600	$200.04	$216.19	$16.15	8.1%	14,600
2,500	1,750	750	$245.20	$265.11	$19.91	8.1%	6,944
3,000	2,100	900	$290.36	$314.03	$23.67	8.2%	2,980
4,000	2,800	1,200	$380.68	$411.87	$31.19	8.2%	1,783
5,000	3,500	1,500	$471.01	$509.72	$38.71	8.2%	419
6,000	4,200	1,800	$561.33	$607.56	$46.24	8.2%	179
7,000	4,900	2,100	$651.65	$705.41	$53.76	8.2%	77

		Rate Yr 2	Rate Yr 3
	UOM	SC8	SC8
Customer Charge	Monthly	$ 18.50	$ 19.60
Delivery Charge On Peak kWh	kWh-On	$ 0.04769	$ 0.05521
Delivery Charge Off Peak kWh	kWh-Off	$ 0.04769	$ 0.05521
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kWh	kWh	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00078	$ 0.00078
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90
Supply Charge On Peak kWh	kWh-On	$ 0.03759	$ 0.03759
Supply Charge Off Peak kWh	kWh-Off	$ 0.02774	$ 0.02774
MFC per kWh	kWh	$ 0.00236	$ 0.00236

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2022 - April 30, 2023

Including Supply

PSC #120 - SC 12 - Residential - TOU						increase / (decrease)		
kWh	Peak	Mid Peak	Off Peak	Rate Yr 2	Rate Yr 3	Amount	Percent	# of Customers
1,000	140	570	290	$112.50	$117.72	$5.22	4.6%	169
2,000	280	1,140	580	$198.50	$207.40	$8.90	4.5%	396
3,000	420	1,710	870	$284.50	$297.07	$12.57	4.4%	435
4,000	560	2,280	1,160	$370.50	$386.74	$16.24	4.4%	398
5,000	700	2,850	1,450	$456.50	$476.42	$19.91	4.4%	382
6,000	840	3,420	1,740	$542.50	$566.09	$23.59	4.3%	394
7,000	980	3,990	2,030	$628.51	$655.76	$27.26	4.3%	327
8,000	1,120	4,560	2,320	$714.51	$745.44	$30.93	4.3%	255
9,000	1,260	5,130	2,610	$800.51	$835.11	$34.60	4.3%	194
10,000	1,400	5,700	2,900	$886.51	$924.78	$38.28	4.3%	119
15,000	2,100	8,550	4,350	$1,316.51	$1,373.15	$56.64	4.3%	375
20,000	2,800	11,400	5,800	$1,746.52	$1,821.52	$75.00	4.3%	120
30,000	4,200	17,100	8,700	$2,606.53	$2,718.25	$111.73	4.3%	90
40,000	5,600	22,800	11,600	$3,466.53	$3,614.99	$148.45	4.3%	32
50,000	7,000	28,500	14,500	$4,326.54	$4,511.72	$185.18	4.3%	16

		Rate Yr 2	Rate Yr 3
	UOM	SC12	SC12
Customer Charge	Monthly	$ 25.60	$ 27.15
Delivery Charge On Peak kWh	kWh-On	$ 0.04331	$ 0.04698
Delivery Charge Mid Peak kWh	kWh-Mid	$ 0.04331	$ 0.04698
Delivery Charge Off Peak kWh	kWh-Off	$ 0.04331	$ 0.04698
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kWh	kWh	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00078	$ 0.00078
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90
Supply Charge On Peak kWh	kWh-On	$ 0.04489	$ 0.04489
Supply Charge Mid Peak kWh	kWh-Mid	$ 0.03591	$ 0.03591
Supply Charge Off Peak kWh	kWh-Off	$ 0.02738	$ 0.02738
MFC per kWh	kWh	$ 0.00236	$ 0.00236

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2022 - April 30, 2023

Including Supply

PSC #120 - SC 2 - Non Residential - Secondary

Kw	Load Factor	kWh	Rate Yr 2	Rate Yr 3	increase / (decrease) Amount	Percent	# of Customers
5	20%	730	$118.47	$128.36	$9.89	8.4%	4,814
5	30%	1,095	$134.80	$144.57	$9.78	7.3%	1,783
5	40%	1,460	$151.13	$160.78	$9.66	6.4%	1,150
5	50%	1,825	$167.46	$177.00	$9.54	5.7%	737
5	60%	2,190	$183.79	$193.21	$9.42	5.1%	477
5	70%	2,555	$200.12	$209.43	$9.31	4.7%	276
5	80%	2,920	$216.45	$225.64	$9.19	4.2%	221
5	90%	3,285	$232.78	$241.85	$9.07	3.9%	493
25	20%	3,650	$474.13	$506.19	$32.06	6.8%	15,467
25	30%	5,475	$555.78	$587.26	$31.48	5.7%	5,392
25	40%	7,300	$637.44	$668.33	$30.89	4.8%	3,010
25	50%	9,125	$719.09	$749.39	$30.30	4.2%	1,577
25	60%	10,950	$800.75	$830.46	$29.72	3.7%	852
25	70%	12,775	$882.40	$911.53	$29.13	3.3%	448
25	80%	14,600	$964.05	$992.60	$28.54	3.0%	288
25	90%	16,425	$1,045.71	$1,073.67	$27.96	2.7%	371
100	20%	14,600	$1,807.86	$1,923.06	$115.20	6.4%	3,447
100	30%	21,900	$2,134.48	$2,247.33	$112.85	5.3%	1,541
100	40%	29,200	$2,461.10	$2,571.61	$110.51	4.5%	776
100	50%	36,500	$2,787.72	$2,895.88	$108.16	3.9%	343
100	60%	43,800	$3,114.33	$3,220.15	$105.82	3.4%	190
100	70%	51,100	$3,440.95	$3,544.42	$103.47	3.0%	80
100	80%	58,400	$3,767.57	$3,868.70	$101.13	2.7%	27
100	90%	65,700	$4,094.19	$4,192.97	$98.78	2.4%	45
300	20%	43,800	$5,364.49	$5,701.38	$336.90	6.3%	435
300	30%	65,700	$6,344.34	$6,674.20	$329.86	5.2%	412
300	40%	87,600	$7,324.20	$7,647.02	$322.82	4.4%	201
300	50%	109,500	$8,304.05	$8,619.84	$315.79	3.8%	101
300	60%	131,400	$9,283.91	$9,592.66	$308.75	3.3%	51
300	70%	153,300	$10,263.76	$10,565.48	$301.72	2.9%	29
300	80%	175,200	$11,243.61	$11,538.29	$294.68	2.6%	18
300	90%	197,100	$12,223.47	$12,511.11	$287.64	2.4%	28

	UOM	Rate Yr 2 SC2	Rate Yr 3 SC2
Customer Charge	Monthly	$ 28.65	$ 33.00
Demand Charge kW	kW	$ 11.25	$ 12.40
Delivery Charge All Hours kWh	kWh	$ 0.00161	$ 0.00129
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00557	$ 0.00557
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90
Supply Charge All Hours kWh	kWh	$ 0.03506	$ 0.03506
MFC per kWh	kWh	$ 0.00199	$ 0.00199

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2022 - April 30, 2023

Including Supply

PSC #120 - SC 3P - Non Residential - Primary							
					increase / (decrease)		
Kw	Load Factor	kWh	Rate Yr 2	Rate Yr 3	Amount	Percent	# of Customers
5	20%	730	$193.51	$218.33	$24.82	12.8%	8
5	30%	1,095	$209.55	$234.25	$24.71	11.8%	4
5	40%	1,460	$225.58	$250.17	$24.59	10.9%	1
5	50%	1,825	$241.62	$266.09	$24.47	10.1%	2
5	60%	2,190	$257.66	$282.01	$24.35	9.5%	-
5	70%	2,555	$273.70	$297.93	$24.23	8.9%	-
5	80%	2,920	$289.74	$313.85	$24.12	8.3%	-
5	90%	3,285	$305.78	$329.77	$24.00	7.8%	-
25	20%	3,650	$487.94	$540.07	$52.12	10.7%	18
25	30%	5,475	$568.13	$619.67	$51.53	9.1%	9
25	40%	7,300	$648.33	$699.27	$50.94	7.9%	5
25	50%	9,125	$728.52	$778.86	$50.35	6.9%	8
25	60%	10,950	$808.71	$858.46	$49.76	6.2%	1
25	70%	12,775	$888.90	$938.06	$49.17	5.5%	1
25	80%	14,600	$969.09	$1,017.66	$48.58	5.0%	3
25	90%	16,425	$1,049.28	$1,097.26	$47.99	4.6%	-
100	20%	14,600	$1,592.08	$1,746.57	$154.49	9.7%	67
100	30%	21,900	$1,912.84	$2,064.97	$152.12	8.0%	-
100	40%	29,200	$2,233.60	$2,383.36	$149.76	6.7%	15
100	50%	36,500	$2,554.36	$2,701.76	$147.40	5.8%	11
100	60%	43,800	$2,875.13	$3,020.16	$145.03	5.0%	6
100	70%	51,100	$3,195.89	$3,338.56	$142.67	4.5%	3
100	80%	58,400	$3,516.65	$3,656.95	$140.30	4.0%	2
100	90%	65,700	$3,837.41	$3,975.35	$137.94	3.6%	-
300	20%	43,800	$4,536.44	$4,963.90	$427.47	9.4%	69
300	30%	65,700	$5,498.72	$5,919.10	$420.37	7.6%	-
300	40%	87,600	$6,461.01	$6,874.29	$413.28	6.4%	26
300	50%	109,500	$7,423.29	$7,829.48	$406.19	5.5%	22
300	60%	131,400	$8,385.58	$8,784.68	$399.10	4.8%	8
300	70%	153,300	$9,347.87	$9,739.87	$392.00	4.2%	4
300	80%	175,200	$10,310.15	$10,695.07	$384.91	3.7%	7
300	90%	197,100	$11,272.44	$11,650.26	$377.82	3.4%	8

		Rate Yr 2	Rate Yr 3
	UOM	SC3P	SC3P
Customer Charge	Monthly	$ 119.00	$ 137.00
Demand Charge kW	kW	$ 8.30	$ 9.71
Delivery Charge All Hours kWh	kWh	$ 0.00162	$ 0.00130
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00541	$ 0.00541
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90
Supply Charge All Hours kWh	kWh	$ 0.03424	$ 0.03424
MFC per kWh	kWh	$ 0.00199	$ 0.00199

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2022 - April 30, 2023

Including Supply

PSC #120 - SC 3S - Non Residential - SubTransmission

Kw	Load Factor	kWh	Rate Yr 2	Rate Yr 3	increase / (decrease) Amount	Percent	# of Customers
5	20%	730	$443.72	$501.96	$58.24	13.1%	1
5	30%	1,095	$458.28	$516.52	$58.24	12.7%	-
5	40%	1,460	$472.84	$531.08	$58.24	12.3%	-
5	50%	1,825	$487.39	$545.63	$58.24	11.9%	-
5	60%	2,190	$501.95	$560.19	$58.24	11.6%	-
5	70%	2,555	$516.51	$574.75	$58.24	11.3%	-
5	80%	2,920	$531.07	$589.31	$58.24	11.0%	-
5	90%	3,285	$545.62	$603.86	$58.24	10.7%	-
25	20%	3,650	$648.80	$706.21	$57.40	8.8%	2
25	30%	5,475	$721.59	$778.99	$57.40	8.0%	-
25	40%	7,300	$794.38	$851.78	$57.40	7.2%	-
25	50%	9,125	$867.17	$924.57	$57.40	6.6%	-
25	60%	10,950	$939.95	$997.36	$57.40	6.1%	-
25	70%	12,775	$1,012.74	$1,070.15	$57.40	5.7%	-
25	80%	14,600	$1,085.53	$1,142.93	$57.40	5.3%	-
25	90%	16,425	$1,158.32	$1,215.72	$57.40	5.0%	-
100	20%	14,600	$1,417.86	$1,472.12	$54.27	3.8%	2
100	30%	21,900	$1,709.01	$1,763.28	$54.27	3.2%	-
100	40%	29,200	$2,000.16	$2,054.43	$54.27	2.7%	1
100	50%	36,500	$2,291.31	$2,345.58	$54.27	2.4%	1
100	60%	43,800	$2,582.46	$2,636.73	$54.27	2.1%	-
100	70%	51,100	$2,873.62	$2,927.88	$54.27	1.9%	-
100	80%	58,400	$3,164.77	$3,219.04	$54.27	1.7%	-
100	90%	65,700	$3,455.92	$3,510.19	$54.27	1.6%	-
300	20%	43,800	$3,468.67	$3,514.58	$45.90	1.3%	1
300	30%	65,700	$4,342.13	$4,388.03	$45.90	1.1%	-
300	40%	87,600	$5,215.58	$5,261.49	$45.90	0.9%	1
300	50%	109,500	$6,089.04	$6,134.94	$45.90	0.8%	-
300	60%	131,400	$6,962.49	$7,008.40	$45.90	0.7%	-
300	70%	153,300	$7,835.95	$7,881.85	$45.90	0.6%	2
300	80%	175,200	$8,709.40	$8,755.31	$45.90	0.5%	1
300	90%	197,100	$9,582.86	$9,628.76	$45.90	0.5%	-

	UOM	Rate Yr 2 SC3S	Rate Yr 3 SC3S
Customer Charge	Monthly	$ 391.55	$ 450.00
Demand Charge kW	kW	$ 4.43	$ 4.39
Delivery Charge All Hours kWh	kWh	$ -	$ -
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00236	$ 0.00236
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90
Supply Charge All Hours kWh	kWh	$ 0.03181	$ 0.03181
MFC per kWh	kWh	$ 0.00199	$ 0.00199

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2022 - April 30, 2023

Including Supply

PSC #120 - SC 6 - Non Residential					
			increase / (decrease)		
kWh	Rate Yr 2	Rate Yr 3	Amount	Percent	# of Customers
300	$52.67	$57.10	$4.42	8.4%	38,981
400	$63.70	$69.23	$5.53	8.7%	7,133
500	$74.73	$81.36	$6.64	8.9%	5,737
600	$85.75	$93.49	$7.74	9.0%	4,185
700	$96.78	$105.63	$8.85	9.1%	3,094
800	$107.80	$117.76	$9.96	9.2%	2,217
900	$118.83	$129.89	$11.07	9.3%	1,753
1,000	$129.85	$142.02	$12.17	9.4%	1,339
1,100	$140.88	$154.16	$13.28	9.4%	1,105
1,200	$151.90	$166.29	$14.39	9.5%	886
1,500	$184.98	$202.69	$17.71	9.6%	1,756
2,000	$240.10	$263.35	$23.25	9.7%	1,278
2,500	$295.23	$324.01	$28.78	9.7%	461
3,000	$350.35	$384.67	$34.32	9.8%	223
3,500	$405.48	$445.34	$39.86	9.8%	139
8,000	$901.61	$991.30	$89.69	9.9%	408

		Rate Yr 2	Rate Yr 3
	UOM	SC6	SC6
Customer Charge	Monthly	$ 18.70	$ 19.80
Delivery Charge All Hours kWh	kWh	$ 0.06165	$ 0.07272
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kWh	kWh	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00124	$ 0.00124
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90
Supply Charge All Hours kWh	kWh	$ 0.03985	$ 0.03985
MFC per kWh	kWh	$ 0.00265	$ 0.00265

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2022 - April 30, 2023

Including Supply

PSC #120 - SC 7-1 - Non Residential Large General Service - Secondary									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 2	Rate Yr 3	Amount	Percent	# of Customers
25	20%	3,650	1,898	1,752	$592.78	$614.75	$21.98	3.7%	558
25	30%	5,475	2,847	2,628	$669.94	$691.92	$21.98	3.3%	172
25	40%	7,300	3,796	3,504	$747.10	$769.08	$21.98	2.9%	139
25	50%	9,125	4,745	4,380	$824.26	$846.24	$21.98	2.7%	79
25	60%	10,950	5,694	5,256	$901.42	$923.40	$21.98	2.4%	50
25	70%	12,775	6,643	6,132	$978.59	$1,000.56	$21.98	2.2%	23
25	80%	14,600	7,592	7,008	$1,055.75	$1,077.73	$21.98	2.1%	13
25	90%	16,425	8,541	7,884	$1,132.91	$1,154.89	$21.98	1.9%	11
100	20%	14,600	7,592	7,008	$1,741.41	$1,805.32	$63.91	3.7%	585
100	30%	21,900	11,388	10,512	$2,050.06	$2,113.97	$63.91	3.1%	-
100	40%	29,200	15,184	14,016	$2,358.70	$2,422.61	$63.91	2.7%	109
100	50%	36,500	18,980	17,520	$2,667.35	$2,731.26	$63.91	2.4%	82
100	60%	43,800	22,776	21,024	$2,976.00	$3,039.91	$63.91	2.1%	44
100	70%	51,100	26,572	24,528	$3,284.65	$3,348.56	$63.91	1.9%	9
100	80%	58,400	30,368	28,032	$3,593.29	$3,657.20	$63.91	1.8%	4
100	90%	65,700	34,164	31,536	$3,901.94	$3,965.85	$63.91	1.6%	9
500	20%	73,000	37,960	35,040	$7,867.45	$8,155.01	$287.55	3.7%	275
500	30%	109,500	56,940	52,560	$9,410.69	$9,698.24	$287.55	3.1%	151
500	40%	146,000	75,920	70,080	$10,953.92	$11,241.48	$287.55	2.6%	100
500	50%	182,500	94,900	87,600	$12,497.16	$12,784.71	$287.55	2.3%	62
500	60%	219,000	113,880	105,120	$14,040.39	$14,327.95	$287.55	2.0%	27
500	70%	255,500	132,860	122,640	$15,583.63	$15,871.18	$287.55	1.8%	16
500	80%	292,000	151,840	140,160	$17,126.86	$17,414.41	$287.55	1.7%	7
500	90%	328,500	170,820	157,680	$18,670.10	$18,957.65	$287.55	1.5%	-
1,000	20%	146,000	75,920	70,080	$15,525.01	$16,092.11	$567.10	3.7%	32
1,000	30%	219,000	113,880	105,120	$18,611.48	$19,178.58	$567.10	3.0%	24
1,000	40%	292,000	151,840	140,160	$21,697.95	$22,265.05	$567.10	2.6%	21
1,000	50%	365,000	189,800	175,200	$24,784.42	$25,351.52	$567.10	2.3%	-
1,000	60%	438,000	227,760	210,240	$27,870.89	$28,437.99	$567.10	2.0%	16
1,000	70%	511,000	265,720	245,280	$30,957.36	$31,524.46	$567.10	1.8%	4
1,000	80%	584,000	303,680	280,320	$34,043.83	$34,610.93	$567.10	1.7%	5
1,000	90%	657,000	341,640	315,360	$37,130.29	$37,697.40	$567.10	1.5%	9

		Rate Yr 2	Rate Yr 3
	UOM	SC7-1	SC7-1
Customer Charge	Monthly	$ 209.00	$ 217.00
Demand Charge kW	kW	$ 9.13	$ 9.69
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00768	$ 0.00768
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90
Supply Charge On Peak kWh	kWh-On	$ 0.04008	$ 0.04008
Supply Charge Off Peak kWh	kWh-Off	$ 0.02783	$ 0.02783
MFC per kWh	kWh	$ 0.00199	$ 0.00199

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2022 - April 30, 2023

Including Supply

PSC #120 - SC 7-2 - Non Residential Large General Service - Primary									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 2	Rate Yr 3	Amount	Percent	# of Customers
500	20%	73,000	37,960	35,040	$8,037.54	$8,619.21	$581.67	7.2%	90
500	30%	109,500	56,940	52,560	$9,555.01	$10,136.68	$581.67	6.1%	35
500	40%	146,000	75,920	70,080	$11,072.48	$11,654.15	$581.67	5.3%	32
500	50%	182,500	94,900	87,600	$12,589.95	$13,171.62	$581.67	4.6%	27
500	60%	219,000	113,880	105,120	$14,107.42	$14,689.09	$581.67	4.1%	12
500	70%	255,500	132,860	122,640	$15,624.89	$16,206.56	$581.67	3.7%	8
500	80%	292,000	151,840	140,160	$17,142.36	$17,724.03	$581.67	3.4%	-
500	90%	328,500	170,820	157,680	$18,659.83	$19,241.50	$581.67	3.1%	-
1,000	20%	146,000	75,920	70,080	$15,344.18	$16,479.52	$1,135.34	7.4%	21
1,000	30%	219,000	113,880	105,120	$18,379.12	$19,514.46	$1,135.34	6.2%	22
1,000	40%	292,000	151,840	140,160	$21,414.06	$22,549.40	$1,135.34	5.3%	23
1,000	50%	365,000	189,800	175,200	$24,449.00	$25,584.34	$1,135.34	4.6%	-
1,000	60%	438,000	227,760	210,240	$27,483.94	$28,619.28	$1,135.34	4.1%	14
1,000	70%	511,000	265,720	245,280	$30,518.88	$31,654.22	$1,135.34	3.7%	7
1,000	80%	584,000	303,680	280,320	$33,553.82	$34,689.16	$1,135.34	3.4%	2
1,000	90%	657,000	341,640	315,360	$36,588.76	$37,724.10	$1,135.34	3.1%	1
1,500	20%	219,000	113,880	105,120	$22,650.81	$24,339.83	$1,689.01	7.5%	4
1,500	30%	328,500	170,820	157,680	$27,203.22	$28,892.24	$1,689.01	6.2%	2
1,500	40%	438,000	227,760	210,240	$31,755.63	$33,444.65	$1,689.01	5.3%	8
1,500	50%	547,500	284,700	262,800	$36,308.04	$37,997.06	$1,689.01	4.7%	8
1,500	60%	657,000	341,640	315,360	$40,860.45	$42,549.47	$1,689.01	4.1%	-
1,500	70%	766,500	398,580	367,920	$45,412.86	$47,101.88	$1,689.01	3.7%	7
1,500	80%	876,000	455,520	420,480	$49,965.27	$51,654.29	$1,689.01	3.4%	2
1,500	90%	985,500	512,460	473,040	$54,517.68	$56,206.70	$1,689.01	3.1%	-
2,500	20%	365,000	189,800	175,200	$37,264.09	$40,060.45	$2,796.36	7.5%	5
2,500	30%	547,500	284,700	262,800	$44,851.44	$47,647.80	$2,796.36	6.2%	2
2,500	40%	730,000	379,600	350,400	$52,438.79	$55,235.15	$2,796.36	5.3%	11
2,500	50%	912,500	474,500	438,000	$60,026.14	$62,822.50	$2,796.36	4.7%	12
2,500	60%	1,095,000	569,400	525,600	$67,613.49	$70,409.85	$2,796.36	4.1%	-
2,500	70%	1,277,500	664,300	613,200	$75,200.84	$77,997.20	$2,796.36	3.7%	1
2,500	80%	1,460,000	759,200	700,800	$82,788.19	$85,584.55	$2,796.36	3.4%	3
2,500	90%	1,642,500	854,100	788,400	$90,375.54	$93,171.90	$2,796.36	3.1%	5

		Rate Yr 2	Rate Yr 3
	UOM	SC7-2	SC7-2
Customer Charge	Monthly	$ 730.00	$ 758.00
Demand Charge kW	kW	$ 8.53	$ 9.64
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00858	$ 0.00858
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90
Supply Charge On Peak kWh	kWh-On	$ 0.03921	$ 0.03921
Supply Charge Off Peak kWh	kWh-Off	$ 0.02730	$ 0.02730
MFC per kWh	kWh	$ 0.00199	$ 0.00199

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2022 - April 30, 2023

Including Supply

PSC #120 - SC 7-3 - Non Residential Large General Service - SubTransmission									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 2	Rate Yr 3	Amount	Percent	# of Customers
500	20%	73,000	37,960	35,040	$5,636.43	$5,795.79	$159.36	2.8%	18
500	30%	109,500	56,940	52,560	$7,138.09	$7,297.45	$159.36	2.2%	9
500	40%	146,000	75,920	70,080	$8,639.75	$8,799.12	$159.36	1.8%	7
500	50%	182,500	94,900	87,600	$10,141.42	$10,300.78	$159.36	1.6%	6
500	60%	219,000	113,880	105,120	$11,643.08	$11,802.44	$159.36	1.4%	2
500	70%	255,500	132,860	122,640	$13,144.74	$13,304.10	$159.36	1.2%	2
500	80%	292,000	151,840	140,160	$14,646.40	$14,805.77	$159.36	1.1%	-
500	90%	328,500	170,820	157,680	$16,148.07	$16,307.43	$159.36	1.0%	-
2,000	20%	292,000	151,840	140,160	$17,983.01	$18,443.46	$460.45	2.6%	32
2,000	30%	438,000	227,760	210,240	$23,989.66	$24,450.11	$460.45	1.9%	-
2,000	40%	584,000	303,680	280,320	$29,996.31	$30,456.77	$460.45	1.5%	11
2,000	50%	730,000	379,600	350,400	$36,002.96	$36,463.42	$460.45	1.3%	6
2,000	60%	876,000	455,520	420,480	$42,009.62	$42,470.07	$460.45	1.1%	4
2,000	70%	1,022,000	531,440	490,560	$48,016.27	$48,476.72	$460.45	1.0%	2
2,000	80%	1,168,000	607,360	560,640	$54,022.92	$54,483.37	$460.45	0.9%	-
2,000	90%	1,314,000	683,280	630,720	$60,029.57	$60,490.02	$460.45	0.8%	-
4,000	20%	584,000	303,680	280,320	$34,445.13	$35,307.03	$861.90	2.5%	2
4,000	30%	876,000	455,520	420,480	$46,458.43	$47,320.33	$861.90	1.9%	10
4,000	40%	1,168,000	607,360	560,640	$58,471.73	$59,333.63	$861.90	1.5%	4
4,000	50%	1,460,000	759,200	700,800	$70,485.03	$71,346.93	$861.90	1.2%	-
4,000	60%	1,752,000	911,040	840,960	$82,498.33	$83,360.23	$861.90	1.0%	6
4,000	70%	2,044,000	1,062,880	981,120	$94,511.63	$95,373.53	$861.90	0.9%	4
4,000	80%	2,336,000	1,214,720	1,121,280	$106,524.93	$107,386.83	$861.90	0.8%	-
4,000	90%	2,628,000	1,366,560	1,261,440	$118,538.23	$119,400.13	$861.90	0.7%	-
5,000	20%	730,000	379,600	350,400	$42,676.19	$43,738.81	$1,062.63	2.5%	-
5,000	30%	1,095,000	569,400	525,600	$57,692.81	$58,755.44	$1,062.63	1.8%	-
5,000	40%	1,460,000	759,200	700,800	$72,709.44	$73,772.06	$1,062.63	1.5%	-
5,000	50%	1,825,000	949,000	876,000	$87,726.06	$88,788.69	$1,062.63	1.2%	1
5,000	60%	2,190,000	1,138,800	1,051,200	$102,742.69	$103,805.31	$1,062.63	1.0%	1
5,000	70%	2,555,000	1,328,600	1,226,400	$117,759.31	$118,821.94	$1,062.63	0.9%	3
5,000	80%	2,920,000	1,518,400	1,401,600	$132,775.94	$133,838.57	$1,062.63	0.8%	-
5,000	90%	3,285,000	1,708,200	1,576,800	$147,792.57	$148,855.19	$1,062.63	0.7%	5

		Rate Yr 2	Rate Yr 3
	UOM	SC7-3	SC7-3
Customer Charge	Monthly	$ 1,520.00	$ 1,579.00
Demand Charge kW	kW	$ 2.22	$ 2.42
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00536	$ 0.00536
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90
Supply Charge On Peak kWh	kWh-On	$ 0.03873	$ 0.03873
Supply Charge Off Peak kWh	kWh-Off	$ 0.02692	$ 0.02692
MFC per kWh	kWh	$ 0.00199	$ 0.00199

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2022 - April 30, 2023

Including Supply

PSC #120 - SC 7-4 - Non Residential Large General Service - Transmission									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 2	Rate Yr 3	Amount	Percent	# of Customers
1,000	20%	146,000	75,920	70,080	$10,354.98	$10,908.68	$553.69	5.3%	1
1,000	30%	219,000	113,880	105,120	$13,358.31	$13,912.01	$553.69	4.1%	-
1,000	40%	292,000	151,840	140,160	$16,361.64	$16,915.33	$553.69	3.4%	2
1,000	50%	365,000	189,800	175,200	$19,364.97	$19,918.66	$553.69	2.9%	-
1,000	60%	438,000	227,760	210,240	$22,368.30	$22,921.99	$553.69	2.5%	-
1,000	70%	511,000	265,720	245,280	$25,371.62	$25,925.32	$553.69	2.2%	-
1,000	80%	584,000	303,680	280,320	$28,374.95	$28,928.65	$553.69	2.0%	-
1,000	90%	657,000	341,640	315,360	$31,378.28	$31,931.97	$553.69	1.8%	-
7,500	20%	1,095,000	569,400	525,600	$58,156.54	$61,009.23	$2,852.69	4.9%	5
7,500	30%	1,642,500	854,100	788,400	$80,681.50	$83,534.19	$2,852.69	3.5%	-
7,500	40%	2,190,000	1,138,800	1,051,200	$103,206.46	$106,059.15	$2,852.69	2.8%	1
7,500	50%	2,737,500	1,423,500	1,314,000	$125,731.42	$128,584.11	$2,852.69	2.3%	1
7,500	60%	3,285,000	1,708,200	1,576,800	$148,256.38	$151,109.07	$2,852.69	1.9%	-
7,500	70%	3,832,500	1,992,900	1,839,600	$170,781.34	$173,634.03	$2,852.69	1.7%	1
7,500	80%	4,380,000	2,277,600	2,102,400	$193,306.30	$196,158.99	$2,852.69	1.5%	-
7,500	90%	4,927,500	2,562,300	2,365,200	$215,831.26	$218,683.95	$2,852.69	1.3%	-
15,000	20%	2,190,000	1,138,800	1,051,200	$113,312.17	$118,817.56	$5,505.39	4.9%	1
15,000	30%	3,285,000	1,708,200	1,576,800	$158,362.09	$163,867.48	$5,505.39	3.5%	-
15,000	40%	4,380,000	2,277,600	2,102,400	$203,412.02	$208,917.40	$5,505.39	2.7%	1
15,000	50%	5,475,000	2,847,000	2,628,000	$248,461.94	$253,967.32	$5,505.39	2.2%	-
15,000	60%	6,570,000	3,416,400	3,153,600	$293,511.86	$299,017.24	$5,505.39	1.9%	-
15,000	70%	7,665,000	3,985,800	3,679,200	$338,561.78	$344,067.16	$5,505.39	1.6%	2
15,000	80%	8,760,000	4,555,200	4,204,800	$383,611.70	$389,117.08	$5,505.39	1.4%	1
15,000	90%	9,855,000	5,124,600	4,730,400	$428,661.62	$434,167.01	$5,505.39	1.3%	-
50,000	20%	7,300,000	3,796,000	3,504,000	$370,705.15	$388,589.77	$17,884.62	4.8%	-
50,000	30%	10,950,000	5,694,000	5,256,000	$520,871.55	$538,756.17	$17,884.62	3.4%	1
50,000	40%	14,600,000	7,592,000	7,008,000	$671,037.95	$688,922.58	$17,884.62	2.7%	-
50,000	50%	18,250,000	9,490,000	8,760,000	$821,204.35	$839,088.98	$17,884.62	2.2%	-
50,000	60%	21,900,000	11,388,000	10,512,000	$971,370.76	$989,255.38	$17,884.62	1.8%	-
50,000	70%	25,550,000	13,286,000	12,264,000	$1,121,537.16	$1,139,421.78	$17,884.62	1.6%	-
50,000	80%	29,200,000	15,184,000	14,016,000	$1,271,703.56	$1,289,588.18	$17,884.62	1.4%	1
50,000	90%	32,850,000	17,082,000	15,768,000	$1,421,869.96	$1,439,754.59	$17,884.62	1.3%	-

		Rate Yr 2	Rate Yr 3
	UOM	SC7-4	SC7-4
Customer Charge	Monthly	$ 3,000.00	$ 3,200.00
Demand Charge kW	kW	$ 1.34	$ 1.70
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00515	$ 0.00515
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90
Supply Charge On Peak kWh	kWh-On	$ 0.03926	$ 0.03926
Supply Charge Off Peak kWh	kWh-Off	$ 0.02635	$ 0.02635
MFC per kWh	kWh	$ 0.00199	$ 0.00199

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2022 - April 30, 2023

Including Supply

PSC #120 - SC 9 - Non Residential - Day/Night							
					increase / (decrease)		
kWh	Peak	Off Peak	Rate Yr 2	Rate Yr 3	Amount	Percent	# of Customers
300	180	120	$51.74	$55.49	$3.75	7.2%	686
400	240	160	$61.45	$66.02	$4.57	7.4%	214
500	300	200	$71.16	$76.54	$5.38	7.6%	185
600	360	240	$80.87	$87.07	$6.20	7.7%	192
700	420	280	$90.59	$97.60	$7.02	7.7%	171
800	480	320	$100.30	$108.13	$7.83	7.8%	141
900	540	360	$110.01	$118.66	$8.65	7.9%	126
1,000	600	400	$119.72	$129.19	$9.47	7.9%	83
1,100	660	440	$129.44	$139.72	$10.28	7.9%	91
1,200	720	480	$139.15	$150.25	$11.10	8.0%	64
1,500	900	600	$168.28	$181.83	$13.55	8.1%	162
2,000	1,200	800	$216.85	$234.48	$17.63	8.1%	159
2,500	1,500	1,000	$265.41	$287.12	$21.71	8.2%	83
3,000	1,800	1,200	$313.97	$339.77	$25.80	8.2%	47
3,500	2,100	1,400	$362.53	$392.41	$29.88	8.2%	24
5,000	3,000	2,000	$508.22	$550.34	$42.13	8.3%	26

		Rate Yr 2	Rate Yr 3
	UOM	SC9	SC9
Customer Charge	Monthly	$ 21.70	$ 23.00
Delivery Charge On Peak kWh	kWh-On	$ 0.05078	$ 0.05895
Delivery Charge Off Peak kWh	kWh-Off	$ 0.05078	$ 0.05895
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kWh	kWh	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00124	$ 0.00124
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90
Supply Charge On Peak kWh	kWh-On	$ 0.04154	$ 0.04154
Supply Charge Off Peak kWh	kWh-Off	$ 0.03167	$ 0.03167
MFC per kWh	kWh	$ 0.00265	$ 0.00265

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation

Date Sources - NYSEG Electric Bill Impact Statements

Rate	Source of Rate in "Current" Rates	Source of Rate in Rate Years
Customer Charge	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
kW Charge	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
kWh Delivery Charge All Hours	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
kWh Delivery Charge On Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
kWh Delivery Charge Mid Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
kWh Delivery Charge Off Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
Reactive RkVah	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
Billing Charge per Bill	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
SBC (EEtr) per kWh	Current Tariff Rates in Effect 01/01/2020 - (SBC Statement #19)	Included in Delivery Rates
SBC (CEF) per kWh	Current Tariff Rates in Effect 01/01/2020 - (SBC Statement #19)	Current Tariff Rates in Effect 01/01/2020 - (SBC Statement #19)
RAM per kWh	Current Tariff Rates in Effect 07/19/2019 - (RAM Statement #1)	No RAM forecasted. COVID Bill Credits begin 7/1/2021.
RAM per kW	Current Tariff Rates in Effect 07/19/2019 - (RAM Statement #1)	No RAM forecasted. COVID Bill Credits begin 7/1/2021.
Tax Credit per kWh	Case No. 17-M-0815 dated August 9, 2018. Statement Number 1 Effective 10/01/2018	Included in Delivery Rates
Tax Credit per kW	Case No. 17-M-0815 dated August 9, 2018. Statement Number 1 Effective 10/01/2018	Included in Delivery Rates

Rate	Source of Rate in "Current" Rates and Rate Years
Transition Charge per kWh	NBC, Demand Response, and Value Stack: NBC is the Non-Weighted 2019 Average, Dmd Rsp is 05/01/2020 rate, Value Stack at $-0-. RAM is separate.
MFC per kWh	Current Tariff Rates in Effect 05/01/2020
kWh Supply Charge All Hours	2019 Annualized Supply Rates
kWh Supply Charge On Peak	2019 Annualized Supply Rates
kWh Supply Charge Mid Peak	2019 Annualized Supply Rates
kWh Supply Charge Off Peak	2019 Annualized Supply Rates
Customer Count	2018 monthly data - separate Low Income counts

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2022 - April 30, 2023

Delivery Bill Only

PSC #120 - SC 1 - Residential

kWh	Rate Yr 2	Rate Yr 3	increase / (decrease) Amount	Percent	# of Customers	# of Low Income Customers	Percent of Customers	Percent of Low Income Customers
100	$22.76	$24.47	$1.72	7.5%	34,023	683	5%	2%
200	$28.56	$31.04	$2.48	8.7%	48,276	2,803	8%	7%
300	$34.37	$37.62	$3.25	9.4%	61,295	4,359	10%	12%
400	$40.18	$44.19	$4.01	10.0%	67,881	4,939	11%	13%
500	$45.99	$50.76	$4.78	10.4%	67,787	4,476	11%	12%
600	$51.79	$57.33	$5.54	10.7%	63,739	3,926	10%	10%
700	$57.60	$63.91	$6.31	10.9%	55,914	3,162	9%	8%
800	$63.41	$70.48	$7.07	11.1%	47,727	2,751	8%	7%
900	$69.22	$77.05	$7.84	11.3%	39,223	2,184	6%	6%
1,000	$75.03	$83.63	$8.60	11.5%	31,407	1,698	5%	5%
1,100	$80.83	$90.20	$9.37	11.6%	25,132	1,395	4%	4%
1,200	$86.64	$96.77	$10.13	11.7%	19,685	1,124	3%	3%
1,500	$104.06	$116.49	$12.43	11.9%	36,425	2,110	6%	6%
2,000	$133.10	$149.35	$16.25	12.2%	23,598	1,396	4%	4%
3,000	$191.18	$215.08	$23.90	12.5%	12,884	710	2%	2%
					634,997	37,717		

Amount of EE Embedded in Delivery Rates*

Amount	Percent
$ 0.30	1.21%
$ 0.59	1.91%
$ 0.89	2.37%
$ 1.19	2.69%
$ 1.49	2.93%
$ 1.78	3.11%
$ 2.08	3.25%
$ 2.38	3.37%
$ 2.67	3.47%
$ 2.97	3.55%
$ 3.27	3.62%
$ 3.56	3.68%
$ 4.46	3.82%
$ 5.94	3.98%
$ 8.91	4.14%

	UOM	Rate Yr 2 SC1	Rate Yr 3 SC1
Customer Charge	Monthly	$ 16.05	$ 17.00
Delivery Charge All Hours kWh	kWh	$ 0.05244	$ 0.06009
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kWh	kWh	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00078	$ 0.00078
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90

Includes $ 0.00297 per kWh of EE Costs*

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

4. Low income customers represent customers who participated in the Company's low income program and received a credit on their bill each month during calendar year 2018.

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2022 - April 30, 2023

Delivery Bill Only

PSC #120 - SC 8 - Residential - Day/Night

kWh	Peak	Off Peak	Rate Yr 2	Rate Yr 3	increase / (decrease) Amount	Percent	# of Customers
300	210	90	$35.40	$38.75	$3.36	9.5%	11,243
400	280	120	$40.73	$44.84	$4.11	10.1%	7,307
500	350	150	$46.06	$50.92	$4.86	10.6%	8,958
600	420	180	$51.40	$57.01	$5.61	10.9%	9,556
700	490	210	$56.73	$63.09	$6.37	11.2%	9,821
800	560	240	$62.06	$69.18	$7.12	11.5%	9,276
900	630	270	$67.39	$75.26	$7.87	11.7%	8,790
1,000	700	300	$72.73	$81.35	$8.62	11.9%	7,969
1,500	1,050	450	$99.39	$111.77	$12.38	12.5%	27,922
2,000	1,400	600	$126.05	$142.20	$16.15	12.8%	14,600
2,500	1,750	750	$152.72	$172.62	$19.91	13.0%	6,944
3,000	2,100	900	$179.38	$203.05	$23.67	13.2%	2,980
4,000	2,800	1,200	$232.71	$263.90	$31.19	13.4%	1,783
5,000	3,500	1,500	$286.04	$324.75	$38.71	13.5%	419
6,000	4,200	1,800	$339.36	$385.60	$46.24	13.6%	179
7,000	4,900	2,100	$392.69	$446.45	$53.76	13.7%	77

	UOM	Rate Yr 2 SC8	Rate Yr 3 SC8
Customer Charge	Monthly	$ 18.50	$ 19.60
Delivery Charge On Peak kWh	kWh-On	$ 0.04769	$ 0.05521
Delivery Charge Off Peak kWh	kWh-Off	$ 0.04769	$ 0.05521
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kWh	kWh	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00078	$ 0.00078
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2022 - April 30, 2023

Delivery Bill Only

PSC #120 - SC 12 - Residential - TOU								
						increase / (decrease)		
kWh	Peak	Mid Peak	Off Peak	Rate Yr 2	Rate Yr 3	Amount	Percent	# of Customers
1,000	140	570	290	$75.45	$80.68	$5.22	6.9%	169
2,000	280	1,140	580	$124.41	$133.30	$8.90	7.2%	396
3,000	420	1,710	870	$173.36	$185.93	$12.57	7.2%	435
4,000	560	2,280	1,160	$222.31	$238.55	$16.24	7.3%	398
5,000	700	2,850	1,450	$271.26	$291.18	$19.91	7.3%	382
6,000	840	3,420	1,740	$320.22	$343.80	$23.59	7.4%	394
7,000	980	3,990	2,030	$369.17	$396.43	$27.26	7.4%	327
8,000	1,120	4,560	2,320	$418.12	$449.05	$30.93	7.4%	255
9,000	1,260	5,130	2,610	$467.08	$501.68	$34.60	7.4%	194
10,000	1,400	5,700	2,900	$516.03	$554.30	$38.28	7.4%	119
15,000	2,100	8,550	4,350	$760.79	$817.43	$56.64	7.4%	375
20,000	2,800	11,400	5,800	$1,005.56	$1,080.56	$75.00	7.5%	120
30,000	4,200	17,100	8,700	$1,495.09	$1,606.81	$111.73	7.5%	90
40,000	5,600	22,800	11,600	$1,984.62	$2,133.07	$148.45	7.5%	32
50,000	7,000	28,500	14,500	$2,474.14	$2,659.32	$185.18	7.5%	16

	UOM	Rate Yr 2 SC12	Rate Yr 3 SC12
Customer Charge	Monthly	$ 25.60	$ 27.15
Delivery Charge On Peak kWh	kWh-On	$ 0.04331	$ 0.04698
Delivery Charge Mid Peak kWh	kWh-Mid	$ 0.04331	$ 0.04698
Delivery Charge Off Peak kWh	kWh-Off	$ 0.04331	$ 0.04698
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kWh	kWh	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00078	$ 0.00078
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2022 - April 30, 2023

Delivery Bill Only

PSC #120 - SC 2 - Non Residential - Secondary							
					increase / (decrease)		
Kw	Load Factor	kWh	Rate Yr 2	Rate Yr 3	Amount	Percent	# of Customers
5	20%	730	$91.42	$101.31	$9.89	10.8%	4,814
5	30%	1,095	$94.23	$104.00	$9.78	10.4%	1,783
5	40%	1,460	$97.03	$106.69	$9.66	10.0%	1,150
5	50%	1,825	$99.84	$109.38	$9.54	9.6%	737
5	60%	2,190	$102.65	$112.07	$9.42	9.2%	477
5	70%	2,555	$105.46	$114.76	$9.31	8.8%	276
5	80%	2,920	$108.26	$117.45	$9.19	8.5%	221
5	90%	3,285	$111.07	$120.14	$9.07	8.2%	493
25	20%	3,650	$338.90	$370.96	$32.06	9.5%	15,467
25	30%	5,475	$352.93	$384.41	$31.48	8.9%	5,392
25	40%	7,300	$366.97	$397.86	$30.89	8.4%	3,010
25	50%	9,125	$381.01	$411.31	$30.30	8.0%	1,577
25	60%	10,950	$395.05	$424.77	$29.72	7.5%	852
25	70%	12,775	$409.09	$438.22	$29.13	7.1%	448
25	80%	14,600	$423.12	$451.67	$28.54	6.7%	288
25	90%	16,425	$437.16	$465.12	$27.96	6.4%	371
100	20%	14,600	$1,266.93	$1,382.13	$115.20	9.1%	3,447
100	30%	21,900	$1,323.09	$1,435.94	$112.85	8.5%	1,541
100	40%	29,200	$1,379.24	$1,489.75	$110.51	8.0%	776
100	50%	36,500	$1,435.39	$1,543.55	$108.16	7.5%	343
100	60%	43,800	$1,491.54	$1,597.36	$105.82	7.1%	190
100	70%	51,100	$1,547.70	$1,651.17	$103.47	6.7%	80
100	80%	58,400	$1,603.85	$1,704.98	$101.13	6.3%	27
100	90%	65,700	$1,660.00	$1,758.79	$98.78	6.0%	45
300	20%	43,800	$3,741.70	$4,078.59	$336.90	9.0%	435
300	30%	65,700	$3,910.16	$4,240.02	$329.86	8.4%	412
300	40%	87,600	$4,078.62	$4,401.44	$322.82	7.9%	201
300	50%	109,500	$4,247.08	$4,562.86	$315.79	7.4%	101
300	60%	131,400	$4,415.54	$4,724.29	$308.75	7.0%	51
300	70%	153,300	$4,583.99	$4,885.71	$301.72	6.6%	29
300	80%	175,200	$4,752.45	$5,047.13	$294.68	6.2%	18
300	90%	197,100	$4,920.91	$5,208.56	$287.64	5.8%	28

		Rate Yr 2	Rate Yr 3
	UOM	SC2	SC2
Customer Charge	Monthly	$ 28.65	$ 33.00
Demand Charge kW	kW	$ 11.25	$ 12.40
Delivery Charge All Hours kWh	kWh	$ 0.00161	$ 0.00129
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00557	$ 0.00557
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2022 - April 30, 2023

Delivery Bill Only

PSC #120 - SC 3P - Non Residential - Primary							
					increase / (decrease)		
Kw	Load Factor	kWh	Rate Yr 2	Rate Yr 3	Amount	Percent	# of Customers
5	20%	730	$167.06	$191.88	$24.82	14.9%	8
5	30%	1,095	$169.87	$194.58	$24.71	14.5%	4
5	40%	1,460	$172.68	$197.27	$24.59	14.2%	1
5	50%	1,825	$175.49	$199.96	$24.47	13.9%	2
5	60%	2,190	$178.31	$202.66	$24.35	13.7%	-
5	70%	2,555	$181.12	$205.35	$24.23	13.4%	-
5	80%	2,920	$183.93	$208.05	$24.12	13.1%	-
5	90%	3,285	$186.74	$210.74	$24.00	12.9%	-
25	20%	3,650	$355.69	$407.81	$52.12	14.7%	18
25	30%	5,475	$369.75	$421.28	$51.53	13.9%	9
25	40%	7,300	$383.81	$434.75	$50.94	13.3%	5
25	50%	9,125	$397.87	$448.22	$50.35	12.7%	8
25	60%	10,950	$411.93	$461.69	$49.76	12.1%	1
25	70%	12,775	$425.99	$475.16	$49.17	11.5%	1
25	80%	14,600	$440.06	$488.63	$48.58	11.0%	3
25	90%	16,425	$454.12	$502.10	$47.99	10.6%	-
100	20%	14,600	$1,063.05	$1,217.54	$154.49	14.5%	67
100	30%	21,900	$1,119.29	$1,271.42	$152.12	13.6%	-
100	40%	29,200	$1,175.54	$1,325.30	$149.76	12.7%	15
100	50%	36,500	$1,231.79	$1,379.18	$147.40	12.0%	11
100	60%	43,800	$1,288.03	$1,433.07	$145.03	11.3%	6
100	70%	51,100	$1,344.28	$1,486.95	$142.67	10.6%	3
100	80%	58,400	$1,400.53	$1,540.83	$140.30	10.0%	2
100	90%	65,700	$1,456.77	$1,594.71	$137.94	9.5%	-
300	20%	43,800	$2,949.34	$3,376.81	$427.47	14.5%	69
300	30%	65,700	$3,118.08	$3,538.46	$420.37	13.5%	-
300	40%	87,600	$3,286.82	$3,700.10	$413.28	12.6%	26
300	50%	109,500	$3,455.56	$3,861.75	$406.19	11.8%	22
300	60%	131,400	$3,624.30	$4,023.40	$399.10	11.0%	8
300	70%	153,300	$3,793.04	$4,185.05	$392.00	10.3%	4
300	80%	175,200	$3,961.78	$4,346.69	$384.91	9.7%	7
300	90%	197,100	$4,130.52	$4,508.34	$377.82	9.1%	8

		Rate Yr 2	Rate Yr 3
	UOM	SC3P	SC3P
Customer Charge	Monthly	$ 119.00	$ 137.00
Demand Charge kW	kW	$ 8.30	$ 9.71
Delivery Charge All Hours kWh	kWh	$ 0.00162	$ 0.00130
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00541	$ 0.00541
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2022 - April 30, 2023

Delivery Bill Only

PSC #120 - SC 3S - Non Residential - SubTransmission

Kw	Load Factor	kWh	Rate Yr 2	Rate Yr 3	increase / (decrease) Amount	Percent	# of Customers
5	20%	730	$419.05	$477.29	$58.24	13.9%	1
5	30%	1,095	$421.27	$479.51	$58.24	13.8%	-
5	40%	1,460	$423.49	$481.73	$58.24	13.8%	-
5	50%	1,825	$425.71	$483.95	$58.24	13.7%	-
5	60%	2,190	$427.93	$486.17	$58.24	13.6%	-
5	70%	2,555	$430.15	$488.39	$58.24	13.5%	-
5	80%	2,920	$432.38	$490.62	$58.24	13.5%	-
5	90%	3,285	$434.60	$492.84	$58.24	13.4%	-
25	20%	3,650	$525.44	$582.84	$57.40	10.9%	2
25	30%	5,475	$536.55	$593.95	$57.40	10.7%	-
25	40%	7,300	$547.65	$605.06	$57.40	10.5%	-
25	50%	9,125	$558.76	$616.16	$57.40	10.3%	-
25	60%	10,950	$569.86	$627.27	$57.40	10.1%	-
25	70%	12,775	$580.97	$638.38	$57.40	9.9%	-
25	80%	14,600	$592.08	$649.48	$57.40	9.7%	-
25	90%	16,425	$603.18	$660.59	$57.40	9.5%	-
100	20%	14,600	$924.41	$978.67	$54.27	5.9%	2
100	30%	21,900	$968.83	$1,023.10	$54.27	5.6%	-
100	40%	29,200	$1,013.26	$1,067.53	$54.27	5.4%	1
100	50%	36,500	$1,057.68	$1,111.95	$54.27	5.1%	1
100	60%	43,800	$1,102.11	$1,156.38	$54.27	4.9%	-
100	70%	51,100	$1,146.54	$1,200.81	$54.27	4.7%	-
100	80%	58,400	$1,190.96	$1,245.23	$54.27	4.6%	-
100	90%	65,700	$1,235.39	$1,289.66	$54.27	4.4%	-
300	20%	43,800	$1,988.32	$2,034.22	$45.90	2.3%	1
300	30%	65,700	$2,121.60	$2,167.50	$45.90	2.2%	-
300	40%	87,600	$2,254.88	$2,300.78	$45.90	2.0%	1
300	50%	109,500	$2,388.16	$2,434.06	$45.90	1.9%	-
300	60%	131,400	$2,521.43	$2,567.34	$45.90	1.8%	-
300	70%	153,300	$2,654.71	$2,700.62	$45.90	1.7%	2
300	80%	175,200	$2,787.99	$2,833.90	$45.90	1.6%	1
300	90%	197,100	$2,921.27	$2,967.18	$45.90	1.6%	-

	UOM	Rate Yr 2 SC3S	Rate Yr 3 SC3S
Customer Charge	Monthly	$ 391.55	$ 450.00
Demand Charge kW	kW	$ 4.43	$ 4.39
Delivery Charge All Hours kWh	kWh	$ -	$ -
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00236	$ 0.00236
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2022 - April 30, 2023

Delivery Bill Only

PSC #120 - SC 6 - Non Residential					
			increase / (decrease)		# of
kWh	Rate Yr 2	Rate Yr 3	Amount	Percent	Customers
300	$39.92	$44.35	$4.42	11.1%	38,981
400	$46.70	$52.23	$5.53	11.8%	7,133
500	$53.47	$60.11	$6.64	12.4%	5,737
600	$60.25	$67.99	$7.74	12.9%	4,185
700	$67.02	$75.88	$8.85	13.2%	3,094
800	$73.80	$83.76	$9.96	13.5%	2,217
900	$80.57	$91.64	$11.07	13.7%	1,753
1,000	$87.35	$99.52	$12.17	13.9%	1,339
1,100	$94.12	$107.41	$13.28	14.1%	1,105
1,200	$100.90	$115.29	$14.39	14.3%	886
1,500	$121.22	$138.94	$17.71	14.6%	1,756
2,000	$155.10	$178.35	$23.25	15.0%	1,278
2,500	$188.97	$217.76	$28.78	15.2%	461
3,000	$222.85	$257.17	$34.32	15.4%	223
3,500	$256.73	$296.58	$39.86	15.5%	139
8,000	$561.60	$651.29	$89.69	16.0%	408

		Rate Yr 2	Rate Yr 3
	UOM	SC6	SC6
Customer Charge	Monthly	$ 18.70	$ 19.80
Delivery Charge All Hours kWh	kWh	$ 0.06165	$ 0.07272
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kWh	kWh	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00124	$ 0.00124
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2022 - April 30, 2023

Delivery Bill Only

PSC #120 - SC 7-1 - Non Residential Large General Service - Secondary									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 2	Rate Yr 3	Amount	Percent	# of Customers
25	20%	3,650	1,898	1,752	$460.67	$482.64	$21.98	4.8%	558
25	30%	5,475	2,847	2,628	$471.77	$493.75	$21.98	4.7%	172
25	40%	7,300	3,796	3,504	$482.88	$504.86	$21.98	4.6%	139
25	50%	9,125	4,745	4,380	$493.99	$515.96	$21.98	4.4%	79
25	60%	10,950	5,694	5,256	$505.09	$527.07	$21.98	4.4%	50
25	70%	12,775	6,643	6,132	$516.20	$538.18	$21.98	4.3%	23
25	80%	14,600	7,592	7,008	$527.31	$549.28	$21.98	4.2%	13
25	90%	16,425	8,541	7,884	$538.41	$560.39	$21.98	4.1%	11
100	20%	14,600	7,592	7,008	$1,212.97	$1,276.88	$63.91	5.3%	585
100	30%	21,900	11,388	10,512	$1,257.40	$1,321.31	$63.91	5.1%	-
100	40%	29,200	15,184	14,016	$1,301.82	$1,365.73	$63.91	4.9%	109
100	50%	36,500	18,980	17,520	$1,346.25	$1,410.16	$63.91	4.7%	82
100	60%	43,800	22,776	21,024	$1,390.67	$1,454.59	$63.91	4.6%	44
100	70%	51,100	26,572	24,528	$1,435.10	$1,499.01	$63.91	4.5%	9
100	80%	58,400	30,368	28,032	$1,479.53	$1,543.44	$63.91	4.3%	4
100	90%	65,700	34,164	31,536	$1,523.95	$1,587.86	$63.91	4.2%	9
500	20%	73,000	37,960	35,040	$5,225.25	$5,512.80	$287.55	5.5%	275
500	30%	109,500	56,940	52,560	$5,447.38	$5,734.93	$287.55	5.3%	151
500	40%	146,000	75,920	70,080	$5,669.51	$5,957.06	$287.55	5.1%	100
500	50%	182,500	94,900	87,600	$5,891.64	$6,179.20	$287.55	4.9%	62
500	60%	219,000	113,880	105,120	$6,113.78	$6,401.33	$287.55	4.7%	27
500	70%	255,500	132,860	122,640	$6,335.91	$6,623.46	$287.55	4.5%	16
500	80%	292,000	151,840	140,160	$6,558.04	$6,845.59	$287.55	4.4%	7
500	90%	328,500	170,820	157,680	$6,780.17	$7,067.72	$287.55	4.2%	-
1,000	20%	146,000	75,920	70,080	$10,240.60	$10,807.70	$567.10	5.5%	32
1,000	30%	219,000	113,880	105,120	$10,684.86	$11,251.97	$567.10	5.3%	24
1,000	40%	292,000	151,840	140,160	$11,129.13	$11,696.23	$567.10	5.1%	21
1,000	50%	365,000	189,800	175,200	$11,573.39	$12,140.49	$567.10	4.9%	-
1,000	60%	438,000	227,760	210,240	$12,017.65	$12,584.76	$567.10	4.7%	16
1,000	70%	511,000	265,720	245,280	$12,461.92	$13,029.02	$567.10	4.6%	4
1,000	80%	584,000	303,680	280,320	$12,906.18	$13,473.28	$567.10	4.4%	5
1,000	90%	657,000	341,640	315,360	$13,350.44	$13,917.55	$567.10	4.2%	9

		Rate Yr 2	Rate Yr 3
	UOM	SC7-1	SC7-1
Customer Charge	Monthly	$ 209.00	$ 217.00
Demand Charge kW	kW	$ 9.13	$ 9.69
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00768	$ 0.00768
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2022 - April 30, 2023

Delivery Bill Only

PSC #120 - SC 7-2 - Non Residential Large General Service - Primary									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 2	Rate Yr 3	Amount	Percent	# of Customers
500	20%	73,000	37,960	35,040	$5,446.86	$6,028.53	$581.67	10.7%	90
500	30%	109,500	56,940	52,560	$5,668.99	$6,250.66	$581.67	10.3%	35
500	40%	146,000	75,920	70,080	$5,891.12	$6,472.80	$581.67	9.9%	32
500	50%	182,500	94,900	87,600	$6,113.26	$6,694.93	$581.67	9.5%	27
500	60%	219,000	113,880	105,120	$6,335.39	$6,917.06	$581.67	9.2%	12
500	70%	255,500	132,860	122,640	$6,557.52	$7,139.19	$581.67	8.9%	8
500	80%	292,000	151,840	140,160	$6,779.65	$7,361.32	$581.67	8.6%	-
500	90%	328,500	170,820	157,680	$7,001.78	$7,583.45	$581.67	8.3%	-
1,000	20%	146,000	75,920	70,080	$10,162.82	$11,298.17	$1,135.34	11.2%	21
1,000	30%	219,000	113,880	105,120	$10,607.09	$11,742.43	$1,135.34	10.7%	22
1,000	40%	292,000	151,840	140,160	$11,051.35	$12,186.69	$1,135.34	10.3%	23
1,000	50%	365,000	189,800	175,200	$11,495.61	$12,630.96	$1,135.34	9.9%	-
1,000	60%	438,000	227,760	210,240	$11,939.88	$13,075.22	$1,135.34	9.5%	14
1,000	70%	511,000	265,720	245,280	$12,384.14	$13,519.48	$1,135.34	9.2%	7
1,000	80%	584,000	303,680	280,320	$12,828.40	$13,963.75	$1,135.34	8.9%	2
1,000	90%	657,000	341,640	315,360	$13,272.67	$14,408.01	$1,135.34	8.6%	1
1,500	20%	219,000	113,880	105,120	$14,878.79	$16,567.80	$1,689.01	11.4%	4
1,500	30%	328,500	170,820	157,680	$15,545.18	$17,234.19	$1,689.01	10.9%	2
1,500	40%	438,000	227,760	210,240	$16,211.58	$17,900.59	$1,689.01	10.4%	8
1,500	50%	547,500	284,700	262,800	$16,877.97	$18,566.98	$1,689.01	10.0%	8
1,500	60%	657,000	341,640	315,360	$17,544.37	$19,233.38	$1,689.01	9.6%	-
1,500	70%	766,500	398,580	367,920	$18,210.76	$19,899.77	$1,689.01	9.3%	7
1,500	80%	876,000	455,520	420,480	$18,877.16	$20,566.17	$1,689.01	8.9%	2
1,500	90%	985,500	512,460	473,040	$19,543.55	$21,232.57	$1,689.01	8.6%	-
2,500	20%	365,000	189,800	175,200	$24,310.71	$27,107.07	$2,796.36	11.5%	5
2,500	30%	547,500	284,700	262,800	$25,421.37	$28,217.72	$2,796.36	11.0%	2
2,500	40%	730,000	379,600	350,400	$26,532.03	$29,328.38	$2,796.36	10.5%	11
2,500	50%	912,500	474,500	438,000	$27,642.68	$30,439.04	$2,796.36	10.1%	12
2,500	60%	1,095,000	569,400	525,600	$28,753.34	$31,549.70	$2,796.36	9.7%	-
2,500	70%	1,277,500	664,300	613,200	$29,864.00	$32,660.36	$2,796.36	9.4%	1
2,500	80%	1,460,000	759,200	700,800	$30,974.66	$33,771.02	$2,796.36	9.0%	3
2,500	90%	1,642,500	854,100	788,400	$32,085.32	$34,881.68	$2,796.36	8.7%	5

		Rate Yr 2	Rate Yr 3
	UOM	SC7-2	SC7-2
Customer Charge	Monthly	$ 730.00	$ 758.00
Demand Charge kW	kW	$ 8.53	$ 9.64
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00858	$ 0.00858
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2022 - April 30, 2023

Delivery Bill Only

PSC #120 - SC 7-3 - Non Residential Large General Service - SubTransmission

Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 2	Rate Yr 3	increase / (decrease) Amount	Percent	# of Customers
500	20%	73,000	37,960	35,040	$3,077.37	$3,236.73	$159.36	5.2%	18
500	30%	109,500	56,940	52,560	$3,299.50	$3,458.86	$159.36	4.8%	9
500	40%	146,000	75,920	70,080	$3,521.63	$3,680.99	$159.36	4.5%	7
500	50%	182,500	94,900	87,600	$3,743.76	$3,903.12	$159.36	4.3%	6
500	60%	219,000	113,880	105,120	$3,965.89	$4,125.26	$159.36	4.0%	2
500	70%	255,500	132,860	122,640	$4,188.02	$4,347.39	$159.36	3.8%	2
500	80%	292,000	151,840	140,160	$4,410.16	$4,569.52	$159.36	3.6%	-
500	90%	328,500	170,820	157,680	$4,632.29	$4,791.65	$159.36	3.4%	-
2,000	20%	292,000	151,840	140,160	$7,746.77	$8,207.22	$460.45	5.9%	32
2,000	30%	438,000	227,760	210,240	$8,635.29	$9,095.74	$460.45	5.3%	-
2,000	40%	584,000	303,680	280,320	$9,523.82	$9,984.27	$460.45	4.8%	11
2,000	50%	730,000	379,600	350,400	$10,412.35	$10,872.80	$460.45	4.4%	6
2,000	60%	876,000	455,520	420,480	$11,300.87	$11,761.33	$460.45	4.1%	4
2,000	70%	1,022,000	531,440	490,560	$12,189.40	$12,649.85	$460.45	3.8%	2
2,000	80%	1,168,000	607,360	560,640	$13,077.93	$13,538.38	$460.45	3.5%	-
2,000	90%	1,314,000	683,280	630,720	$13,966.45	$14,426.91	$460.45	3.3%	-
4,000	20%	584,000	303,680	280,320	$13,972.63	$14,834.54	$861.90	6.2%	2
4,000	30%	876,000	455,520	420,480	$15,749.69	$16,611.59	$861.90	5.5%	10
4,000	40%	1,168,000	607,360	560,640	$17,526.74	$18,388.64	$861.90	4.9%	4
4,000	50%	1,460,000	759,200	700,800	$19,303.80	$20,165.70	$861.90	4.5%	-
4,000	60%	1,752,000	911,040	840,960	$21,080.85	$21,942.75	$861.90	4.1%	6
4,000	70%	2,044,000	1,062,880	981,120	$22,857.90	$23,719.80	$861.90	3.8%	4
4,000	80%	2,336,000	1,214,720	1,121,280	$24,634.96	$25,496.86	$861.90	3.5%	-
4,000	90%	2,628,000	1,366,560	1,261,440	$26,412.01	$27,273.91	$861.90	3.3%	-
5,000	20%	730,000	379,600	350,400	$17,085.57	$18,148.20	$1,062.63	6.2%	-
5,000	30%	1,095,000	569,400	525,600	$19,306.89	$20,369.51	$1,062.63	5.5%	-
5,000	40%	1,460,000	759,200	700,800	$21,528.20	$22,590.83	$1,062.63	4.9%	-
5,000	50%	1,825,000	949,000	876,000	$23,749.52	$24,812.15	$1,062.63	4.5%	1
5,000	60%	2,190,000	1,138,800	1,051,200	$25,970.84	$27,033.46	$1,062.63	4.1%	1
5,000	70%	2,555,000	1,328,600	1,226,400	$28,192.15	$29,254.78	$1,062.63	3.8%	3
5,000	80%	2,920,000	1,518,400	1,401,600	$30,413.47	$31,476.10	$1,062.63	3.5%	-
5,000	90%	3,285,000	1,708,200	1,576,800	$32,634.79	$33,697.41	$1,062.63	3.3%	5

	UOM	Rate Yr 2 SC7-3	Rate Yr 3 SC7-3
Customer Charge	Monthly	$ 1,520.00	$ 1,579.00
Demand Charge kW	kW	$ 2.22	$ 2.42
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00536	$ 0.00536
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2022 - April 30, 2023

Delivery Bill Only

PSC #120 - SC 7-4 - Non Residential Large General Service - Transmission									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 2	Rate Yr 3	Amount	Percent	# of Customers
1,000	20%	146,000	75,920	70,080	$5,236.86	$5,790.55	$553.69	10.6%	1
1,000	30%	219,000	113,880	105,120	$5,681.12	$6,234.81	$553.69	9.7%	-
1,000	40%	292,000	151,840	140,160	$6,125.38	$6,679.07	$553.69	9.0%	2
1,000	50%	365,000	189,800	175,200	$6,569.65	$7,123.34	$553.69	8.4%	-
1,000	60%	438,000	227,760	210,240	$7,013.91	$7,567.60	$553.69	7.9%	-
1,000	70%	511,000	265,720	245,280	$7,458.17	$8,011.86	$553.69	7.4%	-
1,000	80%	584,000	303,680	280,320	$7,902.44	$8,456.13	$553.69	7.0%	-
1,000	90%	657,000	341,640	315,360	$8,346.70	$8,900.39	$553.69	6.6%	-
7,500	20%	1,095,000	569,400	525,600	$19,770.57	$22,623.26	$2,852.69	14.4%	5
7,500	30%	1,642,500	854,100	788,400	$23,102.54	$25,955.24	$2,852.69	12.3%	-
7,500	40%	2,190,000	1,138,800	1,051,200	$26,434.52	$29,287.21	$2,852.69	10.8%	1
7,500	50%	2,737,500	1,423,500	1,314,000	$29,766.49	$32,619.19	$2,852.69	9.6%	1
7,500	60%	3,285,000	1,708,200	1,576,800	$33,098.47	$35,951.16	$2,852.69	8.6%	-
7,500	70%	3,832,500	1,992,900	1,839,600	$36,430.44	$39,283.14	$2,852.69	7.8%	1
7,500	80%	4,380,000	2,277,600	2,102,400	$39,762.42	$42,615.11	$2,852.69	7.2%	-
7,500	90%	4,927,500	2,562,300	2,365,200	$43,094.40	$45,947.09	$2,852.69	6.6%	-
15,000	20%	2,190,000	1,138,800	1,051,200	$36,540.24	$42,045.62	$5,505.39	15.1%	1
15,000	30%	3,285,000	1,708,200	1,576,800	$43,204.19	$48,709.57	$5,505.39	12.7%	-
15,000	40%	4,380,000	2,277,600	2,102,400	$49,868.14	$55,373.52	$5,505.39	11.0%	1
15,000	50%	5,475,000	2,847,000	2,628,000	$56,532.09	$62,037.48	$5,505.39	9.7%	-
15,000	60%	6,570,000	3,416,400	3,153,600	$63,196.04	$68,701.43	$5,505.39	8.7%	-
15,000	70%	7,665,000	3,985,800	3,679,200	$69,859.99	$75,365.38	$5,505.39	7.9%	2
15,000	80%	8,760,000	4,555,200	4,204,800	$76,523.94	$82,029.33	$5,505.39	7.2%	1
15,000	90%	9,855,000	5,124,600	4,730,400	$83,187.89	$88,693.28	$5,505.39	6.6%	-
50,000	20%	7,300,000	3,796,000	3,504,000	$114,798.68	$132,683.31	$17,884.62	15.6%	-
50,000	30%	10,950,000	5,694,000	5,256,000	$137,011.85	$154,896.48	$17,884.62	13.1%	1
50,000	40%	14,600,000	7,592,000	7,008,000	$159,225.02	$177,109.65	$17,884.62	11.2%	-
50,000	50%	18,250,000	9,490,000	8,760,000	$181,438.19	$199,322.82	$17,884.62	9.9%	-
50,000	60%	21,900,000	11,388,000	10,512,000	$203,651.36	$221,535.99	$17,884.62	8.8%	-
50,000	70%	25,550,000	13,286,000	12,264,000	$225,864.53	$243,749.16	$17,884.62	7.9%	-
50,000	80%	29,200,000	15,184,000	14,016,000	$248,077.70	$265,962.33	$17,884.62	7.2%	1
50,000	90%	32,850,000	17,082,000	15,768,000	$270,290.87	$288,175.50	$17,884.62	6.6%	-

		Rate Yr 2	Rate Yr 3
	UOM	SC7-4	SC7-4
Customer Charge	Monthly	$ 3,000.00	$ 3,200.00
Demand Charge kW	kW	$ 1.34	$ 1.70
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00123	$ 0.00123
Transition Charge per kW	kW	$ 0.00515	$ 0.00515
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

New York State Electric & Gas Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2022 - April 30, 2023

Delivery Bill Only

PSC #120 - SC 9 - Non Residential - Day/Night							
					increase / (decrease)		
kWh	Peak	Off Peak	Rate Yr 2	Rate Yr 3	Amount	Percent	# of Customers
300	180	120	$39.66	$43.41	$3.75	9.5%	686
400	240	160	$45.35	$49.92	$4.57	10.1%	214
500	300	200	$51.04	$56.42	$5.38	10.5%	185
600	360	240	$56.73	$62.93	$6.20	10.9%	192
700	420	280	$62.42	$69.43	$7.02	11.2%	171
800	480	320	$68.11	$75.94	$7.83	11.5%	141
900	540	360	$73.79	$82.44	$8.65	11.7%	126
1,000	600	400	$79.48	$88.95	$9.47	11.9%	83
1,100	660	440	$85.17	$95.45	$10.28	12.1%	91
1,200	720	480	$90.86	$101.96	$11.10	12.2%	64
1,500	900	600	$107.92	$121.47	$13.55	12.6%	162
2,000	1,200	800	$136.37	$154.00	$17.63	12.9%	159
2,500	1,500	1,000	$164.81	$186.52	$21.71	13.2%	83
3,000	1,800	1,200	$193.25	$219.05	$25.80	13.3%	47
3,500	2,100	1,400	$221.69	$251.57	$29.88	13.5%	24
5,000	3,000	2,000	$307.02	$349.14	$42.13	13.7%	26

		Rate Yr 2	Rate Yr 3
	UOM	SC9	SC9
Customer Charge	Monthly	$ 21.70	$ 23.00
Delivery Charge On Peak kWh	kWh-On	$ 0.05078	$ 0.05895
Delivery Charge Off Peak kWh	kWh-Off	$ 0.05078	$ 0.05895
SBC (EEtr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00486	$ 0.00486
RAM per kWh	kWh	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ 0.00124	$ 0.00124
Billing Charge per Bill	Monthly	$ 0.90	$ 0.90

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Electric Rates
Standby Bill Impacts by SC
May 1, 2022 - April 30, 2023

		Rate Yr 2		Rate Yr 3		Increase (000)	% Increase or Decrease
Customer Charge							
SC 2	$	1.4	$	1.6	$	0.2	15.18%
SC 3P	$	8.6	$	9.9	$	1.3	15.13%
SC 3S	$	9.4	$	10.8	$	1.4	14.93%
SC 7-1	$	10.0	$	10.4	$	0.4	3.83%
SC 7-2	$	70.1	$	72.8	$	2.7	3.84%
SC 7-3	$	36.5	$	37.9	$	1.4	3.88%
SC 7-4	$	144.0	$	153.6	$	9.6	6.67%
	$	279.9	$	296.9	$	17.0	6.07%
Contract Demand							
SC 2	$	89.1	$	96.9	$	7.8	8.72%
SC 3P	$	63.5	$	73.0	$	9.5	14.89%
SC 3S	$	3.6	$	3.5	$	(0.0)	-0.74%
SC 7-1	$	128.0	$	135.7	$	7.7	6.02%
SC 7-2	$	683.6	$	773.5	$	89.9	13.15%
SC 7-3	$	6.1	$	6.7	$	0.6	9.39%
SC 7-4	$	75.4	$	95.3	$	19.8	26.30%
	$	1,049.3	$	1,184.4	$	135.2	12.88%
Daily As-Used Demand							
SC 2	$	50.0	$	54.4	$	4.4	8.72%
SC 3P	$	15.0	$	17.3	$	2.2	14.89%
SC 3S	$	0.3	$	0.3	$	(0.0)	-0.74%
SC 7-1	$	64.6	$	68.4	$	3.9	6.02%
SC 7-2	$	360.9	$	408.4	$	47.5	13.15%
SC 7-3	$	0.2	$	0.2	$	0.0	9.39%
SC 7-4	$	63.9	$	80.7	$	16.8	26.30%
	$	555.0	$	629.7	$	74.8	13.47%
Total							
SC 2	$	140.5	$	152.8	$	12.3	8.79%
SC 3P	$	87.1	$	100.1	$	13.0	14.91%
SC 3S	$	13.3	$	14.6	$	1.4	10.36%
SC 7-1	$	202.5	$	214.5	$	12.0	5.91%
SC 7-2	$	1,114.6	$	1,254.6	$	140.0	12.56%
SC 7-3	$	42.8	$	44.8	$	2.0	4.69%
SC 7-4	$	283.4	$	329.6	$	46.2	16.32%
	$	1,884.2	$	2,111.1	$	226.9	12.04%

New York State Electric & Gas Corporation		
Date Sources - NYSEG Electric Bill Impact Statements		
Rate	**Source of Rate in "Current" Rates**	**Source of Rate in Rate Years**
Customer Charge	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
kW Charge	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
kWh Delivery Charge All Hours	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
kWh Delivery Charge On Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
kWh Delivery Charge Mid Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
kWh Delivery Charge Off Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
Reactive RkVah	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
Billing Charge per Bill	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2019)	New
SBC (EEtr) per kWh	Current Tariff Rates in Effect 01/01/2020 - (SBC Statement #19)	Included in Delivery Rates
SBC (CEF) per kWh	Current Tariff Rates in Effect 01/01/2020 - (SBC Statement #19)	Current Tariff Rates in Effect 01/01/2020 - (SBC Statement #19)
RAM per kWh	Current Tariff Rates in Effect 07/19/2019 - (RAM Statement #1)	No RAM forecasted. COVID Bill Credits begin 7/1/2021.
RAM per kW	Current Tariff Rates in Effect 07/19/2019 - (RAM Statement #1)	No RAM forecasted. COVID Bill Credits begin 7/1/2021.
Tax Credit per kWh	Case No. 17-M-0815 dated August 9, 2018. Statement Number 1 Effective 10/01/2018	Included in Delivery Rates
Tax Credit per kW	Case No. 17-M-0815 dated August 9, 2018. Statement Number 1 Effective 10/01/2018	Included in Delivery Rates
Rate	**Source of Rate in "Current" Rates and Rate Years**	
Transition Charge per kWh	NBC, Demand Response, and Value Stack: NBC is the Non-Weighted 2019 Average, Dmd Rsp is 05/01/2020 rate, Value Stack at $-0-. RAM is separate.	
MFC per kWh	Current Tariff Rates in Effect 05/01/2020	
kWh Supply Charge All Hours	2019 Annualized Supply Rates	
kWh Supply Charge On Peak	2019 Annualized Supply Rates	
kWh Supply Charge Mid Peak	2019 Annualized Supply Rates	
kWh Supply Charge Off Peak	2019 Annualized Supply Rates	
Customer Count	2018 monthly data - separate Low Income counts	

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2020 - April 30, 2021

Including Supply

PSC #19 - SC 1 - Residential

kWh	Current Rates	Rate Yr 1	increase / (decrease) Amount	Percent	# of Customers	# of Low Income Customers	Percent of Customers	Percent of Low Income Customers
100	$31.02	$31.25	$0.23	0.8%	10,907	539	3%	1%
200	$39.93	$40.19	$0.26	0.7%	25,369	2,787	7%	8%
300	$48.85	$49.14	$0.29	0.6%	33,669	4,537	10%	12%
400	$57.77	$58.08	$0.31	0.5%	37,090	5,036	11%	14%
500	$66.68	$67.03	$0.34	0.5%	38,010	4,932	11%	13%
600	$75.60	$75.97	$0.37	0.5%	35,693	4,208	11%	11%
700	$84.52	$84.92	$0.40	0.5%	31,811	3,427	9%	9%
800	$93.44	$93.86	$0.42	0.5%	27,030	2,744	8%	7%
900	$102.35	$102.80	$0.45	0.4%	22,238	2,191	7%	6%
1,000	$111.27	$111.75	$0.48	0.4%	17,500	1,598	5%	4%
1,100	$120.19	$120.69	$0.51	0.4%	13,667	1,211	4%	3%
1,200	$129.10	$129.64	$0.53	0.4%	10,434	907	3%	2%
1,500	$155.85	$156.47	$0.61	0.4%	18,454	1,568	5%	4%
2,000	$200.44	$201.19	$0.75	0.4%	11,052	901	3%	2%
3,000	$289.61	$290.63	$1.02	0.4%	5,347	334	2%	1%
					338,269	36,919		

Amount of EE Embedded in Delivery Rates*

Amount	Percent
$ 0.08	0.25%
$ 0.15	0.38%
$ 0.23	0.47%
$ 0.31	0.53%
$ 0.39	0.57%
$ 0.46	0.61%
$ 0.54	0.63%
$ 0.62	0.66%
$ 0.69	0.67%
$ 0.77	0.69%
$ 0.85	0.70%
$ 0.92	0.71%
$ 1.16	0.74%
$ 1.54	0.77%
$ 2.31	0.79%

	UOM	Current Rates SC01	Rate Yr 1 SC01
Customer Charge	Monthly	$ 21.38	$ 21.38
Delivery Charge All Hours kWh	kWh	$ 0.04645	$ 0.04569
SBC (EETr) per kWh	kWh	$ 0.00105	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kWh	kWh	$ 0.00218	$ -
Tax Credit All Hours kWh	kWh	$ (0.00426)	$ -
Transition Charge per kWh	kWh	$ (0.00206)	$ (0.00206)
Billing Charge per Bill	Monthly	$ 0.72	$ 0.93
Supply Charge All Hours kWh	kWh	$ 0.03736	$ 0.03736
MFC per kWh	kWh	$ 0.00309	$ 0.00309

Includes $ 0.00077 per kWh of EE Costs*

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Low income customers represent customers who participated in the Company's low income program and received a credit on their bill each month during calendar year 2018.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2020 - April 30, 2021

Including Supply

PSC #19 - SC 2 - General Service - Non Demand					
			increase / (decrease)		# of
kWh	Current Rates	Rate Yr 1	Amount	Percent	Customers
300	$46.91	$47.00	$0.09	0.2%	11,999
400	$55.18	$55.24	$0.05	0.1%	2,601
500	$63.45	$63.47	$0.02	0.0%	2,299
600	$71.72	$71.70	($0.02)	0.0%	1,892
700	$79.99	$79.93	($0.06)	-0.1%	1,541
800	$88.26	$88.17	($0.10)	-0.1%	1,322
900	$96.53	$96.40	($0.13)	-0.1%	1,021
1,000	$104.80	$104.63	($0.17)	-0.2%	904
1,500	$146.16	$145.79	($0.36)	-0.2%	2,999
2,000	$187.51	$186.96	($0.55)	-0.3%	1,654
2,500	$228.86	$228.12	($0.74)	-0.3%	845
3,000	$270.21	$269.28	($0.93)	-0.3%	385
4,000	$352.92	$351.61	($1.31)	-0.4%	203
5,000	$435.62	$433.94	($1.69)	-0.4%	60
6,000	$518.33	$516.26	($2.07)	-0.4%	21
7,000	$601.03	$598.59	($2.45)	-0.4%	59

		Current Rates	Rate Yr 1
	UOM	SC02	SC02
Customer Charge	Monthly	$ 21.38	$ 21.38
Delivery Charge All Hours kWh	kWh	$ 0.03712	$ 0.03592
SBC (EETr) per kWh	kWh	$ 0.00105	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kWh	kWh	$ 0.00194	$ -
Tax Credit All Hours kWh	kWh	$ (0.00381)	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Billing Charge per Bill	Monthly	$ 0.72	$ 0.93
Supply Charge All Hours kWh	kWh	$ 0.03819	$ 0.03819
MFC per kWh	kWh	$ 0.00309	$ 0.00309

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2020 - April 30, 2021

Including Supply

PSC #19 - SC 3 - General Service - Demand

Kw	Load Factor	kWh	Current Rates	Rate Yr 1	increase / (decrease) Amount	Percent	# of Customers
50	20%	7,300	$1,449.60	$1,447.90	($1.70)	-0.1%	45
50	30%	10,950	$1,599.86	$1,594.32	($5.54)	-0.3%	19
50	40%	14,600	$1,750.13	$1,740.74	($9.39)	-0.5%	18
50	50%	18,250	$1,900.39	$1,887.17	($13.23)	-0.7%	18
50	60%	21,900	$2,050.66	$2,033.59	($17.07)	-0.8%	1
50	70%	25,550	$2,200.93	$2,180.01	($20.92)	-1.0%	3
50	80%	29,200	$2,351.19	$2,326.43	($24.76)	-1.1%	3
50	90%	32,850	$2,501.46	$2,472.85	($28.60)	-1.1%	2
100	20%	14,600	$2,601.35	$2,597.74	($3.60)	-0.1%	43
100	30%	21,900	$2,901.88	$2,890.59	($11.29)	-0.4%	73
100	40%	29,200	$3,202.41	$3,183.43	($18.98)	-0.6%	122
100	50%	36,500	$3,502.94	$3,476.27	($26.66)	-0.8%	115
100	60%	43,800	$3,803.47	$3,769.12	($34.35)	-0.9%	47
100	70%	51,100	$4,104.00	$4,061.96	($42.04)	-1.0%	32
100	80%	58,400	$4,404.53	$4,354.81	($49.73)	-1.1%	9
100	90%	65,700	$4,705.06	$4,647.65	($57.41)	-1.2%	6
275	20%	40,150	$6,632.46	$6,622.19	($10.27)	-0.2%	146
275	30%	60,225	$7,458.92	$7,427.51	($31.41)	-0.4%	223
275	40%	80,300	$8,285.38	$8,232.83	($52.55)	-0.6%	130
275	50%	100,375	$9,111.84	$9,038.16	($73.69)	-0.8%	69
275	60%	120,450	$9,938.31	$9,843.48	($94.83)	-1.0%	24
275	70%	140,525	$10,764.77	$10,648.80	($115.97)	-1.1%	8
275	80%	160,600	$11,591.23	$11,454.12	($137.10)	-1.2%	2
275	90%	180,675	$12,417.69	$12,259.44	($158.24)	-1.3%	2
300	20%	43,800	$7,208.34	$7,197.11	($11.22)	-0.2%	-
300	30%	65,700	$8,109.93	$8,075.64	($34.28)	-0.4%	2
300	40%	87,600	$9,011.52	$8,954.18	($57.34)	-0.6%	2
300	50%	109,500	$9,913.12	$9,832.71	($80.41)	-0.8%	3
300	60%	131,400	$10,814.71	$10,711.24	($103.47)	-1.0%	-
300	70%	153,300	$11,716.30	$11,589.78	($126.53)	-1.1%	2
300	80%	175,200	$12,617.90	$12,468.31	($149.59)	-1.2%	2
300	90%	197,100	$13,519.49	$13,346.84	($172.65)	-1.3%	3

	UOM	Current Rates SC03	Rate Yr 1 SC03
Customer Charge	Monthly	$ 297.13	$ 297.13
Demand Charge kW	kW	$ 17.57	$ 17.14
SBC (EETr) per kWh	kWh	$ 0.00105	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ 0.56433	$ -
Tax Credit per kW	kW	$ (1.11000)	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.72	$ 0.93
Supply Charge All Hours kWh	kWh	$ 0.03293	$ 0.03293
MFC per kWh	kWh	$ 0.00206	$ 0.00206

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2020 - April 30, 2021

Including Supply

PSC #19 - SC 4-I - Residential - Day/Night							
					increase / (decrease)		
kWh	Peak	Off Peak	Current Rates	Rate Yr 1	Amount	Percent	# of Customers
300	210	90	52.80	52.40	(0.40)	-0.8%	126
400	280	120	61.71	61.10	(0.61)	-1.0%	91
500	350	150	70.61	69.80	(0.81)	-1.1%	104
600	420	180	79.52	78.50	(1.01)	-1.3%	131
700	490	210	88.42	87.21	(1.22)	-1.4%	172
800	560	240	97.33	95.91	(1.42)	-1.5%	191
900	630	270	106.24	104.61	(1.62)	-1.5%	145
1,000	700	300	115.14	113.32	(1.83)	-1.6%	157
1,500	1,050	450	159.67	156.83	(2.84)	-1.8%	589
2,000	1,400	600	204.21	200.35	(3.86)	-1.9%	302
2,500	1,750	750	248.74	243.86	(4.87)	-2.0%	149
3,000	2,100	900	293.27	287.38	(5.89)	-2.0%	61
4,000	2,800	1,200	382.33	374.41	(7.92)	-2.1%	26
5,000	3,500	1,500	471.39	461.44	(9.95)	-2.1%	11
6,000	4,200	1,800	560.46	548.47	(11.98)	-2.1%	1
7,000	4,900	2,100	649.52	635.51	(14.01)	-2.2%	5

	UOM	Current Rates SC04-I	Rate Yr 1 SC04-I
Customer Charge	Monthly	$ 25.36	$ 25.36
Delivery Charge On Peak kWh	kWh-On	$ 0.04792	$ 0.04486
Delivery Charge Off Peak kWh	kWh-Off	$ 0.04792	$ 0.04486
SBC (EETr) per kWh	kWh	$ 0.00105	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kWh	kWh	$ 0.00213	$ -
Tax Credit All Hours kWh	kWh	$ (0.00422)	$ -
Transition Charge per kWh	kWh	$ (0.00206)	$ (0.00206)
Billing Charge per Bill	Monthly	$ 0.72	$ 0.93
Supply Charge On Peak kWh	kWh-On	$ 0.04005	$ 0.04005
Supply Charge Off Peak kWh	kWh-Off	$ 0.02742	$ 0.02742
MFC per kWh	kWh	$ 0.00261	$ 0.00261

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2020 - April 30, 2021

Including Supply

PSC #19 - SC 4-II - Residential - Day/Night

kWh	Peak	Off Peak	Current Rates	Rate Yr 1	increase / (decrease) Amount	Percent	# of Customers
300	210	90	$59.41	$59.02	($0.40)	-0.7%	18
400	280	120	$69.37	$68.77	($0.60)	-0.9%	9
500	350	150	$79.32	$78.52	($0.80)	-1.0%	15
600	420	180	$89.27	$88.27	($1.00)	-1.1%	28
700	490	210	$99.22	$98.02	($1.20)	-1.2%	29
800	560	240	$109.17	$107.77	($1.40)	-1.3%	38
900	630	270	$119.12	$117.52	($1.60)	-1.3%	33
1,000	700	300	$129.07	$127.27	($1.80)	-1.4%	52
1,500	1,050	450	$178.83	$176.03	($2.80)	-1.6%	238
2,000	1,400	600	$228.59	$224.78	($3.80)	-1.7%	190
2,500	1,750	750	$278.34	$273.54	($4.81)	-1.7%	165
3,000	2,100	900	$328.10	$322.29	($5.81)	-1.8%	83
4,000	2,800	1,200	$427.61	$419.80	($7.81)	-1.8%	84
5,000	3,500	1,500	$527.12	$517.31	($9.82)	-1.9%	49
6,000	4,200	1,800	$626.64	$614.81	($11.82)	-1.9%	33
7,000	4,900	2,100	$726.15	$712.32	($13.83)	-1.9%	28

	UOM	Current Rates SC04-II	Rate Yr 1 SC04-II
Customer Charge	Monthly	$ 28.84	$ 28.84
Delivery Charge On Peak kWh	kWh-On	$ 0.05823	$ 0.05533
Delivery Charge Off Peak kWh	kWh-Off	$ 0.05823	$ 0.05533
SBC (EETr) per kWh	kWh	$ 0.00105	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kWh	kWh	$ 0.00213	$ -
Tax Credit All Hours kWh	kWh	$ (0.00408)	$ -
Transition Charge per kWh	kWh	$ (0.00206)	$ (0.00206)
Billing Charge per Bill	Monthly	$ 0.72	$ 0.93
Supply Charge On Peak kWh	kWh-On	$ 0.04005	$ 0.04005
Supply Charge Off Peak kWh	kWh-Off	$ 0.02742	$ 0.02742
MFC per kWh	kWh	$ 0.00261	$ 0.00261

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2020 - April 30, 2021

Including Supply

PSC #19 - SC 7 - General Service - Demand							
					increase / (decrease)		
Kw	Load Factor	kWh	Current Rates	Rate Yr 1	Amount	Percent	# of Customers
5	20%	730	$210.50	$210.73	$0.24	0.1%	178
5	30%	1,095	$228.59	$227.83	($0.75)	-0.3%	51
5	40%	1,460	$246.67	$244.93	($1.75)	-0.7%	36
5	50%	1,825	$264.76	$262.02	($2.74)	-1.0%	34
5	60%	2,190	$282.85	$279.12	($3.73)	-1.3%	16
5	70%	2,555	$300.93	$296.21	($4.72)	-1.6%	14
5	80%	2,920	$319.02	$313.31	($5.71)	-1.8%	6
5	90%	3,285	$337.11	$330.40	($6.70)	-2.0%	6
25	20%	3,650	$694.53	$694.89	$0.36	0.1%	2,778
25	30%	5,475	$784.97	$780.37	($4.60)	-0.6%	1,673
25	40%	7,300	$875.40	$865.85	($9.55)	-1.1%	888
25	50%	9,125	$965.83	$951.32	($14.51)	-1.5%	403
25	60%	10,950	$1,056.27	$1,036.80	($19.46)	-1.8%	155
25	70%	12,775	$1,146.70	$1,122.28	($24.42)	-2.1%	46
25	80%	14,600	$1,237.13	$1,207.76	($29.37)	-2.4%	12
25	90%	16,425	$1,327.57	$1,293.24	($34.33)	-2.6%	7
100	20%	14,600	$2,509.66	$2,510.47	$0.81	0.0%	1,560
100	30%	21,900	$2,871.39	$2,852.38	($19.01)	-0.7%	618
100	40%	29,200	$3,233.13	$3,194.30	($38.83)	-1.2%	240
100	50%	36,500	$3,594.86	$3,536.21	($58.65)	-1.6%	74
100	60%	43,800	$3,956.59	$3,878.13	($78.47)	-2.0%	44
100	70%	51,100	$4,318.33	$4,220.04	($98.29)	-2.3%	8
100	80%	58,400	$4,680.06	$4,561.96	($118.11)	-2.5%	3
100	90%	65,700	$5,041.80	$4,903.87	($137.93)	-2.7%	2
250	20%	36,500	$6,139.91	$6,141.62	$1.72	0.0%	19
250	30%	54,750	$7,044.24	$6,996.41	($47.83)	-0.7%	15
250	40%	73,000	$7,948.58	$7,851.20	($97.38)	-1.2%	5
250	50%	91,250	$8,852.91	$8,705.98	($146.93)	-1.7%	2
250	60%	109,500	$9,757.25	$9,560.77	($196.48)	-2.0%	-
250	70%	127,750	$10,661.59	$10,415.56	($246.03)	-2.3%	1
250	80%	146,000	$11,565.92	$11,270.35	($295.58)	-2.6%	-
250	90%	164,250	$12,470.26	$12,125.13	($345.13)	-2.8%	-

	UOM	Current Rates SC07	Rate Yr 1 SC07
Customer Charge	Monthly	$ 88.77	$ 88.77
Demand Charge kW	kW	$ 17.42	$ 17.37
Delivery Charge All Hours kWh	kWh	$ 0.00887	$ 0.00665
SBC (EETr) per kWh	kWh	$ 0.00105	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ 0.66698	$ -
Tax Credit All Hours kWh	kWh	$ (0.00056)	$ -
Tax Credit per kW	kW	$ (1.12000)	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.72	$ 0.93
Supply Charge All Hours kWh	kWh	$ 0.03301	$ 0.03301
MFC per kWh	kWh	$ 0.00206	$ 0.00206

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2020 - April 30, 2021

Including Supply

PSC #19 - SC 8 - Large General Service - Transmission

Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Current Rates	Rate Yr 1	increase / (decrease) Amount	Percent	# of Customers
6,000	20%	876,000	455,520	420,480	$92,090.03	$91,926.10	($163.93)	-0.2%	-
6,000	30%	1,314,000	683,280	630,720	$109,191.14	$108,566.00	($625.14)	-0.6%	-
6,000	40%	1,752,000	911,040	840,960	$126,292.24	$125,205.89	($1,086.35)	-0.9%	-
6,000	50%	2,190,000	1,138,800	1,051,200	$143,393.35	$141,845.78	($1,547.57)	-1.1%	-
6,000	60%	2,628,000	1,366,560	1,261,440	$160,494.46	$158,485.68	($2,008.78)	-1.3%	-
6,000	70%	3,066,000	1,594,320	1,471,680	$177,595.57	$175,125.57	($2,470.00)	-1.4%	-
6,000	80%	3,504,000	1,822,080	1,681,920	$194,696.68	$191,765.47	($2,931.21)	-1.5%	-
6,000	90%	3,942,000	2,049,840	1,892,160	$211,797.79	$208,405.36	($3,392.42)	-1.6%	-
7,000	20%	1,022,000	531,440	490,560	$106,820.96	$106,580.30	($240.66)	-0.2%	-
7,000	30%	1,533,000	797,160	735,840	$126,772.25	$125,993.51	($778.74)	-0.6%	-
7,000	40%	2,044,000	1,062,880	981,120	$146,723.54	$145,406.72	($1,316.83)	-0.9%	-
7,000	50%	2,555,000	1,328,600	1,226,400	$166,674.84	$164,819.93	($1,854.91)	-1.1%	-
7,000	60%	3,066,000	1,594,320	1,471,680	$186,626.13	$184,233.14	($2,392.99)	-1.3%	1
7,000	70%	3,577,000	1,860,040	1,716,960	$206,577.42	$203,646.35	($2,931.07)	-1.4%	-
7,000	80%	4,088,000	2,125,760	1,962,240	$226,528.72	$223,059.56	($3,469.16)	-1.5%	-
7,000	90%	4,599,000	2,391,480	2,207,520	$246,480.01	$242,472.77	($4,007.24)	-1.6%	-
8,000	20%	1,168,000	607,360	560,640	$121,551.89	$121,234.49	($317.39)	-0.3%	-
8,000	30%	1,752,000	911,040	840,960	$144,353.36	$143,421.02	($932.34)	-0.6%	-
8,000	40%	2,336,000	1,214,720	1,121,280	$167,154.84	$165,607.55	($1,547.30)	-0.9%	-
8,000	50%	2,920,000	1,518,400	1,401,600	$189,956.32	$187,794.07	($2,162.25)	-1.1%	-
8,000	60%	3,504,000	1,822,080	1,681,920	$212,757.80	$209,980.60	($2,777.20)	-1.3%	-
8,000	70%	4,088,000	2,125,760	1,962,240	$235,559.28	$232,167.12	($3,392.15)	-1.4%	-
8,000	80%	4,672,000	2,429,440	2,242,560	$258,360.75	$254,353.65	($4,007.10)	-1.6%	-
8,000	90%	5,256,000	2,733,120	2,522,880	$281,162.23	$276,540.18	($4,622.06)	-1.6%	-
9,000	20%	1,314,000	683,280	630,720	$136,282.82	$135,888.69	($394.13)	-0.3%	-
9,000	30%	1,971,000	1,024,920	946,080	$161,934.48	$160,848.53	($1,085.95)	-0.7%	-
9,000	40%	2,628,000	1,366,560	1,261,440	$187,586.14	$185,808.37	($1,777.77)	-0.9%	-
9,000	50%	3,285,000	1,708,200	1,576,800	$213,237.80	$210,768.21	($2,469.59)	-1.2%	-
9,000	60%	3,942,000	2,049,840	1,892,160	$238,889.47	$235,728.06	($3,161.41)	-1.3%	-
9,000	70%	4,599,000	2,391,480	2,207,520	$264,541.13	$260,687.90	($3,853.23)	-1.5%	-
9,000	80%	5,256,000	2,733,120	2,522,880	$290,192.79	$285,647.74	($4,545.05)	-1.6%	-
9,000	90%	5,913,000	3,074,760	2,838,240	$315,844.45	$310,607.58	($5,236.87)	-1.7%	-

	UOM	Current Rates SC08Trn	Rate Yr 1 SC08Trn
Customer Charge	Monthly	$ 3,703.73	$ 4,000.00
Demand Charge kW	kW	$ 9.31	$ 9.11
SBC (EETr) per kWh	kWh	$ 0.00105	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ 0.29056	$ -
Tax Credit per kW	kW	$ (0.57000)	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.72	$ 0.93
Supply Charge On Peak kWh	kWh-On	$ 0.03594	$ 0.03594
Supply Charge Off Peak kWh	kWh-Off	$ 0.02525	$ 0.02525
MFC per kWh	kWh	$ 0.00206	$ 0.00206

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2020 - April 30, 2021

Including Supply

PSC #19 - SC 8 - Large General Service - SubTransmission - Industrial									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Current Rates	Rate Yr 1	Amount	Percent	# of Customers
500	20%	73,000	37,960	35,040	$9,676.79	$10,013.51	$336.72	3.5%	1
500	30%	109,500	56,940	52,560	$11,101.88	$11,400.16	$298.28	2.7%	4
500	40%	146,000	75,920	70,080	$12,526.97	$12,786.82	$259.85	2.1%	2
500	50%	182,500	94,900	87,600	$13,952.07	$14,173.48	$221.41	1.6%	2
500	60%	219,000	113,880	105,120	$15,377.16	$15,560.14	$182.98	1.2%	-
500	70%	255,500	132,860	122,640	$16,802.25	$16,946.80	$144.54	0.9%	2
500	80%	292,000	151,840	140,160	$18,227.34	$18,333.45	$106.11	0.6%	-
500	90%	328,500	170,820	157,680	$19,652.44	$19,720.11	$67.67	0.3%	1
1,500	20%	219,000	113,880	105,120	$24,795.39	$24,746.66	($48.72)	-0.2%	2
1,500	30%	328,500	170,820	157,680	$29,070.67	$28,906.64	($164.03)	-0.6%	1
1,500	40%	438,000	227,760	210,240	$33,345.94	$33,066.61	($279.33)	-0.8%	3
1,500	50%	547,500	284,700	262,800	$37,621.22	$37,226.59	($394.63)	-1.0%	4
1,500	60%	657,000	341,640	315,360	$41,896.50	$41,386.56	($509.94)	-1.2%	6
1,500	70%	766,500	398,580	367,920	$46,171.77	$45,546.53	($625.24)	-1.4%	-
1,500	80%	876,000	455,520	420,480	$50,447.05	$49,706.51	($740.55)	-1.5%	1
1,500	90%	985,500	512,460	473,040	$54,722.33	$53,866.48	($855.85)	-1.6%	-
4,500	20%	657,000	341,640	315,360	$70,151.19	$68,946.14	($1,205.04)	-1.7%	3
4,500	30%	985,500	512,460	473,040	$82,977.02	$81,426.06	($1,550.96)	-1.9%	2
4,500	40%	1,314,000	683,280	630,720	$95,802.85	$93,905.98	($1,896.87)	-2.0%	4
4,500	50%	1,642,500	854,100	788,400	$108,628.68	$106,385.91	($2,242.78)	-2.1%	1
4,500	60%	1,971,000	1,024,920	946,080	$121,454.51	$118,865.83	($2,588.69)	-2.1%	5
4,500	70%	2,299,500	1,195,740	1,103,760	$134,280.34	$131,345.75	($2,934.60)	-2.2%	-
4,500	80%	2,628,000	1,366,560	1,261,440	$147,106.18	$143,825.67	($3,280.51)	-2.2%	-
4,500	90%	2,956,500	1,537,380	1,419,120	$159,932.01	$156,305.59	($3,626.42)	-2.3%	-
6,000	20%	876,000	455,520	420,480	$92,829.09	$91,045.88	($1,783.21)	-1.9%	-
6,000	30%	1,314,000	683,280	630,720	$109,930.20	$107,685.78	($2,244.42)	-2.0%	-
6,000	40%	1,752,000	911,040	840,960	$127,031.30	$124,325.67	($2,705.63)	-2.1%	-
6,000	50%	2,190,000	1,138,800	1,051,200	$144,132.41	$140,965.57	($3,166.85)	-2.2%	1
6,000	60%	2,628,000	1,366,560	1,261,440	$161,233.52	$157,605.46	($3,628.06)	-2.3%	-
6,000	70%	3,066,000	1,594,320	1,471,680	$178,334.63	$174,245.35	($4,089.28)	-2.3%	-
6,000	80%	3,504,000	1,822,080	1,681,920	$195,435.74	$190,885.25	($4,550.49)	-2.3%	1
6,000	90%	3,942,000	2,049,840	1,892,160	$212,536.85	$207,525.14	($5,011.70)	-2.4%	3

		Current Rates	Rate Yr 1
	UOM	SC08SubTrn-I	SC08SubTrn-I
Customer Charge	Monthly	$ 2,116.77	$ 2,646.00
Demand Charge kW	kW	$ 9.68	$ 9.19
SBC (EETr) per kWh	kWh	$ 0.00105	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ 0.25823	$ -
Tax Credit per kW	kW	$ (0.52000)	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.72	$ 0.93
Supply Charge On Peak kWh	kWh-On	$ 0.03594	$ 0.03594
Supply Charge Off Peak kWh	kWh-Off	$ 0.02525	$ 0.02525
MFC per kWh	kWh	$ 0.00206	$ 0.00206

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2020 - April 30, 2021

Including Supply

PSC #19 - SC 8 - Large General Service - SubTransmission - Commercial									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Current Rates	Rate Yr 1	Amount	Percent	# of Customers
500	20%	73,000	37,960	35,040	$9,993.65	$10,195.04	$201.39	2.0%	-
500	30%	109,500	56,940	52,560	$11,430.07	$11,593.03	$162.96	1.4%	2
500	40%	146,000	75,920	70,080	$12,866.49	$12,991.01	$124.52	1.0%	6
500	50%	182,500	94,900	87,600	$14,302.91	$14,389.00	$86.09	0.6%	4
500	60%	219,000	113,880	105,120	$15,739.33	$15,786.98	$47.65	0.3%	4
500	70%	255,500	132,860	122,640	$17,175.75	$17,184.96	$9.22	0.1%	2
500	80%	292,000	151,840	140,160	$18,612.16	$18,582.95	($29.22)	-0.2%	-
500	90%	328,500	170,820	157,680	$20,048.58	$19,980.93	($67.65)	-0.3%	-
1,500	20%	219,000	113,880	105,120	$25,924.27	$25,513.27	($411.00)	-1.6%	1
1,500	30%	328,500	170,820	157,680	$30,233.53	$29,707.23	($526.30)	-1.7%	3
1,500	40%	438,000	227,760	210,240	$34,542.78	$33,901.18	($641.60)	-1.9%	5
1,500	50%	547,500	284,700	262,800	$38,852.04	$38,095.13	($756.91)	-1.9%	11
1,500	60%	657,000	341,640	315,360	$43,161.30	$42,289.09	($872.21)	-2.0%	4
1,500	70%	766,500	398,580	367,920	$47,470.56	$46,483.04	($987.52)	-2.1%	3
1,500	80%	876,000	455,520	420,480	$51,779.81	$50,676.99	($1,102.82)	-2.1%	-
1,500	90%	985,500	512,460	473,040	$56,089.07	$54,870.95	($1,218.12)	-2.2%	-
4,500	20%	657,000	341,640	315,360	$73,716.13	$71,467.97	($2,248.16)	-3.0%	-
4,500	30%	985,500	512,460	473,040	$86,643.90	$84,049.83	($2,594.08)	-3.0%	2
4,500	40%	1,314,000	683,280	630,720	$99,571.67	$96,631.69	($2,939.99)	-3.0%	3
4,500	50%	1,642,500	854,100	788,400	$112,499.45	$109,213.55	($3,285.90)	-2.9%	1
4,500	60%	1,971,000	1,024,920	946,080	$125,427.22	$121,795.41	($3,631.81)	-2.9%	1
4,500	70%	2,299,500	1,195,740	1,103,760	$138,354.99	$134,377.27	($3,977.72)	-2.9%	1
4,500	80%	2,628,000	1,366,560	1,261,440	$151,282.76	$146,959.13	($4,323.63)	-2.9%	-
4,500	90%	2,956,500	1,537,380	1,419,120	$164,210.53	$159,540.99	($4,669.54)	-2.8%	-
6,000	20%	876,000	455,520	420,480	$97,612.06	$94,445.31	($3,166.75)	-3.2%	-
6,000	30%	1,314,000	683,280	630,720	$114,849.09	$111,221.13	($3,627.96)	-3.2%	-
6,000	40%	1,752,000	911,040	840,960	$132,086.12	$127,996.94	($4,089.18)	-3.1%	-
6,000	50%	2,190,000	1,138,800	1,051,200	$149,323.15	$144,772.76	($4,550.39)	-3.0%	-
6,000	60%	2,628,000	1,366,560	1,261,440	$166,560.18	$161,548.57	($5,011.60)	-3.0%	1
6,000	70%	3,066,000	1,594,320	1,471,680	$183,797.20	$178,324.39	($5,472.82)	-3.0%	1
6,000	80%	3,504,000	1,822,080	1,681,920	$201,034.23	$195,100.20	($5,934.03)	-3.0%	-
6,000	90%	3,942,000	2,049,840	1,892,160	$218,271.26	$211,876.02	($6,395.25)	-2.9%	-

		Current Rates	Rate Yr 1
	UOM	SC08SubTrn-C	SC08SubTrn-C
Customer Charge	Monthly	$ 2,027.62	$ 2,535.00
Demand Charge kW	kW	$ 10.51	$ 9.73
SBC (EETr) per kWh	kWh	$ 0.00105	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ 0.33494	$ -
Tax Credit per kW	kW	$ (0.66000)	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.72	$ 0.93
Supply Charge On Peak kWh	kWh-On	$ 0.03631	$ 0.03631
Supply Charge Off Peak kWh	kWh-Off	$ 0.02550	$ 0.02550
MFC per kWh	kWh	$ 0.00206	$ 0.00206

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2020 - April 30, 2021

Including Supply

PSC #19 - SC 8 - Large General Service - Primary									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Current Rates	Rate Yr 1	Amount	Percent	# of Customers
250	20%	36,500	18,980	17,520	$6,137.86	$6,336.77	$198.91	3.2%	5
250	30%	54,750	28,470	26,280	$6,852.16	$7,031.86	$179.69	2.6%	7
250	40%	73,000	37,960	35,040	$7,566.47	$7,726.95	$160.48	2.1%	3
250	50%	91,250	47,450	43,800	$8,280.78	$8,422.04	$141.26	1.7%	8
250	60%	109,500	56,940	52,560	$8,995.08	$9,117.13	$122.04	1.4%	1
250	70%	127,750	66,430	61,320	$9,709.39	$9,812.21	$102.82	1.1%	2
250	80%	146,000	75,920	70,080	$10,423.70	$10,507.30	$83.61	0.8%	1
250	90%	164,250	85,410	78,840	$11,138.00	$11,202.39	$64.39	0.6%	-
500	20%	73,000	37,960	35,040	$11,130.13	$11,241.61	$111.49	1.0%	2
500	30%	109,500	56,940	52,560	$12,558.74	$12,631.79	$73.05	0.6%	8
500	40%	146,000	75,920	70,080	$13,987.35	$14,021.97	$34.62	0.2%	14
500	50%	182,500	94,900	87,600	$15,415.96	$15,412.15	($3.82)	0.0%	20
500	60%	219,000	113,880	105,120	$16,844.58	$16,802.32	($42.25)	-0.3%	10
500	70%	255,500	132,860	122,640	$18,273.19	$18,192.50	($80.69)	-0.4%	3
500	80%	292,000	151,840	140,160	$19,701.80	$19,582.68	($119.12)	-0.6%	2
500	90%	328,500	170,820	157,680	$21,130.41	$20,972.86	($157.56)	-0.7%	-
1,500	20%	219,000	113,880	105,120	$31,099.20	$30,860.99	($238.22)	-0.8%	4
1,500	30%	328,500	170,820	157,680	$35,385.04	$35,031.52	($353.52)	-1.0%	18
1,500	40%	438,000	227,760	210,240	$39,670.88	$39,202.05	($468.82)	-1.2%	21
1,500	50%	547,500	284,700	262,800	$43,956.71	$43,372.59	($584.13)	-1.3%	12
1,500	60%	657,000	341,640	315,360	$48,242.55	$47,543.12	($699.43)	-1.4%	4
1,500	70%	766,500	398,580	367,920	$52,528.39	$51,713.66	($814.73)	-1.6%	4
1,500	80%	876,000	455,520	420,480	$56,814.23	$55,884.19	($930.04)	-1.6%	1
1,500	90%	985,500	512,460	473,040	$61,100.06	$60,054.72	($1,045.34)	-1.7%	-
2,000	20%	292,000	151,840	140,160	$41,083.74	$40,670.67	($413.07)	-1.0%	-
2,000	30%	438,000	227,760	210,240	$46,798.19	$46,231.39	($566.80)	-1.2%	-
2,000	40%	584,000	303,680	280,320	$52,512.64	$51,792.10	($720.54)	-1.4%	-
2,000	50%	730,000	379,600	350,400	$58,227.09	$57,352.81	($874.28)	-1.5%	2
2,000	60%	876,000	455,520	420,480	$63,941.54	$62,913.52	($1,028.02)	-1.6%	1
2,000	70%	1,022,000	531,440	490,560	$69,655.99	$68,474.23	($1,181.76)	-1.7%	-
2,000	80%	1,168,000	607,360	560,640	$75,370.44	$74,034.94	($1,335.49)	-1.8%	1
2,000	90%	1,314,000	683,280	630,720	$81,084.89	$79,595.66	($1,489.23)	-1.8%	6

	UOM	Current Rates SC08Pri	Rate Yr 1 SC08Pri
Customer Charge	Monthly	$ 1,144.87	$ 1,431.00
Demand Charge kW	kW	$ 14.71	$ 14.06
SBC (EETr) per kWh	kWh	$ 0.00105	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ 0.46463	$ -
Tax Credit per kW	kW	$ (0.92000)	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.72	$ 0.93
Supply Charge On Peak kWh	kWh-On	$ 0.03594	$ 0.03594
Supply Charge Off Peak kWh	kWh-Off	$ 0.02545	$ 0.02545
MFC per kWh	kWh	$ 0.00206	$ 0.00206

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2020 - April 30, 2021

Including Supply

PSC #19 - SC 8 - Large General Service - Secondary

Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Current Rates	Rate Yr 1	increase / (decrease) Amount	Percent	# of Customers
250	20%	36,500	18,980	17,520	$6,045.88	$6,109.28	$63.39	1.0%	15
250	30%	54,750	28,470	26,280	$6,781.45	$6,825.62	$44.18	0.7%	15
250	40%	73,000	37,960	35,040	$7,517.01	$7,541.97	$24.96	0.3%	31
250	50%	91,250	47,450	43,800	$8,252.58	$8,258.32	$5.74	0.1%	37
250	60%	109,500	56,940	52,560	$8,988.14	$8,974.67	($13.47)	-0.1%	27
250	70%	127,750	66,430	61,320	$9,723.71	$9,691.02	($32.69)	-0.3%	5
250	80%	146,000	75,920	70,080	$10,459.27	$10,407.36	($51.91)	-0.5%	4
250	90%	164,250	85,410	78,840	$11,194.84	$11,123.71	($71.13)	-0.6%	-
500	20%	73,000	37,960	35,040	$11,180.57	$11,079.62	($100.95)	-0.9%	6
500	30%	109,500	56,940	52,560	$12,651.70	$12,512.32	($139.38)	-1.1%	35
500	40%	146,000	75,920	70,080	$14,122.83	$13,945.02	($177.82)	-1.3%	65
500	50%	182,500	94,900	87,600	$15,593.96	$15,377.71	($216.25)	-1.4%	40
500	60%	219,000	113,880	105,120	$17,065.09	$16,810.41	($254.69)	-1.5%	27
500	70%	255,500	132,860	122,640	$18,536.23	$18,243.11	($293.12)	-1.6%	11
500	80%	292,000	151,840	140,160	$20,007.36	$19,675.80	($331.55)	-1.7%	5
500	90%	328,500	170,820	157,680	$21,478.49	$21,108.50	($369.99)	-1.7%	1
1,500	20%	219,000	113,880	105,120	$31,719.34	$30,961.02	($758.31)	-2.4%	19
1,500	30%	328,500	170,820	157,680	$36,132.73	$35,259.11	($873.62)	-2.4%	22
1,500	40%	438,000	227,760	210,240	$40,546.12	$39,557.20	($988.92)	-2.4%	18
1,500	50%	547,500	284,700	262,800	$44,959.51	$43,855.29	($1,104.23)	-2.5%	5
1,500	60%	657,000	341,640	315,360	$49,372.90	$48,153.38	($1,219.53)	-2.5%	2
1,500	70%	766,500	398,580	367,920	$53,786.30	$52,451.46	($1,334.83)	-2.5%	2
1,500	80%	876,000	455,520	420,480	$58,199.69	$56,749.55	($1,450.14)	-2.5%	-
1,500	90%	985,500	512,460	473,040	$62,613.08	$61,047.64	($1,565.44)	-2.5%	-
2,000	20%	292,000	151,840	140,160	$41,988.72	$40,901.72	($1,087.00)	-2.6%	-
2,000	30%	438,000	227,760	210,240	$47,873.24	$46,632.51	($1,240.74)	-2.6%	-
2,000	40%	584,000	303,680	280,320	$53,757.76	$52,363.29	($1,394.47)	-2.6%	-
2,000	50%	730,000	379,600	350,400	$59,642.29	$58,094.07	($1,548.21)	-2.6%	-
2,000	60%	876,000	455,520	420,480	$65,526.81	$63,824.86	($1,701.95)	-2.6%	1
2,000	70%	1,022,000	531,440	490,560	$71,411.33	$69,555.64	($1,855.69)	-2.6%	1
2,000	80%	1,168,000	607,360	560,640	$77,295.85	$75,286.43	($2,009.43)	-2.6%	-
2,000	90%	1,314,000	683,280	630,720	$83,180.38	$81,017.21	($2,163.16)	-2.6%	-

	UOM	Current Rates SC08Sec	Rate Yr 1 SC08Sec
Customer Charge	Monthly	$ 910.47	$ 1,138.00
Demand Charge kW	kW	$ 15.13	$ 14.15
SBC (EETr) per kWh	kWh	$ 0.00105	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ 0.49424	$ -
Tax Credit per kW	kW	$ (0.97000)	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.72	$ 0.93
Supply Charge On Peak kWh	kWh-On	$ 0.03761	$ 0.03761
Supply Charge Off Peak kWh	kWh-Off	$ 0.02607	$ 0.02607
MFC per kWh	kWh	$ 0.00206	$ 0.00206

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2020 - April 30, 2021

Including Supply

PSC #19 - SC 8 - Large General Service - SubStation

Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Current Rates	Rate Yr 1	increase / (decrease) Amount	Percent	# of Customers
250	20%	36,500	18,980	17,520	$5,721.23	$5,967.30	$246.07	4.3%	-
250	30%	54,750	28,470	26,280	$6,444.34	$6,671.19	$226.85	3.5%	1
250	40%	73,000	37,960	35,040	$7,167.46	$7,375.09	$207.63	2.9%	2
250	50%	91,250	47,450	43,800	$7,890.57	$8,078.98	$188.42	2.4%	1
250	60%	109,500	56,940	52,560	$8,613.68	$8,782.88	$169.20	2.0%	1
250	70%	127,750	66,430	61,320	$9,336.79	$9,486.78	$149.98	1.6%	2
250	80%	146,000	75,920	70,080	$10,059.91	$10,190.67	$130.76	1.3%	-
250	90%	164,250	85,410	78,840	$10,783.02	$10,894.57	$111.55	1.0%	-
500	20%	73,000	37,960	35,040	$9,472.19	$9,471.67	($0.52)	0.0%	-
500	30%	109,500	56,940	52,560	$10,918.41	$10,879.46	($38.95)	-0.4%	1
500	40%	146,000	75,920	70,080	$12,364.64	$12,287.25	($77.39)	-0.6%	1
500	50%	182,500	94,900	87,600	$13,810.87	$13,695.04	($115.82)	-0.8%	4
500	60%	219,000	113,880	105,120	$15,257.09	$15,102.83	($154.26)	-1.0%	3
500	70%	255,500	132,860	122,640	$16,703.32	$16,510.63	($192.69)	-1.2%	2
500	80%	292,000	151,840	140,160	$18,149.54	$17,918.42	($231.13)	-1.3%	-
500	90%	328,500	170,820	157,680	$19,595.77	$19,326.21	($269.56)	-1.4%	-
2,000	20%	292,000	151,840	140,160	$31,977.94	$30,497.90	($1,480.05)	-4.6%	6
2,000	30%	438,000	227,760	210,240	$37,762.85	$36,129.06	($1,633.79)	-4.3%	4
2,000	40%	584,000	303,680	280,320	$43,547.75	$41,760.23	($1,787.53)	-4.1%	1
2,000	50%	730,000	379,600	350,400	$49,332.66	$47,391.39	($1,941.26)	-3.9%	-
2,000	60%	876,000	455,520	420,480	$55,117.56	$53,022.56	($2,095.00)	-3.8%	-
2,000	70%	1,022,000	531,440	490,560	$60,902.46	$58,653.72	($2,248.74)	-3.7%	-
2,000	80%	1,168,000	607,360	560,640	$66,687.37	$64,284.89	($2,402.48)	-3.6%	-
2,000	90%	1,314,000	683,280	630,720	$72,472.27	$69,916.05	($2,556.22)	-3.5%	-
2,500	20%	365,000	189,800	175,200	$39,479.86	$37,506.64	($1,973.23)	-5.0%	-
2,500	30%	547,500	284,700	262,800	$46,710.99	$44,545.59	($2,165.40)	-4.6%	-
2,500	40%	730,000	379,600	350,400	$53,942.12	$51,584.55	($2,357.57)	-4.4%	-
2,500	50%	912,500	474,500	438,000	$61,173.25	$58,623.51	($2,549.74)	-4.2%	-
2,500	60%	1,095,000	569,400	525,600	$68,404.38	$65,662.47	($2,741.92)	-4.0%	1
2,500	70%	1,277,500	664,300	613,200	$75,635.51	$72,701.42	($2,934.09)	-3.9%	1
2,500	80%	1,460,000	759,200	700,800	$82,866.64	$79,740.38	($3,126.26)	-3.8%	-
2,500	90%	1,642,500	854,100	788,400	$90,097.77	$86,779.34	($3,318.43)	-3.7%	-

	UOM	Current Rates SC08SubSta	Rate Yr 1 SC08SubSta
Customer Charge	Monthly	$ 1,969.55	$ 2,462.00
Demand Charge kW	kW	$ 9.55	$ 8.39
SBC (EETr) per kWh	kWh	$ 0.00105	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ 0.33893	$ -
Tax Credit per kW	kW	$ (0.67000)	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.72	$ 0.93
Supply Charge On Peak kWh	kWh-On	$ 0.03647	$ 0.03647
Supply Charge Off Peak kWh	kWh-Off	$ 0.02588	$ 0.02588
MFC per kWh	kWh	$ 0.00206	$ 0.00206

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2020 - April 30, 2021

Including Supply

PSC #19 - SC 9 - General Service - TOU

Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Current Rates	Rate Yr 1	increase / (decrease) Amount	Percent	# of Customers
10	20%	1,460	759	701	$293.86	$292.64	($1.22)	-0.4%	19
10	30%	2,190	1,139	1,051	$332.87	$328.99	($3.89)	-1.2%	17
10	40%	2,920	1,518	1,402	$371.89	$365.34	($6.56)	-1.8%	25
10	50%	3,650	1,898	1,752	$410.91	$401.69	($9.22)	-2.2%	17
10	60%	4,380	2,278	2,102	$449.93	$438.04	($11.89)	-2.6%	12
10	70%	5,110	2,657	2,453	$488.94	$474.38	($14.56)	-3.0%	7
10	80%	5,840	3,037	2,803	$527.96	$510.73	($17.23)	-3.3%	1
10	90%	6,570	3,416	3,154	$566.98	$547.08	($19.90)	-3.5%	3
25	20%	3,650	1,898	1,752	$590.31	$586.96	($3.36)	-0.6%	11
25	30%	5,475	2,847	2,628	$687.86	$677.83	($10.03)	-1.5%	27
25	40%	7,300	3,796	3,504	$785.40	$768.70	($16.70)	-2.1%	30
25	50%	9,125	4,745	4,380	$882.94	$859.58	($23.37)	-2.6%	24
25	60%	10,950	5,694	5,256	$980.49	$950.45	($30.04)	-3.1%	12
25	70%	12,775	6,643	6,132	$1,078.03	$1,041.32	($36.71)	-3.4%	3
25	80%	14,600	7,592	7,008	$1,175.58	$1,132.20	($43.38)	-3.7%	-
25	90%	16,425	8,541	7,884	$1,273.12	$1,223.07	($50.05)	-3.9%	3
100	20%	14,600	7,592	7,008	$2,072.59	$2,058.55	($14.04)	-0.7%	27
100	30%	21,900	11,388	10,512	$2,462.77	$2,422.04	($40.73)	-1.7%	32
100	40%	29,200	15,184	14,016	$2,852.94	$2,785.53	($67.41)	-2.4%	18
100	50%	36,500	18,980	17,520	$3,243.12	$3,149.03	($94.09)	-2.9%	9
100	60%	43,800	22,776	21,024	$3,633.29	$3,512.52	($120.77)	-3.3%	6
100	70%	51,100	26,572	24,528	$4,023.47	$3,876.01	($147.45)	-3.7%	2
100	80%	58,400	30,368	28,032	$4,413.64	$4,239.51	($174.13)	-3.9%	-
100	90%	65,700	34,164	31,536	$4,803.82	$4,603.00	($200.81)	-4.2%	-
200	20%	29,200	15,184	14,016	$4,048.97	$4,020.67	($28.29)	-0.7%	1
200	30%	43,800	22,776	21,024	$4,829.32	$4,747.66	($81.66)	-1.7%	2
200	40%	58,400	30,368	28,032	$5,609.66	$5,474.64	($135.02)	-2.4%	4
200	50%	73,000	37,960	35,040	$6,390.01	$6,201.63	($188.38)	-2.9%	-
200	60%	87,600	45,552	42,048	$7,170.36	$6,928.62	($241.75)	-3.4%	-
200	70%	102,200	53,144	49,056	$7,950.71	$7,655.60	($295.11)	-3.7%	-
200	80%	116,800	60,736	56,064	$8,731.06	$8,382.59	($348.47)	-4.0%	-
200	90%	131,400	68,328	63,072	$9,511.41	$9,109.58	($401.84)	-4.2%	-

	UOM	Current Rates SC09	Rate Yr 1 SC09
Customer Charge	Monthly	$ 95.50	$ 95.50
Demand Charge kW	kW	$ 12.26	$ 12.35
Delivery Charge On Peak kWh	kWh-On	$ 0.01408	$ 0.01041
Delivery Charge Off Peak kWh	kWh-Off	$ 0.01408	$ 0.01041
SBC (EETr) per kWh	kWh	$ 0.00105	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ 0.62024	$ -
Tax Credit All Hours kWh	kWh	$ (0.00107)	$ -
Tax Credit per kW	kW	$ (0.92000)	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.72	$ 0.93
Supply Charge On Peak kWh	kWh-On	$ 0.03776	$ 0.03776
Supply Charge Off Peak kWh	kWh-Off	$ 0.02619	$ 0.02619
MFC per kWh	kWh	$ 0.00206	$ 0.00206

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation		
Date Sources - RG&E Electric Bill Impact Statements		
Rate	**Source of Rate in "Current" Rates**	**Source of Rate in Rate Years**
Customer Charge	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
kW Charge	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
kWh Delivery Charge All Hours	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
kWh Delivery Charge On Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
kWh Delivery Charge Mid Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
kWh Delivery Charge Off Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
Reactive RkVah	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
Billing Charge per Bill	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
SBC (EETr) per kWh	Current Tariff Rates in Effect 01/01/2020. Statement #26.	Included in Delivery Rates
SBC (CEF) per kWh	Current Tariff Rates in Effect 01/01/2020. Statement #26.	Current Tariff Rates in Effect 01/01/2020. Statement #26.
RAM per kWh	Tariff Rates in Effect 07/01/2019.	No RAM charge is being forecasted at this time for the rate years
RAM per kW	Tariff Rates in Effect 07/01/2019.	No RAM charge is being forecasted at this time for the rate years
Tax Credit per kWh	Case No. 17-M-0815 dated August 9, 2018. Statement Number 1	Included in Delivery Rates
Tax Credit per kW	Case No. 17-M-0815 dated August 9, 2018. Statement Number 1	Included in Delivery Rates
Rate	**Source of Rate in "Current" Rates and Rate Years**	
Transition Charge per kWh	NBC, Demand Response, and Value Stack: NBC is the Non-Weighted 2019 Average. Dmd Rsp iat $-0-. Value Stack at $-0-. RAM is separate.	
MFC per kWh	Non-Weighted 2019 Average of Monthly MFC Charge	
kWh Supply Charge All Hours	2019 Annualized Supply Rates	
kWh Supply Charge On Peak	2019 Annualized Supply Rates	
kWh Supply Charge Mid Peak	2019 Annualized Supply Rates	
kWh Supply Charge Off Peak	2019 Annualized Supply Rates	
Customer Count	2018 monthly data - separate Low Income counts	

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2020 - April 30, 2021

Delivery Bill Only

PSC #19 - SC 1 - Residential

kWh	Current Rates	Rate Yr 1	increase / (decrease) Amount	Percent	# of Customers	# of Low Income Customers	Percent of Customers	Percent of Low Income Customers	Amount of EE Embedded in Delivery Rates* Amount	Percent
100	$26.97	$27.21	$0.23	0.9%	10,907	539	3%	1%	$ 0.08	0.28%
200	$31.84	$32.10	$0.26	0.8%	25,369	2,787	7%	8%	$ 0.15	0.48%
300	$36.72	$37.00	$0.29	0.8%	33,669	4,537	10%	12%	$ 0.23	0.62%
400	$41.59	$41.90	$0.31	0.8%	37,090	5,036	11%	14%	$ 0.31	0.74%
500	$46.46	$46.80	$0.34	0.7%	38,010	4,932	11%	13%	$ 0.39	0.82%
600	$51.33	$51.70	$0.37	0.7%	35,693	4,208	11%	11%	$ 0.46	0.89%
700	$56.21	$56.60	$0.40	0.7%	31,811	3,427	9%	9%	$ 0.54	0.95%
800	$61.08	$61.50	$0.42	0.7%	27,030	2,744	8%	7%	$ 0.62	1.00%
900	$65.95	$66.40	$0.45	0.7%	22,238	2,191	7%	6%	$ 0.69	1.04%
1,000	$70.82	$71.30	$0.48	0.7%	17,500	1,598	5%	4%	$ 0.77	1.08%
1,100	$75.69	$76.20	$0.51	0.7%	13,667	1,211	4%	3%	$ 0.85	1.11%
1,200	$80.57	$81.10	$0.53	0.7%	10,434	907	3%	2%	$ 0.92	1.14%
1,500	$95.18	$95.80	$0.61	0.6%	18,454	1,568	5%	4%	$ 1.16	1.21%
2,000	$119.54	$120.29	$0.75	0.6%	11,052	901	3%	2%	$ 1.54	1.28%
3,000	$168.26	$169.29	$1.02	0.6%	5,347	334	2%	1%	$ 2.31	1.36%
					338,269	36,919				

	UOM	Current Rates SC01	Rate Yr 1 SC01
Customer Charge	Monthly	$ 21.38	$ 21.38
Delivery Charge All Hours kWh	kWh	$ 0.04645	$ 0.04569
SBC (EETr) per kWh	kWh	$ 0.00105	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kWh	kWh	$ 0.00218	$ -
Tax Credit All Hours kWh	kWh	$ (0.00426)	$ -
Transition Charge per kWh	kWh	$ (0.00206)	$ (0.00206)
Billing Charge per Bill	Monthly	$ 0.72	$ 0.93

Includes $ 0.00077 per kWh of EE Costs*

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Low income customers represent customers who participated in the Company's low income program and received a credit on their bill each month during calendar year 2018.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2020 - April 30, 2021

Delivery Bill Only

PSC #19 - SC 2 - General Service - Non Demand					
			increase / (decrease)		
kWh	Current Rates	Rate Yr 1	Amount	Percent	# of Customers
300	$34.53	$34.62	$0.09	0.3%	11,999
400	$38.67	$38.72	$0.05	0.1%	2,601
500	$42.81	$42.83	$0.02	0.0%	2,299
600	$46.95	$46.93	($0.02)	0.0%	1,892
700	$51.10	$51.04	($0.06)	-0.1%	1,541
800	$55.24	$55.14	($0.10)	-0.2%	1,322
900	$59.38	$59.25	($0.13)	-0.2%	1,021
1,000	$63.52	$63.35	($0.17)	-0.3%	904
1,500	$84.23	$83.87	($0.36)	-0.4%	2,999
2,000	$104.95	$104.39	($0.55)	-0.5%	1,654
2,500	$125.66	$124.92	($0.74)	-0.6%	845
3,000	$146.37	$145.44	($0.93)	-0.6%	385
4,000	$187.79	$186.48	($1.31)	-0.7%	203
5,000	$229.21	$227.53	($1.69)	-0.7%	60
6,000	$270.64	$268.57	($2.07)	-0.8%	21
7,000	$312.06	$309.61	($2.45)	-0.8%	59

	UOM	Current Rates SC02	Rate Yr 1 SC02
Customer Charge	Monthly	$ 21.38	$ 21.38
Delivery Charge All Hours kWh	kWh	$ 0.03712	$ 0.03592
SBC (EETr) per kWh	kWh	$ 0.00105	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kWh	kWh	$ 0.00194	$ -
Tax Credit All Hours kWh	kWh	$ (0.00381)	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Billing Charge per Bill	Monthly	$ 0.72	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2020 - April 30, 2021

Delivery Bill Only

PSC #19 - SC 3 - General Service - Demand

Kw	Load Factor	kWh	Current Rates	Rate Yr 1	increase / (decrease) Amount	Percent	# of Customers
50	20%	7,300	$1,194.15	$1,192.45	($1.70)	-0.1%	45
50	30%	10,950	$1,216.69	$1,211.15	($5.54)	-0.5%	19
50	40%	14,600	$1,239.23	$1,229.85	($9.39)	-0.8%	18
50	50%	18,250	$1,261.77	$1,248.54	($13.23)	-1.0%	18
50	60%	21,900	$1,284.31	$1,267.24	($17.07)	-1.3%	1
50	70%	25,550	$1,306.85	$1,285.94	($20.92)	-1.6%	3
50	80%	29,200	$1,329.40	$1,304.64	($24.76)	-1.9%	3
50	90%	32,850	$1,351.94	$1,323.33	($28.60)	-2.1%	2
100	20%	14,600	$2,090.45	$2,086.84	($3.60)	-0.2%	43
100	30%	21,900	$2,135.53	$2,124.24	($11.29)	-0.5%	73
100	40%	29,200	$2,180.61	$2,161.63	($18.98)	-0.9%	122
100	50%	36,500	$2,225.69	$2,199.03	($26.66)	-1.2%	115
100	60%	43,800	$2,270.78	$2,236.43	($34.35)	-1.5%	47
100	70%	51,100	$2,315.86	$2,273.82	($42.04)	-1.8%	32
100	80%	58,400	$2,360.94	$2,311.22	($49.73)	-2.1%	9
100	90%	65,700	$2,406.02	$2,348.61	($57.41)	-2.4%	6
275	20%	40,150	$5,227.49	$5,217.22	($10.27)	-0.2%	146
275	30%	60,225	$5,351.47	$5,320.06	($31.41)	-0.6%	223
275	40%	80,300	$5,475.45	$5,422.90	($52.55)	-1.0%	130
275	50%	100,375	$5,599.42	$5,525.73	($73.69)	-1.3%	69
275	60%	120,450	$5,723.40	$5,628.57	($94.83)	-1.7%	24
275	70%	140,525	$5,847.37	$5,731.41	($115.97)	-2.0%	8
275	80%	160,600	$5,971.35	$5,834.25	($137.10)	-2.3%	2
275	90%	180,675	$6,095.33	$5,937.08	($158.24)	-2.6%	2
300	20%	43,800	$5,675.64	$5,664.42	($11.22)	-0.2%	-
300	30%	65,700	$5,810.89	$5,776.60	($34.28)	-0.6%	2
300	40%	87,600	$5,946.14	$5,888.79	($57.34)	-1.0%	2
300	50%	109,500	$6,081.38	$6,000.98	($80.41)	-1.3%	3
300	60%	131,400	$6,216.63	$6,113.16	($103.47)	-1.7%	-
300	70%	153,300	$6,351.88	$6,225.35	($126.53)	-2.0%	2
300	80%	175,200	$6,487.12	$6,337.54	($149.59)	-2.3%	2
300	90%	197,100	$6,622.37	$6,449.72	($172.65)	-2.6%	3

	UOM	Current Rates SC03	Rate Yr 1 SC03
Customer Charge	Monthly	$ 297.13	$ 297.13
Demand Charge kW	kW	$ 17.57	$ 17.14
SBC (EETr) per kWh	kWh	$ 0.00105	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ 0.56433	$ -
Tax Credit per kW	kW	$ (1.11000)	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.72	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates.
MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2020 - April 30, 2021

Delivery Bill Only

PSC #19 - SC 4-I - Residential - Day/Night							
					increase / (decrease)		
kWh	Peak	Off Peak	Current Rates	Rate Yr 1	Amount	Percent	# of Customers
300	210	90	41.14	40.73	(0.40)	-1.0%	126
400	280	120	46.16	45.55	(0.61)	-1.3%	91
500	350	150	51.18	50.37	(0.81)	-1.6%	104
600	420	180	56.19	55.18	(1.01)	-1.8%	131
700	490	210	61.21	60.00	(1.22)	-2.0%	172
800	560	240	66.23	64.81	(1.42)	-2.1%	191
900	630	270	71.25	69.63	(1.62)	-2.3%	145
1,000	700	300	76.27	74.45	(1.83)	-2.4%	157
1,500	1,050	450	101.37	98.52	(2.84)	-2.8%	589
2,000	1,400	600	126.46	122.60	(3.86)	-3.0%	302
2,500	1,750	750	151.56	146.68	(4.87)	-3.2%	149
3,000	2,100	900	176.65	170.76	(5.89)	-3.3%	61
4,000	2,800	1,200	226.84	218.92	(7.92)	-3.5%	26
5,000	3,500	1,500	277.03	267.08	(9.95)	-3.6%	11
6,000	4,200	1,800	327.22	315.24	(11.98)	-3.7%	1
7,000	4,900	2,100	377.41	363.40	(14.01)	-3.7%	5

	UOM	Current Rates SC04-I	Rate Yr 1 SC04-I
Customer Charge	Monthly	$ 25.36	$ 25.36
Delivery Charge On Peak kWh	kWh-On	$ 0.04792	$ 0.04486
Delivery Charge Off Peak kWh	kWh-Off	$ 0.04792	$ 0.04486
SBC (EETr) per kWh	kWh	$ 0.00105	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kWh	kWh	$ 0.00213	$ -
Tax Credit All Hours kWh	kWh	$ (0.00422)	$ -
Transition Charge per kWh	kWh	$ (0.00206)	$ (0.00206)
Billing Charge per Bill	Monthly	$ 0.72	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates.
MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2020 - April 30, 2021

Delivery Bill Only

PSC #19 - SC 4-II - Residential - Day/Night							
					increase / (decrease)		
kWh	Peak	Off Peak	Current Rates	Rate Yr 1	Amount	Percent	# of Customers
300	210	90	$47.75	$47.36	($0.40)	-0.8%	18
400	280	120	$53.82	$53.22	($0.60)	-1.1%	9
500	350	150	$59.88	$59.08	($0.80)	-1.3%	15
600	420	180	$65.94	$64.95	($1.00)	-1.5%	28
700	490	210	$72.01	$70.81	($1.20)	-1.7%	29
800	560	240	$78.07	$76.67	($1.40)	-1.8%	38
900	630	270	$84.14	$82.54	($1.60)	-1.9%	33
1,000	700	300	$90.20	$88.40	($1.80)	-2.0%	52
1,500	1,050	450	$120.52	$117.72	($2.80)	-2.3%	238
2,000	1,400	600	$150.84	$147.04	($3.80)	-2.5%	190
2,500	1,750	750	$181.16	$176.36	($4.81)	-2.7%	165
3,000	2,100	900	$211.48	$205.67	($5.81)	-2.7%	83
4,000	2,800	1,200	$272.12	$264.31	($7.81)	-2.9%	84
5,000	3,500	1,500	$332.76	$322.94	($9.82)	-3.0%	49
6,000	4,200	1,800	$393.40	$381.58	($11.82)	-3.0%	33
7,000	4,900	2,100	$454.04	$440.22	($13.83)	-3.0%	28

	UOM	Current Rates SC04-II	Rate Yr 1 SC04-II
Customer Charge	Monthly	$ 28.84	$ 28.84
Delivery Charge On Peak kWh	kWh-On	$ 0.05823	$ 0.05533
Delivery Charge Off Peak kWh	kWh-Off	$ 0.05823	$ 0.05533
SBC (EETr) per kWh	kWh	$ 0.00105	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kWh	kWh	$ 0.00213	$ -
Tax Credit All Hours kWh	kWh	$ (0.00408)	$ -
Transition Charge per kWh	kWh	$ (0.00206)	$ (0.00206)
Billing Charge per Bill	Monthly	$ 0.72	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2020 - April 30, 2021

Delivery Bill Only

PSC #19 - SC 7 - General Service - Demand

Kw	Load Factor	kWh	Current Rates	Rate Yr 1	increase / (decrease) Amount	Percent	# of Customers
5	20%	730	$184.90	$185.14	$0.24	0.1%	178
5	30%	1,095	$190.19	$189.43	($0.75)	-0.4%	51
5	40%	1,460	$195.47	$193.73	($1.75)	-0.9%	36
5	50%	1,825	$200.76	$198.02	($2.74)	-1.4%	34
5	60%	2,190	$206.05	$202.32	($3.73)	-1.8%	16
5	70%	2,555	$211.34	$206.62	($4.72)	-2.2%	14
5	80%	2,920	$216.62	$210.91	($5.71)	-2.6%	6
5	90%	3,285	$221.91	$215.21	($6.70)	-3.0%	6
25	20%	3,650	$566.54	$566.89	$0.36	0.1%	2,778
25	30%	5,475	$592.97	$588.38	($4.60)	-0.8%	1,673
25	40%	7,300	$619.41	$609.86	($9.55)	-1.5%	888
25	50%	9,125	$645.85	$631.34	($14.51)	-2.2%	403
25	60%	10,950	$672.28	$652.82	($19.46)	-2.9%	155
25	70%	12,775	$698.72	$674.30	($24.42)	-3.5%	46
25	80%	14,600	$725.16	$695.78	($29.37)	-4.1%	12
25	90%	16,425	$751.59	$717.26	($34.33)	-4.6%	7
100	20%	14,600	$1,997.68	$1,998.49	$0.81	0.0%	1,560
100	30%	21,900	$2,103.42	$2,084.41	($19.01)	-0.9%	618
100	40%	29,200	$2,209.17	$2,170.34	($38.83)	-1.8%	240
100	50%	36,500	$2,314.91	$2,256.27	($58.65)	-2.5%	74
100	60%	43,800	$2,420.66	$2,342.19	($78.47)	-3.2%	44
100	70%	51,100	$2,526.41	$2,428.12	($98.29)	-3.9%	8
100	80%	58,400	$2,632.15	$2,514.04	($118.11)	-4.5%	3
100	90%	65,700	$2,737.90	$2,599.97	($137.93)	-5.0%	2
250	20%	36,500	$4,859.96	$4,861.68	$1.72	0.0%	19
250	30%	54,750	$5,124.32	$5,076.49	($47.83)	-0.9%	15
250	40%	73,000	$5,388.69	$5,291.31	($97.38)	-1.8%	5
250	50%	91,250	$5,653.05	$5,506.12	($146.93)	-2.6%	2
250	60%	109,500	$5,917.41	$5,720.93	($196.48)	-3.3%	-
250	70%	127,750	$6,181.78	$5,935.75	($246.03)	-4.0%	1
250	80%	146,000	$6,446.14	$6,150.56	($295.58)	-4.6%	-
250	90%	164,250	$6,710.50	$6,365.38	($345.13)	-5.1%	-

	UOM	Current Rates SC07	Rate Yr 1 SC07
Customer Charge	Monthly	$ 88.77	$ 88.77
Demand Charge kW	kW	$ 17.42	$ 17.37
Delivery Charge All Hours kWh	kWh	$ 0.00887	$ 0.00665
SBC (EETr) per kWh	kWh	$ 0.00105	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ 0.66698	$ -
Tax Credit All Hours kWh	kWh	$ (0.00056)	$ -
Tax Credit per kW	kW	$ (1.12000)	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.72	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2020 - April 30, 2021

Delivery Bill Only

PSC #19 - SC 8 - Large General Service - Transmission									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Current Rates	Rate Yr 1	Amount	Percent	# of Customers
6,000	20%	876,000	455,520	420,480	$63,297.69	$63,133.77	($163.93)	-0.3%	-
6,000	30%	1,314,000	683,280	630,720	$66,002.64	$65,377.50	($625.14)	-0.9%	-
6,000	40%	1,752,000	911,040	840,960	$68,707.58	$67,621.22	($1,086.35)	-1.6%	-
6,000	50%	2,190,000	1,138,800	1,051,200	$71,412.52	$69,864.95	($1,547.57)	-2.2%	-
6,000	60%	2,628,000	1,366,560	1,261,440	$74,117.46	$72,108.68	($2,008.78)	-2.7%	-
6,000	70%	3,066,000	1,594,320	1,471,680	$76,822.40	$74,352.41	($2,470.00)	-3.2%	-
6,000	80%	3,504,000	1,822,080	1,681,920	$79,527.35	$76,596.14	($2,931.21)	-3.7%	-
6,000	90%	3,942,000	2,049,840	1,892,160	$82,232.29	$78,839.86	($3,392.42)	-4.1%	-
7,000	20%	1,022,000	531,440	490,560	$73,229.90	$72,989.24	($240.66)	-0.3%	-
7,000	30%	1,533,000	797,160	735,840	$76,385.67	$75,606.92	($778.74)	-1.0%	-
7,000	40%	2,044,000	1,062,880	981,120	$79,541.43	$78,224.61	($1,316.83)	-1.7%	-
7,000	50%	2,555,000	1,328,600	1,226,400	$82,697.20	$80,842.29	($1,854.91)	-2.2%	-
7,000	60%	3,066,000	1,594,320	1,471,680	$85,852.96	$83,459.97	($2,392.99)	-2.8%	1
7,000	70%	3,577,000	1,860,040	1,716,960	$89,008.73	$86,077.66	($2,931.07)	-3.3%	-
7,000	80%	4,088,000	2,125,760	1,962,240	$92,164.50	$88,695.34	($3,469.16)	-3.8%	-
7,000	90%	4,599,000	2,391,480	2,207,520	$95,320.26	$91,313.02	($4,007.24)	-4.2%	-
8,000	20%	1,168,000	607,360	560,640	$83,162.11	$82,844.72	($317.39)	-0.4%	-
8,000	30%	1,752,000	911,040	840,960	$86,768.70	$85,836.35	($932.34)	-1.1%	-
8,000	40%	2,336,000	1,214,720	1,121,280	$90,375.29	$88,827.99	($1,547.30)	-1.7%	-
8,000	50%	2,920,000	1,518,400	1,401,600	$93,981.88	$91,819.63	($2,162.25)	-2.3%	-
8,000	60%	3,504,000	1,822,080	1,681,920	$97,588.47	$94,811.27	($2,777.20)	-2.8%	-
8,000	70%	4,088,000	2,125,760	1,962,240	$101,195.06	$97,802.90	($3,392.15)	-3.4%	-
8,000	80%	4,672,000	2,429,440	2,242,560	$104,801.64	$100,794.54	($4,007.10)	-3.8%	-
8,000	90%	5,256,000	2,733,120	2,522,880	$108,408.23	$103,786.18	($4,622.06)	-4.3%	-
9,000	20%	1,314,000	683,280	630,720	$93,094.32	$92,700.19	($394.13)	-0.4%	-
9,000	30%	1,971,000	1,024,920	946,080	$97,151.73	$96,065.78	($1,085.95)	-1.1%	-
9,000	40%	2,628,000	1,366,560	1,261,440	$101,209.14	$99,431.37	($1,777.77)	-1.8%	-
9,000	50%	3,285,000	1,708,200	1,576,800	$105,266.56	$102,796.97	($2,469.59)	-2.3%	-
9,000	60%	3,942,000	2,049,840	1,892,160	$109,323.97	$106,162.56	($3,161.41)	-2.9%	-
9,000	70%	4,599,000	2,391,480	2,207,520	$113,381.38	$109,528.15	($3,853.23)	-3.4%	-
9,000	80%	5,256,000	2,733,120	2,522,880	$117,438.79	$112,893.74	($4,545.05)	-3.9%	-
9,000	90%	5,913,000	3,074,760	2,838,240	$121,496.21	$116,259.33	($5,236.87)	-4.3%	-

		Current Rates	Rate Yr 1
	UOM	SC08Trn	SC08Trn
Customer Charge	Monthly	$ 3,703.73	$ 4,000.00
Demand Charge kW	kW	$ 9.31	$ 9.11
SBC (EETr) per kWh	kWh	$ 0.00105	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ 0.29056	$ -
Tax Credit per kW	kW	$ (0.57000)	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.72	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2020 - April 30, 2021

Delivery Bill Only

PSC #19 - SC 8 - Large General Service - SubTransmission - Industrial

Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Current Rates	Rate Yr 1	increase / (decrease) Amount	Percent	# of Customers
500	20%	73,000	37,960	35,040	$7,277.43	$7,614.14	$336.72	4.6%	1
500	30%	109,500	56,940	52,560	$7,502.84	$7,801.12	$298.28	4.0%	4
500	40%	146,000	75,920	70,080	$7,728.25	$7,988.10	$259.85	3.4%	2
500	50%	182,500	94,900	87,600	$7,953.66	$8,175.08	$221.41	2.8%	2
500	60%	219,000	113,880	105,120	$8,179.08	$8,362.05	$182.98	2.2%	-
500	70%	255,500	132,860	122,640	$8,404.49	$8,549.03	$144.54	1.7%	2
500	80%	292,000	151,840	140,160	$8,629.90	$8,736.01	$106.11	1.2%	-
500	90%	328,500	170,820	157,680	$8,855.31	$8,922.99	$67.67	0.8%	1
1,500	20%	219,000	113,880	105,120	$17,597.31	$17,548.58	($48.72)	-0.3%	2
1,500	30%	328,500	170,820	157,680	$18,273.54	$18,109.51	($164.03)	-0.9%	1
1,500	40%	438,000	227,760	210,240	$18,949.78	$18,670.45	($279.33)	-1.5%	3
1,500	50%	547,500	284,700	262,800	$19,626.01	$19,231.38	($394.63)	-2.0%	4
1,500	60%	657,000	341,640	315,360	$20,302.25	$19,792.31	($509.94)	-2.5%	6
1,500	70%	766,500	398,580	367,920	$20,978.48	$20,353.24	($625.24)	-3.0%	-
1,500	80%	876,000	455,520	420,480	$21,654.72	$20,914.17	($740.55)	-3.4%	1
1,500	90%	985,500	512,460	473,040	$22,330.95	$21,475.11	($855.85)	-3.8%	-
4,500	20%	657,000	341,640	315,360	$48,556.94	$47,351.89	($1,205.04)	-2.5%	3
4,500	30%	985,500	512,460	473,040	$50,585.64	$49,034.69	($1,550.96)	-3.1%	2
4,500	40%	1,314,000	683,280	630,720	$52,614.35	$50,717.49	($1,896.87)	-3.6%	4
4,500	50%	1,642,500	854,100	788,400	$54,643.06	$52,400.28	($2,242.78)	-4.1%	1
4,500	60%	1,971,000	1,024,920	946,080	$56,671.76	$54,083.08	($2,588.69)	-4.6%	5
4,500	70%	2,299,500	1,195,740	1,103,760	$58,700.47	$55,765.87	($2,934.60)	-5.0%	-
4,500	80%	2,628,000	1,366,560	1,261,440	$60,729.18	$57,448.67	($3,280.51)	-5.4%	-
4,500	90%	2,956,500	1,537,380	1,419,120	$62,757.88	$59,131.47	($3,626.42)	-5.8%	-
6,000	20%	876,000	455,520	420,480	$64,036.75	$62,253.55	($1,783.21)	-2.8%	-
6,000	30%	1,314,000	683,280	630,720	$66,741.70	$64,497.28	($2,244.42)	-3.4%	-
6,000	40%	1,752,000	911,040	840,960	$69,446.64	$66,741.00	($2,705.63)	-3.9%	-
6,000	50%	2,190,000	1,138,800	1,051,200	$72,151.58	$68,984.73	($3,166.85)	-4.4%	1
6,000	60%	2,628,000	1,366,560	1,261,440	$74,856.52	$71,228.46	($3,628.06)	-4.8%	-
6,000	70%	3,066,000	1,594,320	1,471,680	$77,561.46	$73,472.19	($4,089.28)	-5.3%	-
6,000	80%	3,504,000	1,822,080	1,681,920	$80,266.41	$75,715.92	($4,550.49)	-5.7%	1
6,000	90%	3,942,000	2,049,840	1,892,160	$82,971.35	$77,959.64	($5,011.70)	-6.0%	3

	UOM	Current Rates SC08SubTrn-I	Rate Yr 1 SC08SubTrn-I
Customer Charge	Monthly	$ 2,116.77	$ 2,646.00
Demand Charge kW	kW	$ 9.68	$ 9.19
SBC (EETr) per kWh	kWh	$ 0.00105	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ 0.25823	$ -
Tax Credit per kW	kW	$ (0.52000)	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.72	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2020 - April 30, 2021

Delivery Bill Only

PSC #19 - SC 8 - Large General Service - SubTransmission - Commercial									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Current Rates	Rate Yr 1	Amount	Percent	# of Customers
500	20%	73,000	37,960	35,040	$7,571.64	$7,773.03	$201.39	2.7%	-
500	30%	109,500	56,940	52,560	$7,797.05	$7,960.00	$162.96	2.1%	2
500	40%	146,000	75,920	70,080	$8,022.46	$8,146.98	$124.52	1.6%	6
500	50%	182,500	94,900	87,600	$8,247.87	$8,333.96	$86.09	1.0%	4
500	60%	219,000	113,880	105,120	$8,473.28	$8,520.94	$47.65	0.6%	4
500	70%	255,500	132,860	122,640	$8,698.69	$8,707.91	$9.22	0.1%	2
500	80%	292,000	151,840	140,160	$8,924.11	$8,894.89	($29.22)	-0.3%	-
500	90%	328,500	170,820	157,680	$9,149.52	$9,081.87	($67.65)	-0.7%	-
1,500	20%	219,000	113,880	105,120	$18,658.23	$18,247.23	($411.00)	-2.2%	1
1,500	30%	328,500	170,820	157,680	$19,334.46	$18,808.16	($526.30)	-2.7%	3
1,500	40%	438,000	227,760	210,240	$20,010.70	$19,369.09	($641.60)	-3.2%	5
1,500	50%	547,500	284,700	262,800	$20,686.93	$19,930.03	($756.91)	-3.7%	11
1,500	60%	657,000	341,640	315,360	$21,363.17	$20,490.96	($872.21)	-4.1%	4
1,500	70%	766,500	398,580	367,920	$22,039.40	$21,051.89	($987.52)	-4.5%	3
1,500	80%	876,000	455,520	420,480	$22,715.64	$21,612.82	($1,102.82)	-4.9%	-
1,500	90%	985,500	512,460	473,040	$23,391.88	$22,173.75	($1,218.12)	-5.2%	-
4,500	20%	657,000	341,640	315,360	$51,918.00	$49,669.84	($2,248.16)	-4.3%	-
4,500	30%	985,500	512,460	473,040	$53,946.71	$51,352.63	($2,594.08)	-4.8%	2
4,500	40%	1,314,000	683,280	630,720	$55,975.41	$53,035.43	($2,939.99)	-5.3%	3
4,500	50%	1,642,500	854,100	788,400	$58,004.12	$54,718.22	($3,285.90)	-5.7%	1
4,500	60%	1,971,000	1,024,920	946,080	$60,032.83	$56,401.02	($3,631.81)	-6.0%	1
4,500	70%	2,299,500	1,195,740	1,103,760	$62,061.53	$58,083.82	($3,977.72)	-6.4%	1
4,500	80%	2,628,000	1,366,560	1,261,440	$64,090.24	$59,766.61	($4,323.63)	-6.7%	-
4,500	90%	2,956,500	1,537,380	1,419,120	$66,118.95	$61,449.41	($4,669.54)	-7.1%	-
6,000	20%	876,000	455,520	420,480	$68,547.89	$65,381.14	($3,166.75)	-4.6%	-
6,000	30%	1,314,000	683,280	630,720	$71,252.83	$67,624.87	($3,627.96)	-5.1%	-
6,000	40%	1,752,000	911,040	840,960	$73,957.77	$69,868.60	($4,089.18)	-5.5%	-
6,000	50%	2,190,000	1,138,800	1,051,200	$76,662.71	$72,112.32	($4,550.39)	-5.9%	-
6,000	60%	2,628,000	1,366,560	1,261,440	$79,367.66	$74,356.05	($5,011.60)	-6.3%	1
6,000	70%	3,066,000	1,594,320	1,471,680	$82,072.60	$76,599.78	($5,472.82)	-6.7%	1
6,000	80%	3,504,000	1,822,080	1,681,920	$84,777.54	$78,843.51	($5,934.03)	-7.0%	-
6,000	90%	3,942,000	2,049,840	1,892,160	$87,482.48	$81,087.24	($6,395.25)	-7.3%	-

		Current Rates	Rate Yr 1
	UOM	SC08SubTrn-C	SC08SubTrn-C
Customer Charge	Monthly	$ 2,027.62	$ 2,535.00
Demand Charge kW	kW	$ 10.51	$ 9.73
SBC (EETr) per kWh	kWh	$ 0.00105	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ 0.33494	$ -
Tax Credit per kW	kW	$ (0.66000)	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.72	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2020 - April 30, 2021

Delivery Bill Only

PSC #19 - SC 8 - Large General Service - Primary

Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Current Rates	Rate Yr 1	increase / (decrease) Amount	Percent	# of Customers
250	20%	36,500	18,980	17,520	$4,934.66	$5,133.57	$198.91	4.0%	5
250	30%	54,750	28,470	26,280	$5,047.36	$5,227.06	$179.69	3.6%	7
250	40%	73,000	37,960	35,040	$5,160.07	$5,320.55	$160.48	3.1%	3
250	50%	91,250	47,450	43,800	$5,272.78	$5,414.03	$141.26	2.7%	8
250	60%	109,500	56,940	52,560	$5,385.48	$5,507.52	$122.04	2.3%	1
250	70%	127,750	66,430	61,320	$5,498.19	$5,601.01	$102.82	1.9%	2
250	80%	146,000	75,920	70,080	$5,610.89	$5,694.50	$83.61	1.5%	1
250	90%	164,250	85,410	78,840	$5,723.60	$5,787.99	$64.39	1.1%	-
500	20%	73,000	37,960	35,040	$8,723.73	$8,835.21	$111.49	1.3%	2
500	30%	109,500	56,940	52,560	$8,949.14	$9,022.19	$73.05	0.8%	8
500	40%	146,000	75,920	70,080	$9,174.55	$9,209.17	$34.62	0.4%	14
500	50%	182,500	94,900	87,600	$9,399.96	$9,396.14	($3.82)	0.0%	20
500	60%	219,000	113,880	105,120	$9,625.37	$9,583.12	($42.25)	-0.4%	10
500	70%	255,500	132,860	122,640	$9,850.79	$9,770.10	($80.69)	-0.8%	3
500	80%	292,000	151,840	140,160	$10,076.20	$9,957.08	($119.12)	-1.2%	2
500	90%	328,500	170,820	157,680	$10,301.61	$10,144.05	($157.56)	-1.5%	-
1,500	20%	219,000	113,880	105,120	$23,880.00	$23,641.78	($238.22)	-1.0%	4
1,500	30%	328,500	170,820	157,680	$24,556.23	$24,202.71	($353.52)	-1.4%	18
1,500	40%	438,000	227,760	210,240	$25,232.47	$24,763.65	($468.82)	-1.9%	21
1,500	50%	547,500	284,700	262,800	$25,908.71	$25,324.58	($584.13)	-2.3%	12
1,500	60%	657,000	341,640	315,360	$26,584.94	$25,885.51	($699.43)	-2.6%	4
1,500	70%	766,500	398,580	367,920	$27,261.18	$26,446.44	($814.73)	-3.0%	4
1,500	80%	876,000	455,520	420,480	$27,937.41	$27,007.37	($930.04)	-3.3%	1
1,500	90%	985,500	512,460	473,040	$28,613.65	$27,568.31	($1,045.34)	-3.7%	-
2,000	20%	292,000	151,840	140,160	$31,458.13	$31,045.07	($413.07)	-1.3%	-
2,000	30%	438,000	227,760	210,240	$32,359.78	$31,792.98	($566.80)	-1.8%	-
2,000	40%	584,000	303,680	280,320	$33,261.43	$32,540.89	($720.54)	-2.2%	-
2,000	50%	730,000	379,600	350,400	$34,163.08	$33,288.80	($874.28)	-2.6%	2
2,000	60%	876,000	455,520	420,480	$35,064.72	$34,036.71	($1,028.02)	-2.9%	1
2,000	70%	1,022,000	531,440	490,560	$35,966.37	$34,784.62	($1,181.76)	-3.3%	-
2,000	80%	1,168,000	607,360	560,640	$36,868.02	$35,532.52	($1,335.49)	-3.6%	1
2,000	90%	1,314,000	683,280	630,720	$37,769.67	$36,280.43	($1,489.23)	-3.9%	6

	UOM	Current Rates SC08Pri	Rate Yr 1 SC08Pri
Customer Charge	Monthly	$ 1,144.87	$ 1,431.00
Demand Charge kW	kW	$ 14.71	$ 14.06
SBC (EETr) per kWh	kWh	$ 0.00105	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ 0.46463	$ -
Tax Credit per kW	kW	$ (0.92000)	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.72	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2020 - April 30, 2021

Delivery Bill Only

PSC #19 - SC 8 - Large General Service - Secondary

Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Current Rates	Rate Yr 1	increase / (decrease) Amount	Percent	# of Customers
250	20%	36,500	18,980	17,520	$4,800.16	$4,863.56	$63.39	1.3%	15
250	30%	54,750	28,470	26,280	$4,912.87	$4,957.05	$44.18	0.9%	15
250	40%	73,000	37,960	35,040	$5,025.57	$5,050.53	$24.96	0.5%	31
250	50%	91,250	47,450	43,800	$5,138.28	$5,144.02	$5.74	0.1%	37
250	60%	109,500	56,940	52,560	$5,250.99	$5,237.51	($13.47)	-0.3%	27
250	70%	127,750	66,430	61,320	$5,363.69	$5,331.00	($32.69)	-0.6%	5
250	80%	146,000	75,920	70,080	$5,476.40	$5,424.49	($51.91)	-0.9%	4
250	90%	164,250	85,410	78,840	$5,589.10	$5,517.98	($71.13)	-1.3%	-
500	20%	73,000	37,960	35,040	$8,689.14	$8,588.19	($100.95)	-1.2%	6
500	30%	109,500	56,940	52,560	$8,914.55	$8,775.16	($139.38)	-1.6%	35
500	40%	146,000	75,920	70,080	$9,139.96	$8,962.14	($177.82)	-1.9%	65
500	50%	182,500	94,900	87,600	$9,365.37	$9,149.12	($216.25)	-2.3%	40
500	60%	219,000	113,880	105,120	$9,590.78	$9,336.10	($254.69)	-2.7%	27
500	70%	255,500	132,860	122,640	$9,816.19	$9,523.07	($293.12)	-3.0%	11
500	80%	292,000	151,840	140,160	$10,041.61	$9,710.05	($331.55)	-3.3%	5
500	90%	328,500	170,820	157,680	$10,267.02	$9,897.03	($369.99)	-3.6%	1
1,500	20%	219,000	113,880	105,120	$24,245.03	$23,486.71	($758.31)	-3.1%	19
1,500	30%	328,500	170,820	157,680	$24,921.26	$24,047.64	($873.62)	-3.5%	22
1,500	40%	438,000	227,760	210,240	$25,597.50	$24,608.57	($988.92)	-3.9%	18
1,500	50%	547,500	284,700	262,800	$26,273.73	$25,169.51	($1,104.23)	-4.2%	5
1,500	60%	657,000	341,640	315,360	$26,949.97	$25,730.44	($1,219.53)	-4.5%	2
1,500	70%	766,500	398,580	367,920	$27,626.20	$26,291.37	($1,334.83)	-4.8%	2
1,500	80%	876,000	455,520	420,480	$28,302.44	$26,852.30	($1,450.14)	-5.1%	-
1,500	90%	985,500	512,460	473,040	$28,978.67	$27,413.23	($1,565.44)	-5.4%	-
2,000	20%	292,000	151,840	140,160	$32,022.97	$30,935.97	($1,087.00)	-3.4%	-
2,000	30%	438,000	227,760	210,240	$32,924.62	$31,683.88	($1,240.74)	-3.8%	-
2,000	40%	584,000	303,680	280,320	$33,826.27	$32,431.79	($1,394.47)	-4.1%	-
2,000	50%	730,000	379,600	350,400	$34,727.91	$33,179.70	($1,548.21)	-4.5%	-
2,000	60%	876,000	455,520	420,480	$35,629.56	$33,927.61	($1,701.95)	-4.8%	1
2,000	70%	1,022,000	531,440	490,560	$36,531.21	$34,675.52	($1,855.69)	-5.1%	1
2,000	80%	1,168,000	607,360	560,640	$37,432.85	$35,423.43	($2,009.43)	-5.4%	-
2,000	90%	1,314,000	683,280	630,720	$38,334.50	$36,171.34	($2,163.16)	-5.6%	-

	UOM	Current Rates SC08Sec	Rate Yr 1 SC08Sec
Customer Charge	Monthly	$ 910.47	$ 1,138.00
Demand Charge kW	kW	$ 15.13	$ 14.15
SBC (EETr) per kWh	kWh	$ 0.00105	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ 0.49424	$ -
Tax Credit per kW	kW	$ (0.97000)	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.72	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2020 - April 30, 2021

Delivery Bill Only

PSC #19 - SC 8 - Large General Service - SubStation

Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Current Rates	Rate Yr 1	increase / (decrease) Amount	Percent	# of Customers
250	20%	36,500	18,980	17,520	$4,500.42	$4,746.48	$246.07	5.5%	-
250	30%	54,750	28,470	26,280	$4,613.12	$4,839.97	$226.85	4.9%	1
250	40%	73,000	37,960	35,040	$4,725.83	$4,933.46	$207.63	4.4%	2
250	50%	91,250	47,450	43,800	$4,838.53	$5,026.95	$188.42	3.9%	1
250	60%	109,500	56,940	52,560	$4,951.24	$5,120.44	$169.20	3.4%	1
250	70%	127,750	66,430	61,320	$5,063.94	$5,213.93	$149.98	3.0%	2
250	80%	146,000	75,920	70,080	$5,176.65	$5,307.42	$130.76	2.5%	-
250	90%	164,250	85,410	78,840	$5,289.36	$5,400.90	$111.55	2.1%	-
500	20%	73,000	37,960	35,040	$7,030.56	$7,030.04	($0.52)	0.0%	-
500	30%	109,500	56,940	52,560	$7,255.97	$7,217.02	($38.95)	-0.5%	1
500	40%	146,000	75,920	70,080	$7,481.38	$7,403.99	($77.39)	-1.0%	1
500	50%	182,500	94,900	87,600	$7,706.80	$7,590.97	($115.82)	-1.5%	4
500	60%	219,000	113,880	105,120	$7,932.21	$7,777.95	($154.26)	-1.9%	3
500	70%	255,500	132,860	122,640	$8,157.62	$7,964.93	($192.69)	-2.4%	2
500	80%	292,000	151,840	140,160	$8,383.03	$8,151.90	($231.13)	-2.8%	-
500	90%	328,500	170,820	157,680	$8,608.44	$8,338.88	($269.56)	-3.1%	-
2,000	20%	292,000	151,840	140,160	$22,211.43	$20,731.38	($1,480.05)	-6.7%	6
2,000	30%	438,000	227,760	210,240	$23,113.08	$21,479.29	($1,633.79)	-7.1%	4
2,000	40%	584,000	303,680	280,320	$24,014.73	$22,227.20	($1,787.53)	-7.4%	1
2,000	50%	730,000	379,600	350,400	$24,916.37	$22,975.11	($1,941.26)	-7.8%	-
2,000	60%	876,000	455,520	420,480	$25,818.02	$23,723.02	($2,095.00)	-8.1%	-
2,000	70%	1,022,000	531,440	490,560	$26,719.67	$24,470.93	($2,248.74)	-8.4%	-
2,000	80%	1,168,000	607,360	560,640	$27,621.32	$25,218.84	($2,402.48)	-8.7%	-
2,000	90%	1,314,000	683,280	630,720	$28,522.96	$25,966.75	($2,556.22)	-9.0%	-
2,500	20%	365,000	189,800	175,200	$27,271.72	$25,298.50	($1,973.23)	-7.2%	-
2,500	30%	547,500	284,700	262,800	$28,398.78	$26,233.38	($2,165.40)	-7.6%	-
2,500	40%	730,000	379,600	350,400	$29,525.84	$27,168.27	($2,357.57)	-8.0%	-
2,500	50%	912,500	474,500	438,000	$30,652.90	$28,103.16	($2,549.74)	-8.3%	-
2,500	60%	1,095,000	569,400	525,600	$31,779.96	$29,038.04	($2,741.92)	-8.6%	1
2,500	70%	1,277,500	664,300	613,200	$32,907.02	$29,972.93	($2,934.09)	-8.9%	1
2,500	80%	1,460,000	759,200	700,800	$34,034.08	$30,907.82	($3,126.26)	-9.2%	-
2,500	90%	1,642,500	854,100	788,400	$35,161.14	$31,842.70	($3,318.43)	-9.4%	-

	UOM	Current Rates SC08SubSta	Rate Yr 1 SC08SubSta
Customer Charge	Monthly	$ 1,969.55	$ 2,462.00
Demand Charge kW	kW	$ 9.55	$ 8.39
SBC (EETr) per kWh	kWh	$ 0.00105	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ 0.33893	$ -
Tax Credit per kW	kW	$ (0.67000)	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.72	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2020 - April 30, 2021

Delivery Bill Only

PSC #19 - SC 9 - General Service - TOU

Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Current Rates	Rate Yr 1	increase / (decrease) Amount	Percent	# of Customers
10	20%	1,460	759	701	$243.83	$242.61	($1.22)	-0.5%	19
10	30%	2,190	1,139	1,051	$257.84	$253.95	($3.89)	-1.5%	17
10	40%	2,920	1,518	1,402	$271.84	$265.29	($6.56)	-2.4%	25
10	50%	3,650	1,898	1,752	$285.85	$276.63	($9.22)	-3.2%	17
10	60%	4,380	2,278	2,102	$299.86	$287.96	($11.89)	-4.0%	12
10	70%	5,110	2,657	2,453	$313.86	$299.30	($14.56)	-4.6%	7
10	80%	5,840	3,037	2,803	$327.87	$310.64	($17.23)	-5.3%	1
10	90%	6,570	3,416	3,154	$341.87	$321.98	($19.90)	-5.8%	3
25	20%	3,650	1,898	1,752	$465.25	$461.90	($3.36)	-0.7%	11
25	30%	5,475	2,847	2,628	$500.27	$490.24	($10.03)	-2.0%	27
25	40%	7,300	3,796	3,504	$535.28	$518.58	($16.70)	-3.1%	30
25	50%	9,125	4,745	4,380	$570.30	$546.93	($23.37)	-4.1%	24
25	60%	10,950	5,694	5,256	$605.31	$575.27	($30.04)	-5.0%	12
25	70%	12,775	6,643	6,132	$640.32	$603.61	($36.71)	-5.7%	3
25	80%	14,600	7,592	7,008	$675.34	$631.96	($43.38)	-6.4%	-
25	90%	16,425	8,541	7,884	$710.35	$660.30	($50.05)	-7.0%	3
100	20%	14,600	7,592	7,008	$1,572.35	$1,558.31	($14.04)	-0.9%	27
100	30%	21,900	11,388	10,512	$1,712.41	$1,671.68	($40.73)	-2.4%	32
100	40%	29,200	15,184	14,016	$1,852.46	$1,785.06	($67.41)	-3.6%	18
100	50%	36,500	18,980	17,520	$1,992.52	$1,898.43	($94.09)	-4.7%	9
100	60%	43,800	22,776	21,024	$2,132.58	$2,011.81	($120.77)	-5.7%	6
100	70%	51,100	26,572	24,528	$2,272.63	$2,125.18	($147.45)	-6.5%	2
100	80%	58,400	30,368	28,032	$2,412.69	$2,238.55	($174.13)	-7.2%	-
100	90%	65,700	34,164	31,536	$2,552.74	$2,351.93	($200.81)	-7.9%	-
200	20%	29,200	15,184	14,016	$3,048.49	$3,020.19	($28.29)	-0.9%	1
200	30%	43,800	22,776	21,024	$3,328.60	$3,246.94	($81.66)	-2.5%	2
200	40%	58,400	30,368	28,032	$3,608.71	$3,473.69	($135.02)	-3.7%	4
200	50%	73,000	37,960	35,040	$3,888.82	$3,700.44	($188.38)	-4.8%	-
200	60%	87,600	45,552	42,048	$4,168.93	$3,927.18	($241.75)	-5.8%	-
200	70%	102,200	53,144	49,056	$4,449.04	$4,153.93	($295.11)	-6.6%	-
200	80%	116,800	60,736	56,064	$4,729.15	$4,380.68	($348.47)	-7.4%	-
200	90%	131,400	68,328	63,072	$5,009.26	$4,607.43	($401.84)	-8.0%	-

	UOM	Current Rates SC09	Rate Yr 1 SC09
Customer Charge	Monthly	$ 95.50	$ 95.50
Demand Charge kW	kW	$ 12.26	$ 12.35
Delivery Charge On Peak kWh	kWh-On	$ 0.01408	$ 0.01041
Delivery Charge Off Peak kWh	kWh-Off	$ 0.01408	$ 0.01041
SBC (EETr) per kWh	kWh	$ 0.00105	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ 0.62024	$ -
Tax Credit All Hours kWh	kWh	$ (0.00107)	$ -
Tax Credit per kW	kW	$ (0.92000)	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.72	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Standby Bill Impacts by SC
May 1, 2020 - April 30, 2021

	$(000) Revenue at Current Rates	$(000) Revenue at Rate Yr 1 Rates	$(000) Increase (000)	% % Increase or Decrease
Customer Charge				
SC3	$ 21.4	$ 21.4	$ -	0.00%
SC8 Pri	$ 41.2	$ 51.5	$ 10.3	24.99%
SC8 Sec	$ 32.8	$ 41.0	$ 8.2	24.99%
SC8 SubTran Ind	$ 97.3	$ 121.7	$ 24.4	25.02%
SC8 SubTran Comm	$ 25.4	$ 31.8	$ 6.4	25.00%
SC8 Substation	$ 94.5	$ 118.2	$ 23.6	25.00%
	$ 312.7	$ 385.5	$ 72.8	23.30%
Contract Demand				
SC3	$ 219.9	$ 195.9	$ (24.1)	-10.95%
SC8 Pri	$ 141.7	$ 145.7	$ 4.0	2.84%
SC8 Sec	$ 99.8	$ 98.6	$ (1.2)	-1.19%
SC8 SubTran Ind	$ 371.4	$ 407.4	$ 36.0	9.69%
SC8 SubTran Comm	$ 607.3	$ 640.9	$ 33.6	5.54%
SC8 Substation	$ 169.1	$ 187.0	$ 17.9	10.61%
	$ 1,609.2	$ 1,675.5	$ 66.3	4.12%
Daily As-Used Demand				
SC3	$ 87.6	$ 78.0	$ (9.6)	-10.95%
SC8 Pri	$ 91.8	$ 94.4	$ 2.6	2.84%
SC8 Sec	$ 65.2	$ 64.5	$ (0.8)	-1.19%
SC8 SubTran Ind	$ 1,417.5	$ 1,554.8	$ 137.3	9.69%
SC8 SubTran Comm	$ 598.2	$ 631.3	$ 33.1	5.54%
SC8 Substation	$ 86.6	$ 95.7	$ 9.2	10.61%
	$ 2,346.8	$ 2,518.7	$ 171.9	7.32%
Total				
SC3	$ 328.9	$ 295.2	$ (33.7)	-10.24%
SC8 Pri	$ 274.7	$ 291.6	$ 16.9	6.16%
SC8 Sec	$ 197.8	$ 204.0	$ 6.2	3.15%
SC8 SubTran Ind	$ 1,886.2	$ 2,083.9	$ 197.7	10.48%
SC8 SubTran Comm	$ 1,230.9	$ 1,304.0	$ 73.1	5.94%
SC8 Substation	$ 350.2	$ 401.0	$ 50.8	14.49%
	$ 4,268.7	$ 4,579.7	$ 311.0	7.29%

Rochester Gas and Electric Corporation

Date Sources - RG&E Electric Bill Impact Statements

Rate	Source of Rate in "Current" Rates	Source of Rate in Rate Years
Customer Charge	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
kW Charge	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
kWh Delivery Charge All Hours	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
kWh Delivery Charge On Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
kWh Delivery Charge Mid Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
kWh Delivery Charge Off Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
Reactive RkVah	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
Billing Charge per Bill	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
SBC (EETr) per kWh	Current Tariff Rates in Effect 01/01/2020. Statement #26.	Included in Delivery Rates
SBC (CEF) per kWh	Current Tariff Rates in Effect 01/01/2020. Statement #26.	Current Tariff Rates in Effect 01/01/2020. Statement #26.
RAM per kWh	Tariff Rates in Effect 07/01/2019.	No RAM charge is being forecasted at this time for the rate years
RAM per kW	Tariff Rates in Effect 07/01/2019.	No RAM charge is being forecasted at this time for the rate years
Tax Credit per kWh	Case No. 17-M-0815 dated August 9, 2018. Statement Number 1	Included in Delivery Rates
Tax Credit per kW	Case No. 17-M-0815 dated August 9, 2018. Statement Number 1	Included in Delivery Rates
Rate	**Source of Rate in "Current" Rates and Rate Years**	
Transition Charge per kWh	NBC, Demand Response, and Value Stack: NBC is the Non-Weighted 2019 Average. Dmd Rsp iat $-0-. Value Stack at $-0-. RAM is separate.	
MFC per kWh	Non-Weighted 2019 Average of Monthly MFC Charge	
kWh Supply Charge All Hours	2019 Annualized Supply Rates	
kWh Supply Charge On Peak	2019 Annualized Supply Rates	
kWh Supply Charge Mid Peak	2019 Annualized Supply Rates	
kWh Supply Charge Off Peak	2019 Annualized Supply Rates	
Customer Count	2018 monthly data - separate Low Income counts	

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2021 - April 30, 2022

Including Supply

PSC #19 - SC 1 - Residential

kWh	Rate Yr 1	Rate Yr 2	increase / (decrease) Amount	Percent	# of Customers	# of Low Income Customers	Percent of Customers	Percent of Low Income Customers	Amount of EE Embedded in Delivery Rates* Amount	Percent
100	$31.25	$32.15	$0.90	2.9%	10,907	539	3%	1%	$ 0.16	0.49%
200	$40.19	$41.68	$1.49	3.7%	25,369	2,787	7%	8%	$ 0.31	0.75%
300	$49.14	$51.21	$2.07	4.2%	33,669	4,537	10%	12%	$ 0.47	0.91%
400	$58.08	$60.74	$2.66	4.6%	37,090	5,036	11%	14%	$ 0.62	1.03%
500	$67.03	$70.27	$3.24	4.8%	38,010	4,932	11%	13%	$ 0.78	1.11%
600	$75.97	$79.79	$3.82	5.0%	35,693	4,208	11%	11%	$ 0.94	1.17%
700	$84.92	$89.32	$4.41	5.2%	31,811	3,427	9%	9%	$ 1.09	1.22%
800	$93.86	$98.85	$4.99	5.3%	27,030	2,744	8%	7%	$ 1.25	1.26%
900	$102.80	$108.38	$5.57	5.4%	22,238	2,191	7%	6%	$ 1.41	1.30%
1,000	$111.75	$117.91	$6.16	5.5%	17,500	1,598	5%	4%	$ 1.56	1.32%
1,100	$120.69	$127.43	$6.74	5.6%	13,667	1,211	4%	3%	$ 1.72	1.35%
1,200	$129.64	$136.96	$7.33	5.7%	10,434	907	3%	2%	$ 1.87	1.37%
1,500	$156.47	$165.55	$9.08	5.8%	18,454	1,568	5%	4%	$ 2.34	1.41%
2,000	$201.19	$213.19	$12.00	6.0%	11,052	901	3%	2%	$ 3.12	1.46%
3,000	$290.63	$308.47	$17.83	6.1%	5,347	334	2%	1%	$ 4.68	1.52%
					338,269	36,919				

	UOM	Rate Yr 1 SC01	Rate Yr 2 SC01
Customer Charge	Monthly	$ 21.38	$ 21.70
Delivery Charge All Hours kWh	kWh	$ 0.04569	$ 0.05153
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kWh	kWh	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00206)	$ (0.00206)
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93
Supply Charge All Hours kWh	kWh	$ 0.03736	$ 0.03736
MFC per kWh	kWh	$ 0.00309	$ 0.00309

Includes $ 0.00156 per kWh of EE Costs*

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

4. Low income customers represent customers who participated in the Company's low income program and received a credit on their bill each month during calendar year 2018.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2021 - April 30, 2022
Including Supply

PSC #19 - SC 2 - General Service - Non Demand					
			increase / (decrease)		# of
kWh	Rate Yr 1	Rate Yr 2	Amount	Percent	Customers
300	$47.00	$48.78	$1.78	3.8%	11,999
400	$55.24	$57.50	$2.26	4.1%	2,601
500	$63.47	$66.22	$2.75	4.3%	2,299
600	$71.70	$74.94	$3.23	4.5%	1,892
700	$79.93	$83.65	$3.72	4.7%	1,541
800	$88.17	$92.37	$4.21	4.8%	1,322
900	$96.40	$101.09	$4.69	4.9%	1,021
1,000	$104.63	$109.81	$5.18	4.9%	904
1,500	$145.79	$153.40	$7.61	5.2%	2,999
2,000	$186.96	$196.99	$10.03	5.4%	1,654
2,500	$228.12	$240.58	$12.46	5.5%	845
3,000	$269.28	$284.17	$14.89	5.5%	385
4,000	$351.61	$371.36	$19.75	5.6%	203
5,000	$433.94	$458.54	$24.60	5.7%	60
6,000	$516.26	$545.72	$29.46	5.7%	21
7,000	$598.59	$632.90	$34.32	5.7%	59

		Rate Yr 1	Rate Yr 2
	UOM	SC02	SC02
Customer Charge	Monthly	$ 21.38	$ 21.70
Delivery Charge All Hours kWh	kWh	$ 0.03592	$ 0.04078
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kWh	kWh	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93
Supply Charge All Hours kWh	kWh	$ 0.03819	$ 0.03819
MFC per kWh	kWh	$ 0.00309	$ 0.00309

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2021 - April 30, 2022

Including Supply

PSC #19 - SC 3 - General Service - Demand

Kw	Load Factor	kWh	Rate Yr 1	Rate Yr 2	increase / (decrease) Amount	Percent	# of Customers
50	20%	7,300	$1,447.90	$1,539.72	$91.82	6.3%	45
50	30%	10,950	$1,594.32	$1,686.14	$91.82	5.8%	19
50	40%	14,600	$1,740.74	$1,832.56	$91.82	5.3%	18
50	50%	18,250	$1,887.17	$1,978.99	$91.82	4.9%	18
50	60%	21,900	$2,033.59	$2,125.41	$91.82	4.5%	1
50	70%	25,550	$2,180.01	$2,271.83	$91.82	4.2%	3
50	80%	29,200	$2,326.43	$2,418.25	$91.82	3.9%	3
50	90%	32,850	$2,472.85	$2,564.67	$91.82	3.7%	2
100	20%	14,600	$2,597.74	$2,729.51	$131.77	5.1%	43
100	30%	21,900	$2,890.59	$3,022.36	$131.77	4.6%	73
100	40%	29,200	$3,183.43	$3,315.20	$131.77	4.1%	122
100	50%	36,500	$3,476.27	$3,608.05	$131.77	3.8%	115
100	60%	43,800	$3,769.12	$3,900.89	$131.77	3.5%	47
100	70%	51,100	$4,061.96	$4,193.74	$131.77	3.2%	32
100	80%	58,400	$4,354.81	$4,486.58	$131.77	3.0%	9
100	90%	65,700	$4,647.65	$4,779.42	$131.77	2.8%	6
275	20%	40,150	$6,622.19	$6,893.79	$271.60	4.1%	146
275	30%	60,225	$7,427.51	$7,699.11	$271.60	3.7%	223
275	40%	80,300	$8,232.83	$8,504.44	$271.60	3.3%	130
275	50%	100,375	$9,038.16	$9,309.76	$271.60	3.0%	69
275	60%	120,450	$9,843.48	$10,115.08	$271.60	2.8%	24
275	70%	140,525	$10,648.80	$10,920.40	$271.60	2.6%	8
275	80%	160,600	$11,454.12	$11,725.72	$271.60	2.4%	2
275	90%	180,675	$12,259.44	$12,531.05	$271.60	2.2%	2
300	20%	43,800	$7,197.11	$7,488.69	$291.58	4.1%	-
300	30%	65,700	$8,075.64	$8,367.22	$291.58	3.6%	2
300	40%	87,600	$8,954.18	$9,245.75	$291.58	3.3%	2
300	50%	109,500	$9,832.71	$10,124.29	$291.58	3.0%	3
300	60%	131,400	$10,711.24	$11,002.82	$291.58	2.7%	-
300	70%	153,300	$11,589.78	$11,881.35	$291.58	2.5%	2
300	80%	175,200	$12,468.31	$12,759.89	$291.58	2.3%	2
300	90%	197,100	$13,346.84	$13,638.42	$291.58	2.2%	3

	UOM	Rate Yr 1 SC03	Rate Yr 2 SC03
Customer Charge	Monthly	$ 297.13	$ 349.00
Demand Charge kW	kW	$ 17.14	$ 17.94
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93
Supply Charge All Hours kWh	kWh	$ 0.03293	$ 0.03293
MFC per kWh	kWh	$ 0.00206	$ 0.00206

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2021 - April 30, 2022

Including Supply

PSC #19 - SC 4-I - Residential - Day/Night							
					increase / (decrease)		# of
kWh	Peak	Off Peak	Rate Yr 1	Rate Yr 2	Amount	Percent	Customers
300	210	90	52.40	53.62	1.22	2.3%	126
400	280	120	61.10	62.58	1.48	2.4%	91
500	350	150	69.80	71.54	1.74	2.5%	104
600	420	180	78.50	80.51	2.00	2.6%	131
700	490	210	87.21	89.47	2.26	2.6%	172
800	560	240	95.91	98.43	2.52	2.6%	191
900	630	270	104.61	107.40	2.78	2.7%	145
1,000	700	300	113.32	116.36	3.04	2.7%	157
1,500	1,050	450	156.83	161.18	4.35	2.8%	589
2,000	1,400	600	200.35	206.00	5.65	2.8%	302
2,500	1,750	750	243.86	250.82	6.95	2.9%	149
3,000	2,100	900	287.38	295.63	8.25	2.9%	61
4,000	2,800	1,200	374.41	385.27	10.86	2.9%	26
5,000	3,500	1,500	461.44	474.90	13.46	2.9%	11
6,000	4,200	1,800	548.47	564.54	16.07	2.9%	1
7,000	4,900	2,100	635.51	654.18	18.67	2.9%	5

		Rate Yr 1	Rate Yr 2
	UOM	SC04-I	SC04-I
Customer Charge	Monthly	$ 25.36	$ 25.80
Delivery Charge On Peak kWh	kWh-On	$ 0.04486	$ 0.04746
Delivery Charge Off Peak kWh	kWh-Off	$ 0.04486	$ 0.04746
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kWh	kWh	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00206)	$ (0.00206)
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93
Supply Charge On Peak kWh	kWh-On	$ 0.04005	$ 0.04005
Supply Charge Off Peak kWh	kWh-Off	$ 0.02742	$ 0.02742
MFC per kWh	kWh	$ 0.00261	$ 0.00261

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.
3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2021 - April 30, 2022

Including Supply

PSC #19 - SC 4-II - Residential - Day/Night							
					increase / (decrease)		
kWh	Peak	Off Peak	Rate Yr 1	Rate Yr 2	Amount	Percent	# of Customers
300	210	90	$59.02	$60.28	$1.26	2.1%	18
400	280	120	$68.77	$70.32	$1.55	2.3%	9
500	350	150	$78.52	$80.35	$1.83	2.3%	15
600	420	180	$88.27	$90.39	$2.12	2.4%	28
700	490	210	$98.02	$100.43	$2.40	2.5%	29
800	560	240	$107.77	$110.46	$2.69	2.5%	38
900	630	270	$117.52	$120.50	$2.97	2.5%	33
1,000	700	300	$127.27	$130.53	$3.26	2.6%	52
1,500	1,050	450	$176.03	$180.71	$4.68	2.7%	238
2,000	1,400	600	$224.78	$230.89	$6.11	2.7%	190
2,500	1,750	750	$273.54	$281.07	$7.53	2.8%	165
3,000	2,100	900	$322.29	$331.25	$8.96	2.8%	83
4,000	2,800	1,200	$419.80	$431.60	$11.80	2.8%	84
5,000	3,500	1,500	$517.31	$531.96	$14.65	2.8%	49
6,000	4,200	1,800	$614.81	$632.31	$17.50	2.8%	33
7,000	4,900	2,100	$712.32	$732.67	$20.35	2.9%	28

		Rate Yr 1	Rate Yr 2
	UOM	SC04-II	SC04-II
Customer Charge	Monthly	$ 28.84	$ 29.25
Delivery Charge On Peak kWh	kWh-On	$ 0.05533	$ 0.05818
Delivery Charge Off Peak kWh	kWh-Off	$ 0.05533	$ 0.05818
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kWh	kWh	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00206)	$ (0.00206)
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93
Supply Charge On Peak kWh	kWh-On	$ 0.04005	$ 0.04005
Supply Charge Off Peak kWh	kWh-Off	$ 0.02742	$ 0.02742
MFC per kWh	kWh	$ 0.00261	$ 0.00261

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.
3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2021 - April 30, 2022

Including Supply

PSC #19 - SC 7 - General Service - Demand

Kw	Load Factor	kWh	Rate Yr 1	Rate Yr 2	increase / (decrease) Amount	Percent	# of Customers
5	20%	730	$210.73	$228.47	$17.74	8.4%	178
5	30%	1,095	$227.83	$245.08	$17.25	7.6%	51
5	40%	1,460	$244.93	$261.69	$16.77	6.8%	36
5	50%	1,825	$262.02	$278.30	$16.28	6.2%	34
5	60%	2,190	$279.12	$294.91	$15.80	5.7%	16
5	70%	2,555	$296.21	$311.52	$15.31	5.2%	14
5	80%	2,920	$313.31	$328.14	$14.83	4.7%	6
5	90%	3,285	$330.40	$344.75	$14.34	4.3%	6
25	20%	3,650	$694.89	$718.66	$23.77	3.4%	2,778
25	30%	5,475	$780.37	$801.71	$21.34	2.7%	1,673
25	40%	7,300	$865.85	$884.76	$18.92	2.2%	888
25	50%	9,125	$951.32	$967.82	$16.49	1.7%	403
25	60%	10,950	$1,036.80	$1,050.87	$14.06	1.4%	155
25	70%	12,775	$1,122.28	$1,133.92	$11.64	1.0%	46
25	80%	14,600	$1,207.76	$1,216.97	$9.21	0.8%	12
25	90%	16,425	$1,293.24	$1,300.02	$6.79	0.5%	7
100	20%	14,600	$2,510.47	$2,556.86	$46.39	1.8%	1,560
100	30%	21,900	$2,852.38	$2,889.07	$36.69	1.3%	618
100	40%	29,200	$3,194.30	$3,221.28	$26.98	0.8%	240
100	50%	36,500	$3,536.21	$3,553.49	$17.28	0.5%	74
100	60%	43,800	$3,878.13	$3,885.70	$7.57	0.2%	44
100	70%	51,100	$4,220.04	$4,217.90	($2.14)	-0.1%	8
100	80%	58,400	$4,561.96	$4,550.11	($11.84)	-0.3%	3
100	90%	65,700	$4,903.87	$4,882.32	($21.55)	-0.4%	2
250	20%	36,500	$6,141.62	$6,233.26	$91.64	1.5%	19
250	30%	54,750	$6,996.41	$7,063.78	$67.37	1.0%	15
250	40%	73,000	$7,851.20	$7,894.30	$43.11	0.5%	5
250	50%	91,250	$8,705.98	$8,724.83	$18.84	0.2%	2
250	60%	109,500	$9,560.77	$9,555.35	($5.42)	-0.1%	-
250	70%	127,750	$10,415.56	$10,385.87	($29.69)	-0.3%	1
250	80%	146,000	$11,270.35	$11,216.39	($53.95)	-0.5%	-
250	90%	164,250	$12,125.13	$12,046.92	($78.22)	-0.6%	-

	UOM	Rate Yr 1 SC07	Rate Yr 2 SC07
Customer Charge	Monthly	$ 88.77	$ 105.00
Demand Charge kW	kW	$ 17.37	$ 17.87
Delivery Charge All Hours kWh	kWh	$ 0.00665	$ 0.00532
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93
Supply Charge All Hours kWh	kWh	$ 0.03301	$ 0.03301
MFC per kWh	kWh	$ 0.00206	$ 0.00206

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.
3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2021 - April 30, 2022

Including Supply

PSC #19 - SC 8 - Large General Service - Transmission									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 1	Rate Yr 2	Amount	Percent	# of Customers
6,000	20%	876,000	455,520	420,480	$91,926.10	$96,150.62	$4,224.52	4.6%	-
6,000	30%	1,314,000	683,280	630,720	$108,566.00	$112,790.52	$4,224.52	3.9%	-
6,000	40%	1,752,000	911,040	840,960	$125,205.89	$129,430.41	$4,224.52	3.4%	-
6,000	50%	2,190,000	1,138,800	1,051,200	$141,845.78	$146,070.31	$4,224.52	3.0%	-
6,000	60%	2,628,000	1,366,560	1,261,440	$158,485.68	$162,710.20	$4,224.52	2.7%	-
6,000	70%	3,066,000	1,594,320	1,471,680	$175,125.57	$179,350.09	$4,224.52	2.4%	-
6,000	80%	3,504,000	1,822,080	1,681,920	$191,765.47	$195,989.99	$4,224.52	2.2%	-
6,000	90%	3,942,000	2,049,840	1,892,160	$208,405.36	$212,629.88	$4,224.52	2.0%	-
7,000	20%	1,022,000	531,440	490,560	$106,580.30	$111,475.57	$4,895.27	4.6%	-
7,000	30%	1,533,000	797,160	735,840	$125,993.51	$130,888.78	$4,895.27	3.9%	-
7,000	40%	2,044,000	1,062,880	981,120	$145,406.72	$150,301.99	$4,895.27	3.4%	-
7,000	50%	2,555,000	1,328,600	1,226,400	$164,819.93	$169,715.20	$4,895.27	3.0%	-
7,000	60%	3,066,000	1,594,320	1,471,680	$184,233.14	$189,128.41	$4,895.27	2.7%	1
7,000	70%	3,577,000	1,860,040	1,716,960	$203,646.35	$208,541.62	$4,895.27	2.4%	-
7,000	80%	4,088,000	2,125,760	1,962,240	$223,059.56	$227,954.83	$4,895.27	2.2%	-
7,000	90%	4,599,000	2,391,480	2,207,520	$242,472.77	$247,368.04	$4,895.27	2.0%	-
8,000	20%	1,168,000	607,360	560,640	$121,234.49	$126,800.52	$5,566.03	4.6%	-
8,000	30%	1,752,000	911,040	840,960	$143,421.02	$148,987.05	$5,566.03	3.9%	-
8,000	40%	2,336,000	1,214,720	1,121,280	$165,607.55	$171,173.57	$5,566.03	3.4%	-
8,000	50%	2,920,000	1,518,400	1,401,600	$187,794.07	$193,360.10	$5,566.03	3.0%	-
8,000	60%	3,504,000	1,822,080	1,681,920	$209,980.60	$215,546.62	$5,566.03	2.7%	-
8,000	70%	4,088,000	2,125,760	1,962,240	$232,167.12	$237,733.15	$5,566.03	2.4%	-
8,000	80%	4,672,000	2,429,440	2,242,560	$254,353.65	$259,919.68	$5,566.03	2.2%	-
8,000	90%	5,256,000	2,733,120	2,522,880	$276,540.18	$282,106.20	$5,566.03	2.0%	-
9,000	20%	1,314,000	683,280	630,720	$135,888.69	$142,125.47	$6,236.78	4.6%	-
9,000	30%	1,971,000	1,024,920	946,080	$160,848.53	$167,085.31	$6,236.78	3.9%	-
9,000	40%	2,628,000	1,366,560	1,261,440	$185,808.37	$192,045.15	$6,236.78	3.4%	-
9,000	50%	3,285,000	1,708,200	1,576,800	$210,768.21	$217,005.00	$6,236.78	3.0%	-
9,000	60%	3,942,000	2,049,840	1,892,160	$235,728.06	$241,964.84	$6,236.78	2.6%	-
9,000	70%	4,599,000	2,391,480	2,207,520	$260,687.90	$266,924.68	$6,236.78	2.4%	-
9,000	80%	5,256,000	2,733,120	2,522,880	$285,647.74	$291,884.52	$6,236.78	2.2%	-
9,000	90%	5,913,000	3,074,760	2,838,240	$310,607.58	$316,844.36	$6,236.78	2.0%	-

		Rate Yr 1	Rate Yr 2
	UOM	SC08Trn	SC08Trn
Customer Charge	Monthly	$ 4,000.00	$ 4,200.00
Demand Charge kW	kW	$ 9.11	$ 9.78
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93
Supply Charge On Peak kWh	kWh-On	$ 0.03594	$ 0.03594
Supply Charge Off Peak kWh	kWh-Off	$ 0.02525	$ 0.02525
MFC per kWh	kWh	$ 0.00206	$ 0.00206

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2021 - April 30, 2022

Including Supply

PSC #19 - SC 8 - Large General Service - SubTransmission - Industrial									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 1	Rate Yr 2	Amount	Percent	# of Customers
500	20%	73,000	37,960	35,040	$10,013.51	$10,275.55	$262.05	2.6%	1
500	30%	109,500	56,940	52,560	$11,400.16	$11,662.21	$262.05	2.3%	4
500	40%	146,000	75,920	70,080	$12,786.82	$13,048.87	$262.05	2.0%	2
500	50%	182,500	94,900	87,600	$14,173.48	$14,435.53	$262.05	1.8%	2
500	60%	219,000	113,880	105,120	$15,560.14	$15,822.18	$262.05	1.7%	-
500	70%	255,500	132,860	122,640	$16,946.80	$17,208.84	$262.05	1.5%	2
500	80%	292,000	151,840	140,160	$18,333.45	$18,595.50	$262.05	1.4%	-
500	90%	328,500	170,820	157,680	$19,720.11	$19,982.16	$262.05	1.3%	1
1,500	20%	219,000	113,880	105,120	$24,746.66	$25,320.81	$574.14	2.3%	2
1,500	30%	328,500	170,820	157,680	$28,906.64	$29,480.78	$574.14	2.0%	1
1,500	40%	438,000	227,760	210,240	$33,066.61	$33,640.75	$574.14	1.7%	3
1,500	50%	547,500	284,700	262,800	$37,226.59	$37,800.73	$574.14	1.5%	4
1,500	60%	657,000	341,640	315,360	$41,386.56	$41,960.70	$574.14	1.4%	6
1,500	70%	766,500	398,580	367,920	$45,546.53	$46,120.67	$574.14	1.3%	-
1,500	80%	876,000	455,520	420,480	$49,706.51	$50,280.65	$574.14	1.2%	1
1,500	90%	985,500	512,460	473,040	$53,866.48	$54,440.62	$574.14	1.1%	-
4,500	20%	657,000	341,640	315,360	$68,946.14	$70,456.56	$1,510.42	2.2%	3
4,500	30%	985,500	512,460	473,040	$81,426.06	$82,936.48	$1,510.42	1.9%	2
4,500	40%	1,314,000	683,280	630,720	$93,905.98	$95,416.41	$1,510.42	1.6%	4
4,500	50%	1,642,500	854,100	788,400	$106,385.91	$107,896.33	$1,510.42	1.4%	1
4,500	60%	1,971,000	1,024,920	946,080	$118,865.83	$120,376.25	$1,510.42	1.3%	5
4,500	70%	2,299,500	1,195,740	1,103,760	$131,345.75	$132,856.17	$1,510.42	1.1%	-
4,500	80%	2,628,000	1,366,560	1,261,440	$143,825.67	$145,336.09	$1,510.42	1.1%	-
4,500	90%	2,956,500	1,537,380	1,419,120	$156,305.59	$157,816.01	$1,510.42	1.0%	-
6,000	20%	876,000	455,520	420,480	$91,045.88	$93,024.44	$1,978.56	2.2%	-
6,000	30%	1,314,000	683,280	630,720	$107,685.78	$109,664.34	$1,978.56	1.8%	-
6,000	40%	1,752,000	911,040	840,960	$124,325.67	$126,304.23	$1,978.56	1.6%	-
6,000	50%	2,190,000	1,138,800	1,051,200	$140,965.57	$142,944.13	$1,978.56	1.4%	1
6,000	60%	2,628,000	1,366,560	1,261,440	$157,605.46	$159,584.02	$1,978.56	1.3%	-
6,000	70%	3,066,000	1,594,320	1,471,680	$174,245.35	$176,223.92	$1,978.56	1.1%	-
6,000	80%	3,504,000	1,822,080	1,681,920	$190,885.25	$192,863.81	$1,978.56	1.0%	1
6,000	90%	3,942,000	2,049,840	1,892,160	$207,525.14	$209,503.70	$1,978.56	1.0%	3

		Rate Yr 1	Rate Yr 2
	UOM	SC08SubTrn-I	SC08SubTrn-I
Customer Charge	Monthly	$ 2,646.00	$ 2,752.00
Demand Charge kW	kW	$ 9.19	$ 9.50
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93
Supply Charge On Peak kWh	kWh-On	$ 0.03594	$ 0.03594
Supply Charge Off Peak kWh	kWh-Off	$ 0.02525	$ 0.02525
MFC per kWh	kWh	$ 0.00206	$ 0.00206

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2021 - April 30, 2022

Including Supply

PSC #19 - SC 8 - Large General Service - SubTransmission - Commercial

Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 1	Rate Yr 2	increase / (decrease) Amount	Percent	# of Customers
500	20%	73,000	37,960	35,040	$10,195.04	$10,559.29	$364.25	3.6%	-
500	30%	109,500	56,940	52,560	$11,593.03	$11,957.27	$364.25	3.1%	2
500	40%	146,000	75,920	70,080	$12,991.01	$13,355.26	$364.25	2.8%	6
500	50%	182,500	94,900	87,600	$14,389.00	$14,753.24	$364.25	2.5%	4
500	60%	219,000	113,880	105,120	$15,786.98	$16,151.23	$364.25	2.3%	4
500	70%	255,500	132,860	122,640	$17,184.96	$17,549.21	$364.25	2.1%	2
500	80%	292,000	151,840	140,160	$18,582.95	$18,947.19	$364.25	2.0%	-
500	90%	328,500	170,820	157,680	$19,980.93	$20,345.18	$364.25	1.8%	-
1,500	20%	219,000	113,880	105,120	$25,513.27	$26,404.01	$890.74	3.5%	1
1,500	30%	328,500	170,820	157,680	$29,707.23	$30,597.96	$890.74	3.0%	3
1,500	40%	438,000	227,760	210,240	$33,901.18	$34,791.92	$890.74	2.6%	5
1,500	50%	547,500	284,700	262,800	$38,095.13	$38,985.87	$890.74	2.3%	11
1,500	60%	657,000	341,640	315,360	$42,289.09	$43,179.83	$890.74	2.1%	4
1,500	70%	766,500	398,580	367,920	$46,483.04	$47,373.78	$890.74	1.9%	3
1,500	80%	876,000	455,520	420,480	$50,676.99	$51,567.73	$890.74	1.8%	-
1,500	90%	985,500	512,460	473,040	$54,870.95	$55,761.69	$890.74	1.6%	-
4,500	20%	657,000	341,640	315,360	$71,467.97	$73,938.18	$2,470.21	3.5%	-
4,500	30%	985,500	512,460	473,040	$84,049.83	$86,520.04	$2,470.21	2.9%	2
4,500	40%	1,314,000	683,280	630,720	$96,631.69	$99,101.90	$2,470.21	2.6%	3
4,500	50%	1,642,500	854,100	788,400	$109,213.55	$111,683.76	$2,470.21	2.3%	1
4,500	60%	1,971,000	1,024,920	946,080	$121,795.41	$124,265.62	$2,470.21	2.0%	1
4,500	70%	2,299,500	1,195,740	1,103,760	$134,377.27	$136,847.49	$2,470.21	1.8%	1
4,500	80%	2,628,000	1,366,560	1,261,440	$146,959.13	$149,429.35	$2,470.21	1.7%	-
4,500	90%	2,956,500	1,537,380	1,419,120	$159,540.99	$162,011.21	$2,470.21	1.5%	-
6,000	20%	876,000	455,520	420,480	$94,445.31	$97,705.26	$3,259.95	3.5%	-
6,000	30%	1,314,000	683,280	630,720	$111,221.13	$114,481.08	$3,259.95	2.9%	-
6,000	40%	1,752,000	911,040	840,960	$127,996.94	$131,256.89	$3,259.95	2.5%	-
6,000	50%	2,190,000	1,138,800	1,051,200	$144,772.76	$148,032.71	$3,259.95	2.3%	-
6,000	60%	2,628,000	1,366,560	1,261,440	$161,548.57	$164,808.52	$3,259.95	2.0%	1
6,000	70%	3,066,000	1,594,320	1,471,680	$178,324.39	$181,584.34	$3,259.95	1.8%	1
6,000	80%	3,504,000	1,822,080	1,681,920	$195,100.20	$198,360.15	$3,259.95	1.7%	-
6,000	90%	3,942,000	2,049,840	1,892,160	$211,876.02	$215,135.97	$3,259.95	1.5%	-

		Rate Yr 1	Rate Yr 2
	UOM	SC08SubTrn-C	SC08SubTrn-C
Customer Charge	Monthly	$ 2,535.00	$ 2,636.00
Demand Charge kW	kW	$ 9.73	$ 10.25
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93
Supply Charge On Peak kWh	kWh-On	$ 0.03631	$ 0.03631
Supply Charge Off Peak kWh	kWh-Off	$ 0.02550	$ 0.02550
MFC per kWh	kWh	$ 0.00206	$ 0.00206

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2021 - April 30, 2022

Including Supply

PSC #19 - SC 8 - Large General Service - Primary									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 1	Rate Yr 2	Amount	Percent	# of Customers
250	20%	36,500	18,980	17,520	$6,336.77	$6,662.04	$325.27	5.1%	5
250	30%	54,750	28,470	26,280	$7,031.86	$7,357.13	$325.27	4.6%	7
250	40%	73,000	37,960	35,040	$7,726.95	$8,052.22	$325.27	4.2%	3
250	50%	91,250	47,450	43,800	$8,422.04	$8,747.31	$325.27	3.9%	8
250	60%	109,500	56,940	52,560	$9,117.13	$9,442.40	$325.27	3.6%	1
250	70%	127,750	66,430	61,320	$9,812.21	$10,137.49	$325.27	3.3%	2
250	80%	146,000	75,920	70,080	$10,507.30	$10,832.57	$325.27	3.1%	1
250	90%	164,250	85,410	78,840	$11,202.39	$11,527.66	$325.27	2.9%	-
500	20%	73,000	37,960	35,040	$11,241.61	$11,835.15	$593.54	5.3%	2
500	30%	109,500	56,940	52,560	$12,631.79	$13,225.33	$593.54	4.7%	8
500	40%	146,000	75,920	70,080	$14,021.97	$14,615.51	$593.54	4.2%	14
500	50%	182,500	94,900	87,600	$15,412.15	$16,005.69	$593.54	3.9%	20
500	60%	219,000	113,880	105,120	$16,802.32	$17,395.87	$593.54	3.5%	10
500	70%	255,500	132,860	122,640	$18,192.50	$18,786.04	$593.54	3.3%	3
500	80%	292,000	151,840	140,160	$19,582.68	$20,176.22	$593.54	3.0%	2
500	90%	328,500	170,820	157,680	$20,972.86	$21,566.40	$593.54	2.8%	-
1,500	20%	219,000	113,880	105,120	$30,860.99	$32,527.61	$1,666.62	5.4%	4
1,500	30%	328,500	170,820	157,680	$35,031.52	$36,698.14	$1,666.62	4.8%	18
1,500	40%	438,000	227,760	210,240	$39,202.05	$40,868.68	$1,666.62	4.3%	21
1,500	50%	547,500	284,700	262,800	$43,372.59	$45,039.21	$1,666.62	3.8%	12
1,500	60%	657,000	341,640	315,360	$47,543.12	$49,209.75	$1,666.62	3.5%	4
1,500	70%	766,500	398,580	367,920	$51,713.66	$53,380.28	$1,666.62	3.2%	4
1,500	80%	876,000	455,520	420,480	$55,884.19	$57,550.81	$1,666.62	3.0%	1
1,500	90%	985,500	512,460	473,040	$60,054.72	$61,721.35	$1,666.62	2.8%	-
2,000	20%	292,000	151,840	140,160	$40,670.67	$42,873.84	$2,203.17	5.4%	-
2,000	30%	438,000	227,760	210,240	$46,231.39	$48,434.55	$2,203.17	4.8%	-
2,000	40%	584,000	303,680	280,320	$51,792.10	$53,995.26	$2,203.17	4.3%	-
2,000	50%	730,000	379,600	350,400	$57,352.81	$59,555.97	$2,203.17	3.8%	2
2,000	60%	876,000	455,520	420,480	$62,913.52	$65,116.69	$2,203.17	3.5%	1
2,000	70%	1,022,000	531,440	490,560	$68,474.23	$70,677.40	$2,203.17	3.2%	-
2,000	80%	1,168,000	607,360	560,640	$74,034.94	$76,238.11	$2,203.17	3.0%	1
2,000	90%	1,314,000	683,280	630,720	$79,595.66	$81,798.82	$2,203.17	2.8%	6

		Rate Yr 1	Rate Yr 2
	UOM	SC08Pri	SC08Pri
Customer Charge	Monthly	$ 1,431.00	$ 1,488.00
Demand Charge kW	kW	$ 14.06	$ 15.13
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93
Supply Charge On Peak kWh	kWh-On	$ 0.03594	$ 0.03594
Supply Charge Off Peak kWh	kWh-Off	$ 0.02545	$ 0.02545
MFC per kWh	kWh	$ 0.00206	$ 0.00206

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2021 - April 30, 2022

Including Supply

PSC #19 - SC 8 - Large General Service - Secondary

Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 1	Rate Yr 2	increase / (decrease) Amount	Percent	# of Customers
250	20%	36,500	18,980	17,520	$6,109.28	$6,407.40	$298.12	4.9%	15
250	30%	54,750	28,470	26,280	$6,825.62	$7,123.75	$298.12	4.4%	15
250	40%	73,000	37,960	35,040	$7,541.97	$7,840.10	$298.12	4.0%	31
250	50%	91,250	47,450	43,800	$8,258.32	$8,556.44	$298.12	3.6%	37
250	60%	109,500	56,940	52,560	$8,974.67	$9,272.79	$298.12	3.3%	27
250	70%	127,750	66,430	61,320	$9,691.02	$9,989.14	$298.12	3.1%	5
250	80%	146,000	75,920	70,080	$10,407.36	$10,705.49	$298.12	2.9%	4
250	90%	164,250	85,410	78,840	$11,123.71	$11,421.84	$298.12	2.7%	-
500	20%	73,000	37,960	35,040	$11,079.62	$11,629.87	$550.25	5.0%	6
500	30%	109,500	56,940	52,560	$12,512.32	$13,062.57	$550.25	4.4%	35
500	40%	146,000	75,920	70,080	$13,945.02	$14,495.27	$550.25	3.9%	65
500	50%	182,500	94,900	87,600	$15,377.71	$15,927.96	$550.25	3.6%	40
500	60%	219,000	113,880	105,120	$16,810.41	$17,360.66	$550.25	3.3%	27
500	70%	255,500	132,860	122,640	$18,243.11	$18,793.35	$550.25	3.0%	11
500	80%	292,000	151,840	140,160	$19,675.80	$20,226.05	$550.25	2.8%	5
500	90%	328,500	170,820	157,680	$21,108.50	$21,658.75	$550.25	2.6%	1
1,500	20%	219,000	113,880	105,120	$30,961.02	$32,519.77	$1,558.74	5.0%	19
1,500	30%	328,500	170,820	157,680	$35,259.11	$36,817.85	$1,558.74	4.4%	22
1,500	40%	438,000	227,760	210,240	$39,557.20	$41,115.94	$1,558.74	3.9%	18
1,500	50%	547,500	284,700	262,800	$43,855.29	$45,414.03	$1,558.74	3.6%	5
1,500	60%	657,000	341,640	315,360	$48,153.38	$49,712.12	$1,558.74	3.2%	2
1,500	70%	766,500	398,580	367,920	$52,451.46	$54,010.21	$1,558.74	3.0%	2
1,500	80%	876,000	455,520	420,480	$56,749.55	$58,308.30	$1,558.74	2.7%	-
1,500	90%	985,500	512,460	473,040	$61,047.64	$62,606.38	$1,558.74	2.6%	-
2,000	20%	292,000	151,840	140,160	$40,901.72	$42,964.71	$2,062.99	5.0%	-
2,000	30%	438,000	227,760	210,240	$46,632.51	$48,695.50	$2,062.99	4.4%	-
2,000	40%	584,000	303,680	280,320	$52,363.29	$54,426.28	$2,062.99	3.9%	-
2,000	50%	730,000	379,600	350,400	$58,094.07	$60,157.07	$2,062.99	3.6%	-
2,000	60%	876,000	455,520	420,480	$63,824.86	$65,887.85	$2,062.99	3.2%	1
2,000	70%	1,022,000	531,440	490,560	$69,555.64	$71,618.63	$2,062.99	3.0%	1
2,000	80%	1,168,000	607,360	560,640	$75,286.43	$77,349.42	$2,062.99	2.7%	-
2,000	90%	1,314,000	683,280	630,720	$81,017.21	$83,080.20	$2,062.99	2.5%	-

	UOM	Rate Yr 1 SC08Sec	Rate Yr 2 SC08Sec
Customer Charge	Monthly	$ 1,138.00	$ 1,184.00
Demand Charge kW	kW	$ 14.15	$ 15.16
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93
Supply Charge On Peak kWh	kWh-On	$ 0.03761	$ 0.03761
Supply Charge Off Peak kWh	kWh-Off	$ 0.02607	$ 0.02607
MFC per kWh	kWh	$ 0.00206	$ 0.00206

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2021 - April 30, 2022

Including Supply

PSC #19 - SC 8 - Large General Service - SubStation

Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 1	Rate Yr 2	increase / (decrease) Amount	Percent	# of Customers
250	20%	36,500	18,980	17,520	$5,967.30	$6,130.11	$162.81	2.7%	-
250	30%	54,750	28,470	26,280	$6,671.19	$6,834.00	$162.81	2.4%	1
250	40%	73,000	37,960	35,040	$7,375.09	$7,537.90	$162.81	2.2%	2
250	50%	91,250	47,450	43,800	$8,078.98	$8,241.79	$162.81	2.0%	1
250	60%	109,500	56,940	52,560	$8,782.88	$8,945.69	$162.81	1.9%	1
250	70%	127,750	66,430	61,320	$9,486.78	$9,649.59	$162.81	1.7%	2
250	80%	146,000	75,920	70,080	$10,190.67	$10,353.48	$162.81	1.6%	-
250	90%	164,250	85,410	78,840	$10,894.57	$11,057.38	$162.81	1.5%	-
500	20%	73,000	37,960	35,040	$9,471.67	$9,699.29	$227.62	2.4%	-
500	30%	109,500	56,940	52,560	$10,879.46	$11,107.08	$227.62	2.1%	1
500	40%	146,000	75,920	70,080	$12,287.25	$12,514.87	$227.62	1.9%	1
500	50%	182,500	94,900	87,600	$13,695.04	$13,922.66	$227.62	1.7%	4
500	60%	219,000	113,880	105,120	$15,102.83	$15,330.45	$227.62	1.5%	3
500	70%	255,500	132,860	122,640	$16,510.63	$16,738.24	$227.62	1.4%	2
500	80%	292,000	151,840	140,160	$17,918.42	$18,146.04	$227.62	1.3%	-
500	90%	328,500	170,820	157,680	$19,326.21	$19,553.83	$227.62	1.2%	-
2,000	20%	292,000	151,840	140,160	$30,497.90	$31,114.37	$616.48	2.0%	6
2,000	30%	438,000	227,760	210,240	$36,129.06	$36,745.54	$616.48	1.7%	4
2,000	40%	584,000	303,680	280,320	$41,760.23	$42,376.71	$616.48	1.5%	1
2,000	50%	730,000	379,600	350,400	$47,391.39	$48,007.87	$616.48	1.3%	-
2,000	60%	876,000	455,520	420,480	$53,022.56	$53,639.04	$616.48	1.2%	-
2,000	70%	1,022,000	531,440	490,560	$58,653.72	$59,270.20	$616.48	1.1%	-
2,000	80%	1,168,000	607,360	560,640	$64,284.89	$64,901.37	$616.48	1.0%	-
2,000	90%	1,314,000	683,280	630,720	$69,916.05	$70,532.53	$616.48	0.9%	-
2,500	20%	365,000	189,800	175,200	$37,506.64	$38,252.74	$746.10	2.0%	-
2,500	30%	547,500	284,700	262,800	$44,545.59	$45,291.69	$746.10	1.7%	-
2,500	40%	730,000	379,600	350,400	$51,584.55	$52,330.65	$746.10	1.4%	-
2,500	50%	912,500	474,500	438,000	$58,623.51	$59,369.61	$746.10	1.3%	-
2,500	60%	1,095,000	569,400	525,600	$65,662.47	$66,408.56	$746.10	1.1%	1
2,500	70%	1,277,500	664,300	613,200	$72,701.42	$73,447.52	$746.10	1.0%	1
2,500	80%	1,460,000	759,200	700,800	$79,740.38	$80,486.48	$746.10	0.9%	-
2,500	90%	1,642,500	854,100	788,400	$86,779.34	$87,525.43	$746.10	0.9%	-

	UOM	Rate Yr 1 SC08SubSta	Rate Yr 2 SC08SubSta
Customer Charge	Monthly	$ 2,462.00	$ 2,560.00
Demand Charge kW	kW	$ 8.39	$ 8.65
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93
Supply Charge On Peak kWh	kWh-On	$ 0.03647	$ 0.03647
Supply Charge Off Peak kWh	kWh-Off	$ 0.02588	$ 0.02588
MFC per kWh	kWh	$ 0.00206	$ 0.00206

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2021 - April 30, 2022

Including Supply

PSC #19 - SC 9 - General Service - TOU

Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 1	Rate Yr 2	increase / (decrease) Amount	Percent	# of Customers
10	20%	1,460	759	701	$292.64	$313.53	$20.89	7.1%	19
10	30%	2,190	1,139	1,051	$328.99	$348.36	$19.37	5.9%	17
10	40%	2,920	1,518	1,402	$365.34	$383.19	$17.85	4.9%	25
10	50%	3,650	1,898	1,752	$401.69	$418.02	$16.33	4.1%	17
10	60%	4,380	2,278	2,102	$438.04	$452.85	$14.81	3.4%	12
10	70%	5,110	2,657	2,453	$474.38	$487.68	$13.29	2.8%	7
10	80%	5,840	3,037	2,803	$510.73	$522.51	$11.77	2.3%	1
10	90%	6,570	3,416	3,154	$547.08	$557.34	$10.25	1.9%	3
25	20%	3,650	1,898	1,752	$586.96	$614.06	$27.10	4.6%	11
25	30%	5,475	2,847	2,628	$677.83	$701.13	$23.30	3.4%	27
25	40%	7,300	3,796	3,504	$768.70	$788.21	$19.50	2.5%	30
25	50%	9,125	4,745	4,380	$859.58	$875.28	$15.70	1.8%	24
25	60%	10,950	5,694	5,256	$950.45	$962.36	$11.91	1.3%	12
25	70%	12,775	6,643	6,132	$1,041.32	$1,049.43	$8.11	0.8%	3
25	80%	14,600	7,592	7,008	$1,132.20	$1,136.50	$4.31	0.4%	-
25	90%	16,425	8,541	7,884	$1,223.07	$1,223.58	$0.51	0.0%	3
100	20%	14,600	7,592	7,008	$2,058.55	$2,116.70	$58.16	2.8%	27
100	30%	21,900	11,388	10,512	$2,422.04	$2,465.00	$42.96	1.8%	32
100	40%	29,200	15,184	14,016	$2,785.53	$2,813.30	$27.76	1.0%	18
100	50%	36,500	18,980	17,520	$3,149.03	$3,161.60	$12.57	0.4%	9
100	60%	43,800	22,776	21,024	$3,512.52	$3,509.89	($2.63)	-0.1%	6
100	70%	51,100	26,572	24,528	$3,876.01	$3,858.19	($17.82)	-0.5%	2
100	80%	58,400	30,368	28,032	$4,239.51	$4,206.49	($33.02)	-0.8%	-
100	90%	65,700	34,164	31,536	$4,603.00	$4,554.79	($48.21)	-1.0%	-
200	20%	29,200	15,184	14,016	$4,020.67	$4,120.23	$99.56	2.5%	1
200	30%	43,800	22,776	21,024	$4,747.66	$4,816.83	$69.17	1.5%	2
200	40%	58,400	30,368	28,032	$5,474.64	$5,513.42	$38.78	0.7%	4
200	50%	73,000	37,960	35,040	$6,201.63	$6,210.02	$8.39	0.1%	-
200	60%	87,600	45,552	42,048	$6,928.62	$6,906.61	($22.00)	-0.3%	-
200	70%	102,200	53,144	49,056	$7,655.60	$7,603.21	($52.39)	-0.7%	-
200	80%	116,800	60,736	56,064	$8,382.59	$8,299.80	($82.79)	-1.0%	-
200	90%	131,400	68,328	63,072	$9,109.58	$8,996.40	($113.18)	-1.2%	-

	UOM	Rate Yr 1 SC09	Rate Yr 2 SC09
Customer Charge	Monthly	$ 95.50	$ 112.25
Demand Charge kW	kW	$ 12.35	$ 13.07
Delivery Charge On Peak kWh	kWh-On	$ 0.01041	$ 0.00833
Delivery Charge Off Peak kWh	kWh-Off	$ 0.01041	$ 0.00833
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93
Supply Charge On Peak kWh	kWh-On	$ 0.03776	$ 0.03776
Supply Charge Off Peak kWh	kWh-Off	$ 0.02619	$ 0.02619
MFC per kWh	kWh	$ 0.00206	$ 0.00206

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation		
Date Sources - RG&E Electric Bill Impact Statements		
Rate	**Source of Rate in "Current" Rates**	**Source of Rate in Rate Years**
Customer Charge	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
kW Charge	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
kWh Delivery Charge All Hours	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
kWh Delivery Charge On Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
kWh Delivery Charge Mid Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
kWh Delivery Charge Off Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
Reactive RkVah	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
Billing Charge per Bill	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
SBC (EETr) per kWh	Current Tariff Rates in Effect 01/01/2020. Statement #26.	Included in Delivery Rates
SBC (CEF) per kWh	Current Tariff Rates in Effect 01/01/2020. Statement #26.	Current Tariff Rates in Effect 01/01/2020. Statement #26.
RAM per kWh	Tariff Rates in Effect 07/01/2019.	No RAM forecasted. COVID Bill Credits begin 7/1/2021.
RAM per kW	Tariff Rates in Effect 07/01/2019.	No RAM forecasted. COVID Bill Credits begin 7/1/2021.
Tax Credit per kWh	Case No. 17-M-0815 dated August 9, 2018. Statement Number 1	Included in Delivery Rates
Tax Credit per kW	Case No. 17-M-0815 dated August 9, 2018. Statement Number 1	Included in Delivery Rates
Rate	**Source of Rate in "Current" Rates and Rate Years**	
Transition Charge per kWh	NBC, Demand Response, and Value Stack: NBC is the Non-Weighted 2019 Average. Dmd Rsp at $-0-. Value Stack at $-0-. RAM is separate.	
MFC per kWh	Non-Weighted 2019 Average of Monthly MFC Charge	
kWh Supply Charge All Hours	2019 Annualized Supply Rates	
kWh Supply Charge On Peak	2019 Annualized Supply Rates	
kWh Supply Charge Mid Peak	2019 Annualized Supply Rates	
kWh Supply Charge Off Peak	2019 Annualized Supply Rates	
Customer Count	2018 monthly data - separate Low Income counts	

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2021 - April 30, 2022

Delivery Bill Only

PSC #19 - SC 1 - Residential

kWh	Rate Yr 1	Rate Yr 2	increase / (decrease) Amount	Percent	# of Customers	# of Low Income Customers	Percent of Customers	Percent of Low Income Customers	Amount of EE Embedded in Delivery Rates* Amount	Percent
100	$27.21	$28.11	$0.90	3.3%	10,907	539	3%	1%	$ 0.16	0.56%
200	$32.10	$33.59	$1.49	4.6%	25,369	2,787	7%	8%	$ 0.31	0.93%
300	$37.00	$39.08	$2.07	5.6%	33,669	4,537	10%	12%	$ 0.47	1.20%
400	$41.90	$44.56	$2.66	6.3%	37,090	5,036	11%	14%	$ 0.62	1.40%
500	$46.80	$50.04	$3.24	6.9%	38,010	4,932	11%	13%	$ 0.78	1.56%
600	$51.70	$55.53	$3.82	7.4%	35,693	4,208	11%	11%	$ 0.94	1.69%
700	$56.60	$61.01	$4.41	7.8%	31,811	3,427	9%	9%	$ 1.09	1.79%
800	$61.50	$66.49	$4.99	8.1%	27,030	2,744	8%	7%	$ 1.25	1.88%
900	$66.40	$71.97	$5.57	8.4%	22,238	2,191	7%	6%	$ 1.41	1.95%
1,000	$71.30	$77.46	$6.16	8.6%	17,500	1,598	5%	4%	$ 1.56	2.02%
1,100	$76.20	$82.94	$6.74	8.8%	13,667	1,211	4%	3%	$ 1.72	2.07%
1,200	$81.10	$88.42	$7.33	9.0%	10,434	907	3%	2%	$ 1.87	2.12%
1,500	$95.80	$104.87	$9.08	9.5%	18,454	1,568	5%	4%	$ 2.34	2.23%
2,000	$120.29	$132.29	$12.00	10.0%	11,052	901	3%	2%	$ 3.12	2.36%
3,000	$169.29	$187.12	$17.83	10.5%	5,347	334	2%	1%	$ 4.68	2.50%
					338,269	36,919				

	UOM	Rate Yr 1 SC01	Rate Yr 2 SC01	
Customer Charge	Monthly	$ 21.38	$ 21.70	
Delivery Charge All Hours kWh	kWh	$ 0.04569	$ 0.05153	Includes $ 0.00156 per kWh of EE Costs*
SBC (EETr) per kWh	kWh	$ -	$ -	
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536	
RAM per kWh	kWh	$ -	$ -	
Tax Credit All Hours kWh	kWh	$ -	$ -	
Transition Charge per kWh	kWh	$ (0.00206)	$ (0.00206)	
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93	

Notes:
1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2021 - April 30, 2022

Delivery Bill Only

PSC #19 - SC 2 - General Service - Non Demand					
			increase / (decrease)		# of
kWh	Rate Yr 1	Rate Yr 2	Amount	Percent	Customers
300	$34.62	$36.40	$1.78	5.1%	11,999
400	$38.72	$40.99	$2.26	5.8%	2,601
500	$42.83	$45.58	$2.75	6.4%	2,299
600	$46.93	$50.17	$3.23	6.9%	1,892
700	$51.04	$54.76	$3.72	7.3%	1,541
800	$55.14	$59.35	$4.21	7.6%	1,322
900	$59.25	$63.94	$4.69	7.9%	1,021
1,000	$63.35	$68.53	$5.18	8.2%	904
1,500	$83.87	$91.48	$7.61	9.1%	2,999
2,000	$104.39	$114.43	$10.03	9.6%	1,654
2,500	$124.92	$137.38	$12.46	10.0%	845
3,000	$145.44	$160.33	$14.89	10.2%	385
4,000	$186.48	$206.23	$19.75	10.6%	203
5,000	$227.53	$252.13	$24.60	10.8%	60
6,000	$268.57	$298.03	$29.46	11.0%	21
7,000	$309.61	$343.93	$34.32	11.1%	59

		Rate Yr 1	Rate Yr 2
	UOM	SC02	SC02
Customer Charge	Monthly	$ 21.38	$ 21.70
Delivery Charge All Hours kWh	kWh	$ 0.03592	$ 0.04078
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kWh	kWh	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2021 - April 30, 2022

Delivery Bill Only

PSC #19 - SC 3 - General Service - Demand

Kw	Load Factor	kWh	Rate Yr 1	Rate Yr 2	increase / (decrease) Amount	Percent	# of Customers
50	20%	7,300	$1,192.45	$1,284.27	$91.82	7.7%	45
50	30%	10,950	$1,211.15	$1,302.97	$91.82	7.6%	19
50	40%	14,600	$1,229.85	$1,321.67	$91.82	7.5%	18
50	50%	18,250	$1,248.54	$1,340.36	$91.82	7.4%	18
50	60%	21,900	$1,267.24	$1,359.06	$91.82	7.2%	1
50	70%	25,550	$1,285.94	$1,377.76	$91.82	7.1%	3
50	80%	29,200	$1,304.64	$1,396.46	$91.82	7.0%	3
50	90%	32,850	$1,323.33	$1,415.15	$91.82	6.9%	2
100	20%	14,600	$2,086.84	$2,218.62	$131.77	6.3%	43
100	30%	21,900	$2,124.24	$2,256.01	$131.77	6.2%	73
100	40%	29,200	$2,161.63	$2,293.41	$131.77	6.1%	122
100	50%	36,500	$2,199.03	$2,330.80	$131.77	6.0%	115
100	60%	43,800	$2,236.43	$2,368.20	$131.77	5.9%	47
100	70%	51,100	$2,273.82	$2,405.59	$131.77	5.8%	32
100	80%	58,400	$2,311.22	$2,442.99	$131.77	5.7%	9
100	90%	65,700	$2,348.61	$2,480.38	$131.77	5.6%	6
275	20%	40,150	$5,217.22	$5,488.82	$271.60	5.2%	146
275	30%	60,225	$5,320.06	$5,591.66	$271.60	5.1%	223
275	40%	80,300	$5,422.90	$5,694.50	$271.60	5.0%	130
275	50%	100,375	$5,525.73	$5,797.33	$271.60	4.9%	69
275	60%	120,450	$5,628.57	$5,900.17	$271.60	4.8%	24
275	70%	140,525	$5,731.41	$6,003.01	$271.60	4.7%	8
275	80%	160,600	$5,834.25	$6,105.85	$271.60	4.7%	2
275	90%	180,675	$5,937.08	$6,208.68	$271.60	4.6%	2
300	20%	43,800	$5,664.42	$5,955.99	$291.58	5.1%	-
300	30%	65,700	$5,776.60	$6,068.18	$291.58	5.0%	2
300	40%	87,600	$5,888.79	$6,180.37	$291.58	5.0%	2
300	50%	109,500	$6,000.98	$6,292.55	$291.58	4.9%	3
300	60%	131,400	$6,113.16	$6,404.74	$291.58	4.8%	-
300	70%	153,300	$6,225.35	$6,516.93	$291.58	4.7%	2
300	80%	175,200	$6,337.54	$6,629.11	$291.58	4.6%	2
300	90%	197,100	$6,449.72	$6,741.30	$291.58	4.5%	3

	UOM	Rate Yr 1 SC03	Rate Yr 2 SC03
Customer Charge	Monthly	$ 297.13	$ 349.00
Demand Charge kW	kW	$ 17.14	$ 17.94
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2021 - April 30, 2022

Delivery Bill Only

PSC #19 - SC 4-I - Residential - Day/Night							
					increase / (decrease)		
kWh	Peak	Off Peak	Rate Yr 1	Rate Yr 2	Amount	Percent	# of Customers
300	210	90	40.73	41.96	1.22	3.0%	126
400	280	120	45.55	47.03	1.48	3.3%	91
500	350	150	50.37	52.11	1.74	3.5%	104
600	420	180	55.18	57.18	2.00	3.6%	131
700	490	210	60.00	62.26	2.26	3.8%	172
800	560	240	64.81	67.34	2.52	3.9%	191
900	630	270	69.63	72.41	2.78	4.0%	145
1,000	700	300	74.45	77.49	3.04	4.1%	157
1,500	1,050	450	98.52	102.87	4.35	4.4%	589
2,000	1,400	600	122.60	128.25	5.65	4.6%	302
2,500	1,750	750	146.68	153.63	6.95	4.7%	149
3,000	2,100	900	170.76	179.02	8.25	4.8%	61
4,000	2,800	1,200	218.92	229.78	10.86	5.0%	26
5,000	3,500	1,500	267.08	280.54	13.46	5.0%	11
6,000	4,200	1,800	315.24	331.31	16.07	5.1%	1
7,000	4,900	2,100	363.40	382.07	18.67	5.1%	5

		Rate Yr 1	Rate Yr 2
	UOM	SC04-I	SC04-I
Customer Charge	Monthly	$ 25.36	$ 25.80
Delivery Charge On Peak kWh	kWh-On	$ 0.04486	$ 0.04746
Delivery Charge Off Peak kWh	kWh-Off	$ 0.04486	$ 0.04746
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kWh	kWh	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00206)	$ (0.00206)
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2021 - April 30, 2022

Delivery Bill Only

PSC #19 - SC 4-II - Residential - Day/Night

kWh	Peak	Off Peak	Rate Yr 1	Rate Yr 2	increase / (decrease) Amount	Percent	# of Customers
300	210	90	$47.36	$48.62	$1.26	2.7%	18
400	280	120	$53.22	$54.77	$1.55	2.9%	9
500	350	150	$59.08	$60.92	$1.83	3.1%	15
600	420	180	$64.95	$67.07	$2.12	3.3%	28
700	490	210	$70.81	$73.21	$2.40	3.4%	29
800	560	240	$76.67	$79.36	$2.69	3.5%	38
900	630	270	$82.54	$85.51	$2.97	3.6%	33
1,000	700	300	$88.40	$91.66	$3.26	3.7%	52
1,500	1,050	450	$117.72	$122.40	$4.68	4.0%	238
2,000	1,400	600	$147.04	$153.14	$6.11	4.2%	190
2,500	1,750	750	$176.36	$183.89	$7.53	4.3%	165
3,000	2,100	900	$205.67	$214.63	$8.96	4.4%	83
4,000	2,800	1,200	$264.31	$276.11	$11.80	4.5%	84
5,000	3,500	1,500	$322.94	$337.60	$14.65	4.5%	49
6,000	4,200	1,800	$381.58	$399.08	$17.50	4.6%	33
7,000	4,900	2,100	$440.22	$460.57	$20.35	4.6%	28

	UOM	Rate Yr 1 SC04-II	Rate Yr 2 SC04-II
Customer Charge	Monthly	$ 28.84	$ 29.25
Delivery Charge On Peak kWh	kWh-On	$ 0.05533	$ 0.05818
Delivery Charge Off Peak kWh	kWh-Off	$ 0.05533	$ 0.05818
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kWh	kWh	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00206)	$ (0.00206)
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2021 - April 30, 2022

Delivery Bill Only

PSC #19 - SC 7 - General Service - Demand

Kw	Load Factor	kWh	Rate Yr 1	Rate Yr 2	increase / (decrease) Amount	Percent	# of Customers
5	20%	730	$185.14	$202.87	$17.74	9.6%	178
5	30%	1,095	$189.43	$206.68	$17.25	9.1%	51
5	40%	1,460	$193.73	$210.50	$16.77	8.7%	36
5	50%	1,825	$198.02	$214.31	$16.28	8.2%	34
5	60%	2,190	$202.32	$218.12	$15.80	7.8%	16
5	70%	2,555	$206.62	$221.93	$15.31	7.4%	14
5	80%	2,920	$210.91	$225.74	$14.83	7.0%	6
5	90%	3,285	$215.21	$229.55	$14.34	6.7%	6
25	20%	3,650	$566.89	$590.66	$23.77	4.2%	2,778
25	30%	5,475	$588.38	$609.72	$21.34	3.6%	1,673
25	40%	7,300	$609.86	$628.77	$18.92	3.1%	888
25	50%	9,125	$631.34	$647.83	$16.49	2.6%	403
25	60%	10,950	$652.82	$666.88	$14.06	2.2%	155
25	70%	12,775	$674.30	$685.94	$11.64	1.7%	46
25	80%	14,600	$695.78	$704.99	$9.21	1.3%	12
25	90%	16,425	$717.26	$724.05	$6.79	0.9%	7
100	20%	14,600	$1,998.49	$2,044.88	$46.39	2.3%	1,560
100	30%	21,900	$2,084.41	$2,121.10	$36.69	1.8%	618
100	40%	29,200	$2,170.34	$2,197.32	$26.98	1.2%	240
100	50%	36,500	$2,256.27	$2,273.54	$17.28	0.8%	74
100	60%	43,800	$2,342.19	$2,349.76	$7.57	0.3%	44
100	70%	51,100	$2,428.12	$2,425.98	($2.14)	-0.1%	8
100	80%	58,400	$2,514.04	$2,502.20	($11.84)	-0.5%	3
100	90%	65,700	$2,599.97	$2,578.42	($21.55)	-0.8%	2
250	20%	36,500	$4,861.68	$4,953.31	$91.64	1.9%	19
250	30%	54,750	$5,076.49	$5,143.86	$67.37	1.3%	15
250	40%	73,000	$5,291.31	$5,334.41	$43.11	0.8%	5
250	50%	91,250	$5,506.12	$5,524.96	$18.84	0.3%	2
250	60%	109,500	$5,720.93	$5,715.51	($5.42)	-0.1%	-
250	70%	127,750	$5,935.75	$5,906.06	($29.69)	-0.5%	1
250	80%	146,000	$6,150.56	$6,096.61	($53.95)	-0.9%	-
250	90%	164,250	$6,365.38	$6,287.16	($78.22)	-1.2%	-

	UOM	Rate Yr 1 SC07	Rate Yr 2 SC07
Customer Charge	Monthly	$ 88.77	$ 105.00
Demand Charge kW	kW	$ 17.37	$ 17.87
Delivery Charge All Hours kWh	kWh	$ 0.00665	$ 0.00532
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2021 - April 30, 2022

Delivery Bill Only

PSC #19 - SC 8 - Large General Service - Transmission									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 1	Rate Yr 2	Amount	Percent	# of Customers
6,000	20%	876,000	455,520	420,480	$63,133.77	$67,358.29	$4,224.52	6.7%	-
6,000	30%	1,314,000	683,280	630,720	$65,377.50	$69,602.02	$4,224.52	6.5%	-
6,000	40%	1,752,000	911,040	840,960	$67,621.22	$71,845.75	$4,224.52	6.2%	-
6,000	50%	2,190,000	1,138,800	1,051,200	$69,864.95	$74,089.47	$4,224.52	6.0%	-
6,000	60%	2,628,000	1,366,560	1,261,440	$72,108.68	$76,333.20	$4,224.52	5.9%	-
6,000	70%	3,066,000	1,594,320	1,471,680	$74,352.41	$78,576.93	$4,224.52	5.7%	-
6,000	80%	3,504,000	1,822,080	1,681,920	$76,596.14	$80,820.66	$4,224.52	5.5%	-
6,000	90%	3,942,000	2,049,840	1,892,160	$78,839.86	$83,064.39	$4,224.52	5.4%	-
7,000	20%	1,022,000	531,440	490,560	$72,989.24	$77,884.52	$4,895.27	6.7%	-
7,000	30%	1,533,000	797,160	735,840	$75,606.92	$80,502.20	$4,895.27	6.5%	-
7,000	40%	2,044,000	1,062,880	981,120	$78,224.61	$83,119.88	$4,895.27	6.3%	-
7,000	50%	2,555,000	1,328,600	1,226,400	$80,842.29	$85,737.56	$4,895.27	6.1%	-
7,000	60%	3,066,000	1,594,320	1,471,680	$83,459.97	$88,355.25	$4,895.27	5.9%	1
7,000	70%	3,577,000	1,860,040	1,716,960	$86,077.66	$90,972.93	$4,895.27	5.7%	-
7,000	80%	4,088,000	2,125,760	1,962,240	$88,695.34	$93,590.61	$4,895.27	5.5%	-
7,000	90%	4,599,000	2,391,480	2,207,520	$91,313.02	$96,208.30	$4,895.27	5.4%	-
8,000	20%	1,168,000	607,360	560,640	$82,844.72	$88,410.74	$5,566.03	6.7%	-
8,000	30%	1,752,000	911,040	840,960	$85,836.35	$91,402.38	$5,566.03	6.5%	-
8,000	40%	2,336,000	1,214,720	1,121,280	$88,827.99	$94,394.02	$5,566.03	6.3%	-
8,000	50%	2,920,000	1,518,400	1,401,600	$91,819.63	$97,385.66	$5,566.03	6.1%	-
8,000	60%	3,504,000	1,822,080	1,681,920	$94,811.27	$100,377.29	$5,566.03	5.9%	-
8,000	70%	4,088,000	2,125,760	1,962,240	$97,802.90	$103,368.93	$5,566.03	5.7%	-
8,000	80%	4,672,000	2,429,440	2,242,560	$100,794.54	$106,360.57	$5,566.03	5.5%	-
8,000	90%	5,256,000	2,733,120	2,522,880	$103,786.18	$109,352.21	$5,566.03	5.4%	-
9,000	20%	1,314,000	683,280	630,720	$92,700.19	$98,936.97	$6,236.78	6.7%	-
9,000	30%	1,971,000	1,024,920	946,080	$96,065.78	$102,302.56	$6,236.78	6.5%	-
9,000	40%	2,628,000	1,366,560	1,261,440	$99,431.37	$105,668.15	$6,236.78	6.3%	-
9,000	50%	3,285,000	1,708,200	1,576,800	$102,796.97	$109,033.75	$6,236.78	6.1%	-
9,000	60%	3,942,000	2,049,840	1,892,160	$106,162.56	$112,399.34	$6,236.78	5.9%	-
9,000	70%	4,599,000	2,391,480	2,207,520	$109,528.15	$115,764.93	$6,236.78	5.7%	-
9,000	80%	5,256,000	2,733,120	2,522,880	$112,893.74	$119,130.52	$6,236.78	5.5%	-
9,000	90%	5,913,000	3,074,760	2,838,240	$116,259.33	$122,496.11	$6,236.78	5.4%	-

		Rate Yr 1	Rate Yr 2
	UOM	SC08Trn	SC08Trn
Customer Charge	Monthly	$ 4,000.00	$ 4,200.00
Demand Charge kW	kW	$ 9.11	$ 9.78
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2021 - April 30, 2022

Delivery Bill Only

PSC #19 - SC 8 - Large General Service - SubTransmission - Industrial									
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 1	Rate Yr 2	increase / (decrease) Amount	Percent	# of Customers
500	20%	73,000	37,960	35,040	$7,614.14	$7,876.19	$262.05	3.4%	1
500	30%	109,500	56,940	52,560	$7,801.12	$8,063.17	$262.05	3.4%	4
500	40%	146,000	75,920	70,080	$7,988.10	$8,250.15	$262.05	3.3%	2
500	50%	182,500	94,900	87,600	$8,175.08	$8,437.12	$262.05	3.2%	2
500	60%	219,000	113,880	105,120	$8,362.05	$8,624.10	$262.05	3.1%	-
500	70%	255,500	132,860	122,640	$8,549.03	$8,811.08	$262.05	3.1%	2
500	80%	292,000	151,840	140,160	$8,736.01	$8,998.06	$262.05	3.0%	-
500	90%	328,500	170,820	157,680	$8,922.99	$9,185.03	$262.05	2.9%	1
1,500	20%	219,000	113,880	105,120	$17,548.58	$18,122.72	$574.14	3.3%	2
1,500	30%	328,500	170,820	157,680	$18,109.51	$18,683.65	$574.14	3.2%	1
1,500	40%	438,000	227,760	210,240	$18,670.45	$19,244.59	$574.14	3.1%	3
1,500	50%	547,500	284,700	262,800	$19,231.38	$19,805.52	$574.14	3.0%	4
1,500	60%	657,000	341,640	315,360	$19,792.31	$20,366.45	$574.14	2.9%	6
1,500	70%	766,500	398,580	367,920	$20,353.24	$20,927.38	$574.14	2.8%	-
1,500	80%	876,000	455,520	420,480	$20,914.17	$21,488.31	$574.14	2.7%	1
1,500	90%	985,500	512,460	473,040	$21,475.11	$22,049.25	$574.14	2.7%	-
4,500	20%	657,000	341,640	315,360	$47,351.89	$48,862.31	$1,510.42	3.2%	3
4,500	30%	985,500	512,460	473,040	$49,034.69	$50,545.11	$1,510.42	3.1%	2
4,500	40%	1,314,000	683,280	630,720	$50,717.49	$52,227.91	$1,510.42	3.0%	4
4,500	50%	1,642,500	854,100	788,400	$52,400.28	$53,910.70	$1,510.42	2.9%	1
4,500	60%	1,971,000	1,024,920	946,080	$54,083.08	$55,593.50	$1,510.42	2.8%	5
4,500	70%	2,299,500	1,195,740	1,103,760	$55,765.87	$57,276.29	$1,510.42	2.7%	-
4,500	80%	2,628,000	1,366,560	1,261,440	$57,448.67	$58,959.09	$1,510.42	2.6%	-
4,500	90%	2,956,500	1,537,380	1,419,120	$59,131.47	$60,641.89	$1,510.42	2.6%	-
6,000	20%	876,000	455,520	420,480	$62,253.55	$64,232.11	$1,978.56	3.2%	-
6,000	30%	1,314,000	683,280	630,720	$64,497.28	$66,475.84	$1,978.56	3.1%	-
6,000	40%	1,752,000	911,040	840,960	$66,741.00	$68,719.57	$1,978.56	3.0%	-
6,000	50%	2,190,000	1,138,800	1,051,200	$68,984.73	$70,963.29	$1,978.56	2.9%	1
6,000	60%	2,628,000	1,366,560	1,261,440	$71,228.46	$73,207.02	$1,978.56	2.8%	-
6,000	70%	3,066,000	1,594,320	1,471,680	$73,472.19	$75,450.75	$1,978.56	2.7%	-
6,000	80%	3,504,000	1,822,080	1,681,920	$75,715.92	$77,694.48	$1,978.56	2.6%	1
6,000	90%	3,942,000	2,049,840	1,892,160	$77,959.64	$79,938.21	$1,978.56	2.5%	3

		Rate Yr 1	Rate Yr 2
	UOM	SC08SubTrn-I	SC08SubTrn-I
Customer Charge	Monthly	$ 2,646.00	$ 2,752.00
Demand Charge kW	kW	$ 9.19	$ 9.50
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2021 - April 30, 2022

Delivery Bill Only

PSC #19 - SC 8 - Large General Service - SubTransmission - Commercial									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 1	Rate Yr 2	Amount	Percent	# of Customers
500	20%	73,000	37,960	35,040	$7,773.03	$8,137.27	$364.25	4.7%	-
500	30%	109,500	56,940	52,560	$7,960.00	$8,324.25	$364.25	4.6%	2
500	40%	146,000	75,920	70,080	$8,146.98	$8,511.23	$364.25	4.5%	6
500	50%	182,500	94,900	87,600	$8,333.96	$8,698.21	$364.25	4.4%	4
500	60%	219,000	113,880	105,120	$8,520.94	$8,885.18	$364.25	4.3%	4
500	70%	255,500	132,860	122,640	$8,707.91	$9,072.16	$364.25	4.2%	2
500	80%	292,000	151,840	140,160	$8,894.89	$9,259.14	$364.25	4.1%	-
500	90%	328,500	170,820	157,680	$9,081.87	$9,446.11	$364.25	4.0%	-
1,500	20%	219,000	113,880	105,120	$18,247.23	$19,137.97	$890.74	4.9%	1
1,500	30%	328,500	170,820	157,680	$18,808.16	$19,698.90	$890.74	4.7%	3
1,500	40%	438,000	227,760	210,240	$19,369.09	$20,259.83	$890.74	4.6%	5
1,500	50%	547,500	284,700	262,800	$19,930.03	$20,820.76	$890.74	4.5%	11
1,500	60%	657,000	341,640	315,360	$20,490.96	$21,381.70	$890.74	4.3%	4
1,500	70%	766,500	398,580	367,920	$21,051.89	$21,942.63	$890.74	4.2%	3
1,500	80%	876,000	455,520	420,480	$21,612.82	$22,503.56	$890.74	4.1%	-
1,500	90%	985,500	512,460	473,040	$22,173.75	$23,064.49	$890.74	4.0%	-
4,500	20%	657,000	341,640	315,360	$49,669.84	$52,140.05	$2,470.21	5.0%	-
4,500	30%	985,500	512,460	473,040	$51,352.63	$53,822.85	$2,470.21	4.8%	2
4,500	40%	1,314,000	683,280	630,720	$53,035.43	$55,505.64	$2,470.21	4.7%	3
4,500	50%	1,642,500	854,100	788,400	$54,718.22	$57,188.44	$2,470.21	4.5%	1
4,500	60%	1,971,000	1,024,920	946,080	$56,401.02	$58,871.23	$2,470.21	4.4%	1
4,500	70%	2,299,500	1,195,740	1,103,760	$58,083.82	$60,554.03	$2,470.21	4.3%	1
4,500	80%	2,628,000	1,366,560	1,261,440	$59,766.61	$62,236.83	$2,470.21	4.1%	-
4,500	90%	2,956,500	1,537,380	1,419,120	$61,449.41	$63,919.62	$2,470.21	4.0%	-
6,000	20%	876,000	455,520	420,480	$65,381.14	$68,641.09	$3,259.95	5.0%	-
6,000	30%	1,314,000	683,280	630,720	$67,624.87	$70,884.82	$3,259.95	4.8%	-
6,000	40%	1,752,000	911,040	840,960	$69,868.60	$73,128.55	$3,259.95	4.7%	-
6,000	50%	2,190,000	1,138,800	1,051,200	$72,112.32	$75,372.28	$3,259.95	4.5%	-
6,000	60%	2,628,000	1,366,560	1,261,440	$74,356.05	$77,616.00	$3,259.95	4.4%	1
6,000	70%	3,066,000	1,594,320	1,471,680	$76,599.78	$79,859.73	$3,259.95	4.3%	1
6,000	80%	3,504,000	1,822,080	1,681,920	$78,843.51	$82,103.46	$3,259.95	4.1%	-
6,000	90%	3,942,000	2,049,840	1,892,160	$81,087.24	$84,347.19	$3,259.95	4.0%	-

		Rate Yr 1	Rate Yr 2
	UOM	SC08SubTrn-C	SC08SubTrn-C
Customer Charge	Monthly	$ 2,535.00	$ 2,636.00
Demand Charge kW	kW	$ 9.73	$ 10.25
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2021 - April 30, 2022

Delivery Bill Only

PSC #19 - SC 8 - Large General Service - Primary

Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 1	Rate Yr 2	increase / (decrease) Amount	Percent	# of Customers
250	20%	36,500	18,980	17,520	$5,133.57	$5,458.84	$325.27	6.3%	5
250	30%	54,750	28,470	26,280	$5,227.06	$5,552.33	$325.27	6.2%	7
250	40%	73,000	37,960	35,040	$5,320.55	$5,645.82	$325.27	6.1%	3
250	50%	91,250	47,450	43,800	$5,414.03	$5,739.31	$325.27	6.0%	8
250	60%	109,500	56,940	52,560	$5,507.52	$5,832.79	$325.27	5.9%	1
250	70%	127,750	66,430	61,320	$5,601.01	$5,926.28	$325.27	5.8%	2
250	80%	146,000	75,920	70,080	$5,694.50	$6,019.77	$325.27	5.7%	1
250	90%	164,250	85,410	78,840	$5,787.99	$6,113.26	$325.27	5.6%	-
500	20%	73,000	37,960	35,040	$8,835.21	$9,428.75	$593.54	6.7%	2
500	30%	109,500	56,940	52,560	$9,022.19	$9,615.73	$593.54	6.6%	8
500	40%	146,000	75,920	70,080	$9,209.17	$9,802.71	$593.54	6.4%	14
500	50%	182,500	94,900	87,600	$9,396.14	$9,989.69	$593.54	6.3%	20
500	60%	219,000	113,880	105,120	$9,583.12	$10,176.66	$593.54	6.2%	10
500	70%	255,500	132,860	122,640	$9,770.10	$10,363.64	$593.54	6.1%	3
500	80%	292,000	151,840	140,160	$9,957.08	$10,550.62	$593.54	6.0%	2
500	90%	328,500	170,820	157,680	$10,144.05	$10,737.59	$593.54	5.9%	-
1,500	20%	219,000	113,880	105,120	$23,641.78	$25,308.41	$1,666.62	7.0%	4
1,500	30%	328,500	170,820	157,680	$24,202.71	$25,869.34	$1,666.62	6.9%	18
1,500	40%	438,000	227,760	210,240	$24,763.65	$26,430.27	$1,666.62	6.7%	21
1,500	50%	547,500	284,700	262,800	$25,324.58	$26,991.20	$1,666.62	6.6%	12
1,500	60%	657,000	341,640	315,360	$25,885.51	$27,552.14	$1,666.62	6.4%	4
1,500	70%	766,500	398,580	367,920	$26,446.44	$28,113.07	$1,666.62	6.3%	4
1,500	80%	876,000	455,520	420,480	$27,007.37	$28,674.00	$1,666.62	6.2%	1
1,500	90%	985,500	512,460	473,040	$27,568.31	$29,234.93	$1,666.62	6.0%	-
2,000	20%	292,000	151,840	140,160	$31,045.07	$33,248.23	$2,203.17	7.1%	-
2,000	30%	438,000	227,760	210,240	$31,792.98	$33,996.14	$2,203.17	6.9%	-
2,000	40%	584,000	303,680	280,320	$32,540.89	$34,744.05	$2,203.17	6.8%	-
2,000	50%	730,000	379,600	350,400	$33,288.80	$35,491.96	$2,203.17	6.6%	2
2,000	60%	876,000	455,520	420,480	$34,036.71	$36,239.87	$2,203.17	6.5%	1
2,000	70%	1,022,000	531,440	490,560	$34,784.62	$36,987.78	$2,203.17	6.3%	-
2,000	80%	1,168,000	607,360	560,640	$35,532.52	$37,735.69	$2,203.17	6.2%	1
2,000	90%	1,314,000	683,280	630,720	$36,280.43	$38,483.60	$2,203.17	6.1%	6

	UOM	Rate Yr 1 SC08Pri	Rate Yr 2 SC08Pri
Customer Charge	Monthly	$ 1,431.00	$ 1,488.00
Demand Charge kW	kW	$ 14.06	$ 15.13
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2021 - April 30, 2022

Delivery Bill Only

PSC #19 - SC 8 - Large General Service - Secondary

Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 1	Rate Yr 2	increase / (decrease) Amount	Percent	# of Customers
250	20%	36,500	18,980	17,520	$4,863.56	$5,161.68	$298.12	6.1%	15
250	30%	54,750	28,470	26,280	$4,957.05	$5,255.17	$298.12	6.0%	15
250	40%	73,000	37,960	35,040	$5,050.53	$5,348.66	$298.12	5.9%	31
250	50%	91,250	47,450	43,800	$5,144.02	$5,442.15	$298.12	5.8%	37
250	60%	109,500	56,940	52,560	$5,237.51	$5,535.64	$298.12	5.7%	27
250	70%	127,750	66,430	61,320	$5,331.00	$5,629.12	$298.12	5.6%	5
250	80%	146,000	75,920	70,080	$5,424.49	$5,722.61	$298.12	5.5%	4
250	90%	164,250	85,410	78,840	$5,517.98	$5,816.10	$298.12	5.4%	-
500	20%	73,000	37,960	35,040	$8,588.19	$9,138.44	$550.25	6.4%	6
500	30%	109,500	56,940	52,560	$8,775.16	$9,325.41	$550.25	6.3%	35
500	40%	146,000	75,920	70,080	$8,962.14	$9,512.39	$550.25	6.1%	65
500	50%	182,500	94,900	87,600	$9,149.12	$9,699.37	$550.25	6.0%	40
500	60%	219,000	113,880	105,120	$9,336.10	$9,886.34	$550.25	5.9%	27
500	70%	255,500	132,860	122,640	$9,523.07	$10,073.32	$550.25	5.8%	11
500	80%	292,000	151,840	140,160	$9,710.05	$10,260.30	$550.25	5.7%	5
500	90%	328,500	170,820	157,680	$9,897.03	$10,447.28	$550.25	5.6%	1
1,500	20%	219,000	113,880	105,120	$23,486.71	$25,045.45	$1,558.74	6.6%	19
1,500	30%	328,500	170,820	157,680	$24,047.64	$25,606.39	$1,558.74	6.5%	22
1,500	40%	438,000	227,760	210,240	$24,608.57	$26,167.32	$1,558.74	6.3%	18
1,500	50%	547,500	284,700	262,800	$25,169.51	$26,728.25	$1,558.74	6.2%	5
1,500	60%	657,000	341,640	315,360	$25,730.44	$27,289.18	$1,558.74	6.1%	2
1,500	70%	766,500	398,580	367,920	$26,291.37	$27,850.11	$1,558.74	5.9%	2
1,500	80%	876,000	455,520	420,480	$26,852.30	$28,411.05	$1,558.74	5.8%	-
1,500	90%	985,500	512,460	473,040	$27,413.23	$28,971.98	$1,558.74	5.7%	-
2,000	20%	292,000	151,840	140,160	$30,935.97	$32,998.96	$2,062.99	6.7%	-
2,000	30%	438,000	227,760	210,240	$31,683.88	$33,746.87	$2,062.99	6.5%	-
2,000	40%	584,000	303,680	280,320	$32,431.79	$34,494.78	$2,062.99	6.4%	-
2,000	50%	730,000	379,600	350,400	$33,179.70	$35,242.69	$2,062.99	6.2%	-
2,000	60%	876,000	455,520	420,480	$33,927.61	$35,990.60	$2,062.99	6.1%	1
2,000	70%	1,022,000	531,440	490,560	$34,675.52	$36,738.51	$2,062.99	5.9%	1
2,000	80%	1,168,000	607,360	560,640	$35,423.43	$37,486.42	$2,062.99	5.8%	-
2,000	90%	1,314,000	683,280	630,720	$36,171.34	$38,234.33	$2,062.99	5.7%	-

	UOM	Rate Yr 1 SC08Sec	Rate Yr 2 SC08Sec
Customer Charge	Monthly	$ 1,138.00	$ 1,184.00
Demand Charge kW	kW	$ 14.15	$ 15.16
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2021 - April 30, 2022

Delivery Bill Only

PSC #19 - SC 8 - Large General Service - SubStation

Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 1	Rate Yr 2	increase / (decrease) Amount	Percent	# of Customers
250	20%	36,500	18,980	17,520	$4,746.48	$4,909.29	$162.81	3.4%	-
250	30%	54,750	28,470	26,280	$4,839.97	$5,002.78	$162.81	3.4%	1
250	40%	73,000	37,960	35,040	$4,933.46	$5,096.27	$162.81	3.3%	2
250	50%	91,250	47,450	43,800	$5,026.95	$5,189.76	$162.81	3.2%	1
250	60%	109,500	56,940	52,560	$5,120.44	$5,283.25	$162.81	3.2%	1
250	70%	127,750	66,430	61,320	$5,213.93	$5,376.74	$162.81	3.1%	2
250	80%	146,000	75,920	70,080	$5,307.42	$5,470.23	$162.81	3.1%	-
250	90%	164,250	85,410	78,840	$5,400.90	$5,563.71	$162.81	3.0%	-
500	20%	73,000	37,960	35,040	$7,030.04	$7,257.66	$227.62	3.2%	-
500	30%	109,500	56,940	52,560	$7,217.02	$7,444.64	$227.62	3.2%	1
500	40%	146,000	75,920	70,080	$7,403.99	$7,631.61	$227.62	3.1%	1
500	50%	182,500	94,900	87,600	$7,590.97	$7,818.59	$227.62	3.0%	4
500	60%	219,000	113,880	105,120	$7,777.95	$8,005.57	$227.62	2.9%	3
500	70%	255,500	132,860	122,640	$7,964.93	$8,192.55	$227.62	2.9%	2
500	80%	292,000	151,840	140,160	$8,151.90	$8,379.52	$227.62	2.8%	-
500	90%	328,500	170,820	157,680	$8,338.88	$8,566.50	$227.62	2.7%	-
2,000	20%	292,000	151,840	140,160	$20,731.38	$21,347.86	$616.48	3.0%	6
2,000	30%	438,000	227,760	210,240	$21,479.29	$22,095.77	$616.48	2.9%	4
2,000	40%	584,000	303,680	280,320	$22,227.20	$22,843.68	$616.48	2.8%	1
2,000	50%	730,000	379,600	350,400	$22,975.11	$23,591.59	$616.48	2.7%	-
2,000	60%	876,000	455,520	420,480	$23,723.02	$24,339.50	$616.48	2.6%	-
2,000	70%	1,022,000	531,440	490,560	$24,470.93	$25,087.41	$616.48	2.5%	-
2,000	80%	1,168,000	607,360	560,640	$25,218.84	$25,835.32	$616.48	2.4%	-
2,000	90%	1,314,000	683,280	630,720	$25,966.75	$26,583.23	$616.48	2.4%	-
2,500	20%	365,000	189,800	175,200	$25,298.50	$26,044.60	$746.10	2.9%	-
2,500	30%	547,500	284,700	262,800	$26,233.38	$26,979.48	$746.10	2.8%	-
2,500	40%	730,000	379,600	350,400	$27,168.27	$27,914.37	$746.10	2.7%	-
2,500	50%	912,500	474,500	438,000	$28,103.16	$28,849.26	$746.10	2.7%	-
2,500	60%	1,095,000	569,400	525,600	$29,038.04	$29,784.14	$746.10	2.6%	1
2,500	70%	1,277,500	664,300	613,200	$29,972.93	$30,719.03	$746.10	2.5%	1
2,500	80%	1,460,000	759,200	700,800	$30,907.82	$31,653.92	$746.10	2.4%	-
2,500	90%	1,642,500	854,100	788,400	$31,842.70	$32,588.80	$746.10	2.3%	-

	UOM	Rate Yr 1 SC08SubSta	Rate Yr 2 SC08SubSta
Customer Charge	Monthly	$ 2,462.00	$ 2,560.00
Demand Charge kW	kW	$ 8.39	$ 8.65
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2021 - April 30, 2022

Delivery Bill Only

PSC #19 - SC 9 - General Service - TOU									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 1	Rate Yr 2	Amount	Percent	# of Customers
10	20%	1,460	759	701	$242.61	$263.50	$20.89	8.6%	19
10	30%	2,190	1,139	1,051	$253.95	$273.32	$19.37	7.6%	17
10	40%	2,920	1,518	1,402	$265.29	$283.14	$17.85	6.7%	25
10	50%	3,650	1,898	1,752	$276.63	$292.96	$16.33	5.9%	17
10	60%	4,380	2,278	2,102	$287.96	$302.78	$14.81	5.1%	12
10	70%	5,110	2,657	2,453	$299.30	$312.59	$13.29	4.4%	7
10	80%	5,840	3,037	2,803	$310.64	$322.41	$11.77	3.8%	1
10	90%	6,570	3,416	3,154	$321.98	$332.23	$10.25	3.2%	3
25	20%	3,650	1,898	1,752	$461.90	$489.00	$27.10	5.9%	11
25	30%	5,475	2,847	2,628	$490.24	$513.54	$23.30	4.8%	27
25	40%	7,300	3,796	3,504	$518.58	$538.09	$19.50	3.8%	30
25	50%	9,125	4,745	4,380	$546.93	$562.63	$15.70	2.9%	24
25	60%	10,950	5,694	5,256	$575.27	$587.18	$11.91	2.1%	12
25	70%	12,775	6,643	6,132	$603.61	$611.72	$8.11	1.3%	3
25	80%	14,600	7,592	7,008	$631.96	$636.27	$4.31	0.7%	-
25	90%	16,425	8,541	7,884	$660.30	$660.81	$0.51	0.1%	3
100	20%	14,600	7,592	7,008	$1,558.31	$1,616.47	$58.16	3.7%	27
100	30%	21,900	11,388	10,512	$1,671.68	$1,714.64	$42.96	2.6%	32
100	40%	29,200	15,184	14,016	$1,785.06	$1,812.82	$27.76	1.6%	18
100	50%	36,500	18,980	17,520	$1,898.43	$1,911.00	$12.57	0.7%	9
100	60%	43,800	22,776	21,024	$2,011.81	$2,009.18	($2.63)	-0.1%	6
100	70%	51,100	26,572	24,528	$2,125.18	$2,107.36	($17.82)	-0.8%	2
100	80%	58,400	30,368	28,032	$2,238.55	$2,205.53	($33.02)	-1.5%	-
100	90%	65,700	34,164	31,536	$2,351.93	$2,303.71	($48.21)	-2.0%	-
200	20%	29,200	15,184	14,016	$3,020.19	$3,119.76	$99.56	3.3%	1
200	30%	43,800	22,776	21,024	$3,246.94	$3,316.11	$69.17	2.1%	2
200	40%	58,400	30,368	28,032	$3,473.69	$3,512.47	$38.78	1.1%	4
200	50%	73,000	37,960	35,040	$3,700.44	$3,708.82	$8.39	0.2%	-
200	60%	87,600	45,552	42,048	$3,927.18	$3,905.18	($22.00)	-0.6%	-
200	70%	102,200	53,144	49,056	$4,153.93	$4,101.54	($52.39)	-1.3%	-
200	80%	116,800	60,736	56,064	$4,380.68	$4,297.89	($82.79)	-1.9%	-
200	90%	131,400	68,328	63,072	$4,607.43	$4,494.25	($113.18)	-2.5%	-

		Rate Yr 1	Rate Yr 2
	UOM	SC09	SC09
Customer Charge	Monthly	$ 95.50	$ 112.25
Demand Charge kW	kW	$ 12.35	$ 13.07
Delivery Charge On Peak kWh	kWh-On	$ 0.01041	$ 0.00833
Delivery Charge Off Peak kWh	kWh-Off	$ 0.01041	$ 0.00833
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation
Electric Rates
Standby Bill Impacts by SC
May 1, 2021 - April 30, 2022

	$(000) Revenue at Rate Yr 1 Rates	$(000) Revenue at Rate Yr 2 Rates	$(000) Increase (000)	% % Increase or Decrease
Customer Charge				
SC3	$ 21.4	$ 25.1	$ 3.7	17.46%
SC8 Pri	$ 51.5	$ 53.6	$ 2.1	3.98%
SC8 Sec	$ 41.0	$ 42.6	$ 1.7	4.04%
SC8 SubTran Ind	$ 121.7	$ 126.5	$ 4.8	3.98%
SC8 SubTran Comm	$ 31.8	$ 33.0	$ 1.3	4.01%
SC8 Substation	$ 118.2	$ 122.9	$ 4.7	3.98%
	$ 385.5	$ 403.8	$ 18.3	4.74%
Contract Demand				
SC3	$ 195.9	$ 204.8	$ 9.0	4.58%
SC8 Pri	$ 145.7	$ 156.7	$ 11.0	7.54%
SC8 Sec	$ 98.6	$ 105.5	$ 6.9	7.03%
SC8 SubTran Ind	$ 407.4	$ 426.3	$ 18.9	4.64%
SC8 SubTran Comm	$ 640.9	$ 660.4	$ 19.5	3.04%
SC8 Substation	$ 187.0	$ 192.5	$ 5.5	2.93%
	$ 1,675.5	$ 1,746.3	$ 70.8	4.22%
Daily As-Used Demand				
SC3	$ 78.0	$ 81.5	$ 3.6	4.58%
SC8 Pri	$ 94.4	$ 101.5	$ 7.1	7.54%
SC8 Sec	$ 64.5	$ 69.0	$ 4.5	7.03%
SC8 SubTran Ind	$ 1,554.8	$ 1,627.0	$ 72.1	4.64%
SC8 SubTran Comm	$ 631.3	$ 650.5	$ 19.2	3.04%
SC8 Substation	$ 95.7	$ 98.6	$ 2.8	2.93%
	$ 2,518.7	$ 2,628.1	$ 109.4	4.34%
Total				
SC3	$ 295.2	$ 311.5	$ 16.3	5.51%
SC8 Pri	$ 291.6	$ 311.8	$ 20.2	6.91%
SC8 Sec	$ 204.0	$ 217.2	$ 13.1	6.43%
SC8 SubTran Ind	$ 2,083.9	$ 2,179.8	$ 95.9	4.60%
SC8 SubTran Comm	$ 1,304.0	$ 1,343.9	$ 39.9	3.06%
SC8 Substation	$ 401.0	$ 414.0	$ 13.0	3.24%
	$ 4,579.7	$ 4,778.1	$ 198.4	4.33%

Rochester Gas and Electric Corporation

Date Sources - RG&E Electric Bill Impact Statements

Rate	Source of Rate in "Current" Rates	Source of Rate in Rate Years
Customer Charge	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
kW Charge	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
kWh Delivery Charge All Hours	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
kWh Delivery Charge On Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
kWh Delivery Charge Mid Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
kWh Delivery Charge Off Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
Reactive RkVah	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
Billing Charge per Bill	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
SBC (EETr) per kWh	Current Tariff Rates in Effect 01/01/2020. Statement #26.	Included in Delivery Rates
SBC (CEF) per kWh	Current Tariff Rates in Effect 01/01/2020. Statement #26.	Current Tariff Rates in Effect 01/01/2020. Statement #26.
RAM per kWh	Tariff Rates in Effect 07/01/2019.	No RAM forecasted. COVID Bill Credits begin 7/1/2021.
RAM per kW	Tariff Rates in Effect 07/01/2019.	No RAM forecasted. COVID Bill Credits begin 7/1/2021.
Tax Credit per kWh	Case No. 17-M-0815 dated August 9, 2018. Statement Number 1	Included in Delivery Rates
Tax Credit per kW	Case No. 17-M-0815 dated August 9, 2018. Statement Number 1	Included in Delivery Rates

Rate	Source of Rate in "Current" Rates and Rate Years
Transition Charge per kWh	NBC, Demand Response, and Value Stack: NBC is the Non-Weighted 2019 Average. Dmd Rsp at $-0-. Value Stack at $-0-. RAM is separate.
MFC per kWh	Non-Weighted 2019 Average of Monthly MFC Charge
kWh Supply Charge All Hours	2019 Annualized Supply Rates
kWh Supply Charge On Peak	2019 Annualized Supply Rates
kWh Supply Charge Mid Peak	2019 Annualized Supply Rates
kWh Supply Charge Off Peak	2019 Annualized Supply Rates
Customer Count	2018 monthly data - separate Low Income counts

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2022 - April 30, 2023

Including Supply

PSC #19 - SC 1 - Residential

kWh	Rate Yr 2	Rate Yr 3	increase / (decrease) Amount	Percent	# of Customers	# of Low Income Customers	Percent of Customers	Percent of Low Income Customers	Amount of EE Embedded in Delivery Rates* Amount	Percent
100	$32.15	$33.09	$0.94	2.9%	10,907	539	3%	1%	$ 0.24	0.72%
200	$41.68	$43.26	$1.58	3.8%	25,369	2,787	7%	8%	$ 0.48	1.10%
300	$51.21	$53.43	$2.22	4.3%	33,669	4,537	10%	12%	$ 0.71	1.34%
400	$60.74	$63.60	$2.86	4.7%	37,090	5,036	11%	14%	$ 0.95	1.50%
500	$70.27	$73.76	$3.50	5.0%	38,010	4,932	11%	13%	$ 1.19	1.61%
600	$79.79	$83.93	$4.14	5.2%	35,693	4,208	11%	11%	$ 1.43	1.70%
700	$89.32	$94.10	$4.78	5.3%	31,811	3,427	9%	9%	$ 1.67	1.77%
800	$98.85	$104.26	$5.41	5.5%	27,030	2,744	8%	7%	$ 1.90	1.83%
900	$108.38	$114.43	$6.05	5.6%	22,238	2,191	7%	6%	$ 2.14	1.87%
1,000	$117.91	$124.60	$6.69	5.7%	17,500	1,598	5%	4%	$ 2.38	1.91%
1,100	$127.43	$134.77	$7.33	5.8%	13,667	1,211	4%	3%	$ 2.62	1.94%
1,200	$136.96	$144.93	$7.97	5.8%	10,434	907	3%	2%	$ 2.86	1.97%
1,500	$165.55	$175.44	$9.89	6.0%	18,454	1,568	5%	4%	$ 3.57	2.03%
2,000	$213.19	$226.27	$13.09	6.1%	11,052	901	3%	2%	$ 4.76	2.10%
3,000	$308.47	$327.94	$19.48	6.3%	5,347	334	2%	1%	$ 7.14	2.18%
					338,269	36,919				

	UOM	Rate Yr 2 SC01	Rate Yr 3 SC01
Customer Charge	Monthly	$ 21.70	$ 22.00
Delivery Charge All Hours kWh	kWh	$ 0.05153	$ 0.05792
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kWh	kWh	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00206)	$ (0.00206)
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93
Supply Charge All Hours kWh	kWh	$ 0.03736	$ 0.03736
MFC per kWh	kWh	$ 0.00309	$ 0.00309

Includes $ 0.00238 per kWh of EE Costs*

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

4. Low income customers represent customers who participated in the Company's low income program and received a credit on their bill each month during calendar year 2018.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2022 - April 30, 2023

Including Supply

PSC #19 - SC 2 - General Service - Non Demand					
			increase / (decrease)		
kWh	Rate Yr 2	Rate Yr 3	Amount	Percent	# of Customers
300	$48.78	$50.73	$1.95	4.0%	11,999
400	$57.50	$60.00	$2.50	4.3%	2,601
500	$66.22	$69.26	$3.05	4.6%	2,299
600	$74.94	$78.53	$3.60	4.8%	1,892
700	$83.65	$87.80	$4.14	5.0%	1,541
800	$92.37	$97.07	$4.69	5.1%	1,322
900	$101.09	$106.33	$5.24	5.2%	1,021
1,000	$109.81	$115.60	$5.79	5.3%	904
1,500	$153.40	$161.94	$8.54	5.6%	2,999
2,000	$196.99	$208.27	$11.28	5.7%	1,654
2,500	$240.58	$254.61	$14.03	5.8%	845
3,000	$284.17	$300.95	$16.78	5.9%	385
4,000	$371.36	$393.62	$22.27	6.0%	203
5,000	$458.54	$486.30	$27.76	6.1%	60
6,000	$545.72	$578.97	$33.25	6.1%	21
7,000	$632.90	$671.65	$38.74	6.1%	59

		Rate Yr 2	Rate Yr 3
	UOM	SC02	SC02
Customer Charge	Monthly	$ 21.70	$ 22.00
Delivery Charge All Hours kWh	kWh	$ 0.04078	$ 0.04627
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kWh	kWh	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93
Supply Charge All Hours kWh	kWh	$ 0.03819	$ 0.03819
MFC per kWh	kWh	$ 0.00309	$ 0.00309

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2022 - April 30, 2023

Including Supply

PSC #19 - SC 3 - General Service - Demand

Kw	Load Factor	kWh	Rate Yr 2	Rate Yr 3	increase / (decrease) Amount	Percent	# of Customers
50	20%	7,300	$1,539.72	$1,637.23	$97.51	6.3%	45
50	30%	10,950	$1,686.14	$1,783.65	$97.51	5.8%	19
50	40%	14,600	$1,832.56	$1,930.07	$97.51	5.3%	18
50	50%	18,250	$1,978.99	$2,076.49	$97.51	4.9%	18
50	60%	21,900	$2,125.41	$2,222.91	$97.51	4.6%	1
50	70%	25,550	$2,271.83	$2,369.34	$97.51	4.3%	3
50	80%	29,200	$2,418.25	$2,515.76	$97.51	4.0%	3
50	90%	32,850	$2,564.67	$2,662.18	$97.51	3.8%	2
100	20%	14,600	$2,729.51	$2,872.52	$143.01	5.2%	43
100	30%	21,900	$3,022.36	$3,165.37	$143.01	4.7%	73
100	40%	29,200	$3,315.20	$3,458.21	$143.01	4.3%	122
100	50%	36,500	$3,608.05	$3,751.06	$143.01	4.0%	115
100	60%	43,800	$3,900.89	$4,043.90	$143.01	3.7%	47
100	70%	51,100	$4,193.74	$4,336.75	$143.01	3.4%	32
100	80%	58,400	$4,486.58	$4,629.59	$143.01	3.2%	9
100	90%	65,700	$4,779.42	$4,922.43	$143.01	3.0%	6
275	20%	40,150	$6,893.79	$7,196.07	$302.28	4.4%	146
275	30%	60,225	$7,699.11	$8,001.39	$302.28	3.9%	223
275	40%	80,300	$8,504.44	$8,806.72	$302.28	3.6%	130
275	50%	100,375	$9,309.76	$9,612.04	$302.28	3.2%	69
275	60%	120,450	$10,115.08	$10,417.36	$302.28	3.0%	24
275	70%	140,525	$10,920.40	$11,222.68	$302.28	2.8%	8
275	80%	160,600	$11,725.72	$12,028.00	$302.28	2.6%	2
275	90%	180,675	$12,531.05	$12,833.33	$302.28	2.4%	2
300	20%	43,800	$7,488.69	$7,813.72	$325.03	4.3%	-
300	30%	65,700	$8,367.22	$8,692.25	$325.03	3.9%	2
300	40%	87,600	$9,245.75	$9,570.79	$325.03	3.5%	2
300	50%	109,500	$10,124.29	$10,449.32	$325.03	3.2%	3
300	60%	131,400	$11,002.82	$11,327.85	$325.03	3.0%	-
300	70%	153,300	$11,881.35	$12,206.39	$325.03	2.7%	2
300	80%	175,200	$12,759.89	$13,084.92	$325.03	2.5%	2
300	90%	197,100	$13,638.42	$13,963.45	$325.03	2.4%	3

	UOM	Rate Yr 2 SC03	Rate Yr 3 SC03
Customer Charge	Monthly	$ 349.00	$ 401.00
Demand Charge kW	kW	$ 17.94	$ 18.85
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93
Supply Charge All Hours kWh	kWh	$ 0.03293	$ 0.03293
MFC per kWh	kWh	$ 0.00206	$ 0.00206

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2022 - April 30, 2023

Including Supply

PSC #19 - SC 4-I - Residential - Day/Night							
					increase / (decrease)		
kWh	Peak	Off Peak	Rate Yr 2	Rate Yr 3	Amount	Percent	# of Customers
300	210	90	53.62	54.83	1.21	2.3%	126
400	280	120	62.58	64.09	1.51	2.4%	91
500	350	150	71.54	73.36	1.81	2.5%	104
600	420	180	80.51	82.62	2.12	2.6%	131
700	490	210	89.47	91.89	2.42	2.7%	172
800	560	240	98.43	101.16	2.72	2.8%	191
900	630	270	107.40	110.42	3.02	2.8%	145
1,000	700	300	116.36	119.69	3.33	2.9%	157
1,500	1,050	450	161.18	166.02	4.84	3.0%	589
2,000	1,400	600	206.00	212.35	6.36	3.1%	302
2,500	1,750	750	250.82	258.68	7.87	3.1%	149
3,000	2,100	900	295.63	305.02	9.38	3.2%	61
4,000	2,800	1,200	385.27	397.68	12.41	3.2%	26
5,000	3,500	1,500	474.90	490.34	15.44	3.3%	11
6,000	4,200	1,800	564.54	583.01	18.47	3.3%	1
7,000	4,900	2,100	654.18	675.67	21.49	3.3%	5

		Rate Yr 2	Rate Yr 3
	UOM	SC04-I	SC04-I
Customer Charge	Monthly	$ 25.80	$ 26.10
Delivery Charge On Peak kWh	kWh-On	$ 0.04746	$ 0.05049
Delivery Charge Off Peak kWh	kWh-Off	$ 0.04746	$ 0.05049
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kWh	kWh	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00206)	$ (0.00206)
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93
Supply Charge On Peak kWh	kWh-On	$ 0.04005	$ 0.04005
Supply Charge Off Peak kWh	kWh-Off	$ 0.02742	$ 0.02742
MFC per kWh	kWh	$ 0.00261	$ 0.00261

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2022 - April 30, 2023

Including Supply

PSC #19 - SC 4-II - Residential - Day/Night							
					increase / (decrease)		
kWh	Peak	Off Peak	Rate Yr 2	Rate Yr 3	Amount	Percent	# of Customers
300	210	90	$60.28	$61.68	$1.39	2.3%	18
400	280	120	$70.32	$72.03	$1.71	2.4%	9
500	350	150	$80.35	$82.38	$2.02	2.5%	15
600	420	180	$90.39	$92.73	$2.34	2.6%	28
700	490	210	$100.43	$103.08	$2.65	2.6%	29
800	560	240	$110.46	$113.43	$2.97	2.7%	38
900	630	270	$120.50	$123.78	$3.28	2.7%	33
1,000	700	300	$130.53	$134.13	$3.60	2.8%	52
1,500	1,050	450	$180.71	$185.88	$5.17	2.9%	238
2,000	1,400	600	$230.89	$237.63	$6.74	2.9%	190
2,500	1,750	750	$281.07	$289.39	$8.32	3.0%	165
3,000	2,100	900	$331.25	$341.14	$9.89	3.0%	83
4,000	2,800	1,200	$431.60	$444.64	$13.04	3.0%	84
5,000	3,500	1,500	$531.96	$548.15	$16.19	3.0%	49
6,000	4,200	1,800	$632.31	$651.65	$19.33	3.1%	33
7,000	4,900	2,100	$732.67	$755.15	$22.48	3.1%	28

	UOM	Rate Yr 2 SC04-II	Rate Yr 3 SC04-II
Customer Charge	Monthly	$ 29.25	$ 29.70
Delivery Charge On Peak kWh	kWh-On	$ 0.05818	$ 0.06133
Delivery Charge Off Peak kWh	kWh-Off	$ 0.05818	$ 0.06133
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kWh	kWh	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00206)	$ (0.00206)
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93
Supply Charge On Peak kWh	kWh-On	$ 0.04005	$ 0.04005
Supply Charge Off Peak kWh	kWh-Off	$ 0.02742	$ 0.02742
MFC per kWh	kWh	$ 0.00261	$ 0.00261

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2022 - April 30, 2023

Including Supply

PSC #19 - SC 7 - General Service - Demand							
					increase / (decrease)		
Kw	Load Factor	kWh	Rate Yr 2	Rate Yr 3	Amount	Percent	# of Customers
5	20%	730	$228.47	$245.25	$16.78	7.3%	178
5	30%	1,095	$245.08	$261.47	$16.39	6.7%	51
5	40%	1,460	$261.69	$277.69	$16.00	6.1%	36
5	50%	1,825	$278.30	$293.92	$15.61	5.6%	34
5	60%	2,190	$294.91	$310.14	$15.22	5.2%	16
5	70%	2,555	$311.52	$326.36	$14.84	4.8%	14
5	80%	2,920	$328.14	$342.58	$14.45	4.4%	6
5	90%	3,285	$344.75	$358.80	$14.06	4.1%	6
25	20%	3,650	$718.66	$742.54	$23.88	3.3%	2,778
25	30%	5,475	$801.71	$823.65	$21.94	2.7%	1,673
25	40%	7,300	$884.76	$904.77	$20.00	2.3%	888
25	50%	9,125	$967.82	$985.88	$18.06	1.9%	403
25	60%	10,950	$1,050.87	$1,066.99	$16.12	1.5%	155
25	70%	12,775	$1,133.92	$1,148.10	$14.18	1.3%	46
25	80%	14,600	$1,216.97	$1,229.21	$12.24	1.0%	12
25	90%	16,425	$1,300.02	$1,310.32	$10.30	0.8%	7
100	20%	14,600	$2,556.86	$2,607.40	$50.54	2.0%	1,560
100	30%	21,900	$2,889.07	$2,931.84	$42.77	1.5%	618
100	40%	29,200	$3,221.28	$3,256.28	$35.01	1.1%	240
100	50%	36,500	$3,553.49	$3,580.73	$27.24	0.8%	74
100	60%	43,800	$3,885.70	$3,905.17	$19.48	0.5%	44
100	70%	51,100	$4,217.90	$4,229.62	$11.71	0.3%	8
100	80%	58,400	$4,550.11	$4,554.06	$3.95	0.1%	3
100	90%	65,700	$4,882.32	$4,878.50	($3.82)	-0.1%	2
250	20%	36,500	$6,233.26	$6,337.10	$103.84	1.7%	19
250	30%	54,750	$7,063.78	$7,148.21	$84.43	1.2%	15
250	40%	73,000	$7,894.30	$7,959.32	$65.02	0.8%	5
250	50%	91,250	$8,724.83	$8,770.43	$45.60	0.5%	2
250	60%	109,500	$9,555.35	$9,581.54	$26.19	0.3%	-
250	70%	127,750	$10,385.87	$10,392.65	$6.78	0.1%	1
250	80%	146,000	$11,216.39	$11,203.76	($12.63)	-0.1%	-
250	90%	164,250	$12,046.92	$12,014.87	($32.05)	-0.3%	-

		Rate Yr 2	Rate Yr 3
	UOM	SC07	SC07
Customer Charge	Monthly	$ 105.00	$ 120.00
Demand Charge kW	kW	$ 17.87	$ 18.38
Delivery Charge All Hours kWh	kWh	$ 0.00532	$ 0.00425
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93
Supply Charge All Hours kWh	kWh	$ 0.03301	$ 0.03301
MFC per kWh	kWh	$ 0.00206	$ 0.00206

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2022 - April 30, 2023

Including Supply

PSC #19 - SC 8 - Large General Service - Transmission									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 2	Rate Yr 3	Amount	Percent	# of Customers
6,000	20%	876,000	455,520	420,480	$96,150.62	$100,691.20	$4,540.57	4.7%	-
6,000	30%	1,314,000	683,280	630,720	$112,790.52	$117,331.09	$4,540.57	4.0%	-
6,000	40%	1,752,000	911,040	840,960	$129,430.41	$133,970.99	$4,540.57	3.5%	-
6,000	50%	2,190,000	1,138,800	1,051,200	$146,070.31	$150,610.88	$4,540.57	3.1%	-
6,000	60%	2,628,000	1,366,560	1,261,440	$162,710.20	$167,250.77	$4,540.57	2.8%	-
6,000	70%	3,066,000	1,594,320	1,471,680	$179,350.09	$183,890.67	$4,540.57	2.5%	-
6,000	80%	3,504,000	1,822,080	1,681,920	$195,989.99	$200,530.56	$4,540.57	2.3%	-
6,000	90%	3,942,000	2,049,840	1,892,160	$212,629.88	$217,170.46	$4,540.57	2.1%	-
7,000	20%	1,022,000	531,440	490,560	$111,475.57	$116,739.57	$5,264.00	4.7%	-
7,000	30%	1,533,000	797,160	735,840	$130,888.78	$136,152.78	$5,264.00	4.0%	-
7,000	40%	2,044,000	1,062,880	981,120	$150,301.99	$155,565.99	$5,264.00	3.5%	-
7,000	50%	2,555,000	1,328,600	1,226,400	$169,715.20	$174,979.21	$5,264.00	3.1%	-
7,000	60%	3,066,000	1,594,320	1,471,680	$189,128.41	$194,392.42	$5,264.00	2.8%	1
7,000	70%	3,577,000	1,860,040	1,716,960	$208,541.62	$213,805.63	$5,264.00	2.5%	-
7,000	80%	4,088,000	2,125,760	1,962,240	$227,954.83	$233,218.84	$5,264.00	2.3%	-
7,000	90%	4,599,000	2,391,480	2,207,520	$247,368.04	$252,632.05	$5,264.00	2.1%	-
8,000	20%	1,168,000	607,360	560,640	$126,800.52	$132,787.95	$5,987.43	4.7%	-
8,000	30%	1,752,000	911,040	840,960	$148,987.05	$154,974.48	$5,987.43	4.0%	-
8,000	40%	2,336,000	1,214,720	1,121,280	$171,173.57	$177,161.00	$5,987.43	3.5%	-
8,000	50%	2,920,000	1,518,400	1,401,600	$193,360.10	$199,347.53	$5,987.43	3.1%	-
8,000	60%	3,504,000	1,822,080	1,681,920	$215,546.62	$221,534.06	$5,987.43	2.8%	-
8,000	70%	4,088,000	2,125,760	1,962,240	$237,733.15	$243,720.58	$5,987.43	2.5%	-
8,000	80%	4,672,000	2,429,440	2,242,560	$259,919.68	$265,907.11	$5,987.43	2.3%	-
8,000	90%	5,256,000	2,733,120	2,522,880	$282,106.20	$288,093.63	$5,987.43	2.1%	-
9,000	20%	1,314,000	683,280	630,720	$142,125.47	$148,836.33	$6,710.86	4.7%	-
9,000	30%	1,971,000	1,024,920	946,080	$167,085.31	$173,796.17	$6,710.86	4.0%	-
9,000	40%	2,628,000	1,366,560	1,261,440	$192,045.15	$198,756.01	$6,710.86	3.5%	-
9,000	50%	3,285,000	1,708,200	1,576,800	$217,005.00	$223,715.86	$6,710.86	3.1%	-
9,000	60%	3,942,000	2,049,840	1,892,160	$241,964.84	$248,675.70	$6,710.86	2.8%	-
9,000	70%	4,599,000	2,391,480	2,207,520	$266,924.68	$273,635.54	$6,710.86	2.5%	-
9,000	80%	5,256,000	2,733,120	2,522,880	$291,884.52	$298,595.38	$6,710.86	2.3%	-
9,000	90%	5,913,000	3,074,760	2,838,240	$316,844.36	$323,555.22	$6,710.86	2.1%	-

		Rate Yr 2	Rate Yr 3
	UOM	SC08Trn	SC08Trn
Customer Charge	Monthly	$ 4,200.00	$ 4,400.00
Demand Charge kW	kW	$ 9.78	$ 10.50
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93
Supply Charge On Peak kWh	kWh-On	$ 0.03594	$ 0.03594
Supply Charge Off Peak kWh	kWh-Off	$ 0.02525	$ 0.02525
MFC per kWh	kWh	$ 0.00206	$ 0.00206

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2022 - April 30, 2023

Including Supply

PSC #19 - SC 8 - Large General Service - SubTransmission - Industrial									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 2	Rate Yr 3	Amount	Percent	# of Customers
500	20%	73,000	37,960	35,040	$10,275.55	$10,549.92	$274.37	2.7%	1
500	30%	109,500	56,940	52,560	$11,662.21	$11,936.58	$274.37	2.4%	4
500	40%	146,000	75,920	70,080	$13,048.87	$13,323.24	$274.37	2.1%	2
500	50%	182,500	94,900	87,600	$14,435.53	$14,709.90	$274.37	1.9%	2
500	60%	219,000	113,880	105,120	$15,822.18	$16,096.55	$274.37	1.7%	-
500	70%	255,500	132,860	122,640	$17,208.84	$17,483.21	$274.37	1.6%	2
500	80%	292,000	151,840	140,160	$18,595.50	$18,869.87	$274.37	1.5%	-
500	90%	328,500	170,820	157,680	$19,982.16	$20,256.53	$274.37	1.4%	1
1,500	20%	219,000	113,880	105,120	$25,320.81	$25,931.91	$611.11	2.4%	2
1,500	30%	328,500	170,820	157,680	$29,480.78	$30,091.89	$611.11	2.1%	1
1,500	40%	438,000	227,760	210,240	$33,640.75	$34,251.86	$611.11	1.8%	3
1,500	50%	547,500	284,700	262,800	$37,800.73	$38,411.83	$611.11	1.6%	4
1,500	60%	657,000	341,640	315,360	$41,960.70	$42,571.81	$611.11	1.5%	6
1,500	70%	766,500	398,580	367,920	$46,120.67	$46,731.78	$611.11	1.3%	-
1,500	80%	876,000	455,520	420,480	$50,280.65	$50,891.75	$611.11	1.2%	1
1,500	90%	985,500	512,460	473,040	$54,440.62	$55,051.73	$611.11	1.1%	-
4,500	20%	657,000	341,640	315,360	$70,456.56	$72,077.89	$1,621.32	2.3%	3
4,500	30%	985,500	512,460	473,040	$82,936.48	$84,557.81	$1,621.32	2.0%	2
4,500	40%	1,314,000	683,280	630,720	$95,416.41	$97,037.73	$1,621.32	1.7%	4
4,500	50%	1,642,500	854,100	788,400	$107,896.33	$109,517.65	$1,621.32	1.5%	1
4,500	60%	1,971,000	1,024,920	946,080	$120,376.25	$121,997.57	$1,621.32	1.3%	5
4,500	70%	2,299,500	1,195,740	1,103,760	$132,856.17	$134,477.49	$1,621.32	1.2%	-
4,500	80%	2,628,000	1,366,560	1,261,440	$145,336.09	$146,957.41	$1,621.32	1.1%	-
4,500	90%	2,956,500	1,537,380	1,419,120	$157,816.01	$159,437.33	$1,621.32	1.0%	-
6,000	20%	876,000	455,520	420,480	$93,024.44	$95,150.87	$2,126.43	2.3%	-
6,000	30%	1,314,000	683,280	630,720	$109,664.34	$111,790.77	$2,126.43	1.9%	-
6,000	40%	1,752,000	911,040	840,960	$126,304.23	$128,430.66	$2,126.43	1.7%	-
6,000	50%	2,190,000	1,138,800	1,051,200	$142,944.13	$145,070.55	$2,126.43	1.5%	1
6,000	60%	2,628,000	1,366,560	1,261,440	$159,584.02	$161,710.45	$2,126.43	1.3%	-
6,000	70%	3,066,000	1,594,320	1,471,680	$176,223.92	$178,350.34	$2,126.43	1.2%	-
6,000	80%	3,504,000	1,822,080	1,681,920	$192,863.81	$194,990.24	$2,126.43	1.1%	1
6,000	90%	3,942,000	2,049,840	1,892,160	$209,503.70	$211,630.13	$2,126.43	1.0%	3

		Rate Yr 2	Rate Yr 3
	UOM	SC08SubTrn-I	SC08SubTrn-I
Customer Charge	Monthly	$ 2,752.00	$ 2,858.00
Demand Charge kW	kW	$ 9.50	$ 9.84
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93
Supply Charge On Peak kWh	kWh-On	$ 0.03594	$ 0.03594
Supply Charge Off Peak kWh	kWh-Off	$ 0.02525	$ 0.02525
MFC per kWh	kWh	$ 0.00206	$ 0.00206

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2022 - April 30, 2023

Including Supply

PSC #19 - SC 8 - Large General Service - SubTransmission - Commercial									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 2	Rate Yr 3	Amount	Percent	# of Customers
500	20%	73,000	37,960	35,040	$10,559.29	$10,952.29	$393.00	3.7%	-
500	30%	109,500	56,940	52,560	$11,957.27	$12,350.27	$393.00	3.3%	2
500	40%	146,000	75,920	70,080	$13,355.26	$13,748.26	$393.00	2.9%	6
500	50%	182,500	94,900	87,600	$14,753.24	$15,146.24	$393.00	2.7%	4
500	60%	219,000	113,880	105,120	$16,151.23	$16,544.23	$393.00	2.4%	4
500	70%	255,500	132,860	122,640	$17,549.21	$17,942.21	$393.00	2.2%	2
500	80%	292,000	151,840	140,160	$18,947.19	$19,340.19	$393.00	2.1%	-
500	90%	328,500	170,820	157,680	$20,345.18	$20,738.18	$393.00	1.9%	-
1,500	20%	219,000	113,880	105,120	$26,404.01	$27,381.01	$977.00	3.7%	1
1,500	30%	328,500	170,820	157,680	$30,597.96	$31,574.96	$977.00	3.2%	3
1,500	40%	438,000	227,760	210,240	$34,791.92	$35,768.92	$977.00	2.8%	5
1,500	50%	547,500	284,700	262,800	$38,985.87	$39,962.87	$977.00	2.5%	11
1,500	60%	657,000	341,640	315,360	$43,179.83	$44,156.82	$977.00	2.3%	4
1,500	70%	766,500	398,580	367,920	$47,373.78	$48,350.78	$977.00	2.1%	3
1,500	80%	876,000	455,520	420,480	$51,567.73	$52,544.73	$977.00	1.9%	-
1,500	90%	985,500	512,460	473,040	$55,761.69	$56,738.69	$977.00	1.8%	-
4,500	20%	657,000	341,640	315,360	$73,938.18	$76,667.18	$2,729.00	3.7%	-
4,500	30%	985,500	512,460	473,040	$86,520.04	$89,249.04	$2,729.00	3.2%	2
4,500	40%	1,314,000	683,280	630,720	$99,101.90	$101,830.90	$2,729.00	2.8%	3
4,500	50%	1,642,500	854,100	788,400	$111,683.76	$114,412.76	$2,729.00	2.4%	1
4,500	60%	1,971,000	1,024,920	946,080	$124,265.62	$126,994.62	$2,729.00	2.2%	1
4,500	70%	2,299,500	1,195,740	1,103,760	$136,847.49	$139,576.48	$2,729.00	2.0%	1
4,500	80%	2,628,000	1,366,560	1,261,440	$149,429.35	$152,158.34	$2,729.00	1.8%	-
4,500	90%	2,956,500	1,537,380	1,419,120	$162,011.21	$164,740.20	$2,729.00	1.7%	-
6,000	20%	876,000	455,520	420,480	$97,705.26	$101,310.26	$3,604.99	3.7%	-
6,000	30%	1,314,000	683,280	630,720	$114,481.08	$118,086.07	$3,604.99	3.1%	-
6,000	40%	1,752,000	911,040	840,960	$131,256.89	$134,861.89	$3,604.99	2.7%	-
6,000	50%	2,190,000	1,138,800	1,051,200	$148,032.71	$151,637.70	$3,604.99	2.4%	-
6,000	60%	2,628,000	1,366,560	1,261,440	$164,808.52	$168,413.52	$3,604.99	2.2%	1
6,000	70%	3,066,000	1,594,320	1,471,680	$181,584.34	$185,189.33	$3,604.99	2.0%	1
6,000	80%	3,504,000	1,822,080	1,681,920	$198,360.15	$201,965.15	$3,604.99	1.8%	-
6,000	90%	3,942,000	2,049,840	1,892,160	$215,135.97	$218,740.96	$3,604.99	1.7%	-

		Rate Yr 2	Rate Yr 3
	UOM	SC08SubTrn-C	SC08SubTrn-C
Customer Charge	Monthly	$ 2,636.00	$ 2,737.00
Demand Charge kW	kW	$ 10.25	$ 10.84
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93
Supply Charge On Peak kWh	kWh-On	$ 0.03631	$ 0.03631
Supply Charge Off Peak kWh	kWh-Off	$ 0.02550	$ 0.02550
MFC per kWh	kWh	$ 0.00206	$ 0.00206

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2022 - April 30, 2023

Including Supply

PSC #19 - SC 8 - Large General Service - Primary									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 2	Rate Yr 3	Amount	Percent	# of Customers
250	20%	36,500	18,980	17,520	$6,662.04	$7,129.64	$467.60	7.0%	5
250	30%	54,750	28,470	26,280	$7,357.13	$7,824.73	$467.60	6.4%	7
250	40%	73,000	37,960	35,040	$8,052.22	$8,519.82	$467.60	5.8%	3
250	50%	91,250	47,450	43,800	$8,747.31	$9,214.91	$467.60	5.3%	8
250	60%	109,500	56,940	52,560	$9,442.40	$9,910.00	$467.60	5.0%	1
250	70%	127,750	66,430	61,320	$10,137.49	$10,605.09	$467.60	4.6%	2
250	80%	146,000	75,920	70,080	$10,832.57	$11,300.18	$467.60	4.3%	1
250	90%	164,250	85,410	78,840	$11,527.66	$11,995.27	$467.60	4.1%	-
500	20%	73,000	37,960	35,040	$11,835.15	$12,712.36	$877.21	7.4%	2
500	30%	109,500	56,940	52,560	$13,225.33	$14,102.54	$877.21	6.6%	8
500	40%	146,000	75,920	70,080	$14,615.51	$15,492.72	$877.21	6.0%	14
500	50%	182,500	94,900	87,600	$16,005.69	$16,882.89	$877.21	5.5%	20
500	60%	219,000	113,880	105,120	$17,395.87	$18,273.07	$877.21	5.0%	10
500	70%	255,500	132,860	122,640	$18,786.04	$19,663.25	$877.21	4.7%	3
500	80%	292,000	151,840	140,160	$20,176.22	$21,053.43	$877.21	4.3%	2
500	90%	328,500	170,820	157,680	$21,566.40	$22,443.61	$877.21	4.1%	-
1,500	20%	219,000	113,880	105,120	$32,527.61	$35,043.23	$2,515.62	7.7%	4
1,500	30%	328,500	170,820	157,680	$36,698.14	$39,213.76	$2,515.62	6.9%	18
1,500	40%	438,000	227,760	210,240	$40,868.68	$43,384.30	$2,515.62	6.2%	21
1,500	50%	547,500	284,700	262,800	$45,039.21	$47,554.83	$2,515.62	5.6%	12
1,500	60%	657,000	341,640	315,360	$49,209.75	$51,725.37	$2,515.62	5.1%	4
1,500	70%	766,500	398,580	367,920	$53,380.28	$55,895.90	$2,515.62	4.7%	4
1,500	80%	876,000	455,520	420,480	$57,550.81	$60,066.43	$2,515.62	4.4%	1
1,500	90%	985,500	512,460	473,040	$61,721.35	$64,236.97	$2,515.62	4.1%	-
2,000	20%	292,000	151,840	140,160	$42,873.84	$46,208.67	$3,334.83	7.8%	-
2,000	30%	438,000	227,760	210,240	$48,434.55	$51,769.38	$3,334.83	6.9%	-
2,000	40%	584,000	303,680	280,320	$53,995.26	$57,330.09	$3,334.83	6.2%	-
2,000	50%	730,000	379,600	350,400	$59,555.97	$62,890.80	$3,334.83	5.6%	2
2,000	60%	876,000	455,520	420,480	$65,116.69	$68,451.51	$3,334.83	5.1%	1
2,000	70%	1,022,000	531,440	490,560	$70,677.40	$74,012.22	$3,334.83	4.7%	-
2,000	80%	1,168,000	607,360	560,640	$76,238.11	$79,572.94	$3,334.83	4.4%	1
2,000	90%	1,314,000	683,280	630,720	$81,798.82	$85,133.65	$3,334.83	4.1%	6

		Rate Yr 2	Rate Yr 3
	UOM	SC08Pri	SC08Pri
Customer Charge	Monthly	$ 1,488.00	$ 1,546.00
Demand Charge kW	kW	$ 15.13	$ 16.77
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93
Supply Charge On Peak kWh	kWh-On	$ 0.03594	$ 0.03594
Supply Charge Off Peak kWh	kWh-Off	$ 0.02545	$ 0.02545
MFC per kWh	kWh	$ 0.00206	$ 0.00206

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2022 - April 30, 2023

Including Supply

PSC #19 - SC 8 - Large General Service - Secondary									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 2	Rate Yr 3	Amount	Percent	# of Customers
250	20%	36,500	18,980	17,520	$6,407.40	$6,727.89	$320.49	5.0%	15
250	30%	54,750	28,470	26,280	$7,123.75	$7,444.24	$320.49	4.5%	15
250	40%	73,000	37,960	35,040	$7,840.10	$8,160.59	$320.49	4.1%	31
250	50%	91,250	47,450	43,800	$8,556.44	$8,876.93	$320.49	3.7%	37
250	60%	109,500	56,940	52,560	$9,272.79	$9,593.28	$320.49	3.5%	27
250	70%	127,750	66,430	61,320	$9,989.14	$10,309.63	$320.49	3.2%	5
250	80%	146,000	75,920	70,080	$10,705.49	$11,025.98	$320.49	3.0%	4
250	90%	164,250	85,410	78,840	$11,421.84	$11,742.33	$320.49	2.8%	-
500	20%	73,000	37,960	35,040	$11,629.87	$12,225.85	$595.98	5.1%	6
500	30%	109,500	56,940	52,560	$13,062.57	$13,658.55	$595.98	4.6%	35
500	40%	146,000	75,920	70,080	$14,495.27	$15,091.24	$595.98	4.1%	65
500	50%	182,500	94,900	87,600	$15,927.96	$16,523.94	$595.98	3.7%	40
500	60%	219,000	113,880	105,120	$17,360.66	$17,956.64	$595.98	3.4%	27
500	70%	255,500	132,860	122,640	$18,793.35	$19,389.33	$595.98	3.2%	11
500	80%	292,000	151,840	140,160	$20,226.05	$20,822.03	$595.98	2.9%	5
500	90%	328,500	170,820	157,680	$21,658.75	$22,254.73	$595.98	2.8%	1
1,500	20%	219,000	113,880	105,120	$32,519.77	$34,217.71	$1,697.94	5.2%	19
1,500	30%	328,500	170,820	157,680	$36,817.85	$38,515.79	$1,697.94	4.6%	22
1,500	40%	438,000	227,760	210,240	$41,115.94	$42,813.88	$1,697.94	4.1%	18
1,500	50%	547,500	284,700	262,800	$45,414.03	$47,111.97	$1,697.94	3.7%	5
1,500	60%	657,000	341,640	315,360	$49,712.12	$51,410.06	$1,697.94	3.4%	2
1,500	70%	766,500	398,580	367,920	$54,010.21	$55,708.15	$1,697.94	3.1%	2
1,500	80%	876,000	455,520	420,480	$58,308.30	$60,006.24	$1,697.94	2.9%	-
1,500	90%	985,500	512,460	473,040	$62,606.38	$64,304.32	$1,697.94	2.7%	-
2,000	20%	292,000	151,840	140,160	$42,964.71	$45,213.63	$2,248.92	5.2%	-
2,000	30%	438,000	227,760	210,240	$48,695.50	$50,944.42	$2,248.92	4.6%	-
2,000	40%	584,000	303,680	280,320	$54,426.28	$56,675.20	$2,248.92	4.1%	-
2,000	50%	730,000	379,600	350,400	$60,157.07	$62,405.99	$2,248.92	3.7%	-
2,000	60%	876,000	455,520	420,480	$65,887.85	$68,136.77	$2,248.92	3.4%	1
2,000	70%	1,022,000	531,440	490,560	$71,618.63	$73,867.55	$2,248.92	3.1%	1
2,000	80%	1,168,000	607,360	560,640	$77,349.42	$79,598.34	$2,248.92	2.9%	-
2,000	90%	1,314,000	683,280	630,720	$83,080.20	$85,329.12	$2,248.92	2.7%	-

		Rate Yr 2	Rate Yr 3
	UOM	SC08Sec	SC08Sec
Customer Charge	Monthly	$ 1,184.00	$ 1,229.00
Demand Charge kW	kW	$ 15.16	$ 16.26
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93
Supply Charge On Peak kWh	kWh-On	$ 0.03761	$ 0.03761
Supply Charge Off Peak kWh	kWh-Off	$ 0.02607	$ 0.02607
MFC per kWh	kWh	$ 0.00206	$ 0.00206

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2022 - April 30, 2023

Including Supply

PSC #19 - SC 8 - Large General Service - SubStation

Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 2	Rate Yr 3	increase / (decrease) Amount	Percent	# of Customers
250	20%	36,500	18,980	17,520	$6,130.11	$6,300.53	$170.43	2.8%	-
250	30%	54,750	28,470	26,280	$6,834.00	$7,004.43	$170.43	2.5%	1
250	40%	73,000	37,960	35,040	$7,537.90	$7,708.33	$170.43	2.3%	2
250	50%	91,250	47,450	43,800	$8,241.79	$8,412.22	$170.43	2.1%	1
250	60%	109,500	56,940	52,560	$8,945.69	$9,116.12	$170.43	1.9%	1
250	70%	127,750	66,430	61,320	$9,649.59	$9,820.01	$170.43	1.8%	2
250	80%	146,000	75,920	70,080	$10,353.48	$10,523.91	$170.43	1.6%	-
250	90%	164,250	85,410	78,840	$11,057.38	$11,227.80	$170.43	1.5%	-
500	20%	73,000	37,960	35,040	$9,699.29	$9,941.14	$241.86	2.5%	-
500	30%	109,500	56,940	52,560	$11,107.08	$11,348.93	$241.86	2.2%	1
500	40%	146,000	75,920	70,080	$12,514.87	$12,756.73	$241.86	1.9%	1
500	50%	182,500	94,900	87,600	$13,922.66	$14,164.52	$241.86	1.7%	4
500	60%	219,000	113,880	105,120	$15,330.45	$15,572.31	$241.86	1.6%	3
500	70%	255,500	132,860	122,640	$16,738.24	$16,980.10	$241.86	1.4%	2
500	80%	292,000	151,840	140,160	$18,146.04	$18,387.89	$241.86	1.3%	-
500	90%	328,500	170,820	157,680	$19,553.83	$19,795.68	$241.86	1.2%	-
2,000	20%	292,000	151,840	140,160	$31,114.37	$31,784.80	$670.42	2.2%	6
2,000	30%	438,000	227,760	210,240	$36,745.54	$37,415.96	$670.42	1.8%	4
2,000	40%	584,000	303,680	280,320	$42,376.71	$43,047.13	$670.42	1.6%	1
2,000	50%	730,000	379,600	350,400	$48,007.87	$48,678.29	$670.42	1.4%	-
2,000	60%	876,000	455,520	420,480	$53,639.04	$54,309.46	$670.42	1.2%	-
2,000	70%	1,022,000	531,440	490,560	$59,270.20	$59,940.62	$670.42	1.1%	-
2,000	80%	1,168,000	607,360	560,640	$64,901.37	$65,571.79	$670.42	1.0%	-
2,000	90%	1,314,000	683,280	630,720	$70,532.53	$71,202.95	$670.42	1.0%	-
2,500	20%	365,000	189,800	175,200	$38,252.74	$39,066.01	$813.28	2.1%	-
2,500	30%	547,500	284,700	262,800	$45,291.69	$46,104.97	$813.28	1.8%	-
2,500	40%	730,000	379,600	350,400	$52,330.65	$53,143.93	$813.28	1.6%	-
2,500	50%	912,500	474,500	438,000	$59,369.61	$60,182.88	$813.28	1.4%	-
2,500	60%	1,095,000	569,400	525,600	$66,408.56	$67,221.84	$813.28	1.2%	1
2,500	70%	1,277,500	664,300	613,200	$73,447.52	$74,260.80	$813.28	1.1%	1
2,500	80%	1,460,000	759,200	700,800	$80,486.48	$81,299.75	$813.28	1.0%	-
2,500	90%	1,642,500	854,100	788,400	$87,525.43	$88,338.71	$813.28	0.9%	-

	UOM	Rate Yr 2 SC08SubSta	Rate Yr 3 SC08SubSta
Customer Charge	Monthly	$ 2,560.00	$ 2,659.00
Demand Charge kW	kW	$ 8.65	$ 8.93
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93
Supply Charge On Peak kWh	kWh-On	$ 0.03647	$ 0.03647
Supply Charge Off Peak kWh	kWh-Off	$ 0.02588	$ 0.02588
MFC per kWh	kWh	$ 0.00206	$ 0.00206

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Total Bill Impact - May 1, 2022 - April 30, 2023

Including Supply

PSC #19 - SC 9 - General Service - TOU									
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 2	Rate Yr 3	increase / (decrease) Amount	Percent	# of Customers
10	20%	1,460	759	701	$313.53	$334.27	$20.74	6.6%	19
10	30%	2,190	1,139	1,051	$348.36	$367.88	$19.52	5.6%	17
10	40%	2,920	1,518	1,402	$383.19	$401.49	$18.31	4.8%	25
10	50%	3,650	1,898	1,752	$418.02	$435.11	$17.09	4.1%	17
10	60%	4,380	2,278	2,102	$452.85	$468.72	$15.87	3.5%	12
10	70%	5,110	2,657	2,453	$487.68	$502.34	$14.66	3.0%	7
10	80%	5,840	3,037	2,803	$522.51	$535.95	$13.44	2.6%	1
10	90%	6,570	3,416	3,154	$557.34	$569.56	$12.23	2.2%	3
25	20%	3,650	1,898	1,752	$614.06	$640.78	$26.72	4.4%	11
25	30%	5,475	2,847	2,628	$701.13	$724.81	$23.68	3.4%	27
25	40%	7,300	3,796	3,504	$788.21	$808.85	$20.64	2.6%	30
25	50%	9,125	4,745	4,380	$875.28	$892.88	$17.60	2.0%	24
25	60%	10,950	5,694	5,256	$962.36	$976.92	$14.56	1.5%	12
25	70%	12,775	6,643	6,132	$1,049.43	$1,060.95	$11.52	1.1%	3
25	80%	14,600	7,592	7,008	$1,136.50	$1,144.99	$8.48	0.7%	-
25	90%	16,425	8,541	7,884	$1,223.58	$1,229.02	$5.44	0.4%	3
100	20%	14,600	7,592	7,008	$2,116.70	$2,173.33	$56.62	2.7%	27
100	30%	21,900	11,388	10,512	$2,465.00	$2,509.47	$44.47	1.8%	32
100	40%	29,200	15,184	14,016	$2,813.30	$2,845.61	$32.31	1.1%	18
100	50%	36,500	18,980	17,520	$3,161.60	$3,181.75	$20.15	0.6%	9
100	60%	43,800	22,776	21,024	$3,509.89	$3,517.89	$8.00	0.2%	6
100	70%	51,100	26,572	24,528	$3,858.19	$3,854.03	($4.16)	-0.1%	2
100	80%	58,400	30,368	28,032	$4,206.49	$4,190.17	($16.32)	-0.4%	-
100	90%	65,700	34,164	31,536	$4,554.79	$4,526.31	($28.47)	-0.6%	-
200	20%	29,200	15,184	14,016	$4,120.23	$4,216.73	$96.49	2.3%	1
200	30%	43,800	22,776	21,024	$4,816.83	$4,889.01	$72.18	1.5%	2
200	40%	58,400	30,368	28,032	$5,513.42	$5,561.29	$47.87	0.9%	4
200	50%	73,000	37,960	35,040	$6,210.02	$6,233.57	$23.55	0.4%	-
200	60%	87,600	45,552	42,048	$6,906.61	$6,905.85	($0.76)	0.0%	-
200	70%	102,200	53,144	49,056	$7,603.21	$7,578.14	($25.07)	-0.3%	-
200	80%	116,800	60,736	56,064	$8,299.80	$8,250.42	($49.38)	-0.6%	-
200	90%	131,400	68,328	63,072	$8,996.40	$8,922.70	($73.70)	-0.8%	-

	UOM	Rate Yr 2 SC09	Rate Yr 3 SC09
Customer Charge	Monthly	$ 112.25	$ 129.00
Demand Charge kW	kW	$ 13.07	$ 13.71
Delivery Charge On Peak kWh	kWh-On	$ 0.00833	$ 0.00666
Delivery Charge Off Peak kWh	kWh-Off	$ 0.00833	$ 0.00666
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93
Supply Charge On Peak kWh	kWh-On	$ 0.03776	$ 0.03776
Supply Charge Off Peak kWh	kWh-Off	$ 0.02619	$ 0.02619
MFC per kWh	kWh	$ 0.00206	$ 0.00206

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation		
Date Sources - RG&E Electric Bill Impact Statements		
Rate	**Source of Rate in "Current" Rates**	**Source of Rate in Rate Years**
Customer Charge	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
kW Charge	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
kWh Delivery Charge All Hours	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
kWh Delivery Charge On Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
kWh Delivery Charge Mid Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
kWh Delivery Charge Off Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
Reactive RkVah	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
Billing Charge per Bill	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
SBC (EETr) per kWh	Current Tariff Rates in Effect 01/01/2020. Statement #26.	Included in Delivery Rates
SBC (CEF) per kWh	Current Tariff Rates in Effect 01/01/2020. Statement #26.	Current Tariff Rates in Effect 01/01/2020. Statement #26.
RAM per kWh	Tariff Rates in Effect 07/01/2019.	No RAM forecasted. COVID Bill Credits begin 7/1/2021.
RAM per kW	Tariff Rates in Effect 07/01/2019.	No RAM forecasted. COVID Bill Credits begin 7/1/2021.
Tax Credit per kWh	Case No. 17-M-0815 dated August 9, 2018. Statement Number 1	Included in Delivery Rates
Tax Credit per kW	Case No. 17-M-0815 dated August 9, 2018. Statement Number 1	Included in Delivery Rates
Rate	**Source of Rate in "Current" Rates and Rate Years**	
Transition Charge per kWh	NBC, Demand Response, and Value Stack: NBC is the Non-Weighted 2019 Average. Dmd Rsp at $-0-. Value Stack at $-0-. RAM is separate.	
MFC per kWh	Non-Weighted 2019 Average of Monthly MFC Charge	
kWh Supply Charge All Hours	2019 Annualized Supply Rates	
kWh Supply Charge On Peak	2019 Annualized Supply Rates	
kWh Supply Charge Mid Peak	2019 Annualized Supply Rates	
kWh Supply Charge Off Peak	2019 Annualized Supply Rates	
Customer Count	2018 monthly data - separate Low Income counts	

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2022 - April 30, 2023

Delivery Bill Only

PSC #19 - SC 1 - Residential

kWh	Rate Yr 2	Rate Yr 3	increase / (decrease) Amount	Percent	# of Customers	# of Low Income Customers	Percent of Customers	Percent of Low Income Customers	Amt of EE embedded in Delivery Rates* Amount	Percent
100	$28.11	$29.05	$0.94	3.3%	10,907	539	3%	1%	$ 0.24	0.82%
200	$33.59	$35.17	$1.58	4.7%	25,369	2,787	7%	8%	$ 0.48	1.35%
300	$39.08	$41.29	$2.22	5.7%	33,669	4,537	10%	12%	$ 0.71	1.73%
400	$44.56	$47.42	$2.86	6.4%	37,090	5,036	11%	14%	$ 0.95	2.01%
500	$50.04	$53.54	$3.50	7.0%	38,010	4,932	11%	13%	$ 1.19	2.22%
600	$55.53	$59.66	$4.14	7.4%	35,693	4,208	11%	11%	$ 1.43	2.39%
700	$61.01	$65.78	$4.78	7.8%	31,811	3,427	9%	9%	$ 1.67	2.53%
800	$66.49	$71.91	$5.41	8.1%	27,030	2,744	8%	7%	$ 1.90	2.65%
900	$71.97	$78.03	$6.05	8.4%	22,238	2,191	7%	6%	$ 2.14	2.75%
1,000	$77.46	$84.15	$6.69	8.6%	17,500	1,598	5%	4%	$ 2.38	2.83%
1,100	$82.94	$90.27	$7.33	8.8%	13,667	1,211	4%	3%	$ 2.62	2.90%
1,200	$88.42	$96.40	$7.97	9.0%	10,434	907	3%	2%	$ 2.86	2.96%
1,500	$104.87	$114.76	$9.89	9.4%	18,454	1,568	5%	4%	$ 3.57	3.11%
2,000	$132.29	$145.38	$13.09	9.9%	11,052	901	3%	2%	$ 4.76	3.27%
3,000	$187.12	$206.60	$19.48	10.4%	5,347	334	2%	1%	$ 7.14	3.46%
					338,269	36,919				

	UOM	Rate Yr 2 SC01	Rate Yr 3 SC01
Customer Charge	Monthly	$ 21.70	$ 22.00
Delivery Charge All Hours kWh	kWh	$ 0.05153	$ 0.05792
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kWh	kWh	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00206)	$ (0.00206)
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93

Includes $ 0.00238 per kWh of EE Costs*

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

4. Low income customers represent customers who participated in the Company's low income program and received a credit on their bill each month during calendar year 2018.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2022 - April 30, 2023

Delivery Bill Only

PSC #19 - SC 2 - General Service - Non Demand					
			increase / (decrease)		
kWh	Rate Yr 2	Rate Yr 3	Amount	Percent	# of Customers
300	$36.40	$38.34	$1.95	5.4%	11,999
400	$40.99	$43.48	$2.50	6.1%	2,601
500	$45.58	$48.62	$3.05	6.7%	2,299
600	$50.17	$53.76	$3.60	7.2%	1,892
700	$54.76	$58.90	$4.14	7.6%	1,541
800	$59.35	$64.04	$4.69	7.9%	1,322
900	$63.94	$69.18	$5.24	8.2%	1,021
1,000	$68.53	$74.32	$5.79	8.5%	904
1,500	$91.48	$100.01	$8.54	9.3%	2,999
2,000	$114.43	$125.71	$11.28	9.9%	1,654
2,500	$137.38	$151.41	$14.03	10.2%	845
3,000	$160.33	$177.10	$16.78	10.5%	385
4,000	$206.23	$228.49	$22.27	10.8%	203
5,000	$252.13	$279.89	$27.76	11.0%	60
6,000	$298.03	$331.28	$33.25	11.2%	21
7,000	$343.93	$382.67	$38.74	11.3%	59

		Rate Yr 2	Rate Yr 3
	UOM	SC02	SC02
Customer Charge	Monthly	$ 21.70	$ 22.00
Delivery Charge All Hours kWh	kWh	$ 0.04078	$ 0.04627
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kWh	kWh	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2022 - April 30, 2023

Delivery Bill Only

PSC #19 - SC 3 - General Service - Demand

Kw	Load Factor	kWh	Rate Yr 2	Rate Yr 3	increase / (decrease) Amount	Percent	# of Customers
50	20%	7,300	$1,284.27	$1,381.78	$97.51	7.6%	45
50	30%	10,950	$1,302.97	$1,400.47	$97.51	7.5%	19
50	40%	14,600	$1,321.67	$1,419.17	$97.51	7.4%	18
50	50%	18,250	$1,340.36	$1,437.87	$97.51	7.3%	18
50	60%	21,900	$1,359.06	$1,456.57	$97.51	7.2%	1
50	70%	25,550	$1,377.76	$1,475.26	$97.51	7.1%	3
50	80%	29,200	$1,396.46	$1,493.96	$97.51	7.0%	3
50	90%	32,850	$1,415.15	$1,512.66	$97.51	6.9%	2
100	20%	14,600	$2,218.62	$2,361.63	$143.01	6.4%	43
100	30%	21,900	$2,256.01	$2,399.02	$143.01	6.3%	73
100	40%	29,200	$2,293.41	$2,436.42	$143.01	6.2%	122
100	50%	36,500	$2,330.80	$2,473.81	$143.01	6.1%	115
100	60%	43,800	$2,368.20	$2,511.21	$143.01	6.0%	47
100	70%	51,100	$2,405.59	$2,548.60	$143.01	5.9%	32
100	80%	58,400	$2,442.99	$2,586.00	$143.01	5.9%	9
100	90%	65,700	$2,480.38	$2,623.39	$143.01	5.8%	6
275	20%	40,150	$5,488.82	$5,791.10	$302.28	5.5%	146
275	30%	60,225	$5,591.66	$5,893.94	$302.28	5.4%	223
275	40%	80,300	$5,694.50	$5,996.78	$302.28	5.3%	130
275	50%	100,375	$5,797.33	$6,099.61	$302.28	5.2%	69
275	60%	120,450	$5,900.17	$6,202.45	$302.28	5.1%	24
275	70%	140,525	$6,003.01	$6,305.29	$302.28	5.0%	8
275	80%	160,600	$6,105.85	$6,408.13	$302.28	5.0%	2
275	90%	180,675	$6,208.68	$6,510.96	$302.28	4.9%	2
300	20%	43,800	$5,955.99	$6,281.03	$325.03	5.5%	-
300	30%	65,700	$6,068.18	$6,393.21	$325.03	5.4%	2
300	40%	87,600	$6,180.37	$6,505.40	$325.03	5.3%	2
300	50%	109,500	$6,292.55	$6,617.59	$325.03	5.2%	3
300	60%	131,400	$6,404.74	$6,729.77	$325.03	5.1%	-
300	70%	153,300	$6,516.93	$6,841.96	$325.03	5.0%	2
300	80%	175,200	$6,629.11	$6,954.15	$325.03	4.9%	2
300	90%	197,100	$6,741.30	$7,066.33	$325.03	4.8%	3

	UOM	Rate Yr 2 SC03	Rate Yr 3 SC03
Customer Charge	Monthly	$ 349.00	$ 401.00
Demand Charge kW	kW	$ 17.94	$ 18.85
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2022 - April 30, 2023

Delivery Bill Only

PSC #19 - SC 4-I - Residential - Day/Night

kWh	Peak	Off Peak	Rate Yr 2	Rate Yr 3	increase / (decrease) Amount	Percent	# of Customers
300	210	90	41.96	43.16	1.21	2.9%	126
400	280	120	47.03	48.54	1.51	3.2%	91
500	350	150	52.11	53.92	1.81	3.5%	104
600	420	180	57.18	59.30	2.12	3.7%	131
700	490	210	62.26	64.68	2.42	3.9%	172
800	560	240	67.34	70.06	2.72	4.0%	191
900	630	270	72.41	75.44	3.02	4.2%	145
1,000	700	300	77.49	80.82	3.33	4.3%	157
1,500	1,050	450	102.87	107.71	4.84	4.7%	589
2,000	1,400	600	128.25	134.61	6.36	5.0%	302
2,500	1,750	750	153.63	161.50	7.87	5.1%	149
3,000	2,100	900	179.02	188.40	9.38	5.2%	61
4,000	2,800	1,200	229.78	242.19	12.41	5.4%	26
5,000	3,500	1,500	280.54	295.98	15.44	5.5%	11
6,000	4,200	1,800	331.31	349.77	18.47	5.6%	1
7,000	4,900	2,100	382.07	403.56	21.49	5.6%	5

	UOM	Rate Yr 2 SC04-I	Rate Yr 3 SC04-I
Customer Charge	Monthly	$ 25.80	$ 26.10
Delivery Charge On Peak kWh	kWh-On	$ 0.04746	$ 0.05049
Delivery Charge Off Peak kWh	kWh-Off	$ 0.04746	$ 0.05049
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kWh	kWh	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00206)	$ (0.00206)
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2022 - April 30, 2023

Delivery Bill Only

PSC #19 - SC 4-II - Residential - Day/Night							
					increase / (decrease)		
kWh	Peak	Off Peak	Rate Yr 2	Rate Yr 3	Amount	Percent	# of Customers
300	210	90	$48.62	$50.02	$1.39	2.9%	18
400	280	120	$54.77	$56.48	$1.71	3.1%	9
500	350	150	$60.92	$62.94	$2.02	3.3%	15
600	420	180	$67.07	$69.40	$2.34	3.5%	28
700	490	210	$73.21	$75.87	$2.65	3.6%	29
800	560	240	$79.36	$82.33	$2.97	3.7%	38
900	630	270	$85.51	$88.79	$3.28	3.8%	33
1,000	700	300	$91.66	$95.26	$3.60	3.9%	52
1,500	1,050	450	$122.40	$127.57	$5.17	4.2%	238
2,000	1,400	600	$153.14	$159.89	$6.74	4.4%	190
2,500	1,750	750	$183.89	$192.20	$8.32	4.5%	165
3,000	2,100	900	$214.63	$224.52	$9.89	4.6%	83
4,000	2,800	1,200	$276.11	$289.15	$13.04	4.7%	84
5,000	3,500	1,500	$337.60	$353.78	$16.19	4.8%	49
6,000	4,200	1,800	$399.08	$418.42	$19.33	4.8%	33
7,000	4,900	2,100	$460.57	$483.05	$22.48	4.9%	28

		Rate Yr 2	Rate Yr 3
	UOM	SC04-II	SC04-II
Customer Charge	Monthly	$ 29.25	$ 29.70
Delivery Charge On Peak kWh	kWh-On	$ 0.05818	$ 0.06133
Delivery Charge Off Peak kWh	kWh-Off	$ 0.05818	$ 0.06133
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kWh	kWh	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00206)	$ (0.00206)
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

19 will be collected through the RAM beginning July 1, 2021. The costs wil

Electric Rates

Monthly Delivery Bill Impact - May 1, 2022 - April 30, 2023

Delivery Bill Only

PSC #19 - SC 7 - General Service - Demand							
					increase / (decrease)		
Kw	Load Factor	kWh	Rate Yr 2	Rate Yr 3	Amount	Percent	# of Customers
5	20%	730	$202.87	$219.65	$16.78	8.3%	178
5	30%	1,095	$206.68	$223.07	$16.39	7.9%	51
5	40%	1,460	$210.50	$226.50	$16.00	7.6%	36
5	50%	1,825	$214.31	$229.92	$15.61	7.3%	34
5	60%	2,190	$218.12	$233.34	$15.22	7.0%	16
5	70%	2,555	$221.93	$236.76	$14.84	6.7%	14
5	80%	2,920	$225.74	$240.19	$14.45	6.4%	6
5	90%	3,285	$229.55	$243.61	$14.06	6.1%	6
25	20%	3,650	$590.66	$614.55	$23.88	4.0%	2,778
25	30%	5,475	$609.72	$631.66	$21.94	3.6%	1,673
25	40%	7,300	$628.77	$648.78	$20.00	3.2%	888
25	50%	9,125	$647.83	$665.89	$18.06	2.8%	403
25	60%	10,950	$666.88	$683.00	$16.12	2.4%	155
25	70%	12,775	$685.94	$700.12	$14.18	2.1%	46
25	80%	14,600	$704.99	$717.23	$12.24	1.7%	12
25	90%	16,425	$724.05	$734.34	$10.30	1.4%	7
100	20%	14,600	$2,044.88	$2,095.42	$50.54	2.5%	1,560
100	30%	21,900	$2,121.10	$2,163.87	$42.77	2.0%	618
100	40%	29,200	$2,197.32	$2,232.33	$35.01	1.6%	240
100	50%	36,500	$2,273.54	$2,300.78	$27.24	1.2%	74
100	60%	43,800	$2,349.76	$2,369.24	$19.48	0.8%	44
100	70%	51,100	$2,425.98	$2,437.69	$11.71	0.5%	8
100	80%	58,400	$2,502.20	$2,506.15	$3.95	0.2%	3
100	90%	65,700	$2,578.42	$2,574.60	($3.82)	-0.1%	2
250	20%	36,500	$4,953.31	$5,057.15	$103.84	2.1%	19
250	30%	54,750	$5,143.86	$5,228.29	$84.43	1.6%	15
250	40%	73,000	$5,334.41	$5,399.43	$65.02	1.2%	5
250	50%	91,250	$5,524.96	$5,570.57	$45.60	0.8%	2
250	60%	109,500	$5,715.51	$5,741.70	$26.19	0.5%	-
250	70%	127,750	$5,906.06	$5,912.84	$6.78	0.1%	1
250	80%	146,000	$6,096.61	$6,083.98	($12.63)	-0.2%	-
250	90%	164,250	$6,287.16	$6,255.12	($32.05)	-0.5%	-

		Rate Yr 2	Rate Yr 3
	UOM	SC07	SC07
Customer Charge	Monthly	$ 105.00	$ 120.00
Demand Charge kW	kW	$ 17.87	$ 18.38
Delivery Charge All Hours kWh	kWh	$ 0.00532	$ 0.00425
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.
3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2022 - April 30, 2023

Delivery Bill Only

PSC #19 - SC 8 - Large General Service - Transmission

Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 2	Rate Yr 3	increase / (decrease) Amount	Percent	# of Customers
6,000	20%	876,000	455,520	420,480	$67,358.29	$71,898.86	$4,540.57	6.7%	-
6,000	30%	1,314,000	683,280	630,720	$69,602.02	$74,142.59	$4,540.57	6.5%	-
6,000	40%	1,752,000	911,040	840,960	$71,845.75	$76,386.32	$4,540.57	6.3%	-
6,000	50%	2,190,000	1,138,800	1,051,200	$74,089.47	$78,630.05	$4,540.57	6.1%	-
6,000	60%	2,628,000	1,366,560	1,261,440	$76,333.20	$80,873.78	$4,540.57	5.9%	-
6,000	70%	3,066,000	1,594,320	1,471,680	$78,576.93	$83,117.50	$4,540.57	5.8%	-
6,000	80%	3,504,000	1,822,080	1,681,920	$80,820.66	$85,361.23	$4,540.57	5.6%	-
6,000	90%	3,942,000	2,049,840	1,892,160	$83,064.39	$87,604.96	$4,540.57	5.5%	-
7,000	20%	1,022,000	531,440	490,560	$77,884.52	$83,148.52	$5,264.00	6.8%	-
7,000	30%	1,533,000	797,160	735,840	$80,502.20	$85,766.20	$5,264.00	6.5%	-
7,000	40%	2,044,000	1,062,880	981,120	$83,119.88	$88,383.88	$5,264.00	6.3%	-
7,000	50%	2,555,000	1,328,600	1,226,400	$85,737.56	$91,001.57	$5,264.00	6.1%	-
7,000	60%	3,066,000	1,594,320	1,471,680	$88,355.25	$93,619.25	$5,264.00	6.0%	1
7,000	70%	3,577,000	1,860,040	1,716,960	$90,972.93	$96,236.93	$5,264.00	5.8%	-
7,000	80%	4,088,000	2,125,760	1,962,240	$93,590.61	$98,854.62	$5,264.00	5.6%	-
7,000	90%	4,599,000	2,391,480	2,207,520	$96,208.30	$101,472.30	$5,264.00	5.5%	-
8,000	20%	1,168,000	607,360	560,640	$88,410.74	$94,398.18	$5,987.43	6.8%	-
8,000	30%	1,752,000	911,040	840,960	$91,402.38	$97,389.81	$5,987.43	6.6%	-
8,000	40%	2,336,000	1,214,720	1,121,280	$94,394.02	$100,381.45	$5,987.43	6.3%	-
8,000	50%	2,920,000	1,518,400	1,401,600	$97,385.66	$103,373.09	$5,987.43	6.1%	-
8,000	60%	3,504,000	1,822,080	1,681,920	$100,377.29	$106,364.72	$5,987.43	6.0%	-
8,000	70%	4,088,000	2,125,760	1,962,240	$103,368.93	$109,356.36	$5,987.43	5.8%	-
8,000	80%	4,672,000	2,429,440	2,242,560	$106,360.57	$112,348.00	$5,987.43	5.6%	-
8,000	90%	5,256,000	2,733,120	2,522,880	$109,352.21	$115,339.64	$5,987.43	5.5%	-
9,000	20%	1,314,000	683,280	630,720	$98,936.97	$105,647.83	$6,710.86	6.8%	-
9,000	30%	1,971,000	1,024,920	946,080	$102,302.56	$109,013.42	$6,710.86	6.6%	-
9,000	40%	2,628,000	1,366,560	1,261,440	$105,668.15	$112,379.02	$6,710.86	6.4%	-
9,000	50%	3,285,000	1,708,200	1,576,800	$109,033.75	$115,744.61	$6,710.86	6.2%	-
9,000	60%	3,942,000	2,049,840	1,892,160	$112,399.34	$119,110.20	$6,710.86	6.0%	-
9,000	70%	4,599,000	2,391,480	2,207,520	$115,764.93	$122,475.79	$6,710.86	5.8%	-
9,000	80%	5,256,000	2,733,120	2,522,880	$119,130.52	$125,841.38	$6,710.86	5.6%	-
9,000	90%	5,913,000	3,074,760	2,838,240	$122,496.11	$129,206.98	$6,710.86	5.5%	-

	UOM	Rate Yr 2 SC08Trn	Rate Yr 3 SC08Trn
Customer Charge	Monthly	$ 4,200.00	$ 4,400.00
Demand Charge kW	kW	$ 9.78	$ 10.50
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2022 - April 30, 2023

Delivery Bill Only

PSC #19 - SC 8 - Large General Service - SubTransmission - Industrial

Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 2	Rate Yr 3	increase / (decrease) Amount	Percent	# of Customers
500	20%	73,000	37,960	35,040	$7,876.19	$8,150.56	$274.37	3.5%	1
500	30%	109,500	56,940	52,560	$8,063.17	$8,337.54	$274.37	3.4%	4
500	40%	146,000	75,920	70,080	$8,250.15	$8,524.52	$274.37	3.3%	2
500	50%	182,500	94,900	87,600	$8,437.12	$8,711.49	$274.37	3.3%	2
500	60%	219,000	113,880	105,120	$8,624.10	$8,898.47	$274.37	3.2%	-
500	70%	255,500	132,860	122,640	$8,811.08	$9,085.45	$274.37	3.1%	2
500	80%	292,000	151,840	140,160	$8,998.06	$9,272.42	$274.37	3.0%	-
500	90%	328,500	170,820	157,680	$9,185.03	$9,459.40	$274.37	3.0%	1
1,500	20%	219,000	113,880	105,120	$18,122.72	$18,733.83	$611.11	3.4%	2
1,500	30%	328,500	170,820	157,680	$18,683.65	$19,294.76	$611.11	3.3%	1
1,500	40%	438,000	227,760	210,240	$19,244.59	$19,855.69	$611.11	3.2%	3
1,500	50%	547,500	284,700	262,800	$19,805.52	$20,416.63	$611.11	3.1%	4
1,500	60%	657,000	341,640	315,360	$20,366.45	$20,977.56	$611.11	3.0%	6
1,500	70%	766,500	398,580	367,920	$20,927.38	$21,538.49	$611.11	2.9%	-
1,500	80%	876,000	455,520	420,480	$21,488.31	$22,099.42	$611.11	2.8%	1
1,500	90%	985,500	512,460	473,040	$22,049.25	$22,660.35	$611.11	2.8%	-
4,500	20%	657,000	341,640	315,360	$48,862.31	$50,483.64	$1,621.32	3.3%	3
4,500	30%	985,500	512,460	473,040	$50,545.11	$52,166.43	$1,621.32	3.2%	2
4,500	40%	1,314,000	683,280	630,720	$52,227.91	$53,849.23	$1,621.32	3.1%	4
4,500	50%	1,642,500	854,100	788,400	$53,910.70	$55,532.02	$1,621.32	3.0%	1
4,500	60%	1,971,000	1,024,920	946,080	$55,593.50	$57,214.82	$1,621.32	2.9%	5
4,500	70%	2,299,500	1,195,740	1,103,760	$57,276.29	$58,897.62	$1,621.32	2.8%	-
4,500	80%	2,628,000	1,366,560	1,261,440	$58,959.09	$60,580.41	$1,621.32	2.7%	-
4,500	90%	2,956,500	1,537,380	1,419,120	$60,641.89	$62,263.21	$1,621.32	2.7%	-
6,000	20%	876,000	455,520	420,480	$64,232.11	$66,358.54	$2,126.43	3.3%	-
6,000	30%	1,314,000	683,280	630,720	$66,475.84	$68,602.27	$2,126.43	3.2%	-
6,000	40%	1,752,000	911,040	840,960	$68,719.57	$70,845.99	$2,126.43	3.1%	-
6,000	50%	2,190,000	1,138,800	1,051,200	$70,963.29	$73,089.72	$2,126.43	3.0%	1
6,000	60%	2,628,000	1,366,560	1,261,440	$73,207.02	$75,333.45	$2,126.43	2.9%	-
6,000	70%	3,066,000	1,594,320	1,471,680	$75,450.75	$77,577.18	$2,126.43	2.8%	-
6,000	80%	3,504,000	1,822,080	1,681,920	$77,694.48	$79,820.91	$2,126.43	2.7%	1
6,000	90%	3,942,000	2,049,840	1,892,160	$79,938.21	$82,064.63	$2,126.43	2.7%	3

	UOM	Rate Yr 2 SC08SubTrn-I	Rate Yr 3 SC08SubTrn-I
Customer Charge	Monthly	$ 2,752.00	$ 2,858.00
Demand Charge kW	kW	$ 9.50	$ 9.84
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2022 - April 30, 2023

Delivery Bill Only

PSC #19 - SC 8 - Large General Service - SubTransmission - Commercial									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 2	Rate Yr 3	Amount	Percent	# of Customers
500	20%	73,000	37,960	35,040	$8,137.27	$8,530.27	$393.00	4.8%	-
500	30%	109,500	56,940	52,560	$8,324.25	$8,717.25	$393.00	4.7%	2
500	40%	146,000	75,920	70,080	$8,511.23	$8,904.23	$393.00	4.6%	6
500	50%	182,500	94,900	87,600	$8,698.21	$9,091.20	$393.00	4.5%	4
500	60%	219,000	113,880	105,120	$8,885.18	$9,278.18	$393.00	4.4%	4
500	70%	255,500	132,860	122,640	$9,072.16	$9,465.16	$393.00	4.3%	2
500	80%	292,000	151,840	140,160	$9,259.14	$9,652.14	$393.00	4.2%	-
500	90%	328,500	170,820	157,680	$9,446.11	$9,839.11	$393.00	4.2%	-
1,500	20%	219,000	113,880	105,120	$19,137.97	$20,114.97	$977.00	5.1%	1
1,500	30%	328,500	170,820	157,680	$19,698.90	$20,675.90	$977.00	5.0%	3
1,500	40%	438,000	227,760	210,240	$20,259.83	$21,236.83	$977.00	4.8%	5
1,500	50%	547,500	284,700	262,800	$20,820.76	$21,797.76	$977.00	4.7%	11
1,500	60%	657,000	341,640	315,360	$21,381.70	$22,358.69	$977.00	4.6%	4
1,500	70%	766,500	398,580	367,920	$21,942.63	$22,919.63	$977.00	4.5%	3
1,500	80%	876,000	455,520	420,480	$22,503.56	$23,480.56	$977.00	4.3%	-
1,500	90%	985,500	512,460	473,040	$23,064.49	$24,041.49	$977.00	4.2%	-
4,500	20%	657,000	341,640	315,360	$52,140.05	$54,869.05	$2,729.00	5.2%	-
4,500	30%	985,500	512,460	473,040	$53,822.85	$56,551.84	$2,729.00	5.1%	2
4,500	40%	1,314,000	683,280	630,720	$55,505.64	$58,234.64	$2,729.00	4.9%	3
4,500	50%	1,642,500	854,100	788,400	$57,188.44	$59,917.43	$2,729.00	4.8%	1
4,500	60%	1,971,000	1,024,920	946,080	$58,871.23	$61,600.23	$2,729.00	4.6%	1
4,500	70%	2,299,500	1,195,740	1,103,760	$60,554.03	$63,283.03	$2,729.00	4.5%	1
4,500	80%	2,628,000	1,366,560	1,261,440	$62,236.83	$64,965.82	$2,729.00	4.4%	-
4,500	90%	2,956,500	1,537,380	1,419,120	$63,919.62	$66,648.62	$2,729.00	4.3%	-
6,000	20%	876,000	455,520	420,480	$68,641.09	$72,246.09	$3,604.99	5.3%	-
6,000	30%	1,314,000	683,280	630,720	$70,884.82	$74,489.81	$3,604.99	5.1%	-
6,000	40%	1,752,000	911,040	840,960	$73,128.55	$76,733.54	$3,604.99	4.9%	-
6,000	50%	2,190,000	1,138,800	1,051,200	$75,372.28	$78,977.27	$3,604.99	4.8%	-
6,000	60%	2,628,000	1,366,560	1,261,440	$77,616.00	$81,221.00	$3,604.99	4.6%	1
6,000	70%	3,066,000	1,594,320	1,471,680	$79,859.73	$83,464.73	$3,604.99	4.5%	1
6,000	80%	3,504,000	1,822,080	1,681,920	$82,103.46	$85,708.45	$3,604.99	4.4%	-
6,000	90%	3,942,000	2,049,840	1,892,160	$84,347.19	$87,952.18	$3,604.99	4.3%	-

		Rate Yr 2	Rate Yr 3
	UOM	SC08SubTrn-C	SC08SubTrn-C
Customer Charge	Monthly	$ 2,636.00	$ 2,737.00
Demand Charge kW	kW	$ 10.25	$ 10.84
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2022 - April 30, 2023

Delivery Bill Only

PSC #19 - SC 8 - Large General Service - Primary

Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 2	Rate Yr 3	increase / (decrease) Amount	Percent	# of Customers
250	20%	36,500	18,980	17,520	$5,458.84	$5,926.44	$467.60	8.6%	5
250	30%	54,750	28,470	26,280	$5,552.33	$6,019.93	$467.60	8.4%	7
250	40%	73,000	37,960	35,040	$5,645.82	$6,113.42	$467.60	8.3%	3
250	50%	91,250	47,450	43,800	$5,739.31	$6,206.91	$467.60	8.1%	8
250	60%	109,500	56,940	52,560	$5,832.79	$6,300.40	$467.60	8.0%	1
250	70%	127,750	66,430	61,320	$5,926.28	$6,393.89	$467.60	7.9%	2
250	80%	146,000	75,920	70,080	$6,019.77	$6,487.37	$467.60	7.8%	1
250	90%	164,250	85,410	78,840	$6,113.26	$6,580.86	$467.60	7.6%	-
500	20%	73,000	37,960	35,040	$9,428.75	$10,305.96	$877.21	9.3%	2
500	30%	109,500	56,940	52,560	$9,615.73	$10,492.94	$877.21	9.1%	8
500	40%	146,000	75,920	70,080	$9,802.71	$10,679.91	$877.21	8.9%	14
500	50%	182,500	94,900	87,600	$9,989.69	$10,866.89	$877.21	8.8%	20
500	60%	219,000	113,880	105,120	$10,176.66	$11,053.87	$877.21	8.6%	10
500	70%	255,500	132,860	122,640	$10,363.64	$11,240.85	$877.21	8.5%	3
500	80%	292,000	151,840	140,160	$10,550.62	$11,427.82	$877.21	8.3%	2
500	90%	328,500	170,820	157,680	$10,737.59	$11,614.80	$877.21	8.2%	-
1,500	20%	219,000	113,880	105,120	$25,308.41	$27,824.03	$2,515.62	9.9%	4
1,500	30%	328,500	170,820	157,680	$25,869.34	$28,384.96	$2,515.62	9.7%	18
1,500	40%	438,000	227,760	210,240	$26,430.27	$28,945.89	$2,515.62	9.5%	21
1,500	50%	547,500	284,700	262,800	$26,991.20	$29,506.82	$2,515.62	9.3%	12
1,500	60%	657,000	341,640	315,360	$27,552.14	$30,067.76	$2,515.62	9.1%	4
1,500	70%	766,500	398,580	367,920	$28,113.07	$30,628.69	$2,515.62	8.9%	4
1,500	80%	876,000	455,520	420,480	$28,674.00	$31,189.62	$2,515.62	8.8%	1
1,500	90%	985,500	512,460	473,040	$29,234.93	$31,750.55	$2,515.62	8.6%	-
2,000	20%	292,000	151,840	140,160	$33,248.23	$36,583.06	$3,334.83	10.0%	-
2,000	30%	438,000	227,760	210,240	$33,996.14	$37,330.97	$3,334.83	9.8%	-
2,000	40%	584,000	303,680	280,320	$34,744.05	$38,078.88	$3,334.83	9.6%	-
2,000	50%	730,000	379,600	350,400	$35,491.96	$38,826.79	$3,334.83	9.4%	2
2,000	60%	876,000	455,520	420,480	$36,239.87	$39,574.70	$3,334.83	9.2%	1
2,000	70%	1,022,000	531,440	490,560	$36,987.78	$40,322.61	$3,334.83	9.0%	-
2,000	80%	1,168,000	607,360	560,640	$37,735.69	$41,070.52	$3,334.83	8.8%	1
2,000	90%	1,314,000	683,280	630,720	$38,483.60	$41,818.43	$3,334.83	8.7%	6

	UOM	Rate Yr 2 SC08Pri	Rate Yr 3 SC08Pri
Customer Charge	Monthly	$ 1,488.00	$ 1,546.00
Demand Charge kW	kW	$ 15.13	$ 16.77
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2022 - April 30, 2023

Delivery Bill Only

PSC #19 - SC 8 - Large General Service - Secondary									
							increase / (decrease)		
Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 2	Rate Yr 3	Amount	Percent	# of Customers
250	20%	36,500	18,980	17,520	$5,161.68	$5,482.17	$320.49	6.2%	15
250	30%	54,750	28,470	26,280	$5,255.17	$5,575.66	$320.49	6.1%	15
250	40%	73,000	37,960	35,040	$5,348.66	$5,669.15	$320.49	6.0%	31
250	50%	91,250	47,450	43,800	$5,442.15	$5,762.64	$320.49	5.9%	37
250	60%	109,500	56,940	52,560	$5,535.64	$5,856.13	$320.49	5.8%	27
250	70%	127,750	66,430	61,320	$5,629.12	$5,949.61	$320.49	5.7%	5
250	80%	146,000	75,920	70,080	$5,722.61	$6,043.10	$320.49	5.6%	4
250	90%	164,250	85,410	78,840	$5,816.10	$6,136.59	$320.49	5.5%	-
500	20%	73,000	37,960	35,040	$9,138.44	$9,734.42	$595.98	6.5%	6
500	30%	109,500	56,940	52,560	$9,325.41	$9,921.39	$595.98	6.4%	35
500	40%	146,000	75,920	70,080	$9,512.39	$10,108.37	$595.98	6.3%	65
500	50%	182,500	94,900	87,600	$9,699.37	$10,295.35	$595.98	6.1%	40
500	60%	219,000	113,880	105,120	$9,886.34	$10,482.32	$595.98	6.0%	27
500	70%	255,500	132,860	122,640	$10,073.32	$10,669.30	$595.98	5.9%	11
500	80%	292,000	151,840	140,160	$10,260.30	$10,856.28	$595.98	5.8%	5
500	90%	328,500	170,820	157,680	$10,447.28	$11,043.26	$595.98	5.7%	1
1,500	20%	219,000	113,880	105,120	$25,045.45	$26,743.39	$1,697.94	6.8%	19
1,500	30%	328,500	170,820	157,680	$25,606.39	$27,304.33	$1,697.94	6.6%	22
1,500	40%	438,000	227,760	210,240	$26,167.32	$27,865.26	$1,697.94	6.5%	18
1,500	50%	547,500	284,700	262,800	$26,728.25	$28,426.19	$1,697.94	6.4%	5
1,500	60%	657,000	341,640	315,360	$27,289.18	$28,987.12	$1,697.94	6.2%	2
1,500	70%	766,500	398,580	367,920	$27,850.11	$29,548.05	$1,697.94	6.1%	2
1,500	80%	876,000	455,520	420,480	$28,411.05	$30,108.99	$1,697.94	6.0%	-
1,500	90%	985,500	512,460	473,040	$28,971.98	$30,669.92	$1,697.94	5.9%	-
2,000	20%	292,000	151,840	140,160	$32,998.96	$35,247.88	$2,248.92	6.8%	-
2,000	30%	438,000	227,760	210,240	$33,746.87	$35,995.79	$2,248.92	6.7%	-
2,000	40%	584,000	303,680	280,320	$34,494.78	$36,743.70	$2,248.92	6.5%	-
2,000	50%	730,000	379,600	350,400	$35,242.69	$37,491.61	$2,248.92	6.4%	-
2,000	60%	876,000	455,520	420,480	$35,990.60	$38,239.52	$2,248.92	6.2%	1
2,000	70%	1,022,000	531,440	490,560	$36,738.51	$38,987.43	$2,248.92	6.1%	1
2,000	80%	1,168,000	607,360	560,640	$37,486.42	$39,735.34	$2,248.92	6.0%	-
2,000	90%	1,314,000	683,280	630,720	$38,234.33	$40,483.25	$2,248.92	5.9%	-

		Rate Yr 2	Rate Yr 3
	UOM	SC08Sec	SC08Sec
Customer Charge	Monthly	$ 1,184.00	$ 1,229.00
Demand Charge kW	kW	$ 15.16	$ 16.26
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2022 - April 30, 2023

Delivery Bill Only

PSC #19 - SC 8 - Large General Service - SubStation

Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 2	Rate Yr 3	increase / (decrease) Amount	Percent	# of Customers
250	20%	36,500	18,980	17,520	$4,909.29	$5,079.72	$170.43	3.5%	-
250	30%	54,750	28,470	26,280	$5,002.78	$5,173.21	$170.43	3.4%	1
250	40%	73,000	37,960	35,040	$5,096.27	$5,266.70	$170.43	3.3%	2
250	50%	91,250	47,450	43,800	$5,189.76	$5,360.19	$170.43	3.3%	1
250	60%	109,500	56,940	52,560	$5,283.25	$5,453.68	$170.43	3.2%	1
250	70%	127,750	66,430	61,320	$5,376.74	$5,547.16	$170.43	3.2%	2
250	80%	146,000	75,920	70,080	$5,470.23	$5,640.65	$170.43	3.1%	-
250	90%	164,250	85,410	78,840	$5,563.71	$5,734.14	$170.43	3.1%	-
500	20%	73,000	37,960	35,040	$7,257.66	$7,499.52	$241.86	3.3%	-
500	30%	109,500	56,940	52,560	$7,444.64	$7,686.49	$241.86	3.2%	1
500	40%	146,000	75,920	70,080	$7,631.61	$7,873.47	$241.86	3.2%	1
500	50%	182,500	94,900	87,600	$7,818.59	$8,060.45	$241.86	3.1%	4
500	60%	219,000	113,880	105,120	$8,005.57	$8,247.42	$241.86	3.0%	3
500	70%	255,500	132,860	122,640	$8,192.55	$8,434.40	$241.86	3.0%	2
500	80%	292,000	151,840	140,160	$8,379.52	$8,621.38	$241.86	2.9%	-
500	90%	328,500	170,820	157,680	$8,566.50	$8,808.36	$241.86	2.8%	-
2,000	20%	292,000	151,840	140,160	$21,347.86	$22,018.28	$670.42	3.1%	6
2,000	30%	438,000	227,760	210,240	$22,095.77	$22,766.19	$670.42	3.0%	4
2,000	40%	584,000	303,680	280,320	$22,843.68	$23,514.10	$670.42	2.9%	1
2,000	50%	730,000	379,600	350,400	$23,591.59	$24,262.01	$670.42	2.8%	-
2,000	60%	876,000	455,520	420,480	$24,339.50	$25,009.92	$670.42	2.8%	-
2,000	70%	1,022,000	531,440	490,560	$25,087.41	$25,757.83	$670.42	2.7%	-
2,000	80%	1,168,000	607,360	560,640	$25,835.32	$26,505.74	$670.42	2.6%	-
2,000	90%	1,314,000	683,280	630,720	$26,583.23	$27,253.65	$670.42	2.5%	-
2,500	20%	365,000	189,800	175,200	$26,044.60	$26,857.87	$813.28	3.1%	-
2,500	30%	547,500	284,700	262,800	$26,979.48	$27,792.76	$813.28	3.0%	-
2,500	40%	730,000	379,600	350,400	$27,914.37	$28,727.65	$813.28	2.9%	-
2,500	50%	912,500	474,500	438,000	$28,849.26	$29,662.53	$813.28	2.8%	-
2,500	60%	1,095,000	569,400	525,600	$29,784.14	$30,597.42	$813.28	2.7%	1
2,500	70%	1,277,500	664,300	613,200	$30,719.03	$31,532.31	$813.28	2.6%	1
2,500	80%	1,460,000	759,200	700,800	$31,653.92	$32,467.19	$813.28	2.6%	-
2,500	90%	1,642,500	854,100	788,400	$32,588.80	$33,402.08	$813.28	2.5%	-

	UOM	Rate Yr 2 SC08SubSta	Rate Yr 3 SC08SubSta
Customer Charge	Monthly	$ 2,560.00	$ 2,659.00
Demand Charge kW	kW	$ 8.65	$ 8.93
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

Rochester Gas and Electric Corporation
Electric Rates
Monthly Delivery Bill Impact - May 1, 2022 - April 30, 2023

Delivery Bill Only

PSC #19 - SC 9 - General Service - TOU

Kw	Load Factor	kWh	Peak kWh	Off Peak kWh	Rate Yr 2	Rate Yr 3	increase / (decrease) Amount	Percent	# of Customers
10	20%	1,460	759	701	$263.50	$284.24	$20.74	7.9%	19
10	30%	2,190	1,139	1,051	$273.32	$292.84	$19.52	7.1%	17
10	40%	2,920	1,518	1,402	$283.14	$301.45	$18.31	6.5%	25
10	50%	3,650	1,898	1,752	$292.96	$310.05	$17.09	5.8%	17
10	60%	4,380	2,278	2,102	$302.78	$318.65	$15.87	5.2%	12
10	70%	5,110	2,657	2,453	$312.59	$327.25	$14.66	4.7%	7
10	80%	5,840	3,037	2,803	$322.41	$335.86	$13.44	4.2%	1
10	90%	6,570	3,416	3,154	$332.23	$344.46	$12.23	3.7%	3
25	20%	3,650	1,898	1,752	$489.00	$515.72	$26.72	5.5%	11
25	30%	5,475	2,847	2,628	$513.54	$537.22	$23.68	4.6%	27
25	40%	7,300	3,796	3,504	$538.09	$558.73	$20.64	3.8%	30
25	50%	9,125	4,745	4,380	$562.63	$580.23	$17.60	3.1%	24
25	60%	10,950	5,694	5,256	$587.18	$601.74	$14.56	2.5%	12
25	70%	12,775	6,643	6,132	$611.72	$623.24	$11.52	1.9%	3
25	80%	14,600	7,592	7,008	$636.27	$644.75	$8.48	1.3%	-
25	90%	16,425	8,541	7,884	$660.81	$666.25	$5.44	0.8%	3
100	20%	14,600	7,592	7,008	$1,616.47	$1,673.09	$56.62	3.5%	27
100	30%	21,900	11,388	10,512	$1,714.64	$1,759.11	$44.47	2.6%	32
100	40%	29,200	15,184	14,016	$1,812.82	$1,845.13	$32.31	1.8%	18
100	50%	36,500	18,980	17,520	$1,911.00	$1,931.15	$20.15	1.1%	9
100	60%	43,800	22,776	21,024	$2,009.18	$2,017.17	$8.00	0.4%	6
100	70%	51,100	26,572	24,528	$2,107.36	$2,103.20	($4.16)	-0.2%	2
100	80%	58,400	30,368	28,032	$2,205.53	$2,189.22	($16.32)	-0.7%	-
100	90%	65,700	34,164	31,536	$2,303.71	$2,275.24	($28.47)	-1.2%	-
200	20%	29,200	15,184	14,016	$3,119.76	$3,216.25	$96.49	3.1%	1
200	30%	43,800	22,776	21,024	$3,316.11	$3,388.29	$72.18	2.2%	2
200	40%	58,400	30,368	28,032	$3,512.47	$3,560.34	$47.87	1.4%	4
200	50%	73,000	37,960	35,040	$3,708.82	$3,732.38	$23.55	0.6%	-
200	60%	87,600	45,552	42,048	$3,905.18	$3,904.42	($0.76)	0.0%	-
200	70%	102,200	53,144	49,056	$4,101.54	$4,076.47	($25.07)	-0.6%	-
200	80%	116,800	60,736	56,064	$4,297.89	$4,248.51	($49.38)	-1.1%	-
200	90%	131,400	68,328	63,072	$4,494.25	$4,420.55	($73.70)	-1.6%	-

	UOM	Rate Yr 2 SC09	Rate Yr 3 SC09
Customer Charge	Monthly	$ 112.25	$ 129.00
Demand Charge kW	kW	$ 13.07	$ 13.71
Delivery Charge On Peak kWh	kWh-On	$ 0.00833	$ 0.00666
Delivery Charge Off Peak kWh	kWh-Off	$ 0.00833	$ 0.00666
SBC (EETr) per kWh	kWh	$ -	$ -
SBC (CEF) per kWh	kWh	$ 0.00536	$ 0.00536
RAM per kW	kW	$ -	$ -
Tax Credit All Hours kWh	kWh	$ -	$ -
Tax Credit per kW	kW	$ -	$ -
Transition Charge per kWh	kWh	$ (0.00024)	$ (0.00024)
Transition Charge per kW	kW	$ -	$ -
Billing Charge per Bill	Monthly	$ 0.93	$ 0.93

Notes:

1. SBC-EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and Proposed rates for Transition and Supply are based on the 2019 average monthly rates. MFC rates are based on 05/01/2020 approved rates.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation
Electric Rates
Standby Bill Impacts by SC
May 1, 2022 - April 30, 2023

	$(000) Revenue at Rate Yr 2 Rates	$(000) Revenue at Rate Yr 3 Rates	$(000) Increase (000)	% % Increase or Decrease
Customer Charge				
SC3	$ 25.1	$ 28.9	$ 3.7	14.90%
SC8 Pri	$ 53.6	$ 55.7	$ 2.1	3.90%
SC8 Sec	$ 42.6	$ 44.2	$ 1.6	3.80%
SC8 SubTran Ind	$ 126.5	$ 131.4	$ 4.8	3.83%
SC8 SubTran Comm	$ 33.0	$ 34.3	$ 1.3	3.85%
SC8 Substation	$ 122.9	$ 127.6	$ 4.8	3.87%
	$ 403.8	$ 422.1	$ 18.3	4.54%
Contract Demand				
SC3	$ 204.8	$ 215.0	$ 10.1	4.95%
SC8 Pri	$ 156.7	$ 173.5	$ 16.8	10.69%
SC8 Sec	$ 105.5	$ 113.1	$ 7.5	7.15%
SC8 SubTran Ind	$ 426.3	$ 450.3	$ 24.0	5.63%
SC8 SubTran Comm	$ 660.4	$ 683.1	$ 22.7	3.44%
SC8 Substation	$ 192.5	$ 198.5	$ 6.0	3.11%
	$ 1,746.3	$ 1,833.5	$ 87.2	4.99%
Daily As-Used Demand				
SC3	$ 81.5	$ 85.6	$ 4.0	4.95%
SC8 Pri	$ 101.5	$ 112.3	$ 10.8	10.69%
SC8 Sec	$ 69.0	$ 73.9	$ 4.9	7.15%
SC8 SubTran Ind	$ 1,627.0	$ 1,718.5	$ 91.5	5.63%
SC8 SubTran Comm	$ 650.5	$ 672.9	$ 22.4	3.44%
SC8 Substation	$ 98.6	$ 101.6	$ 3.1	3.11%
	$ 2,628.1	$ 2,764.9	$ 136.8	5.21%
Total				
SC3	$ 311.5	$ 329.4	$ 17.9	5.76%
SC8 Pri	$ 311.8	$ 341.5	$ 29.7	9.52%
SC8 Sec	$ 217.2	$ 231.3	$ 14.1	6.49%
SC8 SubTran Ind	$ 2,179.8	$ 2,300.2	$ 120.4	5.52%
SC8 SubTran Comm	$ 1,343.9	$ 1,390.4	$ 46.4	3.45%
SC8 Substation	$ 414.0	$ 427.8	$ 13.8	3.34%
	$ 4,778.1	$ 5,020.4	$ 242.3	5.07%

Rochester Gas and Electric Corporation

Date Sources - RG&E Electric Bill Impact Statements

Rate	Source of Rate in "Current" Rates	Source of Rate in Rate Years
Customer Charge	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
kW Charge	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
kWh Delivery Charge All Hours	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
kWh Delivery Charge On Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
kWh Delivery Charge Mid Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
kWh Delivery Charge Off Peak	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
Reactive RkVah	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
Billing Charge per Bill	Current Tariff Rates in Effect 07/01/2016 - (Last Updated 05/01/2018)	New
SBC (EETr) per kWh	Current Tariff Rates in Effect 01/01/2020. Statement #26.	Included in Delivery Rates
SBC (CEF) per kWh	Current Tariff Rates in Effect 01/01/2020. Statement #26.	Current Tariff Rates in Effect 01/01/2020. Statement #26.
RAM per kWh	Tariff Rates in Effect 07/01/2019.	No RAM forecasted. COVID Bill Credits begin 7/1/2021.
RAM per kW	Tariff Rates in Effect 07/01/2019.	No RAM forecasted. COVID Bill Credits begin 7/1/2021.
Tax Credit per kWh	Case No. 17-M-0815 dated August 9, 2018. Statement Number 1	Included in Delivery Rates
Tax Credit per kW	Case No. 17-M-0815 dated August 9, 2018. Statement Number 1	Included in Delivery Rates

Rate	Source of Rate in "Current" Rates and Rate Years
Transition Charge per kWh	NBC, Demand Response, and Value Stack: NBC is the Non-Weighted 2019 Average. Dmd Rsp at $-0-. Value Stack at $-0-. RAM is separate.
MFC per kWh	Non-Weighted 2019 Average of Monthly MFC Charge
kWh Supply Charge All Hours	2019 Annualized Supply Rates
kWh Supply Charge On Peak	2019 Annualized Supply Rates
kWh Supply Charge Mid Peak	2019 Annualized Supply Rates
kWh Supply Charge Off Peak	2019 Annualized Supply Rates
Customer Count	2018 monthly data - separate Low Income counts

Gas Revenue Allocation and Rate Design

New York State Electric & Gas Corporation – Gas
Rochester Gas and Electric Corporation - Gas

Cost of Service

In their next gas rate cases, the Companies will develop a method to perform a zero-intercept or minimum system study, or some other equitable allocation, for classifying gas distribution mains (Account 376) between customer and demand. The Companies will provide Gas Embedded Cost of Service ("ECOS") studies based on the results of this analysis.

i. The Companies will convene a meeting to explain the methodology they plan to use for their study to classify gas distribution mains. The Companies will target the meeting to be held during the last six months of Rate Year 2.
ii. Within 30 days after filing their next rate cases, the Companies will convene a technical conference to explain the results of the gas distribution mains classification.

In their next gas rate cases, the Companies will file the results of the ECOS studies that classify gas distribution mains (Account 376) on a 100% demand basis (for illustrative purposes only).

Notwithstanding the foregoing, the Companies are free to recommend the use of any cost study they believe is appropriate.

Energy Efficiency Costs in Base Delivery Rates

The base delivery rates include Energy Efficiency ("EE") Tracker costs for energy efficiency programs that are administered by the Companies and currently collected through the System Benefits Charge ("SBC") consistent with the Commission's Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025, issued January 16, 2020 in Case 18-M-0084 ("January 16, 2020 Order"), and the proposed utilization of unspent funds through 2019. Upon implementation of new delivery rates, the Companies will discontinue the EE Tracker component of the SBC surcharge currently applied to customer bills.

The dollar amounts allocated to gas service classes for each Rate Year for these programs are set forth in Schedule A for NYSEG and Schedule B for RG&E to this Appendix.

Revenue Allocation

The Signatory Parties recognize that the revenue allocation determined in these proceedings does not use or otherwise reflect any one ECOS study sponsored by any party in these proceedings in reaching agreement on each Company's allocation of the revenue increases to service classifications.

The base delivery revenue increases begin with the total levelized/shaped delivery revenue increases as presented in Appendix A, net of Gross Receipts Taxes. For NYSEG, the delivery revenue includes revenues associated with interruptible customers. The revenue allocation process consists first of separate allocations to the firm service classes for: energy efficiency costs associated with the EE Tracker, Advanced Metering Infrastructure ("AMI") costs associated with Information Technology ("IT") infrastructure, and AMI costs associated with all other investments and expenses. For RY1, RY2 and RY3, the residual revenue requirement (i.e., the total base delivery revenue increase net of the increases associated with the aforementioned separate allocations) is allocated to the firm service classes as shown in this Appendix. Subsequently, for NYSEG, revenue for the interruptible service classes is calculated based on discounted rates. The resulting interruptible revenue is then allocated to all firm service classes except for SC No. 5 – Seasonal Gas Cooling Sales Service.

The separate allocations to service classifications are summarized below.

- Energy Efficiency – EE Tracker costs are allocated to service classes as follows: 83.81% based on energy (i.e., therms); and 16.19% based on a peak day design demand allocator.

- AMI costs associated with IT infrastructure, such as IT hardware and software, are allocated to service classes based on the labor expense allocation factors per the ECOS study.

- AMI costs associated with all other investments and expenses, such as meters and communications network equipment, are allocated to service classes based on number of customers.

The overall resulting base delivery revenue increases by service class, and the delivery increases associated with the aforementioned separate revenue allocations and the residual revenue requirement by service class, are set forth in Schedule C to this Appendix.

Rate Design

Firm Service Classes

The delivery revenue requirement is recovered through customer charges ($/month) and volumetric (per therm) delivery charges. Customer charges for the NYSEG and RG&E gas service classes are increased as listed in the tables below. The revenue requirement, net of the customer charge revenue for each firm service class, is recovered through volumetric delivery charges, proportionally through each respective service class' block rates.

NYSEG GAS SERVICE CLASS	Current Monthly Customer Charge	Monthly Customer Charge Rate Year 1	Monthly Customer Charge Rate Year 2	Monthly Customer Charge Rate Year 3
SC1 RESIDENTIAL FIRM SALES SERVICE AND SC13 RESIDENTIAL FIRM TRANSPORTATION SERVICE-HEATING	$ 16.30	$ 16.30	$ 17.30	$ 18.30
SC1 RESIDENTIAL FIRM SALES SERVICE AND SC13 RESIDENTIAL FIRM TRANSPORTATION SERVICE- NON-HEATING	$ 12.30	$ 12.30	$ 13.30	$ 14.30
SC2 GENERAL FIRM SALES SERVICE AND SC14 NON-RESIDENTIAL FIRM TRANSPORTATION SERVICE	$ 23.60	$ 23.60	$ 24.60	$ 25.60
SC5 SEASONAL GAS COOLING FIRM SALES SERVICE	$ 16.86	$ 16.86	$ 16.86	$ 16.86
SC9 INDUSTRIAL MANUFACTURING OR PROCESSING FIRM SALES SERVICE	$ 352.77	$ 352.77	$ 352.77	$ 352.77
SC1 LARGE FIRM TRANSPORTATION SERVICE	$ 1,723.55	$ 2,154.44	$ 2,334.09	$ 2,552.99
SC 5 SMALL FIRM TRANSPORTATION SERVICE	$ 357.39	$ 357.39	$ 357.39	$ 357.39
INTERRUPTIBLE CLASS SC 1 LARGE FIRM TRANSPORTATION SERVICE		$ 2,154.44	$ 2,334.09	$ 2,552.99
INTERRUPTIBLE CLASS SC 5 SMALL FIRM TRANSPORTATION SERVICE		$ 357.39	$ 357.39	$ 357.39

RG&E GAS SERVICE CLASS	Current Monthly Customer Charge	Monthly Customer Charge Rate Year 1	Monthly Customer Charge Rate Year 2	Monthly Customer Charge Rate Year 3
SC1 GENERAL FIRM SALES SERVICE AND SC5 SMALL FIRM TRANSPORTATION SERVICE	$ 16.30	$ 16.30	$ 17.30	$ 18.30
SC3 LARGE FIRM TRANSPORTATION SERVICE	$ 1,479.53	$ 1,849.41	$ 1,984.51	$ 2,239.18
SC3 LARGE FIRM TRANSPORTATION SERVICE HIGH PRESSURE	$ 1,550.00	$ 1,552.65	$ 1,600.92	$ 1,667.59
SC16 INTERRUPTIBLE TRANSPORTATION SERVICE	$ 1,183.62	$ 1,849.41	$ 1,984.51	$ 2,239.18

Interruptible Service Classes

Customer charges for the interruptible service classes are set at the same level as the otherwise applicable service classes. The otherwise applicable service classes are SC No. 1 Large Firm Transportation Service and SC No. 5 Small Firm Transportation Service at NYSEG, and SC No. 3 Large Firm Transportation Service at RG&E. Volumetric delivery rates for the interruptible service classes are capped at 70% of the customers' otherwise applicable service class' firm volumetric delivery rates.

Distributed Generation ("DG") Service

DG delivery rates for NYSEG service classes 10, 11, 16, and 19, and RG&E service classes 6, 7, 8, and 9 are updated in accordance with Commission orders in Case 02-M-0515 such that the current relationships between the DG rates of these classes and the rates of the non-DG service classes are maintained.

Delivery rates by Company and Rate Year are set forth in Appendix EE.

Competitive Service Rates

Competitive service rates (i.e., the Bill Issuance and Payment Processing ("BIPP") Charge, the Credit and Collections/Call Center component of the Merchant Function Charge ("MFC") and Purchase of Receivables ("POR") discount, and the Administrative component of the MFC) are based on the ECOS studies filed as part of the Companies' rebuttal in these proceedings. The MFC and the POR Discount will continue to be calculated as stated in the respective Companies' currently-effective tariffs.

MFC and POR Rates

The Companies continue to follow the process outlined in the Amended Stipulation Regarding Purchase of Receivables Discount and Merchant Function Charge (included as Appendix W in the Joint Proposal approved in Cases 09-E-0715, et. al.) and updated in Appendix W of the Joint Proposal approved in the 2016 Rate Order (page 6) for calculating the MFC and POR discount. The fixed components are set by the ECOS study and can be found in Schedule D to this Appendix. The fixed percentage factor as discussed in Appendix W of the Joint Proposal approved in the 2016 Rate Order has been updated using current data.

Bill Issuance and Payment Processing Charges

NYSEG's BIPP charge will increase from the current charge of $0.81 per bill to $0.90 per bill. RG&E's BIPP charge will increase from the current charge of $0.72 per bill to $0.93 per bill.

A combination electric and gas customer will receive one BIPP charge applied to the bill. An electric-only or gas-only customer will receive one BIPP charge applied to each bill. The BIPP charge for a combination customer will be the same as that for an electric-only customer or a gas-only customer.

If an energy service company ("ESCO") is providing both the electric and gas service, it will be billed an amount equivalent to the BIPP charge for each consolidated bill. If the ESCO is only providing a consolidated bill for either gas or electric service, it will also be billed an amount equivalent to the BIPP charge per consolidated bill. If a customer has separate ESCOs for electric and gas, the charge for consolidated billing will be prorated between the ESCOs.

Economic Development Rates

Discounted rates offered under NYSEG's Economic Development Zone Incentive ("EDZI") Program, RG&E's Empire Zone Rates ("EZR") Program, and the Companies' Excelsior Jobs Programs are updated based on the results of the Companies' filed marginal cost of service studies in these proceedings.

Gas Interruptible Service

The following modifications are made to Gas Interruptible Service:

- NYSEG will provide gas interruptible service throughout its entire service territory. The Companies will consider requests from interruptible customers to return to firm service only if the Companies have available capacity and supply to provide firm service.

- NYSEG will eliminate the Incremental Interruptible Transportation Service.

- The minimum use requirement for customers to qualify for gas interruptible service at NYSEG is 40,000 therms per month for the November through March period.

- Interruptible customers will be required to meet or have the potential to meet the proposed minimum use requirement. In the event a customer does not meet the minimum use requirement, the customer will be required to take firm service. In constrained areas, as determined by NYSEG and RG&E, the minimum use requirement may be waived because in these circumstances, the Companies would not have the ability to serve customers on a firm basis.

- An amount of delivery revenues associated with interruptible customers is embedded into NYSEG base delivery rates. No interruptible delivery revenues have been embedded into RG&E base delivery rates. For both NYSEG and RG&E, any difference between actual interruptible delivery revenues and the level embedded in delivery rates will be reconciled annually and recovered or returned to all firm customers. The credit or surcharge associated with the interruptible allocation will be included with the Revenue Decoupling Mechanism credit or surcharge on customer bills.

- Supply pricing for interruptible customers that purchase their commodity from NYSEG will be determined as follows:
    - The daily price per dekatherm will be established, at the end of each gas day for each pooling area as defined in the table below. The Daily Cost of Gas will be summed and charged to the customer monthly. The daily Cost of Gas Rate ("Cost of Gas Rate") per dekatherm will be the sum of: (1) the daily midpoint index as published in the Platts *Gas Daily* ("GD") Publication for the respective pooling area; plus (2) the published firm intrastate pipeline variable transportation rates and fuel rates for the respective pooling area; plus (3) the published firm intrastate pipeline demand rates as defined per pooling area, at a 70% load factor.

Pooling Area	Rate Components
Algonquin and Algonquin - Orange & Rockland	a. GD Iroquois Receipts midpoint; plus b: Iroquois & Algonquin variable and fuel; plus c: Iroquois & Algonquin Demand (@ 70% load factor)
Columbia and Olean	a: Average of GD Tennessee, LA 500 leg and 800 leg midpoints; plus b: Tennessee & Columbia variable and fuel; plus c: Tennessee & Columbia Demand (@ 70% load factor)
Dominion	a: GD Dominion South point; plus b: Dominion variable and fuel rates; plus c: Dominion demand (@ 70% load factor)
Iroquois	a: GD Iroquois Receipts midpoint; plus b: Iroquois variable and fuel rates; plus c: Iroquois demand (@ 70% load factor)
Tennessee	a: Average of GD Tennessee, LA 500 leg and 800 leg midpoints; plus b: Tennessee variable and fuel rates; plus c: Tennessee demand (@ 70% load factor)
North Country	a: GD Iroquois Receipts midpoint; plus b: TransCanada (Iroquois to Napierville) variable and fuel rates; plus c: TransCanada (Iroquois to Napierville) demand (@ 70% load factor)

  - The Daily Cost of Gas shall be calculated as the product of: (1) the customer's usage at the citygate; and (2) the (daily Cost of Gas Rate + Capacity Surcharge) for the respective pooling area. A daily volumetric Capacity Surcharge will be added to the Daily Cost of Gas Rate for customers whose natural gas transportation utilizes intermediary local distribution company or intrastate pipeline capacity in addition to interstate pipeline capacity.

- Supply pricing for interruptible customers that purchase their commodity from RG&E will be determined as follows:
  - The daily price per dekatherm will be established at the end of each gas day for the Dominion / Empire pooling area. The Daily Cost of Gas will be summed and charged to the customer monthly. The daily Cost of Gas Rate ("Cost of Gas Rate") per dekatherm will be the average of: the sum of: (1) the daily midpoint index as published in the Platts GD Publication; plus (b) the published firm intrastate pipeline variable transportation rates and fuel rates; plus (c) the published firm intrastate pipeline demand rates, as defined below, at a 70% load factor, for Dominion; and the sum of (d) the daily midpoint index as published in the Platts GD Publication; plus (e) the published firm intrastate pipeline variable transportation rates and fuel rates;

plus (f) the published firm intrastate pipeline demand rates, as defined below, at a 70% load factor, for Empire.

Pooling Area	Rate Components
Dominion / Empire	(1): a: GD Appalachia, Dominion Southpoint midpoint; plus b: Variable and fuel to Caledonia city gate on Dominion; plus c: Dominion Demand (@ 70% load factor) (2): d: GD Dawn Ontario midpoint; plus e: Variable and fuel to Mendon city gate on Empire; plus f: Empire Demand (@ 70% load factor)

- The Daily Cost of Gas shall be calculated as the product of (1) the customer's usage at the citygate and (2) the average daily Cost of Gas Rate.

- The compliance filing submitted in these proceedings will include changes to each Company's current tariff provisions for interruptible service. The compliance filing will also include tariff provisions for charges for unauthorized use of gas supply by interruptible customers, and penalty provisions that apply to interruptible customers that fail to comply with the tariff, in addition to the charges for unauthorized use of gas supply.

Tariffs

The compliance filing submitted in these proceedings will include tariff changes to implement the rates and other provisions of this Joint Proposal. The specific language will be set forth in the compliance tariff leaves filed with the Commission.

Customer Bill Impacts

The estimated total bill and delivery(i bill impacts resulting from the rates set forth in this Joint Proposal are set forth in Appendix EE.

Gas Revenue Allocation and Rate Design
Index of Schedules

New York State Gas & Electric Corporation
Gas Department
Gas Allocation of EE Tracker

Cumulative per Year	Rate Year 1	Rate Year 1 Billing Units and Rate per Billing Unit			Rate Year 2 Inclusive of Rate Year 1	Rate Year 2 Billing Units and Rate per Billing Unit			Rate Year 3 Inclusive of Rate Year 2	Rate Year 3 Billing Units and Rate per Billing Unit		
	SBC EE Tracker	**Billing Units**	**Rate per Customer**	**Rate per Therm**	**SBC EE Tracker**	**Billing Units**	**Rate per Customer**	**Rate per Therm**	**SBC EE Tracker**	**Billing Units**	**Rate per Customer**	**Rate per Therm**
Service Classifications (SC)												
Service Class 1												
Customer Charge - Heat		2,493,170				2,502,607				2,512,153		
Customer Charge - Non Heat		83,299				83,617				83,935		
Next 47 Therms	$ (211,052)	79,692,927		$ (0.00265)	$ 397,796	80,452,323		$ 0.00494	$ 1,006,213	80,465,770		$ 0.01250
Over 50 Therms	$ (70,466)	113,130,377		$ (0.00062)	$ 132,816	114,208,676		$ 0.00116	$ 335,955	114,227,785		$ 0.00294
TOTAL	$ (281,517)				$ 530,612				$ 1,342,167			
Service Classes 2: General Service												
Customer Charge (includes 3 therms)		279,251				280,634				282,017		
Next 497 Therms	$ (50,847)	26,733,575		$ (0.00190)	$ 95,185	26,839,345		$ 0.00355	$ 241,390	26,903,067		$ 0.00897
Next 14,500 Therms	$ (34,166)	30,911,585		$ (0.00111)	$ 63,956	31,033,311		$ 0.00206	$ 162,194	31,106,423		$ 0.00521
Over 15,000 Therms	$ (2,423)	3,533,617		$ (0.00069)	$ 4,535	3,547,603		$ 0.00128	$ 11,501	3,556,042		$ 0.00323
TOTAL	$ (87,435)				$ 163,676				$ 415,085			
Service Class 5: Seasonal Gas Cooling												
Customer Charge (includes 3 therms)		6				6				6		
Over 3 Therms	$ (25)	20,999		$ (0.00120)	$ 47	21,108		$ 0.00223	$ 120	21,183		$ 0.00564
TOTAL	$ (25)				$ 47				$ 120			
Service Class 9: Industrial (Binghamton Only)												
Customer Charge (includes 500 therms)		0				12				12		
Next 14,500 Therms	$ (80)	58,357		$ (0.00137)	$ 150	58,473		$ 0.00256	$ 379	58,489		$ 0.00648
Over 15,000 Therms	$ -	0			$ -	0			$ -	0		
TOTAL	$ (80)				$ 150				$ 379			
Service Class 1: Firm Transportation												
Customer Charge (includes 500 therms)		1,009			$ 86,500	994	$ 87.02		$ 175,390	982	$ 178.60	
Next 14,500 Therms	$ (37,017)	15,317,800		$ (0.00242)	$ 41,771	15,348,274		$ 0.00272	$ 119,763	15,357,191		$ 0.00780
Next 35,000 Therms	$ (33,201)	25,392,187		$ (0.00131)	$ 37,463	25,441,820		$ 0.00147	$ 107,412	25,456,100		$ 0.00422
Over 50,000 Therms	$ (47,005)	46,811,471		$ (0.00100)	$ 53,039	46,903,194		$ 0.00113	$ 152,070	46,929,541		$ 0.00324
TOTAL	$ (117,223)				$ 218,772				$ 554,636			
Service Class 5: Small Firm Transportation												
Customer Charge (includes 500 therms)		4,059				4,038				4,019		
Next 14,500 Therms	$ (32,553)	20,700,417		$ (0.00157)	$ 60,617	20,697,101		$ 0.00293	$ 153,663	20,684,262		$ 0.00743
Over 15,000 Therms	$ (4,690)	4,874,700		$ (0.00096)	$ 8,738	4,875,419		$ 0.00179	$ 22,151	4,873,402		$ 0.00455
TOTAL	$ (37,244)				$ 69,355				$ 175,813			
Service Class 13: Residential Aggregation												
Customer Charge - Heat		264,735				265,743				266,756		
Customer Charge - Non-Heat		12,105				12,151				12,197		
Next 47 Therms	$ (26,013)	9,822,343		$ (0.00265)	$ 49,031	9,916,190		$ 0.00494	$ 124,023	9,917,949		$ 0.01250
Over 50 Therms	$ (8,575)	13,767,228		$ (0.00062)	$ 16,164	13,898,831		$ 0.00116	$ 40,885	13,901,246		$ 0.00294
TOTAL	$ (34,588)				$ 65,195				$ 164,908			
Service Class 14: Non-Residential Aggregation												
Customer Charge (includes 3 therms)		102,371				102,367				102,361		
Next 497 Therms	$ (59,848)	31,466,033		$ (0.00190)	$ 111,821	31,551,236		$ 0.00354	$ 283,566	31,602,625		$ 0.00897
Next 14,500 Therms	$ (39,684)	35,904,047		$ (0.00111)	$ 74,145	36,001,086		$ 0.00206	$ 188,026	36,059,877		$ 0.00521
Over 15,000 Therms	$ (2,952)	4,305,827		$ (0.00069)	$ 5,516	4,317,753		$ 0.00128	$ 13,989	4,324,924		$ 0.00323
TOTAL	$ (102,484)				$ 191,482				$ 485,581			
TOTAL THERMS		462,443,490				465,111,743				465,445,877		
Total Base Revenue	$ (660,596)				$ 1,239,289				$ 3,138,689			

Rochester Gas and Electric Corporation
Gas Department
Gas Allocation of EE Tracker

Cumulative per Year	Rate Year 1	Rate Year 1 Billing Units and Rate per Billing Unit			Rate Year 2 Inclusive of Rate Year 1	Rate Year 2 Billing Units and Rate per Billing Unit			Rate Year 3 Inclusive of Rate Year 2	Rate Year 3 Billing Units and Rate per Billing Unit		
	SBC EE Tracker	**Billing Units**	**Rate per Customer**	**Rate per Therm**	**SBC EE Tracker**	**Billing Units**	**Rate per Customer**	**Rate per Therm**	**SBC EE Tracker**	**Billing Units**	**Rate per Customer**	**Rate per Therm**
Service Classifications (SC)												
Service Class 1: Sales												
Customer Charge (includes 3 therms)		3,357,527				3,373,318				3,389,387		
Next 97 Therms	$ (448,496)	174,877,035		$ (0.00256)	$ (91,169)	176,859,784		$ (0.00052)	$ 432,485	177,360,767		$ 0.00244
Next 400 Therms	$ (180,625)	75,556,620		$ (0.00239)	$ (36,750)	76,395,941		$ (0.00048)	$ 174,231	76,661,064		$ 0.00227
Next 500 Therms	$ (15,796)	7,412,772		$ (0.00213)	$ (3,236)	7,481,616		$ (0.00043)	$ 15,233	7,528,635		$ 0.00202
Over 1000 Therms	$ (11,964)	13,183,990		$ (0.00091)	$ (2,492)	13,249,666		$ (0.00019)	$ 11,428	13,323,917		$ 0.00086
TOTAL	$ (656,882)				$ (133,647)				$ 633,376			
Service Class 3: Large Transportation												
Customer Charge (includes 1000 therms)		2,836		$ -	$ 166,740	2,728	$ 61.12		$ 415,934	2,620	$ 158.75	
Next 29,000 Therms	$ (192,267)	45,583,120		$ (0.00422)	$ (122,198)	45,531,697		$ (0.00268)	$ (22,023)	45,662,153		$ (0.00048)
Next 70,000 Therms	$ (97,289)	28,875,378		$ (0.00337)	$ (61,914)	28,777,382		$ (0.00215)	$ (11,477)	28,781,266		$ (0.00040)
Next 900,000 Therms	$ (68,590)	52,606,442		$ (0.00130)	$ (43,604)	52,524,763		$ (0.00083)	$ (7,962)	52,557,610		$ (0.00015)
Over 1,000,000 Therms	$ (42,855)	69,927,742		$ (0.00061)	$ (27,859)	67,067,354		$ (0.00042)	$ (6,448)	67,170,198		$ (0.00010)
TOTAL	$ (401,002)				$ (88,836)				$ 368,022			
Service Class 3: HP												
Customer Charge (includes 1000 therms)		12			$ 615	12	$ 51.27		$ 1,515	12	$ 126.21	
Next 29,000 Therms	$ (736)	348,000		$ (0.00211)	$ (331)	348,000		$ (0.00095)	$ 261	348,000		$ 0.00075
Next 70,000 Therms	$ (1,404)	663,884		$ (0.00211)	$ (631)	663,884		$ (0.00095)	$ 497	663,884		$ 0.00075
Next 900,000 Therms	$ (429)	203,027		$ (0.00211)	$ (193)	203,027		$ (0.00095)	$ 152	203,027		$ 0.00075
Over 1,000,000 Therms	$ -	0				0			$ -	0		
TOTAL	$ (2,569)				$ (540)				$ 2,425			
Service Class 5: Aggregation												
Customer Charge (includes 3 therms)		469,549				471,627				473,742		
Next 97 Therms	$ (72,881)	28,417,496		$ (0.00256)	$ (14,844)	28,725,223		$ (0.00052)	$ 70,293	28,835,799		$ 0.00244
Next 400 Therms	$ (61,197)	25,599,026		$ (0.00239)	$ (12,525)	25,844,375		$ (0.00048)	$ 59,005	25,990,774		$ 0.00227
Next 500 Therms	$ (24,539)	11,515,662		$ (0.00213)	$ (5,060)	11,603,481		$ (0.00044)	$ 23,593	11,680,175		$ 0.00202
Over 1000 Therms	$ (33,105)	36,480,858		$ (0.00091)	$ (6,915)	36,634,560		$ (0.00019)	$ 31,581	36,849,198		$ 0.00086
TOTAL	$ (191,722)				$ (39,344)				$ 184,473			
TOTAL THERMS		571,251,052				571,910,753				573,616,467		
Total Base Revenue	$ (1,252,174)				$ (262,368)				$ 1,188,296			

New York State Electric & Gas Corporation
Gas Department
Development of Delivery Revenues
Rate Year May 1, 2020 through April 30, 2021

		A	B	C	D = B plus C	E=D minus A	F = E divided by A
		Delivery Revenue Prior to EE Tracker Transfer and Delivery Rate Increase (000 $)	Rate Year Delivery Revenue For Firm Customers (000 $)	Interupptible Revenue Allocation (000 $)	Rate Year Delivery Revenue Firm and Interrubtible Customers (000 $)	Revenue Increase/ (Decrease) (000 $)	Change (%)
1	SC 1 and SC 13 - Residential Service and Residential Firm Aggregation Transportation Service	127,057,709	128,430,716	(1,323,875)	127,106,841	49,132	0.0%
2	SC 2 and SC 14 - General Service and Non-Residential Firm Aggregation Transportation Service	50,698,991	50,957,242	(525,272)	50,431,970	(267,021)	-0.5%
3	SC 5 - Seasonal Gas Cooling Service	921	895	-	895	(25)	-2.7%
4	SC 9 - Industrial Manufacturing or Processing Purposes	9,069	9,069	(93)	8,975	(93)	-1.0%
5	SC 1 - Firm Transportation Service	8,453,976	8,411,484	(72,825)	8,338,658	(115,317)	-1.4%
6	SC 5 - Small Firm Transportation Service	5,843,596	5,858,009	(59,546)	5,798,463	(45,133)	-0.8%
7	**Total PSC 87, PSC 88 Firm Revenue Firm for Increase (Decrease)**	***$192,064,261***	***$193,667,414***	***($1,981,612)***	***$191,685,803***	***($378,458)***	**-0.2%**
8	Interruptible associated with SC 1T	1,886,214	-	1,898,935	1,898,935	12,721	
9	Interruptible associated with SC5T	56,103	-	82,677	82,677	26,574	
10	**Total PSC 87, PSC 88 Firm Revenue Firm for Increase (Decrease) and Interruptible Revenue**	***$194,006,578***	***$193,667,414***	***$0***	***$193,667,414***	***($339,163)***	
11	SC 7 - Firm or Limited Firm Negotiated Transportation Service	2,098,920	2,098,920		2,098,920	-	
12	SC 10 - Non-Residential Distributed Generation Firm Sales Service						
13	SC 11 - Residential Distributed Generation Firm Sales Service						
14	SC 15 - Basic Electric Generation Transportation Service						
15	SC 16 - Non-Residential Distributed Generation Firm Transportation Service						
16	SC 19 - Residential Distributed Generation Firm Transportation Service						
17	**Total PSC 87, PSC 88 Firm and Interruptible Firm**	***$196,105,498***	***$195,766,335***	***$0***	***$195,766,335***	***($339,163)***	
18	Bill Issuance and Payment Processing (BIPP) Revenue	1,782,594	1,782,594		1,782,594	-	
19	**Total PSC 87, PSC 88 and BIPP Revenue**	***$197,888,092***	***$197,548,929***	***$0***	***$197,548,929***	***($339,163)***	
	Other Delivery Revenue Adjustments:						
20	Economic Development Discounts --- NYSERDA Surcharge	77,000	77,000		77,000	-	
21	Merchant Function Charge	3,375,625	3,375,625		3,375,625	-	
22	R&D Revenues	649,972	649,972		649,972	-	
23	Revenue Taxes	3,368,466	3,193,360		3,193,360	(175,106)	
24	**Total Retail Revenue**	**$205,359,155**	**$204,844,886**	**$0**	**$204,844,886**	**(514,269)**	**-0.3%**

New York State Electric & Gas Corporation
Gas Department
Revenue Allocation
Rate Year May 1, 2020 through April 30, 2021

1	Current Delivery Revenue with forecasted billing determinants	**$ 192,064,261**
2	Total Proposed Delivery Increase (Decrease)	**$ (339,163)**
3	EE Tracker Moved to Delivery	**(660,596)**
4	AMI Investment	-
5	AMI IT Costs	-
6	Net Delivery Revenue Increase (Decrease)	**321,433**
7	Less: Change in BIPP Revenue	-
8	Less: Change in MFC Revenue	-
9	Plus: Interruptible Revenue Adjustment	1,942,317
10	Residual Delivery Revenue Increase (Decrease)	**2,263,750**
11	Total Proposed Revenue (at overall increase or decrease)	**$193,667,414**

										Detail of Revenue Increase Components				
		A	B	C	D	E	F	G	H	I	J	K	L	M
	PSC 87 and 88 - Gas	Sales (th)	Delivery Revenue Prior to Rate Increase* $	Revenue Requirement Increase/ (Decrease) for Firm Customers $	Rate Year Delivery Revenue For Firm Customers $	Interruptible Revenue Allocation $	Revenue Requirement Increase/(Decrease) After Interruptible Revenue Allocation $	Rate Year Delivery Revenue Firm and Interrubtible Customers $	Total Proposed Revenue Percent Change (%)	Total Proposed Revenue Percent Change Residual Only (%)	Total Proposed Revenue Percent Change Interruptible Allocation (%)	Percent of Total Change Attributed to EE Tracker (%)	Percent of Total Change Attributed to AMI Investment in Delivery (%)	Percent of Total Change Attributed to AMI IT Costs (%)
1	SC No.1S - Residential Sales	199,874,823	113,738,339	1,230,526	114,968,866	(1,179,018)	51,508	113,789,847						
2	SC No. 13T - Residential Transportation	24,453,524	13,319,369	142,481	13,461,850	(144,857)	(2,376)	13,316,993						
3	**Subtotal - Residential**	**224,328,347**	**$ 127,057,709**	**$ 1,373,007**	**$ 128,430,716**	**$ (1,323,875)**	**$ 49,132**	**$ 127,106,841**	**0.0%**	**1.3%**	**-1.0%**	**-0.2%**	**0.0%**	**0.0%**
4	SC No. 2S - General Service Sales	61,616,045	25,784,892	140,498	25,925,391	(241,825)	(101,327)	25,683,565						
5	SC No. 14T - General Service Transportation	72,214,009	24,914,099	117,752	25,031,851	(283,446)	(165,694)	24,748,405						
6	**Subtotal - General Service**	**133,830,054**	**$ 50,698,991**	**$ 258,251**	**$ 50,957,242**	**$ (525,272)**	**$ (267,021)**	**$ 50,431,970**	**-0.5%**	**0.9%**	**-1.0%**	**-0.4%**	**0.0%**	**0.0%**
7	SC No. 5S - Seasonal Gas Cooling	21,338	921	(25)	895		(25)	895	-2.7%	0.0%	0.0%	-2.7%	0.0%	0.0%
8	SC No. 9S - Industrial Manufacturing	65,080	9,069	0	9,069	(93)	(93)	8,975	-1.0%	0.9%	-1.0%	-0.9%	0.0%	0.0%
9	SC No. 1T - Large Firm Transportation	88,092,106	8,453,976	(42,492)	8,411,484	(72,825)	(115,317)	8,338,658	-1.4%	0.9%	-0.9%	-1.4%	0.0%	0.0%
10	SC No. 5T - Small Firm Transportation	27,538,396	5,843,596	14,413	5,858,009	(59,546)	(45,133)	5,798,463	-0.8%	0.9%	-1.0%	-0.6%	0.0%	0.0%
11	**Total Firm classes to which increase is spread**	**473,875,321**	**$ 192,064,261**	**$ 1,603,154**	**$ 193,667,414**	**$ (1,981,612)**	**$ (378,458)**	**$ 191,685,803**	**-0.2%**	**1.2%**	**-1.0%**	**-0.3%**	**0.0%**	**0.0%**
12	Interruptible associated with SC 1T	24,008,830	$1,886,214			1,898,935	12,721	1,898,935						
13	Interruptible associated with SC5T	705,959	$56,103			82,677	26,574	82,677						
14	**Total Firm and Interruptible Revenue**	**498,590,109**	**$ 194,006,578**	**$ 1,603,154**	**$ 193,667,414**	**$ 0**	**$ (339,163)**	**$ 193,667,414**						

*Does Not Includes Energy Efficiency Costs transferred into Delivery Rates

New York State Electric & Gas Corporation
Gas Department
Development of Delivery Revenues
Rate Year May 1, 2021 through April 30, 2022

		A	B	C	D= B plus C	E = D minus A	F=E divided by A
		Delivery Revenue Prior to Delivery Rate Increase (000 $)	Rate Year Delivery Revenue For Firm Customers (000 $)	Interupptible Revenue Allocation (000 $)	Rate Year Delivery Revenue Firm and Interrubtible Customers (000 $)	Revenue Increase/ (Decrease) (000 $)	Change (%)
1	SC 1 and SC 13 - Residential Service and Residential Firm Aggregation Transportation Service	128,053,505	131,299,369	(1,390,062)	129,909,306	1,855,802	1.4%
2	SC 2 and SC 14 - General Service and Non-Residential Firm Aggregation Transportation Service	50,600,347	51,838,124	(548,809)	51,289,315	688,968	1.4%
3	SC 5 - Seasonal Gas Cooling Service	900	972		972	72	8.0%
4	SC 9 - Industrial Manufacturing or Processing Purposes	13,226	13,567	(144)	13,423	197	1.5%
5	SC 1 - Firm Transportation Service	8,318,472	8,759,488	(77,915)	8,681,573	363,101	4.4%
6	SC 5 - Small Firm Transportation Service	5,790,429	5,966,760	(62,292)	5,904,468	114,039	2.0%
7	**Total PSC 87, PSC 88 Firm Revenue Firm for Increase (Decrease)**	***$192,776,879***	***$197,878,279***	***($2,079,222)***	***$195,799,057***	***$3,022,179***	**1.6%**
8	Interruptible associated with SC 1T	1,898,935		1,994,939	1,994,939	96,004	
9	Interruptible associated with SC5T	82,677		84,283	84,283	1,606	
10	**Total PSC 87, PSC 88 Firm Revenue Firm for Increase (Decrease) and Interruptible Revenue**	***$194,758,491***	***$197,878,279***	***$0***	***$197,878,279***	***$3,119,789***	
11	Revenue Adjustment	$ 3,595				$ (3,595)	
12	SC 7 - Firm or Limited Firm Negotiated Transportation Service	2,104,649	2,104,649		2,104,649	-	
13	SC 10 - Non-Residential Distributed Generation Firm Sales Service						
14	SC 11 - Residential Distributed Generation Firm Sales Service						
15	SC 15 - Basic Electric Generation Transportation Service						
16	SC 16 - Non-Residential Distributed Generation Firm Transportation Service						
17	SC 19 - Residential Distributed Generation Firm Transportation Service						
18	**Total PSC 87, PSC 88 Firm and Interruptible Firm**	***$196,866,734***	***$199,982,928***	***$0***	***$199,982,928***	***$3,116,194***	
19	Bill Issuance and Payment Processing (BIPP) Revenue	1,789,531	1,789,531		1,789,531	-	
20	**Total PSC 87, PSC 88 and BIPP Revenue**	***$198,656,265***	***$201,772,459***	***$0***	***$201,772,459***	***$3,116,194***	
	Other Delivery Revenue Adjustments:						
21	Economic Development Discounts --- NYSERDA Surcharge	$43	$43		$43	$ -	
22	Merchant Function Charge	$3,375,625	$3,375,625		$3,375,625	$ -	
23	R&D Revenues	$649,972	$649,972		$649,972	$ -	
24	Revenue Taxes	$3,239,563	$3,473,731		$3,473,731	$ 234,169	
25	Levelization Deferral	$ (10,161,124)	$ (10,161,124)		($10,161,124)	**$0**	
26	**Total Retail Revenue**	**$195,760,343**	**$199,110,706**	**$0**	**$199,110,706**	**$3,350,363**	**1.7%**

New York State Electric & Gas Corporation
Gas Department
Revenue Allocation
Rate Year May 1, 2021 through April 30, 2022

1	Current Delivery Revenue with forecasted billing determinants	**$ 192,776,879**
2	Total Proposed Delivery Increase (Decrease)	**$ 3,116,194**
3	EE Tracker Moved to Delivery (No change since the amount is same as RY1)	**1,899,885**
4	AMI Investment	**681,646**
5	AMI IT Costs	**991,003**
6	Net Delivery Revenue Increase (Decrease)	**(456,340)**
7	Less: Change in BIPP Revenue	-
8	Less: Change in MFC Revenue	-
9	Plus: Interruptible Revenue Adjustment	1,981,612
10	Plus: Adj to Match RR (Units & Rates Differences)	3,595
11	Residual Delivery Revenue Increase (Decrease)	**1,528,866**
12	Total Proposed Revenue (at overall increase or decrease)	**$197,878,279**

		A	B	C	D	E	F	G	H	Detail of Revenue Increase Components I	J	K	L	M
	PSC 87 and 88 - Gas	Sales (th)	Delivery Revenue Prior to Rate Increase* $	Revenue Requirement Increase/ (Decrease) Before Interruptible Allocation $	Revenue Before Interruptible Allocation $	Interruptible Revenue Allocation $	Revenue Requirement Increase/ (Decrease) After Interruptible Allocation $	Rate Year Delivery Revenues After Interruptible Allocation $	Total Proposed Revenue Percent Change (%)	Total Proposed Revenue Percent Change Residual Only (%)	Total Proposed Revenue Percent Change Interruptible Allocation (%)	Percent of Total Change Attributed to EE Tracker (%)	Percent of Total Change Attributed to AMI Investment in Delivery (%)	Percent of Total Change Attributed to AMI IT Costs (%)
1	SC No.1S - Residential Sales	201,779,689	114,627,088	2,895,340	117,522,428	(1,237,960)	1,657,380	116,284,468						
2	SC No. 13T - Residential Transportation	24,687,223	13,426,416	350,524	13,776,941	(152,102)	198,422	13,624,838						
3	**Subtotal - Residential**	**226,466,912**	**$ 128,053,505**	**$ 3,245,864**	**$ 131,299,369**	**$ (1,390,062)**	**$ 1,855,802**	**$ 129,909,306**	**1.4%**	**0.8%**	**-1.1%**	**0.7%**	**0.5%**	**0.6%**
4	SC No. 2S - General Service Sales	61,859,266	25,769,906	589,731	26,359,637	(252,830)	336,901	26,106,807						
5	SC No. 14T - General Service Transportation	72,409,646	24,830,441	648,045	25,478,487	(295,978)	352,067	25,182,508						
6	**Subtotal - General Service**	**134,268,913**	**$ 50,600,347**	**$ 1,237,776**	**$ 51,838,124**	**$ (548,809)**	**$ 688,968**	**$ 51,289,315**	**1.4%**	**0.8%**	**-1.1%**	**1.1%**	**0.2%**	**0.4%**
7	SC No. 5S - Seasonal Gas Cooling	21,449	900	72	972		72	972	8.0%	0.0%	0.0%	8.0%	0.0%	0.0%
8	SC No. 9S - Industrial Manufacturing	65,210	13,226	341	13,567	(144)	197	13,423	1.5%	0.8%	-1.1%	1.7%	0.0%	0.0%
9	SC No. 1T - Large Firm Transportation	88,265,078	8,318,472	441,016	8,759,488	(77,915)	363,101	8,681,573	4.4%	0.8%	-0.9%	4.0%	0.0%	0.5%
10	SC No. 5T - Small Firm Transportation	27,536,404	5,790,429	176,331	5,966,760	(62,292)	114,039	5,904,468	2.0%	0.8%	-1.1%	1.8%	0.0%	0.4%
11	**Total Firm classes to which increase is spread**	**476,623,966**	**$ 192,776,879**	**$ 5,101,400**	**$ 197,878,279**	**$ (2,079,222)**	**$ 3,022,179**	**$ 195,799,057**	**1.6%**	**0.8%**	**-1.1%**	**1.0%**	**0.4%**	**0.5%**
12	Interruptible associated with SC 1T	24,008,830	1,898,935			1,994,939	96,004	1,994,939						
13	Interruptible associated with SC5T	705,959	82,677			84,283	1,606	84,283						
14	**Total Firm and Interruptible Revenue**	**$ 501,338,755**	**$ 194,758,491**	**$ 5,101,400**	**$ 197,878,279**	**$ 0**	**$ 3,119,789**	**$ 197,878,279**						

New York State Electric & Gas Corporation
Gas Department
Development of Delivery Revenues
Rate Year May 1, 2022 through April 30, 2023

		A	B	C	D= B plus C	E = D minus A	F=E divided by A
		Delivery Revenue Prior to Delivery Rate Increase (000 $)	Rate Year Delivery Revenue Before Interupptible Allocation (000 $)	Interupptible Revenue Allocation (000 $)	Rate Year Delivery Revenue After Interrubtible Allocation (000 $)	Revenue Increase/ (Decrease) (000 $)	Change (%)
1	SC 1 and SC 13 - Residential Service and Residential Firm Aggregation Transportation Service	130,110,400	134,895,061	(1,466,212)	133,428,849	3,318,449	2.6%
2	SC 2 and SC 14 - General Service and Non-Residential Firm Aggregation Transportation Service	51,405,707	53,010,636	(576,187)	52,434,449	1,028,742	2.0%
3	SC 5 - Seasonal Gas Cooling Service	975	1,047		1,047	72	7.4%
4	SC 9 - Industrial Manufacturing or Processing Purposes	13,426	13,785	(150)	13,635	209	1.6%
5	SC 1 - Firm Transportation Service	8,657,129	9,151,571	(83,580)	9,067,991	410,862	4.7%
6	SC 5 - Small Firm Transportation Service	5,895,026	6,103,445	(65,418)	6,038,027	143,001	2.4%
7	**Total PSC 87, PSC 88 Firm Revenue Firm for Increase (Decrease)**	***$196,082,663***	***$203,175,546***	***($2,191,548)***	***$200,983,998***	***$4,901,336***	**2.5%**
8	Interruptible associated with SC 1T	1,994,939		2,105,249	2,105,249	110,310	
9	Interruptible associated with SC5T	84,283		86,298	86,298	2,015	
10	**Total PSC 87, PSC 88 Firm Revenue Firm for Increase (Decrease) and Interruptible Revenue**	***$198,161,885***	***$203,175,546***	***$0***	***$203,175,546***	***$5,013,661***	
11	Revenue Adjustment	$ (5,756)	$ -			$ 5,756	
12	SC 7 - Firm or Limited Firm Negotiated Transportation Service	2,107,029	2,107,029		2,107,029	-	
13	SC 10 - Non-Residential Distributed Generation Firm Sales Service						
14	SC 11 - Residential Distributed Generation Firm Sales Service						
15	SC 15 - Basic Electric Generation Transportation Service						
16	SC 16 - Non-Residential Distributed Generation Firm Transportation Service						
17	SC 19 - Residential Distributed Generation Firm Transportation Service						
18	**Total PSC 87, PSC 88 Firm and Interruptible Firm**	***$200,263,158***	***$205,282,575***	***$0***	***$205,282,575***	***$5,019,417***	
19	Bill Issuance and Payment Processing (BIPP) Revenue	1,796,537	1,796,537		1,796,537	-	
20	**Total PSC 87, PSC 88 and BIPP Revenue**	***202,059,695***	***207,079,112***	***0***	***207,079,112***	***5,019,417***	
	Other Delivery Revenue Adjustments:						
21	Economic Development Discounts --- NYSERDA Surcharge	43	43		43	-	
22	Merchant Function Charge	3,375,625	3,375,625		3,375,625	-	
23	R&D Revenues	649,972	649,972		649,972	-	
24	Revenue Taxes	3,484,008	3,733,480		3,733,480	249,471	
25	Levelization Deferral	$638,876	$ 638,876		$638,876	-	
26	**Total Retail Revenue**	***210,208,219***	***215,477,107***	***0***	***215,477,107***	***5,268,888***	**2.5%**

New York State Electric & Gas Corporation
Gas Department
Revenue Allocation
Rate Year May 1, 2022 through April 30, 2023

1	Current Delivery Revenue with forecasted billing determinants	**$ 196,082,663**
2	Total Proposed Delivery Increase (Decrease)	**$ 5,019,417**
3	EE Tracker Moved to Delivery	**1,899,400**
4	AMI Investment	**1,373,757**
5	AMI IT Costs	**2,114,361**
6	Net Delivery Revenue Increase (Decrease)	**(368,100)**
7	Less: Change in BIPP Revenue	-
8	Less: Change in MFC Revenue	-
9	Plus: Interruptible Revenue Adjustment	2,079,222
10	Plus: Adj to Match RR (Units & Rates Differences)	633,120
11	Residual Delivery Revenue Increase (Decrease)	**2,344,241**
12	Total Proposed Revenue (at overall increase or decrease)	**$203,814,422**

										Detail of Revenue Increase Components				
		A	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**	**K**	**L**	**M**
	PSC 87 and 88 - Gas	Sales (th)	Delivery Revenue Prior to Rate Increase* $	Revenue Requirement Increase/ (Decrease) Before Interruptible Allocation $	Revenue Before Interruptible Allocation $	Interruptible Revenue Allocation $	Revenue Requirement Increase/ (Decrease) After Interruptible Allocation $	Rate Year Delivery Revenues After Interruptible Allocation $	Total Proposed Revenue Percent Change (%)	Total Proposed Revenue Percent Change Residual Only (%)	Total Proposed Revenue Percent Change Interruptible Allocation (%)	Percent of Total Change Attributed to EE Tracker (%)	Percent of Total Change Attributed to AMI Investment in Delivery (%)	Percent of Total Change Attributed to AMI IT Costs (%)
1	SC No.1S - Residential Sales	201,813,439	116,496,724	4,266,534	120,763,258	(1,305,776)	2,960,758	119,457,483						
2	SC No. 13T - Residential Transportation	24,691,556	13,613,676	518,127	14,131,803	(160,436)	357,691	13,971,367						
3	**Subtotal - Residential**	**226,504,995**	**$ 130,110,400**	**$ 4,784,661**	**$ 134,895,061**	**$ (1,466,212)**	**$ 3,318,449**	**$ 133,428,849**	**2.6%**	**0.9%**	**-1.1%**	**0.7%**	**0.9%**	**1.2%**
4	SC No. 2S - General Service Sales	62,005,597	26,271,188	762,103	27,033,291	(265,548)	496,555	26,767,743						
5	SC No. 14T - General Service Transportation	72,527,869	25,134,519	842,826	25,977,345	(310,639)	532,187	25,666,706						
6	**Subtotal - General Service**	**134,533,466**	**$ 51,405,707**	**$ 1,604,929**	**$ 53,010,636**	**$ (576,187)**	**$ 1,028,742**	**$ 52,434,449**	**2.0%**	**0.9%**	**-1.1%**	**1.1%**	**0.3%**	**0.9%**
7	SC No. 5S - Seasonal Gas Cooling	21,526	975	72	1,047		72	1,047	7.4%	0.0%	0.0%	7.4%	0.0%	0.0%
8	SC No. 9S - Industrial Manufacturing	65,227	13,426	359	13,785	(150)	209	13,635	1.6%	0.9%	-1.1%	1.7%	0.0%	0.1%
9	SC No. 1T - Large Firm Transportation	88,314,959	8,657,129	494,442	9,151,571	(83,580)	410,862	9,067,991	4.7%	0.9%	-1.0%	3.9%	0.0%	1.0%
10	SC No. 5T - Small Firm Transportation	27,520,942	5,895,026	208,419	6,103,445	(65,418)	143,001	6,038,027	2.4%	0.9%	-1.1%	1.8%	0.0%	0.8%
11	**Total classes to which increase is spread**	**476,961,114**	**$ 196,082,663**	**$ 7,092,883**	**$ 203,175,546**	**$ (2,191,548)**	**$ 4,901,336**	**$ 200,983,998**	**2.5%**	**0.9%**	**-1.1%**	**1.0%**	**0.7%**	**1.1%**
12	Interruptible associated with SC 1T	24,008,830	1,994,939			2,105,249	110,310	2,105,249						
13	Interruptible associated with SC5T	705,959	84,283			86,298	2,015	86,298						
14	**Total Firm and Interruptible Revenue**	**$ 501,675,903**	**$ 198,161,885**	**$ 7,092,883**	**$ 203,175,546**	**$ 0**	**$ 5,013,661**	**$ 203,175,546**						

Rochester Gas and Electric Corporation
Gas Department
Development of Delivery Revenues
Rate Year May 1, 2020 through April 30, 2021

		A	B	C = B minus A	D = C divided by A
	PSC 16 Service Classifications (SC)	Delivery Revenue Prior to EE Tracker Transfer and Delivery Rate Increase (000 $)	Rate Year Delivery Revenue	Revenue Increase/ (Decrease) (000 $)	Change (%)
1	SC 1 and SC 5 - General Service and Small Transportation Service	$157,802,308	$157,287,123	($515,185)	-0.3%
2	SC 3 - Large Transportation Service	$10,045,630	$9,671,240	($374,390)	-3.7%
3	SC 3HP - Large Transportation Service at High Pressure	$63,892	$61,426	($2,466)	-3.9%
4	Total PSC 16	**$167,911,830**	**$167,019,789**	**($892,041)**	**-0.5%**
5	Bill Issuance and Payment Processing (BIPP) Revenue	1,968,409	$ 1,968,409	$0	
6	Total PSC 16 and BIPP Revenue	169,880,239	168,988,198	(892,041)	
	Other Delivery Revenue Adjustments:				
7	Merchant Function Charge	4,780,157	$4,780,157	$0	
8	R&D Surcharge	314,000	314,000	$0	
9	NYSERDA EE Surcharge	74,009	74,009	$0	
10	Revenue Taxes	3,837,300	3,602,564	($234,736)	
11	**Total Retail Revenue**	**178,885,705**	**177,758,929**	**(1,126,776)**	**-0.6%**

Rochester Gas and Electric Corporation
Gas Department
Revenue Allocation
Rate Year May 1, 2020 through April 30, 2021

		($000)
1	Current Delivery Revenue with forecasted billing determinants	**$167,911,830**
2	Total Proposed Delivery Increase (Decrease)	($892,041)
3	EE Tracker Moved to Delivery	(1,252,174)
4	AMI Investment	-
5	AMI IT Costs	-
6	Net Delivery Revenue Increase (Decrease)	**360,133**
7	Less: Change in BIPP Revenue	-
8	Less: Change in MFC Revenue	-
9	Residual Delivery Revenue Increase (Decrease)	**360,133**
10	Total Proposed Revenue (at overall increase or decrease)	**$167,019,789**

							Detail of Revenue Increase Components			
		A	B	C	D	E	F	G	H	I
	PSC 16 Service Classification	Sales (th)	Delivery Revenue Prior to Rate Increase* ($000)	Revenue Requirement Increase (Decrease) ($000)	Rate Year Delivery Revenue ($000)	Total Proposed Revenue Percent Change (%)	Total Proposed Revenue Percent Change Residual Only (%)	Percent of Total Change Attributed to EE Tracker (%)	Percent of Total Change Attributed to AMI Investment in Delivery (%)	Percent of Total Change Attributed to AMI IT Costs (%)
1	**SC1** General Service and **SC5** Small Transportation Serviced	383,983,552	157,802,308	(515,185)	157,287,123	-0.3%	0.2%	-0.5%	0.0%	0.0%
2	SC 3 - Large Transportation Service	200,241,009	10,045,630	(374,390)	9,671,240	-3.7%	0.3%	-4.0%	0.0%	0.0%
3	SC 3HP - Large Transportation Service at High Pressure	1,226,911	63,892	(2,466)	61,426	-3.9%	0.2%	-4.0%	0.0%	0.0%
4	**Total**	**585,451,472**	**$167,911,830**	**($892,041)**	**167,019,789**	**-0.5%**	**0.2%**	**-0.7%**	**0.0%**	**0.0%**

*Does Not Includes Energy Efficiency Costs transferred into Delivery Rates

Rochester Gas and Electric Corporation
Gas Department
Development of Delivery Revenues
Rate Year May 1, 2021 through April 30, 2022

		A	B	C = B minus A	D = C divided by A
	PSC 16 Service Classifications (SC)	Delivery & EE Revenue Prior to Delivery Rate Increase ($)	Revenue Increase/ (Decrease) ($)	Change ($)	Change (%)
1	SC 1 and SC 5 - General Service and Small Transportation Service	$158,584,945	$158,959,186	$374,241	0.2%
2	SC 3 - Large Transportation Service	$9,444,939	$9,739,156	$294,217	3.1%
3	SC 3HP - Large Transportation Service at High Pressure	$61,426	$63,338	$1,912	3.1%
4	Total PSC 16	**$168,091,310**	**$168,761,680**	**$670,370**	**0.4%**
5	Revenue Adjustment	*$ 36,749*		*$ (36,749)*	
6	Bill Issuance and Payment Processing (BIPP) Revenue	1,976,509	$ 1,976,509	$0	
7	Total PSC 16 and BIPP Revenue	170,104,568	170,738,189	633,621	
	Other Delivery Revenue Adjustments:				
8	Merchant Function Charge	4,780,157	$4,780,157	$0	
9	R&D Surcharge	314,000	314,000	$0	
10	NYSERDA EE Surcharge	-	-	$0	
11	Revenue Taxes	3,643,764	3,868,837	$225,073	
12	Levelization Deferral	(9,816,042)	(9,816,042)	$0	
13	**Total Retail Revenue**	**$169,026,447**	**$169,885,141**	**$858,694**	**0.5%**

Rochester Gas and Electric Corporation
Gas Department
Revenue Allocation
Forecast Year May 1, 2021 through April 30, 2022

1	Current Delivery Revenue with forecasted billing determinants	**$168,091,310**
2	Total Proposed Delivery Increase (Decrease)	$633,621
3	EE Tracker Moved to Delivery	$989,806
4	AMI Investment	-
5	AMI IT Costs	-
6	Net Delivery Revenue Increase (Decrease)	**(356,185)**
7	Less: Change in BIPP Revenue	-
8	Less: Change in MFC Revenue	-
9	Plus: Adj to Match RR (Units & Rates Differences)	36,749
10	Residual Delivery Revenue Increase (Decrease)	**(319,437)**
11	Total Proposed Revenue (at overall increase or decrease)	**$168,761,680**

		A	B	C	D	E	F	G	H	I
							Detail of Revenue Increase Components			
		Sales (th)	Delivery Revenue Prior to Rate Increase $	Revenue Requirement Increase (Decrease) $	Rate Year Delivery Revenues at Proposed Rates $	Total Proposed Revenue Percent Change (%)	Total Proposed Revenue Percent Change Residual Only (%)	Percent of Total Change Attributed to EE Tracker (%)	Percent of Total Change Attributed to AMI Investment in Delivery (%)	Percent of Total Change Attributed to AMI IT Costs (%)
	PSC 16 Service Classification									
1	**SC1** General Service and **SC5** Small Transportation Serviced	387,858,295	$158,584,945	374,241	158,959,186	0.2%	-0.2%	0.4%	0.0%	0.0%
2	SC 3 - Large Transportation Service	197,149,518	$9,444,939	294,217	9,739,156	3.1%	-0.2%	3.3%	0.0%	0.0%
3	SC 3HP - Large Transportation Service at High Pressure	1,226,911	$61,426	1,912	63,338	3.1%	-0.2%	3.3%	0.0%	0.0%
4	**Total**	**586,234,724**	**$168,091,310**	**$670,370**	**$168,761,680**	**0.4%**	**-0.2%**	**0.6%**	**0.0%**	**0.0%**

Rochester Gas and Electric Corporation
Gas Department
Development of Delivery Revenues
Rate Year May 1, 2022 through April 30, 2023

		A	B	C = B minus A	D = C divided by A
	PSC 16 Service Classifications (SC)	Delivery & EE Revenue Prior to Delivery Rate Increase ($)	Revenue Increase/ (Decrease) ($)	Change ($)	Change (%)
1	SC 1 and SC 5 - General Service and Small Transportation Service	$159,605,548	$162,722,061	$3,116,513	2.0%
2	SC 3 - Large Transportation Service	$9,532,091	$10,005,432	$473,342	5.0%
3	SC 3HP - Large Transportation Service at High Pressure	$63,338	$66,087	$2,750	4.3%
4	Total PSC 16	**$169,200,976**	**$172,793,581**	**$3,592,605**	**2.1%**
5	Revenue Adjustment	*$ 53,604*		*$ (53,604)*	
6	Bill Issuance and Payment Processing (BIPP) Revenue	$1,984,409	$ 1,984,409	$0	
7	Total PSC 16 and BIPP Revenue	171,238,989	174,777,990	3,539,001	
	Other Delivery Revenue Adjustments:				
8	Merchant Function Charge	4,779,857	$4,779,857	$0	
9	R&D Surcharge	314,000	314,000	$0	
10	NYSERDA EE Surcharge	-	-	$0	
11	Revenue Taxes	3,886,037	4,212,590	$326,553	
12	Levelization Deferral	($234,099)	($234,099)	$0	
13	**Total Retail Revenue**	**$179,984,784**	**$183,850,338**	**$3,865,554**	**2.1%**

Rochester Gas and Electric Corporation
Gas Department
Revenue Allocation
Rate Year May 1, 2022 through April 30, 2023

1	Current Delivery Revenue with forecasted billing determinants	**$169,200,976**
2	Total Proposed Delivery Increase (Decrease)	$3,539,001
3	EE Tracker Moved to Delivery	$1,450,664
4	AMI Investment	3,037,365
5	AMI IT Costs	3,486,584
6	Net Delivery Revenue Increase (Decrease)	**(4,435,611)**
7	Less: Change in BIPP Revenue	-
8	Less: Change in MFC Revenue	-
9	Plus: Adj to Match RR (Units & Rates Differences)	53,604
10	Residual Delivery Revenue Increase (Decrease)	**(4,382,007)**
11	Total Proposed Revenue (at overall increase or decrease)	**$172,793,581**

		A	B	C	D	E	F	G	H	I
							Detail of Revenue Increase Components			
		Sales (th)	Delivery Revenue Prior to Rate Increase ($)	Revenue Requirement Increase (Decrease) ($)	Rate Year Delivery Revenues at Proposed Rates ($)	Total Proposed Revenue Percent Change (%)	Total Proposed Revenue Percent Change Residual Only (%)	Percent of Total Change Attributed to EE Tracker (%)	Percent of Total Change Attributed to AMI Investment in Delivery (%)	Percent of Total Change Attributed to AMI IT Costs (%)
	PSC 16 Service Classification									
1	**SC1** General Service and **SC5** Small Transportation Serviced	389,326,391	$159,605,548	3,116,513	162,722,061	2.0%	-2.6%	0.6%	1.9%	2.0%
2	SC 3 - Large Transportation Service	197,433,092	$9,532,091	473,342	10,005,432	5.0%	-2.6%	4.8%	0.0%	2.7%
3	SC 3HP - Large Transportation Service at High Pressure	1,226,911	$63,338	2,750	66,087	4.3%	-2.6%	4.7%	0.0%	2.2%
4	**Total**	**587,986,394**	**$169,200,976**	**$3,592,605**	**$172,793,581**	**2.1%**	**-2.6%**	**0.9%**	**1.8%**	**2.1%**

New York State Electric & Gas Corporation
Rochester Gas and Electric Corporation
Embedded Cost of Service Information for Rate Development

Line					
1	**Information from ECOS Studies**	**Source**			
2					
3	New York State Electric & Gas Corporation BIPP	October 15, 2019 Exhibit RARD-R12		$0.90	Per bill
4					
5	Rochester Gas and Electric Corporation BIPP	October 15, 2019 Exhibit RARD-R12		$0.93	Per bill
6					
7					
8	NYSEG Electric CCCC Expenses	October 15, 2019 Exhibit RARD-R12		$5,788,841	
9	NYSEG Gas CCCC Expenses	October 15, 2019 Exhibit RARD-R12		$1,688,215	
10	RGE Electric CCCC Expenses	October 15, 2019 Exhibit RARD-R12		$1,887,365	
11	RGE Gas CCCC Expenses	October 15, 2019 Exhibit RARD-R12		$2,126,991	
12					
13	NYSEG Electric Admin Expenses	October 15, 2019 Exhibit RARD-R12		$8,811,637	
14	NYSEG Gas Admin Expenses	October 15, 2019 Exhibit RARD-R12		$1,687,410	
15	RGE Electric Admin Expenses	October 15, 2019 Exhibit RARD-R12		$3,671,643	
16	RGE Gas Admin Expenses	October 15, 2019 Exhibit RARD-R12		$2,653,167	
17					
18					
19	**CCCC Fixed Factor Percentage Based on Billed units from Twelve months ending 12/31/2019**				
20	**Determines how much of CCCC will be recovered through POR Discount Rate and how much recovered through MFC rate**				
21		Units			
22	NYSEG Electric MFC	7,239,263,171	91.9%	$5,317,693	
23	NYSEG Electric POR	641,399,488	8.1%	$471,148	
24		7,880,662,659		$5,788,841	
25					
26	NYSEG Gas MFC	278,333,990	94.9%	$1,601,499	
27	NYSEG Gas POR	15,070,845	5.1%	$86,716	
28		293,404,835		$1,688,215	
29					
30	RGE Electric MFC	2,959,521,617	92.8%	$1,751,910	
31	RGE Electric POR	228,826,434	7.2%	$135,455	
32		3,188,348,051		$1,887,365	
33					
34	RGE Gas MFC	307,670,446	95.3%	$2,027,558	
35	RGE Gas POR	15,088,406	4.7%	$99,433	
		322,758,852		2,126,991	

Note:
BIPP = Bill Issuance and Payment Processing Charge
CCCC = Credit and Collection and Call Center Expenses

Gas Rate Plan Rates and Bill Impacts

Index of Schedules

New York State Electric & Gas Corporation
Gas Department
Retail Delivery Rates
Comparison of Current, Rate Year 1, Rate Year 2 and Rate Year 3 Rates
PSC 87 Service Classifications 1, 2, 5, and 9 Sales
PSC 88 Service Classifications 1, 5, 13, and 14 Transportation
Interruptible Service Classifications 1T and 5T

			Current RATES				RY1 - 5/1/20 to 4/30/21 RATES				RY2 - 5/1/21 to 4/30/22 RATES				RY3 - 5/1/22 to 4/30/23 RATES			
			Customer Charge Without Sales Status Reserved	Customer Charge With Sales Status Reserved	Volumetric Rate Without Sales Status Reserved	Volumetric Rate With Sales Status Reserved	Customer Charge Without Sales Status Reserved	Customer Charge With Sales Status Reserved	Volumetric Rate Without Sales Status Reserved	Volumetric Rate With Sales Status Reserved	Customer Charge Without Sales Status Reserved	Customer Charge With Sales Status Reserved	Volumetric Rate Without Sales Status Reserved	Volumetric Rate With Sales Status Reserved	Customer Charge Without Sales Status Reserved	Customer Charge With Sales Status Reserved	Volumetric Rate Without Sales Status Reserved	Volumetric Rate With Sales Status Reserved
SC1S / SC13T (Res Agg) HEAT																		
Basic Service Charge			$16.30				$16.30				$17.30				$18.30			
	0	3			$0.00000				$0.00000				$0.00000				$0.00000	
	4	50			$0.67803				$0.67844				$0.67007				$0.67375	
	Over	50			$0.15947				$0.15957				$0.15760				$0.15846	
SC1S / SC13T (Res Agg) NON-HEAT																		
Basic Service Charge			$12.30				$12.30				$13.30				$14.30			
	0	3			$0.00000				$0.00000				$0.00000				$0.00000	
	4	50			$0.67803				$0.67844				$0.67007				$0.67375	
	Over	50			$0.15947				$0.15957				$0.15760				$0.15846	
SC2S / SC14T (Non-Res Agg) RATES																		
Basic Service Charge			$23.60	$23.93			$23.60	$23.93			$24.60	$24.93			$25.60	$25.93		
	0	3			$0.00000				$0.00000				$0.00000				$0.00000	
	4	500			$0.41754	$0.52864			$0.41487	$0.52597			$0.41792	$0.52902			$0.42434	$0.53544
	501	15,000			$0.24264	$0.35374			$0.24109	$0.35219			$0.24286	$0.35396			$0.24659	$0.35769
	Over	15,000			$0.15051	$0.26161			$0.14955	$0.26065			$0.15065	$0.26175			$0.15296	$0.26406
SC5S Seasonal Gas Cooling																		
Basic Service Charge			$16.86				$16.86				$16.86				$16.86			
	0	3			$0.00000				$0.00000				$0.00000				$0.00000	
	Over	3			$0.03902				$0.03782				$0.04125				$0.04467	
SC9S Industrial (Binghamton Only)																		
Basic Service Charge			$352.77				$352.77				$352.77				$352.77			
	0	500			$0.00000				$0.00000				$0.00000				$0.00000	
	501	15,000			$0.15540				$0.15380				$0.15717				$0.16075	
	Over	15,000			$0.12000				$0.11982				$0.11932				$0.11890	
SC1T RATES (All areas)																		
Basic Service Charge			$1,723.55	$1,779.10			$2,154.44	$2,209.99			$2,337.75	$2,393.30			$2,553.40	$2,608.95		
	0	500			$0.00000				$0.00000				$0.00000				$0.00000	
	501	15,000			$0.13843	$0.24953			$0.12709	$0.23819			$0.13081	$0.24191			$0.13491	$0.24601
	15,001	50,000			$0.07490	$0.18600			$0.06876	$0.17986			$0.07078	$0.18188			$0.07299	$0.18409
	Over	50,000			$0.05752	$0.16862			$0.05281	$0.16391			$0.05435	$0.16545			$0.05606	$0.16716
SC5T RATES																		
Basic Service Charge			$357.39	$412.94			$357.39	$412.94			$357.39	$412.94			$357.39	$412.94		
	0	500			$0.00000				$0.00000				$0.00000				$0.00000	
	501	15,000			$0.18549	$0.29659			$0.18358	$0.29468			$0.18840	$0.29950			$0.19444	$0.30554
	Over	15,000			$0.11349	$0.22459			$0.11232	$0.22342			$0.11527	$0.22637			$0.11897	$0.23007
Interruptible Class 1T RATES																		
Basic Service Charge							$2,154.44				$2,337.75				$2,553.40			
	0	500							$0.00000				$0.00000				$0.00000	
	501	15,000							$0.08896				$0.09157				$0.09443	
	15,001	50,000							$0.04813				$0.04954				$0.05110	
	Over	50,000							$0.03697				$0.03805				$0.03924	
Interruptible Class 5T RATES							$357.39				$357.39				$357.39			
Basic Service Charge									$0.00000				$0.00000				$0.00000	
	0	500							$0.12851				$0.13188				$0.13611	
	501	15,000							$0.07863				$0.08069				$0.08328	
	Over	15,000																

New York State Electric & Gas Corporation
Gas Department
Comparison of Current, Rate Year 1, Rate Year 2 and Rate Year 3 Rates
PSC 87 Service Classifications 10 and 11 Sales
PSC 88 Service Classifications 16 and 19 Transportation

		Current RATES				RY1 - 5/1/20 to 4/30/21 RATES				RY2 - 5/1/21 to 4/30/22 RATES				RY3 - 5/1/22 to 4/30/23 RATES			
		Winter (Nov-Mar)		*Summer (Apr-Oct)*		*Winter (Nov-Mar)*		*Summer (Apr-Oct)*		*Winter (Nov-Mar)*		*Summer (Apr-Oct)*		*Winter (Nov-Mar)*		*Summer (Apr-Oct)*	
		Customer Charge	Volumetric Rate	Customer Charge	Volumetric Rate	Customer Charge	Volumetric Rate	Customer Charge	Volumetric Rate	Customer Charge	Volumetric Rate	Customer Charge	Volumetric Rate	Customer Charge	Volumetric Rate	Customer Charge	Volumetric Rate
SC10/SC16 NON-RESIDENTIAL DISTRIBUTED GENERATION FIRM SALES RATES																	
A. Non-residential Small DG Customer with DG < 5MW Usage																	
1) Using 1 to 40,000 therms/year																	
0	3	$23.60	$0.00000	$23.60	$0.00000	$23.60	$0.00000	$23.60	$0.00000	$24.60	$0.00000	$24.60	$0.00000	$25.60	$0.00000	$25.60	$0.00000
4	500		$0.20349		$0.17408		$0.20735		$0.17615		$0.20939		$0.17789		$0.21401		$0.18181
501	15,000		$0.11700		$0.10116		$0.11850		$0.10236		$0.11967		$0.10337		$0.12231		$0.10565
15,001	1,000,000		$0.07316		$0.06275		$0.07478		$0.06350		$0.07552		$0.06412		$0.07719		$0.06554
2. Using 40,001 to 250,000 therms/year																	
0	3	$357.39	$0.00000	$357.39	$0.00000	$357.39	$0.00000	$357.39	$0.00000	$357.39	$0.00000	$357.39	$0.00000	$357.39	$0.00000	$357.39	$0.00000
4	15,000		$0.09867		$0.08454		$0.10271		$0.08724		$0.10569		$0.08977		$0.10985		$0.09329
15,001	1,000,000		$0.05965		$0.05173		$0.06321		$0.05338		$0.06505		$0.05492		$0.06761		$0.05708
3. Using > 250,000 therms/year																	
0	500	$1,723.55	$0.00000	$1,723.55	$0.00000	$2,154.44	$0.00000	$2,154.44	$0.00000	$2,337.76	$0.00000	$2,337.76	$0.00000	$2,553.18	$0.00000	$2,553.18	$0.00000
500	15,000		$0.12518		$0.09973		$0.12028		$0.09542		$0.12413		$0.09848		$0.12895		$0.10229
15,001	50,000		$0.06556		$0.05396		$0.06343		$0.05163		$0.06547		$0.05328		$0.06800		$0.05535
50,001	1,000,000		$0.05025		$0.04144		$0.04862		$0.03965		$0.05018		$0.04092		$0.05213		$0.04250
B. Large DG Customers - DG 5 MW - < 50 MW																	
0	500	$1,723.55	$0.00000	$1,723.55	$0.00000	$2,154.44	$0.00000	$2,154.44	$0.00000	$2,337.76	$0.00000	$2,337.76	$0.00000	$2,553.18	$0.00000	$2,553.18	$0.00000
Demand Charge per therm of MDQ > 23 therms:			$1.15000		$1.15000		$0.99000		$0.99000		$1.02000		$1.02000		$1.06000		$1.06000
Usage Charge per therm of All therms over 500			$0.01742		$0.01427		$0.01619		$0.01314		$0.01671		$0.01356		$0.01736		$0.01408

SC11/SC19 RESIDENTIAL DISTRIBUTED GENERATION FIRM SALES RATES		Current RATES		RY1 RATES		RY2 RATES		RY3 RATES	
		Customer Charge	Volumetric Rate	Customer Charge	Volumetric Rate	Customer Charge	Volumetric Rate	Customer Charge	Volumetric Rate
0	3	$16.30	$0.00000	$16.30	$0.00000	$17.30	$0.00000	$18.30	$0.00000
4	30,000		$0.22585		$0.22546		$0.22340		$0.22660

Rochester Gas and Electric Corporation
Gas Department
Comparison of Current, Rate Year 1, Rate Year 2 and Rate Year 3 Rates
PSC 16 Service Classifications 1, 3, 5 and SC16 Interruptible

		CURRENT RATES		RY1 5/1/2020-4/30/2021 RATES		RY2 5/1/2021-4/30/2022 RATES		RY3 5/1/2022-4/30/2023 RATES	
		Customer Charge	Volumetric Rate	Customer Charge	Volumetric Rate	Customer Charge	Volumetric Rate	Customer Charge	Volumetric Rate
SC1 & SC5 RATES									
0	3	$16.30	$0.00000	$16.30	$0.00000	$17.30	$0.00000	$18.30	$0.00000
4	100		$0.28838		$0.28682		$0.27644		$0.27422
101	500		$0.26881		$0.26736		$0.25768		$0.25561
501	1,000		$0.23961		$0.23832		$0.22969		$0.22784
1,001	30,000		$0.10204		$0.10149		$0.09782		$0.09703
SC3 RATES									
0	1,000	$1,479.53	$0.00000	$1,849.41	$0.00000	$1,984.52	$0.00000	$2,239.18	$0.00000
1,001	30,000		$0.06153		$0.04656		$0.04577		$0.04372
30,001	100,000		$0.04915		$0.03719		$0.03656		$0.03493
100,001	1,000,000		$0.01902		$0.01439		$0.01415		$0.01352
1,000,001	10,000,000		$0.00894		$0.00676		$0.00665		$0.00635
SC3HP RATES									
0	1,000	$1,550.00	$0.00000	$1,552.60	$0.00000	$1,600.92	$0.00000	$1,670.42	$0.00000
1,001	30,000		$0.03728		$0.03522		$0.03632		$0.03790
30,001	100,000		$0.03728		$0.03522		$0.03632		$0.03790
100,001	1,000,000		$0.03728		$0.03522		$0.03632		$0.03790
1,000,001	10,000,000		$0.00964		$0.00966		$0.00964		$0.00940
SC16 Interruptible RATES									
0	1,000	$1,183.62	$0.00000	$1,849.41	$0.00000	$1,984.52	$0.00000	$2,239.18	$0.00000
1,001	30,000		$0.05461		$0.03259		$0.03204		$0.03061
30,001	100,000		$0.04217		$0.02603		$0.02559		$0.02445
100,001	1,000,000		$0.01204		$0.01007		$0.00990		$0.00946
1,000,001	10,000,000		$0.00212		$0.00474		$0.00466		$0.00445

Rochester Gas and Electric Corporation
Gas Department
Comparison of Current and Proposed Rates
PSC 16 Service Classifications 6, 7, 8, and 9

		CURRENT RATES				RY1 5/1/2020-4/30/2021 RATES				RY2 5/1/2021-4/30/2022 RATES				RY3 5/1/2022-4/30/2023 RATES			
		Winter (Nov-Mar)		*Summer (Apr-Oct)*		*Winter (Nov-Mar)*		*Summer (Apr-Oct)*		*Winter (Nov-Mar)*		*Summer (Apr-Oct)*		*Winter (Nov-Mar)*		*Summer (Apr-Oct)*	
		Customer Charge	Volumetric Rate	Customer Charge	Volumetric Rate	Customer Charge	Volumetric Rate	Customer Charge	Volumetric Rate	Customer Charge	Volumetric Rate	Customer Charge	Volumetric Rate	Customer Charge	Volumetric Rate	Customer Charge	Volumetric Rate
SC6 & SC7 RATES																	
A. Non-residential Small DG Customer with DG < 5MW and Usage < 35,000 therms																	
0	3	$16.30	$0.00000	$16.30	$0.00000	$16.30	$0.00000	$16.30	$0.00000	$17.30	$0.00000	$17.30	$0.00000	$18.30	$0.00000	$18.30	$0.00000
4	100		$0.12008		$0.10347		$0.12478		$0.10267		$0.11550		$0.09895		$0.11457		$0.09816
101	500		$0.11215		$0.09644		$0.11191		$0.09570		$0.10519		$0.09224		$0.10435		$0.09149
501	1,000		$0.09979		$0.08597		$0.10123		$0.08530		$0.09691		$0.08222		$0.09613		$0.08156
1,001	30,000		$0.04253		$0.03662		$0.04265		$0.03633		$0.04098		$0.03501		$0.04065		$0.03473
B. Non-residential Small DG Customer with DG < 5MW and Usage ≥ 35,000 therms																	
0	1,000	$1,479.53	$0.00000	$1,479.53	$0.00000	$1,849.41	$0.00000	$1,849.41	$0.00000	$1,984.52	$0.00000	$1,984.52	$0.00000	$2,239.18	$0.00000	$2,239.18	$0.00000
1,001	30,000		$0.04699		$0.03942		$0.03431		$0.02861		$0.03411		$0.02812		$0.03257		$0.02687
30,001	100,000		$0.03837		$0.03148		$0.02804		$0.02285		$0.02753		$0.02247		$0.02630		$0.02146
100,001	1,000,000		$0.01461		$0.01218		$0.01094		$0.00884		$0.01055		$0.00869		$0.01008		$0.00830
1,000,001	10,000,000		$0.00769		$0.00573		$0.00562		$0.00416		$0.00512		$0.00409		$0.00490		$0.00390
C. Non-residential Large DG Customer with DG of 5MW to less than 50MW																	
0	1,000	$1,479.53	$0.00000	$1,479.53	$0.00000	$1,849.41	$0.00000	$1,849.41	$0.00000	$1,984.52	$0.00000	$1,984.52	$0.00000	$2,239.18	$0.00000	$2,239.18	$0.00000
1,001	10,000,000		$0.00693		$0.00573		$0.00510		$0.00416		$0.00501		$0.00409		$0.00480		$0.00390
Demand Charge per therm of MDQ > 47 therms:			$0.62		$0.62		$0.25		$0.25		$0.25		$0.25		$0.24		$0.24

		CURRENT RATES		RY1 RATES		RY2 RATES		RY3 RATES	
SC8 & SC9 RATES		Customer Charge	Volumetric Rate	Customer Charge	Volumetric Rate	Customer Charge	Volumetric Rate	Customer Charge	Volumetric Rate
0	3	$16.30	$0.00000	$16.30	$0.00000	$17.30	$0.00000	$18.30	$0.00000
4	30,000		$0.11736		$0.14042		$0.13541		$0.13429

New York State Electric & Gas Corporation
Gas Rates
Monthly Total Bill Impact - May 1, 2020 - April 30, 2021
PSC No. 87 Service Classification No. 1 – Residential Sales Service

Heating

			increase / (decrease)		Number of Customers		Number of Low Income Customers		Percent of Customers	Percent of Low Income Customers	Amount of EE Embedded in Delivery Rates	
Therms	**Current Rates**	**RY 1**	**Amount**	**Percent**	**January**	**July**	**January**	**July**	**January**	**January**	**Amount**	**Percent**
3	$18.22	$18.31	$0.09	0.5%	825	16,166	94	2,471	0.4%	0.3%	$ -	0.00%
10	$25.57	$25.65	$0.08	0.3%	1,706	51,791	238	7,283	0.8%	0.8%	$ (0.00)	-0.02%
20	$36.07	$36.13	$0.07	0.2%	2,386	70,243	382	8,776	1.2%	1.3%	$ (0.01)	-0.03%
30	$46.56	$46.62	$0.06	0.1%	2,649	38,798	396	4,847	1.3%	1.4%	$ (0.02)	-0.04%
40	$57.06	$57.10	$0.05	0.1%	2,948	14,670	446	1,809	1.4%	1.5%	$ (0.02)	-0.04%
50	$67.55	$67.59	$0.04	0.1%	3,212	5,510	538	654	1.5%	1.9%	$ (0.03)	-0.04%
60	$72.86	$72.88	$0.02	0.0%	3,314	2,422	593	272	1.6%	2.1%	$ (0.03)	-0.04%
70	$78.17	$78.18	$0.01	0.0%	4,141	1,373	725	137	2.0%	2.5%	$ (0.03)	-0.04%
80	$83.48	$83.47	($0.00)	0.0%	4,736	903	805	99	2.3%	2.8%	$ (0.03)	-0.04%
90	$88.79	$88.77	($0.02)	0.0%	5,602	571	967	45	2.7%	3.4%	$ (0.04)	-0.04%
100	$94.10	$94.07	($0.03)	0.0%	6,128	460	1,066	45	3.0%	3.7%	$ (0.04)	-0.04%
125	$107.37	$107.31	($0.07)	-0.1%	19,875	1,126	3,086	88	9.6%	10.7%	$ (0.04)	-0.04%
150	$120.64	$120.54	($0.10)	-0.1%	23,125	599	3,394	47	11.2%	11.8%	$ (0.04)	-0.04%
175	$133.92	$133.78	($0.13)	-0.1%	24,139	348	3,273	26	11.6%	11.4%	$ (0.05)	-0.04%
200	$147.19	$147.02	($0.17)	-0.1%	22,189	191	2,915	15	10.7%	10.1%	$ (0.05)	-0.04%
250	$173.74	$173.50	($0.24)	-0.1%	33,946	311	4,197	19	16.4%	14.6%	$ (0.06)	-0.03%
300	$200.29	$199.98	($0.31)	-0.2%	20,297	152	2,560	13	9.8%	8.9%	$ (0.07)	-0.03%
350	$226.83	$226.46	($0.37)	-0.2%	11,266	103	1,400	5	5.4%	4.9%	$ (0.07)	-0.03%
400	$253.38	$252.94	($0.44)	-0.2%	6,077	56	796	4	2.9%	2.8%	$ (0.08)	-0.03%
500	$306.47	$305.89	($0.58)	-0.2%	5,092	77	614	7	2.5%	2.1%	$ (0.10)	-0.03%
750	$439.21	$438.29	($0.92)	-0.2%	2,704	59	277	7	1.3%	1.0%	$ (0.13)	-0.03%
1,000	$571.94	$570.68	($1.27)	-0.2%	488	26	24	2	0.2%	0.1%	$ (0.17)	-0.03%
1,500	$837.41	$835.46	($1.95)	-0.2%	315	19	14	1	0.2%	0.0%	$ (0.25)	-0.03%
2,000	$1,102.88	$1,100.25	($2.64)	-0.2%	114	3	3	0	0.1%	0.0%	$ (0.32)	-0.03%
3,000	$1,633.82	$1,629.82	($4.01)	-0.2%	75	6	2	1	0.0%	0.0%	$ (0.47)	-0.03%
5,000	$2,695.71	$2,688.96	($6.75)	-0.3%	41	4	0	0	0.0%	0.0%	$ (0.77)	-0.03%
					207,391		28,806					

Billing Determinants				
		Current Rates	**RY 1**	
	UOM	**SC1 - Heating**	**SC1 - Heating**	
First 3 therms	Monthly	$ 16.30	$ 16.30	
Next 47 therms	Next 47 therms	$ 0.72809	$ 0.67844	$ (0.00265) EE Tracker
Over 50 therms	Over 50 therms	$ 0.17105	$ 0.15957	$ (0.00062) EE Tracker
Tax Credit - Next 47 therms	Next 47 therms	$ (0.05006)	$ -	
Tax Credit - Over 50 therms	Over 50 therms	$ (0.01158)	$ -	
Bill Charge	Monthly	$ 0.81	$ 0.90	
R&D Adjustment	Therm	$ 0.00138	$ 0.00138	
Transition Charge	Therm	$ 0.01185	$ 0.01185	
SBC - CEF NYSERDA	Therm	$ 0.00020	$ 0.00020	
SBC - EE Tracker	Therm	$ 0.00147	$ -	
GRT - Delivery	%	0.00%	0.00%	
Gas Supply Charge	Therm	$ 0.33795	$ 0.33795	
MFC	Therm	$ 0.01863	$ 0.01863	

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.
3. Low Income customers represent customers who participated in the Company's low income program and received a credit on their bill each month during calendar year 2018.

New York State Electric & Gas Corporation
Gas Rates
Annual Total Bill Impact - May 1, 2020 - April 30, 2021
PSC No. 87 Service Classification No. 1 – Residential Sales Service

Heating

Month	Therms	Current Rates	RY 1	increase / (decrease) Amount	increase / (decrease) Percent
Jan	180	$136.57	$136.43	($0.14)	-0.1%
Feb	156	$123.83	$123.72	($0.11)	-0.1%
March	139	$114.80	$114.72	($0.09)	-0.1%
April	70	$78.17	$78.18	$0.01	0.0%
May	27	$43.41	$43.47	$0.06	0.1%
June	20	$36.07	$36.13	$0.07	0.2%
July	16	$31.87	$31.94	$0.07	0.2%
August	28	$44.46	$44.52	$0.06	0.1%
September	27	$43.41	$43.47	$0.06	0.1%
October	51	$68.08	$68.12	$0.04	0.1%
November	106	$97.28	$97.24	($0.04)	0.0%
December	160	$125.95	$125.84	($0.11)	-0.1%
Annual Totals	**980**	**$943.92**	**$943.80**	**($0.12)**	**0.0%**

Billing Determinants	UOM	Current Rates SC1 - Heating	RY 1 SC1 - Heating
First 3 therms	Monthly	$ 16.30	$ 16.30
Next 47 therms	Next 47 therms	$ 0.72809	$ 0.67844
Over 50 therms	Over 50 therms	$ 0.17105	$ 0.15957
Tax Credit - Next 47 therms	Next 47 therms	$ (0.05006)	$ -
Tax Credit - Over 50 therms	Over 50 therms	$ (0.01158)	$ -
Bill Charge	Monthly	$ 0.81	$ 0.90
R&D Adjustment	Therm	$ 0.00138	$ 0.00138
Transition Charge	Therm	$ 0.01185	$ 0.01185
SBC - CEF NYSERDA	Therm	$ 0.00020	$ 0.00020
SBC - EE Tracker	Therm	$ 0.00147	$ -
GRT - Delivery	%	0.00%	0.00%
Gas Supply Charge	Therm	$ 0.33795	$ 0.33795
MFC	Therm	$ 0.01863	$ 0.01863

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

New York State Electric & Gas Corporation
Gas Rates
Annual Total Bill Impact - May 1, 2020 - April 30, 2021
PSC No. 87 Service Classification No. 1 – Residential Sales Service

Non-Heating

				increase / (decrease)	
Month	**Therms**	**Current Rates**	**RY 1**	**Amount**	**Percent**
Jan	42	$55.15	$55.20	$0.05	0.1%
Feb	43	$56.20	$56.25	$0.04	0.1%
March	41	$54.11	$54.15	$0.05	0.1%
April	37	$49.91	$49.96	$0.05	0.1%
May	23	$35.21	$35.28	$0.07	0.2%
June	15	$26.82	$26.89	$0.07	0.3%
July	10	$21.57	$21.65	$0.08	0.4%
August	10	$21.57	$21.65	$0.08	0.4%
September	12	$23.67	$23.75	$0.08	0.3%
October	13	$24.72	$24.80	$0.08	0.3%
November	24	$36.26	$36.33	$0.06	0.2%
December	39	$52.01	$52.05	$0.05	0.1%
Annual Totals	**309**	**$457.21**	**$457.96**	**$0.75**	**0.2%**

Billing Determinants			
		Current Rates	**RY 1**
	UOM	**SC1 - Non Heating**	**SC1 - Non Heating**
First 3 therms	Monthly	$ 12.30	$ 12.30
Next 47 therms	Next 47 therms	$ 0.72809	$ 0.67844
Over 50 therms	Over 50 therms	$ 0.17105	$ 0.15957
Tax Credit - Next 47 therms	Next 47 therms	$ (0.05006)	$ -
Tax Credit - Over 50 therms	Over 50 therms	$ (0.01158)	$ -
Bill Charge	Monthly	$ 0.81	$ 0.90
R&D Adjustment	Therm	$ 0.00138	$ 0.00138
Transition Charge	Therm	$ 0.01185	$ 0.01185
SBC - CEF NYSERDA	Therm	$ 0.00020	$ 0.00020
SBC - EE Tracker	Therm	$ 0.00147	$ -
GRT - Delivery	%	0.00%	0.00%
Gas Supply Charge	Therm	$ 0.33795	$ 0.33795
MFC	Therm	$ 0.01863	$ 0.01863

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

New York State Electric & Gas Corporation
Gas Rates
Monthly Total Bill Impact - May 1, 2020 - April 30, 2021
PSC No. 87 Service Classification No. 2 - General Sales Service

Therms	Current Rates	RY 1	increase / (decrease) Amount	increase / (decrease) Percent	Number of Customers January	Number of Customers July
3	$25.51	$25.59	$0.09	0.3%	359	3,585
10	$30.98	$31.04	$0.06	0.2%	531	5,012
20	$38.81	$38.83	$0.02	0.0%	450	3,688
50	$62.29	$62.18	($0.11)	-0.2%	1,421	5,257
100	$101.43	$101.11	($0.32)	-0.3%	2,283	2,092
150	$140.56	$140.04	($0.52)	-0.4%	2,337	859
200	$179.70	$178.97	($0.73)	-0.4%	2,071	469
250	$218.83	$217.90	($0.94)	-0.4%	1,827	314
300	$257.97	$256.82	($1.14)	-0.4%	1,592	279
350	$297.10	$295.75	($1.35)	-0.5%	1,335	197
400	$336.24	$334.68	($1.56)	-0.5%	1,121	162
500	$414.51	$412.53	($1.97)	-0.5%	1,648	252
750	$566.46	$563.73	($2.73)	-0.5%	2,447	373
1,000	$718.41	$714.92	($3.48)	-0.5%	1,223	160
1,250	$870.36	$866.12	($4.24)	-0.5%	708	85
1,500	$1,022.31	$1,017.31	($4.99)	-0.5%	498	47
2,000	$1,326.21	$1,319.70	($6.51)	-0.5%	562	53
3,000	$1,934.01	$1,924.48	($9.53)	-0.5%	465	27
5,000	$3,149.60	$3,134.03	($15.57)	-0.5%	326	14
10,000	$6,188.60	$6,157.92	($30.68)	-0.5%	177	9
15,000	$9,227.60	$9,181.81	($45.79)	-0.5%	50	4
20,000	$11,805.94	$11,747.99	($57.95)	-0.5%	18	3
30,000	$16,962.64	$16,880.37	($82.27)	-0.5%	19	3
50,000	$27,276.02	$27,145.12	($130.91)	-0.5%	3	0
75,000	$40,167.76	$39,976.05	($191.71)	-0.5%	3	0
100,000	$53,059.49	$52,806.98	($252.51)	-0.5%	1	0

Billing Determinants	UOM	Current Rates SC2	RY 1 SC2
First 3 therms	Monthly	$ 23.60	$ 23.60
Next 497 therms	Next 497 therms	$ 0.43958	$ 0.41487
Next 14,500 therms	Next 14,500 therms	$ 0.25323	$ 0.24109
Over 15,000 therms	Over 15,000 therms	$ 0.15577	$ 0.14955
Tax Credit - Next 497 therms	Next 497 therms	$ (0.02204)	$ -
Tax Credit - Next 14,500 therms	Next 14,500 therms	$ (0.01059)	$ -
Tax Credit - Over 15,000 therms	Over 15,000 therms	$ (0.00526)	$ -
Bill Charge	Monthly	$ 0.81	$ 0.90
R&D Adjustment	Therm	$ 0.00138	$ 0.00138
Transition Charge	Therm	$ 0.01185	$ 0.01185
SBC - CEF NYSERDA	Therm	$ 0.00020	$ 0.00020
SBC - EE Tracker	Therm	$ 0.00147	$ -
GRT - Delivery	%	0.00%	0.00%
Gas Supply Charge	Therm	$ 0.33591	$ 0.33591
MFC	Therm	$ 0.01437	$ 0.01437

Notes:

1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

New York State Electric & Gas Corporation
Gas Rates
Annual Total Bill Impact - May 1, 2020 - April 30, 2021
PSC No. 87 Service Classification No. 2 - General Sales Service

Month	Therms	Current Rates	RY 1	increase / (decrease) Amount	Percent
Jan	529	$432.13	$430.07	($2.06)	-0.5%
Feb	463	$385.55	$383.73	($1.82)	-0.5%
March	404	$339.37	$337.79	($1.57)	-0.5%
April	225	$199.26	$198.43	($0.83)	-0.4%
May	106	$106.12	$105.78	($0.34)	-0.3%
June	55	$66.21	$66.08	($0.13)	-0.2%
July	60	$70.12	$69.97	($0.15)	-0.2%
August	91	$94.38	$94.11	($0.28)	-0.3%
September	73	$80.29	$80.09	($0.20)	-0.3%
October	154	$143.69	$143.15	($0.54)	-0.4%
November	269	$233.70	$232.69	($1.02)	-0.4%
December	466	$387.90	$386.06	($1.83)	-0.5%
Annual Totals	**2,895**	**$2,538.73**	**$2,527.96**	**($10.77)**	**-0.4%**

Billing Determinants	UOM	Current Rates SC2	RY 1 SC2
First 3 therms	Monthly	$ 23.60	$ 23.60
Next 497 therms	Next 497 therms	$ 0.43958	$ 0.41487
Next 14,500 therms	Next 14,500 therms	$ 0.25323	$ 0.24109
Over 15,000 therms	Over 15,000 therms	$ 0.15577	$ 0.14955
Tax Credit - Next 497 therms	Next 497 therms	$ (0.02204)	$ -
Tax Credit - Next 14,500 therms	Next 14,500 therms	$ (0.01059)	$ -
Tax Credit - Over 15,000 therms	Over 15,000 therms	$ (0.00526)	$ -
Bill Charge	Monthly	$ 0.81	$ 0.90
R&D Adjustment	Therm	$ 0.00138	$ 0.00138
Transition Charge	Therm	$ 0.01185	$ 0.01185
SBC - CEF NYSERDA	Therm	$ 0.00020	$ 0.00020
SBC - EE Tracker	Therm	$ 0.00147	$ -
GRT - Delivery	%	0.00%	0.00%
Gas Supply Charge	Therm	$ 0.33591	$ 0.33591
MFC	Therm	$ 0.01437	$ 0.01437

Notes:

1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

New York State Electric & Gas Corporation
Gas Rates
Monthly Total Bill Impact - May 1, 2020 - April 30, 2021
PSC No. 87 Service Classification No. 9 - Industrial Manufacturing or Processing Purposes Sales Service

			increase / (decrease)		Number of Customers	
Therms	**Current Rates**	**RY 1**	**Amount**	**Percent**	**January**	**July**
-	$353.58	$353.67	$0.09	0.0%		
500	$512.43	$511.78	($0.64)	-0.1%	0	0
750	$630.70	$629.29	($1.41)	-0.2%	0	0
1,000	$748.97	$746.79	($2.18)	-0.3%	0	0
1,250	$867.24	$864.30	($2.94)	-0.3%	0	0
1,500	$985.52	$981.80	($3.71)	-0.4%	0	0
2,000	$1,222.06	$1,216.81	($5.25)	-0.4%	0	0
3,000	$1,695.15	$1,686.84	($8.31)	-0.5%	0	0
5,000	$2,641.33	$2,626.88	($14.45)	-0.5%	0	1
10,000	$5,006.78	$4,976.99	($29.80)	-0.6%	1	0
15,000	$7,372.23	$7,327.09	($45.14)	-0.6%	0	0
20,000	$9,560.68	$9,507.31	($53.37)	-0.6%	0	0
30,000	$13,937.58	$13,867.76	($69.83)	-0.5%	0	0
50,000	$22,691.38	$22,588.64	($102.74)	-0.5%	0	0
75,000	$33,633.64	$33,489.75	($143.89)	-0.4%	0	0
100,000	$44,575.89	$44,390.86	($185.03)	-0.4%	0	0

Billing Determinants			
		Current Rates	**RY 1**
	UOM	**SC9**	**SC9**
First 500 Therms	Monthly	$ 352.77	$ 352.77
Next 14,500 therms	Next 14,500 therms	$ 0.17820	$ 0.15380
Over 15,000 therms	Over 15,000 therms	$ 0.12000	$ 0.11982
Tax Credit - Next 14,500 therms	Next 14,500 therms	$ (0.02280)	$ -
Tax Credit - Over 15,000 therms	Over 15,000 therms	$ -	$ -
Bill Charge	Monthly	$ 0.81	$ 0.90
R&D Adjustment	Therm	$ 0.00138	$ 0.00138
Transition Charge	Therm	$ 0.01185	$ 0.01185
SBC - CEF NYSERDA	Therm	$ 0.00020	$ 0.00020
SBC - EE Tracker	Therm	$ 0.00147	$ -
GRT - Delivery	%	0.00%	0.00%
Gas Supply Charge	Therm	$ 0.28844	$ 0.28844
MFC	Therm	$ 0.01437	$ 0.01437

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

New York State Electric & Gas Corporation
Data Sources - NYSEG Gas Bill Impact Statements

Rate	Source of Rate in "Current" Rates	Source of Rate in Rate Years
Basic Service Charge (Non-Heating)	Current Tariff Rates in Effect January 1, 2019 (Last updated 5/1/2018)	New
Basic Service Charge (Heating)	Current Tariff Rates in Effect January 1, 2019 (Last updated 5/1/2018)	New
Usage Charge	Current Tariff Rates in Effect January 1, 2019 (Last updated 5/1/2018)	New
SBC (NYSERDA EE) - per Therm	Current Tariff Rates in Effect January 1, 2020	Current Tariff Rates in Effect January 1, 2020
SBC (EE Tracker) - per Therm	Current Tariff Rates in Effect January 1, 2020	Included in Delivery Rates
Billing Charge per Bill	Current Tariff Rates in Effect January 1, 2019 - (Last Updated 07/01/2016)	Results of 2019 Embedded Cost Study
Usage Charge - Tax Credit	Current Tariff Rates in Effect 10/1/2018	Included in Delivery Rates

	Source of Rate in "Current" Rates and Rate Years
Transition Charge per Therm	Non Weighted Average of Monthly Transition Charge in 2019
R&D Charge per Therm	Current Tariff Rates in Effect January 1, 2020
MFC per Therm	Current Tariff Rates in Effect May 1, 2020
Gas Supply Charge	Non Weighted Average of Monthly GSC in 2019
Customer Count	2018 Billing Information

New York State Electric & Gas Corporation
Gas Rates
Monthly Delivery Bill Impact - May 1, 2020 - April 30, 2021
PSC No. 87 Service Classification No. 1 – Residential Sales Service
PSC No. 88 Service Classification No. 13 - Residential Firm Aggregation Transportation Service

			increase / (decrease)		Number of Customers		Number of Low Income Customers		Percent of Customers	Percent of Low Income Customers	Amount of EE Embedded in Delivery Rates	
Therms	Current Rates	RY 1	Amount	Percent	January	July	January	July	January	January	Amount	Percent
3	$17.16	$17.24	$0.09	0.5%	849	17,340	98	2,589	0.4%	0.3%	$0.00	0.00%
10	$22.01	$22.09	$0.08	0.4%	1,732	57,168	251	7,747	0.8%	0.8%	($0.00)	-0.02%
20	$28.94	$29.01	$0.07	0.2%	2,479	78,018	393	9,309	1.1%	1.3%	($0.01)	-0.04%
30	$35.87	$35.93	$0.06	0.2%	2,763	43,093	421	5,105	1.2%	1.4%	($0.02)	-0.05%
40	$42.80	$42.85	$0.05	0.1%	3,080	16,213	477	1,911	1.3%	1.6%	($0.02)	-0.05%
50	$49.73	$49.77	$0.04	0.1%	3,341	6,060	557	690	1.5%	1.8%	($0.03)	-0.06%
60	$51.48	$51.50	$0.02	0.0%	3,505	2,689	623	284	1.5%	2.0%	($0.03)	-0.06%
70	$53.23	$53.24	$0.01	0.0%	4,440	1,518	772	141	1.9%	2.5%	($0.03)	-0.06%
80	$54.97	$54.97	($0.00)	0.0%	5,083	1,005	853	100	2.2%	2.8%	($0.03)	-0.06%
90	$56.72	$56.70	($0.02)	0.0%	6,050	655	1023	47	2.6%	3.4%	($0.04)	-0.06%
100	$58.47	$58.43	($0.03)	-0.1%	6,802	524	1139	48	3.0%	3.7%	($0.04)	-0.06%
125	$62.83	$62.77	($0.07)	-0.1%	21,992	1,255	3300	96	9.6%	10.8%	($0.04)	-0.07%
150	$67.20	$67.10	($0.10)	-0.1%	25,822	663	3604	49	11.2%	11.8%	($0.04)	-0.07%
175	$71.56	$71.43	($0.13)	-0.2%	27,038	380	3492	29	11.8%	11.4%	($0.05)	-0.07%
200	$75.93	$75.76	($0.17)	-0.2%	24,867	213	3106	16	10.8%	10.2%	($0.05)	-0.07%
250	$84.66	$84.42	($0.24)	-0.3%	38,031	350	4452	19	16.6%	14.6%	($0.06)	-0.07%
300	$93.39	$93.08	($0.31)	-0.3%	22,616	174	2701	14	9.8%	8.8%	($0.07)	-0.07%
350	$102.12	$101.75	($0.37)	-0.4%	12,476	117	1468	6	5.4%	4.8%	($0.07)	-0.07%
400	$110.85	$110.41	($0.44)	-0.4%	6,742	68	830	4	2.9%	2.7%	($0.08)	-0.07%
500	$128.31	$127.73	($0.58)	-0.5%	5,627	81	639	7	2.4%	2.1%	($0.10)	-0.08%
750	$171.97	$171.05	($0.92)	-0.5%	3,032	64	287	8	1.3%	0.9%	($0.13)	-0.08%
1,000	$215.62	$214.36	($1.27)	-0.6%	586	28	27	2	0.3%	0.1%	($0.17)	-0.08%
1,500	$302.94	$300.98	($1.95)	-0.6%	408	24	14	1	0.2%	0.0%	($0.25)	-0.08%
2,000	$390.25	$387.61	($2.64)	-0.7%	159	4	3	0	0.1%	0.0%	($0.32)	-0.08%
3,000	$564.87	$560.86	($4.01)	-0.7%	114	6	2	1	0.0%	0.0%	($0.47)	-0.08%
5,000	$914.11	$907.36	($6.75)	-0.7%	67	5	0	0	0.0%	0.0%	($0.77)	-0.08%
					229,704		30,530					

Billing Determinants				
		Current Rates	RY 1	
	UOM	SC1/SC13 - Heating	SC1/SC13 - Heating	
First 3 therms	Monthly	$ 16.30	$ 16.30	
Next 47 therms	Next 47 therms	$ 0.72809	$ 0.67844	$ (0.00265) EE Tracker
Over 50 therms	Over 50 therms	$ 0.17105	$ 0.15957	$ (0.00062) EE Tracker
Tax Credit - Next 47 therms	Next 47 therms	$ (0.05006)	$ -	
Tax Credit - Over 50 therms	Over 50 therms	$ (0.01158)	$ -	
Bill Charge	Monthly	$ 0.81	$ 0.90	
R&D Adjustment	Therm	$ 0.00138	$ 0.00138	
Transition Charge	Therm	$ 0.01211	$ 0.01211	
SBC - CEF NYSERDA	Therm	$ 0.00020	$ 0.00020	
SBC - EE Tracker	Therm	$ 0.00147	$ -	
GRT - Delivery	%	0.00%	0.00%	

Notes:

1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

3. Low Income customers represent customers who participated in the Company's low income program and received a credit on their bill each month during calendar year 2018.

New York State Electric & Gas Corporation
Gas Rates
Annual Delivery Bill Impact - May 1, 2020 - April 30, 2021
PSC No. 87 Service Classification No. 1 – Residential Sales Service
PSC No. 88 Service Classification No. 13 - Residential Firm Aggregation Transportation Service

				increase / (decrease)	
Month	**Therms**	**Current Rates**	**RY 1**	**Amount**	**Percent**
Jan	180	$72.44	$72.29	($0.14)	-0.2%
Feb	156	$68.24	$68.14	($0.11)	-0.2%
March	139	$65.28	$65.19	($0.09)	-0.1%
April	70	$53.23	$53.24	$0.01	0.0%
May	27	$33.79	$33.85	$0.06	0.2%
June	20	$28.94	$29.01	$0.07	0.2%
July	16	$26.17	$26.24	$0.07	0.3%
August	28	$34.48	$34.55	$0.06	0.2%
September	27	$33.79	$33.85	$0.06	0.2%
October	51	$49.91	$49.95	$0.04	0.1%
November	106	$59.51	$59.47	($0.04)	-0.1%
December	160	$68.94	$68.83	($0.11)	-0.2%
Annual Totals	**980**	**$594.73**	**$594.61**	**($0.12)**	**0.0%**

Billing Determinants			
		Current Rates	**RY 1**
	UOM	**SC1/SC13 - Heating**	**SC1/SC13 - Heating**
First 3 therms	Monthly	$ 16.30	$ 16.30
Next 47 therms	Next 47 therms	$ 0.72809	$ 0.67844
Over 50 therms	Over 50 therms	$ 0.17105	$ 0.15957
Tax Credit - Next 47 therms	Next 47 therms	$ (0.05006)	$ -
Tax Credit - Over 50 therms	Over 50 therms	$ (0.01158)	$ -
Bill Charge	Monthly	$ 0.81	$ 0.90
R&D Adjustment	Therm	$ 0.00138	$ 0.00138
Transition Charge	Therm	$ 0.01211	$ 0.01211
SBC - CEF NYSERDA	Therm	$ 0.00020	$ 0.00020
SBC - EE Tracker	Therm	$ 0.00147	$ -
GRT - Delivery	%	0.00%	0.00%

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

New York State Electric & Gas Corporation
Gas Rates
Monthly Delivery Bill Impact - May 1, 2020 - April 30, 2021
PSC No. 87 Service Classification No. 2 - General Sales Service
PSC No. 88 Service Classification No. 14 - Non-Residential Firm Aggregation Transportation Service

			increase / (decrease)		Number of Customers	
Therms	Current Rates	RY 1	Amount	Percent	January	July
3	$24.46	$24.54	$0.09	0.4%	408	4,503
10	$27.48	$27.54	$0.06	0.2%	657	6,522
20	$31.81	$31.83	$0.02	0.1%	562	4,696
50	$44.79	$44.68	($0.11)	-0.2%	1,643	6,619
100	$66.43	$66.11	($0.32)	-0.5%	2,766	3,026
150	$88.06	$87.54	($0.52)	-0.6%	2,882	1,375
200	$109.70	$108.97	($0.73)	-0.7%	2,618	765
250	$131.33	$130.39	($0.94)	-0.7%	2,262	536
300	$152.96	$151.82	($1.14)	-0.7%	1,968	438
350	$174.60	$173.25	($1.35)	-0.8%	1,668	313
400	$196.23	$194.68	($1.56)	-0.8%	1,472	291
500	$239.50	$237.53	($1.97)	-0.8%	2,234	494
750	$303.95	$301.22	($2.73)	-0.9%	3,437	772
1,000	$368.40	$364.92	($3.48)	-0.9%	1,899	385
1,250	$432.85	$428.61	($4.24)	-1.0%	1,184	192
1,500	$497.29	$492.30	($4.99)	-1.0%	844	139
2,000	$626.19	$619.68	($6.51)	-1.0%	1,002	145
3,000	$883.98	$874.45	($9.53)	-1.1%	981	108
5,000	$1,399.56	$1,383.99	($15.57)	-1.1%	752	71
10,000	$2,688.52	$2,657.84	($30.68)	-1.1%	502	43
15,000	$3,977.47	$3,931.68	($45.79)	-1.2%	144	18
20,000	$4,805.78	$4,747.83	($57.95)	-1.2%	51	7
30,000	$6,462.38	$6,380.11	($82.27)	-1.3%	62	4
50,000	$9,775.60	$9,644.69	($130.91)	-1.3%	20	1
75,000	$13,917.13	$13,725.42	($191.71)	-1.4%	5	3
100,000	$18,058.65	$17,806.14	($252.51)	-1.4%	2	1

Billing Determinants					
		Current Rates		RY 1	
	UOM	SC2/14		SC2/14	
First 3 therms	Monthly	$	23.60	$	23.60
Next 497 therms	Next 497 therms	$	0.43958	$	0.41487
Next 14,500 therms	Next 14,500 therms	$	0.25323	$	0.24109
Over 15,000 therms	Over 15,000 therms	$	0.15577	$	0.14955
Tax Credit - Next 497 therms	Next 497 therms	$	(0.02204)	$	-
Tax Credit - Next 14,500 therms	Next 14,500 therms	$	(0.01059)	$	-
Tax Credit - Over 15,000 therms	Over 15,000 therms	$	(0.00526)	$	-
Bill Charge	Monthly	$	0.81	$	0.90
R&D Adjustment	Therm	$	0.00138	$	0.00138
Transition Charge	Therm	$	0.01211	$	0.01211
SBC - CEF NYSERDA	Therm	$	0.00020	$	0.00020
SBC - EE Tracker	Therm	$	0.00147	$	-
GRT - Delivery	%		0.00%		0.00%

Notes:

1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

New York State Electric & Gas Corporation
Gas Rates
Annual Delivery Bill Impact - May 1, 2020 - April 30, 2021
PSC No. 87 Service Classification No. 2 - General Sales Service
PSC No. 88 Service Classification No. 14 - Non-Residential Firm Aggregation Transportation Service

				increase / (decrease)	
Month	**Therms**	**Current Rates**	**RY 1**	**Amount**	**Percent**
Jan	529	$246.98	$244.92	($2.06)	-0.8%
Feb	463	$223.49	$221.67	($1.82)	-0.8%
March	404	$197.96	$196.39	($1.57)	-0.8%
April	225	$120.51	$119.68	($0.83)	-0.7%
May	106	$69.02	$68.68	($0.34)	-0.5%
June	55	$46.96	$46.83	($0.13)	-0.3%
July	60	$49.12	$48.97	($0.15)	-0.3%
August	91	$62.53	$62.25	($0.28)	-0.4%
September	73	$54.74	$54.54	($0.20)	-0.4%
October	154	$89.79	$89.25	($0.54)	-0.6%
November	269	$139.55	$138.54	($1.02)	-0.7%
December	466	$224.79	$222.96	($1.83)	-0.8%
Annual Totals	**2,895**	**$1,525.46**	**$1,514.69**	**($10.77)**	**-0.7%**

Billing Determinants			
	UOM	**Current Rates SC2/14**	**RY 1 SC2/14**
First 3 therms	Monthly	$ 23.60	$ 23.60
Next 497 therms	Next 497 therms	$ 0.43958	$ 0.41487
Next 14,500 therms	Next 14,500 therms	$ 0.25323	$ 0.24109
Over 15,000 therms	Over 15,000 therms	$ 0.15577	$ 0.14955
Tax Credit - Next 497 therms	Next 497 therms	$ (0.02204)	$ -
Tax Credit - Next 14,500 therms	Next 14,500 therms	$ (0.01059)	$ -
Tax Credit - Over 15,000 therms	Over 15,000 therms	$ (0.00526)	$ -
Bill Charge	Monthly	$ 0.81	$ 0.90
R&D Adjustment	Therm	$ 0.00138	$ 0.00138
Transition Charge	Therm	$ 0.01211	$ 0.01211
SBC - CEF NYSERDA	Therm	$ 0.00020	$ 0.00020
SBC - EE Tracker	Therm	$ 0.00147	$ -
GRT - Delivery	%	0.00%	0.00%

Notes:

1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

New York State Electric & Gas Corporation
Gas Rates
Monthly Delivery Bill Impact - May 1, 2020 - April 30, 2021
PSC No. 88 Service Classification No. 1 - Firm Transportation Service

			increase / (decrease)		Number of Customers	
Therms	**Current Rates**	**RY 1**	**Amount**	**Percent**	**January**	**July**
-	$1,724.36	$2,155.34	$430.98	25.0%	0	0
500	$1,725.84	$2,156.09	$430.25	24.9%	0	3
750	$1,761.19	$2,188.24	$427.04	24.2%	1	1
1,000	$1,796.54	$2,220.38	$423.84	23.6%	0	0
1,250	$1,831.89	$2,252.53	$420.64	23.0%	0	0
1,500	$1,867.24	$2,284.68	$417.44	22.4%	0	1
2,000	$1,937.94	$2,348.97	$411.03	21.2%	0	1
3,000	$2,079.34	$2,477.56	$398.23	19.2%	0	4
5,000	$2,362.13	$2,734.74	$372.61	15.8%	1	7
10,000	$3,069.12	$3,377.68	$308.57	10.1%	0	7
15,000	$3,776.10	$4,020.63	$244.53	6.5%	2	7
20,000	$4,165.44	$4,371.94	$206.51	5.0%	0	10
30,000	$4,944.11	$5,074.58	$130.47	2.6%	3	21
50,000	$6,501.45	$6,479.84	($21.60)	-0.3%	21	30
75,000	$8,013.62	$7,837.51	($176.11)	-2.2%	23	11
100,000	$9,525.80	$9,195.19	($330.61)	-3.5%	38	21

Billing Determinants			
		Current Rates	**RY 1**
	UOM	**SC1T**	**SC1T**
First 500 Therms	Monthly	$ 1,723.55	$ 2,154.44
Next 14,500 therms	Next 14,500 therms	$ 0.14683	$ 0.12709
Next 35,000 therms	Next 35,000 therms	$ 0.07911	$ 0.06876
Over 50,000 therms	Over 50,000 therms	$ 0.06050	$ 0.05281
Tax Credit - Next 14,500 therms	Next 14,500 therms	$ (0.00840)	$ -
Tax Credit - Next 35,000 therms	Next 35,000 therms	$ (0.00421)	$ -
Tax Credit - Over 50,000 therms	Over 50,000 therms	$ (0.00298)	$ -
Bill Charge	Monthly	$ 0.81	$ 0.90
R&D Adjustment	Therm	$ 0.00138	$ 0.00138
Transition Charge	Therm	$ (0.00007)	$ (0.00007)
SBC - CEF NYSERDA	Therm	$ 0.00020	$ 0.00020
SBC - EE Tracker	Therm	$ 0.00147	$ -
GRT - Delivery	%	0.00%	0.00%

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

New York State Electric & Gas Corporation
Gas Rates
Monthly Delivery Bill Impact - May 1, 2020 - April 30, 2021
PSC No. 88 Service Classification No. 5 - Small Firm Transportation Service

Therms	Current Rates	RY 1	increase / (decrease) Amount	increase / (decrease) Percent	Number of Customers January	Number of Customers July
-	$358.20	$358.29	$0.09	0.0%	0	0
500	$359.68	$359.04	($0.64)	-0.2%	1	147
750	$406.80	$405.31	($1.49)	-0.4%	1	25
1,000	$453.91	$451.58	($2.33)	-0.5%	1	24
1,250	$501.03	$497.85	($3.17)	-0.6%	4	24
1,500	$548.14	$544.12	($4.02)	-0.7%	0	12
2,000	$642.37	$636.67	($5.70)	-0.9%	9	19
3,000	$830.83	$821.75	($9.08)	-1.1%	13	29
5,000	$1,207.74	$1,191.92	($15.82)	-1.3%	30	17
10,000	$2,150.03	$2,117.33	($32.69)	-1.5%	117	19
15,000	$3,092.31	$3,042.75	($49.56)	-1.6%	65	12
20,000	$3,674.60	$3,611.86	($62.73)	-1.7%	41	2
30,000	$4,839.17	$4,750.09	($89.07)	-1.8%	38	2
50,000	$7,168.31	$7,026.55	($141.75)	-2.0%	16	4
75,000	$10,079.73	$9,872.13	($207.60)	-2.1%	1	3
100,000	$12,991.16	$12,717.70	($273.45)	-2.1%	1	1

Billing Determinants	UOM	Current Rates SC5T	RY 1 SC5T
First 500 Therms	Monthly	$ 357.39	$ 357.39
Next 14,500 therms	Next 14,500 therms	$ 0.19813	$ 0.18358
Over 15,000 therms	Over 15,000 therms	$ 0.12000	$ 0.11232
Tax Credit - Next 14,500 therms	Next 14,500 therms	$ (0.01264)	$ -
Tax Credit - Over 15,000 therms	Over 15,000 therms	$ (0.00651)	$ -
Bill Charge	Monthly	$ 0.81	$ 0.90
R&D Adjustment	Therm	$ 0.00138	$ 0.00138
Transition Charge	Therm	$ (0.00007)	$ (0.00007)
SBC - CEF NYSERDA	Therm	$ 0.00020	$ 0.00020
SBC - EE Tracker	Therm	$ 0.00147	$ -
GRT - Delivery	%	0.00%	0.00%

Notes:

1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

New York State Electric & Gas Corporation
Data Sources - NYSEG Gas Bill Impact Statements

Rate	Source of Rate in "Current" Rates	Source of Rate in Rate Years
Basic Service Charge (Non-Heating)	Current Tariff Rates in Effect January 1, 2019 (Last updated 5/1/2018)	New
Basic Service Charge (Heating)	Current Tariff Rates in Effect January 1, 2019 (Last updated 5/1/2018)	New
Usage Charge	Current Tariff Rates in Effect January 1, 2019 (Last updated 5/1/2018)	New
SBC (NYSERDA EE) - per Therm	Current Tariff Rates in Effect January 1, 2020	Current Tariff Rates in Effect January 1, 2020
SBC (EE Tracker) - per Therm	Current Tariff Rates in Effect January 1, 2020	Included in Delivery Rates
Billing Charge per Bill	Current Tariff Rates in Effect January 1, 2019 - (Last Updated 07/01/2016)	Results of 2019 Embedded Cost Study
Usage Charge - Tax Credit	Current Tariff Rates in Effect 10/1/2018	Included in Delivery Rates

	Source of Rate in "Current" Rates and Rate Years
Transition Charge per Therm	Non Weighted Average of Monthly Transition Charge in 2019
R&D Charge per Therm	Current Tariff Rates in Effect January 1, 2020
MFC per Therm	Current Tariff Rates in Effect May 1, 2020
Gas Supply Charge	Non Weighted Average of Monthly GSC in 2019
Customer Count	2018 Billing Information

New York State Electric & Gas Corporation
Gas Rates
Monthly Total Bill Impact - May 1, 2021 - April 30, 2022
PSC No. 87 Service Classification No. 1 – Residential Sales Service

Heating

			increase / (decrease)		Number of Customers		Number of Low Income Customers		Percent of Customers	Percent of Low Income Customers	Amount of EE Embedded in Delivery Rates	
Therms	**RY 1**	**RY 2**	**Amount**	**Percent**	**January**	**July**	**January**	**July**	**January**	**January**	**Amount**	**Percent**
3	$18.31	$19.31	$1.00	5.5%	825	16,166	94	2,471	0.4%	0.3%	$0.00	0.00%
10	$25.65	$26.59	$0.94	3.7%	1,706	51,791	238	7,283	0.8%	0.8%	$0.05	0.20%
20	$36.13	$36.99	$0.86	2.4%	2,386	70,243	382	8,776	1.2%	1.3%	$0.13	0.35%
30	$46.62	$47.39	$0.77	1.7%	2,649	38,798	396	4,847	1.3%	1.4%	$0.21	0.44%
40	$57.10	$57.79	$0.69	1.2%	2,948	14,670	446	1,809	1.4%	1.5%	$0.28	0.49%
50	$67.59	$68.19	$0.61	0.9%	3,212	5,510	538	654	1.5%	1.9%	$0.36	0.53%
60	$72.88	$73.47	$0.59	0.8%	3,314	2,422	593	272	1.6%	2.1%	$0.38	0.52%
70	$78.18	$78.75	$0.57	0.7%	4,141	1,373	725	137	2.0%	2.5%	$0.40	0.50%
80	$83.47	$84.02	$0.55	0.7%	4,736	903	805	99	2.3%	2.8%	$0.41	0.49%
90	$88.77	$89.30	$0.53	0.6%	5,602	571	967	45	2.7%	3.4%	$0.43	0.48%
100	$94.07	$94.57	$0.51	0.5%	6,128	460	1,066	45	3.0%	3.7%	$0.45	0.48%
125	$107.31	$107.76	$0.46	0.4%	19,875	1,126	3,086	88	9.6%	10.7%	$0.50	0.46%
150	$120.54	$120.95	$0.41	0.3%	23,125	599	3,394	47	11.2%	11.8%	$0.54	0.45%
175	$133.78	$134.14	$0.36	0.3%	24,139	348	3,273	26	11.6%	11.4%	$0.59	0.44%
200	$147.02	$147.33	$0.31	0.2%	22,189	191	2,915	15	10.7%	10.1%	$0.63	0.43%
250	$173.50	$173.71	$0.21	0.1%	33,946	311	4,197	19	16.4%	14.6%	$0.72	0.42%
300	$199.98	$200.09	$0.11	0.1%	20,297	152	2,560	13	9.8%	8.9%	$0.81	0.41%
350	$226.46	$226.47	$0.02	0.0%	11,266	103	1,400	5	5.4%	4.9%	$0.90	0.40%
400	$252.94	$252.85	($0.08)	0.0%	6,077	56	796	4	2.9%	2.8%	$0.99	0.39%
500	$305.89	$305.62	($0.28)	-0.1%	5,092	77	614	7	2.5%	2.1%	$1.17	0.38%
750	$438.29	$437.52	($0.77)	-0.2%	2,704	59	277	7	1.3%	1.0%	$1.62	0.37%
1,000	$570.68	$569.42	($1.26)	-0.2%	488	26	24	2	0.2%	0.1%	$2.07	0.36%
1,500	$835.46	$833.22	($2.25)	-0.3%	315	19	14	1	0.2%	0.0%	$2.98	0.36%
2,000	$1,100.25	$1,097.02	($3.23)	-0.3%	114	3	3	0	0.1%	0.0%	$3.88	0.35%
3,000	$1,629.82	$1,624.62	($5.20)	-0.3%	75	6	2	1	0.0%	0.0%	$5.68	0.35%
5,000	$2,688.96	$2,679.82	($9.14)	-0.3%	41	4	0	0	0.0%	0.0%	$9.29	0.35%
					207,391		28,806					

Billing Determinants					
		RY 1	**RY 2**		
	UOM	**SC1 - Heating**	**SC1 - Heating**		
First 3 therms	Monthly	$ 16.30	$ 17.30		
Next 47 therms	Next 47 therms	$ 0.67844	$ 0.67007	$ 0.00494	EE Tracker
Over 50 therms	Over 50 therms	$ 0.15957	$ 0.15760	$ 0.00116	EE Tracker
Tax Credit - Next 47 therms	Next 47 therms	$ -	$ -		
Tax Credit - Over 50 therms	Over 50 therms	$ -	$ -		
Bill Charge	Monthly	$ 0.90	$ 0.90		
R&D Adjustment	Therm	$ 0.00138	$ 0.00138		
Transition Charge	Therm	$ 0.01185	$ 0.01185		
SBC - CEF NYSERDA	Therm	$ 0.00020	$ 0.00020		
SBC - EE Tracker	Therm	$ -	$ -		
GRT - Delivery	%	0.00%	0.00%		
Gas Supply Charge	Therm	$ 0.33795	$ 0.33795		
MFC	Therm	$ 0.01863	$ 0.01863		

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.
3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.
4. Low Income customers represent customers who participated in the Company's low income program and received a credit on their bill each month during calendar year 2018.

New York State Electric & Gas Corporation
Gas Rates
Annual Total Bill Impact - May 1, 2021 - April 30, 2022
PSC No. 87 Service Classification No. 1 – Residential Sales Service

Heating

Month	Therms	RY 1	RY 2	increase / (decrease) Amount	Percent
Jan	180	$136.43	$136.78	$0.35	0.3%
Feb	156	$123.72	$124.12	$0.40	0.3%
March	139	$114.72	$115.15	$0.43	0.4%
April	70	$78.18	$78.75	$0.57	0.7%
May	27	$43.47	$44.27	$0.80	1.8%
June	20	$36.13	$36.99	$0.86	2.4%
July	16	$31.94	$32.83	$0.89	2.8%
August	28	$44.52	$45.31	$0.79	1.8%
September	27	$43.47	$44.27	$0.80	1.8%
October	51	$68.12	$68.72	$0.60	0.9%
November	106	$97.24	$97.74	$0.50	0.5%
December	160	$125.84	$126.23	$0.39	0.3%
Annual Totals	**980**	**$943.80**	**$951.18**	**$7.38**	**0.8%**

Billing Determinants			
		RY 1	**RY 2**
	UOM	**SC1 - Heating**	**SC1 - Heating**
First 3 therms	Monthly	$ 16.30	$ 17.30
Next 47 therms	Next 47 therms	$ 0.67844	$ 0.67007
Over 50 therms	Over 50 therms	$ 0.15957	$ 0.15760
Tax Credit - Next 47 therms	Next 47 therms	$ -	$ -
Tax Credit - Over 50 therms	Over 50 therms	$ -	$ -
Bill Charge	Monthly	$ 0.90	$ 0.90
R&D Adjustment	Therm	$ 0.00138	$ 0.00138
Transition Charge	Therm	$ 0.01185	$ 0.01185
SBC - CEF NYSERDA	Therm	$ 0.00020	$ 0.00020
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%
Gas Supply Charge	Therm	$ 0.33795	$ 0.33795
MFC	Therm	$ 0.01863	$ 0.01863

Notes:

1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Gas Rates
Annual Total Bill Impact - May 1, 2021 - April 30, 2022
PSC No. 87 Service Classification No. 1 – Residential Sales Service

Non-Heating

				increase / (decrease)	
Month	**Therms**	**RY 1**	**RY 2**	**Amount**	**Percent**
Jan	42	$55.20	$55.87	$0.67	1.2%
Feb	43	$56.25	$56.91	$0.67	1.2%
March	41	$54.15	$54.83	$0.68	1.3%
April	37	$49.96	$50.67	$0.72	1.4%
May	23	$35.28	$36.11	$0.83	2.4%
June	15	$26.89	$27.79	$0.90	3.3%
July	10	$21.65	$22.59	$0.94	4.3%
August	10	$21.65	$22.59	$0.94	4.3%
September	12	$23.75	$24.67	$0.92	3.9%
October	13	$24.80	$25.71	$0.92	3.7%
November	24	$36.33	$37.15	$0.82	2.3%
December	39	$52.05	$52.75	$0.70	1.3%
Annual Totals	**309**	**$457.96**	**$467.67**	**$9.72**	**2.1%**

Billing Determinants			
		RY 1	**RY 2**
	UOM	**SC1 - Non Heating**	**SC1 - Non Heating**
First 3 therms	Monthly	$ 12.30	$ 13.30
Next 47 therms	Next 47 therms	$ 0.67844	$ 0.67007
Over 50 therms	Over 50 therms	$ 0.15957	$ 0.15760
Tax Credit - Next 47 therms	Next 47 therms	$ -	$ -
Tax Credit - Over 50 therms	Over 50 therms	$ -	$ -
Bill Charge	Monthly	$ 0.90	$ 0.90
R&D Adjustment	Therm	$ 0.00138	$ 0.00138
Transition Charge	Therm	$ 0.01185	$ 0.01185
SBC - CEF NYSERDA	Therm	$ 0.00020	$ 0.00020
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%
Gas Supply Charge	Therm	$ 0.33795	$ 0.33795
MFC	Therm	$ 0.01863	$ 0.01863

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.
3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Gas Rates
Monthly Total Bill Impact - May 1, 2021 - April 30, 2022
PSC No. 87 Service Classification No. 2 - General Sales Service

			increase / (decrease)		Number of Customers	
Therms	**RY 1**	**RY 2**	**Amount**	**Percent**	**January**	**July**
3	$25.59	$26.59	$1.00	3.9%	359	3,585
10	$31.04	$32.06	$1.02	3.3%	531	5,012
20	$38.83	$39.88	$1.05	2.7%	450	3,688
50	$62.18	$63.33	$1.14	1.8%	1,421	5,257
100	$101.11	$102.41	$1.30	1.3%	2,283	2,092
150	$140.04	$141.49	$1.45	1.0%	2,337	859
200	$178.97	$180.57	$1.60	0.9%	2,071	469
250	$217.90	$219.65	$1.75	0.8%	1,827	314
300	$256.82	$258.73	$1.91	0.7%	1,592	279
350	$295.75	$297.81	$2.06	0.7%	1,335	197
400	$334.68	$336.89	$2.21	0.7%	1,121	162
500	$412.53	$415.05	$2.52	0.6%	1,648	252
750	$563.73	$566.69	$2.96	0.5%	2,447	373
1,000	$714.92	$718.33	$3.41	0.5%	1,223	160
1,250	$866.12	$869.97	$3.85	0.4%	708	85
1,500	$1,017.31	$1,021.61	$4.29	0.4%	498	47
2,000	$1,319.70	$1,324.88	$5.18	0.4%	562	53
3,000	$1,924.48	$1,931.43	$6.95	0.4%	465	27
5,000	$3,134.03	$3,144.54	$10.50	0.3%	326	14
10,000	$6,157.92	$6,177.30	$19.38	0.3%	177	9
15,000	$9,181.81	$9,210.06	$28.25	0.3%	50	4
20,000	$11,747.99	$11,781.75	$33.76	0.3%	18	3
30,000	$16,880.37	$16,925.13	$44.77	0.3%	19	3
50,000	$27,145.12	$27,211.90	$66.79	0.2%	3	0
75,000	$39,976.05	$40,070.36	$94.31	0.2%	3	0
100,000	$52,806.98	$52,928.82	$121.83	0.2%	1	0

Billing Determinants			
		RY 1	**RY 2**
	UOM	**SC2**	**SC2**
First 3 therms	Monthly	$ 23.60	$ 24.60
Next 497 therms	Next 497 therms	$ 0.41487	$ 0.41792
Next 14,500 therms	Next 14,500 therms	$ 0.24109	$ 0.24286
Over 15,000 therms	Over 15,000 therms	$ 0.14955	$ 0.15065
Tax Credit - Next 497 therms	Next 497 therms	$ -	$ -
Tax Credit - Next 14,500 therms	Next 14,500 therms	$ -	$ -
Tax Credit - Over 15,000 therms	Over 15,000 therms	$ -	$ -
Bill Charge	Monthly	$ 0.90	$ 0.90
R&D Adjustment	Therm	$ 0.00138	$ 0.00138
Transition Charge	Therm	$ 0.01185	$ 0.01185
SBC - CEF NYSERDA	Therm	$ 0.00020	$ 0.00020
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%
Gas Supply Charge	Therm	$ 0.33591	$ 0.33591
MFC	Therm	$ 0.01437	$ 0.01437

Notes:

1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Gas Rates
Annual Total Bill Impact - May 1, 2021 - April 30, 2022
PSC No. 87 Service Classification No. 2 - General Sales Service

				increase / (decrease)	
Month	**Therms**	**RY 1**	**RY 2**	**Amount**	**Percent**
Jan	529	$430.07	$432.64	$2.57	0.6%
Feb	463	$383.73	$386.13	$2.40	0.6%
March	404	$337.79	$340.02	$2.22	0.7%
April	225	$198.43	$200.11	$1.68	0.8%
May	106	$105.78	$107.10	$1.31	1.2%
June	55	$66.08	$67.24	$1.16	1.8%
July	60	$69.97	$71.14	$1.17	1.7%
August	91	$94.11	$95.37	$1.27	1.3%
September	73	$80.09	$81.30	$1.21	1.5%
October	154	$143.15	$144.62	$1.46	1.0%
November	269	$232.69	$234.50	$1.81	0.8%
December	466	$386.06	$388.48	$2.41	0.6%
Annual Totals	**2,895**	**$2,527.96**	**$2,548.65**	**$20.69**	**0.8%**

Billing Determinants			
		RY 1	**RY 2**
	UOM	**SC2**	**SC2**
First 3 therms	Monthly	$ 23.60	$ 24.60
Next 497 therms	Next 497 therms	$ 0.41487	$ 0.41792
Next 14,500 therms	Next 14,500 therms	$ 0.24109	$ 0.24286
Over 15,000 therms	Over 15,000 therms	$ 0.14955	$ 0.15065
Tax Credit - Next 497 therms	Next 497 therms	$ -	$ -
Tax Credit - Next 14,500 therms	Next 14,500 therms	$ -	$ -
Tax Credit - Over 15,000 therms	Over 15,000 therms	$ -	$ -
Bill Charge	Monthly	$ 0.90	$ 0.90
R&D Adjustment	Therm	$ 0.00138	$ 0.00138
Transition Charge	Therm	$ 0.01185	$ 0.01185
SBC - CEF NYSERDA	Therm	$ 0.00020	$ 0.00020
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%
Gas Supply Charge	Therm	$ 0.33591	$ 0.33591
MFC	Therm	$ 0.01437	$ 0.01437

Notes:

1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Gas Rates
Monthly Total Bill Impact - May 1, 2021 - April 30, 2022
PSC No. 87 Service Classification No. 9 - Industrial Manufacturing or Processing Purposes Sales Service

			increase / (decrease)		Number of Customers	
Therms	**RY 1**	**RY 2**	**Amount**	**Percent**	**January**	**July**
-	$353.67	$353.67	$0.00	0.0%		
500	$511.78	$511.78	$0.00	0.0%	0	0
750	$629.29	$630.13	$0.84	0.1%	0	0
1,000	$746.79	$748.48	$1.68	0.2%	0	0
1,250	$864.30	$866.83	$2.53	0.3%	0	0
1,500	$981.80	$985.17	$3.37	0.3%	0	0
2,000	$1,216.81	$1,221.87	$5.05	0.4%	0	0
3,000	$1,686.84	$1,695.26	$8.42	0.5%	0	0
5,000	$2,626.88	$2,642.04	$15.16	0.6%	0	1
10,000	$4,976.99	$5,009.00	$32.01	0.6%	1	0
15,000	$7,327.09	$7,375.96	$48.86	0.7%	0	0
20,000	$9,507.31	$9,553.66	$46.35	0.5%	0	0
30,000	$13,867.76	$13,909.08	$41.32	0.3%	0	0
50,000	$22,588.64	$22,619.90	$31.26	0.1%	0	0
75,000	$33,489.75	$33,508.44	$18.69	0.1%	0	0
100,000	$44,390.86	$44,396.97	$6.11	0.0%	0	0

Billing Determinants			
		RY 1	**RY 2**
	UOM	**SC9**	**SC9**
First 500 Therms	Monthly	$ 352.77	$ 352.77
Next 14,500 therms	Next 14,500 therms	$ 0.15380	$ 0.15717
Over 15,000 therms	Over 15,000 therms	$ 0.11982	$ 0.11932
Tax Credit - Next 14,500 therms	Next 14,500 therms	$ -	$ -
Tax Credit - Over 15,000 therms	Over 15,000 therms	$ -	$ -
Bill Charge	Monthly	$ 0.90	$ 0.90
R&D Adjustment	Therm	$ 0.00138	$ 0.00138
Transition Charge	Therm	$ 0.01185	$ 0.01185
SBC - CEF NYSERDA	Therm	$ 0.00020	$ 0.00020
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%
Gas Supply Charge	Therm	$ 0.28844	$ 0.28844
MFC	Therm	$ 0.01437	$ 0.01437

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.
3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Data Sources - NYSEG Gas Bill Impact Statements

Rate	Source of Rate in "Current" Rates	Source of Rate in Rate Years
Basic Service Charge (Non-Heating)	Current Tariff Rates in Effect January 1, 2019 (Last updated 5/1/2018)	New
Basic Service Charge (Heating)	Current Tariff Rates in Effect January 1, 2019 (Last updated 5/1/2018)	New
Usage Charge	Current Tariff Rates in Effect January 1, 2019 (Last updated 5/1/2018)	New
SBC (NYSERDA EE) - per Therm	Current Tariff Rates in Effect January 1, 2020	Current Tariff Rates in Effect January 1, 2020
SBC (EE Tracker) - per Therm	Current Tariff Rates in Effect January 1, 2020	Included in Delivery Rates
Billing Charge per Bill	Current Tariff Rates in Effect January 1, 2019 - (Last Updated 07/01/2016)	Results of 2019 Embedded Cost Study
Usage Charge - Tax Credit	Current Tariff Rates in Effect 10/1/2018	Included in Delivery Rates

	Source of Rate in "Current" Rates and Rate Years
Transition Charge per Therm	Non Weighted Average of Monthly Transition Charge in 2019
R&D Charge per Therm	Current Tariff Rates in Effect January 1, 2020
MFC per Therm	Current Tariff Rates in Effect May 1, 2020
Gas Supply Charge	Non Weighted Average of Monthly GSC in 2019
Customer Count	2018 Billing Information

New York State Electric & Gas Corporation
Gas Rates
Monthly Delivery Bill Impact - May 1, 2021 - April 30, 2022
PSC No. 87 Service Classification No. 1 – Residential Sales Service
PSC No. 88 Service Classification No. 13 - Residential Firm Aggregation Transportation Service

			increase / (decrease)		Number of Customers		Number of Low Income Customers		Percent of Customers	Percent of Low Income Customers	Amount of EE Embedded in Delivery Rates	
Therms	**RY 1**	**RY 2**	**Amount**	**Percent**	**January**	**July**	**January**	**July**	**January**	**January**	**Amount**	**Percent**
3	$17.24	$18.24	$1.00	5.8%	849	17,340	98	2,589	0.4%	0.3%	$0.00	0.00%
10	$22.09	$23.03	$0.94	4.3%	1,732	57,168	251	7,747	0.8%	0.8%	$0.05	0.23%
20	$29.01	$29.87	$0.86	3.0%	2,479	78,018	393	9,309	1.1%	1.3%	$0.13	0.44%
30	$35.93	$36.70	$0.77	2.2%	2,763	43,093	421	5,105	1.2%	1.4%	$0.21	0.56%
40	$42.85	$43.54	$0.69	1.6%	3,080	16,213	477	1,911	1.3%	1.6%	$0.28	0.65%
50	$49.77	$50.38	$0.61	1.2%	3,341	6,060	557	690	1.5%	1.8%	$0.36	0.72%
60	$51.50	$52.09	$0.59	1.1%	3,505	2,689	623	284	1.5%	2.0%	$0.38	0.73%
70	$53.24	$53.80	$0.57	1.1%	4,440	1,518	772	141	1.9%	2.5%	$0.40	0.74%
80	$54.97	$55.52	$0.55	1.0%	5,083	1,005	853	100	2.2%	2.8%	$0.41	0.75%
90	$56.70	$57.23	$0.53	0.9%	6,050	655	1023	47	2.6%	3.4%	$0.43	0.76%
100	$58.43	$58.94	$0.51	0.9%	6,802	524	1139	48	3.0%	3.7%	$0.45	0.76%
125	$62.77	$63.22	$0.46	0.7%	21,992	1,255	3300	96	9.6%	10.8%	$0.50	0.78%
150	$67.10	$67.51	$0.41	0.6%	25,822	663	3604	49	11.2%	11.8%	$0.54	0.80%
175	$71.43	$71.79	$0.36	0.5%	27,038	380	3492	29	11.8%	11.4%	$0.59	0.82%
200	$75.76	$76.07	$0.31	0.4%	24,867	213	3106	16	10.8%	10.2%	$0.63	0.83%
250	$84.42	$84.63	$0.21	0.3%	38,031	350	4452	19	16.6%	14.6%	$0.72	0.85%
300	$93.08	$93.20	$0.11	0.1%	22,616	174	2701	14	9.8%	8.8%	$0.81	0.87%
350	$101.75	$101.76	$0.02	0.0%	12,476	117	1468	6	5.4%	4.8%	$0.90	0.89%
400	$110.41	$110.33	($0.08)	-0.1%	6,742	68	830	4	2.9%	2.7%	$0.99	0.90%
500	$127.73	$127.46	($0.28)	-0.2%	5,627	81	639	7	2.4%	2.1%	$1.17	0.92%
750	$171.05	$170.28	($0.77)	-0.5%	3,032	64	287	8	1.3%	0.9%	$1.62	0.95%
1,000	$214.36	$213.10	($1.26)	-0.6%	586	28	27	2	0.3%	0.1%	$2.07	0.97%
1,500	$300.98	$298.74	($2.25)	-0.7%	408	24	14	1	0.2%	0.0%	$2.98	1.00%
2,000	$387.61	$384.38	($3.23)	-0.8%	159	4	3	0	0.1%	0.0%	$3.88	1.01%
3,000	$560.86	$555.66	($5.20)	-0.9%	114	6	2	1	0.0%	0.0%	$5.68	1.02%
5,000	$907.36	$898.22	($9.14)	-1.0%	67	5	0	0	0.0%	0.0%	$9.29	1.03%
					229,704		30,530					

Billing Determinants		RY 1	RY 2		
	UOM	**SC1/SC13 - Heating**	**SC1/SC13 - Heating**		
First 3 therms	Monthly	$ 16.30	$ 17.30		
Next 47 therms	Next 47 therms	$ 0.67844	$ 0.67007	$ 0.00494	EE Tracker
Over 50 therms	Over 50 therms	$ 0.15957	$ 0.15760	$ 0.00116	EE Tracker
Tax Credit - Next 47 therms	Next 47 therms	$ -	$ -		
Tax Credit - Over 50 therms	Over 50 therms	$ -	$ -		
Bill Charge	Monthly	$ 0.90	$ 0.90		
R&D Adjustment	Therm	$ 0.00138	$ 0.00138		
Transition Charge	Therm	$ 0.01211	$ 0.01211		
SBC - CEF NYSERDA	Therm	$ 0.00020	$ 0.00020		
SBC - EE Tracker	Therm	$ -	$ -		
GRT - Delivery	%	0.00%	0.00%		

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.
3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.
4. Low Income customers represent customers who participated in the Company's low income program and received a credit on their bill each month during calendar year 2018.

New York State Electric & Gas Corporation
Gas Rates
Annual Delivery Bill Impact - May 1, 2021 - April 30, 2022
PSC No. 87 Service Classification No. 1 – Residential Sales Service
PSC No. 88 Service Classification No. 13 - Residential Firm Aggregation Transportation Service

				increase / (decrease)	
Month	**Therms**	**RY 1**	**RY 2**	**Amount**	**Percent**
Jan	180	$72.29	$72.65	$0.35	0.5%
Feb	156	$68.14	$68.53	$0.40	0.6%
March	139	$65.19	$65.62	$0.43	0.7%
April	70	$53.24	$53.80	$0.57	1.1%
May	27	$33.85	$34.65	$0.80	2.4%
June	20	$29.01	$29.87	$0.86	3.0%
July	16	$26.24	$27.13	$0.89	3.4%
August	28	$34.55	$35.34	$0.79	2.3%
September	27	$33.85	$34.65	$0.80	2.4%
October	51	$49.95	$50.55	$0.60	1.2%
November	106	$59.47	$59.97	$0.50	0.8%
December	160	$68.83	$69.22	$0.39	0.6%
Annual Totals	**980**	**$594.61**	**$601.98**	**$7.38**	**1.2%**

Billing Determinants			
		RY 1	**RY 2**
	UOM	**SC1/SC13 - Heating**	**SC1/SC13 - Heating**
First 3 therms	Monthly	$ 16.30	$ 17.30
Next 47 therms	Next 47 therms	$ 0.67844	$ 0.67007
Over 50 therms	Over 50 therms	$ 0.15957	$ 0.15760
Tax Credit - Next 47 therms	Next 47 therms	$ -	$ -
Tax Credit - Over 50 therms	Over 50 therms	$ -	$ -
Bill Charge	Monthly	$ 0.90	$ 0.90
R&D Adjustment	Therm	$ 0.00138	$ 0.00138
Transition Charge	Therm	$ 0.01211	$ 0.01211
SBC - CEF NYSERDA	Therm	$ 0.00020	$ 0.00020
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.
3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Gas Rates
Monthly Delivery Bill Impact - May 1, 2021 - April 30, 2022
PSC No. 87 Service Classification No. 2 - General Sales Service
PSC No. 88 Service Classification No. 14 - Non-Residential Firm Aggregation Transportation Service

			increase / (decrease)		Number of Customers	
Therms	RY 1	RY 2	Amount	Percent	January	July
3	$24.54	$25.54	$1.00	4.1%	408	4,503
10	$27.54	$28.56	$1.02	3.7%	657	6,522
20	$31.83	$32.88	$1.05	3.3%	562	4,696
50	$44.68	$45.83	$1.14	2.6%	1,643	6,619
100	$66.11	$67.41	$1.30	2.0%	2,766	3,026
150	$87.54	$88.99	$1.45	1.7%	2,882	1,375
200	$108.97	$110.57	$1.60	1.5%	2,618	765
250	$130.39	$132.15	$1.75	1.3%	2,262	536
300	$151.82	$153.73	$1.91	1.3%	1,968	438
350	$173.25	$175.31	$2.06	1.2%	1,668	313
400	$194.68	$196.89	$2.21	1.1%	1,472	291
500	$237.53	$240.05	$2.52	1.1%	2,234	494
750	$301.22	$304.18	$2.96	1.0%	3,437	772
1,000	$364.92	$368.32	$3.41	0.9%	1,899	385
1,250	$428.61	$432.46	$3.85	0.9%	1,184	192
1,500	$492.30	$496.59	$4.29	0.9%	844	139
2,000	$619.68	$624.86	$5.18	0.8%	1,002	145
3,000	$874.45	$881.41	$6.95	0.8%	981	108
5,000	$1,383.99	$1,394.50	$10.50	0.8%	752	71
10,000	$2,657.84	$2,677.21	$19.38	0.7%	502	43
15,000	$3,931.68	$3,959.93	$28.25	0.7%	144	18
20,000	$4,747.83	$4,781.58	$33.76	0.7%	51	7
30,000	$6,380.11	$6,424.88	$44.77	0.7%	62	4
50,000	$9,644.69	$9,711.48	$66.79	0.7%	20	1
75,000	$13,725.42	$13,819.73	$94.31	0.7%	5	3
100,000	$17,806.14	$17,927.97	$121.83	0.7%	2	1

Billing Determinants			
		RY 1	RY 2
	UOM	SC2/14	SC2/14
First 3 therms	Monthly	$ 23.60	$ 24.60
Next 497 therms	Next 497 therms	$ 0.41487	$ 0.41792
Next 14,500 therms	Next 14,500 therms	$ 0.24109	$ 0.24286
Over 15,000 therms	Over 15,000 therms	$ 0.14955	$ 0.15065
Tax Credit - Next 497 therms	Next 497 therms	$ -	$ -
Tax Credit - Next 14,500 therms	Next 14,500 therms	$ -	$ -
Tax Credit - Over 15,000 therms	Over 15,000 therms	$ -	$ -
Bill Charge	Monthly	$ 0.90	$ 0.90
R&D Adjustment	Therm	$ 0.00138	$ 0.00138
Transition Charge	Therm	$ 0.01211	$ 0.01211
SBC - CEF NYSERDA	Therm	$ 0.00020	$ 0.00020
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%

Notes:

1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Gas Rates
Annual Delivery Bill Impact - May 1, 2021 - April 30, 2022
PSC No. 87 Service Classification No. 2 - General Sales Service
PSC No. 88 Service Classification No. 14 - Non-Residential Firm Aggregation Transportation Service

				increase / (decrease)	
Month	**Therms**	**RY 1**	**RY 2**	**Amount**	**Percent**
Jan	529	$244.92	$247.49	$2.57	1.0%
Feb	463	$221.67	$224.08	$2.40	1.1%
March	404	$196.39	$198.61	$2.22	1.1%
April	225	$119.68	$121.36	$1.68	1.4%
May	106	$68.68	$70.00	$1.31	1.9%
June	55	$46.83	$47.99	$1.16	2.5%
July	60	$48.97	$50.14	$1.17	2.4%
August	91	$62.25	$63.52	$1.27	2.0%
September	73	$54.54	$55.75	$1.21	2.2%
October	154	$89.25	$90.71	$1.46	1.6%
November	269	$138.54	$140.35	$1.81	1.3%
December	466	$222.96	$225.37	$2.41	1.1%
Annual Totals	**2,895**	**$1,514.69**	**$1,535.38**	**$20.69**	**1.4%**

Billing Determinants			
		RY 1	**RY 2**
	UOM	**SC2/14**	**SC2/14**
First 3 therms	Monthly	$ 23.60	$ 24.60
Next 497 therms	Next 497 therms	$ 0.41487	$ 0.41792
Next 14,500 therms	Next 14,500 therms	$ 0.24109	$ 0.24286
Over 15,000 therms	Over 15,000 therms	$ 0.14955	$ 0.15065
Tax Credit - Next 497 therms	Next 497 therms	$ -	$ -
Tax Credit - Next 14,500 therms	Next 14,500 therms	$ -	$ -
Tax Credit - Over 15,000 therms	Over 15,000 therms	$ -	$ -
Bill Charge	Monthly	$ 0.90	$ 0.90
R&D Adjustment	Therm	$ 0.00138	$ 0.00138
Transition Charge	Therm	$ 0.01211	$ 0.01211
SBC - CEF NYSERDA	Therm	$ 0.00020	$ 0.00020
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%

Notes:

1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Gas Rates
Monthly Delivery Bill Impact - May 1, 2021 - April 30, 2022
PSC No. 88 Service Classification No. 1 - Firm Transportation Service

Therms	RY 1	RY 2	increase / (decrease) Amount	Percent	Number of Customers January	July
-	$2,155.34	$2,338.66	$183.31	8.5%	0	0
500	$2,156.09	$2,339.40	$183.31	8.5%	0	3
750	$2,188.24	$2,372.48	$184.24	8.4%	1	1
1,000	$2,220.38	$2,405.56	$185.18	8.3%	0	0
1,250	$2,252.53	$2,438.64	$186.11	8.3%	0	0
1,500	$2,284.68	$2,471.72	$187.04	8.2%	0	1
2,000	$2,348.97	$2,537.87	$188.90	8.0%	0	1
3,000	$2,477.56	$2,670.18	$192.62	7.8%	0	4
5,000	$2,734.74	$2,934.80	$200.06	7.3%	1	7
10,000	$3,377.68	$3,596.36	$218.67	6.5%	0	7
15,000	$4,020.63	$4,257.91	$237.28	5.9%	2	7
20,000	$4,371.94	$4,619.29	$247.35	5.7%	0	10
30,000	$5,074.58	$5,342.06	$267.48	5.3%	3	21
50,000	$6,479.84	$6,787.60	$307.76	4.7%	21	30
75,000	$7,837.51	$8,183.93	$346.42	4.4%	23	11
100,000	$9,195.19	$9,580.27	$385.08	4.2%	38	21

Billing Determinants

	UOM	RY 1 SC1T	RY 2 SC1T
First 500 Therms	Monthly	$ 2,154.44	$ 2,337.75
Next 14,500 therms	Next 14,500 therms	$ 0.12709	$ 0.13081
Next 35,000 therms	Next 35,000 therms	$ 0.06876	$ 0.07078
Over 50,000 therms	Over 50,000 therms	$ 0.05281	$ 0.05435
Tax Credit - Next 14,500 therms	Next 14,500 therms	$ -	$ -
Tax Credit - Next 35,000 therms	Next 35,000 therms	$ -	$ -
Tax Credit - Over 50,000 therms	Over 50,000 therms	$ -	$ -
Bill Charge	Monthly	$ 0.90	$ 0.90
R&D Adjustment	Therm	$ 0.00138	$ 0.00138
Transition Charge	Therm	$ (0.00007)	$ (0.00007)
SBC - CEF NYSERDA	Therm	$ 0.00020	$ 0.00020
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

New York State Electric & Gas Corporation
Gas Rates
Monthly Delivery Bill Impact - May 1, 2021 - April 30, 2022
PSC No. 88 Service Classification No. 5 - Small Firm Transportation Service

			increase / (decrease)		Number of Customers	
Therms	**RY 1**	**RY 2**	**Amount**	**Percent**	**January**	**July**
-	$358.29	$358.29	$0.00	0.0%	0	0
500	$359.04	$359.04	$0.00	0.0%	1	147
750	$405.31	$406.52	$1.20	0.3%	1	25
1,000	$451.58	$453.99	$2.41	0.5%	1	24
1,250	$497.85	$501.46	$3.61	0.7%	4	24
1,500	$544.12	$548.94	$4.82	0.9%	0	12
2,000	$636.67	$643.89	$7.22	1.1%	9	19
3,000	$821.75	$833.79	$12.04	1.5%	13	29
5,000	$1,191.92	$1,213.59	$21.67	1.8%	30	17
10,000	$2,117.33	$2,163.08	$45.75	2.2%	117	19
15,000	$3,042.75	$3,112.58	$69.83	2.3%	65	12
20,000	$3,611.86	$3,696.42	$84.56	2.3%	41	2
30,000	$4,750.09	$4,864.12	$114.03	2.4%	38	2
50,000	$7,026.55	$7,199.51	$172.96	2.5%	16	4
75,000	$9,872.13	$10,118.75	$246.62	2.5%	1	3
100,000	$12,717.70	$13,037.98	$320.28	2.5%	1	1

Billing Determinants			
		RY 1	**RY 2**
	UOM	**SC5T**	**SC5T**
First 500 Therms	Monthly	$ 357.39	$ 357.39
Next 14,500 therms	Next 14,500 therms	$ 0.18358	$ 0.18840
Over 15,000 therms	Over 15,000 therms	$ 0.11232	$ 0.11527
Tax Credit - Next 14,500 therms	Next 14,500 therms	$ -	$ -
Tax Credit - Over 15,000 therms	Over 15,000 therms	$ -	$ -
Bill Charge	Monthly	$ 0.90	$ 0.90
R&D Adjustment	Therm	$ 0.00138	$ 0.00138
Transition Charge	Therm	$ (0.00007)	$ (0.00007)
SBC - CEF NYSERDA	Therm	$ 0.00020	$ 0.00020
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.
3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Data Sources - NYSEG Gas Bill Impact Statements

Rate	Source of Rate in "Current" Rates	Source of Rate in Rate Years
Basic Service Charge (Non-Heating)	Current Tariff Rates in Effect January 1, 2019 (Last updated 5/1/2018)	New
Basic Service Charge (Heating)	Current Tariff Rates in Effect January 1, 2019 (Last updated 5/1/2018)	New
Usage Charge	Current Tariff Rates in Effect January 1, 2019 (Last updated 5/1/2018)	New
SBC (NYSERDA EE) - per Therm	Current Tariff Rates in Effect January 1, 2020	Current Tariff Rates in Effect January 1, 2020
SBC (EE Tracker) - per Therm	Current Tariff Rates in Effect January 1, 2020	Included in Delivery Rates
Billing Charge per Bill	Current Tariff Rates in Effect January 1, 2019 - (Last Updated 07/01/2016)	Results of 2019 Embedded Cost Study
Usage Charge - Tax Credit	Current Tariff Rates in Effect 10/1/2018	Included in Delivery Rates

	Source of Rate in "Current" Rates and Rate Years
Transition Charge per Therm	Non Weighted Average of Monthly Transition Charge in 2019
R&D Charge per Therm	Current Tariff Rates in Effect January 1, 2020
MFC per Therm	Current Tariff Rates in Effect May 1, 2020
Gas Supply Charge	Non Weighted Average of Monthly GSC in 2019
Customer Count	2018 Billing Information

New York State Electric & Gas Corporation
Gas Rates
Monthly Total Bill Impact - May 1, 2022 - April 30, 2023
PSC No. 87 Service Classification No. 1 – Residential Sales Service

Heating

Therms	RY 2	RY 3	increase / (decrease) Amount	increase / (decrease) Percent	Number of Customers January	Number of Customers July	Number of Low Income Customers January	Number of Low Income Customers July	Percent of Customers January	Percent of Low Income Customers January	Amount of EE Embedded in Delivery Rates Amount	Amount of EE Embedded in Delivery Rates Percent
3	$19.31	$20.31	$1.00	5.2%	825	16,166	94	2,471	0.4%	0.3%	$0.00	0.00%
10	$26.59	$27.62	$1.03	3.9%	1,706	51,791	238	7,283	0.8%	0.8%	$0.09	0.32%
20	$36.99	$38.05	$1.06	2.9%	2,386	70,243	382	8,776	1.2%	1.3%	$0.21	0.56%
30	$47.39	$48.49	$1.10	2.3%	2,649	38,798	396	4,847	1.3%	1.4%	$0.34	0.70%
40	$57.79	$58.93	$1.14	2.0%	2,948	14,670	446	1,809	1.4%	1.5%	$0.46	0.78%
50	$68.19	$69.37	$1.17	1.7%	3,212	5,510	538	654	1.5%	1.9%	$0.59	0.85%
60	$73.47	$74.65	$1.18	1.6%	3,314	2,422	593	272	1.6%	2.1%	$0.62	0.83%
70	$78.75	$79.94	$1.19	1.5%	4,141	1,373	725	137	2.0%	2.5%	$0.65	0.81%
80	$84.02	$85.22	$1.20	1.4%	4,736	903	805	99	2.3%	2.8%	$0.68	0.79%
90	$89.30	$90.51	$1.21	1.4%	5,602	571	967	45	2.7%	3.4%	$0.71	0.78%
100	$94.57	$95.79	$1.22	1.3%	6,128	460	1,066	45	3.0%	3.7%	$0.73	0.77%
125	$107.76	$109.00	$1.24	1.1%	19,875	1,126	3,086	88	9.6%	10.7%	$0.81	0.74%
150	$120.95	$122.21	$1.26	1.0%	23,125	599	3,394	47	11.2%	11.8%	$0.88	0.72%
175	$134.14	$135.43	$1.28	1.0%	24,139	348	3,273	26	11.6%	11.4%	$0.95	0.71%
200	$147.33	$148.64	$1.30	0.9%	22,189	191	2,915	15	10.7%	10.1%	$1.03	0.69%
250	$173.71	$175.06	$1.35	0.8%	33,946	311	4,197	19	16.4%	14.6%	$1.18	0.67%
300	$200.09	$201.48	$1.39	0.7%	20,297	152	2,560	13	9.8%	8.9%	$1.32	0.66%
350	$226.47	$227.91	$1.43	0.6%	11,266	103	1,400	5	5.4%	4.9%	$1.47	0.64%
400	$252.85	$254.33	$1.48	0.6%	6,077	56	796	4	2.9%	2.8%	$1.62	0.64%
500	$305.62	$307.18	$1.56	0.5%	5,092	77	614	7	2.5%	2.1%	$1.91	0.62%
750	$437.52	$439.29	$1.78	0.4%	2,704	59	277	7	1.3%	1.0%	$2.65	0.60%
1,000	$569.42	$571.41	$1.99	0.4%	488	26	24	2	0.2%	0.1%	$3.38	0.59%
1,500	$833.22	$835.64	$2.43	0.3%	315	19	14	1	0.2%	0.0%	$4.85	0.58%
2,000	$1,097.02	$1,099.88	$2.86	0.3%	114	3	3	0	0.1%	0.0%	$6.32	0.57%
3,000	$1,624.62	$1,628.34	$3.73	0.2%	75	6	2	1	0.0%	0.0%	$9.26	0.57%
5,000	$2,679.82	$2,685.28	$5.46	0.2%	41	4	0	0	0.0%	0.0%	$15.14	0.56%
					207,391		28,806					

Billing Determinants	UOM	RY 2 SC1 - Heating	RY 3 SC1 - Heating		
First 3 therms	Monthly	$ 17.30	$ 18.30		
Next 47 therms	Next 47 therms	$ 0.67007	$ 0.67375	$ 0.01250	EE Tracker
Over 50 therms	Over 50 therms	$ 0.15760	$ 0.15846	$ 0.00294	EE Tracker
Tax Credit - Next 47 therms	Next 47 therms	$ -	$ -		
Tax Credit - Over 50 therms	Over 50 therms	$ -	$ -		
Bill Charge	Monthly	$ 0.90	$ 0.90		
R&D Adjustment	Therm	$ 0.00138	$ 0.00138		
Transition Charge	Therm	$ 0.01185	$ 0.01185		
SBC - CEF NYSERDA	Therm	$ 0.00020	$ 0.00020		
SBC - EE Tracker	Therm	$ -	$ -		
GRT - Delivery	%	0.00%	0.00%		
Gas Supply Charge	Therm	$ 0.33795	$ 0.33795		
MFC	Therm	$ 0.01863	$ 0.01863		

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.
3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.
4. Low Income customers represent customers who participated in the Company's low income program and received a credit on their bill each month during calendar year 2018.

New York State Electric & Gas Corporation
Gas Rates
Annual Total Bill Impact - May 1, 2022 - April 30, 2023
PSC No. 87 Service Classification No. 1 – Residential Sales Service

Heating

Month	Therms	RY 2	RY 3	increase / (decrease) Amount	Percent
Jan	180	$136.78	$138.07	$1.29	0.9%
Feb	156	$124.12	$125.38	$1.26	1.0%
March	139	$115.15	$116.40	$1.25	1.1%
April	70	$78.75	$79.94	$1.19	1.5%
May	27	$44.27	$45.36	$1.09	2.5%
June	20	$36.99	$38.05	$1.06	2.9%
July	16	$32.83	$33.88	$1.05	3.2%
August	28	$45.31	$46.40	$1.09	2.4%
September	27	$44.27	$45.36	$1.09	2.5%
October	51	$68.72	$69.90	$1.17	1.7%
November	106	$97.74	$98.96	$1.22	1.2%
December	160	$126.23	$127.50	$1.27	1.0%
Annual Totals	**980**	**$951.18**	**$965.21**	**$14.03**	**1.5%**

Billing Determinants

	UOM	RY 2 SC1 - Heating	RY 3 SC1 - Heating
First 3 therms	Monthly	$ 17.30	$ 18.30
Next 47 therms	Next 47 therms	$ 0.67007	$ 0.67375
Over 50 therms	Over 50 therms	$ 0.15760	$ 0.15846
Tax Credit - Next 47 therms	Next 47 therms	$ -	$ -
Tax Credit - Over 50 therms	Over 50 therms	$ -	$ -
Bill Charge	Monthly	$ 0.90	$ 0.90
R&D Adjustment	Therm	$ 0.00138	$ 0.00138
Transition Charge	Therm	$ 0.01185	$ 0.01185
SBC - CEF NYSERDA	Therm	$ 0.00020	$ 0.00020
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%
Gas Supply Charge	Therm	$ 0.33795	$ 0.33795
MFC	Therm	$ 0.01863	$ 0.01863

Notes:

1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Gas Rates
Annual Total Bill Impact - May 1, 2022 - April 30, 2023
PSC No. 87 Service Classification No. 1 – Residential Sales Service

Non-Heating

Month	Therms	RY 2	RY 3	increase / (decrease) Amount	increase / (decrease) Percent
Jan	42	$55.87	$57.02	$1.14	2.0%
Feb	43	$56.91	$58.06	$1.15	2.0%
March	41	$54.83	$55.97	$1.14	2.1%
April	37	$50.67	$51.80	$1.13	2.2%
May	23	$36.11	$37.19	$1.07	3.0%
June	15	$27.79	$28.84	$1.04	3.8%
July	10	$22.59	$23.62	$1.03	4.5%
August	10	$22.59	$23.62	$1.03	4.5%
September	12	$24.67	$25.70	$1.03	4.2%
October	13	$25.71	$26.75	$1.04	4.0%
November	24	$37.15	$38.23	$1.08	2.9%
December	39	$52.75	$53.89	$1.13	2.1%
Annual Totals	**309**	**$467.67**	**$480.68**	**$13.00**	**2.8%**

Billing Determinants

	UOM	RY 2 SC1 - Non Heating	RY 3 SC1 - Non Heating
First 3 therms	Monthly	$ 13.30	$ 14.30
Next 47 therms	Next 47 therms	$ 0.67007	$ 0.67375
Over 50 therms	Over 50 therms	$ 0.15760	$ 0.15846
Tax Credit - Next 47 therms	Next 47 therms	$ -	$ -
Tax Credit - Over 50 therms	Over 50 therms	$ -	$ -
Bill Charge	Monthly	$ 0.90	$ 0.90
R&D Adjustment	Therm	$ 0.00138	$ 0.00138
Transition Charge	Therm	$ 0.01185	$ 0.01185
SBC - CEF NYSERDA	Therm	$ 0.00020	$ 0.00020
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%
Gas Supply Charge	Therm	$ 0.33795	$ 0.33795
MFC	Therm	$ 0.01863	$ 0.01863

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.
3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Gas Rates
Monthly Total Bill Impact - May 1, 2022 - April 30, 2023
PSC No. 87 Service Classification No. 2 - General Sales Service

			increase / (decrease)		Number of Customers	
Therms	**RY 2**	**RY 3**	**Amount**	**Percent**	**January**	**July**
3	$26.59	$27.59	$1.00	3.8%	359	3,585
10	$32.06	$33.11	$1.04	3.3%	531	5,012
20	$39.88	$40.99	$1.11	2.8%	450	3,688
50	$63.33	$64.63	$1.30	2.1%	1,421	5,257
100	$102.41	$104.03	$1.62	1.6%	2,283	2,092
150	$141.49	$143.43	$1.94	1.4%	2,337	859
200	$180.57	$182.83	$2.26	1.3%	2,071	469
250	$219.65	$222.24	$2.59	1.2%	1,827	314
300	$258.73	$261.64	$2.91	1.1%	1,592	279
350	$297.81	$301.04	$3.23	1.1%	1,335	197
400	$336.89	$340.44	$3.55	1.1%	1,121	162
500	$415.05	$419.24	$4.19	1.0%	1,648	252
750	$566.69	$571.81	$5.12	0.9%	2,447	373
1,000	$718.33	$724.38	$6.06	0.8%	1,223	160
1,250	$869.97	$876.96	$6.99	0.8%	708	85
1,500	$1,021.61	$1,029.53	$7.92	0.8%	498	47
2,000	$1,324.88	$1,334.67	$9.79	0.7%	562	53
3,000	$1,931.43	$1,944.95	$13.52	0.7%	465	27
5,000	$3,144.54	$3,165.51	$20.98	0.7%	326	14
10,000	$6,177.30	$6,216.93	$39.63	0.6%	177	9
15,000	$9,210.06	$9,268.34	$58.28	0.6%	50	4
20,000	$11,781.75	$11,851.60	$69.85	0.6%	18	3
30,000	$16,925.13	$17,018.13	$92.99	0.5%	19	3
50,000	$27,211.90	$27,351.17	$139.27	0.5%	3	0
75,000	$40,070.36	$40,267.48	$197.12	0.5%	3	0
100,000	$52,928.82	$53,183.79	$254.97	0.5%	1	0

Billing Determinants			
		RY 2	**RY 3**
	UOM	**SC2**	**SC2**
First 3 therms	Monthly	$ 24.60	$ 25.60
Next 497 therms	Next 497 therms	$ 0.41792	$ 0.42434
Next 14,500 therms	Next 14,500 therms	$ 0.24286	$ 0.24659
Over 15,000 therms	Over 15,000 therms	$ 0.15065	$ 0.15296
Tax Credit - Next 497 therms	Next 497 therms	$ -	$ -
Tax Credit - Next 14,500 therms	Next 14,500 therms	$ -	$ -
Tax Credit - Over 15,000 therms	Over 15,000 therms	$ -	$ -
Bill Charge	Monthly	$ 0.90	$ 0.90
R&D Adjustment	Therm	$ 0.00138	$ 0.00138
Transition Charge	Therm	$ 0.01185	$ 0.01185
SBC - CEF NYSERDA	Therm	$ 0.00020	$ 0.00020
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%
Gas Supply Charge	Therm	$ 0.33591	$ 0.33591
MFC	Therm	$ 0.01437	$ 0.01437

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.
3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Gas Rates
Annual Total Bill Impact - May 1, 2022 - April 30, 2023
PSC No. 87 Service Classification No. 2 - General Sales Service

				increase / (decrease)	
Month	**Therms**	**RY 2**	**RY 3**	**Amount**	**Percent**
Jan	529	$432.64	$436.94	$4.30	1.0%
Feb	463	$386.13	$390.09	$3.95	1.0%
March	404	$340.02	$343.59	$3.57	1.1%
April	225	$200.11	$202.53	$2.43	1.2%
May	106	$107.10	$108.76	$1.66	1.6%
June	55	$67.24	$68.57	$1.33	2.0%
July	60	$71.14	$72.51	$1.37	1.9%
August	91	$95.37	$96.94	$1.56	1.6%
September	73	$81.30	$82.75	$1.45	1.8%
October	154	$144.62	$146.58	$1.97	1.4%
November	269	$234.50	$237.21	$2.71	1.2%
December	466	$388.48	$392.45	$3.97	1.0%
Annual Totals	**2,895**	**$2,548.65**	**$2,578.93**	**$30.27**	**1.2%**

Billing Determinants			
		RY 2	**RY 3**
	UOM	**SC2**	**SC2**
First 3 therms	Monthly	$ 24.60	$ 25.60
Next 497 therms	Next 497 therms	$ 0.41792	$ 0.42434
Next 14,500 therms	Next 14,500 therms	$ 0.24286	$ 0.24659
Over 15,000 therms	Over 15,000 therms	$ 0.15065	$ 0.15296
Tax Credit - Next 497 therms	Next 497 therms	$ -	$ -
Tax Credit - Next 14,500 therms	Next 14,500 therms	$ -	$ -
Tax Credit - Over 15,000 therms	Over 15,000 therms	$ -	$ -
Bill Charge	Monthly	$ 0.90	$ 0.90
R&D Adjustment	Therm	$ 0.00138	$ 0.00138
Transition Charge	Therm	$ 0.01185	$ 0.01185
SBC - CEF NYSERDA	Therm	$ 0.00020	$ 0.00020
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%
Gas Supply Charge	Therm	$ 0.33591	$ 0.33591
MFC	Therm	$ 0.01437	$ 0.01437

Notes:

1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Gas Rates
Monthly Total Bill Impact - May 1, 2022 - April 30, 2023
PSC No. 87 Service Classification No. 9 - Industrial Manufacturing or Processing Purposes Sales Service

			increase / (decrease)		Number of Customers	
Therms	RY 2	RY 3	Amount	Percent	January	July
-	$353.67	$353.67	$0.00	0.0%		
500	$511.78	$511.78	$0.00	0.0%	0	0
750	$630.13	$631.02	$0.89	0.1%	0	0
1,000	$748.48	$750.27	$1.79	0.2%	0	0
1,250	$866.83	$869.51	$2.68	0.3%	0	0
1,500	$985.17	$988.75	$3.58	0.4%	0	0
2,000	$1,221.87	$1,227.24	$5.37	0.4%	0	0
3,000	$1,695.26	$1,704.21	$8.95	0.5%	0	0
5,000	$2,642.04	$2,658.15	$16.10	0.6%	0	1
10,000	$5,009.00	$5,042.99	$33.99	0.7%	1	0
15,000	$7,375.96	$7,427.84	$51.89	0.7%	0	0
20,000	$9,553.66	$9,603.46	$49.80	0.5%	0	0
30,000	$13,909.08	$13,954.69	$45.61	0.3%	0	0
50,000	$22,619.90	$22,657.15	$37.25	0.2%	0	0
75,000	$33,508.44	$33,535.23	$26.80	0.1%	0	0
100,000	$44,396.97	$44,413.31	$16.34	0.0%	0	0

Billing Determinants			
		RY 2	RY 3
	UOM	SC9	SC9
First 500 Therms	Monthly	$ 352.77	$ 352.77
Next 14,500 therms	Next 14,500 therms	$ 0.15717	$ 0.16075
Over 15,000 therms	Over 15,000 therms	$ 0.11932	$ 0.11890
Tax Credit - Next 14,500 therms	Next 14,500 therms	$ -	$ -
Tax Credit - Over 15,000 therms	Over 15,000 therms	$ -	$ -
Bill Charge	Monthly	$ 0.90	$ 0.90
R&D Adjustment	Therm	$ 0.00138	$ 0.00138
Transition Charge	Therm	$ 0.01185	$ 0.01185
SBC - CEF NYSERDA	Therm	$ 0.00020	$ 0.00020
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%
Gas Supply Charge	Therm	$ 0.28844	$ 0.28844
MFC	Therm	$ 0.01437	$ 0.01437

Notes:

1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Data Sources - NYSEG Gas Bill Impact Statements

Rate	Source of Rate in "Current" Rates	Source of Rate in Rate Years
Basic Service Charge (Non-Heating)	Current Tariff Rates in Effect January 1, 2019 (Last updated 5/1/2018)	New
Basic Service Charge (Heating)	Current Tariff Rates in Effect January 1, 2019 (Last updated 5/1/2018)	New
Usage Charge	Current Tariff Rates in Effect January 1, 2019 (Last updated 5/1/2018)	New
SBC (NYSERDA EE) - per Therm	Current Tariff Rates in Effect January 1, 2020	Current Tariff Rates in Effect January 1, 2020
SBC (EE Tracker) - per Therm	Current Tariff Rates in Effect January 1, 2020	Included in Delivery Rates
Billing Charge per Bill	Current Tariff Rates in Effect January 1, 2019 - (Last Updated 07/01/2016)	Results of 2019 Embedded Cost Study
Usage Charge - Tax Credit	Current Tariff Rates in Effect 10/1/2018	Included in Delivery Rates

	Source of Rate in "Current" Rates and Rate Years
Transition Charge per Therm	Non Weighted Average of Monthly Transition Charge in 2019
R&D Charge per Therm	Current Tariff Rates in Effect January 1, 2020
MFC per Therm	Current Tariff Rates in Effect May 1, 2020
Gas Supply Charge	Non Weighted Average of Monthly GSC in 2019
Customer Count	2018 Billing Information

New York State Electric & Gas Corporation
Gas Rates
Monthly Delivery Bill Impact - May 1, 2022 - April 30, 2023
PSC No. 87 Service Classification No. 1 – Residential Sales Service
PSC No. 88 Service Classification No. 13 - Residential Firm Aggregation Transportation Service

			increase / (decrease)		Number of Customers		Number of Low Income Customers		Percent of Customers	Percent of Low Income Customers	Amount of EE Embedded in Delivery Rates	
Therms	**RY 2**	**RY 3**	**Amount**	**Percent**	**January**	**July**	**January**	**July**	**January**	**January**	**Amount**	**Percent**
3	$18.24	$19.24	$1.00	5.5%	849	17,340	98	2,589	0.4%	0.3%	$0.00	0.00%
10	$23.03	$24.05	$1.03	4.5%	1,732	57,168	251	7,747	0.8%	0.8%	$0.09	0.36%
20	$29.87	$30.93	$1.06	3.6%	2,479	78,018	393	9,309	1.1%	1.3%	$0.21	0.69%
30	$36.70	$37.80	$1.10	3.0%	2,763	43,093	421	5,105	1.2%	1.4%	$0.34	0.89%
40	$43.54	$44.68	$1.14	2.6%	3,080	16,213	477	1,911	1.3%	1.6%	$0.46	1.04%
50	$50.38	$51.55	$1.17	2.3%	3,341	6,060	557	690	1.5%	1.8%	$0.59	1.14%
60	$52.09	$53.27	$1.18	2.3%	3,505	2,689	623	284	1.5%	2.0%	$0.62	1.16%
70	$53.80	$54.99	$1.19	2.2%	4,440	1,518	772	141	1.9%	2.5%	$0.65	1.18%
80	$55.52	$56.72	$1.20	2.2%	5,083	1,005	853	100	2.2%	2.8%	$0.68	1.19%
90	$57.23	$58.44	$1.21	2.1%	6,050	655	1023	47	2.6%	3.4%	$0.71	1.21%
100	$58.94	$60.16	$1.22	2.1%	6,802	524	1139	48	3.0%	3.7%	$0.73	1.22%
125	$63.22	$64.46	$1.24	2.0%	21,992	1,255	3300	96	9.6%	10.8%	$0.81	1.25%
150	$67.51	$68.77	$1.26	1.9%	25,822	663	3604	49	11.2%	11.8%	$0.88	1.28%
175	$71.79	$73.07	$1.28	1.8%	27,038	380	3492	29	11.8%	11.4%	$0.95	1.31%
200	$76.07	$77.37	$1.30	1.7%	24,867	213	3106	16	10.8%	10.2%	$1.03	1.33%
250	$84.63	$85.98	$1.35	1.6%	38,031	350	4452	19	16.6%	14.6%	$1.18	1.37%
300	$93.20	$94.59	$1.39	1.5%	22,616	174	2701	14	9.8%	8.8%	$1.32	1.40%
350	$101.76	$103.20	$1.43	1.4%	12,476	117	1468	6	5.4%	4.8%	$1.47	1.42%
400	$110.33	$111.80	$1.48	1.3%	6,742	68	830	4	2.9%	2.7%	$1.62	1.45%
500	$127.46	$129.02	$1.56	1.2%	5,627	81	639	7	2.4%	2.1%	$1.91	1.48%
750	$170.28	$172.05	$1.78	1.0%	3,032	64	287	8	1.3%	0.9%	$2.65	1.54%
1,000	$213.10	$215.09	$1.99	0.9%	586	28	27	2	0.3%	0.1%	$3.38	1.57%
1,500	$298.74	$301.16	$2.43	0.8%	408	24	14	1	0.2%	0.0%	$4.85	1.61%
2,000	$384.38	$387.24	$2.86	0.7%	159	4	3	0	0.1%	0.0%	$6.32	1.63%
3,000	$555.66	$559.39	$3.73	0.7%	114	6	2	1	0.0%	0.0%	$9.26	1.66%
5,000	$898.22	$903.68	$5.46	0.6%	67	5	0	0	0.0%	0.0%	$15.14	1.68%
					229,704		30,530					

Billing Determinants					
		RY 2	**RY 3**		
	UOM	**SC1/SC13 - Heating**	**SC1/SC13 - Heating**		
First 3 therms	Monthly	$ 17.30	$ 18.30		
Next 47 therms	Next 47 therms	$ 0.67007	$ 0.67375	$ 0.01250	EE Tracker
Over 50 therms	Over 50 therms	$ 0.15760	$ 0.15846	$ 0.00294	EE Tracker
Tax Credit - Next 47 therms	Next 47 therms	$ -	$ -		
Tax Credit - Over 50 therms	Over 50 therms	$ -	$ -		
Bill Charge	Monthly	$ 0.90	$ 0.90		
R&D Adjustment	Therm	$ 0.00138	$ 0.00138		
Transition Charge	Therm	$ 0.01211	$ 0.01211		
SBC - CEF NYSERDA	Therm	$ 0.00020	$ 0.00020		
SBC - EE Tracker	Therm	$ -	$ -		
GRT - Delivery	%	0.00%	0.00%		

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.
3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.
4. Low Income customers represent customers who participated in the Company's low income program and received a credit on their bill each month during calendar year 2018.

New York State Electric & Gas Corporation
Gas Rates
Annual Delivery Bill Impact - May 1, 2022 - April 30, 2023
PSC No. 87 Service Classification No. 1 – Residential Sales Service
PSC No. 88 Service Classification No. 13 - Residential Firm Aggregation Transportation Service

				increase / (decrease)	
Month	**Therms**	**RY 2**	**RY 3**	**Amount**	**Percent**
Jan	180	$72.65	$73.93	$1.29	1.8%
Feb	156	$68.53	$69.80	$1.26	1.8%
March	139	$65.62	$66.87	$1.25	1.9%
April	70	$53.80	$54.99	$1.19	2.2%
May	27	$34.65	$35.74	$1.09	3.1%
June	20	$29.87	$30.93	$1.06	3.6%
July	16	$27.13	$28.18	$1.05	3.9%
August	28	$35.34	$36.43	$1.09	3.1%
September	27	$34.65	$35.74	$1.09	3.1%
October	51	$50.55	$51.72	$1.17	2.3%
November	106	$59.97	$61.19	$1.22	2.0%
December	160	$69.22	$70.49	$1.27	1.8%
Annual Totals	**980**	**$601.98**	**$616.02**	**$14.03**	**2.3%**

Billing Determinants			
		RY 2	**RY 3**
	UOM	**SC1/SC13 - Heating**	**SC1/SC13 - Heating**
First 3 therms	Monthly	$ 17.30	$ 18.30
Next 47 therms	Next 47 therms	$ 0.67007	$ 0.67375
Over 50 therms	Over 50 therms	$ 0.15760	$ 0.15846
Tax Credit - Next 47 therms	Next 47 therms	$ -	$ -
Tax Credit - Over 50 therms	Over 50 therms	$ -	$ -
Bill Charge	Monthly	$ 0.90	$ 0.90
R&D Adjustment	Therm	$ 0.00138	$ 0.00138
Transition Charge	Therm	$ 0.01211	$ 0.01211
SBC - CEF NYSERDA	Therm	$ 0.00020	$ 0.00020
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.
3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Gas Rates
Monthly Delivery Bill Impact - May 1, 2022 - April 30, 2023
PSC No. 87 Service Classification No. 2 - General Sales Service
PSC No. 88 Service Classification No. 14 - Non-Residential Firm Aggregation Transportation Service

			increase / (decrease)		Number of Customers	
Therms	**RY 2**	**RY 3**	**Amount**	**Percent**	**January**	**July**
3	$25.54	$26.54	$1.00	3.9%	408	4,503
10	$28.56	$29.61	$1.04	3.7%	657	6,522
20	$32.88	$33.99	$1.11	3.4%	562	4,696
50	$45.83	$47.13	$1.30	2.8%	1,643	6,619
100	$67.41	$69.03	$1.62	2.4%	2,766	3,026
150	$88.99	$90.93	$1.94	2.2%	2,882	1,375
200	$110.57	$112.83	$2.26	2.0%	2,618	765
250	$132.15	$134.73	$2.59	2.0%	2,262	536
300	$153.73	$156.63	$2.91	1.9%	1,968	438
350	$175.31	$178.54	$3.23	1.8%	1,668	313
400	$196.89	$200.44	$3.55	1.8%	1,472	291
500	$240.05	$244.24	$4.19	1.7%	2,234	494
750	$304.18	$309.31	$5.12	1.7%	3,437	772
1,000	$368.32	$374.38	$6.06	1.6%	1,899	385
1,250	$432.46	$439.44	$6.99	1.6%	1,184	192
1,500	$496.59	$504.51	$7.92	1.6%	844	139
2,000	$624.86	$634.65	$9.79	1.6%	1,002	145
3,000	$881.41	$894.92	$13.52	1.5%	981	108
5,000	$1,394.50	$1,415.47	$20.98	1.5%	752	71
10,000	$2,677.21	$2,716.84	$39.63	1.5%	502	43
15,000	$3,959.93	$4,018.21	$58.28	1.5%	144	18
20,000	$4,781.58	$4,851.43	$69.85	1.5%	51	7
30,000	$6,424.88	$6,517.87	$92.99	1.4%	62	4
50,000	$9,711.48	$9,850.75	$139.27	1.4%	20	1
75,000	$13,819.73	$14,016.85	$197.12	1.4%	5	3
100,000	$17,927.97	$18,182.94	$254.97	1.4%	2	1

Billing Determinants			
		RY 2	**RY 3**
	UOM	**SC2/14**	**SC2/14**
First 3 therms	Monthly	$ 24.60	$ 25.60
Next 497 therms	Next 497 therms	$ 0.41792	$ 0.42434
Next 14,500 therms	Next 14,500 therms	$ 0.24286	$ 0.24659
Over 15,000 therms	Over 15,000 therms	$ 0.15065	$ 0.15296
Tax Credit - Next 497 therms	Next 497 therms	$ -	$ -
Tax Credit - Next 14,500 therms	Next 14,500 therms	$ -	$ -
Tax Credit - Over 15,000 therms	Over 15,000 therms	$ -	$ -
Bill Charge	Monthly	$ 0.90	$ 0.90
R&D Adjustment	Therm	$ 0.00138	$ 0.00138
Transition Charge	Therm	$ 0.01211	$ 0.01211
SBC - CEF NYSERDA	Therm	$ 0.00020	$ 0.00020
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%

Notes:

1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Gas Rates
Annual Delivery Bill Impact - May 1, 2022 - April 30, 2023
PSC No. 87 Service Classification No. 2 - General Sales Service
PSC No. 88 Service Classification No. 14 - Non-Residential Firm Aggregation Transportation Service

				increase / (decrease)	
Month	**Therms**	**RY 2**	**RY 3**	**Amount**	**Percent**
Jan	529	$247.49	$251.79	$4.30	1.7%
Feb	463	$224.08	$228.03	$3.95	1.8%
March	404	$198.61	$202.19	$3.57	1.8%
April	225	$121.36	$123.78	$2.43	2.0%
May	106	$70.00	$71.66	$1.66	2.4%
June	55	$47.99	$49.32	$1.33	2.8%
July	60	$50.14	$51.51	$1.37	2.7%
August	91	$63.52	$65.09	$1.56	2.5%
September	73	$55.75	$57.20	$1.45	2.6%
October	154	$90.71	$92.68	$1.97	2.2%
November	269	$140.35	$143.06	$2.71	1.9%
December	466	$225.37	$229.35	$3.97	1.8%
Annual Totals	**2,895**	**$1,535.38**	**$1,565.66**	**$30.27**	**2.0%**

Billing Determinants			
		RY 2	**RY 3**
	UOM	**SC2/14**	**SC2/14**
First 3 therms	Monthly	$ 24.60	$ 25.60
Next 497 therms	Next 497 therms	$ 0.41792	$ 0.42434
Next 14,500 therms	Next 14,500 therms	$ 0.24286	$ 0.24659
Over 15,000 therms	Over 15,000 therms	$ 0.15065	$ 0.15296
Tax Credit - Next 497 therms	Next 497 therms	$ -	$ -
Tax Credit - Next 14,500 therms	Next 14,500 therms	$ -	$ -
Tax Credit - Over 15,000 therms	Over 15,000 therms	$ -	$ -
Bill Charge	Monthly	$ 0.90	$ 0.90
R&D Adjustment	Therm	$ 0.00138	$ 0.00138
Transition Charge	Therm	$ 0.01211	$ 0.01211
SBC - CEF NYSERDA	Therm	$ 0.00020	$ 0.00020
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%

Notes:

1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Gas Rates
Monthly Delivery Bill Impact - May 1, 2022 - April 30, 2023
PSC No. 88 Service Classification No. 1 - Firm Transportation Service

Therms	RY 2	RY 3	increase / (decrease) Amount	increase / (decrease) Percent	Number of Customers January	Number of Customers July
-	$2,338.66	$2,554.30	$215.65	9.2%	0	0
500	$2,339.40	$2,555.05	$215.65	9.2%	0	3
750	$2,372.48	$2,589.15	$216.67	9.1%	1	1
1,000	$2,405.56	$2,623.26	$217.70	9.0%	0	0
1,250	$2,438.64	$2,657.36	$218.72	9.0%	0	0
1,500	$2,471.72	$2,691.46	$219.74	8.9%	0	1
2,000	$2,537.87	$2,759.66	$221.79	8.7%	0	1
3,000	$2,670.18	$2,896.06	$225.88	8.5%	0	4
5,000	$2,934.80	$3,168.87	$234.07	8.0%	1	7
10,000	$3,596.36	$3,850.90	$254.54	7.1%	0	7
15,000	$4,257.91	$4,532.92	$275.01	6.5%	2	7
20,000	$4,619.29	$4,905.38	$286.09	6.2%	0	10
30,000	$5,342.06	$5,650.30	$308.24	5.8%	3	21
50,000	$6,787.60	$7,140.14	$352.54	5.2%	21	30
75,000	$8,183.93	$8,579.00	$395.07	4.8%	23	11
100,000	$9,580.27	$10,017.87	$437.60	4.6%	38	21

Billing Determinants

	UOM	RY 2 SC1T	RY 3 SC1T
First 500 Therms	Monthly	$ 2,337.75	$ 2,553.40
Next 14,500 therms	Next 14,500 therms	$ 0.13081	$ 0.13491
Next 35,000 therms	Next 35,000 therms	$ 0.07078	$ 0.07299
Over 50,000 therms	Over 50,000 therms	$ 0.05435	$ 0.05606
Tax Credit - Next 14,500 therms	Next 14,500 therms	$ -	$ -
Tax Credit - Next 35,000 therms	Next 35,000 therms	$ -	$ -
Tax Credit - Over 50,000 therms	Over 50,000 therms	$ -	$ -
Bill Charge	Monthly	$ 0.90	$ 0.90
R&D Adjustment	Therm	$ 0.00138	$ 0.00138
Transition Charge	Therm	$ (0.00007)	$ (0.00007)
SBC - CEF NYSERDA	Therm	$ 0.00020	$ 0.00020
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

New York State Electric & Gas Corporation
Gas Rates
Monthly Delivery Bill Impact - May 1, 2022 - April 30, 2023
PSC No. 88 Service Classification No. 5 - Small Firm Transportation Service

Therms	RY 2	RY 3	increase / (decrease)		Number of Customers	
			Amount	Percent	January	July
-	$358.29	$358.29	$0.00	0.0%	0	0
500	$359.04	$359.04	$0.00	0.0%	1	147
750	$406.52	$408.03	$1.51	0.4%	1	25
1,000	$453.99	$457.01	$3.02	0.7%	1	24
1,250	$501.46	$506.00	$4.53	0.9%	4	24
1,500	$548.94	$554.98	$6.04	1.1%	0	12
2,000	$643.89	$652.95	$9.06	1.4%	9	19
3,000	$833.79	$848.89	$15.11	1.8%	13	29
5,000	$1,213.59	$1,240.78	$27.19	2.2%	30	17
10,000	$2,163.08	$2,220.49	$57.40	2.7%	117	19
15,000	$3,112.58	$3,200.19	$87.62	2.8%	65	12
20,000	$3,696.42	$3,802.53	$106.10	2.9%	41	2
30,000	$4,864.12	$5,007.19	$143.07	2.9%	38	2
50,000	$7,199.51	$7,416.52	$217.01	3.0%	16	4
75,000	$10,118.75	$10,428.18	$309.44	3.1%	1	3
100,000	$13,037.98	$13,439.85	$401.86	3.1%	1	1

Billing Determinants			
		RY 2	RY 3
	UOM	SC5T	SC5T
First 500 Therms	Monthly	$ 357.39	$ 357.39
Next 14,500 therms	Next 14,500 therms	$ 0.18840	$ 0.19444
Over 15,000 therms	Over 15,000 therms	$ 0.11527	$ 0.11897
Tax Credit - Next 14,500 therms	Next 14,500 therms	$ -	$ -
Tax Credit - Over 15,000 therms	Over 15,000 therms	$ -	$ -
Bill Charge	Monthly	$ 0.90	$ 0.90
R&D Adjustment	Therm	$ 0.00138	$ 0.00138
Transition Charge	Therm	$ (0.00007)	$ (0.00007)
SBC - CEF NYSERDA	Therm	$ 0.00020	$ 0.00020
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%

Notes:

1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and proposed rates for the Transition Charge and Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

New York State Electric & Gas Corporation
Data Sources - NYSEG Gas Bill Impact Statements

Rate	Source of Rate in "Current" Rates	Source of Rate in Rate Years
Basic Service Charge (Non-Heating)	Current Tariff Rates in Effect January 1, 2019 (Last updated 5/1/2018)	New
Basic Service Charge (Heating)	Current Tariff Rates in Effect January 1, 2019 (Last updated 5/1/2018)	New
Usage Charge	Current Tariff Rates in Effect January 1, 2019 (Last updated 5/1/2018)	New
SBC (NYSERDA EE) - per Therm	Current Tariff Rates in Effect January 1, 2020	Current Tariff Rates in Effect January 1, 2020
SBC (EE Tracker) - per Therm	Current Tariff Rates in Effect January 1, 2020	Included in Delivery Rates
Billing Charge per Bill	Current Tariff Rates in Effect January 1, 2019 - (Last Updated 07/01/2016)	Results of 2019 Embedded Cost Study
Usage Charge - Tax Credit	Current Tariff Rates in Effect 10/1/2018	Included in Delivery Rates

	Source of Rate in "Current" Rates and Rate Years
Transition Charge per Therm	Non Weighted Average of Monthly Transition Charge in 2019
R&D Charge per Therm	Current Tariff Rates in Effect January 1, 2020
MFC per Therm	Current Tariff Rates in Effect May 1, 2020
Gas Supply Charge	Non Weighted Average of Monthly GSC in 2019
Customer Count	2018 Billing Information

Rochester Gas and Electric Corporation
Gas Rates
Monthly Total Bill Impact - May 1, 2020 - April 30, 2021
PSC No. 16 Service Classification No. 1 – General Service

Residential

Therms	Current Rates	RY 1	increase / (decrease) Amount	increase / (decrease) Percent	Number of Customers January	Number of Customers July
3	$18.03	$18.23	$0.20	1.1%	2,095	14,469
10	$22.41	$22.59	$0.18	0.8%	2,677	62,561
20	$28.67	$28.82	$0.15	0.5%	3,262	99,253
30	$34.93	$35.04	$0.12	0.3%	3,151	51,378
40	$41.19	$41.27	$0.08	0.2%	3,516	17,138
50	$47.44	$47.50	$0.05	0.1%	3,496	6,418
60	$53.70	$53.72	$0.02	0.0%	4,377	2,686
70	$59.96	$59.95	($0.01)	0.0%	5,316	1,758
80	$66.22	$66.17	($0.04)	-0.1%	6,322	1,086
90	$72.47	$72.40	($0.08)	-0.1%	6,782	798
100	$78.73	$78.63	($0.11)	-0.1%	8,813	598
125	$93.89	$93.70	($0.18)	-0.2%	27,463	1,600
150	$109.04	$108.78	($0.26)	-0.2%	34,147	841
175	$124.20	$123.86	($0.34)	-0.3%	35,174	418
250	$169.66	$169.10	($0.57)	-0.3%	42,265	424
300	$199.97	$199.25	($0.72)	-0.4%	21,594	244
350	$230.29	$229.41	($0.88)	-0.4%	10,892	185
400	$260.60	$259.57	($1.03)	-0.4%	5,400	113
500	$321.22	$319.88	($1.34)	-0.4%	4,448	130
750	$465.47	$463.40	($2.07)	-0.4%	2,196	127
1,000	$609.72	$606.92	($2.80)	-0.5%	373	50
1,500	$829.44	$825.55	($3.89)	-0.5%	244	42
2,000	$1,049.16	$1,044.18	($4.98)	-0.5%	68	11
3,000	$1,488.60	$1,481.44	($7.15)	-0.5%	59	4
5,000	$2,367.48	$2,355.97	($11.51)	-0.5%	38	2

Amount of EE Embedded in Delivery Rates Amount	Amount of EE Embedded in Delivery Rates Percent
$ -	0.00%
$ (0.01)	-0.05%
$ (0.03)	-0.09%
$ (0.04)	-0.12%
$ (0.06)	-0.14%
$ (0.07)	-0.15%
$ (0.09)	-0.16%
$ (0.10)	-0.17%
$ (0.12)	-0.18%
$ (0.13)	-0.19%
$ (0.15)	-0.19%
$ (0.19)	-0.20%
$ (0.22)	-0.20%
$ (0.26)	-0.21%
$ (0.37)	-0.22%
$ (0.44)	-0.22%
$ (0.51)	-0.22%
$ (0.58)	-0.22%
$ (0.73)	-0.23%
$ (1.05)	-0.23%
$ (1.37)	-0.23%
$ (1.64)	-0.20%
$ (1.92)	-0.18%
$ (2.46)	-0.17%
$ (3.56)	-0.15%

Billing Determinants	UOM	Current Rates SC1	RY 1 SC1		
First 3 therms	Monthly	$ 16.30	$ 16.30		
Next 97 therms	Next 97 therms	$ 0.30946	$ 0.28682	$ (0.00256)	EE Tracker
Next 400 therms	Next 400 therms	$ 0.28857	$ 0.26736	$ (0.00239)	EE Tracker
Next 500 therms	Next 500 therms	$ 0.25511	$ 0.23832	$ (0.00213)	EE Tracker
Over 1,000 Therms	Over 1,000 Therms	$ 0.10859	$ 0.10149	$ (0.00091)	EE Tracker
Tax Credit - Next 97 therms	Next 97 therms	$ (0.02108)	$ -		
Tax Credit - Next 400 therms	Next 400 therms	$ (0.01976)	$ -		
Tax Credit - Next 500 therms	Next 500 therms	$ (0.01550)	$ -		
Tax Credit - Over 1,000 therms	Over 1,000 Therms	$ (0.00655)	$ -		
Bill Charge	Monthly	$ 0.72	$ 0.93		
SBC - CEF NYSERDA	Therm	$ 0.00021	$ 0.00021		
SBC - EE Tracker	Therm	$ 0.00163	$ -		
GRT - Delivery	%	0.00%	0.00%		
Gas Supply Charge	Therm	$ 0.31811	$ 0.31811		
MFC	Therm	$ 0.01746	$ 0.01746		

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

Rochester Gas and Electric Corporation
Gas Rates
Annual Total Bill Impact - May 1, 2020 - April 30, 2021
PSC No. 16 Service Classification No. 1 – General Service
Residential

Residential Spaceheating

				increase / (decrease)	
Month	**Therms**	**Current Rates**	**RY 1**	**Amount**	**Percent**
January	155	$112.07	$111.80	($0.28)	-0.2%
February	161	$115.71	$115.42	($0.29)	-0.3%
March	145	$106.01	$105.77	($0.25)	-0.2%
April	106	$82.37	$82.24	($0.13)	-0.2%
May	65	$56.83	$56.83	$0.00	0.0%
June	35	$38.06	$38.16	$0.10	0.3%
July	18	$27.42	$27.57	$0.15	0.6%
August	18	$27.42	$27.57	$0.15	0.6%
September	21	$29.30	$29.44	$0.14	0.5%
October	30	$34.93	$35.04	$0.12	0.3%
November	75	$63.09	$63.06	($0.03)	0.0%
December	120	$90.86	$90.69	($0.17)	-0.2%
Annual Total	949	$784.06	$783.60	($0.46)	-0.1%

Residential Non-Spaceheating

				increase / (decrease)	
Month	**Therms**	**Current Rates**	**RY 1**	**Amount**	**Percent**
January	80	$66.22	$66.17	($0.04)	-0.1%
February	82	$67.47	$67.42	($0.05)	-0.1%
March	74	$62.46	$62.44	($0.02)	0.0%
April	55	$50.57	$50.61	$0.04	0.1%
May	38	$39.93	$40.02	$0.09	0.2%
June	24	$31.17	$31.31	$0.14	0.4%
July	14	$24.92	$25.08	$0.17	0.7%
August	13	$24.29	$24.46	$0.17	0.7%
September	16	$26.17	$26.33	$0.16	0.6%
October	18	$27.42	$27.57	$0.15	0.6%
November	42	$42.44	$42.52	$0.08	0.2%
December	63	$55.58	$55.59	$0.01	0.0%
Annual Total	519	$518.64	$519.52	$0.88	0.2%

Billing Determinants			
		Current Rates	**RY 1**
	UOM	**SC1**	**SC1**
First 3 therms	Monthly	$ 16.30	$ 16.30
Next 97 therms	Next 97 therms	$ 0.30946	$ 0.28682
Next 400 therms	Next 400 therms	$ 0.28857	$ 0.26736
Next 500 therms	Next 500 therms	$ 0.25511	$ 0.23832
Over 1,000 Therms	Over 1,000 Therms	$ 0.10859	$ 0.10149
Tax Credit - Next 97 therms	Next 97 therms	$ (0.02108)	$ -
Tax Credit - Next 400 therms	Next 400 therms	$ (0.01976)	$ -
Tax Credit - Next 500 therms	Next 500 therms	$ (0.01550)	$ -
Tax Credit - Over 1,000 therms	Over 1,000 Therms	$ (0.00655)	$ -
Bill Charge	Monthly	$ 0.72	$ 0.93
SBC - CEF NYSERDA	Therm	$ 0.00021	$ 0.00021
SBC - EE Tracker	Therm	$ 0.00163	$ -
GRT - Delivery	%	0.00%	0.00%
Gas Supply Charge	Therm	$ 0.31811	$ 0.31811
MFC	Therm	$ 0.01746	$ 0.01746

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

Rochester Gas and Electric Corporation
Gas Rates
Monthly Total Bill Impact - May 1, 2020 - April 30, 2021
PSC No. 16 Service Classification No. 1 – General Service

Non-Residential

			increase / (decrease)		Number of Customers	
Therms	**Current Rates**	**RY 1**	**Amount**	**Percent**	**January**	**July**
3	$18.02	$18.22	$0.20	1.1%	262	2,687
10	$22.38	$22.56	$0.18	0.8%	476	3,884
20	$28.60	$28.75	$0.15	0.5%	460	2,352
50	$47.27	$47.32	$0.05	0.1%	1,093	2,885
100	$78.38	$78.27	($0.11)	-0.1%	1,862	1,379
150	$108.51	$108.25	($0.26)	-0.2%	1,634	529
200	$138.64	$138.23	($0.41)	-0.3%	1,430	350
250	$168.77	$168.20	($0.57)	-0.3%	1,180	244
300	$198.91	$198.18	($0.72)	-0.4%	916	175
350	$229.04	$228.16	($0.88)	-0.4%	728	150
400	$259.17	$258.14	($1.03)	-0.4%	623	104
500	$319.44	$318.10	($1.34)	-0.4%	988	207
750	$462.80	$460.73	($2.07)	-0.4%	1,404	297
1,000	$606.16	$603.36	($2.80)	-0.5%	816	105
1,500	$824.10	$820.21	($3.89)	-0.5%	326	26
2,000	$1,042.04	$1,037.06	($4.98)	-0.5%	402	23
3,000	$1,477.91	$1,470.76	($7.15)	-0.5%	354	21
5,000	$2,349.67	$2,338.16	($11.51)	-0.5%	236	15
10,000	$4,529.05	$4,506.65	($22.40)	-0.5%	121	10
15,000	$6,708.44	$6,675.15	($33.29)	-0.5%	30	3
20,000	$8,887.82	$8,843.64	($44.18)	-0.5%	7	1
30,000	$13,246.59	$13,180.63	($65.96)	-0.5%	8	3
50,000	$21,964.13	$21,854.62	($109.52)	-0.5%	4	1
75,000	$32,861.06	$32,697.09	($163.96)	-0.5%	2	0
100,000	$43,757.98	$43,539.57	($218.41)	-0.5%	0	0

Billing Determinants			
		Current Rates	**RY 1**
	UOM	**SC1**	**SC1**
First 3 therms	Monthly	$ 16.30	$ 16.30
Next 97 therms	Next 97 therms	$ 0.30946	$ 0.28682
Next 400 therms	Next 400 therms	$ 0.28857	$ 0.26736
Next 500 therms	Next 500 therms	$ 0.25511	$ 0.23832
Over 1,000 Therms	Over 1,000 Therms	$ 0.10859	$ 0.10149
Tax Credit - Next 97 therms	Next 97 therms	$ (0.02108)	$ -
Tax Credit - Next 400 therms	Next 400 therms	$ (0.01976)	$ -
Tax Credit - Next 500 therms	Next 500 therms	$ (0.01550)	$ -
Tax Credit - Over 1,000 therms	Over 1,000 Therms	$ (0.00655)	$ -
Bill Charge	Monthly	$ 0.72	$ 0.93
SBC - CEF NYSERDA	Therm	$ 0.00021	$ 0.00021
SBC - EE Tracker	Therm	$ 0.00163	$ -
GRT - Delivery	%	0.00%	0.00%
Gas Supply Charge	Therm	$ 0.31811	$ 0.31811
MFC	Therm	$ 0.01389	$ 0.01389

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

Rochester Gas and Electric Corporation
Gas Rates
Annual Total Bill Impact - May 1, 2020 - April 30, 2021
PSC No. 16 Service Classification No. 1 – General Service
Non-Residential

Commercial

				increase / (decrease)	
Monthly	**Therms**	**Current Rates**	**RY 1**	**Amount**	**Percent**
January	393	$254.95	$253.94	($1.01)	-0.4%
February	404	$261.58	$260.54	($1.04)	-0.4%
March	369	$240.49	$239.55	($0.94)	-0.4%
April	268	$179.62	$179.00	($0.62)	-0.3%
May	173	$122.37	$122.04	($0.33)	-0.3%
June	87	$70.29	$70.22	($0.07)	-0.1%
July	46	$44.78	$44.84	$0.06	0.1%
August	50	$47.27	$47.32	$0.05	0.1%
September	61	$54.11	$54.13	$0.02	0.0%
October	87	$70.29	$70.22	($0.07)	-0.1%
November	194	$135.03	$134.63	($0.40)	-0.3%
December	311	$205.54	$204.78	($0.76)	-0.4%
Annual Total	2,443	$1,686.30	$1,681.21	($5.09)	-0.3%

Industrial

				increase / (decrease)	
Monthly	**Therms**	**Current Rates**	**RY 1**	**Amount**	**Percent**
January	2,000	$1,042.04	$1,037.06	($4.98)	-0.5%
February	2,174	$1,117.88	$1,112.52	($5.36)	-0.5%
March	2,048	$1,062.96	$1,057.88	($5.08)	-0.5%
April	914	$556.84	$554.29	($2.55)	-0.5%
May	692	$429.54	$427.64	($1.90)	-0.4%
June	274	$183.24	$182.59	($0.64)	-0.4%
July	157	$112.73	$112.45	($0.28)	-0.3%
August	110	$84.40	$84.27	($0.14)	-0.2%
September	126	$94.05	$93.86	($0.19)	-0.2%
October	160	$114.54	$114.24	($0.29)	-0.3%
November	769	$473.69	$471.57	($2.12)	-0.4%
December	1,499	$823.66	$819.78	($3.89)	-0.5%
Annual Total	10,923	$6,095.55	$6,068.14	($27.41)	-0.4%

Municipal

				increase / (decrease)	
Monthly	**Therms**	**Current Rates**	**RY 1**	**Amount**	**Percent**
January	1,324	$747.38	$743.88	($3.50)	-0.5%
February	1,366	$765.69	$762.09	($3.60)	-0.5%
March	1,240	$710.77	$707.45	($3.32)	-0.5%
April	905	$551.68	$549.16	($2.52)	-0.5%
May	586	$368.75	$367.16	($1.59)	-0.4%
June	266	$178.42	$177.80	($0.62)	-0.3%
July	169	$119.96	$119.64	($0.32)	-0.3%
August	159	$113.93	$113.64	($0.29)	-0.3%
September	195	$135.63	$135.23	($0.40)	-0.3%
October	271	$181.43	$180.80	($0.63)	-0.3%
November	641	$400.29	$398.54	($1.75)	-0.4%
December	971	$589.53	$586.81	($2.71)	-0.5%
Annual Total	8,093	$4,863.46	$4,842.21	($21.25)	-0.4%

Billing Determinants			
		Current Rates	**RY 1**
	UOM	**SC1**	**SC1**
First 3 therms	Monthly	$ 16.30	$ 16.30
Next 97 therms	Next 97 therms	$ 0.30946	$ 0.28682
Next 400 therms	Next 400 therms	$ 0.28857	$ 0.26736
Next 500 therms	Next 500 therms	$ 0.25511	$ 0.23832
Over 1,000 Therms	Over 1,000 Therms	$ 0.10859	$ 0.10149
Tax Credit - Next 97 therms	Next 97 therms	$ (0.02108)	$ -
Tax Credit - Next 400 therms	Next 400 therms	$ (0.01976)	$ -
Tax Credit - Next 500 therms	Next 500 therms	$ (0.01550)	$ -
Tax Credit - Over 1,000 therms	Over 1,000 Therms	$ (0.00655)	$ -
Bill Charge	Monthly	$ 0.72	$ 0.93
SBC - CEF NYSERDA	Therm	$ 0.00021	$ 0.00021
SBC - EE Tracker	Therm	$ 0.00163	$ -
GRT - Delivery	%	0.00%	0.00%
Gas Supply Charge	Therm	$ 0.31811	$ 0.31811
MFC	Therm	$ 0.01389	$ 0.01389

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

Rochester Gas and Electric Corporation
Data Sources - RG&E Gas Bill Impact Statements

Rate	Source of Rate in "Current" Rates	Source of Rate in Rate Years
Basic Service Charge	Current Tariff Rates in Effect January 1, 2019 (Last updated 5/1/2018)	New
Usage Charge	Current Tariff Rates in Effect January 1, 2019 (Last updated 5/1/2018)	New
SBC (NYSERDA EE) - per Therm	Current Tariff Rates in Effect January 1, 2020	Current Tariff Rates in Effect January 1, 2020
SBC (EE Tracker) - per Therm	Current Tariff Rates in Effect January 1, 2020	Included in Delivery Rates
Billing Charge per Bill	Current Tariff Rates in Effect January 1, 2019 - (Last Updated 07/01/2016)	Results of 2019 Embedded Cost Study
Usage Charge - Tax Credit	Current Tariff Rates in Effect 10/1/2018	Included in Delivery Rates

	Source of Rate in "Current" Rates and Rate Years
MFC per Therm	Current Tariff Rates in Effect May 1, 2020
Gas Supply Charge	Non Weighted Average of Monthly GSC in 2019
Customer Count	2018 Billing Information

Rochester Gas and Electric Corporation
Gas Rates
Monthly Delivery Bill Impact - May 1, 2020 - April 30, 2021
PSC No. 16 Service Classification No. 1 – General Service
PSC No. 16 Service Classification No. 5 – Small Transportation Service

Residential

			increase / (decrease)		Number of Customers		Number of Low Income Customers		Percent of Customers	Percent of Low Income Customers	Amount of EE Embedded in Delivery Rates	
Therms	**Current Rates**	**RY 1**	**Amount**	**Percent**	**January**	**July**	**January**	**July**	**January**	**January**	**Amount**	**Percent**
3	$17.03	$17.23	$0.20	1.2%	2,161	15,658	231	1,566	0.7%	0.8%	$0.00	0.00%
10	$19.06	$19.24	$0.18	0.9%	2,834	69,672	398	6,332	1.0%	1.3%	($0.01)	-0.06%
20	$21.96	$22.11	$0.15	0.7%	3,425	111,491	405	9,997	1.2%	1.3%	($0.03)	-0.12%
30	$24.86	$24.98	$0.12	0.5%	3,329	57,504	458	6,445	1.1%	1.5%	($0.04)	-0.17%
40	$27.76	$27.85	$0.08	0.3%	3,712	19,044	478	2,607	1.3%	1.6%	($0.06)	-0.21%
50	$30.67	$30.72	$0.05	0.2%	3,709	7,148	432	1,139	1.3%	1.4%	($0.07)	-0.24%
60	$33.57	$33.59	$0.02	0.1%	4,655	3,000	604	469	1.6%	2.0%	($0.09)	-0.26%
70	$36.47	$36.46	($0.01)	0.0%	5,698	1,966	678	288	1.9%	2.2%	($0.10)	-0.28%
80	$39.37	$39.33	($0.04)	-0.1%	6,802	1,237	769	155	2.3%	2.5%	($0.12)	-0.30%
90	$42.27	$42.20	($0.08)	-0.2%	7,416	912	843	124	2.5%	2.8%	($0.13)	-0.32%
100	$45.18	$45.07	($0.11)	-0.2%	9,786	665	1,040	67	3.3%	3.4%	($0.15)	-0.33%
125	$51.94	$51.76	($0.18)	-0.4%	30,645	1,797	2,904	162	10.4%	9.6%	($0.19)	-0.36%
150	$58.71	$58.45	($0.26)	-0.4%	38,413	959	3,235	83	13.0%	10.7%	($0.22)	-0.38%
175	$65.48	$65.14	($0.34)	-0.5%	39,860	474	3,288	49	13.5%	10.8%	($0.26)	-0.40%
200	$72.24	$71.83	($0.41)	-0.6%	34,193	338	2,856	32	11.6%	9.4%	($0.29)	-0.41%
250	$85.77	$85.20	($0.57)	-0.7%	47,674	470	4,486	40	16.1%	14.8%	($0.37)	-0.43%
300	$99.31	$98.58	($0.72)	-0.7%	24,190	266	2,911	28	8.2%	9.6%	($0.44)	-0.44%
350	$112.84	$111.96	($0.88)	-0.8%	12,196	207	1,864	22	4.1%	6.1%	($0.51)	-0.46%
400	$126.37	$125.34	($1.03)	-0.8%	6,013	122	1,026	18	2.0%	3.4%	($0.58)	-0.46%
500	$153.44	$152.10	($1.34)	-0.9%	5,013	138	957	21	1.7%	3.2%	($0.73)	-0.48%
750	$213.80	$211.73	($2.07)	-1.0%	2,534	142	414	27	0.9%	1.4%	($1.05)	-0.49%
1,000	$274.16	$271.36	($2.80)	-1.0%	454	56	43	9	0.2%	0.1%	($1.37)	-0.50%
1,500	$326.10	$322.21	($3.89)	-1.2%	314	44	21	9	0.1%	0.1%	($1.64)	-0.51%
2,000	$378.04	$373.06	($4.98)	-1.3%	108	14	4	3	0.0%	0.0%	($1.92)	-0.51%
3,000	$481.91	$474.76	($7.15)	-1.5%	102	5	3	0	0.0%	0.0%	($2.46)	-0.52%
5,000	$689.67	$678.16	($11.51)	-1.7%	78	2	3	1	0.0%	0.0%	($3.56)	-0.52%
					295,313		30,350					

Billing Determinants				
		Current Rates	**RY 1**	
	UOM	**SC1&5**	**SC1&5**	
First 3 therms	Monthly	$ 16.30	$ 16.30	
Next 97 therms	Next 97 therms	$ 0.30946	$ 0.28682	$ (0.00256) EE Tracker
Next 400 therms	Next 400 therms	$ 0.28857	$ 0.26736	$ (0.00239) EE Tracker
Next 500 therms	Next 500 therms	$ 0.25511	$ 0.23832	$ (0.00213) EE Tracker
Over 1,000 Therms	Over 1,000 Therms	$ 0.10859	$ 0.10149	$ (0.00091) EE Tracker
Tax Credit - Next 97 therms	Next 97 therms	$ (0.02108)	$ -	
Tax Credit - Next 400 therms	Next 400 therms	$ (0.01976)	$ -	
Tax Credit - Next 500 therms	Next 500 therms	$ (0.01550)	$ -	
Tax Credit - Over 1,000 therms	Over 1,000 Therms	$ (0.00655)	$ -	
Bill Charge	Monthly	$ 0.72	$ 0.93	
SBC - CEF NYSERDA	Therm	$ 0.00021	$ 0.00021	
SBC - EE Tracker	Therm	$ 0.00163	$ -	
GRT - Delivery	%	0.00%	0.00%	

Notes:

1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and proposed rates for the Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

3. Low Income customers represent customers who participated in the Company's low income program and received a credit on their bill each month during calendar year 2018.

Rochester Gas and Electric Corporation
Gas Rates
Annual Delivery Bill Impact - May 1, 2020 - April 30, 2021
PSC No. 16 Service Classification No. 1 – General Service
PSC No. 16 Service Classification No. 5 – Small Transportation Service

Residential Spaceheating

				increase / (decrease)	
Month	**Therms**	**Current Rates**	**RY 1**	**Amount**	**Percent**
January	155	$60.06	$59.79	($0.28)	-0.5%
February	161	$61.69	$61.39	($0.29)	-0.5%
March	145	$57.36	$57.11	($0.25)	-0.4%
April	106	$46.80	$46.68	($0.13)	-0.3%
May	65	$35.02	$35.02	$0.00	0.0%
June	35	$26.31	$26.41	$0.10	0.4%
July	18	$21.38	$21.53	$0.15	0.7%
August	18	$21.38	$21.53	$0.15	0.7%
September	21	$22.25	$22.39	$0.14	0.6%
October	30	$24.86	$24.98	$0.12	0.5%
November	75	$37.92	$37.89	($0.03)	-0.1%
December	120	$50.59	$50.42	($0.17)	-0.3%
Annual Total	949	$465.61	$465.15	($0.46)	-0.1%

Residential Non-Spaceheating

				increase / (decrease)	
Month	**Therms**	**Current Rates**	**RY 1**	**Amount**	**Percent**
January	80	$39.37	$39.33	($0.04)	-0.1%
February	82	$39.95	$39.90	($0.05)	-0.1%
March	74	$37.63	$37.61	($0.02)	-0.1%
April	55	$32.12	$32.15	$0.04	0.1%
May	38	$27.18	$27.27	$0.09	0.3%
June	24	$23.12	$23.26	$0.14	0.6%
July	14	$20.22	$20.38	$0.17	0.8%
August	13	$19.93	$20.10	$0.17	0.9%
September	16	$20.80	$20.96	$0.16	0.8%
October	18	$21.38	$21.53	$0.15	0.7%
November	42	$28.34	$28.42	$0.08	0.3%
December	63	$34.44	$34.45	$0.01	0.0%
Annual Total	519	$344.48	$345.37	$0.88	0.3%

Billing Determinants			
		Current Rates	**RY 1**
	UOM	**SC1&5**	**SC1&5**
First 3 therms	Monthly	$ 16.30	$ 16.30
Next 97 therms	Next 97 therms	$ 0.30946	$ 0.28682
Next 400 therms	Next 400 therms	$ 0.28857	$ 0.26736
Next 500 therms	Next 500 therms	$ 0.25511	$ 0.23832
Over 1,000 Therms	Over 1,000 Therms	$ 0.10859	$ 0.10149
Tax Credit - Next 97 therms	Next 97 therms	$ (0.02108)	$ -
Tax Credit - Next 400 therms	Next 400 therms	$ (0.01976)	$ -
Tax Credit - Next 500 therms	Next 500 therms	$ (0.01550)	$ -
Tax Credit - Over 1,000 therms	Over 1,000 Therms	$ (0.00655)	$ -
Bill Charge	Monthly	$ 0.72	$ 0.93
SBC - CEF NYSERDA	Therm	$ 0.00021	$ 0.00021
SBC - EE Tracker	Therm	$ 0.00163	$ -
GRT - Delivery	%	0.00%	0.00%

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

Rochester Gas and Electric Corporation
Gas Rates
Monthly Delivery Bill Impact - May 1, 2020 - April 30, 2021
PSC No. 16 Service Classification No. 1 – General Service
PSC No. 16 Service Classification No. 5 – Small Transportation Service

Non-Residential

			increase / (decrease)		Number of Customers	
Therms	**Current Rates**	**RY 1**	**Amount**	**Percent**	**January**	**July**
3	$17.03	$17.23	$0.20	1.2%	330	3,515
10	$19.06	$19.24	$0.18	0.9%	587	5,015
20	$21.96	$22.11	$0.15	0.7%	539	3,019
50	$30.67	$30.72	$0.05	0.2%	1,334	4,240
100	$45.18	$45.07	($0.11)	-0.2%	2,237	2,588
150	$58.71	$58.45	($0.26)	-0.4%	2,031	1,056
200	$72.24	$71.83	($0.41)	-0.6%	1,819	668
250	$85.77	$85.20	($0.57)	-0.7%	1,563	485
300	$99.31	$98.58	($0.72)	-0.7%	1,298	358
350	$112.84	$111.96	($0.88)	-0.8%	1,075	347
400	$126.37	$125.34	($1.03)	-0.8%	973	257
500	$153.44	$152.10	($1.34)	-0.9%	1,695	442
750	$213.80	$211.73	($2.07)	-1.0%	2,446	697
1,000	$274.16	$271.36	($2.80)	-1.0%	1,418	371
1,250	$300.13	$296.79	($3.34)	-1.1%	932	194
1,500	$326.10	$322.21	($3.89)	-1.2%	705	106
2,000	$378.04	$373.06	($4.98)	-1.3%	892	149
3,000	$481.91	$474.76	($7.15)	-1.5%	829	82
5,000	$689.67	$678.16	($11.51)	-1.7%	693	61
10,000	$1,209.05	$1,186.65	($22.40)	-1.9%	524	41
15,000	$1,728.44	$1,695.15	($33.29)	-1.9%	156	5
20,000	$2,247.82	$2,203.64	($44.18)	-2.0%	49	3
30,000	$3,286.59	$3,220.63	($65.96)	-2.0%	34	7
50,000	$5,364.13	$5,254.62	($109.52)	-2.0%	11	1
75,000	$7,961.06	$7,797.09	($163.96)	-2.1%	4	0
100,000	$10,557.98	$10,339.57	($218.41)	-2.1%	0	0

Billing Determinants			
		Current Rates	**RY 1**
	UOM	**SC1&5**	**SC1&5**
First 3 therms	Monthly	$ 16.30	$ 16.30
Next 97 therms	Next 97 therms	$ 0.30946	$ 0.28682
Next 400 therms	Next 400 therms	$ 0.28857	$ 0.26736
Next 500 therms	Next 500 therms	$ 0.25511	$ 0.23832
Over 1,000 Therms	Over 1,000 Therms	$ 0.10859	$ 0.10149
Tax Credit - Next 97 therms	Next 97 therms	$ (0.02108)	$ -
Tax Credit - Next 400 therms	Next 400 therms	$ (0.01976)	$ -
Tax Credit - Next 500 therms	Next 500 therms	$ (0.01550)	$ -
Tax Credit - Over 1,000 therms	Over 1,000 Therms	$ (0.00655)	$ -
Bill Charge	Monthly	$ 0.72	$ 0.93
SBC - CEF NYSERDA	Therm	$ 0.00021	$ 0.00021
SBC - EE Tracker	Therm	$ 0.00163	$ -
GRT - Delivery	%	0.00%	0.00%

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

Rochester Gas and Electric Corporation
Gas Rates
Annual Delivery Bill Impact - May 1, 2020 - April 30, 2021
PSC No. 16 Service Classification No. 1 – General Service
PSC No. 16 Service Classification No. 5 – Small Transportation Service
Non-Residential

Commercial

				increase / (decrease)	
Monthly	Therms	Current Rates	RY 1	Amount	Percent
January	393	$124.48	$123.47	($1.01)	-0.8%
February	404	$127.45	$126.41	($1.04)	-0.8%
March	369	$117.98	$117.05	($0.94)	-0.8%
April	268	$90.65	$90.02	($0.62)	-0.7%
May	173	$64.93	$64.60	($0.33)	-0.5%
June	87	$41.40	$41.34	($0.07)	-0.2%
July	46	$29.50	$29.57	$0.06	0.2%
August	50	$30.67	$30.72	$0.05	0.2%
September	61	$33.86	$33.88	$0.02	0.1%
October	87	$41.40	$41.34	($0.07)	-0.2%
November	194	$70.62	$70.22	($0.40)	-0.6%
December	311	$102.28	$101.53	($0.76)	-0.7%
Annual Total	2,443	$875.23	$870.13	($5.09)	-0.6%

Industrial

				increase / (decrease)	
Monthly	Therms	Current Rates	RY 1	Amount	Percent
January	2,000	$378.04	$373.06	($4.98)	-1.3%
February	2,174	$396.11	$390.75	($5.36)	-1.4%
March	2,048	$383.02	$377.94	($5.08)	-1.3%
April	914	$253.39	$250.85	($2.55)	-1.0%
May	692	$199.79	$197.89	($1.90)	-1.0%
June	274	$92.27	$91.63	($0.64)	-0.7%
July	157	$60.60	$60.32	($0.28)	-0.5%
August	110	$47.88	$47.75	($0.14)	-0.3%
September	126	$52.21	$52.03	($0.19)	-0.4%
October	160	$61.42	$61.12	($0.29)	-0.5%
November	769	$218.38	$216.26	($2.12)	-1.0%
December	1,499	$325.99	$322.11	($3.89)	-1.2%
Annual Total	10,923	$2,469.12	$2,441.71	($27.41)	-1.1%

Municipal

				increase / (decrease)	
Monthly	Therms	Current Rates	RY 1	Amount	Percent
January	1,324	$307.82	$304.31	($3.50)	-1.1%
February	1,366	$312.18	$308.58	($3.60)	-1.2%
March	1,240	$299.09	$295.77	($3.32)	-1.1%
April	905	$251.22	$248.70	($2.52)	-1.0%
May	586	$174.20	$172.61	($1.59)	-0.9%
June	266	$90.10	$89.49	($0.62)	-0.7%
July	169	$63.85	$63.53	($0.32)	-0.5%
August	159	$61.14	$60.86	($0.29)	-0.5%
September	195	$70.89	$70.49	($0.40)	-0.6%
October	271	$91.46	$90.82	($0.63)	-0.7%
November	641	$187.48	$185.73	($1.75)	-0.9%
December	971	$267.16	$264.44	($2.71)	-1.0%
Annual Total	8,093	$2,176.58	$2,155.33	($21.25)	-1.0%

Billing Determinants			
		Current Rates	RY 1
	UOM	SC1&5	SC1&5
First 3 therms	Monthly	$ 16.30	$ 16.30
Next 97 therms	Next 97 therms	$ 0.30946	$ 0.28682
Next 400 therms	Next 400 therms	$ 0.28857	$ 0.26736
Next 500 therms	Next 500 therms	$ 0.25511	$ 0.23832
Over 1,000 Therms	Over 1,000 Therms	$ 0.10859	$ 0.10149
Tax Credit - Next 97 therms	Next 97 therms	$ (0.02108)	$ -
Tax Credit - Next 400 therms	Next 400 therms	$ (0.01976)	$ -
Tax Credit - Next 500 therms	Next 500 therms	$ (0.01550)	$ -
Tax Credit - Over 1,000 therms	Over 1,000 Therms	$ (0.00655)	$ -
Bill Charge	Monthly	$ 0.72	$ 0.93
SBC - CEF NYSERDA	Therm	$ 0.00021	$ 0.00021
SBC - EE Tracker	Therm	$ 0.00163	$ -
GRT - Delivery	%	0.00%	0.00%

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

Rochester Gas and Electric Corporation
Gas Rates
Monthly Delivery Bill Impact - May 1, 2020 - April 30, 2021
PSC No. 16 Service Classification No. 3 – Large Transportation Service

Non-Residential

			increase / (decrease)		Number of Customers	
Therms	**Current Rates**	**RY 1**	**Amount**	**Percent**	**January**	**July**
500	$1,481.17	$1,850.44	$369.27	24.9%	0	39
750	$1,481.63	$1,850.49	$368.87	24.9%	0	5
1,000	$1,482.09	$1,850.55	$368.46	24.9%	1	8
1,250	$1,497.93	$1,862.24	$364.31	24.3%	0	5
1,500	$1,513.77	$1,873.93	$360.16	23.8%	0	8
2,000	$1,545.45	$1,897.32	$351.86	22.8%	1	13
3,000	$1,608.82	$1,944.08	$335.26	20.8%	1	24
5,000	$1,735.56	$2,037.62	$302.06	17.4%	4	34
10,000	$2,052.39	$2,271.46	$219.07	10.7%	28	35
15,000	$2,369.23	$2,505.30	$136.08	5.7%	37	15
20,000	$2,686.06	$2,739.14	$53.08	2.0%	43	11
30,000	$3,319.73	$3,206.83	($112.90)	-3.4%	53	13
50,000	$4,339.47	$3,954.84	($384.63)	-8.9%	44	16
75,000	$5,614.15	$4,889.85	($724.29)	-12.9%	19	6
100,000	$6,888.82	$5,824.87	($1,063.95)	-15.4%	3	4

Billing Determinants			
		Current Rates	**RY 1**
	UOM	**SC3**	**SC3**
First 1,000 therms	Monthly	$ 1,479.53	$ 1,849.41
Next 29,000 therms	Next 29,000 therms	$ 0.06531	$ 0.04656
Next 70,000 therms	Next 70,000 therms	$ 0.05175	$ 0.03719
Next 900,000 therms	Next 900,000 therms	$ 0.02002	$ 0.01439
Over 1,000,000 Therms	Over 1,000,000 Therms	$ 0.00964	$ 0.00676
Tax Credit - Next 29,000 therms	Next 29,000 therms	$ (0.00378)	$ -
Tax Credit - Next 70,000 therms	Next 70,000 therms	$ (0.00260)	$ -
Tax Credit - Next 900,000 therms	Next 900,000 therms	$ (0.00100)	$ -
Tax Credit - Over 1,000,000 Therms	Over 1,000,000 Therms	$ (0.00070)	$ -
Bill Charge	Monthly	$ 0.72	$ 0.93
SBC - CEF NYSERDA	Therm	$ 0.00021	$ 0.00021
SBC - EE Tracker	Therm	$ 0.00163	$ -
GRT - Delivery	%	0.00%	0.00%

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

Rochester Gas and Electric Corporation
Gas Rates
Annual Delivery Bill Impact - May 1, 2020 - April 30, 2021
PSC No. 16 Service Classification No. 3 – Large Transportation Service

Commercial

				increase / (decrease)	
Monthly	**Therms**	**Current Rates**	**RY 1**	**Amount**	**Percent**
January	37,692	$3,711.92	$3,494.51	($217.41)	-5.9%
February	37,887	$3,721.86	$3,501.80	($220.06)	-5.9%
March	36,696	$3,661.14	$3,457.26	($203.88)	-5.6%
April	29,763	$3,304.71	$3,195.74	($108.97)	-3.3%
May	24,992	$3,002.39	$2,972.61	($29.78)	-1.0%
June	22,558	$2,848.15	$2,858.78	$10.62	0.4%
July	25,802	$3,053.72	$3,010.49	($43.22)	-1.4%
August	24,282	$2,957.40	$2,939.41	($17.99)	-0.6%
September	24,264	$2,956.26	$2,938.56	($17.69)	-0.6%
October	22,436	$2,840.42	$2,853.07	$12.65	0.4%
November	33,948	$3,521.03	$3,354.48	($166.54)	-4.7%
December	40,718	$3,866.21	$3,607.69	($258.52)	-6.7%
Annual Totals	361,038	$39,445.21	$38,184.41	($1,260.80)	-3.2%

Industrial

				increase / (decrease)	
Monthly	**Therms**	**Current Rates**	**RY 1**	**Amount**	**Percent**
January	81,352	$5,938.01	$5,127.42	($810.59)	-13.7%
February	74,710	$5,599.36	$4,879.01	($720.35)	-12.9%
March	75,113	$5,619.91	$4,894.08	($725.83)	-12.9%
April	60,957	$4,898.13	$4,364.64	($533.50)	-10.9%
May	46,902	$4,181.51	$3,838.97	($342.54)	-8.2%
June	44,357	$4,051.75	$3,743.79	($307.96)	-7.6%
July	41,442	$3,903.12	$3,634.76	($268.36)	-6.9%
August	48,414	$4,258.60	$3,895.52	($363.08)	-8.5%
September	48,162	$4,245.76	$3,886.10	($359.66)	-8.5%
October	56,559	$4,673.89	$4,200.15	($473.74)	-10.1%
November	67,138	$5,213.29	$4,595.81	($617.48)	-11.8%
December	80,232	$5,880.91	$5,085.53	($795.38)	-13.5%
Annual Totals	725,338	$58,464.25	$52,145.78	($6,318.47)	-10.8%

Municipal

				increase / (decrease)	
Monthly	**Therms**	**Current Rates**	**RY 1**	**Amount**	**Percent**
January	27,101	$3,136.03	$3,071.25	($64.78)	-2.1%
February	26,071	$3,070.76	$3,023.07	($47.69)	-1.6%
March	24,726	$2,985.53	$2,960.17	($25.36)	-0.8%
April	16,353	$2,454.96	$2,568.58	$113.62	4.6%
May	8,208	$1,938.84	$2,187.65	$248.82	12.8%
June	6,098	$1,805.13	$2,088.97	$283.84	15.7%
July	7,108	$1,869.13	$2,136.21	$267.07	14.3%
August	6,679	$1,841.95	$2,116.14	$274.20	14.9%
September	7,410	$1,888.27	$2,150.33	$262.06	13.9%
October	13,817	$2,294.26	$2,449.98	$155.71	6.8%
November	18,966	$2,620.54	$2,690.79	$70.25	2.7%
December	31,428	$3,392.54	$3,260.23	($132.31)	-3.9%
Annual Totals	193,965	$29,297.94	$30,703.37	$1,405.43	4.8%

Billing Determinants			
		Current Rates	**RY 1**
	UOM	**SC3**	**SC3**
First 1,000 therms	Monthly	$ 1,479.53	$ 1,849.41
Next 29,000 therms	Next 29,000 therms	$ 0.06531	$ 0.04656
Next 70,000 therms	Next 70,000 therms	$ 0.05175	$ 0.03719
Next 900,000 therms	Next 900,000 therms	$ 0.02002	$ 0.01439
Over 1,000,000 Therms	Over 1,000,000 Ther	$ 0.00964	$ 0.00676
Tax Credit - Next 29,000 therms	Next 29,000 therms	$ (0.00378)	$ -
Tax Credit - Next 70,000 therms	Next 70,000 therms	$ (0.00260)	$ -
Tax Credit - Next 900,000 therms	Next 900,000 therms	$ (0.00100)	$ -
Tax Credit - Over 1,000,000 Therms	Over 1,000,000 Ther	$ (0.00070)	$ -
Bill Charge	Monthly	$ 0.72	$ 0.93
SBC - CEF NYSERDA	Therm	$ 0.00021	$ 0.00021
SBC - EE Tracker	Therm	$ 0.00163	$ -
GRT - Delivery	%	0.00%	0.00%

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

Rochester Gas and Electric Corporation
Gas Rates
Monthly Delivery Bill Impact - May 1, 2020 - April 30, 2021
PSC No. 16 Service Classification No. 3 – High Pressure Option

Non-Residential

			increase / (decrease)	
Therms	**Current Rates**	**RY 1**	**Amount**	**Percent**
500	$1,551.64	$1,553.63	$1.99	0.1%
750	$1,552.10	$1,553.68	$1.58	0.1%
1,000	$1,552.56	$1,553.73	$1.18	0.1%
1,250	$1,562.34	$1,562.59	$0.26	0.0%
1,500	$1,572.12	$1,571.45	($0.66)	0.0%
2,000	$1,591.67	$1,589.17	($2.50)	-0.2%
3,000	$1,630.79	$1,624.60	($6.19)	-0.4%
5,000	$1,709.03	$1,695.47	($13.55)	-0.8%
10,000	$1,904.61	$1,872.65	($31.96)	-1.7%
15,000	$2,100.20	$2,049.82	($50.37)	-2.4%
20,000	$2,295.78	$2,226.99	($68.79)	-3.0%
30,000	$2,686.95	$2,581.34	($105.61)	-3.9%
50,000	$3,469.29	$3,290.03	($179.26)	-5.2%
75,000	$4,447.22	$4,175.90	($271.31)	-6.1%
100,000	$5,425.14	$5,061.77	($363.37)	-6.7%

Billing Determinants			
		Current Rates	**RY 1**
	UOM	**SC3HP**	**SC3HP**
First 1,000 therms	Monthly	$ 1,550.00	$ 1,552.60
Next 29,000 therms	Next 29,000 therms	$ 0.03955	$ 0.03522
Next 70,000 therms	Next 70,000 therms	$ 0.03955	$ 0.03522
Next 900,000 therms	Next 900,000 therms	$ 0.03955	$ 0.03522
Over 1,000,000 Therms	Over 1,000,000 Therms	$ 0.00964	$ 0.00966
Tax Credit - Next 29,000 therms	Next 29,000 therms	$ (0.00227)	$ -
Tax Credit - Next 70,000 therms	Next 70,000 therms	$ (0.00227)	$ -
Tax Credit - Next 900,000 therms	Next 900,000 therms	$ (0.00227)	$ -
Tax Credit - Over 1,000,000 Therms	Over 1,000,000 Therms	$ -	$ -
Bill Charge	Monthly	$ 0.72	$ 0.93
SBC - CEF NYSERDA	Therm	$ 0.00021	$ 0.00021
SBC - EE Tracker	Therm	$ 0.00163	$ -
GRT - Delivery	%	0.00%	0.00%

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

Rochester Gas and Electric Corporation
Data Sources - RG&E Gas Bill Impact Statements

Rate	Source of Rate in "Current" Rates	Source of Rate in Rate Years
Basic Service Charge	Current Tariff Rates in Effect January 1, 2019 (Last updated 5/1/2018)	New
Usage Charge	Current Tariff Rates in Effect January 1, 2019 (Last updated 5/1/2018)	New
SBC (NYSERDA EE) - per Therm	Current Tariff Rates in Effect January 1, 2020	Current Tariff Rates in Effect January 1, 2020
SBC (EE Tracker) - per Therm	Current Tariff Rates in Effect January 1, 2020	Included in Delivery Rates
Billing Charge per Bill	Current Tariff Rates in Effect January 1, 2019 - (Last Updated 07/01/2016)	Results of 2019 Embedded Cost Study
Usage Charge - Tax Credit	Current Tariff Rates in Effect 10/1/2018	Included in Delivery Rates

	Source of Rate in "Current" Rates and Rate Years
MFC per Therm	Current Tariff Rates in Effect May 1, 2020
Gas Supply Charge	Non Weighted Average of Monthly GSC in 2019
Customer Count	2018 Billing Information

Rochester Gas and Electric Corporation
Gas Rates
Monthly Total Bill Impact - May 1, 2021 - April 30, 2022
PSC No. 16 Service Classification No. 1 – General Service

Residential

Therms	RY 1	RY 2	increase / (decrease) Amount	increase / (decrease) Percent	Number of Customers January	Number of Customers July	Amount of EE Embedded in Delivery Rates Amount	Amount of EE Embedded in Delivery Rates Percent
3	$18.23	$19.23	$1.00	5.5%	2,095	14,469	$0.00	0.00%
10	$22.59	$23.52	$0.93	4.1%	2,677	62,561	$0.01	0.02%
20	$28.82	$29.64	$0.82	2.9%	3,262	99,253	$0.01	0.04%
30	$35.04	$35.76	$0.72	2.1%	3,151	51,378	$0.02	0.06%
40	$41.27	$41.89	$0.62	1.5%	3,516	17,138	$0.03	0.07%
50	$47.50	$48.01	$0.51	1.1%	3,496	6,418	$0.04	0.07%
60	$53.72	$54.13	$0.41	0.8%	4,377	2,686	$0.04	0.08%
70	$59.95	$60.25	$0.30	0.5%	5,316	1,758	$0.05	0.08%
80	$66.17	$66.37	$0.20	0.3%	6,322	1,086	$0.06	0.09%
90	$72.40	$72.50	$0.10	0.1%	6,782	798	$0.07	0.09%
100	$78.63	$78.62	($0.01)	0.0%	8,813	598	$0.07	0.09%
125	$93.70	$93.46	($0.25)	-0.3%	27,463	1,600	$0.09	0.10%
150	$108.78	$108.29	($0.49)	-0.5%	34,147	841	$0.11	0.10%
175	$123.86	$123.13	($0.73)	-0.6%	35,174	418	$0.13	0.10%
250	$169.10	$167.64	($1.46)	-0.9%	42,265	424	$0.18	0.11%
300	$199.25	$197.31	($1.94)	-1.0%	21,594	244	$0.21	0.11%
350	$229.41	$226.98	($2.43)	-1.1%	10,892	185	$0.25	0.11%
400	$259.57	$256.66	($2.91)	-1.1%	5,400	113	$0.29	0.11%
500	$319.88	$316.00	($3.88)	-1.2%	4,448	130	$0.36	0.11%
750	$463.40	$457.37	($6.03)	-1.3%	2,196	127	$0.51	0.11%
1,000	$606.92	$598.73	($8.19)	-1.3%	373	50	$0.67	0.11%
1,500	$825.55	$815.53	($10.02)	-1.2%	244	42	$0.80	0.10%
2,000	$1,044.18	$1,032.32	($11.86)	-1.1%	68	11	$0.94	0.09%
3,000	$1,481.44	$1,465.91	($15.53)	-1.0%	59	4	$1.20	0.08%
5,000	$2,355.97	$2,333.09	($22.88)	-1.0%	38	2	$1.73	0.07%

Billing Determinants

	UOM	RY 1 SC1	RY 2 SC1		
First 3 therms	Monthly	$ 16.30	$ 17.30		
Next 97 therms	Next 97 therms	$ 0.28682	$ 0.27644	$ (0.00052)	EE Tracker
Next 400 therms	Next 400 therms	$ 0.26736	$ 0.25768	$ (0.00048)	EE Tracker
Next 500 therms	Next 500 therms	$ 0.23832	$ 0.22969	$ (0.00043)	EE Tracker
Over 1,000 Therms	Over 1,000 Therms	$ 0.10149	$ 0.09782	$ (0.00019)	EE Tracker
Tax Credit - Next 97 therms	Next 97 therms	$ -	$ -		
Tax Credit - Next 400 therms	Next 400 therms	$ -	$ -		
Tax Credit - Next 500 therms	Next 500 therms	$ -	$ -		
Tax Credit - Over 1,000 therms	Over 1,000 Therms	$ -	$ -		
Bill Charge	Monthly	$ 0.93	$ 0.93		
SBC - CEF NYSERDA	Therm	$ 0.00021	$ 0.00021		
SBC - EE Tracker	Therm	$ -	$ -		
GRT - Delivery	%	0.00%	0.00%		
Gas Supply Charge	Therm	$ 0.31811	$ 0.31811		
MFC	Therm	$ 0.01746	$ 0.01746		

Notes:

1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and proposed rates for the Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation
Gas Rates
Annual Total Bill Impact - May 1, 2021 - April 30, 2022
PSC No. 16 Service Classification No. 1 – General Service
Residential

Residential Spaceheating

Month	Therms	RY 1	RY 2	increase / (decrease) Amount	Percent
January	155	$111.80	$111.26	($0.54)	-0.5%
February	161	$115.42	$114.82	($0.60)	-0.5%
March	145	$105.77	$105.32	($0.44)	-0.4%
April	106	$82.24	$82.18	($0.06)	-0.1%
May	65	$56.83	$57.19	$0.36	0.6%
June	35	$38.16	$38.83	$0.67	1.8%
July	18	$27.57	$28.42	$0.84	3.1%
August	18	$27.57	$28.42	$0.84	3.1%
September	21	$29.44	$30.25	$0.81	2.8%
October	30	$35.04	$35.76	$0.72	2.1%
November	75	$63.06	$63.31	$0.25	0.4%
December	120	$90.69	$90.49	($0.20)	-0.2%
Annual Total	949	$783.60	$786.25	$2.66	0.3%

Residential Non-Spaceheating

Month	Therms	RY 1	RY 2	increase / (decrease) Amount	Percent
January	80	$66.17	$66.37	$0.20	0.3%
February	82	$67.42	$67.60	$0.18	0.3%
March	74	$62.44	$62.70	$0.26	0.4%
April	55	$50.61	$51.07	$0.46	0.9%
May	38	$40.02	$40.66	$0.64	1.6%
June	24	$31.31	$32.09	$0.78	2.5%
July	14	$25.08	$25.97	$0.89	3.5%
August	13	$24.46	$25.36	$0.90	3.7%
September	16	$26.33	$27.19	$0.87	3.3%
October	18	$27.57	$28.42	$0.84	3.1%
November	42	$42.52	$43.11	$0.60	1.4%
December	63	$55.59	$55.97	$0.38	0.7%
Annual Total	519	$519.52	$526.51	$6.99	1.3%

Billing Determinants			
	UOM	RY 1 SC1	RY 2 SC1
First 3 therms	Monthly	$ 16.30	$ 17.30
Next 97 therms	Next 97 therms	$ 0.28682	$ 0.27644
Next 400 therms	Next 400 therms	$ 0.26736	$ 0.25768
Next 500 therms	Next 500 therms	$ 0.23832	$ 0.22969
Over 1,000 Therms	Over 1,000 Therms	$ 0.10149	$ 0.09782
Tax Credit - Next 97 therms	Next 97 therms	$ -	$ -
Tax Credit - Next 400 therms	Next 400 therms	$ -	$ -
Tax Credit - Next 500 therms	Next 500 therms	$ -	$ -
Tax Credit - Over 1,000 therms	Over 1,000 Therms	$ -	$ -
Bill Charge	Monthly	$ 0.93	$ 0.93
SBC - CEF NYSERDA	Therm	$ 0.00021	$ 0.00021
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%
Gas Supply Charge	Therm	$ 0.31811	$ 0.31811
MFC	Therm	$ 0.01746	$ 0.01746

Notes:

1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and proposed rates for the Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation
Gas Rates
Monthly Total Bill Impact - May 1, 2021 - April 30, 2022
PSC No. 16 Service Classification No. 1 – General Service

Non-Residential

			increase / (decrease)		Number of Customers	
Therms	**RY 1**	**RY 2**	**Amount**	**Percent**	**January**	**July**
3	$18.22	$19.22	$1.00	5.5%	262	2,687
10	$22.56	$23.48	$0.93	4.1%	476	3,884
20	$28.75	$29.57	$0.82	2.9%	460	2,352
50	$47.32	$47.83	$0.51	1.1%	1,093	2,885
100	$78.27	$78.26	($0.01)	0.0%	1,862	1,379
150	$108.25	$107.76	($0.49)	-0.5%	1,634	529
200	$138.23	$137.25	($0.97)	-0.7%	1,430	350
250	$168.20	$166.75	($1.46)	-0.9%	1,180	244
300	$198.18	$196.24	($1.94)	-1.0%	916	175
350	$228.16	$225.74	($2.43)	-1.1%	728	150
400	$258.14	$255.23	($2.91)	-1.1%	623	104
500	$318.10	$314.22	($3.88)	-1.2%	988	207
750	$460.73	$454.70	($6.03)	-1.3%	1,404	297
1,000	$603.36	$595.17	($8.19)	-1.4%	816	105
1,500	$820.21	$810.19	($10.02)	-1.2%	326	26
2,000	$1,037.06	$1,025.20	($11.86)	-1.1%	402	23
3,000	$1,470.76	$1,455.22	($15.53)	-1.1%	354	21
5,000	$2,338.16	$2,315.28	($22.88)	-1.0%	236	15
10,000	$4,506.65	$4,465.41	($41.24)	-0.9%	121	10
15,000	$6,675.15	$6,615.54	($59.60)	-0.9%	30	3
20,000	$8,843.64	$8,765.68	($77.97)	-0.9%	7	1
30,000	$13,180.63	$13,065.94	($114.69)	-0.9%	8	3
50,000	$21,854.62	$21,666.47	($188.14)	-0.9%	4	1
75,000	$32,697.09	$32,417.14	($279.95)	-0.9%	2	0
100,000	$43,539.57	$43,167.80	($371.77)	-0.9%	0	0

Billing Determinants					
		RY 1		RY 2	
	UOM	**SC1**		**SC1**	
First 3 therms	Monthly	$	16.30	$	17.30
Next 97 therms	Next 97 therms	$	0.28682	$	0.27644
Next 400 therms	Next 400 therms	$	0.26736	$	0.25768
Next 500 therms	Next 500 therms	$	0.23832	$	0.22969
Over 1,000 Therms	Over 1,000 Therms	$	0.10149	$	0.09782
Tax Credit - Next 97 therms	Next 97 therms	$	-	$	-
Tax Credit - Next 400 therms	Next 400 therms	$	-	$	-
Tax Credit - Next 500 therms	Next 500 therms	$	-	$	-
Tax Credit - Over 1,000 therms	Over 1,000 Therms	$	-	$	-
Bill Charge	Monthly	$	0.93	$	0.93
SBC - CEF NYSERDA	Therm	$	0.00021	$	0.00021
SBC - EE Tracker	Therm	$	-	$	-
GRT - Delivery	%		0.00%		0.00%
Gas Supply Charge	Therm	$	0.31811	$	0.31811
MFC	Therm	$	0.01389	$	0.01389

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.
3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation
Gas Rates
Annual Total Bill Impact - May 1, 2021 - April 30, 2022
PSC No. 16 Service Classification No. 1 – General Service
Non-Residential

Commercial

				increase / (decrease)	
Monthly	**Therms**	**RY 1**	**RY 2**	**Amount**	**Percent**
January	393	$253.94	$251.10	($2.84)	-1.1%
February	404	$260.54	$257.59	($2.95)	-1.1%
March	369	$239.55	$236.94	($2.61)	-1.1%
April	268	$179.00	$177.37	($1.63)	-0.9%
May	173	$122.04	$121.33	($0.71)	-0.6%
June	87	$70.22	$70.35	$0.13	0.2%
July	46	$44.84	$45.40	$0.55	1.2%
August	50	$47.32	$47.83	$0.51	1.1%
September	61	$54.13	$54.53	$0.40	0.7%
October	87	$70.22	$70.35	$0.13	0.2%
November	194	$134.63	$133.71	($0.92)	-0.7%
December	311	$204.78	$202.73	($2.05)	-1.0%
Annual Total	2,443	$1,681.21	$1,669.22	($11.99)	-0.7%

Industrial

				increase / (decrease)	
Monthly	**Therms**	**RY 1**	**RY 2**	**Amount**	**Percent**
January	2,000	$1,037.06	$1,025.20	($11.86)	-1.1%
February	2,174	$1,112.52	$1,100.02	($12.50)	-1.1%
March	2,048	$1,057.88	$1,045.84	($12.04)	-1.1%
April	914	$554.29	$546.85	($7.45)	-1.3%
May	692	$427.64	$422.11	($5.53)	-1.3%
June	274	$182.59	$180.90	($1.69)	-0.9%
July	157	$112.45	$111.89	($0.56)	-0.5%
August	110	$84.27	$84.16	($0.10)	-0.1%
September	126	$93.86	$93.60	($0.26)	-0.3%
October	160	$114.24	$113.66	($0.59)	-0.5%
November	769	$471.57	$465.37	($6.20)	-1.3%
December	1,499	$819.78	$809.75	($10.02)	-1.2%
Annual Total	10,923	$6,068.14	$5,999.35	($68.79)	-1.1%

Municipal

				increase / (decrease)	
Monthly	**Therms**	**RY 1**	**RY 2**	**Amount**	**Percent**
January	1,324	$743.88	$734.50	($9.38)	-1.3%
February	1,366	$762.09	$752.56	($9.53)	-1.3%
March	1,240	$707.45	$698.38	($9.07)	-1.3%
April	905	$549.16	$541.79	($7.37)	-1.3%
May	586	$367.16	$362.54	($4.62)	-1.3%
June	266	$177.80	$176.19	($1.61)	-0.9%
July	169	$119.64	$118.97	($0.67)	-0.6%
August	159	$113.64	$113.07	($0.58)	-0.5%
September	195	$135.23	$134.30	($0.93)	-0.7%
October	271	$180.80	$179.13	($1.66)	-0.9%
November	641	$398.54	$393.45	($5.09)	-1.3%
December	971	$586.81	$578.88	($7.94)	-1.4%
Annual Total	8,093	$4,842.21	$4,783.76	($58.45)	-1.2%

Billing Determinants					
		RY 1		**RY 2**	
	UOM	**SC1**		**SC1**	
First 3 therms	Monthly	$	16.30	$	17.30
Next 97 therms	Next 97 therms	$	0.28682	$	0.27644
Next 400 therms	Next 400 therms	$	0.26736	$	0.25768
Next 500 therms	Next 500 therms	$	0.23832	$	0.22969
Over 1,000 Therms	Over 1,000 Therms	$	0.10149	$	0.09782
Tax Credit - Next 97 therms	Next 97 therms	$	-	$	-
Tax Credit - Next 400 therms	Next 400 therms	$	-	$	-
Tax Credit - Next 500 therms	Next 500 therms	$	-	$	-
Tax Credit - Over 1,000 therms	Over 1,000 Therms	$	-	$	-
Bill Charge	Monthly	$	0.93	$	0.93
SBC - CEF NYSERDA	Therm	$	0.00021	$	0.00021
SBC - EE Tracker	Therm	$	-	$	-
GRT - Delivery	%		0.00%		0.00%
Gas Supply Charge	Therm	$	0.31811	$	0.31811
MFC	Therm	$	0.01389	$	0.01389

Notes:

1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and proposed rates for the Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation
Data Sources - RG&E Gas Bill Impact Statements

Rate	Source of Rate in "Current" Rates	Source of Rate in Rate Years
Basic Service Charge	Current Tariff Rates in Effect January 1, 2019 (Last updated 5/1/2018)	New
Usage Charge	Current Tariff Rates in Effect January 1, 2019 (Last updated 5/1/2018)	New
SBC (NYSERDA EE) - per Therm	Current Tariff Rates in Effect January 1, 2020	Current Tariff Rates in Effect January 1, 2020
SBC (EE Tracker) - per Therm	Current Tariff Rates in Effect January 1, 2020	Included in Delivery Rates
Billing Charge per Bill	Current Tariff Rates in Effect January 1, 2019 - (Last Updated 07/01/2016)	Results of 2019 Embedded Cost Study
Usage Charge - Tax Credit	Current Tariff Rates in Effect 10/1/2018	Included in Delivery Rates

	Source of Rate in "Current" Rates and Rate Years
MFC per Therm	Current Tariff Rates in Effect May 1, 2020
Gas Supply Charge	Non Weighted Average of Monthly GSC in 2019
Customer Count	2018 Billing Information

Rochester Gas and Electric Corporation
Gas Rates
Monthly Delivery Bill Impact - May 1, 2021 - April 30, 2022
PSC No. 16 Service Classification No. 1 – General Service
PSC No. 16 Service Classification No. 5 – Small Transportation Service

Residential

			increase / (decrease)		Number of Customers		Number of Low Income Customers		Percent of Customers	Percent of Low Income Customers	Amount of EE Embedded in Delivery Rates	
Therms	**RY 1**	**RY 2**	**Amount**	**Percent**	**January**	**July**	**January**	**July**	**January**	**January**	**Amount**	**Percent**
3	$17.23	$18.23	$1.00	5.8%	2,161	15,658	231	1,566	0.7%	0.8%	$0.00	0.00%
10	$19.24	$20.16	$0.93	4.8%	2,834	69,672	398	6,332	1.0%	1.3%	$0.01	0.03%
20	$22.11	$22.93	$0.82	3.7%	3,425	111,491	405	9,997	1.2%	1.3%	$0.01	0.06%
30	$24.98	$25.70	$0.72	2.9%	3,329	57,504	458	6,445	1.1%	1.5%	$0.02	0.08%
40	$27.85	$28.46	$0.62	2.2%	3,712	19,044	478	2,607	1.3%	1.6%	$0.03	0.10%
50	$30.72	$31.23	$0.51	1.7%	3,709	7,148	432	1,139	1.3%	1.4%	$0.04	0.11%
60	$33.59	$34.00	$0.41	1.2%	4,655	3,000	604	469	1.6%	2.0%	$0.04	0.13%
70	$36.46	$36.76	$0.30	0.8%	5,698	1,966	678	288	1.9%	2.2%	$0.05	0.14%
80	$39.33	$39.53	$0.20	0.5%	6,802	1,237	769	155	2.3%	2.5%	$0.06	0.15%
90	$42.20	$42.30	$0.10	0.2%	7,416	912	843	124	2.5%	2.8%	$0.07	0.16%
100	$45.07	$45.06	($0.01)	0.0%	9,786	665	1,040	67	3.3%	3.4%	$0.07	0.16%
125	$51.76	$51.51	($0.25)	-0.5%	30,645	1,797	2,904	162	10.4%	9.6%	$0.09	0.18%
150	$58.45	$57.96	($0.49)	-0.8%	38,413	959	3,235	83	13.0%	10.7%	$0.11	0.19%
175	$65.14	$64.40	($0.73)	-1.1%	39,860	474	3,288	49	13.5%	10.8%	$0.13	0.20%
200	$71.83	$70.85	($0.97)	-1.4%	34,193	338	2,856	32	11.6%	9.4%	$0.14	0.20%
250	$85.20	$83.75	($1.46)	-1.7%	47,674	470	4,486	40	16.1%	14.8%	$0.18	0.21%
300	$98.58	$96.64	($1.94)	-2.0%	24,190	266	2,911	28	8.2%	9.6%	$0.21	0.22%
350	$111.96	$109.54	($2.43)	-2.2%	12,196	207	1,864	22	4.1%	6.1%	$0.25	0.23%
400	$125.34	$122.43	($2.91)	-2.3%	6,013	122	1,026	18	2.0%	3.4%	$0.29	0.23%
500	$152.10	$148.22	($3.88)	-2.5%	5,013	138	957	21	1.7%	3.2%	$0.36	0.24%
750	$211.73	$205.70	($6.03)	-2.8%	2,534	142	414	27	0.9%	1.4%	$0.51	0.25%
1,000	$271.36	$263.17	($8.19)	-3.0%	454	56	43	9	0.2%	0.1%	$0.67	0.25%
1,500	$322.21	$312.19	($10.02)	-3.1%	314	44	21	9	0.1%	0.1%	$0.80	0.26%
2,000	$373.06	$361.20	($11.86)	-3.2%	108	14	4	3	0.0%	0.0%	$0.94	0.26%
3,000	$474.76	$459.22	($15.53)	-3.3%	102	5	3	0	0.0%	0.0%	$1.20	0.26%
5,000	$678.16	$655.28	($22.88)	-3.4%	78	2	3	1	0.0%	0.0%	$1.73	0.26%
					295,313		30,350					

Billing Determinants				
		RY 1	**RY 2**	
	UOM	**SC1&5**	**SC1&5**	
First 3 therms	Monthly	$ 16.30	$ 17.30	
Next 97 therms	Next 97 therms	$ 0.28682	$ 0.27644	$ (0.00052) EE Tracker
Next 400 therms	Next 400 therms	$ 0.26736	$ 0.25768	$ (0.00048) EE Tracker
Next 500 therms	Next 500 therms	$ 0.23832	$ 0.22969	$ (0.00043) EE Tracker
Over 1,000 Therms	Over 1,000 Therms	$ 0.10149	$ 0.09782	$ (0.00019) EE Tracker
Tax Credit - Next 97 therms	Next 97 therms	$ -	$ -	
Tax Credit - Next 400 therms	Next 400 therms	$ -	$ -	
Tax Credit - Next 500 therms	Next 500 therms	$ -	$ -	
Tax Credit - Over 1,000 therms	Over 1,000 Therms	$ -	$ -	
Bill Charge	Monthly	$ 0.93	$ 0.93	
SBC - CEF NYSERDA	Therm	$ 0.00021	$ 0.00021	
SBC - EE Tracker	Therm	$ -	$ -	
GRT - Delivery	%	0.00%	0.00%	

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.
3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.
4. Low Income customers represent customers who participated in the Company's low income program and received a credit on their bill each month during calendar year 2018.

Rochester Gas and Electric Corporation
Gas Rates
Annual Delivery Bill Impact - May 1, 2021 - April 30, 2022
PSC No. 16 Service Classification No. 1 – General Service
PSC No. 16 Service Classification No. 5 – Small Transportation Service

Residential Spaceheating

				increase / (decrease)	
Month	**Therms**	**RY 1**	**RY 2**	**Amount**	**Percent**
January	155	$59.79	$59.25	($0.54)	-0.9%
February	161	$61.39	$60.79	($0.60)	-1.0%
March	145	$57.11	$56.67	($0.44)	-0.8%
April	106	$46.68	$46.61	($0.06)	-0.1%
May	65	$35.02	$35.38	$0.36	1.0%
June	35	$26.41	$27.08	$0.67	2.5%
July	18	$21.53	$22.38	$0.84	3.9%
August	18	$21.53	$22.38	$0.84	3.9%
September	21	$22.39	$23.21	$0.81	3.6%
October	30	$24.98	$25.70	$0.72	2.9%
November	75	$37.89	$38.15	$0.25	0.7%
December	120	$50.42	$50.22	($0.20)	-0.4%
Annual Total	949	$465.15	$467.81	$2.66	0.6%

Residential Non-Spaceheating

				increase / (decrease)	
Month	**Therms**	**RY 1**	**RY 2**	**Amount**	**Percent**
January	80	$39.33	$39.53	$0.20	0.5%
February	82	$39.90	$40.08	$0.18	0.5%
March	74	$37.61	$37.87	$0.26	0.7%
April	55	$32.15	$32.61	$0.46	1.4%
May	38	$27.27	$27.91	$0.64	2.3%
June	24	$23.26	$24.04	$0.78	3.4%
July	14	$20.38	$21.27	$0.89	4.3%
August	13	$20.10	$20.99	$0.90	4.5%
September	16	$20.96	$21.82	$0.87	4.1%
October	18	$21.53	$22.38	$0.84	3.9%
November	42	$28.42	$29.02	$0.60	2.1%
December	63	$34.45	$34.83	$0.38	1.1%
Annual Total	519	$345.37	$352.35	$6.99	2.0%

Billing Determinants			
		RY 1	**RY 2**
	UOM	**SC1&5**	**SC1&5**
First 3 therms	Monthly	$ 16.30	$ 17.30
Next 97 therms	Next 97 therms	$ 0.28682	$ 0.27644
Next 400 therms	Next 400 therms	$ 0.26736	$ 0.25768
Next 500 therms	Next 500 therms	$ 0.23832	$ 0.22969
Over 1,000 Therms	Over 1,000 Therms	$ 0.10149	$ 0.09782
Tax Credit - Next 97 therms	Next 97 therms	$ -	$ -
Tax Credit - Next 400 therms	Next 400 therms	$ -	$ -
Tax Credit - Next 500 therms	Next 500 therms	$ -	$ -
Tax Credit - Over 1,000 therms	Over 1,000 Therms	$ -	$ -
Bill Charge	Monthly	$ 0.93	$ 0.93
SBC - CEF NYSERDA	Therm	$ 0.00021	$ 0.00021
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.
3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation
Gas Rates
Monthly Delivery Bill Impact - May 1, 2021 - April 30, 2022
PSC No. 16 Service Classification No. 1 – General Service
PSC No. 16 Service Classification No. 5 – Small Transportation Service

Non-Residential

			increase / (decrease)		Number of Customers	
Therms	RY 1	RY 2	Amount	Percent	January	July
3	$17.23	$18.23	$1.00	5.8%	330	3,515
10	$19.24	$20.16	$0.93	4.8%	587	5,015
20	$22.11	$22.93	$0.82	3.7%	539	3,019
50	$30.72	$31.23	$0.51	1.7%	1,334	4,240
100	$45.07	$45.06	($0.01)	0.0%	2,237	2,588
150	$58.45	$57.96	($0.49)	-0.8%	2,031	1,056
200	$71.83	$70.85	($0.97)	-1.4%	1,819	668
250	$85.20	$83.75	($1.46)	-1.7%	1,563	485
300	$98.58	$96.64	($1.94)	-2.0%	1,298	358
350	$111.96	$109.54	($2.43)	-2.2%	1,075	347
400	$125.34	$122.43	($2.91)	-2.3%	973	257
500	$152.10	$148.22	($3.88)	-2.5%	1,695	442
750	$211.73	$205.70	($6.03)	-2.8%	2,446	697
1,000	$271.36	$263.17	($8.19)	-3.0%	1,418	371
1,250	$296.79	$287.68	($9.11)	-3.1%	932	194
1,500	$322.21	$312.19	($10.02)	-3.1%	705	106
2,000	$373.06	$361.20	($11.86)	-3.2%	892	149
3,000	$474.76	$459.22	($15.53)	-3.3%	829	82
5,000	$678.16	$655.28	($22.88)	-3.4%	693	61
10,000	$1,186.65	$1,145.41	($41.24)	-3.5%	524	41
15,000	$1,695.15	$1,635.54	($59.60)	-3.5%	156	5
20,000	$2,203.64	$2,125.68	($77.97)	-3.5%	49	3
30,000	$3,220.63	$3,105.94	($114.69)	-3.6%	34	7
50,000	$5,254.62	$5,066.47	($188.14)	-3.6%	11	1
75,000	$7,797.09	$7,517.14	($279.95)	-3.6%	4	0
100,000	$10,339.57	$9,967.80	($371.77)	-3.6%	0	0

Billing Determinants			
		RY 1	RY 2
	UOM	SC1&5	SC1&5
First 3 therms	Monthly	$ 16.30	$ 17.30
Next 97 therms	Next 97 therms	$ 0.28682	$ 0.27644
Next 400 therms	Next 400 therms	$ 0.26736	$ 0.25768
Next 500 therms	Next 500 therms	$ 0.23832	$ 0.22969
Over 1,000 Therms	Over 1,000 Therms	$ 0.10149	$ 0.09782
Tax Credit - Next 97 therms	Next 97 therms	$ -	$ -
Tax Credit - Next 400 therms	Next 400 therms	$ -	$ -
Tax Credit - Next 500 therms	Next 500 therms	$ -	$ -
Tax Credit - Over 1,000 therms	Over 1,000 Therms	$ -	$ -
Bill Charge	Monthly	$ 0.93	$ 0.93
SBC - CEF NYSERDA	Therm	$ 0.00021	$ 0.00021
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%

Notes:

1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and proposed rates for the Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation
Gas Rates
Annual Delivery Bill Impact - May 1, 2021 - April 30, 2022
PSC No. 16 Service Classification No. 1 – General Service
PSC No. 16 Service Classification No. 5 – Small Transportation Service
Non-Residential

Commercial

				increase / (decrease)	
Monthly	**Therms**	**RY 1**	**RY 2**	**Amount**	**Percent**
January	393	$123.47	$120.63	($2.84)	-2.3%
February	404	$126.41	$123.46	($2.95)	-2.3%
March	369	$117.05	$114.44	($2.61)	-2.2%
April	268	$90.02	$88.39	($1.63)	-1.8%
May	173	$64.60	$63.89	($0.71)	-1.1%
June	87	$41.34	$41.47	$0.13	0.3%
July	46	$29.57	$30.12	$0.55	1.9%
August	50	$30.72	$31.23	$0.51	1.7%
September	61	$33.88	$34.27	$0.40	1.2%
October	87	$41.34	$41.47	$0.13	0.3%
November	194	$70.22	$69.30	($0.92)	-1.3%
December	311	$101.53	$99.48	($2.05)	-2.0%
Annual Total	2,443	$870.13	$858.15	($11.99)	-1.4%

Industrial

				increase / (decrease)	
Monthly	**Therms**	**RY 1**	**RY 2**	**Amount**	**Percent**
January	2,000	$373.06	$361.20	($11.86)	-3.2%
February	2,174	$390.75	$378.25	($12.50)	-3.2%
March	2,048	$377.94	$365.90	($12.04)	-3.2%
April	914	$250.85	$243.40	($7.45)	-3.0%
May	692	$197.89	$192.36	($5.53)	-2.8%
June	274	$91.63	$89.94	($1.69)	-1.8%
July	157	$60.32	$59.76	($0.56)	-0.9%
August	110	$47.75	$47.64	($0.10)	-0.2%
September	126	$52.03	$51.77	($0.26)	-0.5%
October	160	$61.12	$60.54	($0.59)	-1.0%
November	769	$216.26	$210.06	($6.20)	-2.9%
December	1,499	$322.11	$312.09	($10.02)	-3.1%
Annual Total	10,923	$2,441.71	$2,372.92	($68.79)	-2.8%

Municipal

				increase / (decrease)	
Monthly	**Therms**	**RY 1**	**RY 2**	**Amount**	**Percent**
January	1,324	$304.31	$294.93	($9.38)	-3.1%
February	1,366	$308.58	$299.05	($9.53)	-3.1%
March	1,240	$295.77	$286.70	($9.07)	-3.1%
April	905	$248.70	$241.33	($7.37)	-3.0%
May	586	$172.61	$167.99	($4.62)	-2.7%
June	266	$89.49	$87.87	($1.61)	-1.8%
July	169	$63.53	$62.86	($0.67)	-1.1%
August	159	$60.86	$60.28	($0.58)	-0.9%
September	195	$70.49	$69.56	($0.93)	-1.3%
October	271	$90.82	$89.16	($1.66)	-1.8%
November	641	$185.73	$180.64	($5.09)	-2.7%
December	971	$264.44	$256.50	($7.94)	-3.0%
Annual Total	8,093	$2,155.33	$2,096.88	($58.45)	-2.7%

Billing Determinants			
		RY 1	**RY 2**
	UOM	**SC1&5**	**SC1&5**
First 3 therms	Monthly	$ 16.30	$ 17.30
Next 97 therms	Next 97 therms	$ 0.28682	$ 0.27644
Next 400 therms	Next 400 therms	$ 0.26736	$ 0.25768
Next 500 therms	Next 500 therms	$ 0.23832	$ 0.22969
Over 1,000 Therms	Over 1,000 Therms	$ 0.10149	$ 0.09782
Tax Credit - Next 97 therms	Next 97 therms	$ -	$ -
Tax Credit - Next 400 therms	Next 400 therms	$ -	$ -
Tax Credit - Next 500 therms	Next 500 therms	$ -	$ -
Tax Credit - Over 1,000 therms	Over 1,000 Therms	$ -	$ -
Bill Charge	Monthly	$ 0.93	$ 0.93
SBC - CEF NYSERDA	Therm	$ 0.00021	$ 0.00021
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.
3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation
Gas Rates
Monthly Delivery Bill Impact - May 1, 2021 - April 30, 2022
PSC No. 16 Service Classification No. 3 – Large Transportation Service

Non-Residential

			increase / (decrease)		Number of Customers	
Therms	**RY 1**	**RY 2**	**Amount**	**Percent**	**January**	**July**
500	$1,850.44	$1,985.55	$135.11	7.3%	0	39
750	$1,850.49	$1,985.60	$135.11	7.3%	0	5
1,000	$1,850.55	$1,985.65	$135.11	7.3%	1	8
1,250	$1,862.24	$1,997.15	$134.91	7.2%	0	5
1,500	$1,873.93	$2,008.64	$134.71	7.2%	0	8
2,000	$1,897.32	$2,031.63	$134.32	7.1%	1	13
3,000	$1,944.08	$2,077.61	$133.53	6.9%	1	24
5,000	$2,037.62	$2,169.58	$131.96	6.5%	4	34
10,000	$2,271.46	$2,399.49	$128.02	5.6%	28	35
15,000	$2,505.30	$2,629.39	$124.09	5.0%	37	15
20,000	$2,739.14	$2,859.30	$120.16	4.4%	43	11
30,000	$3,206.83	$3,319.11	$112.29	3.5%	53	13
50,000	$3,954.84	$4,054.56	$99.72	2.5%	44	16
75,000	$4,889.85	$4,973.86	$84.01	1.7%	19	6
100,000	$5,824.87	$5,893.16	$68.30	1.2%	3	4

Billing Determinants			
		RY 1	**RY 2**
	UOM	**SC3**	**SC3**
First 1,000 therms	Monthly	$ 1,849.41	$ 1,984.52
Next 29,000 therms	Next 29,000 therms	$ 0.04656	$ 0.04577
Next 70,000 therms	Next 70,000 therms	$ 0.03719	$ 0.03656
Next 900,000 therms	Next 900,000 therms	$ 0.01439	$ 0.01415
Over 1,000,000 Therms	Over 1,000,000 Therms	$ 0.00676	$ 0.00665
Tax Credit - Next 29,000 therms	Next 29,000 therms	$ -	$ -
Tax Credit - Next 70,000 therms	Next 70,000 therms	$ -	$ -
Tax Credit - Next 900,000 therms	Next 900,000 therms	$ -	$ -
Tax Credit - Over 1,000,000 Therms	Over 1,000,000 Therms	$ -	$ -
Bill Charge	Monthly	$ 0.93	$ 0.93
SBC - CEF NYSERDA	Therm	$ 0.00021	$ 0.00021
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

Rochester Gas and Electric Corporation
Gas Rates
Annual Delivery Bill Impact - May 1, 2021 - April 30, 2022
PSC No. 16 Service Classification No. 3 – Large Transportation Service

Commercial

Monthly	Therms	RY 1	RY 2	increase / (decrease) Amount	Percent
January	37,692	$3,494.51	$3,601.97	$107.45	3.1%
February	37,887	$3,501.80	$3,609.14	$107.33	3.1%
March	36,696	$3,457.26	$3,565.34	$108.08	3.1%
April	29,763	$3,195.74	$3,308.22	$112.48	3.5%
May	24,992	$2,972.61	$3,088.84	$116.23	3.9%
June	22,558	$2,858.78	$2,976.92	$118.14	4.1%
July	25,802	$3,010.49	$3,126.08	$115.59	3.8%
August	24,282	$2,939.41	$3,056.19	$116.79	4.0%
September	24,264	$2,938.56	$3,055.37	$116.80	4.0%
October	22,436	$2,853.07	$2,971.31	$118.24	4.1%
November	33,948	$3,354.48	$3,464.29	$109.81	3.3%
December	40,718	$3,607.69	$3,713.24	$105.55	2.9%
Annual Totals	361,038	$38,184.41	$39,536.91	$1,352.50	3.5%

Industrial

Monthly	Therms	RY 1	RY 2	increase / (decrease) Amount	Percent
January	81,352	$5,127.42	$5,207.44	$80.02	1.6%
February	74,710	$4,879.01	$4,963.20	$84.19	1.7%
March	75,113	$4,894.08	$4,978.02	$83.94	1.7%
April	60,957	$4,364.64	$4,457.47	$92.83	2.1%
May	46,902	$3,838.97	$3,940.64	$101.67	2.6%
June	44,357	$3,743.79	$3,847.05	$103.27	2.8%
July	41,442	$3,634.76	$3,739.86	$105.10	2.9%
August	48,414	$3,895.52	$3,996.24	$100.72	2.6%
September	48,162	$3,886.10	$3,986.97	$100.87	2.6%
October	56,559	$4,200.15	$4,295.75	$95.60	2.3%
November	67,138	$4,595.81	$4,684.76	$88.95	1.9%
December	80,232	$5,085.53	$5,166.25	$80.72	1.6%
Annual Totals	725,338	$52,145.78	$53,263.64	$1,117.86	2.1%

Municipal

Monthly	Therms	RY 1	RY 2	increase / (decrease) Amount	Percent
January	27,101	$3,071.25	$3,185.81	$114.57	3.7%
February	26,071	$3,023.07	$3,138.45	$115.38	3.8%
March	24,726	$2,960.17	$3,076.61	$116.44	3.9%
April	16,353	$2,568.58	$2,691.61	$123.03	4.8%
May	8,208	$2,187.65	$2,317.09	$129.43	5.9%
June	6,098	$2,088.97	$2,220.07	$131.09	6.3%
July	7,108	$2,136.21	$2,266.51	$130.30	6.1%
August	6,679	$2,116.14	$2,246.78	$130.64	6.2%
September	7,410	$2,150.33	$2,280.39	$130.06	6.0%
October	13,817	$2,449.98	$2,575.00	$125.02	5.1%
November	18,966	$2,690.79	$2,811.76	$120.97	4.5%
December	31,428	$3,260.23	$3,371.63	$111.39	3.4%
Annual Totals	193,965	$30,703.37	$32,181.69	$1,478.32	4.8%

Billing Determinants

	UOM	RY 1 SC3	RY 2 SC3
First 1,000 therms	Monthly	$ 1,849.41	$ 1,984.52
Next 29,000 therms	Next 29,000 therms	$ 0.04656	$ 0.04577
Next 70,000 therms	Next 70,000 therms	$ 0.03719	$ 0.03656
Next 900,000 therms	Next 900,000 therms	$ 0.01439	$ 0.01415
Over 1,000,000 Therms	Over 1,000,000 Therı	$ 0.00676	$ 0.00665
Tax Credit - Next 29,000 therms	Next 29,000 therms	$ -	$ -
Tax Credit - Next 70,000 therms	Next 70,000 therms	$ -	$ -
Tax Credit - Next 900,000 therms	Next 900,000 therms	$ -	$ -
Tax Credit - Over 1,000,000 Therms	Over 1,000,000 Therı	$ -	$ -
Bill Charge	Monthly	$ 0.93	$ 0.93
SBC - CEF NYSERDA	Therm	$ 0.00021	$ 0.00021
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

Rochester Gas and Electric Corporation
Gas Rates
Monthly Delivery Bill Impact - May 1, 2021 - April 30, 2022
PSC No. 16 Service Classification No. 3 – High Pressure Option

Non-Residential

Therms	RY 1	RY 2	increase / (decrease) Amount	increase / (decrease) Percent
500	$1,553.63	$1,601.95	$48.32	3.1%
750	$1,553.68	$1,602.00	$48.32	3.1%
1,000	$1,553.73	$1,602.05	$48.32	3.1%
1,250	$1,562.59	$1,611.19	$48.59	3.1%
1,500	$1,571.45	$1,620.32	$48.87	3.1%
2,000	$1,589.17	$1,638.58	$49.41	3.1%
3,000	$1,624.60	$1,675.11	$50.51	3.1%
5,000	$1,695.47	$1,748.18	$52.70	3.1%
10,000	$1,872.65	$1,930.83	$58.18	3.1%
15,000	$2,049.82	$2,113.49	$63.67	3.1%
20,000	$2,226.99	$2,296.14	$69.15	3.1%
30,000	$2,581.34	$2,661.45	$80.11	3.1%
50,000	$3,290.03	$3,392.07	$102.03	3.1%
75,000	$4,175.90	$4,305.34	$129.44	3.1%
100,000	$5,061.77	$5,218.61	$156.84	3.1%

Billing Determinants	UOM	RY 1 SC3HP	RY 2 SC3HP
First 1,000 therms	Monthly	$ 1,552.60	$ 1,600.92
Next 29,000 therms	Next 29,000 therms	$ 0.03522	$ 0.03632
Next 70,000 therms	Next 70,000 therms	$ 0.03522	$ 0.03632
Next 900,000 therms	Next 900,000 therms	$ 0.03522	$ 0.03632
Over 1,000,000 Therms	Over 1,000,000 Therms	$ 0.00966	$ 0.00964
Tax Credit - Next 29,000 therms	Next 29,000 therms	$ -	$ -
Tax Credit - Next 70,000 therms	Next 70,000 therms	$ -	$ -
Tax Credit - Next 900,000 therms	Next 900,000 therms	$ -	$ -
Tax Credit - Over 1,000,000 Therms	Over 1,000,000 Therms	$ -	$ -
Bill Charge	Monthly	$ 0.93	$ 0.93
SBC - CEF NYSERDA	Therm	$ 0.00021	$ 0.00021
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

Rochester Gas and Electric Corporation
Data Sources - RG&E Gas Bill Impact Statements

Rate	Source of Rate in "Current" Rates	Source of Rate in Rate Years
Basic Service Charge	Current Tariff Rates in Effect January 1, 2019 (Last updated 5/1/2018)	New
Usage Charge	Current Tariff Rates in Effect January 1, 2019 (Last updated 5/1/2018)	New
SBC (NYSERDA EE) - per Therm	Current Tariff Rates in Effect January 1, 2020	Current Tariff Rates in Effect January 1, 2020
SBC (EE Tracker) - per Therm	Current Tariff Rates in Effect January 1, 2020	Included in Delivery Rates
Billing Charge per Bill	Current Tariff Rates in Effect January 1, 2019 - (Last Updated 07/01/2016)	Results of 2019 Embedded Cost Study
Usage Charge - Tax Credit	Current Tariff Rates in Effect 10/1/2018	Included in Delivery Rates

	Source of Rate in "Current" Rates and Rate Years
MFC per Therm	Current Tariff Rates in Effect May 1, 2020
Gas Supply Charge	Non Weighted Average of Monthly GSC in 2019
Customer Count	2018 Billing Information

Rochester Gas and Electric Corporation
Gas Rates
Monthly Total Bill Impact - May 1, 2022 - April 30, 2023
PSC No. 16 Service Classification No. 1 – General Service

Residential

			increase / (decrease)		Number of Customers		Amount of EE Embedded in Delivery Rates	
Therms	**RY 2**	**RY 3**	**Amount**	**Percent**	**January**	**July**	**Amount**	**Percent**
3	$19.23	$20.23	$1.00	5.2%	2,095	14,469	$0.00	0.0%
10	$23.52	$24.50	$0.98	4.2%	2,677	62,561	$0.02	0.1%
20	$29.64	$30.60	$0.96	3.2%	3,262	99,253	$0.04	0.1%
30	$35.76	$36.70	$0.94	2.6%	3,151	51,378	$0.07	0.2%
40	$41.89	$42.80	$0.92	2.2%	3,516	17,138	$0.09	0.2%
50	$48.01	$48.90	$0.90	1.9%	3,496	6,418	$0.11	0.2%
60	$54.13	$55.00	$0.87	1.6%	4,377	2,686	$0.14	0.3%
70	$60.25	$61.10	$0.85	1.4%	5,316	1,758	$0.16	0.3%
80	$66.37	$67.20	$0.83	1.2%	6,322	1,086	$0.19	0.3%
90	$72.50	$73.30	$0.81	1.1%	6,782	798	$0.21	0.3%
100	$78.62	$79.40	$0.78	1.0%	8,813	598	$0.24	0.3%
125	$93.46	$94.19	$0.73	0.8%	27,463	1,600	$0.29	0.3%
150	$108.29	$108.97	$0.68	0.6%	34,147	841	$0.35	0.3%
175	$123.13	$123.76	$0.63	0.5%	35,174	418	$0.41	0.3%
250	$167.64	$168.11	$0.47	0.3%	42,265	424	$0.58	0.3%
300	$197.31	$197.68	$0.37	0.2%	21,594	244	$0.69	0.3%
350	$226.98	$227.25	$0.27	0.1%	10,892	185	$0.80	0.4%
400	$256.66	$256.82	$0.16	0.1%	5,400	113	$0.92	0.4%
500	$316.00	$315.96	($0.05)	0.0%	4,448	130	$1.14	0.4%
750	$457.37	$456.86	($0.51)	-0.1%	2,196	127	$1.65	0.4%
1,000	$598.73	$597.76	($0.97)	-0.2%	373	50	$2.15	0.4%
1,500	$815.53	$814.16	($1.36)	-0.2%	244	42	$2.58	0.3%
2,000	$1,032.32	$1,030.57	($1.76)	-0.2%	68	11	$3.01	0.3%
3,000	$1,465.91	$1,463.37	($2.54)	-0.2%	59	4	$3.86	0.3%
5,000	$2,333.09	$2,328.97	($4.12)	-0.2%	38	2	$5.57	0.2%

Billing Determinants					
		RY 2	**RY 3**		
	UOM	**SC1**	**SC1**		
First 3 therms	Monthly	$ 17.30	$ 18.30		
Next 97 therms	Next 97 therms	$ 0.27644	$ 0.27422	$ 0.00244	EE Tracker
Next 400 therms	Next 400 therms	$ 0.25768	$ 0.25561	$ 0.00227	EE Tracker
Next 500 therms	Next 500 therms	$ 0.22969	$ 0.22784	$ 0.00202	EE Tracker
Over 1,000 Therms	Over 1,000 Therms	$ 0.09782	$ 0.09703	$ 0.00086	EE Tracker
Tax Credit - Next 97 therms	Next 97 therms	$ -	$ -		
Tax Credit - Next 400 therms	Next 400 therms	$ -	$ -		
Tax Credit - Next 500 therms	Next 500 therms	$ -	$ -		
Tax Credit - Over 1,000 therms	Over 1,000 Therms	$ -	$ -		
Bill Charge	Monthly	$ 0.93	$ 0.93		
SBC - CEF NYSERDA	Therm	$ 0.00021	$ 0.00021		
SBC - EE Tracker	Therm	$ -	$ -		
GRT - Delivery	%	0.00%	0.00%		
Gas Supply Charge	Therm	$ 0.31811	$ 0.31811		
MFC	Therm	$ 0.01746	$ 0.01746		

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.
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Rochester Gas and Electric Corporation
Gas Rates
Annual Total Bill Impact - May 1, 2022 - April 30, 2023
PSC No. 16 Service Classification No. 1 – General Service
Residential

Residential Spaceheating

Month	Therms	RY 2	RY 3	increase / (decrease) Amount	Percent
January	155	$111.26	$111.93	$0.67	0.6%
February	161	$114.82	$115.48	$0.66	0.6%
March	145	$105.32	$106.02	$0.69	0.7%
April	106	$82.18	$82.95	$0.77	0.9%
May	65	$57.19	$58.05	$0.86	1.5%
June	35	$38.83	$39.75	$0.93	2.4%
July	18	$28.42	$29.38	$0.97	3.4%
August	18	$28.42	$29.38	$0.97	3.4%
September	21	$30.25	$31.21	$0.96	3.2%
October	30	$35.76	$36.70	$0.94	2.6%
November	75	$63.31	$64.15	$0.84	1.3%
December	120	$90.49	$91.23	$0.74	0.8%
Annual Total	949	$786.25	$796.25	$10.00	1.3%

Residential Non-Spaceheating

Month	Therms	RY 2	RY 3	increase / (decrease) Amount	Percent
January	80	$66.37	$67.20	$0.83	1.2%
February	82	$67.60	$68.42	$0.82	1.2%
March	74	$62.70	$63.54	$0.84	1.3%
April	55	$51.07	$51.95	$0.88	1.7%
May	38	$40.66	$41.58	$0.92	2.3%
June	24	$32.09	$33.04	$0.95	3.0%
July	14	$25.97	$26.94	$0.98	3.8%
August	13	$25.36	$26.33	$0.98	3.9%
September	16	$27.19	$28.16	$0.97	3.6%
October	18	$28.42	$29.38	$0.97	3.4%
November	42	$43.11	$44.02	$0.91	2.1%
December	63	$55.97	$56.83	$0.87	1.5%
Annual Total	519	$526.51	$537.43	$10.93	2.1%

Billing Determinants

	UOM	RY 2 SC1	RY 3 SC1
First 3 therms	Monthly	$ 17.30	$ 18.30
Next 97 therms	Next 97 therms	$ 0.27644	$ 0.27422
Next 400 therms	Next 400 therms	$ 0.25768	$ 0.25561
Next 500 therms	Next 500 therms	$ 0.22969	$ 0.22784
Over 1,000 Therms	Over 1,000 Therms	$ 0.09782	$ 0.09703
Tax Credit - Next 97 therms	Next 97 therms	$ -	$ -
Tax Credit - Next 400 therms	Next 400 therms	$ -	$ -
Tax Credit - Next 500 therms	Next 500 therms	$ -	$ -
Tax Credit - Over 1,000 therms	Over 1,000 Therms	$ -	$ -
Bill Charge	Monthly	$ 0.93	$ 0.93
SBC - CEF NYSERDA	Therm	$ 0.00021	$ 0.00021
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%
Gas Supply Charge	Therm	$ 0.31811	$ 0.31811
MFC	Therm	$ 0.01746	$ 0.01746

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.
3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation
Gas Rates
Monthly Total Bill Impact - May 1, 2022 - April 30, 2023
PSC No. 16 Service Classification No. 1 – General Service

Non-Residential

			increase / (decrease)		Number of Customers	
Therms	RY 2	RY 3	Amount	Percent	January	July
3	$19.22	$20.22	$1.00	5.2%	262	2,687
10	$23.48	$24.47	$0.98	4.2%	476	3,884
20	$29.57	$30.53	$0.96	3.3%	460	2,352
50	$47.83	$48.73	$0.90	1.9%	1,093	2,885
100	$78.26	$79.05	$0.78	1.0%	1,862	1,379
150	$107.76	$108.44	$0.68	0.6%	1,634	529
200	$137.25	$137.83	$0.58	0.4%	1,430	350
250	$166.75	$167.22	$0.47	0.3%	1,180	244
300	$196.24	$196.61	$0.37	0.2%	916	175
350	$225.74	$226.00	$0.27	0.1%	728	150
400	$255.23	$255.39	$0.16	0.1%	623	104
500	$314.22	$314.18	($0.05)	0.0%	988	207
750	$454.70	$454.19	($0.51)	-0.1%	1,404	297
1,000	$595.17	$594.20	($0.97)	-0.2%	816	105
1,500	$810.19	$808.82	($1.36)	-0.2%	326	26
2,000	$1,025.20	$1,023.44	($1.76)	-0.2%	402	23
3,000	$1,455.22	$1,452.68	($2.54)	-0.2%	354	21
5,000	$2,315.28	$2,311.16	($4.12)	-0.2%	236	15
10,000	$4,465.41	$4,457.36	($8.05)	-0.2%	121	10
15,000	$6,615.54	$6,603.55	($11.99)	-0.2%	30	3
20,000	$8,765.68	$8,749.75	($15.93)	-0.2%	7	1
30,000	$13,065.94	$13,042.14	($23.80)	-0.2%	8	3
50,000	$21,666.47	$21,626.93	($39.54)	-0.2%	4	1
75,000	$32,417.14	$32,357.92	($59.22)	-0.2%	2	0
100,000	$43,167.80	$43,088.90	($78.90)	-0.2%	0	0

Billing Determinants			
		RY 2	RY 3
	UOM	SC1	SC1
First 3 therms	Monthly	$ 17.30	$ 18.30
Next 97 therms	Next 97 therms	$ 0.27644	$ 0.27422
Next 400 therms	Next 400 therms	$ 0.25768	$ 0.25561
Next 500 therms	Next 500 therms	$ 0.22969	$ 0.22784
Over 1,000 Therms	Over 1,000 Therms	$ 0.09782	$ 0.09703
Tax Credit - Next 97 therms	Next 97 therms	$ -	$ -
Tax Credit - Next 400 therms	Next 400 therms	$ -	$ -
Tax Credit - Next 500 therms	Next 500 therms	$ -	$ -
Tax Credit - Over 1,000 therms	Over 1,000 Therms	$ -	$ -
Bill Charge	Monthly	$ 0.93	$ 0.93
SBC - CEF NYSERDA	Therm	$ 0.00021	$ 0.00021
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%
Gas Supply Charge	Therm	$ 0.31811	$ 0.31811
MFC	Therm	$ 0.01389	$ 0.01389

Notes:

1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.

2. Current and proposed rates for the Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation
Gas Rates
Annual Total Bill Impact - May 1, 2022 - April 30, 2023
PSC No. 16 Service Classification No. 1 – General Service
Non-Residential

Commercial

Monthly	Therms	RY 2	RY 3	increase / (decrease) Amount	Percent
January	393	$251.10	$251.28	$0.18	0.1%
February	404	$257.59	$257.74	$0.15	0.1%
March	369	$236.94	$237.17	$0.23	0.1%
April	268	$177.37	$177.80	$0.44	0.2%
May	173	$121.33	$121.96	$0.63	0.5%
June	87	$70.35	$71.16	$0.81	1.2%
July	46	$45.40	$46.30	$0.90	2.0%
August	50	$47.83	$48.73	$0.90	1.9%
September	61	$54.53	$55.40	$0.87	1.6%
October	87	$70.35	$71.16	$0.81	1.2%
November	194	$133.71	$134.30	$0.59	0.4%
December	311	$202.73	$203.08	$0.35	0.2%
Annual Total	2,443	$1,669.22	$1,676.08	$6.86	0.4%

Industrial

Monthly	Therms	RY 2	RY 3	increase / (decrease) Amount	Percent
January	2,000	$1,025.20	$1,023.44	($1.76)	-0.2%
February	2,174	$1,100.02	$1,098.13	($1.89)	-0.2%
March	2,048	$1,045.84	$1,044.05	($1.79)	-0.2%
April	914	$546.85	$546.04	($0.81)	-0.1%
May	692	$422.11	$421.71	($0.40)	-0.1%
June	274	$180.90	$181.33	$0.42	0.2%
July	157	$111.89	$112.55	$0.67	0.6%
August	110	$84.16	$84.93	$0.76	0.9%
September	126	$93.60	$94.33	$0.73	0.8%
October	160	$113.66	$114.32	$0.66	0.6%
November	769	$465.37	$464.83	($0.54)	-0.1%
December	1,499	$809.75	$808.39	($1.36)	-0.2%
Annual Total	10,923	$5,999.35	$5,994.03	($5.32)	-0.1%

Municipal

Monthly	Therms	RY 2	RY 3	increase / (decrease) Amount	Percent
January	1,324	$734.50	$733.28	($1.22)	-0.2%
February	1,366	$752.56	$751.30	($1.26)	-0.2%
March	1,240	$698.38	$697.22	($1.16)	-0.2%
April	905	$541.79	$541.00	($0.79)	-0.1%
May	586	$362.54	$362.34	($0.20)	-0.1%
June	266	$176.19	$176.63	$0.44	0.2%
July	169	$118.97	$119.61	$0.64	0.5%
August	159	$113.07	$113.73	$0.66	0.6%
September	195	$134.30	$134.89	$0.59	0.4%
October	271	$179.13	$179.56	$0.43	0.2%
November	641	$393.45	$393.14	($0.31)	-0.1%
December	971	$578.88	$577.96	($0.92)	-0.2%
Annual Total	8,093	$4,783.76	$4,780.65	($3.10)	-0.1%

Billing Determinants

	UOM	RY 2 SC1	RY 3 SC1
First 3 therms	Monthly	$ 17.30	$ 18.30
Next 97 therms	Next 97 therms	$ 0.27644	$ 0.27422
Next 400 therms	Next 400 therms	$ 0.25768	$ 0.25561
Next 500 therms	Next 500 therms	$ 0.22969	$ 0.22784
Over 1,000 Therms	Over 1,000 Therms	$ 0.09782	$ 0.09703
Tax Credit - Next 97 therms	Next 97 therms	$ -	$ -
Tax Credit - Next 400 therms	Next 400 therms	$ -	$ -
Tax Credit - Next 500 therms	Next 500 therms	$ -	$ -
Tax Credit - Over 1,000 therms	Over 1,000 Therms	$ -	$ -
Bill Charge	Monthly	$ 0.93	$ 0.93
SBC - CEF NYSERDA	Therm	$ 0.00021	$ 0.00021
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%
Gas Supply Charge	Therm	$ 0.31811	$ 0.31811
MFC	Therm	$ 0.01389	$ 0.01389

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.
3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation
Data Sources - RG&E Gas Bill Impact Statements

Rate	Source of Rate in "Current" Rates	Source of Rate in Rate Years
Basic Service Charge	Current Tariff Rates in Effect January 1, 2019 (Last updated 5/1/2018)	New
Usage Charge	Current Tariff Rates in Effect January 1, 2019 (Last updated 5/1/2018)	New
SBC (NYSERDA EE) - per Therm	Current Tariff Rates in Effect January 1, 2020	Current Tariff Rates in Effect January 1, 2020
SBC (EE Tracker) - per Therm	Current Tariff Rates in Effect January 1, 2020	Included in Delivery Rates
Billing Charge per Bill	Current Tariff Rates in Effect January 1, 2019 - (Last Updated 07/01/2016)	Results of 2019 Embedded Cost Study
Usage Charge - Tax Credit	Current Tariff Rates in Effect 10/1/2018	Included in Delivery Rates

	Source of Rate in "Current" Rates and Rate Years
MFC per Therm	Current Tariff Rates in Effect May 1, 2020
Gas Supply Charge	Non Weighted Average of Monthly GSC in 2019
Customer Count	2018 Billing Information

Rochester Gas and Electric Corporation
Gas Rates
Monthly Delivery Bill Impact - May 1, 2022 - April 30, 2023
PSC No. 16 Service Classification No. 1 – General Service
PSC No. 16 Service Classification No. 5 – Small Transportation Service

Residential

			increase / (decrease)		Number of Customers		Number of Low Income Customers		Percent of Customers	Percent of Low Income Customers	Amount of EE Embedded in Delivery Rates	
Therms	**RY 2**	**RY 3**	**Amount**	**Percent**	**January**	**July**	**January**	**July**	**January**	**January**	**Amount**	**Percent**
3	$18.23	$19.23	$1.00	5.5%	2,161	15,658	231	1,566	0.7%	0.8%	$0.00	0.00%
10	$20.16	$21.15	$0.98	4.9%	2,834	69,672	398	6,332	1.0%	1.3%	$0.02	0.08%
20	$22.93	$23.89	$0.96	4.2%	3,425	111,491	405	9,997	1.2%	1.3%	$0.04	0.17%
30	$25.70	$26.64	$0.94	3.7%	3,329	57,504	458	6,445	1.1%	1.5%	$0.07	0.25%
40	$28.46	$29.38	$0.92	3.2%	3,712	19,044	478	2,607	1.3%	1.6%	$0.09	0.31%
50	$31.23	$32.13	$0.90	2.9%	3,709	7,148	432	1,139	1.3%	1.4%	$0.11	0.36%
60	$34.00	$34.87	$0.87	2.6%	4,655	3,000	604	469	1.6%	2.0%	$0.14	0.40%
70	$36.76	$37.61	$0.85	2.3%	5,698	1,966	678	288	1.9%	2.2%	$0.16	0.43%
80	$39.53	$40.36	$0.83	2.1%	6,802	1,237	769	155	2.3%	2.5%	$0.19	0.46%
90	$42.30	$43.10	$0.81	1.9%	7,416	912	843	124	2.5%	2.8%	$0.21	0.49%
100	$45.06	$45.85	$0.78	1.7%	9,786	665	1,040	67	3.3%	3.4%	$0.24	0.51%
125	$51.51	$52.24	$0.73	1.4%	30,645	1,797	2,904	162	10.4%	9.6%	$0.29	0.56%
150	$57.96	$58.64	$0.68	1.2%	38,413	959	3,235	83	13.0%	10.7%	$0.35	0.60%
175	$64.40	$65.03	$0.63	1.0%	39,860	474	3,288	49	13.5%	10.8%	$0.41	0.62%
200	$70.85	$71.43	$0.58	0.8%	34,193	338	2,856	32	11.6%	9.4%	$0.46	0.65%
250	$83.75	$84.22	$0.47	0.6%	47,674	470	4,486	40	16.1%	14.8%	$0.58	0.68%
300	$96.64	$97.01	$0.37	0.4%	24,190	266	2,911	28	8.2%	9.6%	$0.69	0.71%
350	$109.54	$109.80	$0.27	0.2%	12,196	207	1,864	22	4.1%	6.1%	$0.80	0.73%
400	$122.43	$122.59	$0.16	0.1%	6,013	122	1,026	18	2.0%	3.4%	$0.92	0.75%
500	$148.22	$148.18	($0.05)	0.0%	5,013	138	957	21	1.7%	3.2%	$1.14	0.77%
750	$205.70	$205.19	($0.51)	-0.2%	2,534	142	414	27	0.9%	1.4%	$1.65	0.80%
1,000	$263.17	$262.20	($0.97)	-0.4%	454	56	43	9	0.2%	0.1%	$2.15	0.82%
1,500	$312.19	$310.82	($1.36)	-0.4%	314	44	21	9	0.1%	0.1%	$2.58	0.83%
2,000	$361.20	$359.44	($1.76)	-0.5%	108	14	4	3	0.0%	0.0%	$3.01	0.84%
3,000	$459.22	$456.68	($2.54)	-0.6%	102	5	3	0	0.0%	0.0%	$3.86	0.85%
5,000	$655.28	$651.16	($4.12)	-0.6%	78	2	3	1	0.0%	0.0%	$5.57	0.86%
					295,313		30,350					

Billing Determinants		RY 2	RY 3		
	UOM	**SC1&5**	**SC1&5**		
First 3 therms	Monthly	$ 17.30	$ 18.30		
Next 97 therms	Next 97 therms	$ 0.27644	$ 0.27422	$ 0.00244	EE Tracker
Next 400 therms	Next 400 therms	$ 0.25768	$ 0.25561	$ 0.00227	EE Tracker
Next 500 therms	Next 500 therms	$ 0.22969	$ 0.22784	$ 0.00202	EE Tracker
Over 1,000 Therms	Over 1,000 Therms	$ 0.09782	$ 0.09703	$ 0.00086	EE Tracker
Tax Credit - Next 97 therms	Next 97 therms	$ -	$ -		
Tax Credit - Next 400 therms	Next 400 therms	$ -	$ -		
Tax Credit - Next 500 therms	Next 500 therms	$ -	$ -		
Tax Credit - Over 1,000 therms	Over 1,000 Therms	$ -	$ -		
Bill Charge	Monthly	$ 0.93	$ 0.93		
SBC - CEF NYSERDA	Therm	$ 0.00021	$ 0.00021		
SBC - EE Tracker	Therm	$ -	$ -		
GRT - Delivery	%	0.00%	0.00%		

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.
3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.
4. Low Income customers represent customers who participated in the Company's low income program and received a credit on their bill each month during calendar year 2018.

Rochester Gas and Electric Corporation
Gas Rates
Annual Delivery Bill Impact - May 1, 2022 - April 30, 2023
PSC No. 16 Service Classification No. 1 – General Service
PSC No. 16 Service Classification No. 5 – Small Transportation Service

Residential Spaceheating

				increase / (decrease)	
Month	**Therms**	**RY 2**	**RY 3**	**Amount**	**Percent**
January	155	$59.25	$59.92	$0.67	1.1%
February	161	$60.79	$61.45	$0.66	1.1%
March	145	$56.67	$57.36	$0.69	1.2%
April	106	$46.61	$47.38	$0.77	1.7%
May	65	$35.38	$36.24	$0.86	2.4%
June	35	$27.08	$28.01	$0.93	3.4%
July	18	$22.38	$23.34	$0.97	4.3%
August	18	$22.38	$23.34	$0.97	4.3%
September	21	$23.21	$24.17	$0.96	4.1%
October	30	$25.70	$26.64	$0.94	3.7%
November	75	$38.15	$38.99	$0.84	2.2%
December	120	$50.22	$50.96	$0.74	1.5%
Annual Total	949	$467.81	$477.80	$10.00	2.1%

Residential Non-Spaceheating

				increase / (decrease)	
Month	**Therms**	**RY 2**	**RY 3**	**Amount**	**Percent**
January	80	$39.53	$40.36	$0.83	2.1%
February	82	$40.08	$40.91	$0.82	2.1%
March	74	$37.87	$38.71	$0.84	2.2%
April	55	$32.61	$33.50	$0.88	2.7%
May	38	$27.91	$28.83	$0.92	3.3%
June	24	$24.04	$24.99	$0.95	4.0%
July	14	$21.27	$22.25	$0.98	4.6%
August	13	$20.99	$21.97	$0.98	4.7%
September	16	$21.82	$22.79	$0.97	4.4%
October	18	$22.38	$23.34	$0.97	4.3%
November	42	$29.02	$29.93	$0.91	3.1%
December	63	$34.83	$35.69	$0.87	2.5%
Annual Total	519	$352.35	$363.28	$10.93	3.1%

Billing Determinants			
		RY 2	**RY 3**
	UOM	**SC1&5**	**SC1&5**
First 3 therms	Monthly	$ 17.30	$ 18.30
Next 97 therms	Next 97 therms	$ 0.27644	$ 0.27422
Next 400 therms	Next 400 therms	$ 0.25768	$ 0.25561
Next 500 therms	Next 500 therms	$ 0.22969	$ 0.22784
Over 1,000 Therms	Over 1,000 Therms	$ 0.09782	$ 0.09703
Tax Credit - Next 97 therms	Next 97 therms	$ -	$ -
Tax Credit - Next 400 therms	Next 400 therms	$ -	$ -
Tax Credit - Next 500 therms	Next 500 therms	$ -	$ -
Tax Credit - Over 1,000 therms	Over 1,000 Therms	$ -	$ -
Bill Charge	Monthly	$ 0.93	$ 0.93
SBC - CEF NYSERDA	Therm	$ 0.00021	$ 0.00021
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.
3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation
Gas Rates
Monthly Delivery Bill Impact - May 1, 2022 - April 30, 2023
PSC No. 16 Service Classification No. 1 – General Service
PSC No. 16 Service Classification No. 5 – Small Transportation Service

Non-Residential

			increase / (decrease)		Number of Customers	
Therms	**RY 2**	**RY 3**	**Amount**	**Percent**	**January**	**July**
3	$18.23	$19.23	$1.00	5.5%	330	3,515
10	$20.16	$21.15	$0.98	4.9%	587	5,015
20	$22.93	$23.89	$0.96	4.2%	539	3,019
50	$31.23	$32.13	$0.90	2.9%	1,334	4,240
100	$45.06	$45.85	$0.78	1.7%	2,237	2,588
150	$57.96	$58.64	$0.68	1.2%	2,031	1,056
200	$70.85	$71.43	$0.58	0.8%	1,819	668
250	$83.75	$84.22	$0.47	0.6%	1,563	485
300	$96.64	$97.01	$0.37	0.4%	1,298	358
350	$109.54	$109.80	$0.27	0.2%	1,075	347
400	$122.43	$122.59	$0.16	0.1%	973	257
500	$148.22	$148.18	($0.05)	0.0%	1,695	442
750	$205.70	$205.19	($0.51)	-0.2%	2,446	697
1,000	$263.17	$262.20	($0.97)	-0.4%	1,418	371
1,250	$287.68	$286.51	($1.17)	-0.4%	932	194
1,500	$312.19	$310.82	($1.36)	-0.4%	705	106
2,000	$361.20	$359.44	($1.76)	-0.5%	892	149
3,000	$459.22	$456.68	($2.54)	-0.6%	829	82
5,000	$655.28	$651.16	($4.12)	-0.6%	693	61
10,000	$1,145.41	$1,137.36	($8.05)	-0.7%	524	41
15,000	$1,635.54	$1,623.55	($11.99)	-0.7%	156	5
20,000	$2,125.68	$2,109.75	($15.93)	-0.7%	49	3
30,000	$3,105.94	$3,082.14	($23.80)	-0.8%	34	7
50,000	$5,066.47	$5,026.93	($39.54)	-0.8%	11	1
75,000	$7,517.14	$7,457.92	($59.22)	-0.8%	4	0
100,000	$9,967.80	$9,888.90	($78.90)	-0.8%	0	0

Billing Determinants			
		RY 2	**RY 3**
	UOM	**SC1&5**	**SC1&5**
First 3 therms	Monthly	$ 17.30	$ 18.30
Next 97 therms	Next 97 therms	$ 0.27644	$ 0.27422
Next 400 therms	Next 400 therms	$ 0.25768	$ 0.25561
Next 500 therms	Next 500 therms	$ 0.22969	$ 0.22784
Over 1,000 Therms	Over 1,000 Therms	$ 0.09782	$ 0.09703
Tax Credit - Next 97 therms	Next 97 therms	$ -	$ -
Tax Credit - Next 400 therms	Next 400 therms	$ -	$ -
Tax Credit - Next 500 therms	Next 500 therms	$ -	$ -
Tax Credit - Over 1,000 therms	Over 1,000 Therms	$ -	$ -
Bill Charge	Monthly	$ 0.93	$ 0.93
SBC - CEF NYSERDA	Therm	$ 0.00021	$ 0.00021
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.
3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation
Gas Rates
Annual Delivery Bill Impact - May 1, 2022 - April 30, 2023
PSC No. 16 Service Classification No. 1 – General Service
PSC No. 16 Service Classification No. 5 – Small Transportation Service
Non-Residential

Commercial

				increase / (decrease)	
Monthly	**Therms**	**RY 2**	**RY 3**	**Amount**	**Percent**
January	393	$120.63	$120.80	$0.18	0.1%
February	404	$123.46	$123.62	$0.15	0.1%
March	369	$114.44	$114.66	$0.23	0.2%
April	268	$88.39	$88.82	$0.44	0.5%
May	173	$63.89	$64.52	$0.63	1.0%
June	87	$41.47	$42.28	$0.81	2.0%
July	46	$30.12	$31.03	$0.90	3.0%
August	50	$31.23	$32.13	$0.90	2.9%
September	61	$34.27	$35.14	$0.87	2.5%
October	87	$41.47	$42.28	$0.81	2.0%
November	194	$69.30	$69.89	$0.59	0.9%
December	311	$99.48	$99.83	$0.35	0.3%
Annual Total	2,443	$858.15	$865.00	$6.86	0.8%

Industrial

				increase / (decrease)	
Monthly	**Therms**	**RY 2**	**RY 3**	**Amount**	**Percent**
January	2,000	$361.20	$359.44	($1.76)	-0.5%
February	2,174	$378.25	$376.36	($1.89)	-0.5%
March	2,048	$365.90	$364.11	($1.79)	-0.5%
April	914	$243.40	$242.59	($0.81)	-0.3%
May	692	$192.36	$191.96	($0.40)	-0.2%
June	274	$89.94	$90.36	$0.42	0.5%
July	157	$59.76	$60.43	$0.67	1.1%
August	110	$47.64	$48.41	$0.76	1.6%
September	126	$51.77	$52.50	$0.73	1.4%
October	160	$60.54	$61.20	$0.66	1.1%
November	769	$210.06	$209.52	($0.54)	-0.3%
December	1,499	$312.09	$310.72	($1.36)	-0.4%
Annual Total	10,923	$2,372.92	$2,367.60	($5.32)	-0.2%

Municipal

				increase / (decrease)	
Monthly	**Therms**	**RY 2**	**RY 3**	**Amount**	**Percent**
January	1,324	$294.93	$293.71	($1.22)	-0.4%
February	1,366	$299.05	$297.79	($1.26)	-0.4%
March	1,240	$286.70	$285.54	($1.16)	-0.4%
April	905	$241.33	$240.54	($0.79)	-0.3%
May	586	$167.99	$167.79	($0.20)	-0.1%
June	266	$87.87	$88.31	$0.44	0.5%
July	169	$62.86	$63.50	$0.64	1.0%
August	159	$60.28	$60.94	$0.66	1.1%
September	195	$69.56	$70.15	$0.59	0.8%
October	271	$89.16	$89.59	$0.43	0.5%
November	641	$180.64	$180.33	($0.31)	-0.2%
December	971	$256.50	$255.59	($0.92)	-0.4%
Annual Total	8,093	$2,096.88	$2,093.78	($3.10)	-0.1%

Billing Determinants			
		RY 2	**RY 3**
	UOM	**SC1&5**	**SC1&5**
First 3 therms	Monthly	$ 17.30	$ 18.30
Next 97 therms	Next 97 therms	$ 0.27644	$ 0.27422
Next 400 therms	Next 400 therms	$ 0.25768	$ 0.25561
Next 500 therms	Next 500 therms	$ 0.22969	$ 0.22784
Over 1,000 Therms	Over 1,000 Therms	$ 0.09782	$ 0.09703
Tax Credit - Next 97 therms	Next 97 therms	$ -	$ -
Tax Credit - Next 400 therms	Next 400 therms	$ -	$ -
Tax Credit - Next 500 therms	Next 500 therms	$ -	$ -
Tax Credit - Over 1,000 therms	Over 1,000 Therms	$ -	$ -
Bill Charge	Monthly	$ 0.93	$ 0.93
SBC - CEF NYSERDA	Therm	$ 0.00021	$ 0.00021
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.
3. Costs associated with the bill credits provided to eligible customers as a result of COVID-19 will be collected through the RAM beginning July 1, 2021. The costs will be recovered from only those service classes which were eligible to receive the bill credits.

Rochester Gas and Electric Corporation
Gas Rates
Monthly Delivery Bill Impact - May 1, 2022 - April 30, 2023
PSC No. 16 Service Classification No. 3 – Large Transportation Service

Non-Residential

			increase / (decrease)		Number of Customers	
Therms	**RY 2**	**RY 3**	**Amount**	**Percent**	**January**	**July**
500	$1,985.55	$2,240.21	$254.67	12.8%	0	39
750	$1,985.60	$2,240.27	$254.67	12.8%	0	5
1,000	$1,985.65	$2,240.32	$254.67	12.8%	1	8
1,250	$1,997.15	$2,251.30	$254.15	12.7%	0	5
1,500	$2,008.64	$2,262.28	$253.64	12.6%	0	8
2,000	$2,031.63	$2,284.25	$252.62	12.4%	1	13
3,000	$2,077.61	$2,328.18	$250.57	12.1%	1	24
5,000	$2,169.58	$2,416.05	$246.47	11.4%	4	34
10,000	$2,399.49	$2,635.72	$236.23	9.8%	28	35
15,000	$2,629.39	$2,855.38	$225.99	8.6%	37	15
20,000	$2,859.30	$3,075.05	$215.75	7.5%	43	11
30,000	$3,319.11	$3,514.38	$195.27	5.9%	53	13
50,000	$4,054.56	$4,217.10	$162.54	4.0%	44	16
75,000	$4,973.86	$5,095.50	$121.64	2.4%	19	6
100,000	$5,893.16	$5,973.90	$80.74	1.4%	3	4

Billing Determinants			
		RY 2	**RY 3**
	UOM	**SC3**	**SC3**
First 1,000 therms	Monthly	$ 1,984.52	$ 2,239.18
Next 29,000 therms	Next 29,000 therms	$ 0.04577	$ 0.04372
Next 70,000 therms	Next 70,000 therms	$ 0.03656	$ 0.03493
Next 900,000 therms	Next 900,000 therms	$ 0.01415	$ 0.01352
Over 1,000,000 Therms	Over 1,000,000 Therms	$ 0.00665	$ 0.00635
Tax Credit - Next 29,000 therms	Next 29,000 therms	$ -	$ -
Tax Credit - Next 70,000 therms	Next 70,000 therms	$ -	$ -
Tax Credit - Next 900,000 therms	Next 900,000 therms	$ -	$ -
Tax Credit - Over 1,000,000 Therms	Over 1,000,000 Therms	$ -	$ -
Bill Charge	Monthly	$ 0.93	$ 0.93
SBC - CEF NYSERDA	Therm	$ 0.00021	$ 0.00021
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

Rochester Gas and Electric Corporation
Gas Rates
Annual Delivery Bill Impact - May 1, 2022 - April 30, 2023
PSC No. 16 Service Classification No. 3 – Large Transportation Service

Commercial

				increase / (decrease)	
Monthly	**Therms**	**RY 2**	**RY 3**	**Amount**	**Percent**
January	37,692	$3,601.97	$3,784.65	$182.68	5.1%
February	37,887	$3,609.14	$3,791.50	$182.36	5.1%
March	36,696	$3,565.34	$3,749.65	$184.31	5.2%
April	29,763	$3,308.22	$3,503.97	$195.75	5.9%
May	24,992	$3,088.84	$3,294.37	$205.52	6.7%
June	22,558	$2,976.92	$3,187.43	$210.51	7.1%
July	25,802	$3,126.08	$3,329.95	$203.87	6.5%
August	24,282	$3,056.19	$3,263.17	$206.98	6.8%
September	24,264	$3,055.37	$3,262.38	$207.02	6.8%
October	22,436	$2,971.31	$3,182.07	$210.76	7.1%
November	33,948	$3,464.29	$3,653.10	$188.81	5.5%
December	40,718	$3,713.24	$3,890.97	$177.73	4.8%
Annual Totals	361,038	$39,536.91	$41,893.21	$2,356.30	6.0%

Industrial

				increase / (decrease)	
Monthly	**Therms**	**RY 2**	**RY 3**	**Amount**	**Percent**
January	81,352	$5,207.44	$5,318.69	$111.25	2.1%
February	74,710	$4,963.20	$5,085.31	$122.12	2.5%
March	75,113	$4,978.02	$5,099.47	$121.46	2.4%
April	60,957	$4,457.47	$4,602.09	$144.62	3.2%
May	46,902	$3,940.64	$4,108.25	$167.61	4.3%
June	44,357	$3,847.05	$4,018.83	$171.78	4.5%
July	41,442	$3,739.86	$3,916.41	$176.55	4.7%
August	48,414	$3,996.24	$4,161.38	$165.14	4.1%
September	48,162	$3,986.97	$4,152.52	$165.55	4.2%
October	56,559	$4,295.75	$4,447.56	$151.81	3.5%
November	67,138	$4,684.76	$4,819.26	$134.50	2.9%
December	80,232	$5,166.25	$5,279.33	$113.08	2.2%
Annual Totals	725,338	$53,263.64	$55,009.10	$1,745.46	3.3%

Municipal

				increase / (decrease)	
Monthly	**Therms**	**RY 2**	**RY 3**	**Amount**	**Percent**
January	27,101	$3,185.81	$3,387.02	$201.20	6.3%
February	26,071	$3,138.45	$3,341.77	$203.31	6.5%
March	24,726	$3,076.61	$3,282.68	$206.07	6.7%
April	16,353	$2,691.61	$2,914.83	$223.22	8.3%
May	8,208	$2,317.09	$2,556.99	$239.90	10.4%
June	6,098	$2,220.07	$2,464.29	$244.22	11.0%
July	7,108	$2,266.51	$2,508.66	$242.16	10.7%
August	6,679	$2,246.78	$2,489.81	$243.03	10.8%
September	7,410	$2,280.39	$2,521.93	$241.54	10.6%
October	13,817	$2,575.00	$2,803.41	$228.41	8.9%
November	18,966	$2,811.76	$3,029.62	$217.87	7.7%
December	31,428	$3,371.63	$3,564.56	$192.93	5.7%
Annual Totals	193,965	$32,181.69	$34,865.57	$2,683.87	8.3%

Billing Determinants			
		RY 2	**RY 3**
	UOM	**SC3**	**SC3**
First 1,000 therms	Monthly	$ 1,984.52	$ 2,239.18
Next 29,000 therms	Next 29,000 therms	$ 0.04577	$ 0.04372
Next 70,000 therms	Next 70,000 therms	$ 0.03656	$ 0.03493
Next 900,000 therms	Next 900,000 therms	$ 0.01415	$ 0.01352
Over 1,000,000 Therms	Over 1,000,000 Therı	$ 0.00665	$ 0.00635
Tax Credit - Next 29,000 therms	Next 29,000 therms	$ -	$ -
Tax Credit - Next 70,000 therms	Next 70,000 therms	$ -	$ -
Tax Credit - Next 900,000 therms	Next 900,000 therms	$ -	$ -
Tax Credit - Over 1,000,000 Therms	Over 1,000,000 Therı	$ -	$ -
Bill Charge	Monthly	$ 0.93	$ 0.93
SBC - CEF NYSERDA	Therm	$ 0.00021	$ 0.00021
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

Rochester Gas and Electric Corporation
Gas Rates
Monthly Delivery Bill Impact - May 1, 2022 - April 30, 2023
PSC No. 16 Service Classification No. 3 – High Pressure Option

Non-Residential

			increase / (decrease)	
Therms	**RY 2**	**RY 3**	**Amount**	**Percent**
500	$1,601.95	$1,671.45	$69.50	4.3%
750	$1,602.00	$1,671.50	$69.50	4.3%
1,000	$1,602.05	$1,671.56	$69.50	4.3%
1,250	$1,611.19	$1,681.08	$69.90	4.3%
1,500	$1,620.32	$1,690.61	$70.29	4.3%
2,000	$1,638.58	$1,709.66	$71.08	4.3%
3,000	$1,675.11	$1,747.77	$72.66	4.3%
5,000	$1,748.18	$1,823.99	$75.81	4.3%
10,000	$1,930.83	$2,014.53	$83.69	4.3%
15,000	$2,113.49	$2,205.07	$91.58	4.3%
20,000	$2,296.14	$2,395.60	$99.46	4.3%
30,000	$2,661.45	$2,776.68	$115.23	4.3%
50,000	$3,392.07	$3,538.84	$146.77	4.3%
75,000	$4,305.34	$4,491.53	$186.19	4.3%
100,000	$5,218.61	$5,444.23	$225.61	4.3%

Billing Determinants			
		RY 2	**RY 3**
	UOM	**SC3HP**	**SC3HP**
First 1,000 therms	Monthly	$ 1,600.92	$ 1,670.42
Next 29,000 therms	Next 29,000 therms	$ 0.03632	$ 0.03790
Next 70,000 therms	Next 70,000 therms	$ 0.03632	$ 0.03790
Next 900,000 therms	Next 900,000 therms	$ 0.03632	$ 0.03790
Over 1,000,000 Therms	Over 1,000,000 Therms	$ 0.00964	$ 0.00940
Tax Credit - Next 29,000 therms	Next 29,000 therms	$ -	$ -
Tax Credit - Next 70,000 therms	Next 70,000 therms	$ -	$ -
Tax Credit - Next 900,000 therms	Next 900,000 therms	$ -	$ -
Tax Credit - Over 1,000,000 Therms	Over 1,000,000 Therms	$ -	$ -
Bill Charge	Monthly	$ 0.93	$ 0.93
SBC - CEF NYSERDA	Therm	$ 0.00021	$ 0.00021
SBC - EE Tracker	Therm	$ -	$ -
GRT - Delivery	%	0.00%	0.00%

Notes:
1. SBC - EE Tracker and Tax Credit are moved to proposed delivery rates beginning in rate year 1.
2. Current and proposed rates for the Gas Supply Charge are based on 2019 data. MFC is the 5/1/2020 approved tariff rate.

Rochester Gas and Electric Corporation
Data Sources - RG&E Gas Bill Impact Statements

Rate	Source of Rate in "Current" Rates	Source of Rate in Rate Years
Basic Service Charge	Current Tariff Rates in Effect January 1, 2019 (Last updated 5/1/2018)	New
Usage Charge	Current Tariff Rates in Effect January 1, 2019 (Last updated 5/1/2018)	New
SBC (NYSERDA EE) - per Therm	Current Tariff Rates in Effect January 1, 2020	Current Tariff Rates in Effect January 1, 2020
SBC (EE Tracker) - per Therm	Current Tariff Rates in Effect January 1, 2020	Included in Delivery Rates
Billing Charge per Bill	Current Tariff Rates in Effect January 1, 2019 - (Last Updated 07/01/2016)	Results of 2019 Embedded Cost Study
Usage Charge - Tax Credit	Current Tariff Rates in Effect 10/1/2018	Included in Delivery Rates

	Source of Rate in "Current" Rates and Rate Years
MFC per Therm	Current Tariff Rates in Effect May 1, 2020
Gas Supply Charge	Non Weighted Average of Monthly GSC in 2019
Customer Count	2018 Billing Information

Revenue Decoupling Mechanisms

New York State Electric & Gas Corporation – Electric
New York State Electric & Gas Corporation – Gas
Rochester Gas and Electric Corporation – Electric
Rochester Gas and Electric Corporation – Gas

The Companies will continue their revenue decoupling mechanisms ("RDMs") as described in the Proposal and as set forth below.

Electric

The Electric RDM will reconcile actual billed delivery service revenue to allowed delivery service revenue.

Actual billed delivery service revenues are defined as customer, demand, reactive, and delivery kWh rate components only. The Rate Adjustment Mechanism ("RAM"), System Benefits charge ("SBC"), Merchant Function charge ("MFC") and Transition Charge, which have separate recovery mechanisms, or delivery service revenues derived from an RDM adjustment will not be included as actual billed delivery service revenue.

For each service class or subclass subject to the RDM, each Company will, on a monthly basis, compare actual billed delivery service revenue exclusive of the COVID-19 Customer Bill Credit to a delivery service revenue target.[1] If the monthly actual billed delivery service revenue exceeds the delivery service revenue target, the delivery service revenue excess will be accrued for refund to customers at the end of the Rate Year. Likewise, if the monthly actual billed delivery service revenue is less than the delivery service revenue target, the delivery revenue shortfall will be accrued for recovery from customers at the end of the Rate Year.

At the end of the Rate Year, total delivery service revenues will be compared to cumulative monthly target revenues for each service class or subclass. Any variance from cumulative target revenues will be either refunded / surcharged to customers over the 12-month period beginning August 1 following the Rate Year. Any surcharge or credit (RDM Adjustment) amount will reflect interest at the then-effective other customer deposit rate and will be either recovered or returned on a service class or subclass specific basis. For reconciliation purposes the residential service classes will be combined as an RDM class at each Company, NYSEG service classes 1, 8 and 12 will be combined and RG&E service classes 1 and 4 will be combined. The surcharge or credit for each applicable service class or subclass shall be determined by dividing the amount to be refunded / surcharged to customers in that service class or subclass by estimated kWh or kW deliveries to customers in that service class or subclass over a 12-month period or RDM Adjustment Period. A per kW surcharge or credit will be applied for those classes that do not have a kWh delivery charge and a per kWh surcharge or credit will apply for all other classes.

[1] See Attachment to Appendix FF.

The Companies will file the service class or subclass specific RDM surcharge / credit rates with the Commission on not less than 30 days' notice, to be effective August 1 of each year. Each service class- or subclass-specific RDM surcharge / credit will be identified on a tariff statement.

Following each RDM Adjustment Period, any difference between the amounts required to be charged or credited to customers in each service class or subclass and the amounts actually charged or credited will be charged or credited to customers in that service class or subclass, with interest, over the subsequent RDM Adjustment period, or as determined by the Commission if no RDM is in effect.

In order to prevent large over- or under-collection of balances accruing during the year, an interim surcharge / credit will be triggered when actual total accumulated billed delivery service revenues vary plus or minus 1.50% or more from the total accumulated delivery service target revenues. Interim surcharges or credits will be developed on a service class or subclass basis and filed with the Commission on not less than 10 days' notice. Each service class or subclass specific RDM surcharge / credit will be identified on a tariff statement.

The interim surcharge / credit will be limited to no more than one per Rate Year. The interim surcharge / credit will be recovered and returned over the longer of four months or the end of the Rate Year.

For purposes of comparing actual to target revenues, actual delivery revenue in the first two months of each Rate Year will be adjusted upward to reverse the effect of proration between old and new rates in actual billed delivery service revenue. This will be accomplished by multiplying actual billing determinants for each RDM applicable service class or subclass by the approved rates for the Rate Year.

Flexible rate and NYPA customer migration will continue to be treated symmetrically in the RDM using the following methodology:

1) If a customer moves from a flexible rate contract to an RDM class, the RDM target will increase by the level of revenue forecast for that customer in the Rate Year under the flexible rate contract prorated by the number of months in the new service class, making the Company whole for delivery revenues below the level forecasted in the Rate Year. Any revenue in excess of the forecast will be credited to the RDM class.

2) If a customer moves from an RDM class to a flexible rate contract, the RDM target will be decreased by that customer's sales in the flexible rate contract priced out at full tariff rates, making the RDM class whole for delivery revenues from the migrating customer.

3) In situations (1) and (2) above, the Companies will adjust the RDM targets for the remaining months of the current Rate Year and in the subsequent Rate Years.

All sales to low income and economic development rate incentive customers will be priced out at full tariff rates in developing class-specific RDM revenue targets and actual revenues for variance and reconciliation purposes.

<u>Gas</u>

Actual billed delivery service revenues will be reconciled to allowed delivery service revenues on a monthly basis. Actual delivery service revenues are defined as the revenue received from base delivery rates (customer charges and per-therm delivery rates). Actual delivery service revenues will reflect the weather normalization adjustment clause. SBC and MFC, which have separate recovery mechanisms, will not be subject to the RDM.

All sales to low income and economic development rate incentive customers will be priced out at full tariff rates in developing revenue targets and actual revenues for variance and reconciliation purposes.

At the end of the Rate Year, actual billed revenues exclusive of the COVID-19 Customer Bill credit by RDM class for the entire Rate Year will be compared to the cumulative monthly targets for the entire Rate Year. Any variance from the cumulative monthly targets for the Rate Year will be either surcharged or credited to customers over the 12-month period beginning August 1 following the Rate Year. Surcharges or credits will be developed on an RDM class basis. Any surcharge or credit amount will reflect interest at the then-effective other customer deposit rate. For reconciliation purposes the residential service classes will be combined as an RDM class at each Company. Any such surcharge or credit under the annual reconciliation or interim reconciliation process (discussed below) will be recovered or returned through RDM class specific rates. Surcharges or credits arrived at in the annual reconciliation will reflect amounts already surcharged or refunded through the interim reconciliation process.

Each Company will file the class-specific RDM surcharge / credit rates with the Commission on not less than 30 days' notice, to be effective August 1 of each year. Each class-specific RDM surcharge / credit will be identified on the filed tariff statement.

In order to prevent large over- or under-collection of balances accruing during the year, an interim surcharge / credit will be triggered when cumulative actual billed revenues vary plus or minus 1.50% or more from the cumulative target revenues as illustrated in Appendix Y attached hereto. Interim surcharges or credits will be developed on an RDM class basis to be filed on not less than 10 days' notice. Each class-specific RDM surcharge / credit will be identified on the filed tariff statement.

The interim surcharge / credit will be limited to no more than one per Rate Year. The interim surcharge / credit will be recovered and returned over the longer or four months or the end of the Rate Year.

For purposes of comparing actual to target revenues, actual delivery revenue in the first two months of each Rate Year will be adjusted upward to reverse the effect of proration between old and new rates in actual billed delivery service revenue. This will be accomplished by multiplying actual billing determinants for each RDM applicable service class by the approved rates for the Rate Year.

New York State Electric & Gas Corporation
Electric Business
Rate Year 1 RDM Targets
Revenue ($000) and Usage (MWH) by Service Class (SC)

Rate Year Revenue By Service Class ($000)

Residential:		May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	Total
SC1	Residential	25,580	26,496	29,642	31,851	28,799	28,098	25,764	29,020	32,751	29,345	29,132	27,446	343,924
SC8	Residential Day/Night	6,967	6,332	6,393	6,844	6,176	6,567	7,007	9,034	10,606	9,144	8,824	8,446	92,342
SC12	Residential TOU	603	512	700	609	631	562	520	604	828	672	691	642	7,575
	Total Residential	33,151	33,340	36,734	39,305	35,607	35,227	33,292	38,658	44,185	39,161	38,648	36,534	443,841
Commercial and Industrial (C&I):		May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	Total
SC2	General Service w/Demand	9,527	10,187	10,410	10,562	10,363	10,738	9,080	9,420	9,684	8,989	9,272	9,559	117,791
SC 6	General Service Regular	2,537	2,420	2,538	2,702	2,694	2,564	2,534	2,679	2,929	2,842	2,795	2,690	31,921
SC9	General Service Day/Night	121	111	114	120	114	110	130	144	169	159	153	141	1,587
SC3P	Primary	353	416	396	(94)	369	477	305	295	297	653	371	367	4,208
SC 3S	Subtransmission	10	11	9	11	11	9	13	13	8	11	11	11	128
SC7-1	Secondary	3,071	3,170	3,185	3,282	2,659	3,188	3,023	3,033	2,907	2,908	2,798	2,913	36,136
SC7-2	Primary	2,432	2,350	2,579	3,001	2,440	2,614	2,561	2,292	2,364	2,320	2,327	2,332	29,611
SC7-3	Subtransmission	639	649	626	686	579	650	713	669	622	626	636	607	7,702
Street Lighting		757	684	609	638	765	845	1,012	1,094	1,203	1,207	942	970	10,726
	Total C&I	19,447	19,998	20,467	20,908	19,993	21,194	19,371	19,637	20,184	19,715	19,304	19,591	239,810
RDM TOTAL		$ 52,598	$ 53,338	$ 57,202	$ 60,213	$ 55,600	$ 56,421	$ 52,663	$ 58,295	$ 64,369	$ 58,876	$ 57,952	$ 56,125	$ 683,651

Rate Year Usage By Service Class (MWH)

Residential		May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	Total
SC1	Residential	352,750	372,758	442,267	491,074	423,683	408,081	356,470	428,525	511,017	435,737	430,874	394,218	5,047,453
SC8	Residential Day/Night	117,074	101,454	103,004	114,128	97,808	107,422	118,297	168,143	206,819	170,967	163,125	153,395	1,621,636
SC12	Residential TOU	13,016	10,718	15,449	13,177	13,723	11,998	10,938	13,052	18,720	14,770	15,268	13,979	164,809
	Total Residential	482,840	484,930	560,720	618,379	535,214	527,500	485,705	609,720	736,556	621,474	609,267	561,592	6,833,898
Commercial and Industrial (C&I)		May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	Total
SC2	General Service w/Demand	217,418	236,977	259,899	269,041	256,180	240,380	210,782	238,919	263,414	229,889	238,240	240,224	2,901,362
SC 6	General Service Regular	24,418	22,045	24,289	27,468	27,367	24,968	24,478	27,303	32,131	30,421	29,497	27,530	321,916
SC9	General Service Day/Night	1,697	1,456	1,540	1,688	1,603	1,523	1,970	2,284	2,782	2,567	2,420	2,156	23,685
SC3P	Primary	14,967	17,253	16,919	(9,695)	15,032	12,559	11,816	12,781	13,369	32,681	15,947	16,649	170,277
SC 3S	Subtransmission	589	660	534	642	651	508	622	879	275	395	688	682	7,126
SC7-1	Secondary	106,679	118,792	122,756	128,567	98,492	110,677	98,190	120,079	117,122	109,181	105,560	110,391	1,346,487
SC7-2	Primary	126,323	124,302	140,745	168,181	134,283	132,711	138,283	123,753	135,389	126,931	125,593	131,382	1,607,875
SC7-3	Subtransmission	97,895	99,262	96,547	109,255	86,986	101,280	111,829	106,522	97,896	99,724	97,700	93,948	1,198,844
Street Lighting		4,869	4,401	3,919	4,104	4,917	5,433	6,507	7,033	7,739	7,759	6,054	6,241	68,974
	Total C&I	594,853	625,148	667,147	699,251	625,509	630,039	604,478	639,553	670,117	639,548	621,700	629,203	7,646,545
RDM TOTAL		1,077,693	1,110,078	1,227,868	1,317,630	1,160,723	1,157,539	1,090,183	1,249,273	1,406,673	1,261,022	1,230,967	1,190,795	14,480,443

Rate Year Customers By Service Class

Residential		May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	Total
SC1	Residential	636,953	637,649	637,774	637,902	637,668	637,941	638,014	637,765	637,719	637,705	638,146	636,286	637,627
SC8	Residential Day/Night	126,475	126,483	126,382	126,277	126,100	126,028	125,913	125,738	125,597	125,466	125,435	126,468	126,030
SC12	Residential TOU	3,640	3,638	3,632	3,627	3,620	3,615	3,610	3,603	3,597	3,591	3,588	3,642	3,617
	Total Residential	767,068	767,770	767,788	767,806	767,388	767,584	767,537	767,106	766,913	766,762	767,169	766,396	767,274
Commercial and Industrial (C&I)		May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	Total
SC2	General Service w/Demand	45,599	45,819	45,881	45,897	45,769	45,558	45,423	45,445	45,582	45,654	45,705	45,288	45,635
SC 6	General Service Regular	72,474	72,785	72,882	72,875	72,723	72,373	72,103	72,064	72,098	72,156	72,201	72,008	72,395
SC9	General Service Day/Night	2,347	2,349	2,304	2,296	2,195	2,171	2,183	2,213	2,356	2,365	2,367	2,349	2,291
SC3P	Primary	313	313	314	315	314	313	313	312	313	313	313	311	313
SC 3S	Subtransmission	12	12	12	12	12	12	12	12	12	12	12	12	12
SC7-1	Secondary	2,545	2,545	2,535	2,525	2,509	2,488	2,470	2,461	2,457	2,449	2,440	2,540	2,497
SC7-2	Primary	361	361	362	362	360	360	360	359	359	359	360	361	360
SC7-3	Subtransmission	132	132	132	131	131	131	131	131	131	130	130	132	131
Street Lighting		1,153	1,154	1,154	1,154	1,154	1,156	1,157	1,157	1,157	1,157	1,158	1,153	1,155
	Total C&I	124,936	125,470	125,576	125,567	125,167	124,562	124,152	124,154	124,465	124,595	124,686	124,154	124,790
RDM TOTAL		892,004	893,240	893,364	893,373	892,555	892,146	891,689	891,260	891,378	891,357	891,855	890,550	892,064

*Schedule does not include the following non RDM service classes: SC 1 Seasonal, SC 8 Seasonal, SC 7-4, SC 11, SC :

New York State Electric & Gas Corporation
Electric Business
Rate Year 2 RDM Targets
Revenue ($000) and Usage (MWH) by Service Class (SC)

Rate Year Revenue By Service Class ($000)

Residential:		**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**Total**
SC1	Residential	29,499	29,743	33,493	35,393	33,181	31,970	29,636	33,161	36,426	33,785	33,603	31,297	391,186
SC8	Residential Day/Night	7,813	6,892	6,990	7,361	6,883	7,240	7,838	10,015	11,384	10,220	9,884	9,350	101,871
SC12	Residential TOU	646	530	728	620	673	591	555	634	837	712	735	674	7,935
	Total Residential	37,959	37,165	41,211	43,374	40,737	39,801	38,029	43,810	48,648	44,716	44,222	41,321	500,992
Commercial and Industrial (C&I):		**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**Total**
SC2	General Service w/Demand	10,703	11,038	11,403	11,251	11,813	11,808	10,287	10,442	10,369	9,996	10,373	10,533	130,017
SC 6	General Service Regular	2,892	2,698	2,853	2,997	3,115	2,891	2,906	3,045	3,266	3,248	3,204	3,045	36,161
SC9	General Service Day/Night	139	124	128	132	132	124	150	165	187	183	176	160	1,801
SC3P	Primary	416	478	460	(91)	442	561	364	346	337	761	437	426	4,938
SC 3S	Subtransmission	11	11	10	12	12	9	14	13	9	11	12	12	136
SC7-1	Secondary	3,278	3,300	3,345	3,379	2,874	3,366	3,261	3,222	3,000	3,092	2,984	3,071	38,171
SC7-2	Primary	2,805	2,660	2,940	3,353	2,841	2,988	2,974	2,627	2,640	2,661	2,675	2,657	33,822
SC7-3	Subtransmission	716	719	694	753	645	722	801	744	679	695	709	671	8,548
Street Lighting		797	716	633	665	805	898	1,093	1,190	1,319	1,320	1,010	1,038	11,483
	Total C&I	21,758	21,743	22,465	22,450	22,681	23,368	21,851	21,794	21,806	21,968	21,581	21,614	265,077
RDM TOTAL		$ 59,716	$ 58,909	$ 63,676	$ 65,824	$ 63,418	$ 63,169	$ 59,879	$ 65,604	$ 70,453	$ 66,683	$ 65,802	$ 62,934	$ 766,069

Rate Year Usage By Service Class (MWH)

Residential		**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**Total**
SC1	Residential	366,871	371,335	442,828	479,005	436,873	413,722	369,177	436,446	498,713	448,283	444,680	401,348	5,109,281
SC8	Residential Day/Night	115,187	95,875	97,971	105,783	95,821	103,345	115,919	161,645	190,400	166,018	158,982	147,417	1,554,362
SC12	Residential TOU	12,805	10,127	14,692	12,212	13,442	11,541	10,719	12,548	17,233	14,341	14,879	13,433	157,972
	Total Residential	494,864	477,336	555,491	597,000	546,136	528,608	495,814	610,639	706,346	628,641	618,541	562,198	6,821,616
Commercial and Industrial (C&I)		**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**Total**
SC2	General Service w/Demand	220,983	231,228	257,061	257,875	265,280	238,518	216,305	239,463	254,014	231,158	241,329	239,156	2,892,370
SC 6	General Service Regular	24,749	21,503	23,979	26,320	28,284	24,751	25,072	27,347	30,916	30,596	29,866	27,368	320,751
SC9	General Service Day/Night	1,721	1,419	1,519	1,615	1,658	1,510	2,018	2,288	2,673	2,582	2,452	2,143	23,598
SC3P	Primary	15,157	16,957	16,819	(8,981)	15,476	12,549	12,093	12,854	12,968	32,860	16,127	16,600	171,478
SC 3S	Subtransmission	598	656	536	632	667	508	638	887	271	400	697	684	7,173
SC7-1	Secondary	108,183	116,799	121,895	124,615	101,690	110,636	100,755	120,982	113,964	110,212	107,039	110,299	1,347,070
SC7-2	Primary	128,649	123,924	141,324	164,842	138,209	133,627	141,782	125,267	133,016	128,482	127,606	132,100	1,618,827
SC7-3	Subtransmission	100,162	99,880	97,728	108,884	89,191	102,582	114,586	108,049	97,082	101,165	99,538	94,924	1,213,771
Street Lighting		4,794	4,304	3,805	3,999	4,838	5,397	6,570	7,152	7,928	7,937	6,073	6,242	69,036
	Total C&I	604,996	616,669	664,666	679,800	645,294	630,077	619,819	644,289	652,831	645,392	630,725	629,516	7,664,074
RDM TOTAL		1,099,860	1,094,006	1,220,157	1,276,800	1,191,430	1,158,685	1,115,633	1,254,928	1,359,177	1,274,033	1,249,266	1,191,714	14,485,690

Rate Year Customers By Service Class

Residential		**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**Total**
SC1	Residential	639,370	639,983	640,065	640,251	640,083	640,290	640,372	640,232	640,260	640,414	640,881	638,746	640,079
SC8	Residential Day/Night	125,420	125,410	125,301	125,207	125,045	124,959	124,845	124,692	124,568	124,468	124,441	125,423	124,982
SC12	Residential TOU	3,582	3,580	3,574	3,569	3,561	3,557	3,551	3,545	3,539	3,534	3,531	3,585	3,559
	Total Residential	768,372	768,973	768,940	769,027	768,689	768,806	768,768	768,469	768,367	768,416	768,853	767,754	768,620
Commercial and Industrial (C&I)		**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**Total**
SC2	General Service w/Demand	46,316	46,542	46,604	46,623	46,495	46,284	46,151	46,178	46,319	46,395	46,451	45,996	46,363
SC 6	General Service Regular	73,087	73,405	73,504	73,497	73,352	73,003	72,736	72,703	72,742	72,807	72,858	72,614	73,026
SC9	General Service Day/Night	2,370	2,372	2,327	2,319	2,217	2,192	2,205	2,237	2,382	2,392	2,394	2,373	2,315
SC3P	Primary	316	316	317	318	317	316	316	316	317	317	317	314	316
SC 3S	Subtransmission	12	12	12	12	12	12	12	12	12	12	12	12	12
SC7-1	Secondary	2,447	2,447	2,440	2,429	2,413	2,391	2,375	2,364	2,361	2,353	2,346	2,443	2,401
SC7-2	Primary	361	362	362	361	361	360	359	358	358	358	357	359	360
SC7-3	Subtransmission	132	132	131	130	130	130	130	130	129	129	129	131	130
Street Lighting		1,155	1,155	1,156	1,156	1,157	1,158	1,160	1,160	1,160	1,160	1,161	1,155	1,158
	Total C&I	126,196	126,743	126,853	126,845	126,454	125,846	125,444	125,458	125,780	125,923	126,025	125,397	126,080
RDM TOTAL		894,568	895,716	895,793	895,872	895,143	894,652	894,212	893,927	894,147	894,339	894,878	893,151	894,700

*Schedule does not include the following non RDM service classes: SC 1 Seasonal, SC 8 Seasonal, SC 7-4, SC 11, SC :

New York State Electric & Gas Corporation
Electric Business
Rate Year 3 RDM Targets
Revenue ($000) and Usage (MWH) by Service Class (SC)

Rate Year Revenue By Service Class ($000)

		May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	Total
Residential:														
SC1	Residential	32,944	34,080	38,028	38,777	38,182	36,303	33,418	37,637	40,956	38,431	38,049	35,089	441,892
SC8	Residential Day/Night	8,457	7,654	7,674	7,808	7,654	7,960	8,572	11,014	12,370	11,263	10,839	10,153	111,416
SC12	Residential TOU	665	564	764	623	719	621	578	662	861	744	765	694	8,260
	Total Residential	42,066	42,298	46,465	47,208	46,555	44,884	42,568	49,313	54,187	50,437	49,653	45,935	561,568
Commercial and Industrial (C&I):		May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	Total
SC2	General Service w/Demand	11,630	12,266	12,544	11,903	13,330	12,992	11,349	11,494	11,207	10,944	11,355	11,454	142,469
SC 6	General Service Regular	3,229	3,048	3,214	3,294	3,586	3,256	3,279	3,440	3,657	3,667	3,614	3,408	40,692
SC9	General Service Day/Night	155	140	144	145	152	140	170	187	210	207	199	179	2,027
SC3P	Primary	472	555	530	(86)	520	649	420	397	381	865	499	483	5,686
SC 3S	Subtransmission	11	12	11	12	13	10	14	14	10	12	13	13	144
SC7-1	Secondary	3,413	3,504	3,530	3,450	3,085	3,551	3,446	3,397	3,112	3,240	3,122	3,197	40,047
SC7-2	Primary	3,131	3,020	3,322	3,672	3,251	3,370	3,348	2,958	2,931	2,979	2,993	2,966	37,939
SC7-3	Subtransmission	766	779	749	799	701	780	865	801	725	747	761	719	9,192
Street Lighting		839	749	657	693	846	953	1,179	1,292	1,443	1,442	1,082	1,109	12,285
	Total C&I	23,647	24,073	24,700	23,882	25,485	25,701	24,070	23,980	23,675	24,102	23,639	23,528	290,481
RDM TOTAL		$ 65,713	$ 66,370	$ 71,166	$ 71,089	$ 72,039	$ 70,585	$ 66,638	$ 73,293	$ 77,862	$ 74,539	$ 73,292	$ 69,463	$ 852,050

Rate Year Usage By Service Class (MWH)

		May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	Total
Residential														
SC1	Residential	366,564	385,310	450,972	463,377	453,558	422,231	374,190	444,464	499,663	457,599	451,119	402,455	5,171,502
SC8	Residential Day/Night	108,994	94,451	94,848	97,313	94,588	100,169	111,286	155,565	180,177	160,152	152,485	139,707	1,489,735
SC12	Residential TOU	12,116	9,975	14,222	11,233	13,267	11,185	10,291	12,076	16,306	13,832	14,270	12,729	151,504
	Total Residential	487,675	489,736	560,042	571,923	561,413	533,585	495,767	612,104	696,146	631,583	617,875	554,891	6,812,740
Commercial and Industrial (C&I)		May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	Total
SC2	General Service w/Demand	217,586	233,742	257,076	246,475	273,296	238,389	216,749	239,570	248,908	229,714	239,912	235,912	2,877,329
SC 6	General Service Regular	24,323	21,741	23,997	25,103	29,159	24,717	25,096	27,331	30,298	30,411	29,671	26,907	318,754
SC9	General Service Day/Night	1,690	1,435	1,520	1,538	1,711	1,508	2,020	2,286	2,618	2,568	2,436	2,106	23,436
SC3P	Primary	14,958	17,135	16,883	(8,270)	15,888	12,584	12,144	12,889	12,753	32,645	16,036	16,391	172,035
SC 3S	Subtransmission	595	665	541	618	682	510	643	892	270	400	695	680	7,190
SC7-1	Secondary	106,947	118,217	122,402	120,244	104,519	111,028	101,264	121,352	112,291	109,862	106,606	109,067	1,343,799
SC7-2	Primary	128,224	126,002	142,748	160,600	141,703	134,635	142,683	126,151	131,852	128,577	127,543	131,768	1,622,487
SC7-3	Subtransmission	100,429	101,945	99,117	107,568	91,150	103,680	115,496	108,998	96,819	101,522	99,785	95,338	1,221,847
Street Lighting		4,720	4,212	3,697	3,898	4,762	5,362	6,631	7,270	8,118	8,114	6,089	6,242	69,115
	Total C&I	599,473	625,095	667,980	657,774	662,869	632,412	622,725	646,739	643,928	643,812	628,773	624,412	7,655,992
RDM TOTAL		1,087,148	1,114,831	1,228,022	1,229,697	1,224,282	1,165,997	1,118,493	1,258,843	1,340,074	1,275,396	1,246,648	1,179,303	14,468,733

Rate Year Customers By Service Class

		May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	Total
Residential														
SC1	Residential	642,258	642,831	642,998	643,195	642,936	643,137	643,188	643,033	643,125	643,261	643,736	641,599	642,941
SC8	Residential Day/Night	124,454	124,435	124,341	124,250	124,069	123,982	123,862	123,707	123,595	123,492	123,466	124,451	124,009
SC12	Residential TOU	3,526	3,523	3,519	3,513	3,507	3,501	3,496	3,489	3,484	3,478	3,475	3,528	3,503
	Total Residential	770,238	770,789	770,858	770,958	770,512	770,620	770,546	770,229	770,204	770,231	770,677	769,578	770,453
Commercial and Industrial (C&I)		May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	Total
SC2	General Service w/Demand	47,074	47,305	47,367	47,385	47,255	47,044	46,910	46,939	47,087	47,164	47,222	46,749	47,125
SC 6	General Service Regular	73,758	74,077	74,180	74,173	74,023	73,677	73,410	73,379	73,422	73,489	73,542	73,280	73,701
SC9	General Service Day/Night	2,396	2,398	2,353	2,344	2,240	2,214	2,228	2,261	2,408	2,418	2,420	2,399	2,340
SC3P	Primary	321	322	322	323	322	321	320	321	322	322	323	319	322
SC 3S	Subtransmission	12	12	12	12	12	12	12	12	12	12	12	12	12
SC7-1	Secondary	2,351	2,350	2,341	2,332	2,313	2,295	2,278	2,269	2,262	2,255	2,246	2,349	2,303
SC7-2	Primary	359	360	360	359	358	357	356	356	357	356	357	358	358
SC7-3	Subtransmission	130	130	129	129	129	129	129	128	128	128	128	129	129
Street Lighting		1,162	1,162	1,163	1,163	1,163	1,163	1,164	1,166	1,166	1,166	1,166	1,161	1,164
	Total C&I	127,563	128,116	128,227	128,220	127,815	127,212	126,807	126,831	127,164	127,310	127,416	126,756	127,453
RDM TOTAL		897,801	898,905	899,085	899,178	898,327	897,832	897,353	897,060	897,368	897,541	898,093	896,334	897,906

*Schedule does not include the following non RDM service classes: SC 1 Seasonal, SC 8 Seasonal, SC 7-4, SC 11, SC :

Rochester Gas and Electric Corporation
Electric Business
RDM Targets - Rate Year 1
Revenue, Usage and Customers By Service Class

RATE YEAR REVENUE BY SC ($000)

			A	B	C	D	E	F	G	H	I	J	K	L	M
1	Residential:		May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	Total
2	SC1	Residential	$ 15,652	$ 16,530	$ 18,075	$ 19,291	$ 17,807	$ 17,287	$ 16,042	$ 17,693	$ 18,861	$ 17,132	$ 17,442	$ 16,188	$ 208,000
3	SC4-I	Residential TOU - Schedule I	$ 163	$ 155	$ 168	$ 171	$ 158	$ 152	$ 170	$ 213	$ 246	$ 206	$ 206	$ 194	$ 2,203
4	SC4-II	Residential TOU - Schedule II	$ 170	$ 170	$ 188	$ 189	$ 173	$ 166	$ 174	$ 217	$ 244	$ 208	$ 205	$ 199	$ 2,304
5		Total Residential	$ 15,985	$ 16,855	$ 18,432	$ 19,651	$ 18,138	$ 17,604	$ 16,386	$ 18,123	$ 19,352	$ 17,547	$ 17,853	$ 16,582	$ 212,508
6	SC2	General Service - Small Use	$ 1,268	$ 1,213	$ 1,242	$ 1,281	$ 1,286	$ 1,218	$ 1,278	$ 1,387	$ 1,348	$ 1,342	$ 1,395	$ 1,285	$ 15,541
7	SC3	General Service - 100 kW Min.	$ 2,617	$ 2,696	$ 2,593	$ 2,735	$ 2,630	$ 2,867	$ 2,558	$ 2,718	$ 2,525	$ 2,469	$ 2,603	$ 2,498	$ 31,507
8	SC7	General Service - 12 kW Min.	$ 4,630	$ 4,675	$ 4,599	$ 4,860	$ 4,771	$ 4,716	$ 4,411	$ 4,628	$ 4,289	$ 4,280	$ 4,457	$ 4,308	$ 54,624
9	SC9	General Service - TOU	$ 236	$ 234	$ 237	$ 225	$ 237	$ 231	$ 238	$ 233	$ 221	$ 224	$ 252	$ 207	$ 2,774
10		Total SC7 & SC9	$ 4,866	$ 4,909	$ 4,836	$ 5,084	$ 5,007	$ 4,948	$ 4,649	$ 4,860	$ 4,509	$ 4,504	$ 4,708	$ 4,516	$ 57,398
11	SC8	Secondary	$ 2,618	$ 2,735	$ 2,567	$ 2,676	$ 2,527	$ 2,745	$ 2,187	$ 2,410	$ 2,404	$ 2,273	$ 2,360	$ 2,385	$ 29,887
12	SC8	Primary	$ 1,899	$ 1,820	$ 2,110	$ 2,064	$ 1,659	$ 2,044	$ 1,834	$ 1,666	$ 1,665	$ 1,594	$ 1,609	$ 1,725	$ 21,689
13	SC8	Substation	$ 253	$ 247	$ 259	$ 278	$ 255	$ 266	$ 235	$ 225	$ 222	$ 220	$ 216	$ 228	$ 2,905
14	SC8	Subtransmission - Commercial	$ 795	$ 736	$ 884	$ 850	$ 775	$ 989	$ 783	$ 657	$ 804	$ 709	$ 673	$ 776	$ 9,431
15	SC8	Subtransmission - Industrial	$ 1,195	$ 1,196	$ 1,299	$ 1,370	$ 1,314	$ 1,378	$ 1,284	$ 1,211	$ 1,105	$ 1,048	$ 1,172	$ 1,196	$ 14,766
16	PSC 18	Street Lighting Service	$ 355	$ 342	$ 329	$ 337	$ 352	$ 373	$ 399	$ 417	$ 411	$ 407	$ 381	$ 380	$ 4,482
17	**RDM REVENUE-TOTAL**		$ 31,848	$ 32,749	$ 34,551	$ 36,326	$ 33,942	$ 34,432	$ 31,593	$ 33,674	$ 34,345	$ 32,114	$ 32,971	$ 31,569	$ 400,115

RATE YEAR USAGE BY SC (MWH)

			May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	Total
18	Residential:														
19	SC1	Residential	184,414	203,577	237,367	263,926	231,399	219,980	192,723	228,810	254,332	216,470	223,205	196,198	2,652,401
20	SC4-I	Residential TOU - Schedule I	2,338	2,168	2,467	2,538	2,239	2,113	2,517	3,476	4,225	3,333	3,327	3,036	33,775
21	SC4-II	Residential TOU - Schedule II	2,499	2,496	2,830	2,840	2,553	2,428	2,573	3,359	3,851	3,199	3,148	3,028	34,804
22		Total Residential	189,251	208,240	242,665	269,303	236,190	224,520	197,813	235,645	262,408	223,002	229,679	202,262	2,720,980
23	SC2	General Service - Small Use	17,696	16,182	16,963	18,042	18,165	16,293	17,954	20,985	19,896	19,724	21,179	18,193	221,273
24	SC3	General Service - 100 kW Min.	46,937	49,800	49,680	53,371	51,162	49,816	47,678	56,243	51,974	49,078	51,070	48,455	605,264
25	SC7	General Service - 12 kW Min.	61,970	64,890	66,806	71,528	70,006	61,666	60,156	69,732	64,370	61,734	64,089	60,973	777,918
26	SC9	General Service - TOU	3,298	3,426	3,594	3,456	3,721	3,213	3,428	3,635	3,469	3,398	3,938	2,974	41,552
27		Total SC7 & SC9	65,268	68,316	70,400	74,984	73,727	64,878	63,584	73,367	67,839	65,132	68,027	63,947	819,470
28	SC8	Secondary	59,502	63,955	61,211	65,676	60,995	61,908	48,749	61,764	62,425	55,375	57,967	59,270	718,796
29	SC8	Primary	51,006	49,482	60,243	59,925	45,710	54,796	50,125	47,967	51,716	46,294	46,636	50,252	614,151
30	SC8	Substation	7,992	8,408	8,436	9,487	8,528	8,848	7,528	7,350	7,992	7,849	7,721	8,262	98,400
31	SC8	Subtransmission - Commercial	30,003	27,367	35,934	35,192	31,137	38,414	29,804	26,739	35,616	30,554	27,578	33,960	382,299
32	SC8	Subtransmission - Industrial	55,325	57,422	61,421	65,133	63,878	62,281	59,892	58,090	51,961	50,800	55,237	58,507	699,947
33	PSC 18	Street Lighting Service	2,959	2,662	2,383	2,556	2,902	3,238	3,814	4,092	4,377	4,262	3,638	3,517	40,400
34	**RDM USAGE-TOTAL**		525,939	551,836	609,336	653,669	592,394	584,993	526,941	592,242	616,203	552,071	568,731	546,625	6,920,980

RATE YEAR CUSTOMERS BY SC

			May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	Average
35	Residential:														
36	SC1	Residential	337,975	338,093	338,164	338,280	338,369	338,428	338,486	338,565	338,646	338,715	338,792	337,879	338,366
37	SC4-I	Residential TOU - Schedule I	2,285	2,281	2,275	2,271	2,265	2,260	2,254	2,250	2,244	2,240	2,234	2,290	2,262
38	SC4-II	Residential TOU - Schedule II	1,101	1,099	1,097	1,095	1,094	1,092	1,090	1,089	1,087	1,085	1,084	1,102	1,093
39		Total Residential	341,361	341,473	341,536	341,646	341,728	341,780	341,830	341,904	341,977	342,040	342,110	341,271	341,721
40	SC2	General Service - Small Use	29,556	29,566	29,587	29,595	29,610	29,610	29,597	29,594	29,624	29,630	29,642	29,516	29,594
41	SC3	General Service - 100 kW Min.	1,167	1,167	1,167	1,168	1,167	1,168	1,167	1,167	1,167	1,167	1,168	1,166	1,167
42	SC7	General Service - 12 kW Min.	8,822	8,826	8,829	8,832	8,836	8,834	8,829	8,828	8,835	8,838	8,840	8,810	8,830
43	SC9	General Service - TOU	311	311	311	312	312	312	312	312	312	312	312	311	312
44		Total SC7 & SC9	9,133	9,137	9,140	9,144	9,148	9,146	9,141	9,140	9,147	9,150	9,152	9,121	109,699
45	SC8	Secondary	392	392	392	392	392	392	392	392	393	393	393	392	392
46	SC8	Primary	162	162	162	161	161	161	161	161	161	161	161	162	161
47	SC8	Substation	29	29	29	29	29	29	29	29	29	29	29	29	29
48	SC8	Subtransmission - Commercial	53	53	53	53	53	53	53	53	53	53	53	53	53
49	SC8	Subtransmission - Industrial	47	47	47	47	47	47	46	46	46	46	46	47	47
50	PSC 18	Street Lighting Service	452	452	452	452	452	452	451	451	451	451	450	452	452
51	**RDM AVERAGE CUSTOMERS**		382,352	382,478	382,565	382,687	382,787	382,838	382,867	382,937	383,048	383,120	383,204	382,209	382,758

Rochester Gas and Electric Corporation
Electric Business
RDM Targets - Rate Year 2
Revenue, Usage and Customers By Service Class

			A	B	C	D	E	F	G	H	I	J	K	L	M
	RATE YEAR REVENUE BY SC ($000)														
1	Residential:		**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**Total**
2	SC1	Residential	$ 16,972	$ 17,726	$ 19,536	$ 20,699	$ 19,433	$ 18,662	$ 17,363	$ 19,048	$ 20,489	$ 18,804	$ 18,936	$ 17,654	$ 225,323
3	SC4-I	Residential TOU - Schedule I	$ 166	$ 156	$ 170	$ 172	$ 161	$ 154	$ 173	$ 215	$ 251	$ 213	$ 210	$ 200	$ 2,240
4	SC4-II	Residential TOU - Schedule II	$ 174	$ 171	$ 190	$ 189	$ 177	$ 168	$ 177	$ 219	$ 249	$ 216	$ 210	$ 206	$ 2,345
5		Total Residential	$ 17,312	$ 18,052	$ 19,897	$ 21,059	$ 19,771	$ 18,984	$ 17,713	$ 19,482	$ 20,988	$ 19,234	$ 19,356	$ 18,060	$ 229,909
6	SC2	General Service - Small Use	$ 1,375	$ 1,298	$ 1,335	$ 1,367	$ 1,396	$ 1,310	$ 1,379	$ 1,489	$ 1,454	$ 1,464	$ 1,512	$ 1,395	$ 16,772
7	SC3	General Service - 100 kW Min.	$ 2,811	$ 2,842	$ 2,747	$ 2,853	$ 2,828	$ 3,039	$ 2,729	$ 2,848	$ 2,679	$ 2,659	$ 2,777	$ 2,687	$ 33,500
8	SC7	General Service - 12 kW Min.	$ 4,837	$ 4,791	$ 4,731	$ 4,925	$ 4,970	$ 4,877	$ 4,578	$ 4,719	$ 4,419	$ 4,487	$ 4,619	$ 4,506	$ 56,459
9	SC9	General Service - TOU	$ 246	$ 240	$ 244	$ 229	$ 248	$ 240	$ 246	$ 236	$ 227	$ 234	$ 260	$ 217	$ 2,867
10		Total SC7 & SC9	$ 5,083	$ 5,031	$ 4,975	$ 5,154	$ 5,218	$ 5,117	$ 4,824	$ 4,955	$ 4,647	$ 4,721	$ 4,879	$ 4,723	$ 59,325
11	SC8	Secondary	$ 2,805	$ 2,886	$ 2,726	$ 2,805	$ 2,719	$ 2,919	$ 2,340	$ 2,540	$ 2,561	$ 2,451	$ 2,525	$ 2,565	$ 31,843
12	SC8	Primary	$ 2,056	$ 1,923	$ 2,247	$ 2,164	$ 1,791	$ 2,191	$ 1,968	$ 1,763	$ 1,775	$ 1,731	$ 1,728	$ 1,862	$ 23,199
13	SC8	Substation	$ 264	$ 253	$ 267	$ 281	$ 265	$ 274	$ 243	$ 230	$ 230	$ 230	$ 224	$ 238	$ 2,999
14	SC8	Subtransmission - Commercial	$ 842	$ 775	$ 924	$ 885	$ 804	$ 1,044	$ 811	$ 690	$ 838	$ 761	$ 706	$ 824	$ 9,904
15	SC8	Subtransmission - Industrial	$ 1,249	$ 1,217	$ 1,328	$ 1,385	$ 1,360	$ 1,419	$ 1,323	$ 1,240	$ 1,134	$ 1,099	$ 1,210	$ 1,248	$ 15,213
16	PSC 18	Street Lighting Service	$ 368	$ 352	$ 338	$ 347	$ 363	$ 386	$ 415	$ 434	$ 429	$ 424	$ 396	$ 395	$ 4,647
17	**RDM REVENUE-TOTAL**		$ 34,164	$ 34,631	$ 36,783	$ 38,299	$ 36,515	$ 36,683	$ 33,745	$ 35,671	$ 36,736	$ 34,774	$ 35,312	$ 33,997	$ 427,310
	RATE YEAR USAGE BY SC (MWH)														
18	Residential:		**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**Total**
19	SC1	Residential	186,631	201,227	236,332	258,857	234,242	219,250	193,988	226,660	254,575	221,850	224,364	199,907	2,657,882
20	SC4-I	Residential TOU - Schedule I	2,293	2,077	2,381	2,413	2,197	2,041	2,456	3,337	4,099	3,311	3,241	2,998	32,845
21	SC4-II	Residential TOU - Schedule II	2,452	2,391	2,732	2,700	2,506	2,346	2,510	3,225	3,736	3,178	3,067	2,990	33,834
22		Total Residential	191,377	205,695	241,445	263,971	238,945	223,637	198,953	233,222	262,410	228,338	230,672	205,895	2,724,561
23	SC2	General Service - Small Use	17,903	16,022	16,899	17,684	18,391	16,282	17,997	20,688	19,814	20,052	21,225	18,413	221,369
24	SC3	General Service - 100 kW Min.	47,466	49,278	49,414	52,217	51,794	49,696	47,808	55,309	51,785	49,755	51,233	49,070	604,825
25	SC7	General Service - 12 kW Min.	62,676	64,163	66,416	69,965	70,790	61,582	60,271	68,659	64,046	62,693	64,228	61,708	777,198
26	SC9	General Service - TOU	3,329	3,392	3,583	3,400	3,781	3,211	3,432	3,571	3,461	3,440	3,947	3,000	41,548
27		Total SC7 & SC9	66,005	67,555	69,998	73,366	74,571	64,793	63,703	72,231	67,507	66,132	68,176	64,709	818,746
28	SC8	Secondary	59,918	63,161	60,896	64,307	61,661	61,674	48,955	60,889	62,357	56,191	58,207	59,971	718,186
29	SC8	Primary	51,692	48,771	59,829	58,438	46,173	54,807	50,229	47,339	51,498	47,092	46,800	50,781	613,447
30	SC8	Substation	8,112	8,307	8,376	9,204	8,602	8,808	7,540	7,295	7,988	7,982	7,728	8,404	98,347
31	SC8	Subtransmission - Commercial	30,301	27,383	35,690	34,672	30,729	38,514	29,353	26,727	35,261	31,346	27,531	34,402	381,910
32	SC8	Subtransmission - Industrial	56,166	56,547	60,797	63,650	64,071	62,178	59,676	57,593	51,693	51,801	55,336	59,295	698,803
33	PSC 18	Street Lighting Service	2,898	2,601	2,322	2,495	2,841	3,177	3,753	4,032	4,317	4,201	3,577	3,455	39,670
34	**RDM USAGE-TOTAL**		531,839	545,320	605,667	640,004	597,778	583,565	527,966	585,324	614,631	562,890	570,484	554,396	6,919,863
	RATE YEAR CUSTOMERS BY SC														
35	Residential:		**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**Average**
36	SC1	Residential	338,939	339,032	339,110	339,207	339,306	339,397	339,488	339,583	339,679	339,768	339,862	338,865	339,353
37	SC4-I	Residential TOU - Schedule I	2,224	2,219	2,214	2,209	2,203	2,199	2,193	2,189	2,183	2,178	2,174	2,229	2,201
38	SC4-II	Residential TOU - Schedule II	1,080	1,079	1,076	1,075	1,074	1,071	1,070	1,069	1,066	1,065	1,064	1,082	1,073
39		Total Residential	342,243	342,330	342,400	342,491	342,583	342,667	342,751	342,841	342,928	343,011	343,100	342,176	342,627
40	SC2	General Service - Small Use	29,718	29,727	29,742	29,746	29,760	29,756	29,743	29,737	29,766	29,769	29,777	29,684	29,744
41	SC3	General Service - 100 kW Min.	1,170	1,170	1,171	1,170	1,170	1,170	1,169	1,167	1,169	1,169	1,170	1,167	1,169
42	SC7	General Service - 12 kW Min.	8,861	8,864	8,867	8,867	8,871	8,869	8,865	8,863	8,870	8,870	8,872	8,852	8,866
43	SC9	General Service - TOU	312	312	312	312	313	313	312	312	313	313	313	312	312
44		Total SC7 & SC9	9,173	9,176	9,179	9,179	9,184	9,182	9,177	9,175	9,183	9,183	9,185	9,164	110,140
45	SC8	Secondary	393	393	394	394	395	395	395	394	395	395	395	393	394
46	SC8	Primary	161	161	162	162	161	161	161	161	161	161	161	161	161
47	SC8	Substation	29	29	29	29	29	29	29	29	29	29	29	29	29
48	SC8	Subtransmission - Commercial	53	53	53	53	53	53	53	53	53	53	53	53	53
49	SC8	Subtransmission - Industrial	46	46	46	46	46	46	46	45	45	45	45	46	46
50	PSC 18	Street Lighting Service	450	449	449	449	449	449	448	448	448	448	448	450	449
51	**RDM AVERAGE CUSTOMERS**		383,436	383,534	383,625	383,719	383,830	383,908	383,972	384,050	384,177	384,263	384,363	383,323	383,850

Rochester Gas and Electric Corporation
Electric Business
RDM Targets - Rate Year 3
Revenue, Usage and Customers By Service Class

RATE YEAR REVENUE BY SC ($000)

			A	B	C	D	E	F	G	H	I	J	K	L	M
1	Residential:		May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	Total
2	SC1	Residential	$ 18,157	$ 19,252	$ 21,227	$ 22,163	$ 21,288	$ 20,201	$ 18,783	$ 20,647	$ 22,210	$ 20,445	$ 20,507	$ 19,014	$ 243,893
3	SC4-I	Residential TOU - Schedule I	$ 167	$ 159	$ 173	$ 172	$ 165	$ 156	$ 176	$ 219	$ 256	$ 218	$ 214	$ 203	$ 2,279
4	SC4-II	Residential TOU - Schedule II	$ 175	$ 175	$ 194	$ 188	$ 183	$ 171	$ 181	$ 223	$ 253	$ 221	$ 213	$ 209	$ 2,387
5		Total Residential	$ 18,500	$ 19,586	$ 21,594	$ 22,523	$ 21,636	$ 20,528	$ 19,140	$ 21,090	$ 22,718	$ 20,884	$ 20,934	$ 19,425	$ 248,559
6	SC2	General Service - Small Use	$ 1,474	$ 1,408	$ 1,444	$ 1,460	$ 1,525	$ 1,414	$ 1,492	$ 1,613	$ 1,566	$ 1,585	$ 1,638	$ 1,500	$ 18,119
7	SC3	General Service - 100 kW Min.	$ 2,967	$ 3,057	$ 2,934	$ 2,989	$ 3,051	$ 3,242	$ 2,908	$ 3,025	$ 2,829	$ 2,831	$ 2,952	$ 2,845	$ 35,630
8	SC7	General Service - 12 kW Min.	$ 4,957	$ 5,009	$ 4,910	$ 5,006	$ 5,206	$ 5,062	$ 4,750	$ 4,870	$ 4,540	$ 4,643	$ 4,770	$ 4,636	$ 58,358
9	SC9	General Service - TOU	$ 253	$ 250	$ 253	$ 234	$ 259	$ 249	$ 255	$ 243	$ 233	$ 242	$ 268	$ 223	$ 2,962
10		Total SC7 & SC9	$ 5,210	$ 5,259	$ 5,163	$ 5,241	$ 5,465	$ 5,311	$ 5,005	$ 5,114	$ 4,772	$ 4,884	$ 5,037	$ 4,859	$ 61,320
11	SC8	Secondary	$ 2,964	$ 3,105	$ 2,912	$ 2,949	$ 2,931	$ 3,121	$ 2,493	$ 2,705	$ 2,710	$ 2,611	$ 2,687	$ 2,717	$ 33,905
12	SC8	Primary	$ 2,235	$ 2,131	$ 2,468	$ 2,331	$ 1,987	$ 2,414	$ 2,162	$ 1,927	$ 1,931	$ 1,895	$ 1,892	$ 2,034	$ 25,407
13	SC8	Substation	$ 271	$ 264	$ 275	$ 285	$ 276	$ 284	$ 250	$ 238	$ 236	$ 238	$ 231	$ 246	$ 3,093
14	SC8	Subtransmission - Commercial	$ 877	$ 831	$ 985	$ 909	$ 859	$ 1,091	$ 856	$ 723	$ 878	$ 799	$ 741	$ 858	$ 10,407
15	SC8	Subtransmission - Industrial	$ 1,274	$ 1,269	$ 1,373	$ 1,395	$ 1,417	$ 1,462	$ 1,362	$ 1,276	$ 1,159	$ 1,127	$ 1,242	$ 1,281	$ 15,636
16	PSC 18	Street Lighting Service	$ 380	$ 364	$ 348	$ 358	$ 376	$ 401	$ 432	$ 453	$ 447	$ 442	$ 411	$ 410	$ 4,823
17	**RDM REVENUE-TOTAL**		$ 36,153	$ 37,273	$ 39,496	$ 40,439	$ 39,523	$ 39,267	$ 36,100	$ 38,164	$ 39,249	$ 37,296	$ 37,766	$ 36,174	$ 456,900

RATE YEAR USAGE BY SC (MWH)

			May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	Total
18	Residential:														
19	SC1	Residential	184,322	203,186	237,247	253,372	238,242	219,447	194,919	227,082	254,027	223,518	224,564	199,141	2,659,065
20	SC4-I	Residential TOU - Schedule I	2,196	2,033	2,317	2,290	2,166	1,981	2,392	3,240	3,964	3,233	3,144	2,895	31,852
21	SC4-II	Residential TOU - Schedule II	2,347	2,341	2,659	2,562	2,471	2,276	2,445	3,132	3,613	3,103	2,976	2,887	32,813
22		Total Residential	188,865	207,560	242,223	258,224	242,879	223,704	199,756	233,454	261,604	229,854	230,684	204,923	2,723,730
23	SC2	General Service - Small Use	17,672	16,244	17,002	17,339	18,734	16,335	18,036	20,653	19,619	20,026	21,150	18,241	221,050
24	SC3	General Service - 100 kW Min.	46,928	49,861	49,557	51,210	52,597	49,831	47,796	55,129	51,202	49,659	51,067	48,653	603,490
25	SC7	General Service - 12 kW Min.	61,852	64,962	66,681	68,492	72,000	61,731	60,346	68,471	63,337	62,563	63,984	61,127	775,547
26	SC9	General Service - TOU	3,294	3,427	3,594	3,357	3,846	3,226	3,429	3,555	3,424	3,434	3,937	2,976	41,501
27		Total SC7 & SC9	65,147	68,389	70,275	71,850	75,846	64,957	63,775	72,026	66,761	65,997	67,921	64,103	817,048
28	SC8	Secondary	59,131	63,751	60,995	63,079	62,492	61,798	48,920	60,774	61,778	56,135	58,035	59,436	716,324
29	SC8	Primary	51,054	49,256	59,804	57,178	46,734	54,943	50,251	47,181	51,008	46,990	46,707	50,445	611,552
30	SC8	Substation	8,051	8,400	8,347	8,986	8,671	8,809	7,527	7,280	7,931	7,957	7,710	8,363	98,032
31	SC8	Subtransmission - Commercial	29,883	27,968	36,175	33,637	31,314	38,221	29,453	26,577	34,986	31,246	27,411	33,936	380,806
32	SC8	Subtransmission - Industrial	55,388	57,189	60,831	61,870	64,691	61,988	59,433	57,244	51,104	51,366	54,936	58,851	694,893
33	PSC 18	Street Lighting Service	2,838	2,540	2,262	2,434	2,780	3,116	3,692	3,971	4,256	4,141	3,516	3,395	38,941
34	**RDM USAGE-TOTAL**		524,956	551,158	607,472	625,807	606,738	583,702	528,640	584,289	610,249	563,372	569,138	550,347	6,905,867

RATE YEAR CUSTOMERS BY SC

			May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	Average
35	Residential:														
36	SC1	Residential	340,051	340,144	340,232	340,325	340,410	340,492	340,574	340,659	340,744	340,826	340,909	339,957	340,444
37	SC4-I	Residential TOU - Schedule I	2,164	2,158	2,153	2,148	2,143	2,138	2,133	2,127	2,123	2,117	2,112	2,168	2,140
38	SC4-II	Residential TOU - Schedule II	1,060	1,059	1,056	1,055	1,054	1,051	1,050	1,049	1,046	1,045	1,043	1,061	1,052
39		Total Residential	343,275	343,361	343,441	343,528	343,607	343,681	343,757	343,835	343,913	343,988	344,064	343,186	343,636
40	SC2	General Service - Small Use	29,850	29,859	29,876	29,884	29,902	29,905	29,896	29,896	29,930	29,939	29,953	29,818	29,892
41	SC3	General Service - 100 kW Min.	1,172	1,172	1,173	1,172	1,172	1,172	1,172	1,170	1,172	1,173	1,174	1,170	1,172
42	SC7	General Service - 12 kW Min.	8,891	8,897	8,901	8,901	8,906	8,904	8,903	8,903	8,910	8,915	8,916	8,883	8,903
43	SC9	General Service - TOU	313	313	313	313	313	313	313	313	314	314	314	313	313
44		Total SC7 & SC9	9,204	9,210	9,214	9,214	9,219	9,217	9,216	9,216	9,224	9,229	9,230	9,196	110,589
45	SC8	Secondary	396	396	397	397	396	396	396	396	396	396	397	395	396
46	SC8	Primary	161	161	161	161	161	161	160	160	160	160	160	161	161
47	SC8	Substation	29	29	29	29	29	29	29	29	29	29	29	29	29
48	SC8	Subtransmission - Commercial	53	53	53	53	53	53	53	53	53	53	53	53	53
49	SC8	Subtransmission - Industrial	45	45	45	45	45	45	45	45	44	44	44	45	45
50	PSC 18	Street Lighting Service	448	448	448	448	448	448	447	447	447	447	447	448	448
51	**RDM AVERAGE CUSTOMERS**		384,633	384,734	384,837	384,931	385,032	385,107	385,171	385,247	385,368	385,458	385,551	384,501	385,048

New York State Electric & Gas Corporation
Gas Business
RDM Targets - Rate Year 1
Revenue ($000) and Usage (Therms) By Service Class

RATE YEAR REVENUE BY SERVICE CLASS ($000)

			A	B	C	D	E	F	G	H	I	J	K	L	M
	Residential:		**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**Total**
1	SC 1S	Residential Sales	$ 9,776	$ 6,994	$ 5,267	$ 4,861	$ 5,218	$ 7,256	$ 10,449	$ 11,971	$ 13,036	$ 13,674	$ 13,146	$ 12,134	$ 113,782
2	SC 13T	Residential Aggregation Transp	$ 1,304	$ 874	$ 570	$ 526	$ 584	$ 788	$ 1,185	$ 1,413	$ 1,497	$ 1,627	$ 1,504	$ 1,453	$ 13,325
3		Total Residential	$ 11,080	$ 7,868	$ 5,837	$ 5,387	$ 5,802	$ 8,044	$ 11,634	$ 13,384	$ 14,533	$ 15,301	$ 14,650	$ 13,588	$ 127,107
	Non-Residential:														
4	SC 2S	General Sales Service	$ 1,716	$ 1,160	$ 934	$ 998	$ 1,056	$ 1,483	$ 2,242	$ 3,030	$ 3,663	$ 3,473	$ 3,233	$ 2,673	$ 25,662
5	SC 14T	Non-Residential Agg Transp	$ 1,707	$ 1,134	$ 874	$ 977	$ 928	$ 1,205	$ 2,007	$ 2,735	$ 3,730	$ 3,630	$ 3,275	$ 2,567	$ 24,770
6	SC 1T	Firm Transportation	$ 709	$ 599	$ 583	$ 632	$ 622	$ 639	$ 674	$ 710	$ 802	$ 836	$ 773	$ 760	$ 8,339
7	SC 5T	Small Firm Transportation	$ 522	$ 314	$ 257	$ 240	$ 257	$ 268	$ 437	$ 605	$ 732	$ 860	$ 681	$ 624	$ 5,798
8		Total Non-Residential	$ 4,654	$ 3,208	$ 2,647	$ 2,847	$ 2,864	$ 3,596	$ 5,359	$ 7,080	$ 8,927	$ 8,799	$ 7,963	$ 6,624	$ 64,569
9	**RDM REVENUE - TOTAL**		$ 15,734	$ 11,075	$ 8,485	$ 8,234	$ 8,666	$ 11,640	$ 16,993	$ 20,464	$ 23,461	$ 24,100	$ 22,612	$ 20,212	$ 191,676

RATE YEAR USAGE BY SERVICE CLASS (Therms)

	Residential:		**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**Total**
10	SC 1S	Residential Sales	13,776,861	6,982,530	3,406,429	2,657,313	3,371,636	7,190,414	15,517,857	24,832,422	32,706,859	34,543,209	30,697,218	24,192,076	199,874,823
11	SC 13T	Residential Aggregation Transp	2,036,201	995,789	376,205	295,396	410,730	791,015	1,810,938	3,045,457	3,842,878	4,245,153	3,587,845	3,015,914	24,453,524
12		Total Residential	15,813,062	7,978,319	3,782,634	2,952,709	3,782,367	7,981,429	17,328,796	27,877,879	36,549,737	38,788,362	34,285,063	27,207,990	224,328,347
	Non-Residential:														
13	SC 2S	General Sales Service	3,572,987	1,905,299	1,304,823	1,488,324	1,656,265	2,984,467	5,320,888	7,990,152	10,246,166	9,716,898	8,739,188	6,690,587	61,616,045
14	SC 14T	Non-Residential Agg Transp	4,604,799	2,887,454	2,236,588	2,529,268	2,345,031	3,197,321	5,685,250	8,180,548	11,627,574	11,421,380	10,032,994	7,465,803	72,214,009
15	SC 1T	Firm Transportation	7,242,103	5,677,507	5,654,954	6,458,696	6,310,805	6,490,149	6,853,181	7,464,528	9,123,349	10,033,461	8,605,203	8,178,169	88,092,106
16	SC 5T	Small Firm Transportation	2,504,997	1,264,204	975,228	851,426	991,851	1,073,149	2,021,423	2,979,319	3,761,246	4,622,175	3,426,779	3,066,599	27,538,396
17		Total Non-Residential	17,924,887	11,734,464	10,171,593	11,327,714	11,303,951	13,745,086	19,880,742	26,614,547	34,758,335	35,793,914	30,804,165	25,401,157	249,460,556
18	**RDM USAGE - TOTAL**		33,737,948	19,712,783	13,954,227	14,280,423	15,086,318	21,726,516	37,209,538	54,492,426	71,308,072	74,582,276	65,089,228	52,609,147	473,788,903

RATE YEAR CUSTOMERS BY SERVICE CLASS

	Residential:		**May-20**	**Jun-20**	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**Average**
19	SC 1S	Residential Sales	214,027	213,889	213,501	213,866	213,972	214,905	215,405	215,291	215,529	215,587	215,815	214,684	214,706
20	SC 13T	Residential Aggregation Transp	23,001	22,984	22,945	22,984	22,998	23,099	23,114	23,096	23,166	23,174	23,200	23,082	23,070
21		Total Residential	237,028	236,873	236,445	236,850	236,969	238,004	238,519	238,387	238,695	238,761	239,015	237,766	237,776
	Non-Residential:														
22	SC 2S	General Sales Service	23,226	23,081	22,953	22,919	22,987	23,118	23,395	23,543	23,489	23,572	23,566	23,404	23,271
23	SC 14T	Non-Residential Agg Transp	8,523	8,514	8,524	8,521	8,517	8,534	8,535	8,540	8,546	8,548	8,539	8,531	8,531
24	SC 1T	Firm Transportation	85	84	84	84	84	84	84	84	84	84	83	85	84
25	SC 5T	Small Firm Transportation	339	339	338	338	338	338	338	338	338	338	338	339	338
26		Total Non-Residential	32,173	32,018	31,899	31,862	31,926	32,074	32,352	32,505	32,457	32,542	32,526	32,359	32,224
27	**RDM CUSTOMERS**		269,201	268,890	268,344	268,712	268,895	270,078	270,871	270,892	271,151	271,302	271,540	270,124	270,000

New York State Electric & Gas Corporation
Gas Business
RDM Targets - Rate Year 2
Revenue ($000) and Usage (Therms) By Service Class

RATE YEAR REVENUE BY SERVICE CLASS ($000)

			A	B	C	D	E	F	G	H	I	J	K	L	M
	Residential:		**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**Total**
1	SC 1S	Residential Sales	$ 9,986	$ 7,211	$ 5,489	$ 5,084	$ 5,440	$ 7,473	$ 10,657	$ 12,176	$ 13,238	$ 13,875	$ 13,348	$ 12,338	$ 116,315
2	SC 13T	Residential Aggregation Transp	$ 1,326	$ 897	$ 594	$ 550	$ 608	$ 811	$ 1,207	$ 1,435	$ 1,518	$ 1,648	$ 1,525	$ 1,475	$ 13,594
3		Total Residential	$ 11,312	$ 8,108	$ 6,083	$ 5,634	$ 6,048	$ 8,284	$ 11,865	$ 13,610	$ 14,756	$ 15,522	$ 14,873	$ 13,813	$ 129,909
	Non-Residential:														
4	SC 2S	General Sales Service	$ 1,756	$ 1,194	$ 965	$ 1,028	$ 1,088	$ 1,519	$ 2,287	$ 3,085	$ 3,724	$ 3,533	$ 3,290	$ 2,723	$ 26,191
5	SC 14T	Non-Residential Agg Transp	$ 1,731	$ 1,153	$ 889	$ 994	$ 944	$ 1,223	$ 2,032	$ 2,768	$ 3,773	$ 3,674	$ 3,315	$ 2,600	$ 25,098
6	SC 1T	Firm Transportation	$ 736	$ 625	$ 609	$ 659	$ 649	$ 667	$ 702	$ 740	$ 835	$ 867	$ 804	$ 789	$ 8,682
7	SC 5T	Small Firm Transportation	$ 532	$ 319	$ 260	$ 243	$ 260	$ 272	$ 444	$ 617	$ 747	$ 878	$ 695	$ 637	$ 5,904
8		Total Non-Residential	$ 4,755	$ 3,291	$ 2,723	$ 2,924	$ 2,942	$ 3,681	$ 5,466	$ 7,209	$ 9,079	$ 8,952	$ 8,104	$ 6,749	$ 65,875
9	**RDM REVENUE - TOTAL**		$ 16,067	$ 11,399	$ 8,805	$ 8,559	$ 8,990	$ 11,965	$ 17,331	$ 20,820	$ 23,836	$ 24,474	$ 22,977	$ 20,562	$ 195,785

RATE YEAR USAGE BY SERVICE CLASS (Therms)

	Residential:		**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**Total**
10	SC 1S	Residential Sales	13,908,190	7,049,140	3,438,901	2,682,546	3,403,664	7,258,765	15,665,714	25,069,513	33,018,407	34,872,403	30,989,782	24,422,663	201,779,689
11	SC 13T	Residential Aggregation Transp	2,055,664	1,005,299	379,787	298,202	414,642	798,566	1,828,246	3,074,572	3,879,615	4,285,738	3,622,144	3,044,748	24,687,223
12		Total Residential	15,963,854	8,054,439	3,818,688	2,980,749	3,818,306	8,057,331	17,493,960	28,144,085	36,898,022	39,158,141	34,611,926	27,467,411	226,466,912
	Non-Residential:														
13	SC 2S	General Sales Service	3,588,103	1,913,945	1,310,995	1,494,020	1,662,642	2,994,744	5,341,877	8,022,477	10,284,725	9,754,731	8,773,761	6,717,247	61,859,266
14	SC 14T	Non-Residential Agg Transp	4,618,832	2,896,838	2,243,937	2,537,275	2,351,396	3,203,803	5,695,660	8,200,186	11,657,806	11,455,545	10,061,222	7,487,147	72,409,646
15	SC 1T	Firm Transportation	7,256,011	5,689,758	5,668,151	6,473,390	6,325,386	6,504,954	6,866,746	7,477,839	9,139,058	10,049,932	8,621,138	8,192,716	88,265,078
16	SC 5T	Small Firm Transportation	2,504,403	1,265,623	977,309	853,289	994,024	1,075,084	2,021,759	2,977,472	3,758,044	4,619,203	3,424,987	3,065,206	27,536,404
17		Total Non-Residential	17,967,350	11,766,164	10,200,392	11,357,974	11,333,449	13,778,585	19,926,041	26,677,974	34,839,632	35,879,411	30,881,108	25,462,315	250,070,395
18	**RDM USAGE - TOTAL**		33,931,204	19,820,603	14,019,080	14,338,722	15,151,755	21,835,916	37,420,001	54,822,059	71,737,654	75,037,552	65,493,034	52,929,726	476,537,307

RATE YEAR CUSTOMERS BY SERVICE CLASS

	Residential:		**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**Average**
19	SC 1S	Residential Sales	214,846	214,696	214,299	214,653	214,766	215,688	216,201	216,114	216,360	216,432	216,657	215,515	215,519
20	SC 13T	Residential Aggregation Transp	23,090	23,072	23,030	23,070	23,082	23,185	23,201	23,185	23,255	23,264	23,290	23,173	23,158
21		Total Residential	237,936	237,767	237,328	237,723	237,848	238,872	239,401	239,299	239,615	239,696	239,947	238,688	238,676
	Non-Residential:														
22	SC 2S	General Sales Service	23,343	23,195	23,066	23,034	23,100	23,231	23,509	23,660	23,606	23,689	23,684	23,519	23,386
23	SC 14T	Non-Residential Agg Transp	8,522	8,514	8,524	8,520	8,517	8,535	8,536	8,541	8,546	8,547	8,537	8,531	8,531
24	SC 1T	Firm Transportation	83	83	83	83	83	83	83	83	83	82	82	83	83
25	SC 5T	Small Firm Transportation	338	338	336	336	336	336	336	336	336	336	336	338	337
26		Total Non-Residential	32,286	32,130	32,009	31,973	32,036	32,185	32,464	32,620	32,571	32,654	32,638	32,471	32,336
27	**RDM CUSTOMERS**		270,221	269,897	269,337	269,695	269,883	271,057	271,865	271,918	272,185	272,350	272,585	271,159	271,012

New York State Electric & Gas Corporation
Gas Business
RDM Targets - Rate Year 3
Revenue ($000) and Usage (Therms) By Service Class

RATE YEAR REVENUE BY SERVICE CLASS ($000)

			A	B	C	D	E	F	G	H	I	J	K	L	M
	Residential:		May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	Total
1	SC 1S	Residential Sales	$ 10,251	$ 7,461	$ 5,729	$ 5,321	$ 5,680	$ 7,725	$ 10,928	$ 12,455	$ 13,524	$ 14,164	$ 13,634	$ 12,618	$ 119,488
2	SC 13T	Residential Aggregation Transp	$ 1,356	$ 925	$ 619	$ 575	$ 634	$ 838	$ 1,237	$ 1,465	$ 1,550	$ 1,680	$ 1,557	$ 1,506	$ 13,941
3		Total Residential	$ 11,607	$ 8,385	$ 6,348	$ 5,897	$ 6,314	$ 8,563	$ 12,164	$ 13,920	$ 15,073	$ 15,844	$ 15,191	$ 14,123	$ 133,429
	Non-Residential:														
4	SC 2S	General Sales Service	$ 1,804	$ 1,231	$ 998	$ 1,063	$ 1,123	$ 1,562	$ 2,344	$ 3,156	$ 3,806	$ 3,611	$ 3,365	$ 2,788	$ 26,850
5	SC 14T	Non-Residential Agg Transp	$ 1,766	$ 1,177	$ 910	$ 1,016	$ 965	$ 1,249	$ 2,071	$ 2,820	$ 3,842	$ 3,743	$ 3,377	$ 2,650	$ 25,584
6	SC 1T	Firm Transportation	$ 768	$ 654	$ 637	$ 690	$ 679	$ 697	$ 734	$ 773	$ 870	$ 903	$ 839	$ 823	$ 9,068
7	SC 5T	Small Firm Transportation	$ 544	$ 325	$ 264	$ 246	$ 264	$ 277	$ 454	$ 632	$ 766	$ 901	$ 712	$ 652	$ 6,038
8		Total Non-Residential	$ 4,882	$ 3,388	$ 2,809	$ 3,015	$ 3,032	$ 3,784	$ 5,603	$ 7,380	$ 9,285	$ 9,158	$ 8,293	$ 6,913	$ 67,540
9	**RDM REVENUE - TOTAL**		$ 16,489	$ 11,773	$ 9,157	$ 8,911	$ 9,346	$ 12,347	$ 17,767	$ 21,300	$ 24,358	$ 25,002	$ 23,484	$ 21,036	$ 200,969

RATE YEAR USAGE BY SERVICE CLASS (Therms)

			May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	Total
	Residential:														
10	SC 1S	Residential Sales	13,910,551	7,050,323	3,439,498	2,683,005	3,404,243	7,259,964	15,668,283	25,073,403	33,024,012	34,878,312	30,995,055	24,426,789	201,813,439
11	SC 13T	Residential Aggregation Transp	2,056,022	1,005,481	379,864	298,268	414,726	798,713	1,828,566	3,075,104	3,880,288	4,286,479	3,622,772	3,045,274	24,691,556
12		Total Residential	15,966,573	8,055,804	3,819,362	2,981,273	3,818,969	8,058,677	17,496,849	28,148,507	36,904,300	39,164,791	34,617,827	27,472,063	226,504,995
	Non-Residential:														
13	SC 2S	General Sales Service	3,597,421	1,919,298	1,314,906	1,497,588	1,666,627	3,000,912	5,354,610	8,042,181	10,307,633	9,776,954	8,794,390	6,733,077	62,005,597
14	SC 14T	Non-Residential Agg Transp	4,627,602	2,902,525	2,248,280	2,541,921	2,354,924	3,207,138	5,701,188	8,211,950	11,676,213	11,477,028	10,078,755	7,500,346	72,527,869
15	SC 1T	Firm Transportation	7,259,922	5,693,686	5,672,476	6,477,981	6,330,212	6,509,798	6,870,722	7,481,647	9,142,921	10,053,509	8,625,657	8,196,427	88,314,959
16	SC 5T	Small Firm Transportation	2,502,726	1,265,893	978,168	854,100	994,958	1,075,854	2,020,957	2,974,697	3,753,962	4,614,893	3,422,061	3,062,672	27,520,942
17		Total Non-Residential	17,987,671	11,781,402	10,213,830	11,371,589	11,346,721	13,793,702	19,947,477	26,710,476	34,880,729	35,922,384	30,920,863	25,492,522	250,369,366
18	**RDM USAGE - TOTAL**		33,954,245	19,837,205	14,033,192	14,352,862	15,165,690	21,852,380	37,444,326	54,858,983	71,785,029	75,087,175	65,538,690	52,964,585	476,874,361

RATE YEAR CUSTOMERS BY SERVICE CLASS

			May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	Average
	Residential:														
19	SC 1S	Residential Sales	215,676	215,513	215,108	215,455	215,571	216,484	217,007	216,943	217,197	217,278	217,503	216,355	216,341
20	SC 13T	Residential Aggregation Transp	23,179	23,159	23,117	23,157	23,172	23,269	23,287	23,273	23,345	23,356	23,380	23,262	23,246
21		Total Residential	238,855	238,672	238,225	238,611	238,743	239,752	240,294	240,216	240,542	240,634	240,883	239,617	239,587
	Non-Residential:														
22	SC 2S	General Sales Service	23,457	23,310	23,179	23,147	23,213	23,346	23,626	23,777	23,722	23,807	23,799	23,637	23,501
23	SC 14T	Non-Residential Agg Transp	8,523	8,515	8,524	8,522	8,518	8,534	8,535	8,540	8,544	8,545	8,537	8,530	8,530
24	SC 1T	Firm Transportation	82	82	82	82	82	82	82	82	82	81	81	82	82
25	SC 5T	Small Firm Transportation	336	336	335	335	335	335	335	334	334	334	334	336	335
26		Total Non-Residential	32,397	32,243	32,120	32,085	32,147	32,297	32,578	32,732	32,681	32,767	32,751	32,584	32,448
27	**RDM CUSTOMERS**		271,252	270,915	270,344	270,696	270,890	272,049	272,871	272,948	273,223	273,400	273,634	272,201	272,035

Rochester Gas and Electric Corporation
Gas Business
RDM Targets - Rate Year 1
Revenue ($000) and Usage (Therms) By Service Class

RATE YEAR REVENUE BY SERVICE CLASS ($000)

			A	B	C	D	E	F	G	H	I	J	K	L	M
	Residential:		**May-20**	**Jun-20**	**Jul-20**	**Aug-21**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**Total**
1	SC 1	Residential Sales	$ 8,710	$ 6,451	$ 5,328	$ 5,156	$ 5,329	$ 6,627	$ 9,220	$ 12,545	$ 14,940	$ 15,125	$ 14,551	$ 12,152	$ 116,133
2	SC 5	Residential Aggregation Transp	$ 1,155	$ 813	$ 627	$ 604	$ 624	$ 779	$ 1,109	$ 1,555	$ 1,851	$ 1,900	$ 1,783	$ 1,548	$ 14,348
3		Total Residential	$ 9,866	$ 7,264	$ 5,955	$ 5,760	$ 5,954	$ 7,405	$ 10,328	$ 14,100	$ 16,791	$ 17,025	$ 16,334	$ 13,700	$ 130,482
	Non-Residential:														
4	SC 1	General Sales Service	$ 768	$ 595	$ 459	$ 460	$ 464	$ 680	$ 1,013	$ 1,475	$ 1,728	$ 1,648	$ 1,596	$ 1,171	$ 12,058
5	SC 5	Non-Residential Agg Transp	$ 951	$ 759	$ 540	$ 566	$ 533	$ 843	$ 1,260	$ 1,799	$ 2,004	$ 2,039	$ 2,037	$ 1,417	$ 14,747
6	SC 3	Large Firm Transportation	$ 827	$ 720	$ 694	$ 700	$ 702	$ 758	$ 818	$ 855	$ 931	$ 926	$ 904	$ 897	$ 9,733
7		Total Non-Residential	$ 2,547	$ 2,074	$ 1,693	$ 1,726	$ 1,699	$ 2,281	$ 3,091	$ 4,129	$ 4,664	$ 4,612	$ 4,537	$ 3,485	$ 36,538
8	**RDM REVENUE - TOTAL**		$ 12,412	$ 9,338	$ 7,648	$ 7,486	$ 7,653	$ 9,686	$ 13,419	$ 18,229	$ 21,455	$ 21,637	$ 20,870	$ 17,185	$ 167,020

RATE YEAR USAGE BY SERVICE CLASS (Therms)

	Residential:		**May-20**	**Jun-20**	**Jul-20**	**Aug-21**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**Total**
9	SC 1	Residential Sales	16,342,689	8,279,477	4,303,370	3,648,238	4,163,311	8,936,345	18,184,620	30,162,394	39,103,456	39,660,671	37,488,327	28,728,623	239,001,521
10	SC 5	Residential Aggregation Transp	2,418,901	1,184,670	513,396	429,749	492,115	1,076,907	2,265,029	3,907,614	5,026,998	5,197,982	4,758,030	3,864,423	31,135,814
11		Total Residential	18,761,590	9,464,147	4,816,766	4,077,987	4,655,426	10,013,252	20,449,649	34,070,008	44,130,454	44,858,653	42,246,357	32,593,046	270,137,335
	Non-Residential:														
12	SC 1	General Sales Service	2,202,111	1,469,436	933,972	942,216	933,874	1,892,289	3,399,354	5,677,324	6,888,608	6,687,179	6,344,746	4,181,898	41,553,007
13	SC 5	Non-Residential Agg Transp	4,114,426	2,986,829	1,921,945	1,992,915	1,909,686	3,462,785	5,892,082	9,666,847	11,168,316	11,134,501	11,104,594	6,938,284	72,293,210
14	SC 3	Large Firm Transportation	16,642,929	12,767,812	13,177,816	13,217,876	12,929,859	14,804,802	15,984,500	18,601,428	21,834,106	21,390,380	20,489,757	19,626,658	201,467,922
15		Total Non-Residential	22,959,466	17,224,077	16,033,733	16,153,007	15,773,419	20,159,876	25,275,936	33,945,599	39,891,030	39,212,060	37,939,097	30,746,840	315,314,139
16	**RDM USAGE - TOTAL**		41,721,056	26,688,224	20,850,499	20,230,994	20,428,845	30,173,128	45,725,585	68,015,607	84,021,484	84,070,713	80,185,454	63,339,886	585,451,474

RATE YEAR CUSTOMERS BY SERVICE CLASS

	Residential:		**May-20**	**Jun-20**	**Jul-20**	**Aug-21**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**Average**
17	SC 1	Residential Sales	263,529	263,462	263,229	263,456	263,624	264,086	264,528	264,982	264,058	265,146	265,344	263,966	264,118
18	SC 5	Residential Aggregation Transp	30,815	30,792	30,761	30,788	30,809	30,866	30,919	30,972	30,863	30,989	31,012	30,863	30,871
19		Total Residential	294,344	294,254	293,990	294,244	294,433	294,952	295,447	295,954	294,921	296,135	296,356	294,829	294,988
	Non-Residential:														
20	SC 1	General Sales Service	15,663	15,587	15,523	15,494	15,487	15,598	15,708	15,761	15,836	15,861	15,859	15,740	15,676
21	SC 5	Non-Residential Agg Transp	8,256	8,217	8,184	8,169	8,165	8,218	8,272	8,299	8,335	8,347	8,345	8,293	8,258
22	SC 3	Large Firm Transportation	239	239	239	238	238	238	238	234	234	234	234	243	237
23		Total Non-Residential	24,158	24,043	23,946	23,901	23,890	24,054	24,218	24,294	24,405	24,442	24,438	24,276	24,172
24	**RDM CUSTOMERS**		318,502	318,297	317,936	318,145	318,323	319,006	319,665	320,248	319,326	320,577	320,794	319,105	319,160

Rochester Gas and Electric Corporation
Gas Business
RDM Targets - Rate Year 2
Revenue ($000) and Usage (Therms) By Service Class

RATE YEAR REVENUE BY SERVICE CLASS ($000)

			A	B	C	D	E	F	G	H	I	J	K	L	M
	Residential:		May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Total
1	SC 1	Residential Sales	$ 8,884	$ 6,681	$ 5,587	$ 5,419	$ 5,588	$ 6,854	$ 9,382	$ 12,624	$ 14,958	$ 15,139	$ 14,580	$ 12,240	$ 117,935
2	SC 5	Residential Aggregation Transp	$ 1,172	$ 839	$ 657	$ 635	$ 655	$ 805	$ 1,127	$ 1,562	$ 1,850	$ 1,898	$ 1,784	$ 1,555	$ 14,539
3		Total Residential	$ 10,056	$ 7,520	$ 6,244	$ 6,054	$ 6,243	$ 7,659	$ 10,509	$ 14,186	$ 16,808	$ 17,037	$ 16,364	$ 13,795	$ 132,474
	Non-Residential:														
4	SC 1	General Sales Service	$ 772	$ 603	$ 470	$ 471	$ 475	$ 684	$ 1,009	$ 1,459	$ 1,705	$ 1,627	$ 1,576	$ 1,163	$ 12,015
5	SC 5	Non-Residential Agg Transp	$ 938	$ 750	$ 538	$ 563	$ 530	$ 831	$ 1,236	$ 1,758	$ 1,957	$ 1,991	$ 1,989	$ 1,388	$ 14,469
6	SC 3	Large Firm Transportation	$ 833	$ 728	$ 702	$ 707	$ 710	$ 765	$ 824	$ 859	$ 935	$ 929	$ 908	$ 902	$ 9,802
7		Total Non-Residential	$ 2,543	$ 2,081	$ 1,710	$ 1,742	$ 1,715	$ 2,280	$ 3,068	$ 4,077	$ 4,597	$ 4,547	$ 4,474	$ 3,454	$ 36,287
8	**RDM REVENUE - TOTAL**		$ 12,599	$ 9,601	$ 7,953	$ 7,796	$ 7,958	$ 9,938	$ 13,577	$ 18,263	$ 21,405	$ 21,585	$ 20,838	$ 17,249	$ 168,762

RATE YEAR USAGE BY SERVICE CLASS (Therms)

	Residential:		May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Total
9	SC 1	Residential Sales	16,528,553	8,373,639	4,352,312	3,689,729	4,210,661	9,037,978	18,391,432	30,505,429	39,548,177	40,111,730	37,914,679	29,055,352	241,719,671
10	SC 5	Residential Aggregation Transp	2,446,411	1,198,143	519,235	434,637	497,712	1,089,155	2,290,789	3,952,055	5,084,169	5,257,098	4,812,143	3,908,373	31,489,920
11		Total Residential	18,974,964	9,571,782	4,871,547	4,124,366	4,708,373	10,127,133	20,682,221	34,457,484	44,632,346	45,368,828	42,726,822	32,963,725	273,209,591
	Non-Residential:														
12	SC 1	General Sales Service	2,224,545	1,482,057	942,908	949,827	941,171	1,904,010	3,426,462	5,724,531	6,944,775	6,742,940	6,398,487	4,217,830	41,899,543
13	SC 5	Non-Residential Agg Transp	4,151,041	3,012,118	1,939,827	2,010,418	1,921,977	3,484,960	5,928,829	9,722,631	11,229,183	11,197,053	11,168,201	6,982,923	72,749,161
14	SC 3	Large Firm Transportation	16,393,189	12,513,190	12,920,286	12,959,164	12,678,997	14,543,534	15,720,416	18,330,762	21,567,511	21,139,460	20,232,417	19,377,504	198,376,430
15		Total Non-Residential	22,768,775	17,007,365	15,803,021	15,919,409	15,542,145	19,932,504	25,075,707	33,777,924	39,741,469	39,079,453	37,799,105	30,578,257	313,025,134
16	**RDM USAGE - TOTAL**		41,743,739	26,579,147	20,674,568	20,043,775	20,250,518	30,059,637	45,757,928	68,235,408	84,373,815	84,448,281	80,525,927	63,541,982	586,234,725

RATE YEAR CUSTOMERS BY SERVICE CLASS

	Residential:		May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Average
17	SC 1	Residential Sales	264,783	264,702	264,467	264,695	264,865	265,331	265,776	266,231	265,308	266,396	266,596	265,218	265,364
18	SC 5	Residential Aggregation Transp	30,947	30,938	30,911	30,937	30,957	31,011	31,063	31,116	31,009	31,136	31,159	30,998	31,015
19		Total Residential	295,730	295,640	295,378	295,632	295,822	296,342	296,839	297,347	296,317	297,532	297,755	296,216	296,379
	Non-Residential:														
20	SC 1	General Sales Service	15,734	15,656	15,592	15,563	15,555	15,666	15,777	15,831	15,906	15,931	15,930	15,809	15,746
21	SC 5	Non-Residential Agg Transp	8,284	8,245	8,213	8,199	8,194	8,247	8,300	8,327	8,363	8,376	8,376	8,321	8,287
22	SC 3	Large Firm Transportation	230	230	230	229	229	229	229	225	225	225	225	234	228
23		Total Non-Residential	24,248	24,131	24,035	23,991	23,978	24,142	24,306	24,383	24,494	24,532	24,531	24,364	24,261
24	**RDM CUSTOMERS**		319,978	319,771	319,413	319,623	319,800	320,484	321,145	321,730	320,811	322,064	322,286	320,580	320,640

Rochester Gas and Electric Corporation
Gas Business
RDM Targets - Rate Year 3
Revenue ($000) and Usage (Therms) By Service Class

RATE YEAR REVENUE BY SERVICE CLASS ($000)

			A	B	C	D	E	F	G	H	I	J	K	L	M
	Residential:		May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	Total
1	SC 1	Residential Sales	$ 9,148	$ 6,958	$ 5,869	$ 5,703	$ 5,871	$ 7,130	$ 9,645	$ 12,869	$ 15,189	$ 15,371	$ 14,815	$ 12,486	$ 121,053
2	SC 5	Residential Aggregation Transp	$ 1,202	$ 870	$ 690	$ 668	$ 688	$ 837	$ 1,157	$ 1,590	$ 1,877	$ 1,925	$ 1,812	$ 1,583	$ 14,899
3		Total Residential	$ 10,350	$ 7,828	$ 6,559	$ 6,371	$ 6,559	$ 7,967	$ 10,802	$ 14,460	$ 17,066	$ 17,295	$ 16,626	$ 14,069	$ 135,952
	Non-Residential:														
4	SC 1	General Sales Service	$ 789	$ 619	$ 487	$ 488	$ 492	$ 701	$ 1,025	$ 1,475	$ 1,721	$ 1,643	$ 1,592	$ 1,180	$ 12,212
5	SC 5	Non-Residential Agg Transp	$ 946	$ 758	$ 546	$ 571	$ 539	$ 839	$ 1,243	$ 1,765	$ 1,964	$ 1,997	$ 1,995	$ 1,395	$ 14,558
6	SC 3	Large Firm Transportation	$ 856	$ 754	$ 729	$ 734	$ 736	$ 789	$ 846	$ 879	$ 951	$ 947	$ 926	$ 924	$ 10,072
7		Total Non-Residential	$ 2,590	$ 2,132	$ 1,762	$ 1,793	$ 1,767	$ 2,329	$ 3,115	$ 4,119	$ 4,636	$ 4,586	$ 4,514	$ 3,499	$ 36,842
8	**RDM REVENUE - TOTAL**		$ 12,940	$ 9,960	$ 8,321	$ 8,164	$ 8,325	$ 10,296	$ 13,917	$ 18,579	$ 21,702	$ 21,882	$ 21,140	$ 17,568	$ 172,794

RATE YEAR USAGE BY SERVICE CLASS (Therms)

	Residential:		May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	Total
9	SC 1	Residential Sales	16,570,947	8,395,116	4,363,475	3,699,193	4,221,460	9,061,159	18,438,604	30,583,672	39,649,614	40,214,612	38,011,926	29,129,875	242,339,653
10	SC 5	Residential Aggregation Transp	2,452,686	1,201,216	520,566	435,751	498,988	1,091,948	2,296,664	3,962,192	5,097,210	5,270,582	4,824,486	3,918,397	31,570,686
11		Total Residential	19,023,633	9,596,332	4,884,041	4,134,944	4,720,448	10,153,107	20,735,268	34,545,864	44,746,824	45,485,194	42,836,412	33,048,272	273,910,339
	Non-Residential:														
12	SC 1	General Sales Service	2,240,628	1,491,793	949,827	956,855	947,822	1,917,435	3,450,710	5,765,225	6,994,267	6,789,224	6,442,856	4,247,496	42,194,138
13	SC 5	Non-Residential Agg Transp	4,179,507	3,032,413	1,953,655	2,024,834	1,934,361	3,509,274	5,969,087	9,786,692	11,302,163	11,265,236	11,237,189	7,027,503	73,221,914
14	SC 3	Large Firm Transportation	16,422,870	12,526,387	12,929,544	12,966,690	12,690,344	14,552,874	15,736,812	18,354,079	21,603,138	21,187,433	20,271,435	19,418,397	198,660,003
15		Total Non-Residential	22,843,005	17,050,593	15,833,026	15,948,379	15,572,527	19,979,583	25,156,609	33,905,996	39,899,568	39,241,893	37,951,480	30,693,396	314,076,055
16	**RDM USAGE - TOTAL**		41,866,638	26,646,925	20,717,067	20,083,323	20,292,975	30,132,690	45,891,877	68,451,860	84,646,392	84,727,087	80,787,892	63,741,668	587,986,394

RATE YEAR CUSTOMERS BY SERVICE CLASS

	Residential:		May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23	Average
17	SC 1	Residential Sales	266,041	265,964	265,731	265,961	266,134	266,602	267,050	267,507	266,586	267,676	267,878	266,473	266,634
18	SC 5	Residential Aggregation Transp	31,094	31,085	31,058	31,085	31,105	31,160	31,212	31,265	31,158	31,285	31,309	31,145	31,163
19		Total Residential	297,135	297,049	296,789	297,046	297,239	297,762	298,262	298,772	297,744	298,961	299,187	297,618	297,797
	Non-Residential:														
20	SC 1	General Sales Service	15,802	15,725	15,660	15,631	15,624	15,736	15,848	15,901	15,977	16,001	15,999	15,880	15,815
21	SC 5	Non-Residential Agg Transp	8,312	8,273	8,242	8,225	8,221	8,275	8,328	8,356	8,392	8,404	8,403	8,350	8,315
22	SC 3	Large Firm Transportation	221	221	221	220	220	220	220	216	216	216	216	225	219
23		Total Non-Residential	24,335	24,219	24,123	24,076	24,065	24,231	24,396	24,473	24,585	24,621	24,618	24,455	24,350
24	**RDM CUSTOMERS**		321,470	321,268	320,912	321,122	321,304	321,993	322,658	323,245	322,329	323,582	323,805	322,073	322,147

Common Allocation Factors

New York State Electric & Gas Corporation

	Electric	Gas	Applies To
Operations & Maintenance Expenses (A&G)			
Common O&M - A&G	80.39%	19.61%	See Footnote 1
Pension / OPEB	79.61%	20.39%	Pension and OPEB expense; Pension Asset and OPEB Reserve in rate base
Customer Service & Energy Efficiency	77.10%	22.90%	Customer Service, Energy Efficiency, and Low Income accounts and expenses not directly assigned to Electric or Gas
Rate Base			
Plant - Common	80.26%	19.74%	To allocate common plant and depreciation expense
Plant - Common Materials & Supplies / Other	76.07%	23.93%	See Footnote 2
Customer Bill Credits			
See Appendix P - Customer Service Quality			Fund to assist customers related to COVID-19

Footnote 1: Examples of Common O&M - A&G include the following:

Other Employee Benefits	Postage
Employee Related	Telephone
Collections	Advertising
Insurance	Rents & Leases
IUMC Costs	Stores
Outside Service Costs	Environmental Remediation
Legal / Regulatory Expense	Security
Transportation	CS Enhancements
Materials & Supplies	Other O&M

Footnote 2: Balance sheet items for rate base: M&S Inventory, Injury & Damage Reserve, Workers Comp Reserve, Prepaid Insurance, Gain/Loss on Reacquired Debt

Common Allocation Factors

Rochester Gas and Electric Corporation

	Electric	Gas	Applies To
Operations & Maintenance Expenses (A&G)			
Common O&M - A&G	67.55%	32.45%	See Footnote 1
Pension / OPEB	61.40%	38.60%	Pension and OPEB expense; Pension Asset and OPEB Reserve in rate base
Customer Service & Energy Efficiency	54.80%	45.20%	Customer Service, Energy Efficiency, and Low Income accounts and expenses not directly assigned to Electric or Gas
Rate Base			
Plant - Common	71.39%	28.61%	To allocate common plant and depreciation expense
Plant - Common Materials & Supplies / Other	74.15%	25.85%	See Footnote 2
Customer Bill Credits			
	See Appendix P - Customer Service Quality		Fund to assist customers related to COVID-19

Footnote 1: Examples of Common O&M - A&G include the following:

Other Employee Benefits	Postage
Employee Related	Telephone
Collections	Advertising
Insurance	Rents & Leases
IUMC Costs	Stores
Outside Service Costs	Environmental Remediation
Legal / Regulatory Expense	Security
Transportation	CS Enhancements
Materials & Supplies	Other O&M

Footnote 2: Balance sheet items for rate base: M&S Inventory, Injury & Damage Reserve, Workers Comp Reserve, Prepaid Insurance, Gain/Loss on Reacquired Debt

Non-Wire Alternatives and Non-Pipe Alternatives

New York State Electric & Gas Corporation – Electric
New York State Electric & Gas Corporation – Gas
Rochester Gas and Electric Corporation – Electric
Rochester Gas and Electric Corporation – Gas

I. Non-Wire Alternatives

The Non-Wire Alternative Incentive Mechanism ("NWA Incentive Mechanism") establishes a methodology for determining incentives applicable to all Non-Wire Alternatives ("NWA"). Through the NWA Incentive Mechanism, New York State Electric & Gas Corporation ("NYSEG") and Rochester Gas and Electric Corporation ("RG&E") (together, the "Companies" and each a "Company") may retain a share of the present value of net benefits identified by comparing a NWA project to the traditional infrastructure project it would defer or replace based on a benefit cost analysis ("BCA").[1] The incentive amount available to the Companies will be adjusted based on the difference between the forecasted cost of achieving deferral and the actual costs of such. In the event the number of megawatts ("MWs") required to defer or avoid the traditional project increases or decreases, the incentive amount would be further adjusted. The NWA Incentive Mechanism provides an incentive floor of $0 and a cap of 50% of the initially-identified net benefits.

BCA

For all NWA projects, the Companies will use a full BCA to compare the present value of the net costs and benefits of an NWA project versus the present value of the net costs and benefits of a traditional infrastructure project. The BCA will consider all of the benefit and cost categories in the Commission's January 21, 2016 Order Establishing Benefit Cost Analysis Framework issued in Case 14-M-0101 and use the Companies' BCA Handbook.

Applicability of the NWA Incentive Mechanism

The Companies will establish an "Initial Incentive" equal to 30% of the present value of net benefits ("Initial Net Benefits"), i.e., the present value of net benefits projected at the time the Companies have either entered into contracts with distributed energy resource ("DER") providers for the entire NWA project portfolio, or when there is reasonable certainty on the price of the NWA project portfolio. To establish the Initial Incentive, the Companies shall make a compliance filing in Case 19-E-0378 (NYSEG) or 19-E-0380 (RG&E). Prior to making its compliance filing to set the Initial Incentive, the Companies shall seek input from Department of Public Service Staff ("Staff"). Once the NWA Project has been fully implemented, the Companies will calculate the difference in NWA Project Cost, which will be equal to the initially forecasted cost of the NWA Project, less the actual cost of the NWA Project. The "Final Incentive" will equal the sum of the Initial Incentive and 50% of the difference in the NWA Project Cost. The Final Incentive is subject to a floor of $0 and a cap of 50% of the Initial Net Benefits.

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[1] The Company may pursue multiple NWA Projects to defer separate traditional infrastructure projects in the same area.

Should additional MWs be needed to achieve the initially proposed deferral of a traditional infrastructure project, or to increase the duration of the deferral, the Company will make a compliance filing in Case 19-E-0378 (NYSEG) or Case 19-E-0380 (RG&E) and seek incremental MW procurements accordingly. So long as it is feasible and remains cost-beneficial to procure the additional MWs to continue deferral, the Company will be authorized to receive cost recovery of the expenditures incurred in obtaining the additional MWs. However, the Company's Final Incentive would not reflect either the costs[2] or the benefits associated with the additional MWs. In the event the Company determines that acquiring additional MWs is technically or operationally infeasible, it will plan to implement a traditional infrastructure solution as needed. Recovery of any incentives related to that project will be halted without requiring a refund of the amounts already collected at that time.

In the event fewer MWs are needed to achieve the intended deferral of traditional infrastructure, the Company will only reduce the number of MWs it plans to procure if both the need for reduced MWs is shown to be a sustained downward trend over a three-year period, and the Company needs only 70% or fewer of the initially-forecasted MWs to achieve the intended deferral.

The following true-up mechanism applies in the event the Companies have not already procured MWs that were later determined as being no longer required per above. The Companies will true-up the incentive by converting the Initial Incentive to an Initial Unit Incentive by dividing its 30% share of Initial Net Benefits by the initial number of MWs it forecasted. Similarly, the Difference in NWA Project Cost to achieve deferral will be calculated on a per-MW basis, the Unit Difference in NWA Project Cost, by dividing the actual NWA Project Cost by the number of MWs required. The Final Incentive will be calculated as the sum or difference of the Initial Unit Incentive plus or minus the Unit Difference in NWA Project Cost, multiplied by the reduced amount of MWs determined to be necessary, subject to the same 50% share of Initial Net Benefits incentive cap and $0 incentive floor provisions.

<u>NWA Cost and Incentive Recovery</u>

To the extent that traditional capital investments are deferred or avoided by NWA(s), the Companies' Net Plant Reconciliation ("NPR") Mechanism targets will be revised accordingly. This will minimize any financial disincentive the Companies might otherwise face when engaging in NWA projects. To the extent an NWA project results in the Company displacing a capital project that is reflected in the targets for Average Electric Plant in Service Balances under the NPR, the target(s) will be reduced to exclude the forecasted net plant associated with the displaced project. The carrying charge associated with the displaced project will be applied as a credit against the recovery of the associated NWA project costs to be recovered from customers. In the event that the carrying charge on the net plant of any displaced project is higher than the recovery of the associated NWA project costs, the difference will be deferred for the benefit of customers.

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[2] The expenditures related to acquiring such additional MWs will not be considered in the Difference in NWA Project Cost used to calculate the Final Incentive.

NWA Final Incentive amounts under the NWA Incentive Mechanism will be allocated to each Service Class ("SC") based on the following allocators: (1) coincident peak demand for the transmission portion (if any) of the deferred traditional project; and (2) non-coincident peak demand allocator for the sub-transmission and distribution portions of the deferred traditional project. For example, the incentives related to an NWA project which defers the need for sub-transmission infrastructure would be allocated to SCs based on their non-coincident sub-transmission demand allocator. Similarly, the costs and incentives related to an NWA project which defers the need for primary-voltage distribution infrastructure would be allocated to SCs based on their non-coincident primary demand allocator. If an NWA project will benefit only certain classes of customers, the cost allocation will be limited to the benefitted classes.

Once allocated to each SC, these costs will be recovered through a component of the Non-Bypassable Charge ("NBC"), which will be filed with the Commission and will reflect how the avoided project would have been recovered.

Amortization of NWA Project Costs and Incentives

The Companies will amortize their NWA project costs over a rolling ten-year period. The ten-year recovery period will begin when the NWA project costs are realized. Any unamortized costs plus carrying charges will be incorporated into base rates when electric base rates are reset.

For all NWA projects, the Companies will be awarded and begin collecting the Final Incentive from customers once 70% of the MWs it procured for the NWA project have become operational and have been verified through the Companies' measurement and verification procedures. Once an NWA project is awarded, the Companies will amortize the Final Incentive of the NWA project over the remaining amortization period for the NWA project, inclusive of carrying costs on the unamortized balance of the Final Incentive.

Reporting Requirements

The Companies will submit a detailed implementation plan and BCA for each NWA project once there is reasonable certainty as to the costs of the NWA project portfolio. The implementation plan for each NWA will include, at a minimum: (1) detailed measurement and verification procedures; (2) the portfolio of component load reductions or DER to be implemented; (3) the anticipated costs of the NWA; (4) a demonstration of whether the costs of the NWA projects are incremental to the Company's revenue requirement or will be displacing a project subject to the Capital Investment Reconciliation Mechanism; (5) a customer and community outreach plan if appropriate for the procured NWA; and (6) the BCA results when available. The implementation plan for each project will be updated at least annually; however, the Companies will also update relevant plans promptly if they determine a need to increase or decrease the number of MWs required to effectuate an NWA project, or if the length of the deferral period for the traditional infrastructure solution associated with the NWA is modified. Annual implementation plans will be filed by January 31 of each year. If the number of MWs or the length of deferral is modified, the Companies shall also file an updated BCA, as appropriate.

In addition, the Companies also will file quarterly reports showing: (1) NWA project expenditures and all relevant details with respect to project costs; (2) a description of the NWA project activities; (3) anticipated project in-service dates; (4) NWA cost and incentive recoveries; and (5) identification of operational savings or other benefits. The quarterly reports shall be filed in Cases 19-E-0378 and 19-E-0380 60 days after the close of each calendar quarter.

II. Non-Pipe Alternatives

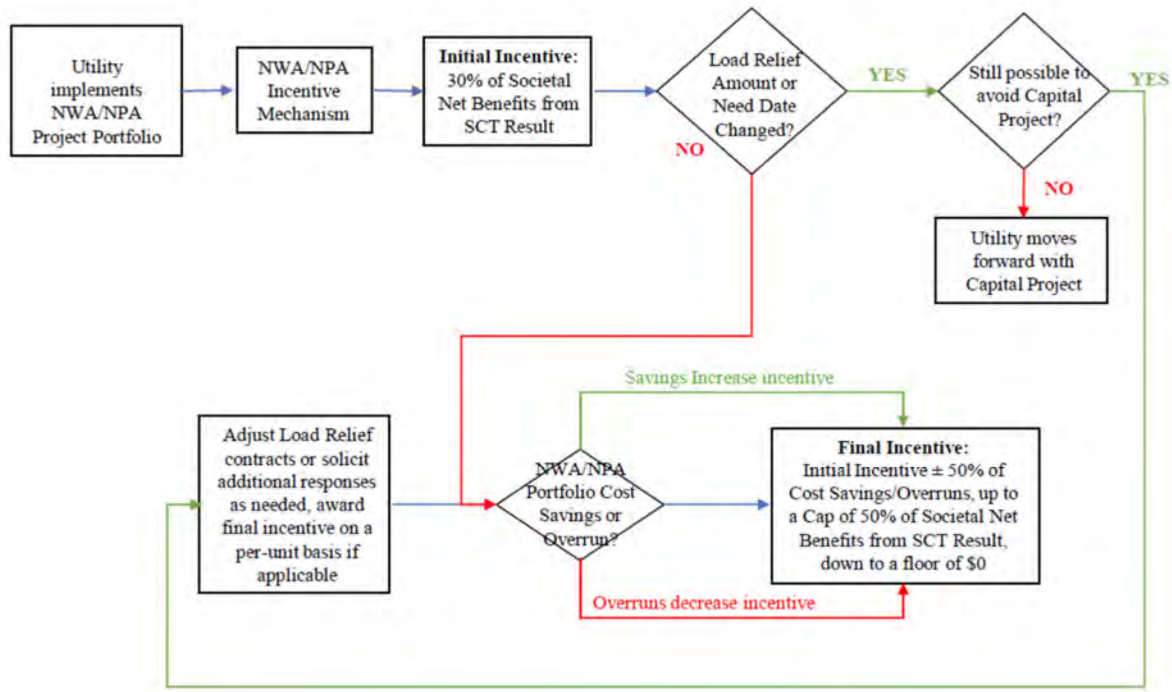
As provided for in Appendix M of this Proposal, the Companies agree that gas projects involving the construction of a new pipeline or the replacement or expansion of an existing pipeline may be potentially suitable for a NPA, except where conditions pose an immediate threat to public safety or where construction is imminent (within 12 months). Following Commission approval of the Proposal, the Companies agree that for other future projects, a two-prong approach to NPA evaluation would be used. The first would be expedited for smaller projects (less than or equal to $2 million) and would utilize a standardized review approach, including an economic and technical analysis (“Streamlined BCA”) to determine the potential economic and technical feasibility of an NPA that may or may not include, a full-scale solicitation of NPA alternatives. The second would be a more comprehensive review for larger projects which would require a full-scale solicitation of NPA alternatives followed by a BCA of potential solutions which would be performed prior to detailed engineering, permitting, and construction, and before more than 5% of the total project cost has been spent (“Comprehensive BCA”). The Companies agree to involve Staff in the application of both the Streamlined BCA and the Comprehensive BCA.

Additionally, Appendix M indicates that NPA projects shall be amortized over the anticipated “used and useful” life of installed assets and equipment. (For example, this may be 20 years for a heat pump and several decades for a ground loop.) NPA projects without a clearly measurable period for amortization shall use a 20-year default amortization period.

As provided for in Appendix M, consistent with the above approaches to NPAs, which will be applied to capital projects in the Companies’ plan beginning in RY1, the Companies will consider non-gas NPAs or other economically viable solutions in lieu of certain leak prone pipe replacements that are suitable.. The Companies would get a credit toward the overall leak-prone pipe replacement mileage targets if a NPA or other economically viable solution was implemented. For example, if in lieu of replacing one mile of leak prone pipe, a NPA was completed, the Company would get credit for one mile of leak prone pipe replacement.

Finally, Appendix M states that the Companies agree to continue to “stack” customer and vendor incentives from the Energy Efficiency order with NPA-based incentives where allowed by applicable Commission order, law or regulation.

The NPA Incentive Mechanism will be developed consistent with the following flow chart (which also addresses the NWA Incentive Mechanism).



Shareholder NPA Final Incentive amounts under the NPA Incentive Mechanism will be allocated to each SC based on a gas peak day design demand allocator. However, if an NPA project will benefit only certain classes of customers, the cost allocation will be limited to the benefitted classes.

Once allocated to each SC, these costs would be recovered through a separate surcharge which will be filed with the Commission.

Additional information on NPAs is set forth in Appendix M.

Electric Cost Incentive Mechanisms

New York State Electric & Gas Corporation – Electric
New York State Electric & Gas Corporation – Gas
Rochester Gas and Electric Corporation – Electric
Rochester Gas and Electric Corporation – Gas

Homer City Generating Station Optimization Revenues

NYSEG will share 80% / 20% between customers and shareholders the cost savings resulting from optimization activities associated with NYSEG's grandfathered transmission entitlements of up to 471 MW from the Homer City Generating Station, located in PJM, into the NYISO. The optimization of these entitlements will benefit all delivery customers through lower electric supply costs in the NBC.

Procurement of Environmental Attributes

The Companies will share 80% / 20% between customers and shareholders any savings associated with procurement activities for Tier-1 eligible renewable energy certificates ("RECs") as defined in the Commission's August 1, 2016 Order Adopting a Clean Energy Standard issued in Case 15-E-0302 ("CES Order') through the two-step process detailed below.

Step 1 will identify the number of RECs that would be subject to Alternative Compliance Payments ("ACP") to NYSERDA through the following formula:

$$REC_{\text{Sharing}} = REC_{\text{Annual Obligation}} - REC_{\text{VDER}} - REC_{\text{NYSERDA}}$$

Where:

REC_{Sharing}: The calculated number of RECs that will be used in calculating/determining any sharing in savings between customers and shareholders.

$REC_{\text{Annual Obligation}}$: Total Load Serving Entity ("LSE") Compliance Year requirements which are established annually as a percentage of LSE total load and will ramp up over time in an effort to meet the State's renewable generation mandates.

REC_{VDER}: The total number of Value of Distributed Energy RECs acquired through the Company's Value Stack tariff and that are allocated to meet obligations for a specific Compliance Year.

REC_{NYSERDA}: The total number of RECs acquired through NYSERDA's Tier-1 REC auctions and closeout period and that are allocated to meet obligations for a specific Compliance Year.

Step 2 will calculate the overall savings by applying the ACP value for that specific Compliance Year to the remaining number of RECs ($REC_{Sharing}$) needed to meet a specific Compliance Year obligation and deducting the procurement costs associated with third-party arrangements, any banked RECs from previous compliance periods, and, if necessary, any ACP for any remaining REC obligations. The following formula provides the process to determine the total savings to be shared between customers and shareholders:

$$REC_{Savings} = REC_{Sharing\ Cost} - REC_{Banked\ Cost} - REC_{Third\text{-}Party\ Cost} - REC_{ACP\ Cost}$$

Where:

$REC_{Savings}$: Represents the total dollars that will be shared between customers (80%) and shareholders (20%).

$REC_{Sharing\ Cost}$: Represents the total costs of remaining number of RECs at the Compliance Year ACP rate.

$REC_{Banked\ Cost}$: Represents the total procurement cost of previously banked RECs from prior compliance years to be used to meet obligations for a specific Compliance Year. As permitted in the CES Implementation Plans and within certain, defined parameters, which may be changed through subsequent CES-related orders, RECs may be banked to meet obligations in future compliance years.

$REC_{Third\text{-}Party\ Cost}$: Represents the total cost of RECs purchased from eligible third-party providers to meet mandated obligations that are allocated for a specific Compliance Year.

$REC_{ACP\ Cost}$: Represents the total ACP cost associated with meeting Compliance Year remaining obligations.

Compliance and Reporting Requirements in the Proposal

New York State Electric & Gas Corporation – Electric
New York State Electric & Gas Corporation – Gas
Rochester Gas and Electric Corporation – Electric
Rochester Gas and Electric Corporation – Gas

The Companies' compliance and reporting requirements (broken down by month) are set forth below.

January

Non-Wires Alternatives Annual Implementation Plans

Annual implementation plans for Non-Wires Alternatives ("NWAs") will be filed by January 31 of each year as discussed in further detail in Appendix JJ.

Customer Service – Annual Reporting Requirements

A final report will be submitted for each calendar year within 30 days of the end of the calendar year. The final report will also state whether a revenue adjustment is applicable, and if so, the amount of the revenue adjustment. The Companies will provide all supporting workpapers related to reported performance when the final report is submitted.

In the event of a Company missing a scheduled appointment with a residential customer, the Company will provide a credit of $35.00 to such customer. The Companies will include in their respective annual Customer Service Performance Indicator reports the total number of credits provided in the calendar year and total dollar amount of the credits given to residential customers. The Companies will send to Staff, confidentially, a list of the customers who received a credit, total number of all missed appointments, and information on any customers who did not receive a credit, yet qualified, in the information reported. The Companies will provide all supporting workpapers related to reported performance when the final report is submitted.

Capital Expenditure Reporting – Quarterly Variance Reports

As discussed in Section XXVIII(B) of the Joint Proposal, the Companies will file with the Secretary to the Commission, with a copy to Staff, a quarterly report which will provide a variance report between actual and forecasted expenditures, including project changes, which will be due the last day of the month following the calendar quarter (i.e., Quarter 1 due April 30, Quarter 2 due July 31, Quarter 3 due October 31, and Quarter 4 due January 30) for each such project that experiences a plus or minus 10% cost variation.

Natural Gas Matters – Quarterly Report

The Companies agree to provide quarterly reports (on a calendar quarter basis) starting with the first full calendar quarter following approval of the Joint Proposal to measure progress on the objectives set forth in Paragraph 1 of Appendix M. These reports will be provided within thirty (30) days after the end of each calendar quarter and will include volumes of actual billed gas use, and volumes of billed gas use normalized for temperature. The reports will identify monthly billed use by sector (residential, commercial and industrial) for each Company, and will track natural gas customer counts and include net change in natural gas customers by month and will also report billed gas use and customer counts associated with the DeRuyter pipeline. To the extent the information is available, on a monthly basis, the reports will also track customer use of heat pump and building efficiency incentives by replaced fuel type as applicable (new construction or oil, natural gas, propane, etc.), as well as BTU's of energy saved with heat pump and building efficiency incentives by replaced fuel type as applicable. For reference, the first issuance of these reports shall also provide data for 2019.

February

Earnings Adjustment Mechanisms – Quarterly Compliance Filing

The Companies will file with the Secretary to the Commission, quarterly reports no later than 60 days after the end of each calendar quarter to describe the Companies' progress toward each EAM's metric's targets, the actions taken by the Companies to achieve target performance, and a forecast of whether the Companies expect to meet annual EAM targets.

The Companies will track and report the progress of three EAM Scorecard metrics: Locational System Relief Value Load Factor; Residential Electric Energy Intensity; and Commercial Electric Energy Intensity. The Companies shall report progress on each of its Scorecard metrics as part of its annual EAM Compliance Filing.

Gas Safety Performance – Annual Report

Within 60 days of the end of each calendar year, each Company shall file with the Secretary to the Commission a report on gas safety performance for the prior calendar year period. With respect to leak prone main projects, these reports will include material type, mileage, project location, rank of the segments addressed at the time of replacement, removal or retirement in place (e.g., due to NPA solution) using the risk-based model, project cost, and a forecast of the scheduled leak prone main removal projects and their rank on the risk-based model for the upcoming calendar year. The report will also include a reconciliation of proposed versus actual leak prone mains.

As part of their annual gas safety performance compliance filings, the Companies will file with the Secretary to the Commission information regarding their First Responder Training efforts, including the dates and times of the drills, who was in attendance, what topics were reviewed, and any applicable recommendations.

Non-Wires Alternatives – Quarterly Reports

The Companies will file quarterly reports showing: (1) NWA project expenditures and all relevant details with respect to project costs; (2) a description of the NWA project activities; (3) anticipated project in-service dates; (4) NWA cost and incentive recoveries; and (5) identification of operational savings or other benefits. The quarterly reports shall be filed in Cases 19-E-0378 and 19-E-0380 60 days after the close of each calendar quarter.

March

Capital Expenditure Reporting – Annual Variance Reports

As discussed in Section XXVIII(B) of the Joint Proposal, the Companies will file with the Secretary to the Commission, with a copy to Staff, an annual report which will provide a variance between actuals to Appendix R at the close of the year due on March 15 of the following year. The report will include an explanation for removing or revising capital projects currently listed in Appendix R or adding new capital projects to those listed in Appendix R. Upon request, the Companies will meet with Staff to review this annual capital expenditure report.

Electric Distribution Vegetation Management – Quarterly Expenditure Reports

The Companies will report to the Secretary to the Commission on a quarterly basis (i.e., by March 15th, June 15th, September 15th and December 15th of each year) the prior quarter's distribution vegetation management expenditures. The report will include, broken down by month and contractor: the number of miles trimmed; circuit names, numbers, voltage, phase, and locations; danger tree program expenditures; and reclamation program expenditures (NYSEG only). The report will also specify the number of danger trees identified and removed, the species of each danger tree, and the circuit where the danger tree was located.

Electric Reliability

By March 15th of each year, each Company shall file with the Secretary to the Commission a report on electric reliability for the prior calendar year period. In the first Reliability Report to be provided on March 15, 2021, the Companies will list Level II deficiencies discovered during calendar year 2019. The list will identify the date the deficiency was discovered and the date of its repair.

Rate Adjustment Mechanism ("RAM") Compliance Filing

For each Business, NYSEG and RG&E shall each measure the deferred regulatory asset and liability balances for the items specified as Type-2 Other RAM Eligible Deferrals and Costs (listed in Appendix Q) as of December 31 for each year. The RAM for each Business shall be identified in each Company's respective RAM Compliance Filings submitted on March 31 of each year and shall be implemented in rates on July 1 of each year for collection over the 12 months from July 1 to June 30. The RAM Compliance Filings will include proposed RAM rates by service classification. Concurrent with the submission of the RAM Compliance Filings, the Companies will provide to Staff and parties to these rate proceedings the Companies' workpapers underlying the calculation of the RAM.

Within 30 calendar days of filing the RAM Compliance Filings, the Companies will convene an informational meeting either in person or via teleconference of all interested parties to these proceedings to review the Companies' calculation of the RAM for each Business.

Customer Service – Quarterly Walk-In Office Reports

The Companies will provide quarterly reporting of customer usage of open offices, number of individual customer appointments requested (individually reported for appointments with a Customer Service employee and for those at New York State Department of Social Services offices), number of appointments made and other relevant information.

Low Income Programs – Quarterly Reports

The Companies will provide quarterly reports on a number of low income program-related topics utilizing the existing template and methodology, in accordance with Commission-approved directives as part of Case 14-M-0565. The Companies will provide quarterly reports to the Secretary on the following Low Income Program components:

a) Number of customers enrolled in the Bill Reduction program;
b) Number of customers enrolled in the Arrears Forgiveness program;
c) Total amount held in arrears for the program;
d) Average amount in arrears;
e) Aggregate amounts of low income bill discounts;
f) Aggregate amount of arrears forgiven; and
g) Number of customers who have defaulted off the program.

Same-Day Reconnection Report – Quarterly Report

The Companies will file a report on same-day reconnections for each calendar quarter ("Reconnection Reporting Period"). Each report will be filed with the Secretary to the Commission with copies by electronic mail to interested parties within 30 days after the end of each Reconnection Reporting Period.

Credit Card Transaction Report – Quarterly Report

The Companies will report to the Secretary, on a quarterly basis, the monthly totals as well as monthly total dollar amounts of credit card transactions.

Electronic Deferred Payment Agreement Report – Quarterly Report

The Companies will file reports to the Secretary detailing: a comparison of e-DPAs and conventional DPAs by type; total dollar amount of all e-DPAs; number of e-DPAs created; number of active e-DPAs; number of e-DPAs completed; number of canceled e-DPAs; and a summary of any customer inquiries and complaints regarding the program that the Companies have received.

April

Capital Expenditure Reporting – Quarterly Variance Reports

As discussed in Section XXVIII(B) of the Joint Proposal, the Companies will file with the Secretary to the Commission, with a copy to Staff, a quarterly report which will provide a variance report between actual and forecasted expenditures, including project changes, which will be due the last day of the month following the calendar quarter (i.e., Quarter 1 due April 30, Quarter 2 due July 31, Quarter 3 due October 31, and Quarter 4 due January 30) for each such project that experiences a plus or minus 10% cost variation.

Capital Expenditure Reporting – Five-Year Plan Report

As discussed in Section XXVIII(B) of the Joint Proposal, the Companies will file a Five-Year Plan Report which will include the projected five-year capital plan and budget with descriptions of the projects. The report will be due on April 1. The Companies will continue to file with the Secretary to the Commission on an annual basis their respective five year projected capital plans and budgets.

Natural Gas Matters – Quarterly Report

The Companies agree to provide quarterly reports (on a calendar quarter basis) starting with the first full calendar quarter following approval of the Joint Proposal to measure progress on the objectives set forth in Paragraph 1 of Appendix M. These reports will be provided within thirty (30) days after the end of each calendar quarter and will include volumes of actual billed gas use, and volumes of billed gas use normalized for temperature. The reports will identify monthly billed use by sector (residential, commercial and industrial) for each Company, and will track natural gas customer counts and include net change in natural gas customers by month and will also report billed gas use and customer counts associated with the DeRuyter pipeline. To the extent the information is available, on a monthly basis, the reports will also track customer use of heat pump and building efficiency incentives by replaced fuel type as applicable (new construction or oil, natural gas, propane, etc.), as well as BTU's of energy saved with heat pump and building efficiency incentives by replaced fuel type as applicable. For reference, the first issuance of these reports shall also provide data for 2019.

May

Earnings Adjustment Mechanisms – Quarterly Compliance Filing

The Companies will file with the Secretary to the Commission, quarterly reports no later than 60 days after the end of each calendar quarter to describe the Companies' progress toward each EAM's metric's targets, the actions taken by the Companies to achieve target performance, and a forecast of whether the Companies expect to meet annual EAM targets.

The Companies will track and report the progress of three EAM Scorecard metrics: Locational System Relief Value Load Factor; Residential Electric Energy Intensity; and Commercial Electric Energy Intensity. The Companies shall report progress on each of its Scorecard metrics as part of its annual EAM Compliance Filing.

Non-Wires Alternatives – Quarterly Reports

The Companies will file quarterly reports showing: (1) NWA project expenditures and all relevant details with respect to project costs; (2) a description of the NWA project activities; (3) anticipated project in-service dates; (4) NWA cost and incentive recoveries; and (5) identification of operational savings or other benefits. The quarterly reports shall be filed in Cases 19-E-0378 and 19-E-0380 60 days after the close of each calendar quarter.

June

Electric Distribution Vegetation Management – Quarterly Expenditure Reports

The Companies will report to the Secretary to the Commission on a quarterly basis (i.e., by March 15th, June 15th, September 15th and December 15th of each year) the prior quarter's distribution vegetation management expenditures. The report will include, broken down by month and contractor: the number of miles trimmed; circuit names, numbers, voltage, phase, and locations; danger tree program expenditures; and reclamation program expenditures (NYSEG only). The report will also specify the number of danger trees identified and removed, the species of each danger tree, and the circuit where the danger tree was located.

Customer Service – Quarterly Walk-In Office Reports

The Companies will provide quarterly reporting of customer usage of open offices, number of individual customer appointments requested (individually reported for appointments with a Customer Service employee and for those at New York State Department of Social Services offices), number of appointments made and other relevant information.

Low Income Programs – Quarterly Reports

The Companies will provide quarterly reports on a number of low income program-related topics utilizing the existing template and methodology, in accordance with Commission-approved directives as part of Case 14-M-0565. The Companies will provide quarterly reports to the Secretary on the following Low Income Program components:

a) Number of customers enrolled in the Bill Reduction program;
b) Number of customers enrolled in the Arrears Forgiveness program;
c) Total amount held in arrears for the program;
d) Average amount in arrears;
e) Aggregate amounts of low income bill discounts;
f) Aggregate amount of arrears forgiven; and
g) Number of customers who have defaulted off the program.

Same-Day Reconnection Report – Quarterly Report

The Companies will file a report on same-day reconnections for each calendar quarter ("Reconnection Reporting Period"). Each report will be filed with the Secretary to the Commission with copies by electronic mail to interested parties within 30 days after the end of each Reconnection Reporting Period.

Credit Card Transaction Report – Quarterly Report

The Companies will report to the Secretary, on a quarterly basis, the monthly totals as well as monthly total dollar amounts of credit card transactions.

Electronic Deferred Payment Agreement Report – Quarterly Report

The Companies will file reports to the Secretary detailing: a comparison of e-DPAs and conventional DPAs by type; total dollar amount of all e-DPAs; number of e-DPAs created; number of active e-DPAs; number of e-DPAs completed; number of canceled e-DPAs; and a summary of any customer inquiries and complaints regarding the program that the Companies have received.

<u>July</u>

Annual Earning Sharing Mechanism Compliance Filings

Regulatory earning calculations will be performed on an annual basis in the same manner as set forth in Appendix G, starting with the twelve months ended April 30, 2021. The Companies shall compute and submit to the Secretary to the Commission the ROE for each Business for the preceding Rate Year within 90 days following the end of each such Rate Year.

Capital Expenditure Reporting – Quarterly Variance Reports

As discussed in Section XXVIII(B) of the Joint Proposal, the Companies will file with the Secretary to the Commission, with a copy to Staff, a quarterly report which will provide a variance report between actual and forecasted expenditures, including project changes, which will be due the last day of the month following the calendar quarter (i.e., Quarter 1 due April 30, Quarter 2 due July 31, Quarter 3 due October 31, and Quarter 4 due January 30) for each such project that experiences a plus or minus 10% cost variation.

Earnings Adjustment Mechanisms – Annual Compliance Filing

On July 31, 2021, 2022, and 2023, NYSEG and RG&E will each make a compliance filing to the Commission showing the calculation of incentives earned under each EAM for the Rate Year preceding the filing. Within 30 calendar days of filing the EAM Compliance Filing, the Companies will convene an informational meeting either in person or via teleconference of all interested parties to these proceedings to review the Companies' calculation of the EAM for each Business.

The Companies will track and report the progress of three Scorecard metrics: Locational System Relief Value Load Factor, Residential Electric Energy Intensity, and Commercial Electric Energy Intensity. The Companies shall report progress on each of its Scorecard metrics as part of its annual EAM Compliance Filing. To facilitate possible development of new EAMs for proposal in a future rate proceeding, the Companies will track for a scorecard load factors at various LSRV areas on their respective distribution systems. The Companies will also track Energy Intensity Data for a scorecard.

Natural Gas Matters – Quarterly Report

The Companies agree to provide quarterly reports (on a calendar quarter basis) starting with the first full calendar quarter following approval of the Joint Proposal to measure progress on the objectives set forth in Paragraph 1 of Appendix M. These reports will be provided within thirty (30) days after the end of each calendar quarter and will include volumes of actual billed gas use, and volumes of billed gas use normalized for temperature. The reports will identify monthly billed use by sector (residential, commercial and industrial) for each Company, and will track natural gas customer counts and include net change in natural gas customers by month and will also report billed gas use and customer counts associated with the DeRuyter pipeline. To the extent the information is available, on a monthly basis, the reports will also track customer use of heat pump and building efficiency incentives by replaced fuel type as applicable (new construction or oil, natural gas, propane, etc.), as well as BTU's of energy saved with heat pump and building efficiency incentives by replaced fuel type as applicable. For reference, the first issuance of these reports shall also provide data for 2019.

Rate Adjustment Mechanism Tariff Statements

Annually, NYSEG and RG&E will submit RAM tariff statements effective on July 1.

Revenue Decoupling Mechanism Surcharge / Credit Rates

The Companies will file the service class or subclass specific RDM surcharge / credit rates with the Commission on not less than 30 days' notice, to be effective August 1 of each year. Each service class- or subclass-specific RDM surcharge / credit will be identified on a tariff statement.

August

Earnings Adjustment Mechanism – Quarterly Compliance Filing

The Companies will file with the Secretary to the Commission quarterly reports no later than 60 days after the end of each calendar quarter to describe the Companies' progress toward each EAM's metric's targets, the actions taken by the Companies to achieve target performance, and a forecast of whether the Companies expect to meet annual EAM targets.

The Companies will track and report the progress of three EAM Scorecard metrics: Locational System Relief Value Load Factor; Residential Electric Energy Intensity; and Commercial Electric Energy Intensity. The Companies shall report progress on each of its Scorecard metrics as part of its annual EAM Compliance Filing.

Non-Wires Alternatives – Quarterly Reports

The Companies also will file quarterly reports showing: (1) NWA project expenditures and all relevant details with respect to project costs; (2) a description of the NWA project activities; (3) anticipated project in-service dates; (4) NWA cost and incentive recoveries; and (5) identification of operational savings or other benefits. The quarterly reports shall be filed in Cases 19-E-0378 and 19-E-0380 60 days after the close of each calendar quarter.

September

Electric Distribution Vegetation Management – Quarterly Expenditure Reports

The Companies will report to the Secretary to the Commission on a quarterly basis (i.e., by March 15th, June 15th, September 15th and December 15th of each year) the prior quarter's distribution vegetation management expenditures. The report will include, broken down by month and contractor: the number of miles trimmed; circuit names, numbers, voltage, phase, and locations; danger tree program expenditures; and reclamation program expenditures (NYSEG only). The report will also specify the number of danger trees identified and removed, the species of each danger tree, and the circuit where the danger tree was located.

Customer Service – Quarterly Walk-In Office Reports

The Companies will provide quarterly reporting of customer usage of open offices, number of individual customer appointments requested (individually reported for appointments with a Customer Service employee and for those at New York State Department of Social Services offices), number of appointments made and other relevant information.

Low Income Programs – Quarterly Reports

The Companies will provide quarterly reports on a number of low income program-related topics utilizing the existing template and methodology, in accordance with Commission-approved directives as part of Case 14-M-0565. The Companies will provide quarterly reports to the Secretary on the following Low Income Program components:

a) Number of customers enrolled in the Bill Reduction program;
b) Number of customers enrolled in the Arrears Forgiveness program;
c) Total amount held in arrears for the program;
d) Average amount in arrears;
e) Aggregate amounts of low income bill discounts;
f) Aggregate amount of arrears forgiven; and
g) Number of customers who have defaulted off the program.

Same-Day Reconnection Report – Quarterly Report

The Companies will file a report on same-day reconnections for each calendar quarter ("Reconnection Reporting Period"). Each report will be filed with the Secretary to the Commission with copies by electronic mail to interested parties within 30 days after the end of each Reconnection Reporting Period.

Credit Card Transaction Report – Quarterly Report

The Companies will report to the Secretary, on a quarterly basis, the monthly totals as well as monthly total dollar amounts of credit card transactions.

Electronic Deferred Payment Agreement Report – Quarterly Report

The Companies will file reports to the Secretary detailing: a comparison of e-DPAs and conventional DPAs by type; total dollar amount of all e-DPAs; number of e-DPAs created; number of active e-DPAs; number of e-DPAs completed; number of canceled e-DPAs; and a summary of any customer inquiries and complaints regarding the program that the Companies have received.

October

Capital Expenditure Reporting – Quarterly Variance Reports

As discussed in Section XXVIII(B) of the Joint Proposal, the Companies will file with the Secretary to the Commission, with a copy to Staff, a quarterly report which will provide a variance report between actual and forecasted expenditures, including project changes, which will be due the last day of the month following the calendar quarter (i.e., Quarter 1 due April 30, Quarter 2 due July 31, Quarter 3 due October 31, and Quarter 4 due January 30) for each such project that experiences a plus or minus 10% cost variation.

Natural Gas Matters – Quarterly Report

The Companies agree to provide quarterly reports (on a calendar quarter basis) starting with the first full calendar quarter following approval of the Joint Proposal to measure progress on the objectives set forth in Paragraph 1 of Appendix M. These reports will be provided within thirty (30) days after the end of each calendar quarter and will include volumes of actual billed gas use, and volumes of billed gas use normalized for temperature. The reports will identify monthly billed use by sector (residential, commercial and industrial) for each Company, and will track natural gas customer counts and include net change in natural gas customers by month and will also report billed gas use and customer counts associated with the DeRuyter pipeline. To the extent the information is available, on a monthly basis, the reports will also track customer use of heat pump and building efficiency incentives by replaced fuel type as applicable (new construction or oil, natural gas, propane, etc.), as well as BTU's of energy saved with heat pump and building efficiency incentives by replaced fuel type as applicable. For reference, the first issuance of these reports shall also provide data for 2019.

<u>November</u>

Earnings Adjustment Mechanism – Quarterly Compliance Filing

The Companies will file with the Secretary to the Commission, quarterly reports no later than 60 days after the end of each calendar quarter to describe the Companies' progress toward each EAM's metric's targets, the actions taken by the Companies to achieve target performance, and a forecast of whether the Companies expect to meet annual EAM targets.

The Companies will track and report the progress of three EAM Scorecard metrics: Locational System Relief Value Load Factor; Residential Electric Energy Intensity; and Commercial Electric Energy Intensity. The Companies shall report progress on each of its Scorecard metrics as part of its annual EAM Compliance Filing.

Non-Wires Alternatives – Quarterly Reports

The Companies will file quarterly reports showing: (1) NWA project expenditures and all relevant details with respect to project costs; (2) a description of the NWA project activities; (3) anticipated project in-service dates; (4) NWA cost and incentive recoveries; and (5) identification of operational savings or other benefits. The quarterly reports shall be filed in Cases 19-E-0378 and 19-E-0380 60 days after the close of each calendar quarter.

December

Electric Distribution Vegetation Management – Quarterly Expenditure Reports

The Companies will report to the Secretary to the Commission on a quarterly basis (i.e., by March 15th, June 15th, September 15th and December 15th of each year) the prior quarter's distribution vegetation management expenditures. The report will include, broken down by month and contractor: the number of miles trimmed; circuit names, numbers, voltage, phase, and locations; danger tree program expenditures; and reclamation program expenditures (NYSEG only). The report will also specify the number of danger trees identified and removed, the species of each danger tree, and the circuit where the danger tree was located.

Customer Service – Quarterly Walk-In Office Reports

The Companies will provide quarterly reporting of customer usage of open offices, number of individual customer appointments requested (individually reported for appointments with a Customer Service employee and for those at New York State Department of Social Services offices), number of appointments made and other relevant information.

Low Income Programs – Quarterly Reports

The Companies will provide quarterly reports on a number of low income program-related topics utilizing the existing template and methodology, in accordance with Commission-approved directives as part of Case 14-M-0565. The Companies will provide quarterly reports to the Secretary on the following Low Income Program components:

a) Number of customers enrolled in the Bill Reduction program;
b) Number of customers enrolled in the Arrears Forgiveness program;
c) Total amount held in arrears for the program;
d) Average amount in arrears;
e) Aggregate amounts of low income bill discounts;
f) Aggregate amount of arrears forgiven; and
g) Number of customers who have defaulted off the program.

Same-Day Reconnection Report – Quarterly Report

The Companies will file a report on same-day reconnections for each calendar quarter ("Reconnection Reporting Period"). Each report will be filed with the Secretary to the Commission with copies by electronic mail to interested parties within 30 days after the end of each Reconnection Reporting Period.

Credit Card Transaction Report – Quarterly Report

The Companies will report to the Secretary, on a quarterly basis, the monthly totals as well as monthly total dollar amounts of credit card transactions.

Electronic Deferred Payment Agreement Report – Quarterly Report

The Companies will file reports to the Secretary detailing: a comparison of e-DPAs and conventional DPAs by type; total dollar amount of all e-DPAs; number of e-DPAs created; number of active e-DPAs; number of e-DPAs completed; number of canceled e-DPAs; and a summary of any customer inquiries and complaints regarding the program that the Companies have received.

Third Party Payment Agent Fees – Annual Report

The Companies will file an annual report to the Secretary evaluating expenditures related to the transaction fees associated with the elimination of Third Part Payment Agent Fees. The annual report will include the quantity of payments processed, fee cost, and dollar of total payments processed.

Other

Customer Service COVID-19 Assistance Outreach Plan

In order to notify customers of potential assistance available to help with their utility bill, the Companies will perform additional outreach as discussed in Section IV of the Proposal. The Companies agree to file an updated Outreach Plan within 60 days of the Commission's issuance of an order approving the Proposal in these proceedings.

Smart Cities Technologies

NYSEG and RG&E will revise their tariff to accommodate unmetered service for Smart City technologies with known and predictable usage, and in conformance with the Companies' pole attachment requirements.

Renewables Integration Study

As discussed in Appendix F, the Companies plan to complete a Renewables Integration Study within one year following a Commission order approving the Joint Proposal. The proposed and final scope of this study will be shared with interested parties to these rate cases, and the completed study shall be filed at the Commission to be noticed and subject to comments.

Gas Safety – Residential Methane Detection ("RMD") Program

Within 120 days of the Commission's issuance of a final order in these proceedings, the Companies will file with the Secretary to the Commission an implementation plan for their RMD Program, which will include deployment strategies, specific RMD units to be utilized and associated costs.

Major Storm Events or Pre-Staging Events

After each Major Storm event or Pre-Staging event which results in costs charged to the Major Storm Reserve, the Companies shall submit a report with supporting documentation to Staff within 120 days of such Major Storm or Pre-Staging event. The Companies may update the report within 90 days of providing the initial report on the event, to provide any updates to cost or other information. For each Major Storm or Pre-Staging event, the Companies' report shall provide certain information as set forth in Appendix H.

Special Studies

The Companies will conduct the following studies during the term of the Rate Plan as discussed in Appendix N:

1) Senior Customer Study for Customer Service;
2) Natural Gas System Resiliency Study;
3) Renewable Natural Gas Study;
4) Geothermal – District Energy Study;
5) Overall Natural Gas and Grid Modernization Report;
6) Depreciation Study Reflecting the Climate Leadership and Community Protection Act ("CLCPA"); and
7) Street Light Replacement Cost Study.

To the extent the Commission institutes a statewide proceeding or initiative to study any of the subjects covered by the above-identified studies, NYSEG or RG&E will not necessarily prepare or provide a separate report or study. The Companies will continue to produce their own report or study for any items not included in a statewide study or initiative.

The Companies will provide interested parties with the proposed scope of the above-identified studies in advance of NYSEG or RG&E performing any such study. Interested parties to these rate proceedings, including NYSERDA and Staff, will be provided the opportunity to provide input to the scope of each study in sufficient time in advance of the Companies performing any study. Additional information concerning the anticipated scope of certain studies is provided below. The Companies will provide the results of each study to interested parties to these rate proceedings and Staff upon completion of a study by NYSEG or RG&E, and in some cases, will file the study results with the Secretary of the Commission as noted in Appendix N.

Non-Wires Alternatives ("NWAs") Implementation Plan and Benefit Cost Analysis

The Companies will submit a detailed implementation plan and Benefit Cost Analysis ("BCA") for each NWA project once there is reasonable certainty as to the costs of the NWA project portfolio. Annual implementation plans will be filed by January 31 of each year. If the number of MWs or the length of deferral is modified, the Companies shall also file an updated BCA, as appropriate.

Non-Wires Alternative Incentive Compliance Filing

To establish the Initial Incentive, the Companies shall make a compliance filing in Case 19-E-0378 (NYSEG) or 19-E-0380 (RG&E). Prior to making its compliance filing to set the Initial Incentive, the Companies shall seek input from Department of Public Service Staff. Should additional MWs be needed to achieve the initially proposed deferral of a traditional infrastructure project, or to increase the duration of the deferral, the Company will make a compliance filing in Case 19-E-0378 (NYSEG) or Case 19-E-0380 (RG&E) and seek incremental MW procurements accordingly.

Electronic Deferred Payment Agreements

The Companies will file, within three months of the issuance of a final Commission order in these rate case proceedings, a plan to implement an electronic deferred payment agreement process for residential customers.

Overall Natural Gas and Grid Modernization Report

Within eighteen months of a Commission Order approving the Joint Proposal in these rate cases, the Companies will prepare a report that evaluates how the Companies' businesses may evolve in the decades ahead and which identifies the potential issues and strategies related to reducing natural gas usage and increasing electricity usage as an alternative and the modernization and expansion of the electric grid needed to support the widespread deployment of renewables and beneficial electrification. The report shall be developed in light of the renewable energy and greenhouse gas reductions goals set forth by the CLCPA.

The report shall provide a meaningful analysis of the scale, timing, and costs of achieving significant, quantifiable reductions in gas use, grid improvements necessary to achieve various levels of renewables deployment and beneficial electrification, and potential financing mechanisms. Interested parties, to the rate case proceeding shall be invited to provide input to the scope of the study.

Natural Gas Marketing

No later than twelve months from receiving a Commission Order adopting the Joint Proposal, the Companies will modify their websites, customer mailings, emails, and marketing material to remove promotion of natural gas. Modifications shall include replacement of the "convert to gas" link with a link that describes programs and incentives available to customers for opportunities to reduce gas use or consider alternate forms of energy consumption and as soon as can be achieved, discontinuation of the use of the phrase "heat smart" in connection with the promotion of natural gas use. The Companies will also provide information about NYSERDA sponsored on-bill financing when providing information about energy efficiency programs and heat pumps.

The Companies commit to develop programs that better inform and encourage customers to consult with organizations such as HeatSmart to make more informed energy choices. The Companies will meet during RY1 with NYSERDA and its HeatSmart partners within the Companies' service territories to discuss advancement of heat pumps and building efficiency efforts.

Gas Interruptible Rates

NYSEG and RG&E will revise their tariff to accommodate unmetered service for Smart City technologies with known and predictable usage, and in conformance with the Companies' pole attachment requirements.

Natural Gas Tariffs

The Companies will modify their natural gas tariffs to provide only the required allowances for mains, service lines and appurtenant facilities (the 100-foot rule) consistent with 16 NYCRR Part 230.

Non-Pipeline Alternative Benefit Cost Analysis

The Companies agree to work with Staff and interested parties to develop a BCA Handbook for NPAs consistent with the Commission's Order Establishing the Benefit Cost Analysis Framework issued on January 21, 2016 in Case 14-M-0101 which will be submitted as a report to the Secretary to the Commission in these proceedings within six months of the Commission's approval of the Joint Proposal. This effort will be coordinated with the Department of Public Service Staff in cooperation with interested parties. The BCA Handbook for NPAs will be subsequently updated subject to the requirements of the CLCPA.

Walk-In Office Closure Customer Outreach Implementation Plan

NYSEG and RG&E shall provide a customer outreach implementation plan to Staff and interested parties to these proceedings a minimum of two months prior to the closure of each walk-in office identified in Appendix P. In the event NYSEG or RG&E proposes to close any additional walk-in office(s), the applicable Company must first file a petition with the Commission and obtain Commission approval for such office closure.

Preferential Reallocation of Natural Gas in Lansing Moratorium Area

The Companies, within six months of the approval of the Joint Proposal, will submit a petition to the Commission regarding the potential preferential reallocation of natural gas made available in the Lansing Moratorium area. This reallocation would be to commercial and industrial customers for reasons of economic development.

Non-Pipeline Alternative Cost Allocation Surcharge Filing

If an NPA project will benefit only certain classes of customers, the cost allocation will be limited to the benefitted classes. Once allocated to each service class, these costs would be recovered through a separate surcharge, which will be filed with the Commission and posted to the appropriate Company's website, indicating that portion of the surcharge represented by the recovery of NPA incentives.

Inside Service Lines Procedure

The Companies agree to work with Staff to submit a procedure within 120 days of the Commission's issuance of a final order in these proceedings by which they will automatically apply a provision to customers whose buildings cannot be accessed for inspection.

Attachment 2

Attachment 2

NYSEG - Electric	RY 1 - 5/1/20 - 4/30/21			RY 2 - 5/1/21 - 4/30/22			RY 3 - 5/1/22 - 4/30/23		
	Present Rates	Change	Proposed Rates	Present Rates	Change	Proposed Rates	Present Rates	Change	Proposed Rates
Delivery Revenues Before Increase	752,198	45,684	797,882	796,698	84,771	881,469	894,201	88,565	982,766
Total Estimated Supply Revenue (Company Supplied and ESCO Supplied)	736,372	-	736,372	736,372	-	736,372	736,372	-	736,372
Other Revenues	74,060	264	74,324	74,653	573	75,226	75,533	341	75,874
Commodity-Related Misc.	(2,994)	-	(2,994)	(2,994)	-	(2,994)	(2,994)	-	(2,994)
RAM Surcharge (July 1 - June 30)	19,300	-	19,300	19,300	(14,708)	4,592	4,592	(2,942)	1,650
EE collections	13,648	(13,648)	-	-	-	-	-	-	-
Total	1,592,585		1,624,884	1,624,029		1,694,665	1,707,704		1,793,668
Overall %			2.03%			4.35%			5.03%

NYSEG - Gas	RY 1 - 5/1/20 - 4/30/21			RY 2 - 5/1/21 - 4/30/22			RY 3 - 5/1/22 - 4/30/23		
	Present Rates	Change	Proposed Rates	Present Rates	Change	Proposed Rates	Present Rates	Change	Proposed Rates
Delivery Revenues Before Increase	205,359	(514)	204,845	195,760	3,351	199,111	210,208	5,269	215,477
Total Estimated Supply Revenue (Company Supplied and ESCO Supplied)	234,751	-	234,751	234,751	-	234,751	234,751	-	234,751
Other Revenues	3,587	(71)	3,516	3,549	93	3,642	3,662	99	3,761
Commodity-Related Misc.									
RAM Surcharge	-	-	-	-	1,375	1,375	1,375	275	1,650
EE collections	1,187	(1,187)	-	-	-	-	-	-	-
Total	444,884		443,112	434,060		438,879	449,996		455,639
Overall %			-0.40%			1.11%			1.25%

RG&E - Electric	RY 1 - 5/1/20 - 4/30/21			RY 2 - 5/1/21 - 4/30/22			RY 3 - 5/1/22 - 4/30/23		
	Present Rates	Change	Proposed Rates	Present Rates	Change	Proposed Rates	Present Rates	Change	Proposed Rates
Delivery Revenues Before Increase	446,030	15,237	461,267	442,223	28,064	470,287	494,304	30,721	525,025
Total Estimated Supply Revenue (Company Supplied and ESCO Supplied)	323,500	-	323,500	323,500	-	323,500	323,500	-	323,500
Other Revenues	6,985	(16)	6,969	7,060	256	7,316	7,329	182	7,511
Commodity-Related Misc.	(868)	-	(868)	(868)	-	(868)	(868)	-	(868)
RAM Surcharge	1,900	(1,900)	-	-	1,125	1,125	1,125	225	1,350
EE collections	7,194	(7,194)	-	-	-	-	-	-	-
Total	784,741		790,868	771,915		801,360	825,390		856,518
Overall %			0.78%			3.81%			3.77%

RG&E - Gas	RY 1 - 5/1/20 - 4/30/21			RY 2 - 5/1/21 - 4/30/22			RY 3 - 5/1/22 - 4/30/23		
	Present Rates	Change	Proposed Rates	Present Rates	Change	Proposed Rates	Present Rates	Change	Proposed Rates
Delivery Revenues Before Increase	178,886	(1,127)	177,759	169,026	859	169,885	179,985	3,865	183,850
Total Estimated Supply Revenue (Company Supplied and ESCO Supplied)	244,899	-	244,899	244,899	-	244,899	244,899	-	244,899
Other Revenues	2,806	(98)	2,708	2,739	123	2,862	2,881	177	3,058
Commodity-Related Misc.									
RAM Surcharge	-	-	-	-	1,125	1,125	1,125	225	1,350
EE collections	1,443	(1,443)	-	-	-	-	-	-	-
Total	428,035		425,366	416,664		418,771	428,890		433,157
Overall %			-0.62%			0.51%			0.99%

Attachment 3

Case 19-E-0378, et al.
Joint Proposal

Revised Appendix A

NYSEG and RG&E
Rate Increase (Decrease) Summary
($000)

		A	B	C	D	E	F
		Rate Increase (Decrease) Summary					
		Without Rate Levelization / Shaping			**With Rate Levelization / Shaping**		
		Rate Year 1 TME 4/30/21	Rate Year 2 TME 4/30/22	Rate Year 3 TME 4/30/23	Rate Year 1 TME 4/30/21	Rate Year 2 TME 4/30/22	Rate Year 3 TME 4/30/23
	Rate Increase (Decrease) - with EE						
1	NYSEG Electric	$ 28,298	$ 77,679	$ 23,813	$ 45,298	$ 45,640	$ 36,007
2	NYSEG Gas	(10,675)	14,150	15,052	(514)	3,350	5,269
3	RG&E Electric	(3,965)	44,768	32,261	21,352	13,898	15,828
4	RG&E Gas	(10,943)	10,441	15,125	(1,127)	859	3,866
5	**Total**	$ 2,714	$ 147,038	$ 86,251	$ 65,008	$ 63,747	$ 60,970
	Rate Increase (Decrease) - without EE						
6	NYSEG Electric	$ 17,294	$ 77,679	$ 23,813	$ 34,294	45,640	36,007
7	NYSEG Gas	(10,161)	12,376	13,121	-	1,576	3,338
8	RG&E Electric	(8,503)	44,768	32,261	16,814	13,898	15,828
9	RG&E Gas	(9,816)	9,582	13,642	-	-	2,383
10	**Total**	$ (11,186)	$ 144,405	$ 82,838	$ 51,108	$ 61,114	$ 57,557
	Delivery Rate Increase (Decrease) with EE						
11	NYSEG Electric	3.8%	10.0%	2.8%	6.0%	5.9%	4.2%
12	NYSEG Gas	(5.2%)	7.2%	7.2%	(0.3%)	1.7%	2.5%
13	RG&E Electric	-0.9%	10.1%	6.6%	4.8%	3.1%	3.3%
14	RG&E Gas	(6.1%)	6.2%	8.4%	(0.6%)	0.5%	2.1%
	Delivery Rate Increase (Decrease) without EE						
15	NYSEG Electric	2.3%	10.1%	2.8%	4.6%	5.9%	4.3%
16	NYSEG Gas	(4.9%)	6.3%	6.3%	0.0%	0.8%	1.6%
17	RG&E Electric	(1.9%)	10.2%	6.7%	3.8%	3.2%	3.3%
18	RG&E Gas	(5.5%)	5.6%	7.6%	0.0%	0.0%	1.3%
	Overall Rate Increase (Decrease) without EE						
19	NYSEG Electric	1.2%	5.2%	1.5%	2.3%	3.0%	2.3%
20	NYSEG Gas	(2.3%)	2.9%	3.0%	0.0%	0.4%	0.8%
21	RG&E Electric	(1.1%)	5.9%	4.0%	2.2%	1.8%	2.0%
22	RG&E Gas	(2.3%)	2.3%	3.2%	0.0%	0.0%	0.6%

NYSEG Electric
Rate Change Levelization Worksheet - without Energy Efficiency
($000)

		A	B	C	D
		Rate Year 1 TME 4/30/21	Rate Year 2 TME 4/30/22	Rate Year 3 TME 4/30/23	Total
	Pre-Levelization Information				
1	Delivery Rate Increase without EE [1]	$ 17,294	$ 77,679	$ 23,813	
2	Delivery Revenues Before Increase without EE [2]	752,198	768,308	844,289	
3	Pre-Levelization Rate Increase % without EE	2.3%	10.1%	2.8%	
	Rate Change Levelization Calculation				
4	Delivery Rate Increase - Total	$ 17,294	$ 77,679	$ 23,813	
5	Period Levelization Deferral	17,000	(32,039)	12,194	
6	Delivery Rate Increase - Post Levelization	$ 34,294	$ 45,640	$ 36,007	
7	Delivery Revenues Before Increase without EE	752,198	768,308	844,289	
8	Post-Levelization Rate Increase % - Delivery without EE	4.6%	5.9%	4.3%	
	Carrying Costs Calculation				
9	Starting Levelization Deferral	-	(17,383)	(2,785)	
10	Levelization Deferral	(17,000)	15,039	2,845	
11	Accrued Carrying Costs	(383)	(440)	(60)	
12	Ending Levelization Deferral	(17,383)	(2,785)	0	
13	Average Levelization Deferral	(8,500)	(9,864)	(1,362)	
14	x 1 - Effective Tax Rate	73.9%	73.9%	73.9%	
15	Post-Tax Levelization Deferral	(6,279)	(7,286)	(1,006)	
16	Post-Tax WACC	6.10%	6.04%	6.00%	
17	Accrued Carrying Costs	(383)	(440)	(60)	$ (884)
	Verification				
18	Pre-Levelization Cumulative Delivery Rate Increase	$ 51,881	$ 155,358	$ 23,813	$ 231,051
19	Post-Levelization Cumulative Delivery Rate Increase	102,881	91,280	36,007	230,167
20	Less: Carrying Costs (from line 17)				(884)
21	Total - Cross Check				$ 231,051

	Post-Tax WACC	LTD	Customer Dep	Equity	Total
	Rate Year 1 Calculation				
22	Weight	51.61%	0.39%	48.00%	100.00%
23	Cost Rate	3.63%	0.90%	8.80%	
24	Percent	1.88%	0.00%	4.22%	6.10%
	Rate Year 2 Calculation				
25	Weight	51.67%	0.33%	48.00%	100.00%
26	Cost Rate	3.52%	0.90%	8.80%	
27	Percent	1.82%	0.00%	4.22%	6.04%
	Rate Year 3 Calculation				
28	Weight	51.71%	0.29%	48.00%	100.00%
29	Cost Rate	3.42%	0.90%	8.80%	
30	Percent	1.77%	0.00%	4.22%	6.00%

Notes:
1) Pre-Levelization Delivery Rate Increase without EE = Appendix A, Page 1, Line 6, Cols. A - C
2) Pre-Levelization Delivery Revenues Before Increase without EE = Appendix B, Schedule B, line 9 less:
  a) Rate year levelized rate increase amount;
  b) Prior year EE amount from Appendix B, Schedule C line 77 divided by retention factor of 0.98343

Case 19-E-0378, et al. **Revised Appendix A**
Joint Proposal

NYSEG Gas
Rate Change Shaping Worksheet - without Energy Efficiency
($000)

		A	B	C	D
		Rate Year 1 TME 4/30/21	Rate Year 2 TME 4/30/22	Rate Year 3 TME 4/30/23	Total
	Pre-Shaping Information				
1	Delivery Rate Increase without EE [1]	$ (10,161)	$ 12,376	$ 13,121	
2	Delivery Revenues Before Increase without EE [2]	205,359	196,330	208,998	
3	Pre-Shaping Rate Increase % without EE	(4.9%)	6.3%	6.3%	
	Rate Change Shaping Calculation				
4	Delivery Rate Increase - Total	$ (10,161)	$ 12,376	$ 13,121	
5	Period Shaping Deferral	10,161	(10,800)	(9,783)	
6	Delivery Rate Increase - Post Shaping	$ -	$ 1,576	$ 3,338	
7	Delivery Revenues Before Increase without EE	205,359	196,330	208,998	
8	Post-Shaping Rate Increase % - Delivery without EE	0.0%	0.8%	1.6%	
	Carrying Costs Calculation				
9	Starting Shaping Deferral	-	(10,390)	(10,201)	
10	Shaping Deferral	(10,161)	639	10,422	
11	Accrued Carrying Costs	(229)	(450)	(221)	
12	Ending Shaping Deferral	(10,390)	(10,201)	0	
13	Average Shaping Deferral	(5,081)	(10,071)	(4,990)	
14	x 1 - Effective Tax Rate	73.9%	73.9%	73.9%	
15	Post-Tax Shaping Deferral	(3,753)	(7,439)	(3,686)	
16	Post-Tax WACC	6.10%	6.04%	6.00%	
17	Accrued Carrying Costs	(229)	(450)	(221)	$ (900)
	Verification				
18	Pre-Shaping Cumulative Delivery Rate Increase	$ (30,483)	$ 24,752	$ 13,121	$ 7,390
19	Post-Shaping Cumulative Delivery Rate Increase	-	3,152	3,338	6,491
20	Less: Carrying Costs (from line 17)				(900)
21	Total - Cross Check				$ 7,390

	Post-Tax WACC	LTD	Customer Dep	Equity	Total
	Rate Year 1 Calculation				
22	Weight	51.61%	0.39%	48.00%	100.00%
23	Cost Rate	3.63%	0.90%	8.80%	
24	Percent	1.88%	0.00%	4.22%	6.10%
	Rate Year 2 Calculation				
25	Weight	51.67%	0.33%	48.00%	100.00%
26	Cost Rate	3.52%	0.90%	8.80%	
27	Percent	1.82%	0.00%	4.22%	6.04%
	Rate Year 3 Calculation				
28	Weight	51.71%	0.29%	48.00%	100.00%
29	Cost Rate	3.42%	0.90%	8.80%	
30	Percent	1.77%	0.00%	4.22%	6.00%

Notes:
1) Pre-Shaping Delivery Rate Increase without EE = Appendix A, Page 1, Line 7, Cols. A - C
2) Pre-Shaping Delivery Revenues Before Increase without EE = Appendix C, Schedule B, line 9 less:
  a) Rate year levelized rate increase amount;
  b) Prior year EE amount from Appendix C, Schedule C line 70 divided by retention factor of 0.98012

Case 19-E-0378, et al. **Revised Appendix A**
Joint Proposal

RG&E Electric
Rate Change Levelization Worksheet - without Energy Efficiency
($000)

		A	B	C	D
		Rate Year 1 TME 4/30/21	Rate Year 2 TME 4/30/22	Rate Year 3 TME 4/30/23	Total
	Pre-Levelization Information				
1	Delivery Rate Increase without EE [1]	$ (8,503)	$ 44,768	$ 32,261	
2	Delivery Revenues Before Increase without EE [2]	446,030	437,064	480,754	
3	Pre-Levelization Rate Increase % without EE	(1.9%)	10.2%	6.7%	
	Rate Change Levelization Calculation				
4	Delivery Rate Increase - Total	$ (8,503)	$ 44,768	$ 32,261	
5	Period Levelization Deferral	25,317	(30,870)	(16,433)	
6	Delivery Rate Increase - Post Levelization	$ 16,814	$ 13,898	$ 15,828	
7	Delivery Revenues Before Increase without EE	446,030	437,064	480,754	
8	Post-Levelization Rate Increase % - Delivery without EE	3.8%	3.2%	3.3%	
	Carrying Costs Calculation				
9	Starting Levelization Deferral	-	(25,936)	(21,492)	
10	Levelization Deferral	(25,317)	5,553	21,986	
11	Accrued Carrying Costs	(619)	(1,109)	(494)	
12	Ending Levelization Deferral	(25,936)	(21,492)	0	
13	Average Levelization Deferral	(12,659)	(23,159)	(10,499)	
14	x 1 - Effective Tax Rate	73.9%	73.9%	73.9%	
15	Post-Tax Levelization Deferral	(9,350)	(17,107)	(7,755)	
16	Post-Tax WACC	6.62%	6.48%	6.37%	
17	Accrued Carrying Costs	(619)	(1,109)	(494)	$ (2,222)
	Verification				
18	Pre-Levelization Cumulative Delivery Rate Increase	$ (25,508)	$ 89,536	$ 32,261	$ 96,289
19	Post-Levelization Cumulative Delivery Rate Increase	50,443	27,796	15,828	$ 94,067
20	Less: Carrying Costs (from line 17)				(2,222)
21	Total - Cross Check				$ 96,289

	Post-Tax WACC	LTD	Customer Dep	Equity	Total
	Rate Year 1 Calculation				
22	Weight	51.79%	0.21%	48.00%	100.00%
23	Cost Rate	4.62%	0.90%	8.80%	
24	Percent	2.39%	0.00%	4.22%	6.62%
	Rate Year 2 Calculation				
25	Weight	51.82%	0.18%	48.00%	100.00%
26	Cost Rate	4.35%	0.90%	8.80%	
27	Percent	2.26%	0.00%	4.22%	6.48%
	Rate Year 3 Calculation				
28	Weight	51.84%	0.16%	48.00%	100.00%
29	Cost Rate	4.14%	0.90%	8.80%	
30	Percent	2.15%	0.00%	4.22%	6.37%

Notes:
1) Pre-Levelization Delivery Rate Increase without EE = Appendix A, Page 1, Line 8, Cols. A - C
2) Pre-Levelization Delivery Revenues Before Increase without EE = Appendix D, Schedule B, line 10 less:
  a) Rate year levelized rate increase amount;
  b) Prior year EE amount from Appendix D, Schedule C line 76 divided by retention factor of 0.97841

Case 19-E-0378, et al. **Revised Appendix A**
Joint Proposal

RG&E Gas
Rate Change Shaping Worksheet - without Energy Efficiency
($000)

		A	B	C	D
		Rate Year 1 TME 4/30/21	Rate Year 2 TME 4/30/22	Rate Year 3 TME 4/30/23	Total
	Pre-Shaping Information				
1	Delivery Rate Increase without EE [1]	$ (9,816)	$ 9,582	$ 13,642	
2	Delivery Revenues Before Increase without EE [2]	178,886	170,230	180,253	
3	Pre-Shaping Rate Increase % without EE	(5.5%)	5.6%	7.6%	
	Rate Change Shaping Calculation				
4	Delivery Rate Increase - Total	$ (9,816)	$ 9,582	$ 13,642	
5	Period Shaping Deferral	9,816	(9,582)	(11,259)	
6	Delivery Rate Increase - Post Shaping	$ -	$ -	$ 2,383	
7	Delivery Revenues Before Increase without EE	178,886	170,230	180,253	
8	Post-Shaping Rate Increase % - Delivery without EE	0.0%	0.0%	1.3%	
	Carrying Costs Calculation				
9	Starting Shaping Deferral	-	(10,056)	(10,777)	
10	Shaping Deferral	(9,816)	(234)	11,025	
11	Accrued Carrying Costs	(240)	(487)	(248)	
12	Ending Shaping Deferral	(10,056)	(10,777)	0	
13	Average Shaping Deferral	(4,908)	(10,173)	(5,265)	
14	x 1 - Effective Tax Rate	73.9%	73.9%	73.9%	
15	Post-Tax Shaping Deferral	(3,625)	(7,514)	(3,889)	
16	Post-Tax WACC	6.62%	6.48%	6.37%	
17	Accrued Carrying Costs	(240)	(487)	(248)	$ (975)
	Verification				
18	Pre-Shaping Cumulative Delivery Rate Increase	$ (29,448)	$ 19,164	$ 13,642	$ 3,358
19	Post-Shaping Cumulative Delivery Rate Increase	-	-	2,383	2,383
20	Less: Carrying Costs (from line 17)				(975)
21	Total - Cross Check				$ 3,358

	Post-Tax WACC	LTD	Customer Dep	Equity	Total
	Rate Year 1 Calculation				
22	Weight	51.79%	0.21%	48.00%	100.00%
23	Cost Rate	4.62%	0.90%	8.80%	
24	Percent	2.39%	0.00%	4.22%	6.62%
	Rate Year 2 Calculation				
25	Weight	51.82%	0.18%	48.00%	100.00%
26	Cost Rate	4.35%	0.90%	8.80%	
27	Percent	2.26%	0.00%	4.22%	6.48%
	Rate Year 3 Calculation				
28	Weight	51.84%	0.16%	48.00%	100.00%
29	Cost Rate	4.14%	0.90%	8.80%	
30	Percent	2.15%	0.00%	4.22%	6.37%

Notes:
1) Pre-Shaping Delivery Rate Increase without EE = Appendix A, Page 1, Line 9, Cols. A - C
2) Pre-Shaping Delivery Revenues Before Increase without EE = Appendix E, Schedule B, line 9 less:
  a) Rate year levelized rate increase amount;
  b) Prior year EE amount from Appendix E, Schedule C line 67 divided by retention factor of 0.9695

Attachment 4

New York State Electric & Gas Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023

Case 19-E-0378, et al. **Revised Appendix B**
Joint Proposal **Schedule A**

New York State Electric & Gas Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Rate of Return Statement
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
	Operating Revenues			
1	Sales Revenue	$ 752,198	$ 779,312	$ 855,293
2	Impact of Rate Increase	45,298	45,640	36,007
3	Late Payments	4,626	5,152	5,318
4	Total Retail Revenue	802,122	830,104	896,619
5	Other Revenue	150,395	171,327	159,967
6	**Total Revenue**	952,517	1,001,430	1,056,586
7	Gross Revenue Taxes	11,097	12,339	12,736
8	Net Revenue	941,421	989,091	1,043,849
9	O&M Expenses	509,790	527,696	538,054
10	Depreciation & Amortizations	132,620	141,719	157,695
11	Taxes Other Than Income Taxes	113,053	114,762	116,831
12	**Total Operating Expenses**	755,463	784,177	812,580
13	**Operating Income Before Income Taxes**	185,957	204,914	231,269
14	Income Taxes	36,959	41,006	46,524
15	**Operating Income Available for Return**	$ 148,998	$ 163,907	$ 184,745
16	**Rate Base**	$ 2,441,222	$ 2,712,038	$ 3,081,203
17	**Rate of Return**	6.10%	6.04%	6.00%
18	**Return on Equity**	8.80%	8.80%	8.80%
	Calculation of Return on Equity			
19	Operating Income Available for Return	$ 148,998	$ 163,907	$ 184,745
20	Less: Interest Expense	(45,881)	(49,351)	(54,595)
21	**Balance for Common**	103,117	114,556	130,150
22	Rate Base	2,441,222	2,712,038	3,081,203
23	Common Equity Percentage	48%	48%	48%
24	**Equity Component of Rate Base**	1,171,787	1,301,778	1,478,977
25	Balance for Common	103,117	114,556	130,150
26	Equity Component of Rate Base	1,171,787	1,301,778	1,478,977
27	**Return on Equity**	8.80%	8.80%	8.80%
	Revenue Requirement Value of 1bp ROE			
28	Net Income Attributable to 1bp of ROE (line 24 x 1bp)	$ 117	$ 130	$ 148
29	/ Retention Factor including FIT/SIT	72.64%	72.64%	72.64%
30	**Revenue Requirement Value of 1bp ROE**	$ 161	$ 179	$ 204

New York State Electric & Gas Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Revenue
($000)

			A	B	C
			Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
		Sales Revenue			
1		Gross Base Delivery	$ 646,045	$ 674,070	$ 750,443
2		Plus: Rate Increase	45,298	45,640	36,007
3		BIPP Charges	8,211	8,229	8,251
4		Net Base Delivery Charges	699,554	727,938	794,701
5	a	Clean Energy Fund	68,091	66,401	64,581
6		Dynamic Load Management Surcharge	4,556	4,791	5,026
7		MFC/POR - Credit/Coll/Call Ctr/Admin	14,600	14,600	14,600
8		Gross Revenue Tax	10,694	11,221	12,391
9		**Total Sales Revenue**	$ 797,496	$ 824,952	$ 891,300
10		Late Payments	4,626	5,152	5,318
		Other Revenue			
11		Other Sales Income	1,068	1,068	1,068
12		Company Use Delivery	1,420	1,450	1,480
13		Damage and Third Party Payments	7,385	7,540	7,698
14		Rent Revenue	5,778	5,899	6,023
15		Wholesale Transmission Revenue	49,165	49,165	49,165
16		SIR Adjustment	4,816	4,816	4,816
17		Connect / Disconnect & Other	157	157	157
18		COVID-19 - General Inflation Adjustment (lines 12-14)	(192)	(246)	(281)
19		**Total**	$ 69,597	$ 69,849	$ 70,127
		Deferrals & Amortizations			
20		Excess Depreciation Reserve Amortization	30,850	38,950	71,600
21		Excess DIT - TCJA - Protected Amortization	7,728	7,380	7,325
22		Excess DIT - TCJA - Protected Pre-RY1 Liability	16,678	-	-
23		Excess DIT - TCJA - Unprotected Amortization	21,803	21,803	21,803
24		Federal Tax Reform - Jan-Sep 2018 Savings Amortization	19,433	-	-
25		Rate Increase Levelization Deferral	(17,000)	32,039	(12,194)
26		Rate Increase Levelization Amortization	1,305	1,305	1,305
27		**Total**	$ 80,798	$ 101,478	$ 89,840
28		**Total Other Revenues + Deferrals & Amortizations**	$ 150,395	$ 171,327	$ 159,967
29		**Total**	**$ 952,517**	**$ 1,001,430**	**$ 1,056,586**

Case 19-E-0378, et al. **Revised Appendix B**
Joint Proposal **Schedule C**

New York State Electric & Gas Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Operation & Maintenance Expense
($000)

			A	B	C
			Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
		O&M Expenses			
1	b	Labor / Payroll	$ 113,630	$ 121,821	$ 128,702
2		Variable Compensation	1,516	1,626	1,717
3		401K	4,057	4,377	4,692
4		Productivity	(2,422)	(3,086)	(3,229)
5		Medical Benefits	11,550	12,468	13,022
6		Other Employee Benefits	2,156	2,201	2,247
7		Electric Reliability Organization - NERC	391	413	436
8	c	Uncollectibles	6,779	7,293	7,484
9		Insurance	2,148	2,193	2,239
10		Workers Comp	2,306	2,354	2,404
11		Injury / Damages	1,955	1,996	2,038
12		ASC Costs	55,319	56,481	57,667
13		Outside Services	46,833	46,029	41,974
14		Legal / Regulatory Expense	2,265	2,296	2,327
15		Vehicle Depreciation	5,667	6,421	7,025
16		Security	676	690	705
17	d	Storm - Major	25,582	25,582	25,582
18		Storm - Minor	3,800	3,800	3,800
19	e	Low Income Program	14,408	14,408	14,408
20	f	Credit & Debit Card Fees	2,040	2,773	3,251
21		CS Enhancements	550	513	527
22		Stray Voltage	1,785	1,823	1,861
23	g	Vegetation Management - Distribution	30,000	30,000	30,000
24		Vegetation Management - Transmission	6,395	6,529	6,666
25		AMI - Incremental O&M	-	1,506	4,019
26		AMI - Incremental O&M Savings	-	-	(428)
27		Occupancy/Overhead costs	7,801	7,965	8,133
28	h	EE Tracker	12,578	12,578	12,578
29	h	EE Heat Pumps	6,137	6,137	6,137
30		NWA General Costs	170	170	170
31		New Studies	192	-	-
32		All Other O&M General Inflator Items	29,574	31,362	32,021
33	i	Pension	17,854	17,854	17,854
34	j	OPEBs	(1,646)	(223)	20
35	k	Economic Development	5,052	5,052	5,052
36	l	Environmental Remediation	15,000	15,000	15,000
37	m	Incremental Maintenance	616	1,460	1,033
38	n	Management / Operations / Staffing Audit	22	22	22
39	o	NEIL Credits	(352)	(352)	(352)
40	p	REV Incremental Costs	2,730	2,975	3,486
41	q	COVID-19 Pandemic Adjustment	-	-	-
42		COVID-19 - General Inflation Adj. (lines 6, 9-13, 16, 22, 24, 27, & 32)	(1,818)	(2,334)	(2,660)
43		**Total Delivery O&M Expense**	$ 433,297	$ 450,172	$ 459,630
		Surcharge Expenses			
44	a	Clean Energy Fund (CEF)	$ 68,091	$ 66,401	$ 64,581
45		**Total Surcharges**	$ 68,091	$ 66,401	$ 64,581
46		**Amortizations - Refer to Schedule H for Detailed Information**	$ 8,402	$ 11,123	$ 13,843
47		**Total O&M Plus Surcharges & Amortizations**	**$ 509,790**	**$ 527,696**	**$ 538,054**

Case 19-E-0378, et al. **Revised Appendix B**
Joint Proposal **Schedule C**

New York State Electric & Gas Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Operation & Maintenance Expense
($000)

			A	B	C
			Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
		Amount in Rates			
48	b	Labor	$ 113,630	$ 121,821	$ 128,702
49	c	Uncollectibles	6,779	7,293	7,484
50	d	Storm - Major	25,582	25,582	25,582
51	e	Low Income Program	14,408	14,408	14,408
52	f	Credit & Debit Card Fees	2,040	2,773	3,251
53	g	Vegetation Management - Distribution	30,000	30,000	30,000
54	i	Pension	17,854	17,854	17,854
55	j	OPEBs	(1,646)	(223)	20
56	k	Economic Development	5,052	5,052	5,052
57	l	Environmental Remediation	15,000	15,000	15,000
58	m	Incremental Maintenance	616	1,460	1,033
59	n	Management / Operations / Staffing Audit	22	22	22
60	o	NEIL Credit	(352)	(352)	(352)
61	p	REV	2,730	2,975	3,486
62	q	COVID-19 Pandemic Adjustment	-	-	-
63		Total	$ 231,715	$ 243,664	$ 251,542
		Low Income Program Summary			
64		Bill Reduction	$ 13,252	$ 13,252	$ 13,252
65		Arrearage Forgiveness	1,157	1,157	1,157
66	e	Total Low Income Program	$ 14,408	$ 14,408	$ 14,408
		Economic Development Reconciliation			
67	k	Total Economic Development Program	$ 5,052	$ 5,052	$ 5,052
68	k	Rate Discounts	$ -	$ -	$ -
69	k	Economic Development Deferral	-	-	-
		Non-Rate discounts:			
70	k	Economic Development - O&M	5,052	5,052	5,052
71		Total Rate and Non-Rate Discounts	$ 5,052	$ 5,052	$ 5,052
		CEF Reconciliation			
		Revenue			
72	a	Clean Energy Fund	$ 68,091	$ 66,401	$ 64,581
		Expense			
73	a	Clean Energy Fund	$ 68,091	$ 66,401	$ 64,581
		Energy Efficiency - Base Delivery			
		O&M Expense			
74	h	EE Tracker	$ 12,578	$ 12,578	$ 12,578
75	h	EE Heat Pumps	6,137	6,137	6,137
76		EE Regulatory Amorts (refer to Schedule H)	(7,893)	(7,893)	(7,893)
77		Total Energy Efficiency - Base Delivery	$ 10,822	$ 10,822	$ 10,822

Case 19-E-0378, et al. **Revised Appendix B**
Joint Proposal **Schedule D**

New York State Electric & Gas Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Depreciation & Amortizations
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
1	**Depreciation Expense**	**$ 132,620**	**$ 141,719**	**$ 157,695**

Case 19-E-0378, et al. **Revised Appendix B**
Joint Proposal **Schedule E**

New York State Electric & Gas Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Operating Taxes
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
	Gross Revenue Taxes			
1	Total Retail Revenue	$ 797,496	$ 824,952	$ 891,300
2	Average GRT Rate	1.39%	1.50%	1.43%
3	Total Gross Revenue Tax	$ 11,097	$ 12,339	$ 12,736
	Other Operating Taxes			
4	Property Taxes	$ 100,367	$ 101,680	$ 103,010
5	Payroll Taxes	12,685	13,083	13,822
6	Total Other Operating Taxes	$ 113,053	$ 114,762	$ 116,831
7	**Total**	**$ 124,149**	**$ 127,102**	**$ 129,567**

Case 19-E-0378, et al. **Revised Appendix B**
Joint Proposal **Schedule F**

New York State Electric & Gas Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Income Taxes
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
1	Operating Income Before Income Taxes	$ 185,957	$ 204,914	$ 231,269
2	Interest Expense	(45,881)	(49,351)	(54,595)
3	Book Income Before Income Taxes (Adjusted for Tax Items)	140,076	155,563	176,674
4	Federal Income Taxes @ 21.000%	29,416	32,668	37,101
5	State Taxes @ 6.500%	9,105	10,112	11,484
6	Fed Benefit of State Tax Deduction @ 1.365%	(1,912)	(2,123)	(2,412)
7	Total Federal & State @ Statutory Rates	36,609	40,656	46,174
	Permanent Differences			
8	Meals and Entertainment	350	350	350
9	Subtotal: Permanent Differences	350	350	350
10	**Delivery Income Taxes (Lines 7 & 9)**	**$ 36,959**	**$ 41,006**	**$ 46,524**

New York State Electric & Gas Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Capital Structure Summary Schedule
($000)

		A	B	C	D	E
		Weight	**Cost Rate**	**Percent**	**Tax Gross-up**	**Before Tax**
	Rate Year 1					
1	Long Term Debt	51.61%	3.63%	1.88%		1.88%
2	Customer Deposits	0.39%	0.90%	0.00%		0.00%
3	Total Debt	52.00%		1.88%		1.88%
4	Common Equity	48.00%	8.80%	4.22%	1.49%	5.72%
5	Total	100.00%		6.10%		7.60%
	Rate Year 2					
6	Long Term Debt	51.67%	3.52%	1.82%		1.82%
7	Customer Deposits	0.33%	0.90%	0.00%		0.00%
8	Total Debt	52.00%		1.82%		1.82%
9	Common Equity	48.00%	8.80%	4.22%	1.49%	5.72%
10	Total	100.00%		6.04%		7.54%
	Rate Year 3					
11	Long Term Debt	51.71%	3.42%	1.77%		1.77%
12	Customer Deposits	0.29%	0.90%	0.00%		0.00%
13	Total Debt	52.00%		1.77%		1.77%
14	Common Equity	48.00%	8.80%	4.22%	1.49%	5.72%
15	Total	100.00%		6.00%		7.49%

	Interest Expense	**Rate Year 1**	**Rate Year 2**	**Rate Year 3**
16	Rate Base	$ 2,441,222	$ 2,712,038	$ 3,081,203
17	Weighted Cost of Debt	1.88%	1.82%	1.77%
18	Interest Expense	$ 45,881	$ 49,351	$ 54,595

New York State Electric & Gas Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Regulatory Amortizations
($000)

		A	B	C	D	E
		Starting Rate Year Asset / (Liab) Balance	Amortization Period (years)	Inc / (Exp) Rate Year 1 Amortization 4/30/2021	Inc / (Exp) Rate Year 2 Amortization 4/30/2022	Inc / (Exp) Rate Year 3 Amortization 4/30/2023
	3-Year Term Amortizations					
1	2018 Windstorm Settlement - Case 19-E-0105	$ (9,000)	3	$ 3,000	$ 3,000	$ 3,000
2	2019 Order - Case 19-E-0302	(2,500)	3	833	833	833
3	NRA - SAIFI	(7,000)	3	2,333	2,333	2,333
4	ACF ASGA - JP Stip 56	(1,300)	3	433	433	433
5	ASGA	2,185	3	(728)	(728)	(728)
6	Bonus Depreciation NCR	(8,485)	3	2,828	2,828	2,828
7	CAIDI/SAIFI Study	19	3	(6)	(6)	(6)
8	CapEx Customer Credit 07-M-0906 Merger Order	(1,473)	3	491	491	491
9	CapEx Shareholder Deferral	2,272	3	(757)	(757)	(757)
10	Cost to Achieve Efficiency Initiatives	139	3	(46)	(46)	(46)
11	Def Inc Tax Deferral - Book Depr Rate Change	(1,067)	3	356	356	356
12	Economic Development - Remaining Amort (15-E-0283 Appx. V)	1,612	3	(537)	(537)	(537)
13	Economic Development - New Amortization	(4,766)	3	1,589	1,589	1,589
14	EEPS	(108)	3	36	36	36
15	EE Tracker	(23,571)	3	7,857	7,857	7,857
16	ESM	(2,622)	3	874	874	874
17	Excess DIT - New York State Tax Rate change	73	3	(24)	(24)	(24)
18	Medicare Subsidy NCR	(1,802)	3	601	601	601
19	MHP Meter Costs	2	3	(1)	(1)	(1)
20	Mixed Use 263(a) NCR	(6,187)	3	2,062	2,062	2,062
21	NYPA Ancillaries	6	3	(2)	(2)	(2)
22	PBA Utilization	(2,958)	3	986	986	986
23	Stray Voltage	(4,967)	3	1,656	1,656	1,656
24	Theoretical Reserve Inc Tax Flow Through	(6,291)	3	2,097	2,097	2,097
25	Unit of Property CTA	21	3	(7)	(7)	(7)
26	Post Term Amortization Deferral - 2010 Joint Proposal	3,915	3	(1,305)	(1,305)	(1,305)
27	**Subtotal**	**$ (73,853)**		**$ 24,618**	**$ 24,618**	**$ 24,618**
	Other Than 3-Year Amortizations					
28	Credit & Debit Card Fees	$ 4,257	5	$ (851)	$ (851)	$ (851)
29	Environmental - Remaining Amort (15-E-0283 Appx. V)	(11,112)	7	1,587	1,587	1,587
30	Environmental - New Amortization	5,519	7	(788)	(788)	(788)
31	Fixed Rate Debt	(27,510)	5	5,502	5,502	5,502
32	Incremental Maintenance	(2,560)	5	512	512	512
33	Low Income Program - Remaining Amort (15-E-0283 Appx. V)	(1,221)	5	244	244	244
34	Low Income Program - New Amortization	1,547	5	(309)	(309)	(309)
35	Management Audit - Remaining Amort (15-E-0283 Appx. V)	(25)	5	5	5	5
36	Management Audit - New Amortization	835	5	(167)	(167)	(167)
37	NEIL Credit	(600)	5	120	120	120
38	NRA - CAIDI	(3,722)	5	744	744	744
39	NY Transco	(2,745)	5	549	549	549
40	OPEB Deferral - Remaining Amort (15-E-0283 Appx. V)	(12,170)	5	2,434	2,434	2,434
41	OPEB Deferral - New Amortization	(7,597)	5	1,519	1,519	1,519
42	Pension Deferral - Remaining Amort (15-E-0283 Appx. V)	19,262	5	(3,852)	(3,852)	(3,852)
43	Pension Deferral - New Amortization	40,153	5	(8,031)	(8,031)	(8,031)
44	Pole Attachment Revenue Requirement	4,374	5	(875)	(875)	(875)
45	PRA - Terminations & Uncollectibles	778	5	(156)	(156)	(156)
46	Property Tax Deferral - Remaining Amort (15-E-0283 Appx. V)	8,469	5	(1,694)	(1,694)	(1,694)
47	Property Tax Deferral - New Amortization	(15,024)	5	3,005	3,005	3,005
48	PSC Assessment	(263)	5	53	53	53
49	Rate Increase Levelization (reflected in Revenue)	(6,526)	5	1,305	1,305	1,305
50	REV Incremental Costs	10,490	5	(2,098)	(2,098)	(2,098)
51	Reliability Support Services	(13)	5	3	3	3
52	Storm - Non-Superstorm - Remaining Amort (15-E-0283 Appx. V)	32,986	5	(6,597)	(6,597)	(6,597)
53	Storm - Non-Superstorm - New Amortization	119,194	10	(11,919)	(11,919)	(11,919)
54	Storm - Superstorm	74,754	10	(7,475)	(7,475)	(7,475)
55	Variable Rate Debt - Remaining Amort (15-E-0283 Appx. V)	(2,371)	5	474	474	474
56	Variable Rate Debt - New Amortization	(2,950)	5	590	590	590
57	Vegetation Management - Danger Tree Deferral $10M per year beginning in RY1		10	(1,000)	(2,000)	(3,000)
58	Vegetation Management - Reclamation Deferral $17.2M per year beginning in RY1		10	(1,720)	(3,441)	(5,161)
59	**Subtotal**	**$ 226,211**		**$ (28,887)**	**$ (31,608)**	**$ (34,328)**
	Income Tax Related Amortizations					
60	Excess DIT - TCJA - Protected Amortization (reflected in Revenue)	$ (296,621)	ARAM	$ 7,728	$ 7,380	$ 7,325
61	Excess DIT - TCJA - Protected Pre-RY1 Liability (reflected in Revenue)	(16,678)	1	16,678	-	-
62	Excess DIT - TCJA - Unprotected Amortization (reflected in Revenue)	(65,409)	3	21,803	21,803	21,803
63	Federal Tax Reform - Jan-Sep 2018 Savings Amortization (reflected in Revenue)	(19,433)	1	19,433	-	-
64	PowerTax Regulatory Asset	82,038	23	(3,567)	(3,567)	(3,567)
65	Unfunded Future Income Taxes	(36,274)	46	789	789	789
66	Unfunded Future Income Taxes - NCR	243	5	(49)	(49)	(49)
67	**Subtotal**	**$ (352,134)**		**$ 62,815**	**$ 26,356**	**$ 26,301**
68	**Total - NYSEG Electric**	**$ (199,776)**		**$ 58,546**	**$ 19,366**	**$ 16,591**

New York State Electric & Gas Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Rate Base
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
	Rate Base			
1	Utility Plant	$ 5,284,213	$ 5,597,667	$ 6,010,163
2	Depreciation Reserve	(2,320,976)	(2,387,571)	(2,451,123)
3	Materials & Supplies	13,142	13,418	13,699
4	Prepayments	40,397	41,245	42,111
5	O&M Working Capital per the FERC Formula	61,826	63,660	64,591
6	Non-Int Bearing Cust Advances	(28,133)	(28,133)	(28,133)
7	Deferred Debits & Credits	(135,212)	(93,663)	(46,693)
8	Deferred Income Taxes	(450,678)	(471,633)	(500,865)
9	Deferred Investment Tax Credit	(12,129)	(11,725)	(11,321)
10	Total Before Earnings Base-Capitalization Adjustment	$ 2,452,450	$ 2,723,265	$ 3,092,430
11	Earnings Base-Capitalization Adjustment	(11,227)	(11,227)	(11,227)
12	**Total**	**$ 2,441,222**	**$ 2,712,038**	**$ 3,081,203**

Case 19-E-0378, et al. **Revised Appendix B**
Joint Proposal **Schedule J**

New York State Electric & Gas Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Deferred Debits and Credits -Average Balances
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
	Regulatory Assets & Liabilities:			
1	2019 Order - Case 19-E-0302	$ (2,083)	$ (1,250)	$ (417)
2	NRA - SAIFI	(5,833)	(3,500)	(1,167)
3	2018 Windstorm Settlement - Case 19-E-0105	(7,500)	(4,500)	(1,500)
4	Credit & Debit Card Fees	3,831	2,980	2,128
5	Economic Development - Remaining Amort (15-E-0283 Appx. V)	1,343	806	269
6	Economic Development - New Amortization	(3,972)	(2,383)	(794)
7	EEPS	(90)	(54)	(18)
8	EE Tracker	(19,642)	(11,785)	(3,928)
9	Environmental - Remaining Amort (15-E-0283 Appx. V)	(10,318)	(8,731)	(7,143)
10	Environmental - New Amortization	5,125	4,336	3,548
11	Fixed Rate Debt	(24,759)	(19,257)	(13,755)
12	Incremental Maintenance	(2,304)	(1,792)	(1,280)
13	Low Income Program - Remaining Amort (15-E-0283 Appx. V)	(1,099)	(855)	(610)
14	Low Income Program - New Amortization	1,392	1,083	774
15	Management Audit - Remaining Amort (15-E-0283 Appx. V)	(23)	(18)	(13)
16	Management Audit - New Amortization	751	584	417
17	NEIL Credit	(540)	(420)	(300)
18	MTA Surcharge	338	-	-
19	NRA - CAIDI	(3,350)	(2,605)	(1,861)
20	NY Transco	(2,471)	(1,922)	(1,373)
21	OPEB Deferral - Remaining Amort (15-E-0283 Appx. V)	(10,953)	(8,519)	(6,085)
22	OPEB Deferral - New Amortization	(6,837)	(5,318)	(3,799)
23	Pension Deferral - Remaining Amort (15-E-0283 Appx. V)	17,336	13,484	9,631
24	Pension Deferral - New Amortization	36,138	28,107	20,077
25	Pole Attachment Revenue Requirement	3,937	3,062	2,187
26	PRA - Terminations & Uncollectibles	700	545	389
27	Property Tax Deferral - Remaining Amort (15-E-0283 Appx. V)	7,623	5,929	4,235
28	Property Tax Deferral - New Amortization	(13,522)	(10,517)	(7,512)
29	PSC Assessment	(237)	(184)	(132)
30	Rate Increase Levelization	(5,874)	(4,568)	(3,263)
31	REV Incremental Costs	9,441	7,343	5,245
32	Reliability Support Services	(11)	(9)	(6)
33	Storm - Non-Superstorm - Remaining Amort (15-E-0283 Appx. V)	29,688	23,090	16,493
34	Storm - Non-Superstorm - New Amortization	113,234	101,315	89,396
35	Storm - Superstorm	71,017	63,541	56,066
36	Variable Rate Debt - Remaining Amort (15-E-0283 Appx. V)	(2,134)	(1,659)	(1,185)
37	Variable Rate Debt - New Amortization	(2,655)	(2,065)	(1,475)
38	Vegetation Management - Danger Tree Deferral	4,500	13,000	20,500
39	Vegetation Management - Reclamation Deferral	7,741	22,364	35,266
40	ACF ASGA - JP Stip 56	(1,083)	(650)	(217)
41	ASGA	1,821	1,093	364
42	Bonus Depreciation NCR	(7,071)	(4,242)	(1,414)
43	CAIDI/SAIFI Study	16	10	3
44	CapEx Customer Credit 07-M-0906 Merger Order	(1,228)	(737)	(246)
45	CapEx Shareholder Deferral	1,894	1,136	379
46	Cost to Achieve Efficiency Initiatives	116	69	23
47	Def Inc Tax Deferral - Book Depr Rate Change	(889)	(534)	(178)
48	ESM	(2,185)	(1,311)	(437)
49	Excess DIT - New York State Tax Rate change	61	37	12
50	Medicare Subsidy NCR	(1,501)	(901)	(300)
51	MHP Meter Costs	2	1	0

New York State Electric & Gas Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Deferred Debits and Credits -Average Balances
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
52	Mixed Use 263(a) NCR	(5,156)	(3,093)	(1,031)
53	NYPA Ancillaries	5	3	1
54	PBA Utilization	(2,465)	(1,479)	(493)
55	Stray Voltage	(4,139)	(2,483)	(828)
56	Theoretical Reserve Inc Tax Flow Through	(5,242)	(3,145)	(1,048)
57	Unit of Property CTA	17	10	3
58	Post Term Amortization Deferral - 2010 Joint Proposal	3,262	1,957	652
59	Excess DIT - TCJA - Protected Amortization	(292,757)	(285,203)	(277,850)
60	Excess DIT - TCJA - Protected Pre-RY1 Liability	(8,339)	-	-
61	Excess DIT - TCJA - Unprotected Amortization	(54,507)	(32,704)	(10,901)
62	Federal Tax Reform - Jan-Sep 2018 Savings Amortization	(9,717)	-	-
63	PowerTax Regulatory Asset	80,255	76,688	73,121
64	Unfunded Future Income Taxes	(35,880)	(35,091)	(34,302)
65	Unfunded Future Income Taxes - NCR	219	170	122
66	Subtotal	$ (156,563)	$ (90,742)	$ (45,561)
	Other Deferred Assets & Liabilities:			
67	Accrued Pension	$ 87,938	$ 59,007	$ 56,889
68	Accident & Sickness Reserve	-	-	-
69	Commodity Hedge Margin	-	-	-
70	Gain / Loss on Reacquired Debt	12,661	12,661	12,661
71	Injuries & Damages Reserve	(9,406)	(9,406)	(9,406)
72	Marcy South	-	-	-
73	NBWC True-up	-	-	-
74	OPEB Reserve	(72,024)	(67,365)	(63,459)
75	Preliminary Engineering	6,155	6,155	6,155
76	PSC Assessment	(252)	(252)	(252)
77	Purchase of Receivables	107	107	107
78	RDM	-	-	-
79	SFAS-112	(3,833)	(3,833)	(3,833)
80	Workman's Comp Reserve	-	-	-
81	All Other	6	6	6
82	Subtotal	$ 21,351	$ (2,920)	$ (1,132)
83	**Grand Total**	**$ (135,212)**	**$ (93,663)**	**$ (46,693)**

Attachment 5

Rochester Gas and Electric Corporation

Electric Department

Revenue Requirement for Forecast Years Ending April 30, 2021, 2022, 2023

Case 19-E-0378, et al. **Revised Appendix D**
Joint Proposal **Schedule A**

Rochester Gas and Electric Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Rate of Return Statement
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
	Operating Revenues			
1	Sales Revenue	$ 446,030	$ 441,602	$ 485,291
2	Impact of Rate Increase	21,352	13,898	15,828
3	Late Payments	2,188	2,423	2,512
4	Total Retail Revenue	469,570	457,923	503,631
5	Other Revenue	(4,921)	49,183	32,591
6	**Total Revenue**	464,649	507,106	536,222
7	Gross Revenue Taxes	6,535	7,340	7,880
8	Net Revenue	458,113	499,766	528,342
9	O&M Expenses	169,605	174,732	175,777
10	Depreciation & Amortizations	74,181	82,604	92,053
11	Taxes Other Than Income Taxes	92,399	97,268	102,478
12	**Total Operating Expenses**	336,186	354,604	370,308
13	**Operating Income Before Income Taxes**	121,928	145,162	158,035
14	Income Taxes	22,601	27,336	30,166
15	**Operating Income Available for Return**	$ 99,327	$ 117,826	$ 127,868
16	**Rate Base**	$ 1,500,901	$ 1,817,758	$ 2,007,118
17	**Rate of Return**	6.62%	6.48%	6.37%
18	**Return on Equity**	8.80%	8.80%	8.80%
	Calculation of Return on Equity			
19	Operating Income Available for Return	$ 99,327	$ 117,826	$ 127,868
20	Less: Interest Expense	(35,929)	(41,044)	(43,088)
21	**Balance for Common**	63,398	76,782	84,781
22	Rate Base	1,500,901	1,817,758	2,007,118
23	Common Equity Percentage	48%	48%	48%
24	**Equity Component of Rate Base**	720,432	872,524	963,417
25	Balance for Common	63,398	76,782	84,781
26	Equity Component of Rate Base	720,432	872,524	963,417
27	**Return on Equity**	8.80%	8.80%	8.80%
	Revenue Requirement Value of 1bp ROE			
28	Net income Attributable to 1bp of ROE (line 24 x 1bp)	$ 72	$ 87	$ 96
29	/ Retention Factor including FIT/SIT	72.27%	72.27%	72.27%
30	**Revenue Requirement Value of 1bp ROE**	$ 100	$ 121	$ 133

Rochester Gas and Electric Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Operation & Maintenance Expense
($000)

			A	B	C
			Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
		O&M Expenses			
1	c	Labor / Payroll	$ 39,404	$ 41,319	$ 42,730
2		Variable Compensation	1,183	1,240	1,282
3		401K	1,802	2,003	2,194
4		Productivity	(884)	(1,101)	(1,130)
5		Medical Benefits	3,428	3,548	3,649
6		Other Employee Benefits	658	672	686
7	r	Uncollectibles	5,435	5,863	6,239
8		Insurance	975	995	1,016
9		Workers Comp	1,264	1,291	1,318
10		Injury / Damages	406	414	423
11		ASC Costs	23,190	23,677	24,174
12		Outside Services	18,762	18,800	18,476
13		Legal / Regulatory Expense	1,634	1,657	1,680
14		Vehicle Depreciation	1,857	1,958	2,061
15	p	Storm - Major	3,400	3,400	3,400
16		Storm - Minor	1,000	1,000	1,000
17	f	Vegetation Management - Distribution	8,270	8,443	8,621
18		Vegetation Management - Transmission	2,176	2,222	2,269
19		Security	1,067	1,089	1,112
20	n	Low Income Program	11,837	11,837	11,837
21	o	Credit & Debit Card Fees	884	1,121	1,345
22		CS Enhancements	191	166	166
23		Stray Voltage	1,043	1,065	1,087
24		Electric Reliability Organization _NERC	147	156	167
25		AMI - Incremental O&M	-	647	1,616
26		AMI - Incremental O&M Savings	-	-	(350)
27		Occupancy/Overhead costs	4,448	4,541	4,637
28	k	EE Tracker	8,546	8,546	8,546
29	k	EE Heat Pumps	786	786	786
30		NWA General Costs	100	100	100
31		New Studies	176	-	-
32		All Other O&M General Inflator Items	10,262	11,369	11,607
33	d	Pension	5,805	5,805	5,805
34	e	OPEBs	990	1,068	838
35	a	Economic Development	7,000	7,000	7,000
36	l	Environmental Remediation	988	988	988
37	j	Incremental Maintenance	2,087	5,298	5,875
38	g	Management / Operations / Staffing Audit	21	21	21
39	q	NEIL Credits	(3,613)	(3,688)	(3,766)
40	h	REV Incremental Costs	1,341	1,321	1,580
41	i	COVID-19 Pandemic Adjustment	-	-	-
42		COVID-19 - General Inflation Adj. (lines 6, 8-12, 18, 19, 23, 27, 32, & 39)	(716)	(919)	(1,048)
43		**Total Delivery O&M Expense**	$ 167,350	$ 175,718	$ 180,039
		Surcharge Expense			
44	b	Clean Energy Fund (CEF)	$ 36,980	$ 35,880	$ 34,697
45		**Total Surcharges**	$ 36,980	$ 35,880	$ 34,697
46		**Amortizations - Refer to Schedule H for Detailed Information**	$ (34,724)	$ (36,867)	$ (38,959)
47		**Total O&M Plus Surcharges & Amortizations**	**$ 169,605**	**$ 174,732**	**$ 175,777**

Rochester Gas and Electric Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Operation & Maintenance Expense
($000)

			A	B	C
			Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
		Amount in Rates			
48	c	Labor / Payroll	$ 39,404	$ 41,319	$ 42,730
49	d	Pension	5,805	5,805	5,805
50	e	OPEBs	990	1,068	838
51	f	Vegetation Management	8,270	8,443	8,621
52	g	Management Audit	21	21	21
53	h	REV	1,341	1,321	1,580
54	i	COVID-19 Pandemic Adjustment	-	-	-
55	j	Incremental Maintenance	2,087	5,298	5,875
56	l	Environmental Remediation	988	988	988
57	a	Economic Development	7,024	7,000	7,000
58	n	Low Income Program	11,837	11,837	11,837
59	o	Credit & Debit Card Fee Deferral	884	1,121	1,345
60	p	Storm - Major	3,400	3,400	3,400
61	q	NEIL Credit	(3,613)	(3,688)	(3,766)
62	r	Uncollectibles	5,435	5,863	6,239
63		Total	$ 83,873	$ 89,796	$ 92,513
		Low Income Program Summary			
64		Arrearage Forgiveness	$ 619	$ 619	$ 619
65		Bill Reduction	11,218	11,218	11,218
66	n	Total Low Income Program	$ 11,837	$ 11,837	$ 11,837
		Economic Development Reconciliation			
67	a	Total Economic Development Program	$ 7,024	$ 7,000	$ 7,000
68	a	Rate Discounts	$ 24	$ -	$ -
		Non-Rate discounts:			
69	a	Economic Development - O&M	7,000	7,000	7,000
70		Total Rate and Non-Rate Discounts	$ 7,024	$ 7,000	$ 7,000
		CEF Reconciliation			
		Revenue			
71	b	Clean Energy Fund	$ 36,980	$ 35,880	$ 34,697
		Expense			
72	b	Clean Energy Fund	$ 36,980	$ 35,880	$ 34,697
		Energy Efficiency - Base Delivery			
		O&M Expense			
73	k	EE Tracker	$ 8,546	$ 8,546	$ 8,546
74	k	EE Heat Pumps	786	786	786
75		EE Regulatory Amorts (refer to Schedule H)	(4,892)	(4,892)	(4,892)
76		Total Energy Efficiency - Base Delivery	$ 4,440	$ 4,440	$ 4,440

Rochester Gas and Electric Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Operation & Maintenance Expense
($000)

			A	**B**	**C**
			Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
		O&M Expenses			
1	c	Labor / Payroll	$ 39,404	$ 41,319	$ 42,730
2		Variable Compensation	1,183	1,240	1,282
3		401K	1,802	2,003	2,194
4		Productivity	(884)	(1,101)	(1,130)
5		Medical Benefits	3,428	3,548	3,649
6		Other Employee Benefits	658	672	686
7	r	Uncollectibles	5,435	5,863	6,239
8		Insurance	975	995	1,016
9		Workers Comp	1,264	1,291	1,318
10		Injury / Damages	406	414	423
11		ASC Costs	23,190	23,677	24,174
12		Outside Services	18,762	18,800	18,476
13		Legal / Regulatory Expense	1,634	1,657	1,680
14		Vehicle Depreciation	1,857	1,958	2,061
15	p	Storm - Major	3,400	3,400	3,400
16		Storm - Minor	1,000	1,000	1,000
17	f	Vegetation Management - Distribution	8,270	8,443	8,621
18		Vegetation Management - Transmission	2,176	2,222	2,269
19		Security	1,067	1,089	1,112
20	n	Low Income Program	11,837	11,837	11,837
21	o	Credit & Debit Card Fees	884	1,121	1,345
22		CS Enhancements	191	166	166
23		Stray Voltage	1,043	1,065	1,087
24		Electric Reliability Organization _NERC	147	156	167
25		AMI - Incremental O&M	-	647	1,616
26		AMI - Incremental O&M Savings	-	-	(350)
27		Occupancy/Overhead costs	4,448	4,541	4,637
28	k	EE Tracker	8,546	8,546	8,546
29	k	EE Heat Pumps	786	786	786
30		NWA General Costs	100	100	100
31		New Studies	176	-	-
32		All Other O&M General Inflator Items	10,262	11,369	11,607
33	d	Pension	5,805	5,805	5,805
34	e	OPEBs	990	1,068	838
35	a	Economic Development	7,000	7,000	7,000
36	l	Environmental Remediation	988	988	988
37	j	Incremental Maintenance	2,087	5,298	5,875
38	g	Management / Operations / Staffing Audit	21	21	21
39	q	NEIL Credits	(3,613)	(3,688)	(3,766)
40	h	REV Incremental Costs	1,341	1,321	1,580
41	i	COVID-19 Pandemic Adjustment	-	-	-
42		COVID-19 - General Inflation Adj. (lines 6, 8-12, 18, 19, 23, 27, 32, & 39)	(716)	(919)	(1,048)
43		**Total Delivery O&M Expense**	$ 167,350	$ 175,718	$ 180,039
		Surcharge Expense			
44	b	Clean Energy Fund (CEF)	$ 36,980	$ 35,880	$ 34,697
45		**Total Surcharges**	$ 36,980	$ 35,880	$ 34,697
46		**Amortizations - Refer to Schedule H for Detailed Information**	$ (34,724)	$ (36,867)	$ (38,959)
47		**Total O&M Plus Surcharges & Amortizations**	**$ 169,605**	**$ 174,732**	**$ 175,777**

Rochester Gas and Electric Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Operation & Maintenance Expense
($000)

			A	B	C
			Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
		Amount in Rates			
48	c	Labor / Payroll	$ 39,404	$ 41,319	$ 42,730
49	d	Pension	5,805	5,805	5,805
50	e	OPEBs	990	1,068	838
51	f	Vegetation Management	8,270	8,443	8,621
52	g	Management Audit	21	21	21
53	h	REV	1,341	1,321	1,580
54	i	COVID-19 Pandemic Adjustment	-	-	-
55	j	Incremental Maintenance	2,087	5,298	5,875
56	l	Environmental Remediation	988	988	988
57	a	Economic Development	7,024	7,000	7,000
58	n	Low Income Program	11,837	11,837	11,837
59	o	Credit & Debit Card Fee Deferral	884	1,121	1,345
60	p	Storm - Major	3,400	3,400	3,400
61	q	NEIL Credit	(3,613)	(3,688)	(3,766)
62	r	Uncollectibles	5,435	5,863	6,239
63		Total	$ 83,873	$ 89,796	$ 92,513
		Low Income Program Summary			
64		Arrearage Forgiveness	$ 619	$ 619	$ 619
65		Bill Reduction	11,218	11,218	11,218
66	n	Total Low Income Program	$ 11,837	$ 11,837	$ 11,837
		Economic Development Reconciliation			
67	a	Total Economic Development Program	$ 7,024	$ 7,000	$ 7,000
68	a	Rate Discounts	$ 24	$ -	$ -
		Non-Rate discounts:			
69	a	Economic Development - O&M	7,000	7,000	7,000
70		Total Rate and Non-Rate Discounts	$ 7,024	$ 7,000	$ 7,000
		CEF Reconciliation			
		Revenue			
71	b	Clean Energy Fund	$ 36,980	$ 35,880	$ 34,697
		Expense			
72	b	Clean Energy Fund	$ 36,980	$ 35,880	$ 34,697
		Energy Efficiency - Base Delivery			
		O&M Expense			
73	k	EE Tracker	$ 8,546	$ 8,546	$ 8,546
74	k	EE Heat Pumps	786	786	786
75		EE Regulatory Amorts (refer to Schedule H)	(4,892)	(4,892)	(4,892)
76		Total Energy Efficiency - Base Delivery	$ 4,440	$ 4,440	$ 4,440

Rochester Gas and Electric Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Depreciation & Amortizations
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
1	**Depreciation Expense**	**$ 74,181**	**$ 82,604**	**$ 92,053**

Rochester Gas and Electric Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Operating Taxes
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
	Gross Revenue Taxes			
1	Total Retail Revenue	$ 467,382	$ 455,500	$ 501,120
2	Average GRT Rate	1.40%	1.61%	1.57%
3	Total Gross Revenue Tax	$ 6,535	$ 7,340	$ 7,880
	Other Operating Taxes			
4	Property Taxes	$ 88,443	$ 93,255	$ 98,328
5	Payroll Taxes	3,956	4,014	4,151
6	**Total Other Operating Taxes**	$ 92,399	$ 97,268	$ 102,478
7	**Total**	**$ 98,935**	**$ 104,608**	**$ 110,358**

Rochester Gas and Electric Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Income Taxes
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
1	Operating Income Before Income Taxes	$ 121,928	$ 145,162	$ 158,035
2	Interest Expense	(35,929)	(41,044)	(43,088)
3	Book Income Before Income Taxes (Adjusted for Tax Items)	85,999	104,118	114,947
4	Federal Income Taxes @ 21.000%	18,060	21,865	24,139
5	State Taxes @ 6.500%	5,590	6,768	7,472
6	Fed Benefit of State Tax Deduction @ 1.365%	(1,174)	(1,421)	(1,569)
7	Total Federal & State @ Statutory Rates	22,476	27,211	30,041
	Permanent Differences			
8	Meals and Entertainment	125	125	125
9	Subtotal: Permanent Differences	125	125	125
10	**Delivery Income Taxes (Lines 7 & 9)**	**$ 22,601**	**$ 27,336**	**$ 30,166**

Rochester Gas and Electric Corporation
Electric Department
Revenue Requirement for Forecast Years Ending April 30, 2021, 2022, 2023
Capital Structure Summary Schedule
($000)

		A	B	C	D	E
		Weight	**Cost Rate**	**Percent**	**Tax Gross-up**	**Before Tax**
	Rate Year 1					
1	Long Term Debt	51.79%	4.62%	2.39%		2.39%
2	Customer Deposits	0.21%	0.90%	0.00%		0.00%
3	Total Debt	52.00%		2.39%		2.39%
4	Common Equity	48.00%	8.80%	4.22%	1.49%	5.72%
5	Total	100.00%		6.62%		8.11%
	Rate Year 2					
6	Long Term Debt	51.82%	4.35%	2.26%		2.26%
7	Customer Deposits	0.18%	0.90%	0.00%		0.00%
8	Total Debt	52.00%		2.26%		2.26%
9	Common Equity	48.00%	8.80%	4.22%	1.49%	5.72%
10	Total	100.00%		6.48%		7.98%
	Rate Year 3					
11	Long Term Debt	51.84%	4.14%	2.15%		2.15%
12	Customer Deposits	0.16%	0.90%	0.00%		0.00%
13	Total Debt	52.00%		2.15%		2.15%
14	Common Equity	48.00%	8.80%	4.22%	1.49%	5.72%
15	Total	100.00%		6.37%		7.87%

	Interest Expense	**Rate Year 1**	**Rate Year 2**	**Rate Year 3**
16	Rate Base	$ 1,500,901	$ 1,817,758	$ 2,007,118
17	Weighted Cost of Debt	2.39%	2.26%	2.15%
18	Interest Expense	$ 35,929	$ 41,044	$ 43,088

Case 19-E-0378, et al.
Joint Proposal

Revised Appendix D
Schedule H

Rochester Gas and Electric Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Regulatory Amortizations
($000)

		A	B	C	D	E
		Starting Rate Year Asset / (Liab) Balance	Amortization Period (years)	Inc / (Exp) Rate Year 1 Amortization 4/30/2021	Inc / (Exp) Rate Year 2 Amortization 4/30/2022	Inc / (Exp) Rate Year 3 Amortization 4/30/2023
	Specific or 3-Year Term Amortizations					
1	ASGA	$ (10,851)	Specific	$ 5,370	$ 5,481	$ -
2	Bonus Depreciation NCR	(18,974)	Specific	3,795	5,984	9,195
3	Fixed Rate Debt	(16,501)	Specific	3,300	3,300	7,820
4	2018 Windstorm Settlement - Case 19-E-0105	(1,500)	3	500	500	500
5	EEPS	(53)	3	18	18	18
6	EE Tracker	(14,624)	3	4,875	4,875	4,875
7	**Subtotal**	**$ (62,503)**		**$ 17,857**	**$ 20,157**	**$ 22,407**
	Other Than 3-Year Amortizations					
8	Allegheny Sale Loss and Savings	$ (5,121)	5	$ 1,024	$ 1,024	$ 1,024
9	Beebee Decommissioning	(764)	5	153	153	153
10	CAIDI/SAIFI Study	95	5	(19)	(19)	(19)
11	Cap Ex NCR 03-E-0765, 03-G-0766	3,401	5	(680)	(680)	(680)
12	CapEx Customer Credit 07-M-0906 Merger Order	(10,000)	5	2,000	2,000	2,000
13	Cost to Achieve Efficiency Initiatives	105	5	(21)	(21)	(21)
14	Credit & Debit Card Fees	1,781	5	(356)	(356)	(356)
15	Economic Development - Remaining Amort (15-E-0283 Appx. V)	(17,052)	$3M/Yr	3,000	3,000	3,000
16	Economic Development - New Amortization	(571)	0	-	-	-
17	Electric Reliability Organization	304	5	(61)	(61)	(61)
18	Environmental - Remaining Amort (15-E-0283 Appx. V)	(21,617)	7	3,088	3,088	3,088
19	Environmental - New Amortization	(14,550)	7	2,079	2,079	2,079
20	ESM - Remaining Amort (15-E-0283 Appx. V)	(5,422)	5	1,084	1,084	1,084
21	ESM - New Amortization	(2,170)	5	434	434	434
22	Excess DIT - New York State Tax Rate change - Remaining Amort (15-E-0283 Appx. V)	(2,898)	5	580	580	580
23	Incremental Maintenance - New Amortization	(167)	5	33	33	33
24	IRS Audit - 1998-2001 - Remaining Amort (15-E-0283 Appx. V)	70	5	(14)	(14)	(14)
25	Low Income Program - Remaining Amort (15-E-0283 Appx. V)	(3,634)	5	727	727	727
26	Low Income Program - New Amortization	20,296	5	(4,059)	(4,059)	(4,059)
27	Management Audit - Remaining Amort (15-E-0283 Appx. V)	(217)	5	43	43	43
28	Management Audit - New Amortization	50	5	(10)	(10)	(10)
29	Medicare Part D	(241)	5	48	48	48
30	MHP Meter Costs - Remaining Amort (15-E-0283 Appx. V)	(4)	5	1	1	1
31	Mixed Use 263(a) NCR - Remaining Amort (15-E-0283 Appx. V)	(4,241)	5	848	848	848
32	NEIL Credit	(6,357)	5	1,271	1,271	1,271
33	Net Plant Reconciliation - Remaining Amort (15-E-0283 Appx. V)	(9,623)	5	1,925	1,925	1,925
34	Net Plant Reconciliation - New Amortization	(12,978)	5	2,596	2,596	2,596
35	Nine Mile II - TCCs - Remaining Amort (15-E-0283 Appx. V)	(11,472)	5	2,294	2,294	2,294
36	Nine Mile II - TCCs - New Amortization	(9,673)	5	1,935	1,935	1,935
37	Nuclear Fuel DOE Liability True-up - Remaining Amort (15-E-0283 Appx. V)	(12,188)	5	2,438	2,438	2,438
38	Nuclear Fuel DOE Liability True-up - New Amortization	2,888	5	(578)	(578)	(578)
39	NYS Tax Audit - Remaining Amort (15-E-0283 Appx. V)	228	5	(46)	(46)	(46)
40	NYS Tax Rate - New Amortization	(319)	5	64	64	64
41	OPEB Deferral	(1,559)	5	312	312	312
42	OPEB Deferral - New Amortization	(219)	5	44	44	44
43	PBA Utilization	(32,987)	5	6,597	6,597	6,597
44	Pension Deferral - Remaining Amort (15-E-0283 Appx. V)	21,403	5	(4,281)	(4,281)	(4,281)
45	Pension Deferral - New Amortization	8,101	5	(1,620)	(1,620)	(1,620)
46	PRA - Terminations & Uncollectibles	171	5	(34)	(34)	(34)
47	Property Tax	(12,105)	5	2,421	2,421	2,421
48	Rate Increase Shaping (reflected in Revenue)	364	5	(73)	(73)	(73)
49	Property Tax 481(a) - NCR	(346)	5	69	69	69
50	PSC Assessment	(126)	5	25	25	25
51	REV Incremental Costs	5,013	5	(1,003)	(1,003)	(1,003)
52	Russell Decommissioning	4,143	5	(829)	(829)	(829)
53	ROW Tree Trim	1,480	5	(296)	(296)	(296)
54	Sarbanes-Oxley	386	5	(77)	(77)	(77)
55	Service Quality Performance	(393)	5	79	79	79
56	SO2 Allowance	(829)	5	166	166	166
57	Storm - Non-Superstorm - Remaining Amort (15-E-0283 Appx. V)	(4,163)	5	833	833	833
58	Storm - Non-Superstorm - New Amortization	53,183	5	(10,637)	(10,637)	(10,637)
59	Stray Voltage	585	5	(117)	(117)	(117)
60	Theoretical Reserve Inc Tax Flow Through- Remaining Amort (15-E-0283 Appx. V)	(6,279)	5	1,256	1,256	1,256
61	Unit of Property CTA	76	5	(15)	(15)	(15)
62	Variable Rate Debt- Remaining Amort (15-E-0283 Appx. V)	(284)	5	57	57	57
63	Variable Rate Debt - New Amortization	1,447	5	(289)	(289)	(289)
64	Vegetation Management	(682)	5	136	136	136
65	Vegetation Management - Danger Tree Deferral $1.575M per year beginning in RY1		10	(158)	(315)	(473)
66	Post Term Amortization Deferral - 2010 JP	(1,590)	5	318	318	318
67	**Subtotal**	**$ (87,269)**		**$ 14,705**	**$ 14,548**	**$ 14,390**

Rochester Gas and Electric Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Regulatory Amortizations
($000)

		A	B	C	D	E
		Starting Rate Year Asset / (Liab) Balance	Amortization Period (years)	Inc / (Exp) Rate Year 1 Amortization 4/30/2021	Inc / (Exp) Rate Year 2 Amortization 4/30/2022	Inc / (Exp) Rate Year 3 Amortization 4/30/2023
	Income Tax Related Amortizations					
68	Excess DIT - TCJA - Protected Amortization (reflected in Revenue)	(207,111)	ARAM	3,963	4,119	4,196
69	Excess DIT - TCJA - Protected Pre-RY1 Liability (reflected in Revenue)	(8,957)	3	2,986	2,986	2,986
70	Excess DIT - TCJA - Unprotected Amortization	(12,358)	3	4,119	4,119	4,119
71	Federal Tax Reform - Jan-Sep 2018 Savings Amortization (reflected in Revenue)	(6,934)	1.5	4,623	2,311	-
72	PowerTax Regulatory Asset	36,031	35	(1,029)	(1,029)	(1,029)
73	Unfunded Future Income Taxes	132,082	46	(2,871)	(2,871)	(2,871)
74	Unfunded Future Income Taxes - NCR	(29,947)	5	5,989	5,989	5,989
75	**Subtotal**	**$ (97,195)**		**$ 17,780**	**$ 15,624**	**$ 13,390**
76	**Total - RG&E Electric**	**$ (246,967)**		**$ 50,342**	**$ 50,329**	**$ 50,188**

Rochester Gas and Electric Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Deferred Debits and Credits
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
	Regulatory Assets & Liabilities:			
1	2018 Windstorm Settlement - Case 19-E-0105	$ (1,250)	$ (750)	$ (250)
2	Allegheny Sale Loss and Savings	(4,608)	(3,584)	(2,560)
3	ASGA	(8,166)	(2,740)	(0)
4	Beebee Decommissioning	(688)	(535)	(382)
5	Bonus Depreciation NCR - Remaining Amort (15-E-0283 Appx. V)	(17,077)	(12,187)	(4,597)
6	CAIDI/SAIFI Study	86	67	48
7	Cap Ex NCR 03-E-0765, 03-G-0766	3,061	2,381	1,701
8	CapEx Customer Credit 07-M-0906 Merger Order	(9,000)	(7,000)	(5,000)
9	Cost to Achieve Efficiency Initiatives	94	73	52
10	Credit & Debit Card Fees	1,603	1,247	891
11	Economic Development	(15,552)	(12,552)	(9,552)
12	Economic Development - New Amortization	(571)	(571)	(571)
13	EEPS	(44)	(27)	(9)
14	EE Tracker	(12,186)	(7,312)	(2,437)
15	Electric Reliability Organization	273	213	152
16	Environmental - Remaining Amort (15-E-0283 Appx. V)	(20,073)	(16,985)	(13,897)
17	Environmental - New Amortization	(13,511)	(11,432)	(9,354)
18	ESM - Remaining Amort (15-E-0283 Appx. V)	(4,880)	(3,796)	(2,711)
19	ESM - New Amortization	(1,953)	(1,519)	(1,085)
20	Excess DIT - New York State Tax Rate change - Remaining Amort (15-E-0283 Appx. V)	(2,608)	(2,029)	(1,449)
21	Fixed Rate Debt	(14,851)	(11,551)	(5,990)
22	Incremental Maintenance	(150)	(117)	(84)
23	IRS Audit - 1998-2001 - Remaining Amort (15-E-0283 Appx. V)	63	49	35
24	Low Income Program - Remaining Amort (15-E-0283 Appx. V)	(3,270)	(2,544)	(1,817)
25	Low Income Program - New Amortization	18,267	14,207	10,148
26	Major Storm Reserve - Remaining Amort (15-E-0283 Appx. V)	(3,747)	(2,914)	(2,082)
27	Major Storm Reserve - New Amortization	47,865	37,228	26,592
28	Management Audit - Remaining Amort (15-E-0283 Appx. V)	(195)	(152)	(108)
29	Management Audit - New Amortization	45	35	25
30	Medicare Part D	(217)	(169)	(121)
31	MHP Meter Costs	(4)	(3)	(2)
32	Mixed Use 263(a) NCR - Remaining Amort (15-E-0283 Appx. V)	(3,817)	(2,968)	(2,120)
33	NEIL Credit	(5,721)	(4,450)	(3,178)
34	Net Plant Reconciliation - Remaining Amort (15-E-0283 Appx. V)	(8,661)	(6,736)	(4,812)
35	Net Plant Reconciliation - New Amortization	(11,681)	(9,085)	(6,489)
36	Nine Mile II - TCCs - Remaining Amort (15-E-0283 Appx. V)	(10,325)	(8,031)	(5,736)
37	Nine Mile II - TCCs - New Amortization	(8,705)	(6,771)	(4,836)
38	Nuclear Fuel DOE Liability True-up - Remaining Amort (15-E-0283 Appx. V)	(10,969)	(8,531)	(6,094)
39	Nuclear Fuel DOE Liability True-up - New Amortization	2,599	2,022	1,444
40	NYS Tax Audit - Remaining Amort (15-E-0283 Appx. V)	205	159	114
41	NYS Tax Rate - New Amortization	(287)	(223)	(160)
42	OPEB Deferral - Remaining Amort (15-E-0283 Appx. V)	(1,403)	(1,091)	(779)
43	OPEB Deferral - New Amortization	(197)	(153)	(109)
44	PBA Utilization	(29,688)	(23,091)	(16,493)
45	Pension Deferral - Remaining Amort (15-E-0283 Appx. V)	19,263	14,982	10,702
46	Pension Deferral - New Amortization	7,291	5,671	4,051
47	PRA - Terminations & Uncollectibles	154	120	86
48	Property Tax	(10,895)	(8,474)	(6,053)
49	Rate Increase Shaping	328	255	182
50	Property Tax 481(a) - NCR	(311)	(242)	(173)
51	PSC Assessment	(113)	(88)	(63)
52	REV Incremental Costs	4,512	3,509	2,507
53	Russell Decommissioning	3,729	2,900	2,072

Rochester Gas and Electric Corporation
Electric Department
Revenue Requirement for Forecast Rate Years Ending April 30, 2021, 2022, 2023
Deferred Debits and Credits
($000)

		A	B	C
		Rate Year 1 TME 4/30/2021	Rate Year 2 TME 4/30/2022	Rate Year 3 TME 4/30/2023
54	ROW Tree Trim	1,332	1,036	740
55	Sarbanes-Oxley	348	271	193
56	Service Quality Performance	(354)	(275)	(197)
57	SO2 Allowance	(746)	(580)	(414)
58	Stray Voltage	526	409	292
59	Theoretical Reserve Inc Tax Flow Through- Remaining Amort (15-E-0283 Appx. V)	(5,651)	(4,395)	(3,139)
60	Unit of Property CTA	68	53	38
61	Variable Rate Debt- Remaining Amort (15-E-0283 Appx. V)	(256)	(199)	(142)
62	Variable Rate Debt - New Amortization	1,302	1,013	723
63	Vegetation Management	(614)	(477)	(341)
64	Vegetation Management - Danger Tree Deferral	709	2,048	3,229
65	Post Term Amortization Deferral - 2010 JP	(1,431)	(1,113)	(795)
66	Excess DIT - TCJA - Protected Amortization	(205,130)	(201,089)	(196,931)
67	Excess DIT - TCJA - Protected Pre-RY1 Liability	(7,465)	(4,479)	(1,493)
68	Excess DIT - TCJA - Unprotected Amortization	(10,298)	(6,179)	(2,060)
69	Federal Tax Reform - Jan-Sep 2018 Savings Amortization	(4,623)	(1,156)	-
70	PowerTax Regulatory Asset	35,516	34,487	33,457
71	Unfunded Future Income Taxes	130,647	127,775	124,904
72	Unfunded Future Income Taxes - NCR	(26,953)	(20,963)	(14,974)
73	Subtotal	$ (221,008)	$ (169,097)	$ (117,264)
	<u>Other Deferred Assets & Liabilities:</u>			
74	Commodity Hedge Margin	-	-	-
75	DOE Liability	(125,931)	(125,931)	(125,931)
76	FAS-112 Post Employment Benefit Liability	(1,037)	(1,037)	(1,037)
77	Preliminary Survey and Investigation	407	407	407
78	Pension Asset	(15,490)	(11,628)	(3,514)
79	Loss on Reacquired Debt	4,369	4,369	4,369
80	Net (Gains)/Losses on Interest Rate Hedges	28,614	28,307	28,000
81	NBC True-Up	-	-	-
82	OPEB Reserve	(43,825)	(41,621)	(39,380)
83	PSC Assessment - General	-	-	-
84	Injuries and Damages Reserve	(3,407)	(3,407)	(3,407)
85	RDM	-	-	-
86	Workers Comp Reserve	-	-	-
87	All Other	928	928	928
88	**Subtotal**	$ (155,372)	$ (149,614)	$ (139,566)
89	**Grand Total**	**$ (376,381)**	**$ (318,711)**	**$ (256,829)**

Attachment 6

Attachment 6

	NYSEG Electric		RG&E Electric	
	Joint Proposal	**Joint Proposal With Modifications**	**Joint Proposal**	**Joint Proposal With Modifications**
Delivery Rate Increases ($000):				
RY 1	45,684	45,298	15,238	21,352
RY 2	84,770	45,640	28,064	13,898
RY 3	88,565	36,007	30,721	15,828
Increase in Delivery Rates:				
RY 1	6.1%	6.0%	3.4%	4.8%
RY 2	10.6%	5.9%	6.3%	3.1%
RY 3	9.9%	4.2%	6.2%	3.3%
Monthly Resid. Bill Impacts (600 kWh) ($/%)				
RY 1	$2.49/3.6%	$2.48/3.5%	$0.37/0.5%	$1.20/1.6%
RY 2	$4.13/5.7%	$1.84/2.5%	$3.82/5.0%	$1.95/2.5%
RY 3	$5.54/7.2%	$2.42/3.3%	$4.14/5.2%	$2.26/2.9%
Total Bill Impacts				
RY 1	2.0%	2.0%	0.8%	1.6%
RY 2	4.4%	2.0%	3.8%	2.0%
RY 3	5.0%	2.0%	3.8%	2.0%

Attachment 7

Attachment 7

NYSEG - Electric	RY 1 - 5/1/20 - 4/30/21			RY 2 - 5/1/21 - 4/30/22			RY 3 - 5/1/22 - 4/30/23		
	Present Rates	Change	Proposed Rates	Present Rates	Change	Proposed Rates	Present Rates	Change	Proposed Rates
Delivery Revenues Before Increase	752,198	45,298	797,496	779,312	45,640	824,952	855,293	36,007	891,300
Total Estimated Supply Revenue (Company Supplied and ESCO Supplied)	736,372	-	736,372	736,372	-	736,372	736,372	-	736,372
Other Revenues	74,060	163	74,223	74,552	449	75,001	75,308	137	75,445
Commodity-Related Misc.	(2,994)	-	(2,994)	(2,994)	-	(2,994)	(2,994)	-	(2,994)
RAM Surcharge (July 1 - June 30)	19,300	-	19,300	19,300	(14,708)	4,592	4,592	(2,942)	1,650
EE collections	13,648	(13,648)	-	-	-	-	-	-	-
Total	1,592,585		1,624,397	1,606,542		1,637,923	1,668,571		1,701,774
Overall %			2.00%			1.95%			1.99%

RG&E - Electric	RY 1 - 5/1/20 - 4/30/21			RY 2 - 5/1/21 - 4/30/22			RY 3 - 5/1/22 - 4/30/23		
	Present Rates	Change	Proposed Rates	Present Rates	Change	Proposed Rates	Present Rates	Change	Proposed Rates
Delivery Revenues Before Increase	446,030	21,352	467,382	441,602	13,898	455,500	485,291	15,828	501,120
Total Estimated Supply Revenue (Company Supplied and ESCO Supplied)	323,500	-	323,500	323,500	-	323,500	323,500	-	323,500
Other Revenues	6,985	(19)	6,966	7,057	216	7,273	7,286	155	7,441
Commodity-Related Misc.	(868)	-	(868)	(868)	-	(868)	(868)	-	(868)
RAM Surcharge	1,900	(1,900)	-	-	1,125	1,125	1,125	225	1,350
EE collections	7,194	(7,194)	-	-	-	-	-	-	-
Total	784,741		796,980	771,291		786,530	816,335		832,543
Overall %			1.56%			1.98%			1.99%

Attachment 8

Public Statement Hearing Comments from 2019 Hearings

Comments were made by 30 people at the afternoon hearing in Rochester and by 19 people at the evening hearing there; 8 people at the Keene Valley hearing; 43 people at the Ithaca hearing; 40 people at the Binghamton hearing, and 32 people at the hearing in Yorktown Heights. Over 100 individuals spoke on their own behalf or on behalf of other individuals. Others commented on behalf of the City of Auburn, PULP, Central New York Workers Benefit Council, Eastern Farm Workers, FFT, the City of Auburn, the Sane Energy Project, the Housing Assistance Program of Essex County, Mothers Out Front, Keane Clean Energy Committee, Monroe County Workers Benefit Council, the Sierra Club, Sustainable Otsego, Concerned Citizens of Oneonta, Eastern Farm Workers, Binghamton Regional Sustainability Coalition, the Sunrise Movement, Action for a Better Community and the Monroe

Anti-Poverty Initiative. Various elected officials also commented at the hearings.[1]

Numerous commenters opposed the Companies' requested rate increases as unjustified and too high. Some people commented that New York State has some of the highest utility rates in the country, that the Companies' rates already are too high, and that the Companies should consider reducing employee bonuses or using profits to pay for or offset the costs of the programs for which the Companies now seek rate increases. Others suggested that the Commission reduce the Companies' rates of return to make rates more affordable. A few commenters opposing rate increases referred to poor electric service reliability, poor customer service and complicated bills that do not clearly and easily show customers where their money is going. One commenter stated that the Companies should not get

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[1] Comments were made by or on behalf of Rochester City Councilmember Mitch Gruber, Town of Keane Supervisor Joe Pete Wilson, Town of Dryden Councilmember Linda Lavine, Tompkins County Legislator Mike Sigler, Town of Lansing Supervisor Edward Lavine, Town of Caroline Councilmember Irene Weiser, Town of Oneonta Councilmember Patria Jacob, Town of New Lisbon Councilmember Robert Eklund, Binghamton City Councilmember Dan Livingston, Broome County Executive Jason Garnar, Town of Columbus Supervisor Thomas P. Grace, State Senator Pete Harkham, New York State Assemblyperson David Buchwald, Yorktown Town Supervisor Ian Gilbert, Westchester County Legislator Michael Kaplowitz, Westchester County Legislator Kitley Covill, the Town of Lewisboro Supervisor Peter Parsons, Westchester County Executive George Latimer, Town of Bedford Supervisor Chris Burdick, New York State Assemblyperson Kevin Byrne, Yorktown Councilmember Thomas Diana, Town of Yorktown Councilmember Edward Lachterman, Town of Yorktown Councilmember Vishnu Patel, Town of Somers Supervisor Rick Morrissey, Town of North Salem Supervisor Warren Lucas, Town of Yorktown Highway Superintendent David Paganelli, City of Peekskill Councilmember Vanessa Agudelo, and City of Peekskill Councilmember Colin Smith. Comments were submitted by State Senator Shelley B. Mayer.

rate increases to the extent business expenses can be "written off" on federal income taxes. Another commenter stated that ratepayers should not pay for programs, such as the installation of electric vehicle charging stations, that will provide the Companies with a new revenue stream or otherwise increase profits. Several commenters raised concerns with the Companies' foreign corporate ownership, suggesting that it impacted the Companies' commitment to provide safe, affordable and reliable service.

A landlord from Ithaca stated that increased electricity rates would make it more difficult for people to be able to afford to rent apartments in the area. A farm owner noted the consistently low prices he receives for his crops and stated that increased rates would raise his cost of doing business, increase his debt, negatively impact his ability to pay his workers, possibly force him to hire fewer workers for future crop seasons, and negatively impact lower-income people's ability to purchase his crops.

Some people commented that the Companies experienced excessive outages during recent winter and spring storms and need to plan better and invest appropriately to ensure that outages do not continue to occur. A person stated on behalf of three manufacturing companies that reliability of service was of paramount importance and that NYSEG's service has not been reliable, although NYSEG has since switched them "to a different line that was better."[2] One commenter suggested that the electric power grid be made more reliable by putting all power lines underground and that the cost for such work be paid by the State and, eventually, the federal government.

[2] 8/14/19 Ithaca Public Statement Hearing Transcript, p. 10.

Several commenters, including Concerned Citizens of Oneonta, stated that the Companies have not been keeping up with routine maintenance, including vegetation management, and that the Companies should not be allowed to charge ratepayers the costs for repairs and catch-up work that the Companies should have been doing all along. PULP recognized the need for rate increases for the Companies' vegetation management programs but stated that the increased costs should be as reasonable as possible. Some commenters noted concerns with wholesale tree removal rather than targeted tree trimming, while others suggested that the Companies had to coordinate better with homeowners before trimming and cutting trees. Another commenter cautioned against the use of chemical pesticides for vegetation management.

Many commenters, including various individuals, the Sierra Club, the Sunrise Movement, Sustainable Otsego, FFT, the Sane Energy Project and Mothers Out Front spoke about climate change and the need to transition from the use of fossil fuels as quickly as possible, many of them citing the recently-enacted Climate Leadership and Community Protection Act (CLCPA). Commenters requested that the Companies cease further investments in natural gas infrastructure, including proposed work to install larger-diameter pipe along 50 miles of the DeRuyter pipeline, which they contend will become stranded assets when the State converts to 100 percent renewable energy; invest to make the electric grid more reliable, including upgrades to phase-3 power lines and substations to accommodate wind and solar farms; and promote renewable energy sources, including distributed energy.

Some commenters suggested that gas and electric rates be set to encourage customers to transition away from the use of natural gas and towards the use of renewable energy sources, and that further capital spending for gas service should be limited to safety improvements and leak reduction. Several people asserted that NYSEG should offer incentives for the use of heat pumps, stating that presently no such incentives are provided by the Company. The Monroe County Workers Benefit Council and others stated that utilities should be required to cease using fossil fuels entirely and that the State should move to 100 percent renewable energy resources by the year 2030. One person stated that the Companies should pay the cost of switching from fossil-fuel infrastructure to renewable energy sources.

Other commenters suggested that the Companies be subject to performance-based incentives tied to achievement of affordable green-energy goals. Several commenters, including the Binghamton Regional Sustainability Coalition, stated that the Companies should add resources to allow for the timely and affordable connection of community-based solar programs to the grid, process credits for those using community-based solar energy, and make the paperwork and process for customers participating in community-based solar programs less burdensome. Other commenters stated that the Companies should stop offering rebates and discounts for the purchase of gas appliances and instead educate ratepayers on energy choices that would reduce carbon and methane emissions. One commenter stated that the Commission should allow the Companies to provide new gas hookups only to commercial entities that show they have no viable green energy alternatives. Another commenter stated that NYSEG should create beneficial electrification projects in low income neighborhoods and work with neighborhoods to create micro grids.

After noting that the Companies have been responsible in keeping their prices down as compared to other utilities in the State, PULP commented that many of the Companies' electric and gas customers were already struggling to pay their bills and that rate increases several times the rate of inflation and social security cost of living increases are unaffordable. PULP stated that no one should be forced to decide whether to pay rent, buy food or medicine, or to keep the lights and heat on. A farm worker stated that his salary would not allow him to afford rate increases and that rate increases may prevent farm owners from hiring workers.

The Housing Assistance Program of Essex County recognized that rate increases are inevitable but cautioned that any rate increases would hurt low income customers the most because those customers spend the highest percentage of their income on residential energy, live on the thinnest financial margins and thus have the least ability to recover from financial setbacks, and, as echoed by the Sunrise Movement, often live in the least energy-efficient housing. The Housing Assistance Program of Essex County stated that NYSEG customers need better customer service to help low income households manage high electric bills and overdue payments.

PULP also commented about the Companies' transition to smart meters, including concerns about the number of meters to be installed and the cost of the smart meter program, as well as concerns that the use of smart meters may foster the remote shutoff of services and negatively impact the availability of utility workers to conduct onsite inspection and maintenance. One commenter requested a moratorium on the roll out of smart meters, raising concerns that, in addition to the cost involved, smart meters cause cancer, catch on fire, constitute an invasion of privacy, are susceptible to hacking and identity theft, and will eliminate utility workers' jobs. A few commenters stated that people should not have to pay more in a monthly opt-out fee if they choose not to use smart meters and that the proposed monthly opt-out fee of $20 was exorbitant and punitive. Another individual suggested that the money for smart meters be used to upgrade the reliability of the electric system. A few commenters asserted that the use of smart meters would save the Companies' money and increase their profits and that the Companies therefore should bear the cost of installing smart meters. One commenter stated that NYSEG has not shown how smart meters would help ratepayers to reduce their energy usage and that the proposed smart meter program should be rejected. Another commenter stated that smart meters were not needed for gas service and that the money requested for smart gas meters should instead fund incentives for the use of heat pumps. One commenter stated that smart meters were a good idea, especially because they would reduce incorrect meter readings and charges based on estimated usage.

Some commenters stated that fixed customer charges for electric delivery services are excessive and should be exempted from a rate increase, reduced substantially or abolished. One commenter stated that the fixed customer charge includes charges for services that are not actually performed, such as meter reading, which he said RG&E has not done at his residence for several years; a few other commenters also stated that the Companies read their meters only sporadically. Some commenters stated that fixed customer charges do not incentivize conservation but penalize low-usage customers, who, they maintain, are often low- and moderate-income customers. They stated that more emphasis should be placed on conservation to protect the environment and that the Companies should provide incentives for all customers to improve energy efficiency and convert to renewable energy resources, including heat pumps. Another commenter suggested that RG&E offer rebates to customers converting to light-emitting diode (LED) lighting.

The Monroe Workers Benefit Council, the Central New York Workers Benefit Council and others requested that the Commission reject the requested rate increases, enact a year-round moratorium on shut-offs for families at or below 250 percent of the federal poverty level, and cancel utility bill debts of those ratepayers and then other ratepayers, either completely or where the attempt to collect would exceed the applicable statute of limitations. They also stated that utilities should not be guaranteed a nine percent profit, that profits should be reduced to achieve affordable rates, and that the low income affordability plans implemented at the direction of the Commission do not appear to be working. Action for a Better Community and others suggested that the Companies continue their arrears forgiveness programs. The Rochester-Monroe Anti-Poverty Initiative requested that the Commission consider the impact of the requested rate increases on structural racism.

The Central New York Workers Benefit Council also requested that all utility companies be directed to (1) take immediate steps to restore service to all households disconnected from utility service, without fee or fine; (2) develop and submit a plan, within one year, for how they will finance, from their own profits, the switch from carbon-based energy sources to renewable energy sources, and to start implementing that plan within one year of submission to ensure the transition to a fossil-fuel free infrastructure by 2030; and (3) hire and pay from their own profits translators who can communicate in the languages of all customers served. Several individuals requested that the Companies be prevented from shutting off electric service during the winter and summer months and be required to work out billing issues with people who cannot afford service rather than shutting off service.

In commenting on the Companies' requested rate increases, several elected officials raised many of the same issues discussed above. For example, many elected officials noted the outages from various storms during the Winter and Spring in 2018, stating that the quality of service has been poor and that the requested rate hikes were exorbitant and unaffordable, especially for those with low or fixed incomes. Elected officials also requested that the Companies shift investments to improve electric grid resiliency and reliability and to accommodate more renewable-energy resources.

A few officials stated that increased rates would negatively impact businesses and might require municipalities to increase taxes or cut programs. Some officials discussed the need for better communication and coordination between the Companies and municipalities, noted that there was public distrust that the Companies would use ratepayer funds appropriately, and stated that the Companies' priorities did not align with those of their customers or with New York State policy on the reduction of emissions. One official stated that NYSEG's tree-trimming policy resulted in excessive trimming, the cutting of healthy trees and the pile up of debris on private and municipal land. Some officials requested that the Companies' tree-trimming schedule be accelerated to a three-year schedule.

A few officials stated that the process to have community solar projects connected to the electric grid was lengthy, complicated and needed to be streamlined because the process currently disincentivized community solar project development and participation. Officials from the Town of Lansing stated that it was difficult to justify a gas rate increase when the Town was under a gas moratorium. Other officials opposed the work proposed on the DeRuyter pipeline, stating that it was contrary to State emissions-reduction policies, while others noted that it would not provide extra gas to their constituents in any event. Some officials, specifically those representing constituents from Brewster, New York, stated that their areas should have better customer service and more infrastructure improvements than appeared to be part of these rate cases.

Other officials stated that NYSEG has not kept up with necessary infrastructure maintenance and upgrades and that rate increases should not be given until NYSEG establishes that promised improvements have been delivered. One official from the Town of Lewisboro stated that NYSEG's service had improved since 2018, recognized that some amount of rate increase was warranted to support further improvements and spoke in favor of the deployment of smart meters. One official stated that NYSEG should coordinate with NYSERDA and Sustainable Westchester in promoting the use of heat pumps and electric vehicles. Others raised opposition to the Companies' AMI proposals and use of opt-out fees.

<u>Public Statement Hearing Comments on Joint Proposal</u>

Twenty-four people commented at the virtual public statement hearing held in the afternoon on August 26, 2020, and twenty-one people spoke at the public statement hearing held that evening. Several people commented in favor of the Joint Proposal's gas provisions, but all commenters opposed the provisions regarding the Companies' electric businesses.

State Senator Jen Metzger (42^{nd} District), like many other commenters, stated that the proposed rate increases are too high, unaffordable and problematic for low income customers, particularly given the economic contraction resulting from the

COVID-19 pandemic.[3] Senator Metzger also stated that the bill credits proposed to address the economic situation will not help moderate-income customers and will not help in the second and third years of the rate plans. Senator Metzger, as well as various others, commented that fixed monthly charges need to be reduced to properly incentivize energy conservation and the use of renewable energy, that power outages and disruptions occur frequently due to NYSEG’s neglect of distribution infrastructure and vegetation management, and that spending should be focused on improving reliability instead of implementing AMI. Senator Metzger stated that customer service offices should remain open for her constituents because many of her constituents do not have broadband access and use such offices for customer services that cannot be met by third-party agents.

The Monroe County Workers’ Benefit Council, as well as other commenters, stated that rates should not be increased during this time of economic crisis, that the proposed Return on Equity (ROE) is too high, and that the Companies should feel the brunt of the pandemic like everyone else. The Monroe County Workers’ Benefit Council requested that a permanent year-round moratorium on power shut-offs should be enacted for people at or below 250 percent of the federal poverty level and that the Companies should pay for converting to 100 percent renewable energy by 2030. Various people echoed the comments that the proposed ROE was too high and that no increases should be considered during the current economic crisis. Commenters also stated that spending should be reprioritized to focus on putting NYSEG on a five-year tree-trimming cycle and for the Companies to invest in infrastructure improvements.

[3] Senator Metzger also submitted her comments in writing on August 26, 2020.

Tompkins County Legislators Deborah Dawson and Martha Robertson, as well as other commenters, stated that the Advanced Metering Infrastructure (AMI) pilot project shows that AMI benefits the Companies more than ratepayers, that AMI is not ready to be rolled out throughout the Companies' service territories, and that money would be better spent on vegetation management and infrastructure improvements. FFT asserted, among other things, that NYSEG should pay for reclamation costs to make up for the trimming backlog it allowed to occur and that a majority of public interest organizations have opposed the provisions of the Joint Proposal regarding the Companies' electric businesses. One person commented that NYSEG should not be allowed to purchase coal-powered electricity from Pennsylvania.

Six people commented at both the afternoon and the evening sessions of the virtual public statement hearings held on August 28, 2020. A few commenters, including representatives of Ratepayer and Community Intervenors and Fossil Free Tompkins, spoke against the electric provisions of the Joint Proposal. Commenters, including representatives of PULP, opposed the Companies' proposed closing of customer service centers, expressing that face-to-face interactions are important, especially to the elderly and low income customers, and that many people do not have access to the internet or cellular phone service. Commenters also stated that offices should not be closed during the current economic crisis.

<u>Written Comments and Opinion Line Comments</u>

In addition to the public statement hearing comments, there were over one thousand telephone comments received on the Commission's opinion line and thousands of written comments filed with the Commission's Secretary, over a thousand of which were made after the Joint Proposal was filed. The overwhelming majority of the written and opinion line comments received were from individual customers expressing opposition to the proposed rate increases.

A few commenters stated that the Companies are not responsive to local concerns because they are owned by a company based in Spain. Some commenters stated that the Companies were not properly managed and should not be rewarded with rate increases, especially since ratepayers are not receiving similar increases and have no choice in utility providers. Many commenters stated that the requested rate increases are even worse now in light of the impacts from COVID-19, that projects should be reprioritized and deferred where possible, and that discretionary expenses such as pay raises, association membership fees and shareholder dividends should be curtailed. Commenters maintain that the Companies should reduce rates, adjust their profit margins and build toward a renewable future in response to the economic impacts of COVID-19. Various commenters agreed with the Monroe County Workers Benefit Council that rate increases should be denied, a year-round moratorium on utility shutoffs should be enacted, and arrears for residents with incomes at or below 250 percent of the federal poverty level should be cancelled.

Many commenters state that average citizens, low income customers and people living on fixed incomes cannot afford the requested rate increases, particularly given the increasing costs of living. Some commenters state that the requested increases exceed any cost-of-living adjustments and should be absorbed through management pay cuts or decreases in staff. According to some commenters, utilities should not receive any rate increases until they, among other things, convert to a performance-based incentive structure built on achieving affordable green energy goals and allocate a specific amount of funding each year to place electrical lines underground. Others stated that the delivery costs should never be more than the commodity costs.

Some commenters stated that rate increases are not justified given numerous electric outages and poor customer service. Various commenters stated that the residential fixed charges are too high, reduce the incentive for ratepayers to be energy efficient, and disproportionately impact low- and moderate-income customers. Other commenters state that ratepayers should not have to pay increased costs for vegetation management because such increases are due to the Companies' neglect of ongoing vegetation management. According to those commenters, the Companies' vegetation management should be paid by shareholders out of the Companies' profits.

Many commenters oppose rate increases for implementation of AMI. Some commenters raise health concerns about AMI and others state that implementation of AMI will benefit the utilities, not the ratepayers, and that the Companies' shareholders therefore should pay for AMI.

Citing the CLCPA, many commenters stated that the gas-driven business models of utilities must be discarded in favor of modernizing the electric grid to support renewables and beneficial electrification. A few commenters stated that the Companies should not invest in more pipeline that will not be completed for a dozen years and will become stranded assets. Various commenters specifically opposed any upgrades to the DeRuyter Pipeline as unnecessary and inappropriate in light of State policy to reduce fossil fuel emissions.

Commenters stated that the customer service walk-in offices in Sullivan County should not be closed because 18 percent of the population has no computer, 24 percent has no broad band access, and many do not have cellular phone service. They maintain that the closure of such walk-in offices will have a particularly negative effect on elderly and low income customers. One commenter opposed the use of energy from the Homer City Generation Station in Pennsylvania, stating that NYSEG should not be allowed to purchase electricity from coal-powered generating plants.

State Senator Peter B. Harckham (40th District) expressed concern about NYSEG's requested electric rate increase. State Senator Metzger (42nd District) stated, among other things, that NYSEG had poor service as a result of years of underinvestment in distribution infrastructure, vegetation management, and its workforce; that the proposed rate for opting out of AMI was too high; and that fixed customer charges should be reduced. State Senator Shelley B. Mayer (37th District) stated that the requested increases to fixed customer service charges would act as a disincentive to conserve energy and that the requested increases in general were particularly burdensome on low-usage customers and on those with low- and fixed-incomes. Senator Mayer also stated that ratepayers should not be responsible for all of the costs for vegetative management to allow NYSEG to play "catch up" resulting from NYSEG's decision to defer maintenance and operations expenditures. Senator Mayer raised concerns about NYSEG's AMI proposal and stated support for the creation of a State Office of the Utility Consumer Advocate.

Assemblyperson Kevin Byrne (94th District) acknowledged NYSEG's need to upgrade its infrastructure and to implement a more aggressive vegetation management plan, but stated that the costs for such activities should be paid by NYSEG or New York State, and not by ratepayers, many of whom are still recovering from the effects of Winter Storms Riley and Quinn and a subsequent tornado. Assemblyperson Barbara Lifton (125th District) requested that NYSEG's rate cases be resolved in compliance with the State's climate goals stated in the CLCPA and that non-pipe alternative be required where possible. Assemblyperson Marjorie Byrnes (133rd District) opposed the Companies' requested rate increases as too high.

Sullivan County Manager Joshua A. Potosek opposed NYSEG's requested electric rate increases, noting problems with NYSEG's maintenance of lines and poles, vegetation management, emergency planning and adequate staffing. Mr. Potosek raised specific concerns with NYSEG's proposed rate structure, AMI program and opt-out option, closure of walk-in offices and ability to ensure grid reliability. Village of Woodbridge Mayor Joan Collins wrote in support of Mr. Potosek's position, stressing that NYSEG's proposed rate increases were not feasible for many Village residents and that NYSEG's AMI proposal would require many Village residents to upgrade from 60-amp to 100-amp service at a cost of thousands of dollars or pay a $20 monthly opt-out fee that many would find burdensome.

Broome County Executive Jason T. Garnar wrote in opposition to a rate increase for NYSEG, citing the struggles of those with low and fixed incomes, stating that increased rates would negatively impact local businesses, and noting that any increase in rates to be paid by Broome County itself would be funded by taxpayers. City of Norwich Mayor Christine A. Carnrike, Town of Tusten Councilperson Brandi Merolla, Village of Hancock Mayor Carolann McGrath, Town of Hartwick Supervisor Robert J. O'Brien, Town of Keene Supervisor Joseph P. Wilson, Town of Ellington Supervisor Laura M. Cronk, and Village of Hammondsport Emery L. Cummings, Jr. opposed NYSEG's requested rate increases as too costly. The officials from the Towns of Tusten and Keene and the Village of Cayuga Heights complained about NYSEG's actions with respect to the conversion of NYSEG streetlights to LED streetlights and requested that the Commission establish a protocol for the municipal LED streetlight conversion program that would establish clear guidelines, timelines and oversight to ensure NYSEG's accountability in moving the program forward transparently and expeditiously.

The Tompkins County Legislature submitted a resolution listing various concerns with NYSEG's service and requested rate increases and urged the Commission to condition any rate increase on "NYSEG's ability to provide safe, reliable, and sustainable energy to its customers to facilitate connection of solar and wind energy systems on to the grid, and to employ performance-based and earning adjustment mechanisms tied to specific timelines for implementation." The Monroe County Legislature, the Chenango County Board of Supervisors, and the Yates County Legislature also submitted resolutions opposing the requested rate increases as too costly.

Town of North Salem Supervisor Warren J. Lucas and Town of Somers Supervisor Rick Morrissey complained about NYSEG's tree removal policy. They stated that residents have reported that NYSEG does not leave cut trees in manageable lengths for removal by residents and leaves large portions of cut trees on residents' property, sometimes in front yards or on the edge of the roadway where they may create a hazard. They request that NYSEG be required to properly dispose of all trees. In a later public comment, Mr. Lucas stated his concerns that sufficient funding was not established in the rate case for tree removal and that NYSEG would remove cut trees from property only upon request and not automatically.

After the Joint Proposal was filed, numerous commenters filed statements in opposition to the Joint Proposal as inappropriate in light of the economic crisis resulting from the Covid-19 pandemic and as contrary to the Commission's goals in establishing the generic COVID-19 proceeding.[4] Those commenters stated that the Companies should not be allowed to proceed with "unnecessary spending and massive rate increases" during such an economic crisis.

The Rochester City Council opposed the proposed rate increases in the Joint Proposal, stating that it could not support the proposed increases in the midst of the COVID-19 pandemic. The Rochester City Council also opposed the proposed closure of RG&E's customer service walk-in office in Rochester.

State Senators Mayer (37th District) and Harckham (40th District) wrote in opposition to the Joint Proposal in regards to NYSEG Electric, stating that it was unaffordable and would "lock in three years of very large rate increases during an unprecedented health pandemic, soaring unemployment numbers and economic uncertainty." They opposed increases to NYSEG's fixed monthly customer charges and noted concerns with ratepayers having to pay increased rates for vegetation management, stating that ratepayers should not have to pay for the "Company's decision to defer prudent maintenance and operations expenditures."

State Senator Serino (41st District) opposed NYSEG's requested rate increasing, stating that NYSEG unprepared for Tropical Storm Isaias that left many people in her district without power. Yorktown Town Supervisor Matthew J. Slater submitted a petition signed by numerous residents in opposition to the NYSEG's proposed rate increases.

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[4] Case 20-M-0266, Proceeding on Motion of the Commission Regarding the Effects of COVID-19 on Utility Service, Order Establishing Proceeding (issued June 11, 2020).

The New York State Economic Development Council (NYEDC) and the Greater Rochester Enterprise (GRE) separately filed letters in support of the Joint Proposal, stating that the Joint Proposal represents a fair and reasonable settlement for the Companies, their customers and the community. The NYEDC and GRE state that the Joint Proposal makes a sincere effort to incorporate creative and strategic relief for ratepayers in light of the COVID-19 pandemic while providing for improved service and safety. In their view, the necessary projects and economic programs proposed strike an appropriate balance between improved service, job creation and retention, and the path toward economic recovery.

Attachment 9

SUBJECT: Filings by NEW YORK STATE ELECTRIC & GAS CORPORATION

Amendments to Schedule P.S.C. No. 87 – Gas

First Revised Leaves Nos. 11.6, 29
Second Revised Leaves Nos. 28, 30, 31
Third Revised Leaves Nos. 22, 23, 33
Fifth Revised Leaves Nos. 52.1, 52.2
Sixth Revised Leaf No. 27
Seventh Revised Leaves Nos. 2, 38, 54
Eighth Revised Leaf No. 36
Ninth Revised Leaf No. 25
Tenth Revised Leaf No. 24, 32
Eleventh Revised Leaf No. 18
Twelfth Revised Leaves Nos. 52, 55
Sixteenth Revised Leaves Nos. 15, 47
Seventeenth Revised Leaves Nos. 14, 34
Nineteenth Revised Leaf No. 12
Twenty-Fourth Revised Leaf No. 48
Suspension Supplement Nos. 33, 34, 35, 36, 37

Amendments to Schedule P.S.C. 88 – Gas

First Revised Leaves Nos. 64.2, 75.1
Second Revised Leaves Nos. 61.2, 64.1, 117
Third Revised Leaves Nos. 50.35, 75, 109.1
Fourth Revised Leaves Nos. 59, 61.1, 92.1
Fifth Revised Leaves Nos. 50.15, 62, 113.2
Sixth Revised Leaves Nos. 54, 64
Seventh Revised Leaves Nos. 57, 108
Eighth Revised Leaves Nos. 4, 70, 73, 114
Tenth Revised Leaves Nos. 58, 74, 78, 126
Thirteenth Revised Leaves Nos. 2, 50.26
Fourteenth Revised Leaves Nos. 63, 127
Fifteenth Revised Leaves Nos. 3, 52.1, 113, 113.1
Sixteenth Revised Leaf No. 60
Seventeenth Revised Leaf No. 68
Nineteenth Revised Leaf No. 96
Twentieth Revised Leaves Nos. 51, 98.1, 101, 103
Twenty-First Revised Leaf No. 69
Twenty-Sixth Revised Leaf No. 105
Suspension Supplement Nos. 50, 51, 52, 53, 54

Amendments to Schedule P.S.C. No. 90 – Gas

Fifth Revised Leaves Nos. 19, 105.2.1
Sixth Revised Leaf No. 20
Seventh Revised Leaf No. 105.2
Ninth Revised Leaf No. 105
Twelfth Revised Leaf No. 90.6
Sixteenth Revised Leaf No. 3
Nineteenth Revised Leaf No. 3.1
Suspension Supplement Nos. 23, 24, 25, 26, 27

Amendments to Schedule P.S.C. No. 119 – Electricity

Third Revised Leaves Nos. 61, 81
Fifth Revised Leaves Nos. 15, 53, 54, 98
Sixth Revised Leaf No. 2
Eighth Revised Leaf No. 52
Ninth Revised Leaf No. 4
Supplement Nos. 17, 19, 21, 22, 23

Amendments to Schedule P.S.C. No. 120 – Electricity

Original Leaf No. 117.8.0
First Revised Leaves Nos. 113, 114, 115, 117.8.1
Second Revised Leaves Nos. 17.1, 112, 117.43, 117.46.26.2.1, 117.46.30
Third Revised Leaves Nos. 41, 43, 44, 45, 46, 47, 117.46.17, 117.46.29, 117.46.31, 152, 180, 199, 288.3, 292, 319
Fourth Revised Leaves Nos. 48, 117.46.8, 117.46.28, 200, 279
Fifth Revised Leaves Nos. 73, 111, 111.1, 117.46.19, 143, 243.3, 287.2
Sixth Revised Leaves Nos. 23, 183
Seventh Revised Leaves Nos. 117.7, 131.1, 158.1, 294.12
Eighth Revised Leaves Nos. 17, 27.1, 42, 58, 117.6
Ninth Revised Leaves Nos. 117.12, 154, 243.4

Tenth Revised Leaves Nos. 27, 108, 128, 134
Eleventh Revised Leaf No. 198.2
Twelfth Revised Leaf No. 28
Thirteenth Revised Leaves Nos. 26, 185, 195, 207, 243.2, 260, 271, 287.1, 299
Fourteenth Revised Leaves Nos. 21, 122, 203, 257, 268, 288.2, 296
Fifteenth Revised Leaves Nos. 119, 181.1, 193.4, 213
Sixteenth Revised Leaves Nos. 22, 142, 149, 150, 194, 202
Seventeenth Revised Leaves Nos. 147, 155, 156, 170, 176, 184, 212, 214, 274.1
Eighteenth Revised Leaves Nos. 18, 129, 173, 210, 243
Nineteenth Revised Leaf No. 247
Twentieth Revised Leaves Nos. 117.8, 117.9, 161
Twenty-First Revised Leaves Nos. 2, 288.1
Twenty-Third Revised Leaves Nos. 124, 229, 262
Twenty-Fourth Revised Leaves Nos. 201, 216
Twenty-Fifth Revised Leaves Nos. 131, 157, 158, 198, 248, 249, 250
Twenty-Sixth Revised Leaves Nos. 215, 228, 230, 293
Twenty-Seventh Revised Leaves Nos. 139, 167, 287
Twenty-Eighth Revised Leaves Nos. 288, 310, 318
Thirtieth Revised Leaves Nos. 166, 197, 221, 300
Thirty-First Revised Leaves Nos. 123, 133, 261
Thirty-Second Revised Leaf No. 208
Thirty-Three Revised Leaf No. 272
Forty-Sixth Revised Leaf No. 289
Supplement Nos. 53, 54, 55, 56, 57

Amendments to Schedule P.S.C. No. 121 - Electricity

First Revised Leaf No. 15
Second Revised Leaf No. 14.0
Third Revised Leaf No. 39
Fourth Revised Leaves Nos. 58.1, 58.2
Fifth Revised Leaves Nos. 9, 14.2, 62, 63
Sixth Revised Leaf No. 38
Seventh Revised Leaf No. 4

Ninth Revised Leaf No. 14.1
Tenth Revised Leaf No. 16
Eleventh Revised Leaves Nos. 36, 58
Thirteenth Revised Leaves Nos. 26, 54.6, 64
Fifteenth Revised Leaves Nos. 17, 22.2, 40
Sixteenth Revised Leaves Nos. 27, 42
Seventeenth Revised Leaves Nos. 28, 35, 41, 56
Eighteenth Revised Leaves Nos. 34.3, 55
Nineteenth Revised Leaves Nos. 43, 57
Twenty-First Revised Leaf No. 2
Twenty-Eighth Revised Leaves Nos. 24, 59
Twenty-Ninth Revised Leaves Nos. 37
Supplement Nos. 28, 29, 30, 31, 32

SUBJECT: Filings by ROCHESTER GAS AND ELECTRIC CORPORATION

Amendments to Schedule P.S.C. No. 18 – Electricity

First Revised Leaves Nos. 9, 22, 24.5, 25, 35
Second Revised Leaves Nos. 3.1, 16, 24.4, 29.1
Third Revised Leaf No. 31
Fourth Revised Leaf No. 10
Eighth Revised Leaf No. 26.4
Twelfth Revised Leaves Nos. 2, 45.4
Fourteenth Revised Leaf No. 28
Fifteenth Revised Leaf No. 39
Sixteenth Revised Leaf No. 27
Seventeenth Revised Leaves Nos. 26, 26.1.1, 30
Eighteenth Revised Leaf No. 29
Nineteenth Revised Leaves Nos. 37.1.1, 45.1.1
Twentieth Revised Leaf No. 37
Twenty-First Revised Leaf No. 45
Supplement Nos. 26, 27, 28, 29, 30

Amendments to Schedule P.S.C. No. 19 – Electricity

Original Leaf No. 160.26.1.0
First Revised Leaves Nos. 4.2, 81.1.2, 86.11.1
Second Revised Leaves Nos. 51.1, 169.3, 188.1
Third Revised Leaves Nos. 4.3, 51, 64, 70, 86.11, 87, 180, 181, 193.2.1, 201, 214.1.1, 251
Fourth Revised Leaves Nos. 86.23, 160.39.21.2, 170, 199.4, 219, 222.2, 226, 242.1, 242.2

Fifth Revised Leaves Nos. 160.7, 225
Sixth Revised Leaves Nos. 80.1, 160.26.1.1, 174.1, 183, 200.2, 246
Seventh Revised Leaves Nos. 81.1.1, 84, 85.4, 86.20, 211
Ninth Revised Leaves Nos. 53, 85.1, 167, 188, 191, 199.3
Tenth Revised Leaves Nos. 81.3, 187.4, 194.4, 199.2, 243.1, 246.1, 246.3
Eleventh Revised Leaves Nos. 161.2.1, 169.1.1, 213.1.1, 244
Twelfth Revised Leaves Nos. 160.26, 161, 195.1, 246.2
Thirteenth Revised Leaves Nos. 195, 199.1, 210.5
Fourteenth Revised Leaves Nos. 166.4, 190.4
Fifteenth Revised Leaves Nos. 4.1, 169.1, 193.1.1
Sixteenth Revised Leaves Nos. 189, 213.1, 242
Seventeenth Revised Leaves Nos. 164.4, 165, 169, 187.3, 195.2
Eighteenth Revised Leaves Nos. 3, 160.26.1, 194.2
Nineteenth Revised Leaf No. 166.1.1
Twentieth Revised Leaves Nos. 81, 164.1.1, 176, 187, 194, 218
Twenty-First Revised Leaves Nos. 161.1, 193, 193.1
Twenty-Second Revised Leaves Nos. 174.3, 190.3, 210.2
Twenty-Third Revised Leaves Nos. 166, 210
Twenty-Fourth Revised Leaves Nos. 161.2, 164, 190
Twenty-Fifth Revised Leaf No. 2
Twenty-Sixth Revised Leaf No. 174
Supplement Nos. 65, 67, 69, 70, 71

Amendments to Schedule P.S.C. No. 16 – Gas

Second Revised Leaves Nos. 83.1, 127.46.6, 154, 157
Third Revised Leaves Nos. 158, 159
Fourth Revised Leaves Nos. 134.2, 153
Fifth Revised Leaves Nos. 128.1, 130.1, 134.3, 145.1, 145.2, 148
Sixth Revised Leaves Nos. 83, 127.46.1

Seventh Revised Leaves Nos. 53, 65, 127.46.3, 130.6.1
Eighth Revised Leaf No. 147.8
Ninth Revised Leaves Nos. 134, 145, 147.1, 147.3.1
Tenth Revised Leaves Nos. 133.6, 146
Eleventh Revised Leaves Nos. 127.46.2, 133.1
Twelfth Revised Leaves Nos. 134.1, 136
Fourteenth Revised Leaf No. 127.32
Fifteenth Revised Leaves Nos. 130.6, 135
Sixteenth Revised Leaf No. 70
Seventeenth Revised Leaves Nos. 4.1, 147.2
Twentieth Revised Leaf No. 2
Twenty-Second Revised Leaf No. 128
Supplement Nos. 41, 42, 43, 44, 45