STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 21-E-0074 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service.

CASE 21-G-0073 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Gas Service.

ORDER ADOPTING TERMS OF JOINT PROPOSAL AND ESTABLISHING ELECTRIC AND GAS RATE PLANS, WITH ADDITIONAL REQUIREMENTS

Issued and Effective: April 14, 2022

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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

At a session of the Public Service
Commission held in the City of
Albany on April 14, 2022

COMMISSIONERS PRESENT:

Rory M. Christian, Chair
Diane X. Burman
James S. Alesi
Tracey A. Edwards, dissenting
John B. Howard
David J. Valesky
John B. Maggiore

CASE 21-E-0074 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service.

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ORDER ADOPTING TERMS OF JOINT PROPOSAL AND
ESTABLISHING ELECTRIC AND GAS RATE PLANS,
WITH ADDITIONAL REQUIREMENTS

(Issued and Effective April 14, 2022)

I. INTRODUCTION

This Order adopts the terms of the October 29, 2021 Joint Proposal and supporting schedules, which establishes three-year electric and gas rate plans for Orange and Rockland Utilities, Inc. (O&R or the Company) during the period commencing on January 1, 2022 through December 31, 2024 (Rate Plans).[1] In addition to O&R, signatories to the Joint Proposal include the New York State Department of Public Service trial staff (DPS Staff), the New York Power Authority (NYPA), New Yorkers for Cool Refrigerant Management (NYCRM), and the New York Geothermal Energy Organization (NY Geothermal) (collectively, the Signatory Parties). Intervenors Public Utility Law Project of New York, Inc. (PULP), Alliance for a Green Economy (AGREE), and Bruce Levine oppose the Joint Proposal.[2]

For the reasons detailed below, we find that the agreed-upon three-year Rate Plans and the other terms of the Joint Proposal will result in sufficient mitigation of rate impacts on customers, while preserving the Company's operational and financial stability. We further find that the Joint Proposal meets the public interest criteria set forth in Public Service Law (PSL) §65(1) and is consistent with the Commission's Settlement Guidelines insofar as it meets the environmental, social and economic laws and policies of the State and the Commission, including the objectives of the Climate Leadership

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[1] The Joint Proposal and supporting schedules are appended to this Order as Attachment A.

[2] Intervenors the New York Department of State, Consumer Protection Division, Utility Intervention Unit (UIU), Sustainable Warwick, Bob Wyman, and Local Union 503, I.B.E.W. participated as parties in this proceeding, but are not signatories to the Joint Proposal and did not file opposition to it.

and Community Protection Act (CLCPA), and falls within the range of potential outcomes in a fully litigated proceeding. We therefore conclude that the Joint Proposal is in the public interest and will result in O&R's continued provision of safe and reliable electric and gas service at just and reasonable rates.

II. BACKGROUND

O&R, a wholly owned subsidiary of Consolidated Edison, Inc. and an affiliate of Consolidated Edison of New York, Inc., (collectively, Consolidated Edison), serves electric and gas customers in and around Orange, Rockland, and Sullivan Counties.[3] O&R has approximately 1,100 employees and its headquarters is located in Spring Valley, New York.

O&R provides electric service to customers located in the New York Independent System Operator's (NYISO) Zone G, known as the Hudson Valley load zone.[4] O&R also serves natural gas customers within a 615-square mile service area encompassing 66 communities in Orange and Rockland Counties. The Company has 547 miles of electric transmission lines, 45 substation load areas, 1,849 miles of underground electric distribution lines, and 3,994 miles of overhead electric distribution lines.[5]

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[3] Case 21-E-0113, In the Matter of 2020 Electric Reliability Performance in New York State, 2020 ORU Annual Service Performance Report (filed April 1, 2021), p. 11. O&R also serves additional customers in limited areas in northern New Jersey.

[4] Hearing Exhibit 80 (O&R Witness Joseph Briscese/Electric Supply), p. 5.

[5] https://www.oru.com/en/our-energy-future/how-we-source-our-energy/electricity; https://www.oru.com/en/business-partners/hosting-capacity/system-data

It operates 1,877 miles of gas main and maintains a portfolio of 13 gate stations.[6] Except for a few small areas, O&R operates two separately integrated gas distribution systems, one in Orange County and the other in Rockland County. Customers in Orange County are served by Millennium Pipeline Company (Millennium) and Columbia Gas Transmission system. Customers in Rockland County are served by Millennium, Tennessee Gas Pipeline, and Algonquin Gas Pipeline Transmission system.[7]

The Company's gas operations are also headquartered in Spring Valley, but there are three additional field locations, which manage emergency response, maintenance, and construction activities.[8] The Company has a training center in Goshen for operator qualification and various field activities. The Company's gas control center is shared with Consolidated Edison in the Bronx, where both Companies coordinate gas purchases and transportation and share Supervisory Control and Data Acquisition (SCADA) operating resources.

A. <u>O&R's January 29, 2021, Initial Tariff Filing</u>

On January 29, 2021, O&R filed proposed revisions to its electric and gas tariff leaves representing new rate plans to be effective on February 28, 2022. The Company presented a one-year rate plan, but also provided financial information for the two succeeding rate years to allow for the development of a multi-year rate plan. In its initial rate filings, the Company sought a $24.5 million increase in its electric revenue requirement, representing a 3.3 percent increase in total

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[6] Hearing Exhibit 66 (O&R GIO Panel), pp. 7-8.

[7] Hearing Exhibit 66 (O&R Gas Infrastructure and Operations Panel), pp. 10-11.

[8] Hearing Exhibit 66 (O&R Gas Infrastructure and Operations Panel), pp. 7-8.

revenues; and a $9.8 million increase in its gas revenue requirement, representing a 4.0 percent increase in total revenues. O&R also sought a 9.5 percent return on equity for both electric and gas and a 50 percent debt to 50 percent equity ratio.[9]

Electric Service. O&R proposed an electric delivery revenue increase of $24.5 million, including applicable revenue taxes and low-income customer credits, or a net increase of $23.9 million, representing an overall increase to delivery revenues of approximately 5.8 percent or an overall increase in total revenues of approximately 3.3 percent.[10] The electric revenue proposal would increase the monthly bill for an average residential customer using 600 kilowatt hours (kWh) by approximately 7.5 percent for delivery charges and would increase the total bill by approximately 4.9 percent.[11] The Company claimed that the major rate drivers for its proposal

[9] O&R January 29, 2021, Filing Letter, p. 4; Hearing Exhibit 26 (O&R Witness Yukari Saegusa – Cost of Capital), pp. 39-40; Hearing Exhibit 1 (O&R Accounting Panel), p. 8.

[10] Hearing Exhibit 100 (O&R Electric Rates Panel), pp. 6-7. The Company indicates in its testimony that in determining the delivery revenue increase, it allocated the revenue increases among customer classes by first excluding $423,000 in tax revenues (i.e., New York State Gross Receipts and Franchise Tax surcharge revenues, Municipal Tax surcharge revenues and Metropolitan Transportation Authority Business Tax surcharge revenues) and then by excluding $142,746 in low-income customer credits, for an adjusted net delivery revenue increase of $23.9 million.

[11] The projected customer bill impacts reflect the expiration of the temporary surcharge of $5.7 million in the Energy Cost Adjustment authorized in O&R's last rate plan established in Cases 18-E-0067 and 18-G-0068, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric and Gas Service (O&R – Rates), Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans (issued March 14, 2019) (2019 Rate Order).

were related to infrastructure costs associated with return on rate base and depreciation on plant additions, as well as reduced sales and increases to labor expense.

The Company also proposed in its initial filing to perform integrated planning and advanced forecasting; to implement clean energy projects and advanced distribution and energy resource management systems; to adapt its system for increased distributed energy resources; to encourage electric vehicle adoption in its service territory; to support initiatives and programs designed to enhance the customer experience; to undertake storm hardening and strategic undergrounding investments, grid modernization, and distribution automation projects; to expand tree trimming and hazardous tree removal program; and to increase building and transportation electrification measures.[12]

Gas Service. In its initial filing, O&R also proposed a gas delivery revenue increase of approximately $9.82 million (inclusive of adjustments for gross receipts/revenue taxes and low-income customer credits) and a total revenue requirement of $11.10 million, representing a 7.19 percent increase in delivery revenues, or an overall 4.0 percent increase in total revenues.[13] The proposed gas revenue increase would increase the monthly bill for an average residential customer using 100 centum cubic feet (Ccf) monthly by approximately 9.1 percent for delivery charges and increase the total bill by approximately 5.8 percent. The Company claimed that the major rate drivers for its proposal were related to new infrastructure investment,

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[12] Hearing Exhibit 60 (O&R Electric Infrastructure and Operations Panel).

[13] Hearing Exhibit 1 (O&R Gas Rates Panel), pp. 23-26; Hearing Exhibit 223 (DPS Staff Rates Panel), p. 25.

return on rate base and depreciation on plant additions, and reduced sales revenue.[14]

The Company also proposed in its initial filing to implement, among other things, a new Pipeline Safety Management System; to install Advanced Metering Infrastructure (AMI)-enabled Natural Gas Detectors; to replace/upgrade aging infrastructure; to continue removal and/or replacement of leak prone pipes (LPP); and technology investments to improve safety, enhance customer service, and increase operational efficiency.[15] The Company also proposed to shorten depreciation lives of longer-lived gas assets (phased-in during 2023/2024 to mitigate customer impacts during the current economic conditions).

Common Electric and Gas Proposals. For both its electric and gas business operations, the Company proposed to continue investments in customer-facing technology, including implementation of new customer care and billing, information technology solutions, AMI, and Business Cost Optimization efforts forecasted to save in 2022 approximately $1.3 million for electric and $0.6 million for gas.

As additional steps to address the economic impact of Covid-19, the Company proposed to shorten the amortization period for excess deferred federal income taxes from 15 years (as established in the 2019 Rate Order) to three years, which would reduce the electric and gas revenue requirements by $5.7 million and $2.3 million, respectively.[16] In addition, the

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[14] January 27, 2021, Tariff Filing Letter, p. 2; The Company's Tariff Filing Letter indicated that approximately one-third of the proposed revenue increase for gas (or about $3.0 million) is due to a lower gas sales forecast. Hearing Exhibits 1, (O&R Accounting Panel), pp. 7-9.

[15] Hearing Exhibit 66 (O&R Gas Infrastructure and Operations Panel), pp. 22-24.

[16] Hearing Exhibit 1 (O&R Accounting Panel), p. 10.

Company proposed to amortize energy efficiency costs over 10 years, storm costs over five years, and pension and other post-employee benefits (OPEB) over the period 2022 to 2024.

B. O&R's March 31, 2021, Updated Filing

On March 31, 2021, and April 1, 2021, O&R updated its filing and included revised and supplemental testimony and/or exhibits for the following panels: Accounting, Compensation and Benefits, Depreciation, Earnings Adjustment Mechanism, Electric Forecasting, Electric Infrastructure and Operations, Environmental Health and Safety, Gas Forecasting, and Gas Infrastructure and Operations. In its updated filing, O&R proposed a further increase to its electric revenue requirement by $3.4 million, for a total revenue requirement increase of $27.8 million, and a decrease to its gas revenue requirement by approximately $8.6 million, for a total revenue requirement increase of $1.2 million.[17] The Company explained that the main drivers of these changes were due to sales and other operating revenues, Operation and Maintenance (O&M) and depreciation expenses, amortization of deferred costs, income taxes, and carrying charges.[18] With its updated filing, O&R submitted several comparison schedules showing the differences between its January 29, 2021 initial filing and its March 31, 2021 updated filing.[19]

The Company reported sales revenue to be approximately $5.5 million higher for electric and $13 million higher for gas

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[17] Hearing Exhibit 107 (O&R Updated Accounting Panel), pp. 3-4; Hearing Exhibits 108-109 (AP-E2, AP-E3).

[18] Hearing Exhibit 107, pp. 4-7.

[19] Hearing Exhibit 108 (O&R Updated Accounting Panel), pp. 7-8; Hearing Exhibits 109-112 (O&R Updated Accounting Panel Exhibits and Schedules AP-E2, AP-E3, AP-G2, AP-G3, AP-5, AP-7).

than had been stated in its initial filing. Other operating revenues for electric and gas decreased by approximately $1.6 million and $0.5 million, respectively, from the revenue amounts reflected in the initial filing. The Company explained that the decrease was mainly due to the Company reducing to $0 the amount of late payment charges it had forecast, given the uncertainty associated with the Covid-19 pandemic and an inability to accurately project the amount of such charges.[20] The Company also asserted in its updated filing that pending State legislation could extend the moratorium on utility terminations and bar the imposition of late fees until July 2022. The Company again proposed symmetric reconciliation and the imposition of a surcharge, as it had in its initial filing.[21]

With respect to O&M expenses, the Company indicated that they were, respectively, $4.6 million higher for electric and $1.1 million higher for gas than stated in the initial filing due to additional contractor costs for storm restoration ($2.8 million for electric) and increases to OPEB ($1.4 million for electric and $0.7 million for gas).[22]

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[20] Hearing Exhibit 107, pp. 4-5. The Company proposed to sur-credit customers to reconcile the impact of all late fee payments collected.

[21] Hearing Exhibit 107 (O&R Updated Accounting Panel), pp. 23-24. In a law passed in May 2021 amending L. 2020, ch. 108 and PSL §§32, 89-b, 89-l, 91, the moratorium was extended to July 1, 2022, for residential and small business (with fewer than 25 employees) customers and prohibits late fees or penalties on arrears incurred during the moratorium. L. 2021, ch. 106 (A.6255-A/S.1453-B). The law expressly allows recovery of deferred lost revenues. The Company sought approval to reconcile waived late payment fees through a surcharge, if the Commission continued such a waiver in the proceeding.

[22] Id., p. 5.

The Company further indicated that proposed amortization of deferral costs for electric increased the revenue requirement by $3.9 million, consisting of storm cost amortizations ($2.9 million), waived late payment charges ($1.7 million) and increased OPEB deferrals ($1.6 million), which were partially offset by reductions in environmental remediation deferrals ($1.3 million). Proposed amortization of deferral costs increased by $1.8 million the gas revenue requirement, including increases in environmental remediation deferrals ($1 million), pension/OPEB deferrals ($0.8 million), and waived late payment charges ($0.5 million), which were partially offset by reductions in low-income deferrals ($0.4 million).[23]

The Company's updated depreciation expense forecasts resulted in a $1.2 million decrease to the electric revenue requirement and a $0.2 million increase to the gas revenue requirement.[24] The Company increased forecasted electric rate base by approximately $14.0 million more than initially proposed, resulting in a $1.4 million increase to the carrying cost on rate base additions.

The Company indicated that the primary drivers of the increase to electric rate base result from increases in net regulatory deferrals and non-interest-bearing construction work in progress (CWIP), partially offset by net plant decreases. Similarly, the Company projected gas rate base for the Rate Year to be approximately $9.0 million higher than reflected in the initial filing, resulting in a $0.9 million carrying cost increase on gas rate base additions. The Company also indicated that the electric and gas revenue requirements decreased by $1.4 million and $0.1 million, respectively. The change in the

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[23] Id., pp. 7-22.

[24] Id., p. 6.

electric revenue requirement was primarily due to decreases in federal income tax expenses.[25] In addition, the Company speculated that the State and Federal corporate income tax rate may increase and, because of the uncertainty of this change, proposed to defer recovery of increased taxes and to impose a surcharge on customers to recover such amounts.[26] The Company asserted that pending State legislation may extend the moratorium on utility terminations and bar imposition of late fees until July 2022 and again proposed symmetric reconciliation and the imposition of a surcharge.[27]

C. 2019 Rate Order

In a March 14, 2019, Order, the Commission adopted the terms of a Joint Proposal and established three-year electric and gas rate plans for O&R (2019 Rate Order).[28] The Commission's 2019 Rate Order increased the Company's electric revenue requirement for each of the three rate years by $8.61 million, $12.06 million, and $12.17 million, respectively. For gas, the

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[25] Id., pp. 6-7.

[26] Hearing Exhibit 107 (O&R Updated Accounting Panel), pp. 22-23. In addition, the Company sought approval to reconcile waived late payment fees through a surcharge, if the Commission continued such a waiver in the proceeding.

[27] Id., pp. 23-24. In a law passed in May 2021 that amended L. 2020, ch. 108 and PSL §§32, 89-b, 89-l, 91, the moratorium was extended to July 1, 2022, for residential customers and small business customers (with fewer than 25 employees) and prohibits late fees or penalties on arrears incurred during the moratorium. L. 2021, ch. 106 (A.6255-A/S.1453-B). The law expressly allows recovery of lost or deferred revenues or after December 31, 2021.

[28] Cases 18—E-0067 and 18-G-0068, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric and Gas Service, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans (issued March 14, 2019) (O&R – Rates).

2019 Rate Order decreased by $5.92 million the gas revenue requirement in Rate Year 1 but increased it by $0.99 million in each of the two succeeding rate years.

The Commission's 2019 Rate Order adopted or continued additional requirements, including customer service performance metrics; low-income customer discounts, affordability programs, and continuation of the Empower-NY services program; performance mechanisms for electric reliability and gas safety (i.e., leak management, leak prone pipe removal, emergency response, damage prevention, and regulatory non-compliance); energy efficiency programs, budgets and targets; gas research/development and demand/response programs; carbon reduction programs focused on electric vehicles and heat pumps; replacement and modernization of aging infrastructure; expansion of AMI; an earnings adjustment mechanism for system efficiency, energy efficiency and other metrics; earnings sharing tiers directed toward site investigation and remediation costs; storm reserve cost modifications; a revenue decoupling mechanism; and financial incentives to pursue non-wires alternatives.

The 2019 Rate Order approved a 9.0 percent return on equity and included financial protection provisions and reporting requirements. It also provided for a 15-year amortization of unprotected excess deferred federal income tax balances and pass-back to customers associated with the lower Federal tax rate under the Tax Cut and Jobs Act of 2017 (2017 Tax Act).[29] The 2019 Rate Order also adopted the Joint Proposal's agreement that O&R would provide in its next rate case an alternative embedded cost of service (ECOS) study to be used as a reference for parties regarding how gas costs may be

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[29] Cases 18-E-0067 and 18-G-0068, O&R - Rates, 2019 Rate Order, pp. 32-33.

allocated where transmission and distribution components are classified as 100 percent demand-related.[30]

D. Generic Gas Planning Proceeding

In March 2020, the Commission commenced a generic gas planning proceeding, which seeks to ensure, among other things, that gas utilities implement improved planning and operational practices to meet customer needs, to minimize infrastructure investments that may have long-term greenhouse gas emissions and ratepayer implications, and to conduct such practices consistent with the CLCPA (Gas Planning Proceeding).[31] O&R and all other New York gas utilities are parties to the Gas Planning Proceeding and were provided an opportunity to be heard on the issues identified by the Commission.

In initiating the Gas Planning Proceeding, the Commission found that continuing the existing planning and investment in gas infrastructure will have significant, long-term implications for, among other things, potential moratoria and greenhouse gas emissions, and that "[t]he current approach to gas system planning poses risks of incomplete alignment with [the] CLCPA, sub-optimal consideration of alternatives and timeframes, increased risk and cost to consumers, and unsatisfactory provision of service and solutions for those same

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[30] Cases 18-E-0067 and 18-G-0068, O&R - Rates, 2019 Rate Order, pp. 79-80.

[31] See Case 20-G-0131, Proceeding on Motion of the Commission in Regard to Gas Planning Procedures, Order Instituting Proceeding (issued March 19, 2020), pp. 4-10 (Gas Planning Proceeding).

consumers."[32] The Commission's stated objective is to align gas planning procedures with the CLCPA and to recognize viable alternatives to gas infrastructure, taking into account their useful life and resulting costs and risks.

The Commission ordered the gas utilities in the Gas Planning Proceeding to file reports and proposals to modernize the gas planning process; to address peaking services and moratorium management; to analyze supply and demand; and to identify the extent to which they currently use or anticipate using demand reducing measures including energy efficiency, demand response, deployment of non-pipe alternatives, and other measures to address identified areas of supply/demand imbalance or to aid in the management of moratoria, including targeted implementation of existing and new energy efficiency and electrification programs and targets.[33]

On February 12, 2021, DPS assigned staff submitted separate proposals in the Gas Planning Proceeding that addressed modernization of the gas planning process and management of gas service moratoria.[34] On May 3, 2021, and June 4, 2021, O&R and its affiliate, Consolidated Edison, along with several other

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[32] Case 20-G-0131, Gas Planning Proceeding, pp. 6-7. As part of the Gas Planning Proceeding, the Commission also sought greater transparency surrounding the practice of procuring gas supply from affiliates and incentives that are not aligned with the State's policies.

[33] Case 20-G-0131, Gas Planning Proceeding, pp. 12-14.

[34] Id.; Staff Gas System Planning Process Proposal, p. 33 (filed February 12, 2021) (recommending that the Commission direct local distribution companies to begin filing long term plans every three years, which reflect the State's greenhouse gas emissions reductions goals and incorporates stakeholder input); Staff Moratorium Management Proposal, p. 16 (filed February 12, 2021) (recommending that the Commission direct implementation of moratorium management measures that ensure sufficient notice of a moratorium and follow certain protocols during same).

local distribution companies, submitted joint comments to the Commission responding to the DPS proposals and addressing, among other things, the scope of the proceeding, the gas planning process, demand forecasts, resource alternatives, a benefit-cost analysis framework, depreciation, affiliate transactions, and the CLCPA.

The Commission has not issued a final order defining the measures necessary to address the identified issues associated with future gas planning and Commission action in the Gas Planning Proceeding remains pending.

E. CLCPA and Climate Action Council Proceedings

On July 18, 2019, the CLCPA was signed into law.[35] It "is among the most ambitious climate laws in the world and requires New York to reduce economy-wide greenhouse gas emissions 40 percent by 2030 and no less than 85 percent by 2050 from 1990 levels."[36] The law creates the Climate Action Council, which is charged with developing a scoping plan that contains recommendations to meet the emission reduction targets and place New York on a path toward carbon neutrality.[37]

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[35] L. 2019, ch. 106.

[36] https://climate.ny.gov/Our-Climate-Act/Draft-Scoping-Plan.

[37] ECL §75-0103. The Climate Action Council is a 22-member committee led by New York State Department of Environmental Conservation Commissioner and New York Energy Research and Development Authority President to draft the Scoping Plan and related documents. Other members of the Council include the heads of State Agencies and Authorities and several Appointees. See https://climate.ny.gov/Climate-Action-Council.

On December 30, 2022, the Climate Action Council issued its Draft Scoping Plan for public comment.[38] The Draft Scoping Plan identified climate change as a significant present and future threat and provided data and analysis for an integrated approach to address each sector responsible for carbon emissions, including transportation, buildings, electricity, industry, agriculture and forest, and waste. The Draft Scoping Plan notes that the greatest sources of the State's emissions are from the buildings and transportation sectors due to fossil fuel combustion. It identifies buildings that combust natural gas and other fuels as responsible for nearly one-third (32 percent) of all greenhouse gas emissions statewide in 2019.[39]

III. PROCEDURAL BACKGROUND

Following O&R's January 29, 2021, initial rate filings, the Secretary issued a Notice of Procedural and Technical Conference on February 12, 2021. On February 25, 2021, the assigned Administrative Law Judges (ALJs) oversaw the virtual Procedural and Technical Conference, at which time the Company presented information regarding its rate filing, including electric and gas revenue requirements, customer bill impacts, and prioritization of storm hardening and resiliency, customer service technology, infrastructure investments, safety

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[38] New York State Climate Action Council "Draft Scoping Plan" (December 2021), available at https://climate.ny.gov/Our-Climate-Act/Draft-Scoping-Plan. The Climate Action Council notes that public comments on the Draft Scoping Plan will be accepted for 120-days or until July 1, 2022.

[39] Draft Scoping Plan, p. 118. The Plan notes that industrial emissions from methane leaks and combustion of oil and gas make up about nine percent of emissions and the transportation sector makes up approximately 28 percent. Draft Scoping Plan, pp. 94, 179.

measures, and several clean energy and energy efficiency programs.[40]

On February 16, 2021, the ALJs issued a ruling adopting a protective order and certain parties thereafter filed acknowledgements agreeing to be bound by the order's terms. On February 25, 2021, the Secretary issued a notice extending the suspension period through June 26, 2021.[41] On March 3, 2021, the ALJs issued a ruling establishing the procedural schedule for the proceedings, which set dates for O&R's submission of updates to its proposal and testimony, the filing of DPS Staff and Intervenor testimony, the filing of rebuttal testimony, and the commencement of an evidentiary hearing.[42] On March 31, 2021, the Secretary issued a notice of public statement hearings scheduled for April 28, 2021, at which time public comments on O&R's rate proposal would be taken.[43]

On March 31, 2021, and April 1, 2021, O&R filed updated testimony and exhibits. Virtual public statement hearings were held on April 28, 2021. After DPS Staff sought an extension to the deadline for filing testimony, which was supported by PULP and UIU, on May 3, 2021, the ALJs issued a ruling revising the procedural schedule.[44] On May 13, 2021, the Secretary issued a notice further extending the suspension

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[40] The ALJs directed the Company to file the presentation made at the Conference. See DMM Item No. 8.

[41] Notice of Suspension of Effective Date of Major Rate Changes and Initiation of Proceedings (issued February 25, 2021).

[42] Ruling Adopting Protective Order (issued February 16, 2021); Ruling Establishing Procedural Schedule (issued March 3, 2021).

[43] Notice of Public Statement Hearings (issued March 31, 2021).

[44] Ruling Revising Procedural Schedule (issued May 3, 2021).

period through December 26, 2021, subject to the Company being made-whole.[45]

Pursuant to the ALJ's revised procedural ruling, on May 27, 2021, PULP filed testimony and exhibits; on May 28, 2021, DPS Staff, UIU, Bruce Levine, NYPA, and NYCRM filed testimony and exhibits; and on June 1, 2021, DPS Staff filed additional testimony and exhibits.

On June 11, 2021, O&R filed a Notice of Impending Settlement Negotiations (Settlement Notice) and invited the parties to participate in the first settlement meeting to be held virtually on June 25, 2021. Settlement negotiations continued from June 25, 2021, until October 26, 2021, and were held in compliance with the notice requirements of 16 NYCRR §3.9. With the Settlement Notice, O&R requested a postponement of the June 28, 2021 evidentiary hearing date and consented to a 30-day extension of the suspension period through December 26, 2021, subject to a "make-whole" provision that would keep the Company in the same position in the absence of the extension.[46] In a June 15, 2021 ruling, the ALJs granted O&R's postponement

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[45] Notice of Further Suspension of the Effective Date of Major Rate Changes (issued May 13, 2021).

[46] The Company defined the parameters of the make-whole provision in its June 11, 2021, letter as follows: Recovering or refunding any revenue under-collections or over-collections, respectively, including interest, that resulted from the extended suspension period. The Company would calculate any revenue adjustments as the difference between (i) sales revenues it would have billed at the new proposed rates during the extension of the suspension period, and (ii) the same level of sales revenues at current rates. The revenue adjustments would include all applicable surcharges and would be subject to reconciliation in accordance with all applicable adjustment mechanisms (including revenue decoupling mechanisms, where applicable). The amortization of net deferrals reflected in the Commission's final order will commence effective January 2022, on an earnings neutral basis.

request and revised the procedural schedule, establishing a July 26, 2021 date for the evidentiary hearing.[47]

On June 18, 2021, O&R filed rebuttal testimony and exhibits addressing issues associated with accounting, return on equity, cost of capital, credit rating, customer service, earnings adjustment mechanisms, depreciation, environmental health and safety, compensation and benefits, property taxes, information technology, gas and electric forecasting, gas and electric infrastructure and operations, gas and electric rates, demand analysis, and cost of service.

In separate letters dated July 14, 2021, O&R consented to further extend the suspension period until March 26, 2022, and requested postponement of the evidentiary hearing for 60 days in favor of settlement negotiations. In a July 16, 2021, ruling, the ALJs adjourned the hearing until September 20, 2021.[48]

On September 10, 2021, O&R again requested postponement of the evidentiary hearing so that settlement negotiations could continue and, at the same time, agreed to extend the suspension period through May 25, 2022, subject to the make-whole provision. In a September 20, 2021, ruling, the ALJs again postponed the evidentiary hearing date until December 8, 2021.[49]

On October 29, 2021, DPS Staff filed a Joint Proposal and 21 Appendices on behalf of the Signatory Parties, including DPS Staff, NYPA, NYCRM, and NY Geothermal. On November 9, 2021, the Secretary issued a Notice of Evidentiary Hearing scheduled for December 8, 2021. On November 19, 2021, and

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47 Ruling Revising Procedural Schedule (issued June 15, 2021).

48 Ruling Revising Procedural Schedule (issued July 16, 2021).

49 Ruling Revising Procedural Schedule (issued September 20, 2021).

November 22, 2021, O&R, DPS Staff, NYPA, NYCRM, and NY Geothermal filed Statements in Support of the Joint Proposal.[50] PULP, AGREE, and Bruce Levine filed Statements in Opposition. On November 22, 2021, the Commission issued an order approving extension of the maximum suspension period through and including May 25, 2022.

On December 2, 2021, O&R filed affidavits of publication of the Joint Proposal in the Times Herald Record and the Journal News, in which the Joint Proposal's terms were summarized, including customer bill impacts in O&R's service territory. On December 3, 2021, O&R filed minor corrections to the Joint Proposal.[51] On December 3, 2021, O&R and DPS Staff filed Reply Statements in Support of the Joint Proposal and PULP and AGREE filed Reply Statements in Opposition.

The ALJs held an evidentiary hearing on December 8, 2021, at which the Joint Proposal along with supporting testimony, exhibits and additional evidence was

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[50] O&R and DPS Staff thereafter filed affidavits adopting the factual representations made in their respective Statements in Support of the Joint Proposal. O&R's affidavit also affirmed completion of the recommendations contained in the Commission's last Management and Operations Audit. Hearing Exhibit 324 (O&R Affidavit of Cheryl M. Ruggiero), p. 1 (citing Case 14-M-0001, "Comprehensive Management and Operations Audits of Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc.").

[51] One of the Joint Proposal's minor corrections was typographical in nature and involved revisions to the estimated amounts of the Company's potential electric and gas costs due to tax law changes, equating to ten basis points of the return on common equity or more (Joint Proposal, p. 42, n. 20). The second correction involved deletion of language for the reconciliation of uncollectible expenses for electric and gas due to Covid-19, resulting in the Joint Proposal no longer providing accrued interest on such expenses at the Other Customer Provided Capital Rate (Joint Proposal, Appendix 9, p. 12).

admitted into the record. At that time, PULP and Bruce Levine conducted cross examination of certain Company and DPS Staff witness panels.

IV. PUBLIC NOTICE AND COMMENTS

Pursuant to the State Administrative Procedure Act (SAPA) §202(1), notices of these proceedings were published in the State Register on May 12, 2021 (SAPA Nos. 21-E-0074SP1 and 21-G-0073SP1). Two public statement hearings were held on April 28, 2021. Approximately 53 members of the public attended the hearings, and three public comments were made regarding the rate filings.

Of the three commenters, a representative of State Senator Elijah Reichlin-Melnick (District 38) expressed objections to increasing delivery rates in O&R’s service territory because doing so would impose economic hardship on customers, and also indicated that the CLCPA requires the Commission to transition away from natural gas and assure no impacts on environmental justice communities. A representative of PULP noted that O&R’s rates should not be increased, reciting the high percentage of customers in arrears on their utility bills during the Covid-19 pandemic through February 2021 and the high unemployment rates in Orange (6.7 percent), Rockland (6.3 percent) and Sullivan (7.2 percent) Counties. PULP asserted the need for an arrears resolution plan and for language access services to be provided in the Company’s service territory as part of the rate cases. PULP also criticized the Company’s requested 9.5 percent return on investment. The third commenter was an individual ratepayer who expressed similar concerns about a lack of affordability if rates were increased.

Nine additional public comments were filed electronically in the Department’s Document and Matter

Management (DMM) system. One was submitted by the Chair of the Environmental Committee of the Rockland County Legislature, who discussed continued customer hardships due to Covid-19 and expressed concern that many residents of Rockland and Orange Counties lack the financial means to pay for a rate increase or to pay for other basic needs, such as food, and that many are in arrears on their utility bills. Other commenters also opposed any rate increases, asserting that the proposed rate increases are excessive, and that O&R could take business measures to increase productivity and lower operating costs without increasing rates. Senator James Skoufis submitted a March 4, 2022 letter urging the Commission to suspend consideration of any rate increases until the Covid-19 pandemic is over and to investigate price surges in O&R's service area, which had resulted in numerous complaints received from his constituents. Senator Skoufis criticized the Joint Proposal's 9.2 percent return on equity in comparison to other Commission-approved rate cases.

V. STATUTORY AND REGULATORY FRAMEWORK

Pursuant to PSL §65(1), in establishing electric and gas rate plans, the Commission must find that the proposed rates assure continuation of safe and adequate service at just and reasonable rates and produce a result that is in the public interest. In the context of a negotiated Joint Proposal, the Commission will adopt its terms upon a finding that, when viewed as a whole, it meets the public interest standard in PSL §65(1). Applying the Commission's Settlement Guidelines, the Joint Proposal must meet the public interest standard after the Commission's consideration of the following factors:

> Whether the Joint Proposal balances the protection of consumers with fairness to investors and the long-term viability of the utility;

Whether it is consistent with the environmental, social, and economic policies of the Commission and the State;

Whether it falls within the range of reasonable likely outcomes that would have resulted in a fully litigated proceeding; and

Whether the record provides a rational basis for the Commission's adoption of it.[52]

These factors and considerations in the context of a negotiated settlement "are themselves elements of the public interest standard."[53]

Upon the application for a major change in rates, PSL §66(19)(c) requires the Commission to review the electric and gas corporation's "compliance with the directions and recommendations made previously by the Commission, as a result of the most recently completed management and operations audit."

VI. THE JOINT PROPOSAL'S TERMS

As discussed in further detail below, the October 29, 2021 Joint Proposal establishes electric and gas Rate Plans for the period commencing on January 1, 2022 through December 31, 2024, and addresses proposed rates, rate design and revenue allocation, reconciliations, programmatic initiatives, revenue decoupling, performance metrics, customer service measures, low-income customer assistance, operational, accounting, and other relevant matters to assure O&R's continued provision of safe and reliable electric and gas service at just and reasonable rates.

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[52] Cases 90-M-0255 and 92-M-0138, Proceeding on Motion of the Commission Concerning its Procedures for Settlements and Stipulation Agreements, Opinion 92-2, Opinion, Order and Resolution Adopting Settlement Procedures and Guidelines (issued March 24, 1992) (Settlement Guidelines).

[53] Id., Settlement Guidelines, p. 30.

The Joint Proposal contains several rate mitigation measures designed to limit customer bill impacts. The Joint Proposal also requires O&R to undertake environmental sustainability efforts that it states are designed "to assist in achieving the goals of the CLCPA,"[54] including reduction of the "carbon intensity" of the gas transmission and distribution system by retirement of leak prone pipe (LPP) every year from 2022 to 2029, considering non-pipeline alternatives (NPAs) for LPP replacement, enhancing customer awareness of low-carbon heating alternatives, providing customer incentives, and installing natural gas detection units for customers. These provisions are detailed below.

A. Term

The Joint Proposal establishes three-year electric and gas rate plans effective January 1, 2022, through December 31, 2024.[55] This three-year term is consistent with most recent negotiated rate cases that have resulted in a Joint Proposal and provides certainty to the Company, its customers, and the parties, by establishing expectations, allowing long-term planning, and preserving resources that may otherwise be devoted to litigation.

B. Rates and Revenue Levels

The Joint Proposal sets electric and gas sales and delivery revenue forecasts on which the revenue requirements for each Rate Year were established.[56] Based upon the Company's

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[54] Joint Proposal, p. 6; Appendix 20.

[55] Joint Proposal, p. 5. Rate Year 1 means the 12-month period starting January 1, 2022, and ending December 31, 2022; Rate Year 2 means the 12-month period starting January 1, 2023, and ending December 31, 2023; and Rate Year 3 means the 12-month period starting January 1, 2024, and ending December 31, 2024.

[56] Joint Proposal, pp. 5-6; Appendices 4 and 5.

initial electric and gas forecasts, when compared with DPS Staff's testimony, the Joint Proposal's forecasts are within the range of reasonable outcomes in a litigated case.[57]

Percentage Revenue Requirement Increases Based on Total Revenue (Including All Delivery and Commodity Revenues)			
	Rate Year 1	**Rate Year 2**	**Rate Year 3**
Electric	2.0%	2.0%	1.9%
Gas	1.9%	1.9%	1.8%

1. Common

a. Rate Drivers

The main drivers for the electric rate increases are lower sales and revenue forecast, the need for investments in the system to maintain safe and reliable service, and the need to adapt the system to increased distributed energy resources consistent with New York's energy plans and policies, including electric vehicle adoption. Additional drivers include the Company's storm hardening and strategic undergrounding investments, grid modernization and distribution automation projects, and expanded tree trimming and hazardous tree removal program that will help meet increased expectations regarding system reliability, resiliency, and expeditious storm restoration.

The main drivers for the gas rate increases also include costs associated with the Company's Pipeline Safety

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[57] Hearing Exhibit 55 (O&R Electric Forecasting Panel), p. 13; Hearing Exhibit 56 (O&R EFP-1), Schedule 3; DPS Staff's Statement in Support, p. 15; Hearing Exhibit 223 (DPS Staff Rate Panel – SRP-2), Schedule 1; Hearing Exhibit 57 (O&R Gas Forecasting Panel), p. 13; Hearing Exhibit 235 (DPS Staff Yezzi), p. 7.

Management System, AMI-enabled natural gas detectors, leak prone pipe removal/replacement, and the shortening of the depreciation period associated with certain gas assets all contribute to gas rate increases.

b. Rate Mitigation

The rate increases provided in the Joint Proposal are intended to be mitigated through several provisions, which are outlined below. Wage increases are eliminated for senior management (specifically, Band 4 managers and executives) for the twenty-seven month period from October 1, 2020 through December 31, 2022.[58] This will result in total rate mitigation of approximately $510,000. To further mitigate rates, the Company will pass on to customers the benefits realized from Covid-19 relief-related payroll tax credits under the federal Employee Retention Tax Credit of $975,000, which will be spread over all three years of the Rate Plans. This tax credit is for the benefit of customers, rather than for shareholders to retain, as the Company proposed, and is consistent with DPS Staff's litigated position.[59]

In addition, the electric and gas revenue requirements in the Joint Proposal contain productivity and efficiency-related adjustments, including a one percent productivity adjustment to the cost of direct labor, pension, post-employment benefits, employee welfare expenses, and payroll taxes.[60] The Joint Proposal's productivity adjustment is consistent with the position DPS Staff advanced in its testimony and with the Commission's practice to use the productivity imputation to

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58 Joint Proposal, pp. 5-6. Non-senior management employees will receive a wage increase of approximately 3 percent during this same period.

59 Hearing Exhibit 127 (DPS Staff Accounting Panel), pp. 83-87.

60 Joint Proposal, pp. 5-6.

capture efficiency savings that cannot be identified and assure that ratepayers receive the benefit of potential future savings.[61] In addition, the Joint Proposal imputes an additional productivity adjustment of $2.9 million over the three-year term of the Rate Plans. The Joint Proposal indicates that the combined productivity and additional adjustments are equivalent to almost a two percent productivity adjustment for Rate Year 1.[62]

Under the Joint Proposal, the Company also has imputed $19.6 million of forecasted savings for targeted efficiencies over the term of the Rate Plans, with no reconciliation if the targeted savings are not achieved.[63]

Finally, the Joint Proposal accelerates the pass-back to customers of unprotected excess deferred federal income taxes balances related to the Tax Cuts and Jobs Act of 2017 by shortening the amortization of the remaining balances from 12 years to six years. This will further reduce the Company's cost of service by $7.4 million for the benefit of customers over the three-year term of the Rate Plans.[64] Although the Company initially proposed shortening the amortization to three years, DPS Staff expressed rate stability concerns in subsequent rate years.[65] Those concerns are addressed by the Joint Proposal's six-year amortization period, which strikes a reasonable balance between rate mitigation and rate stability.

We find that these provisions of the Joint Proposal will reasonably mitigate overall rate impacts over the three-

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[61] Hearing Exhibit 127 (DPS Staff Accounting Panel), pp. 21-25.

[62] Joint Proposal, p. 6.

[63] Id.

[64] Id.

[65] Hearing Exhibit 1 (O&R Accounting Panel), p. 10; Hearing Exhibit 127 (DPS Staff Accounting Panel), pp. 59-62.

year Rate Plans and provide rate stability, while assuring the Company's continued ability to provide safe and adequate service.

c. Sales Forecasts

i. Electric Revenue Forecasts

The Joint Proposal reflects electric revenues, inclusive of the levelized increases of $477.39 million in Rate Year 1, $487.83 million in Rate Year 2, and $494.56 million in Rate Year 3 based on a total annual megawatt-hour (MWh) delivery volume of approximately 3.9 million MWh.[66] The electric forecasts are based on a 10-year average weather normalization through December 2020.

The Joint Proposal increases the Company's electric delivery rates and charges, resulting in annual revenue increases of $4.94 million in Rate Year 1, $16.16 million in Rate Year 2, and $23.13 million in Rate Year 3.[67] The Joint Proposal recommends the levelization of these increases to provide rate stability so that revenues increase each year by $11.68 million.[68] It provides that, due to levelization, the Company's base rate revenues at the end of Rate Year 3 will be lower than they otherwise would be absent levelization. To address the shortfall, the Joint Proposal recommends that $20.91 million of the Rate Year 3 increase be included in base rates and $9.20 million of the increase be refunded in a temporary credit through the Energy Cost Adjustment (ECA) mechanism.[69]

The revenue requirements set forth in the Joint

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[66] Joint Proposal, p. 6, Appendix 4, pp. 1-4. O&R's estimate of delivery volume was 3.7 million MWh.

[67] Joint Proposal, pp. 7-8; Appendix 1 (showing electric revenue requirement calculations); Appendix 4, p. 1.

[68] Joint Proposal, p. 7; Appendix 1, p. 12.

[69] Joint Proposal, p. 8.

Proposal are net of the amortizations of various deferred customer credits and charges currently on the Company's books of account that were previously deferred by the Company, as well as projections of deferred amounts.[70] The levelized revenue changes to each service class, monthly bill comparisons, and "Rates in Brief" are set forth in Appendix 17 to the Joint Proposal, with bill impacts shown below for residential customers using 600 kWh per month.[71]

Electric Customers	**Rate Year 1 Increase**	**Rate Year 2 Increase**	**Rate Year 3 Increase**
Summer (June – Sept.)	$2.11/1.5%	$3.84/2.8%	$4.73/3.4%
Winter (Other months)	$1.65/1.3%	$3.49/2.7%	$3.87/3.0%

ii. Gas Revenue Forecasts

The Joint Proposal reflects gas revenues of $246.2 million in Rate Year 1, $261.7 million in Rate Year 2, and $265.8 million in Rate Year 3, based on deliveries of between 25.1 million and 25.3 million Mcf.[72] The gas revenues include delivery and commodity revenues as well as gross revenue taxes.[73] The gas sales forecasts are based on a 10-year average weather

70 Joint Proposal, p. 8. The list of deferred customer credits and charges to be applied during the Electric Rate Plan is attached to the Joint Proposal as Appendix 3.

71 Joint Proposal pp. 7-8, n. 5; Appendix 17. The proposed revenue changes for each Rate Year will be effective on the first day of each Rate Year. For Rate Year 1, the Company will recover revenue shortfalls resulting from the extension of the suspension period through its proposed "make-whole" provision and differences will be recovered with interest, over the remaining months of 2022, as detailed in Appendix 17, ¶¶ 6 and 7, and Appendix 18, ¶¶ 6 and 7. O&R bills electric residential customers with different rates during the summer months versus the winter months.

72 Joint Proposal, Appendix 5.

73 Joint Proposal, Appendix 5.

normalization through December 2020.

The Joint Proposal increases the Company's retail gas sales rates and transportation service rates for firm gas customers, which are designed to increase annual revenue by $0.66 million in Rate Year 1, $7.4 million in Rate Year 2, and $9.87 million in Rate Year 3.[74] As levelized, these annual revenue changes would be $4.42 million for each Rate Year and are outlined in Appendix 18 of the Joint Proposal. The Joint Proposal notes that the parties recognize that levelizing the revenue increases over the three-year term of the Rate Plans will result in lower revenues for the Company at the end of Rate Year 3. To address the shortfall, the Joint Proposal includes $9.1 million in base rates in Rate Year 3 with a $4.7 million "temporary credit" through the Monthly Gas Adjustment (MGA).[75] The Joint Proposal sets forth levelized revenue changes to each service class, monthly bill comparisons, and "Rates in Brief," with bill impacts shown below for a residential heating customer using 110 Ccf of natural gas per month.[76]

Gas Customers	**Rate Year 1 Increase**	**Rate Year 2 Increase**	**Rate Year 3 Increase**
	$5.38/3.2%	$3.07/1.8%	$3.99/2.3%

d. Annual Team Incentive Plan (ATIP)

The Company's ATIP program is a management incentive

74 Joint Proposal, p. 10, n. 7.

75 Joint Proposal, pp. 10-11. In the absence of levelization, rates would have increased by $17.93 million. Instead, rates will increase by only $13.26 million, resulting in a $4.66 million shortfall. To address this shortfall, Rate Year 3 base rates will be $9.1 million rather than the $4.42 levelized amount, and a $4.7 million refund provided through the MGA.

76 Joint Proposal, Appendix 18.

program that consists of individual and team goals related to safety, reliability, customer service performance indicators, environmental excellence, public safety, and effective cost management. DPS Staff found that the Company's ATIP program focused too heavily on financial rather than customer goals and incorrectly classified the Company's Operating Budget, comprising 25 percent of the total ATIP expense, as "customer service-related," when it does not actually serve customer interests.[77] DPS Staff testified that the Operating Budget goals should be classified as financial goals, and that the ATIP program should not be so heavily focused on financial goals rather than customer-related goals of safety, reliability, customer service, and environmental protection.

As DPS Staff explained in its testimony, the Commission has established a test to justify a utility's recovery of incentive pay in rates. A utility must either demonstrate that (1) its total compensation package, inclusive of incentive pay, is reasonable relative to its similarly situated peers, with no potential to adversely affect customer interests; or that (2) its incentive compensation program is designed to return quantifiable or demonstrable benefits to ratepayers in a financial sense or in terms of reliability, environmental impact, or customer service; and (3) performance targets included in incentive pay programs must align with customer interests and not be inconsistent with Commission

[77] Hearing Exhibit 189 (DPS Staff Witness Daniel Gadomski), pp. 13-15, 20.

policies.[78] The Commission's criteria is based on its finding that a utility must show that the cost to ratepayers to fund incentive compensation is at least matched by the value of the benefits customers receive. DPS Staff testified that O&R had not met the Commission's test for including the ATIP program expenses in rates.[79]

In its Statement in Support (pp. 28-29), DPS Staff justifies the partially reduced recovery of ATIP expenses in Rate Year 1, while expressing its expectation that the Company will propose modifications to the ATIP by December 2022.

The Joint Proposal provides for the Company to recover most but not all of its ATIP program costs in electric and gas rates during Rate Year 1.[80] The Joint Proposal also requires the Company to confer with DPS Staff to review the program and determine how it can "fully support the customer interest, consistent with Commission policies for safety reliability, environmental protection and customer service." Based on the Company's review and consultation with DPS Staff, the Joint Proposal requires the Company to modify the ATIP program "as appropriate" for Rate Years 2 and 3 and those modifications must

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78 Hearing Exhibits 189 and 192 (DPS Staff Witness Daniel Gadomski and Exhibit DSG-2), pp. 4-7 (citing Case 10-E-0362, O&R - Rates, Order Establishing Rates for Electric Service (issued June 17, 2011), pp. 37-38 (2011 Rate Order); Order Denying Petitions for Rehearing and/or Clarification (issued November 21, 2011).

79 Hearing Exhibit 189 (DPS Staff Witness Daniel Gadomski), p. 15. The Company's study by AON showed that the non-officer management total compensation and benefits in the ATIP program was 2.1 percent above the peer group market median. Id., p. 8

80 Joint Proposal, p. 7. As DPS Staff's Statement in Support explains (p. 18), this adjustment to the ATIP expense is characterized in the Joint Proposal as a "Covid-19 related labor adjustment."

be filed with the Secretary on or before December 31, 2022.

e. O&M Revenue Requirement: Institutional Dues/Subscriptions

The Joint Proposal attaches two separate appendices setting forth the agreed-upon revenue requirements, including costs to be included in rates that are associated with O&R's electric and gas O&M expenses.[81] The O&M electric and gas revenue requirements include line items reflecting expenses for "Institutional Dues and Subscriptions" for each of the three Rate Years.[82]

O&R's initial testimony indicates that the "Institutional Dues and Subscriptions" line items for both electric and gas include "membership fees paid to the Edison Electric Institute (EEI), American Gas Association (AGA), and other association dues and membership fees."[83] O&R does not identify the other association dues and membership fees under this line item. The Company further indicates that it escalates

[81] Joint Proposal, Appendix 1, p. 5; Appendix 2, p. 5. The electric organizational fees are $31,000 in Rate Year 1, $32,000 in Rate Year 2, and $33,000 in Rate Year 3. The gas organizational fees are $7,000 in Rate Years 1 and 2, respectively, and $8,000 in Rate Year 3.

[82] Id., Line Item 16; Hearing Exhibit (O&R Accounting Panel, AP-E3, Schedule 6).

[83] Hearing Exhibit 1 (January 29, 2021, O&R Accounting Panel), p. 50. According to its website, EEI is a trade association representing U.S. investor-owned electric companies in all 50 states that "provides public policy leadership" to make "a positive contribution" to "the long-term success of the electric power industry." See EEI, Our Mission, available at https://www.eei.org/about/Pages/about.aspx. Similarly, AGA is a trade association that represents more than 200 natural gas supply companies in the United States. See AGA, Our Mission, available at https://www.aga.org/about/mission. Both EEI and AGA have multi-million-dollar budgets and are registered lobbyists before the U.S. House of Representatives and the U.S. Senate.

the Historic Year expense for these Institutional Dues and Subscriptions by "the general escalation factor" in order to arrive at the Rate Year amount. The referenced general escalation factor is similarly not identified.

DPS Staff's testimony cited O&R's responses to an Information Request (DPS-6-280), which estimated the portion of O&R's EEI and AGA membership fees that were devoted to lobbying activities, and recommended that the Commission authorize the Company to collect in rates the portion of the organizational dues that are unrelated to EEI's and AGA's lobbying activities.[84]

After DPS Staff's testimony was filed, PSL §114-a was amended, effective August 2, 2021, and provides that in setting rates the Commission "shall not include the cost of membership dues for any organization, association, institution, corporation or any other entity that engages in legislative lobbying as part of any such utility's operational costs." This amendment broadens the previous reach of PSL §114-a and prohibits the Commission from authorizing rates that include membership fees or dues associated with any organization engaged in lobbying efforts, regardless of whether such fees or dues are separate from "below the line" lobbying costs versus "above the line" costs for non-lobbying activities.

In light of the new law, on January 10, 2022, the ALJs sought further information from the Company with respect to the fees included in the Joint Proposal's revenue requirement for O&M. In response to the ALJs' inquiry, O&R provided its response to a DPS Staff discovery request[85] and indicated that it had removed from the revenue requirement the membership dues for EEI ($154,815) and AGA ($149,721) as a result of the amendment

[84] Hearing Exhibit 127 (DPS Staff Accounting Panel), pp. 36-37.

[85] Hearing Exhibit 130 (DPS Staff Accounting Panel Exhibit SAP-3, O&R February 26, 2021, Response to DPS-280).

to PSL §114-a, but that it had retained the dues for the North American Transmission Forum, Inc. ($23,923), the Association of Edison Illuminating Companies ($8,668), and the Society of Gas Lighting ($600). Although this adjustment reduces the revenue requirement for this line item by $304,536, O&R did not submit a revised revenue requirement schedule as a revised attachment to the Joint Proposal reflecting this adjustment. Nevertheless, O&R does not dispute that EEI and AGA are trade organizations engaging in legislative lobbying activities on behalf of their utility members, including O&R and New York's other utilities whose dues may not be recovered from ratepayers.

Discussion

Pursuant to PSL §114-a, O&R and all other New York utilities can no longer recover in rates any membership costs if an organization engages in legislative lobbying activities. This case was pending when the amendment to PSL §114-a became law. The testimony of both DPS Staff and O&R pre-dated the law's August 2, 2021, effective date. In compliance with PSL §114-a, we therefore make clear that, in adopting the Joint Proposal, we are not authorizing rate recovery of any O&M, membership, legal, or other costs associated with "legislative lobbying" or any activities by EEI, AGA or any other lobbying organization that are undertaken to influence legislation or regulatory changes, as discussed above.

Accordingly, we require the Company to submit a report to the Commission, which identifies all such costs included in the revenue requirement forecast, sets forth the revised revenue requirements for electric and gas, estimates the amounts (including carrying charges) to be refunded to customers during each Rate Year, and proposes the treatment of customer refunds. The report is required to contain the underlying analysis, documentation, and workpapers supporting the identified amounts that have been excluded from the revenue requirement. The Company is required to file the report with the Secretary within 60 days of the Commission's issuance of this Order.

2. Electric

a. Market Supply Charge/Energy Cost Adjustment

The Joint Proposal provides for the Company's continued recovery of prudently incurred electric supply and supply-related costs, including power purchase costs.[86] Cost recovery is authorized through the continued Market Supply Charge/Energy Cost Adjustment (MSC/ECA) mechanisms. We are aware of recent volatility and increases in supply costs covered by the MSC/ECA mechanisms, which have increased customer bills. The Company utilizes hedging instruments to minimize fluctuations in supply costs. These instruments are reviewed by DPS for the upcoming winter and summer seasons. We expect O&R to continue to strategically plan to minimize supply cost fluctuations and to timely and effectively communicate with customers and interested stakeholders in advance of significant supply cost price increases and resulting bill impacts.

b. Revenue Decoupling Mechanism

The Joint Proposal allows the Company to continue to implement a Revenue Decoupling Mechanism (RDM), through a modified electric tariff.[87] The RDM, as modified, will continue until revised by the Commission, except the RDM targets for the Rate Year commencing January 1, 2025, will be restated to reflect the expiration of the temporary credit, assuming the Company does not file for new base delivery rates to be effective within 15 days after the expiration of Rate Year 3.

The Joint Proposal provides four changes to the

[86] Joint Proposal, p. 8.

[87] Joint Proposal, Appendix 21.

electric RDM, including (1) extending the RDM to standby customers; (2) excluding customers transferring from an RDM-applicable service class to an individually negotiated contract; (3) updating the RDM targets and thresholds for adjustments based on the new level of delivery revenue; and (4) reducing from ten days to three days, the notice that is required to be provided before an RDM filing becomes effective.[88]

c. Other Charges

The Joint Proposal provides that if the Company is subject to governmental or regional transmission organization (RTO) transmission and/or generation-related charges, costs or credits not listed in or otherwise covered by the then-effective MSC or ECA tariff language, such as those that may be imposed by the Federal Energy Regulatory Commission, the Environmental Protection Agency, or the NYISO, the Company may file a proposed tariff amendment with the Commission providing for recovery from customers of those charges and/or costs, or the application of credits, through the MSC and ECA mechanisms, or a comparable adjustment mechanism, and may include the charges, costs and/or credits applicable to the period prior to the effective date of the tariff amendment.[89]

3. Gas

a. Gas Supply Charge/MGA

The Joint Proposal continues the Company's recovery of all prudently incurred gas supply and supply-related procurement costs through two adjustment charges.[90] The costs associated with balancing assets will continue to be recovered from service classes through a per Ccf component of the MGA. The Company

[88] Joint Proposal, Appendix 21.

[89] Joint Proposal, p. 9.

[90] Joint Proposal, p. 11.

will file monthly statements with the Secretary reflecting the costs, charges and/or credits according to these adjustment mechanisms.

b. Revenue Decoupling Mechanism

The Joint proposal continues but modifies the Company's existing gas RDM, which is based on a total delivery revenue per class methodology applied to the customer groups included in the RDM, as identified in the Company's gas tariff.[91] If the Company does not file for new base delivery rates to take effect within 15 days after the expiration of Rate Year 3, this RDM will remain in effect unless changed by the Commission, and the delivery revenue targets that became effective on January 1, 2024, will continue except for the expiration of the $4.7 million temporary credit being collected through the MGA in Rate Year 3 to address the revenue shortfall resulting from levelization.

c. Base Rate Imputations

The Joint Proposal adopts the Company's proposal to increase the gas base rate imputation to $6.45 million in each Rate Year.[92] This revenue imputation reflects (1) interruptible benefits of $5.8 million (Service Classifications (SCs) 8 and 9, with firm withdrawable revenues minus associated gas costs and revenue tax surcharges); and (2) net benefits of $0.65 million associated with gas delivery to electric generation facilities previously owned by the Company (the Power Generation Imputation).

The Joint Proposal provides that any positive or negative variances between the actual revenue margin and the

[91] Joint Proposal, pp. 11-12, Exhibit 21.

[92] Joint Proposal, p. 12; Hearing Exhibit 103 (O&R Gas Rate Panel), p. 42.

imputations for interruptible benefits during each Rate Year will be shared with customers, who will realize 80 percent of the benefits, with the Company realizing 20 percent. Over- or under-recovery will be addressed through the MGA. Any positive or negative variances between the actual revenue margin and the net benefits associated with gas deliveries to previously-owned generation facilities will be credited to or recovered from customers through the MGA. One hundred percent of the Power Generation Imputation will be credited to or recovered from customers through the MGA during each Rate Year.

d. Lost and Unaccounted for Gas

The Joint Proposal sets the LAUF target, dead bands and factor of adjustment, which will be updated on November 1 of each Rate Year, using the average of the previous 12-months ending on August 31.[93] This provision is consistent with our prior O&R Rate Orders and is reasonably designed to address the necessary calculations for determining LAUF.

Discussion

We find that the rate mitigation, revenue forecasting, and other provisions underlying the Joint Proposal's electric and gas rate plans are reasonable. In particular, the Joint Proposal sets forth rate mitigation measures designed to modestly reduce the rate impact of the proposed electric and gas rate plans by including a freeze on management wage increases, the productivity adjustment, and a shortening of the amortization period for federal taxes from twelve to six years. The Joint Proposal's revenue requirement and rate design

[93] Joint Proposal, Appendix 10, Schedules 1 - 4 (LAUF calculations based on 5-year period from August 2017 to August 2021; illustrative calculations of line loss incentive and penalty and system performance adjustment mechanism; and examples of incentives and penalties applying system performance adjustment mechanism).

provisions appear to be allocated fairly among the service classes consistent with the ECOS study and relevant cost of service principles. The revenue requirements in the Joint Proposal are reduced from the Company's request in its initial filings in these proceedings and represent the adoption of DPS Staff proposals in several respects or a fair negotiated position among the parties.

These provisions of the Joint Proposal were agreed to by the signatories to the Joint Proposal after months of settlement negotiations. The parties that opposed the Joint Proposal did not raise issues associated with these provisions or with the revenue allocation among various service classes or for electric and gas customers. Accordingly, based on the record before us, we find that these provisions of the Joint Proposal will assure safe and adequate service at just and reasonable rates.

C. Cost of Capital

The revenue requirements in the Joint Proposal[94] reflect an overall cost of capital of 6.77 percent in Rate Year 1, consisting of: a Return on Equity (ROE) of 9.20 percent; a common equity ratio of 48.00 percent; a long-term debt ratio of 51.34 percent with a cost rate of 4.58 percent; and a customer deposits ratio of 0.66 percent with a cost rate of 0.05 percent. In Rate Year 2 and Rate Year 3, the long-term debt cost rate decreases to 4.51 percent and 4.49 percent, respectively, which results in a decrease in the overall cost of capital to 6.73 percent in Rate Year 2 and 6.72 percent in Rate Year 3.[95]

In its initial filing, O&R proposed an overall cost of capital of 7.04 percent, with a ROE of 9.50 percent; a common

[94] Joint Proposal, Appendices 1 and 2.

[95] Joint Proposal, Appendices 1 and 2.

equity ratio of 50.00 percent; a long-term debt ratio of 49.37 percent, with a cost rate of 4.62 percent; and a customer deposits ratio of 0.63 percent, with a cost rate of 1.53 percent for its electric and gas operations.[96] DPS Staff's direct testimony recommended an overall cost of capital of 6.56 percent, with a ROE of 8.75 percent; a common equity ratio of 48.00 percent; a long-term debt ratio of 51.34 percent, with a cost rate of 4.60 percent; and a customer deposits ratio of 0.66 percent, with a cost rate of 0.05 percent.[97]

Annually for each of the Rate Years and thereafter until the Commission next sets base rates for O&R, the Joint Proposal institutes earnings sharing thresholds set at 50 basis points above the recommended ROE of 9.20 percent, or 9.70 percent, and earnings above this threshold will be deemed "shared earnings."[98] Earnings above the 9.70 percent threshold but less than 10.20 percent are shared equally (50/50) between customers and the Company. Earnings equal to or more than 10.20 percent but less than 10.70 percent are shared 75/25 percent between customers and the Company, respectively. Finally, earnings equal to or more than 10.70 percent are shared 90/10 percent between customers and the Company, respectively. For electric and/or gas earnings more than the sharing threshold in any Rate Year, the Company will apply 50 percent of its share and the full amount of the customers' share of earnings to reduce the balance of deferred under-collections of Site Investigation and Remediation (SIR) costs. In the event the amount of Shared Earnings for electric and/or gas exceeds the deferred under-collections of SIR costs, the Company will apply

[96] Hearing Exhibits 6, 22 (O&R Accounting Panel and Exhibit AP-G5).

[97] Hearing Exhibit 166, p.1.

[98] Joint Proposal, pp.15-16.

the amount of excess to reduce other deferred costs.

In its Statement in Support, DPS Staff asserts that the Joint Proposal's compromise resulting in a 9.20 percent ROE, while slightly higher than the 9.00 percent ROE agreed to in the most recent Central Hudson rate case,[99] is reasonable given the economic environment in recent months during which equity returns have generally increased.[100] DPS Staff further states that the 9.20 percent ROE in this case is not accompanied by the thicker common equity ratios of 50 percent in Rate Year 1 and 49 percent in Rate Year 2 that were agreed to by the parties in the Central Hudson Case. DPS Staff further explains that the agreed-upon common equity ratio of 48 percent, which has been the same for the Company for the last 15 years, will still allow the Company to access capital at favorable terms. Further, DPS Staff states that the Joint Proposal does not allow for reconciliations of the cost of debt. This places the burden of risk on the Company to effectively manage its overall debt portfolio.

The Company asserts that the provisions of the Joint Proposal relating to a 9.20 percent ROE and the overall costs of capital are significantly lower than current national means and were very difficult to accept, but ultimately agreed to in light of other provisions it favored and because it recognized the

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[99] An ROE of 9.00 percent also was agreed to in the most recent National Grid electric and gas rate case. See Cases 20-E-0380 and 20-G-0381, Proceedings on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Electric and Gas Service, Order Adopting Terms of Joint Proposal, Establishing Rate Plans and Reporting Requirements (issued January 20, 2022) (Niagara Mohawk 2022 Rate Order).

[100] DPS Staff Statement in Support, p. 25, citing Direct Testimony of Staff Finance Panel filed in Case 21-G-0394, Corning Natural Gas Corp. (filed November 12, 2021), p. 6 (Corning Rate Case).

Commission's continued adherence to a cost of capital framework that routinely establishes returns for one-year and multi-year rate plans at the lower end of the range experienced within the utility industry as a whole.[101]

AGREE takes issue with a ROE of 9.20 percent, arguing only that it believes it "is the highest ROE seen in New York rate cases going back to at least 2017."[102] PULP also takes issue with the 9.20 percent ROE, suggesting that there is "no justification in the record" for such a figure.[103] Specifically, PULP argues that the lack of any "proxy group cost of equity calculations" that are equivalent to DPS Staff's initial testimony on this issue, in which DPS Staff advocated for a ROE of 8.75 percent ROE, renders the Signatory Parties' agreement to a ROE of 9.20 percent unsupported by any evidence.[104] PULP states that such a high ROE should be rejected by the Commission as unjust and unreasonable, as it will cause bill impacts that are "unresponsive to the financial hardship in which [the Company's] ratepayers currently find themselves" as a result of the Covid-19 pandemic.[105] PULP echoes AGREE's concern that a 9.20 percent ROE is higher than ROEs approved in rate cases decided since early 2020, and suggests that an ROE between 8.80 percent and 9.00 percent would be more appropriate.[106]

In response to these concerns, DPS Staff posits that PULP exhibits a "fundamental misunderstanding of both the cost

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101 O&R Statement in Support, p. 13.

102 AGREE Statement in Opposition, §A(2) [The statement is not paginated].

103 PULP Statement in Opposition, p.7.

104 PULP Statement in Opposition, p. 7, citing Hearing Exhibit 170 (DPS Staff Finance Panel Exhibit FP-6).

105 PULP Statement in Opposition, p. 8.

106 PULP Statement in Opposition, pp. 8-9.

of capital calculation and the Commission's long-standing methodology for determining cost of equity."[107] DPS Staff points out that, contrary to PULP's suggestion, the Signatory Parties are not obligated to provide proxy group and cost of equity calculations to support the agreed-upon ROE, which was the result of months of negotiations among the interested parties. Responding to PULP's claim that the ROE does not align with ROEs of other recently decided rate cases, DPS Staff reiterates that a 9.20 percent ROE, while admittedly a bit higher than ROEs in recent rate cases, in fact accurately reflects the recent reality of the current economic environment in which equity return requirements are increasing.[108]

The Company takes issue with PULP's claim that the agreed-upon ROE is unsupported by record evidence, pointing to the testimony and supporting documentation on the issue submitted by the Company and by DPS Staff, which supported an ROE of 9.75 percent and 8.75 percent, respectively.[109] Thus, the Company argues, the negotiated ROE of 9.20 percent is well within the range of ROEs that would be supported by the record evidence. The Company asserts that the negotiated ROE therefore is reflective of not only the record evidence, but also of the current market conditions in which equity return requirements have increased, as evidenced in testimony filed in more recent rate cases,[110] and that it appropriately balances the Company's return requirements with the concerns of the ratepayers.

Discussion

The terms of the Joint Proposal adequately recognize

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[107] DPS Staff Reply Statement in Support, p. 2.

[108] DPS Staff Reply Statement in Support, pp.2-3.

[109] O&R Reply Statement in Support, pp 6-7.

[110] O&R Reply Statement in Support, p.7, citing Corning Rate Case, Direct Testimony of Staff Finance Panel, p.6.

the increased financial and business risks inherent in setting rates over a multi-year period. As opposed to a single rate year, the extended term of the Joint Proposal inherently carries more financial risk as investors are subject to additional risk that economic conditions will change and the actual cost of capital could increase during the three-year term. Further, because the Joint Proposal locks in forecasted amounts for numerous elements of expense for the three-year term, O&R's business risk is also affected by the potential that actual operating costs will be greater than those forecasted. The Joint Proposal's terms related to the cost of capital and financial protections from risk represent a reasonable result when compared with a potential litigated outcome. Together the 9.20 percent ROE and the 48 percent equity ratio should preserve the Company's credit ratings while imposing a reasonable cost on ratepayers.

We find reasonable DPS Staff's explanation of its agreement to an upward change in the Joint Proposal's ROE from DPS Staff's testimonial position of 8.75 percent to 9.20 percent based on the most current financial conditions that were not evident when DPS Staff filed its initial testimony. Significantly, the 9.20 percent ROE is lower than both the 9.51 percent national average electric ROE and the 9.54 percent national average gas ROE that have been approved nationwide since the beginning of 2021. Moreover, to mitigate bill impacts considering the Covid-19 pandemic, the Joint Proposal also includes an imputation of $2.9 million in Covid-related adjustments over the term of the three-year Rate Plan.[111] The Joint Proposal also imputes $19.6 million of targeted savings from the Company's Business Cost Optimization Program. If the

[111] Joint Proposal, p. 6.

Company does not achieve the imputed savings targets, it will bear the risk of not achieving its allowed ROE since there is no reconciliation mechanism.[112]

Overall, the allocation of risk and the rate of return reflected in the Joint Proposal reasonably balance the return requirements of O&R's investors with customers' expectations of safe and reliable service at just and reasonable rates. In addition, the Joint Proposal will add a benefit to customers in that the multi-year Rate Plans will provide relative predictability and stability to the Company's operations over the next three years.

Finally, the use of the earnings sharing mechanism is beneficial to customers because it provides the Company with a financial incentive to control its costs that is balanced by allowing the Company's customers to have an opportunity to share in any realized efficiency gains. The earnings sharing mechanism proposed in the Joint Proposal also favors the interests of customers by requiring that the earnings sharing be assessed each Rate Year, rather than on a cumulative basis over the full three-year term of the Rate Plans. Inasmuch as there is no identified sharing "floor" below which a deficiency in earnings lower than forecast is shared between the Company and shareholders, the earnings sharing mechanism benefits customers at the risk of the Company since earnings in any Rate Year that are above the earnings sharing threshold cannot be offset by earnings that may be below the earnings threshold in any other Rate Year.

The use of earnings sharing thresholds and the tiered nature of the resulting sharing is consistent with numerous prior multi-year rate plans approved by the Commission. In

[112] Joint Proposal, p. 6.

addition, the application of a portion of the Company's share, as well as the full customer share, of any excess earnings to offset deferred SIR costs is responsive to the Commission's expectation that the negotiation of earnings sharing mechanisms in rate plans explore the opportunity to allocate some portion of shared earnings to offset SIR costs.[113]

D. Additional Accounting Provisions

1. Amortization of Low-Income Deferrals

The Joint Proposal recommends the return to all ratepayers of $15.5 million in deferred unspent Low-Income Bill Discount Plan (LIBDP) funds over the three-year term of the Rate Plans.[114] PULP objects to this proposal, alleging that the existence of those unspent funds is "almost entirely due to the Company's admitted tier misclassifications over the [15-month] period January 1, 2018 through September 30, 2019", during which time O&R "misclassified the vast majority of LIBDP enrollees as Tier 1 (lowest discount) participants."[115] Consequently, PULP argues, O&R "provided far lower discounts" to a majority of LIBDP participants than were due and "[a]s much as $15.5 million worth of discounts were not paid" due to the misclassified customers.[116] PULP claims that the proposal in the Joint Proposal to amortize the $15.5 million in unspent LIBDP funds to all ratepayers is not justified by the record. Rather, PULP argues, the $15.5 million should first be used to make the misclassified customers whole and, if any funds are remaining,

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113 Case 11-M-0034, Proceeding on Motion of the Commission to Commence a Review and Evaluation of the Treatment of the State's Regulated Utilities' SIR Costs, Order Concerning Costs for Site Investigation and Remediation (issued November 28, 2012), p. 12.

114 Joint Proposal, §B (2); see Appendices 1 and 3.

115 PULP Statement in Opposition, p. 10.

116 PULP Statement in Opposition, p. 11.

the remainder should be used to address low-income customer needs.[117]

In response, the Company asserts that the Joint Proposal appropriately recommends passing back the full $15.5 million regulatory liability to all ratepayers over the term of the electric and gas Rate Plans. While the Company acknowledges that in 2019, a subset of low-income customers participating in the LIBDP were classified in the wrong tier of the program and, therefore, were not given the proper discount that they otherwise should have received,[118] the Company disputes PULP's claim that a majority of the $15.5 million regulatory liability related to the LIBDP is due to that error. Rather, the Company asserts that "approximately a third of the regulatory liability" is associated with the classification error and that the error was corrected in the Company's system.[119] To address this error now, the Company proposes to provide the affected customers "a lump sum credit by the end of first quarter 2022 equal to the total amount they should have but did not receive."[120] In the Company's view, this credit could be properly considered as an out-of-period adjustment for 2019 and is expected to be in an amount below the two percent low-income program cap for 2019.

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[117] PULP Statement in Opposition, p. 12.

[118] See Hearing Exhibit 326. In 2019, due to a system error, approximately 1,300 Tier 2 customers and 5,900 Tier 3 customers were incorrectly placed into Tier 1, thereby receiving lower bill discounts.

[119] O&R Reply Statement in Support, pp. 8-9. See Hearing Exhibits 325-326. As a result of the error, approximately $2.9 million is owed to misclassified electric customers and $2.2 million is owed to misclassified gas customers.

[120] O&R Reply Statement in Support, p. 9. In doing so, the Company commits to forego any carrying charges up to the actual amount of the error if it exceeds the LIBDP targets in the Joint Proposal.

For its part, DPS Staff agrees with the Company that PULP appears to overstate the amount of regulatory liability that is due to the misclassification of LIBDP participants. DPS Staff, like the Company, reports that about $2.9 million and $2.2 million of the $15.5 million regulatory liability is due to the misclassification of electric and gas LIBDP participants, respectively.[121] DPS Staff recommends that the Commission adopt the provision in the Joint Proposal to pass back to all ratepayers the full $15.5 million over the course of these Rate Plans. DPS Staff further recommends that the Company be directed to develop a plan for providing a credit to the affected LIBDP participants, with interest accrued at the customer deposit rate. Staff agrees with the Company that the regulatory liability owed to those affected LIBDP customers should be reconciled without associated interest and carrying charges in the Company's next rate filing.

Discussion

We agree with the Company and DPS Staff that passing-back the $15.5 million regulatory liability to all ratepayers over the term of the proposed Rate Plans is appropriate. Amortization of regulatory liabilities over multi-year periods is an appropriate and commonly used rate-mitigation strategy to reduce customer bill impacts. Further, passing back the full $15.5 million regulatory liability here to all ratepayers is not inconsistent with the Commission's 2016 Low Income Order because no specific treatment of regulatory liabilities and assets that result from variances between actual program costs and amounts allowed to be collected in rates is directed in that Order.

As for the amounts that are still owed to the previously misclassified LIBDP participants, we share PULP's

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[121] Staff Reply Statement in Support, p.7. See Hearing Exhibits 325-326.

concerns that the affected low-income ratepayers have not yet been made whole from the Company error. O&R is directed to submit a plan to the Secretary within 30 days of issuance of this Order in which the Company is required to propose how it will make the affected LIBDP participants whole, including details of the following: (1) the calculation of the missed bill discount credits and associated interest, applied consistent with 16 NYCRR §§145.3 and 277.3, for each affected, misclassified LIBDP participant; (2) an explanation as to how the Company plans to issue a one-time lump sum bill credit equal to the amount of the discount affected misclassified LIBDP participants would have received absent the misclassification error; (3) for each affected misclassified LIBDP participant, an analysis to determine if affected LIBDP participant fell into arrears and/or was assessed additional charges, or was subject to termination or reconnection fees due to the Company's error; (4) a plan explaining how O&R will communicate the error and the one-time lump sum bill credit to impacted LIBDP participants; and (5) details of the Company's internal controls that have been or will be in place to assure such misclassification and bill crediting errors do not occur in the future, including any proposed changes to existing internal controls.

The bill credits will be reflected in the bills of affected LIBDP participants in their respective billing cycles 45 days after submittal unless DPS Staff submits a letter to the Company indicating that the credit amounts should be adjusted. The Company shall set up a regulatory asset which can include the costs of providing the missed bill discount credits, but shall not include the costs of any associated interest provided to affected customers. The regulatory asset created by O&R's misclassification error shall be reconciled without associated interest and carrying charges in the Company's next rate filing.

2. Federal Tax Cuts and Jobs Act of 2017

In 2017, Congress passed the Tax Cuts and Jobs Act of 2017 (2017 Tax Act), which lowered the highest corporate federal income tax rate from 35 percent to 21 percent and eliminated bonus depreciation. Consequently, the Commission issued an order directing New York utilities to preserve for the benefit of ratepayers the net savings resulting from the 2017 Tax Act through deferral accounting until all net benefits are reflected in rates (Tax Act Order).[122]

As of December 31, 2021, the Company had an unprotected excess deferred federal income tax (EDFIT) credit totaling $34.057 million for electric and gas combined and a non-property EDFIT debit balance of $12.218 million, which amounts to a net benefit of $21.839 million owed to customers.[123] The Company proposed to amortize the benefits related to EDFIT over three years (2022-2024), rather than the remaining 12 years (2022-2033) of the 15-year period approved in the 2019 Rate Plan.[124] The Company explained that the acceleration of the refund lowered the electric and gas rate requests by $9 million and $3 million, respectively.

In its direct testimony, DPS Staff stated that it had "rate stability concerns" with the Company's proposal to accelerate the refunds of the tax credits.[125] DPS Staff explained that if the refund were passed back too quickly, then the rate increase experienced by customers would be lower for

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[122] Case 17-M-0815, Proceeding on Motion of the Commission on Changes in Law that May Affect Rates, Order Determining Rate Treatment of Tax Changes (issued August 9, 2018) (Tax Act Order).

[123] Hearing Exhibit 127 (DPS Staff Accounting Panel), p. 60.

[124] Hearing Exhibit 1 (O&R Accounting Panel), p. 10.

[125] Hearing Exhibit 127 (DPS Staff Accounting Panel), pp. 60-61.

the period of the amortization, but that rates would "increase considerably" once the benefit was fully passed back.[126] DPS Staff also cited concerns about a potential change in the federal tax law increasing corporate taxes that could require the reversal of the amortizations.[127] DPS Staff recommended that the unprotected EDFIT balance be refunded to customers over a six-year period, rather than the three years proposed by the Company.[128] The Joint Proposal provides for the unprotected EDFIT balance to be amortized over six years (2022-2027), as recommended by DPS Staff.[129]

PULP opposes the plan to pass back the unprotected EDFIT balances over a six-year period and argues that these benefits should be given to customers over the three-year period proposed by the Company.[130] PULP believes that a shorter pass-back period is appropriate given the ongoing "economic disruptions of the Covid-19 pandemic", which, it states, is causing "severe rate pressure" for the Company's ratepayers.[131] PULP argues that using EDFIT refunds "to provide short-term masking of the impact of potentially unjust and unreasonable rate increases" violates the spirit of the Tax Act Order and, thus, the EDFIT should be returned to the ratepayers during the course of the proposed three-year Rate Plans.[132] Finally, PULP believes that DPS Staff's concerns regarding potential changes in the federal tax law are specious and should not be given any weight.

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126 Id., p. 61.

127 Id.; DPS Staff Reply Statement in Support, p. 8.

128 Hearing Exhibit 127 (DPS Staff Accounting Panel), p. 62.

129 Joint Proposal, p 6.

130 PULP Statement in Opposition, pp. 12-13.

131 Id., p. 13.

132 Id.

Discussion

Although the Joint Proposal does not pass back the unprotected EDFIT as quickly as some parties had desired, the Joint Proposal's treatment strikes a reasonable balance between immediately mitigating the impact of rate increases on customers and providing rate stability for future customers. Amortization over six years, as opposed to the three years proposed by the Company, also is consistent with the Tax Act Order because it passes back a portion of the tax benefit to customers quickly and mitigates the instant rate increase.

Further, we do not consider DPS Staff's concerns about changes in the federal tax law to be unreasonable and should a corporate tax increase occur, a shorter amortization period would worsen the rate impact on the Company's customers, whereas the longer amortization period would provide some measure of relief. Finally, the length of the amortization was negotiated as but one aspect of the Joint Proposal and to disrupt the amortization would necessitate the disruption of other terms of the Joint Proposal that were negotiated to protect ratepayers against potentially precipitous rate increases in the future.

3. Residential Customer Charges

The terms of the Joint Proposal increase the minimum charge for residential electric customers from $19.50 to $20.50 in Rate Year 1, $21.50 in Rate Year 2, and $22.00 in Rate Year 3;[133] and for residential gas customers from $19.50 to $20.00 in Rate Year 1, $21.00 in Rate Year 2, and $22.00 in Rate Year 3.[134]

In testimony, O&R sought to increase residential customer charges for both electric and gas customers to $22.00

[133] Joint Proposal, Appendix 17, Schedule 5, p. 1; Schedule 6, p. 1; Schedule 7, p. 1.

[134] Joint Proposal, Appendix 18, Schedule 5, p. 1; Schedule 6, p. 1; Schedule 7, p. 1.

to bring the Company closer to the customer costs identified in its embedded cost of service (ECOS) study of $31.94, while moderating the rate impacts to low usage customers.[135] DPS Staff recommended that the customer charge for residential customers be increased by the same percentage as the usage charge, but if the final incremental revenue requirement resulted in an increase less than $1.00, then it recommended the customer charge be increased by $1.00. If the incremental revenue requirement was negative, DPS Staff recommended that the customer charges should remain at existing levels.[136] PULP opposed the increases to the residential customer charges and proposed that O&R investigate other rate design options that would result in a decreased customer charge.[137] It advocated for modifying the rate design that would allow for a reduction in customer charges to $18.00.[138]

In its Statement in Opposition, PULP continues to argue that raising such charges "penalizes conservation-minded low and moderate usage customers by denying them any ability to reduce their monthly energy costs for the part of their bills represented by such charges."[139] For electric customers, PULP contends that these charges would result in higher bill impacts for conservation-minded customers compared to "average"

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[135] Hearing Exhibit 100 (O&R Electric Rate Panel), p. 17; Hearing Exhibit 103 (O&R Gas Rate Panel), p. 30; O&R Statement in Support of Joint Proposal, pp. 20-21; Hearing Exhibit 99 (O&R Demand Analysis and Cost of Service Panel Exhibit DAC-2), p. 169.

[136] Hearing Exhibit 223 (DPS Staff Rates Panel), p. 31.

[137] Hearing Exhibit 250, PULP Direct Testimony of William D. Yates, pp. 32-33.

[138] Id., pp. 32-34.

[139] Hearing Exhibit 312, PULP Statement in Opposition, p. 14; see also Hearing Exhibit 250, PULP Direct Testimony of William D. Yates, pp. 27-28, 32-33.

customers. It reiterates its testimonial position that such increases run contrary to "the Commission's historic objectives regarding the promotion of energy efficiency in New York" and the objectives of the CLCPA and requests that the Commission reject any increase in the fixed residential customer charge for electric service.[140] For gas customers, PULP states that "the effect of the proposed increased gas fixed charges on bill impacts would be to substantially (if not completely) offset any savings that low usage customers could realize from the Company's adoption of flat volumetric gas rates."[141]

In response, both DPS Staff and O&R state that the Commission should reject PULP's position. First, they argue that PULP's position ignores the purpose of customer charges, which is to recover costs that do not vary with customer energy usage.[142] Second, they argue that because the current residential customer charge is below the customer costs expressed in the Company's ECOS study, the shortfall of revenue would be recovered through volumetric charges. DPS Staff and O&R state that PULP's position would result in an improper subsidy for lower usage customers by higher usage customers.[143] DPS Staff contends that low and moderate usage customers will continue to have an incentive to reduce monthly energy costs through the volumetric portion of the bill.[144] O&R argues that

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[140] Id.

[141] Hearing Exhibit 312, PULP Statement in Opposition, p. 15.

[142] Hearing Exhibit 317, O&R Reply Statement in Support, p. 11; Hearing Exhibit 318, DPS Staff Statement in Reply to Opposition of Joint Proposal, p. 9.

[143] Hearing Exhibit 317, O&R Reply Statement in Support, p. 11; Hearing Exhibit 318, DPS Staff Statement in Reply to Opposition of Joint Proposal, p. 9.

[144] Hearing Exhibit 318, DPS Staff Statement in Reply to Opposition of Joint Proposal, p. 9.

PULP has failed to provide evidence that the minimum charge increases are at odds with the Commission's energy efficiency objectives or CLCPA goals.[145]

O&R's ECOS study identified the relative cost of service for each customer class and exhibited that the existing customer charges for the residential service class is below the customer-related cost of service.[146] The increased customer charges included in the Joint Proposal remain below the cost of service identified in the ECOS study and will gradually increase over the course of the three-year Rate Plans. We find that the customer charges are reasonable and supported by the record. The increased charges appropriately reflect the fixed costs of providing service and we do not believe they will materially interfere with the State's energy efficiency and climate change objectives. We therefore approve the increases to customer charges.

E. Performance Metrics

The electric and gas performance metrics included in the Joint Proposal are designed to provide financial incentives for the Company to continue to provide safe and reliable service, improve performance, and otherwise act for the benefit of customers.[147] Depending upon whether the targets are met or exceeded, or are not met, the financial incentives are imposed through either positive or negative revenue adjustments, recovered from or credited to ratepayers through the ECA/MGA and measured over a 12-month period beginning on June 1 of each Rate Year. The Company imposes a surcharge or credit to customers subject to the ECA/MGA on a common cents per kWh (for electric)

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[145] Hearing Exhibit 307, O&R Reply Statement in Support, p. 12.

[146] Hearing Exhibit 99, DAC-2, p. 169.

[147] Joint Proposal, p. 25.

and cents per Ccf (for gas) and will reconcile the positive or negative revenue adjustments annually.

The Joint Proposal sets forth the electric and gas performance metrics in Appendices 13 and 14, respectively. Performance metrics are well-recognized tools that the Commission has utilized in other rate cases. Each of the performance metrics and the applicable positive and negative revenue adjustments are discussed below.

1. Electric Reliability

The Joint Proposal leaves unchanged the electric reliability performance mechanism (RPM), which was established in the 2015 Rate Order and continued in the 2019 Rate Order.[148] The two continued RDM targets under the Joint Proposal relate to the frequency and duration of electric service interruptions: the System Average Interruption Frequency Index (or average number of interruptions), which will remain at 1.20; and the Customer Average Interruption Duration Index target (or average duration of interruptions), which will remain at 1.85.[149]

The Joint Proposal also continues a negative revenue adjustment (NRA) of 20 basis points if the Company fails to meet each of these targets per calendar year. Several exclusions from the imposition of the NRA will continue to be applicable, including interruptions and outages resulting from "major storms;" incidents resulting from catastrophic events beyond the

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148 Cases 14-E-0493 and 14-G-0494, O&R – Rates, Order Adopting Terms of Joint Proposal and Establishing Electric Rate Plan (issued October 16, 2015) (2015 Rate Order); Joint Proposal, pp. 51-52, Appendix 15 (setting electric reliability performance targets for customer and system interruptions at 1.85 and 1.20, respectively, with exclusions, and NRAs at 20 basis points); Cases 18-E-0067 and 18-G-0068, O&R – Rates, 2019 Rate Order, pp. 83-84, Appendix 13.

149 Joint Proposal, p. 25, Appendix 13.

Company's control (e.g., plane crash, water main break, natural disaster); and incidents involving either generation or the bulk transmission system (e.g., NYISO load-shedding mandates).

The Joint Proposal requires the Company's continued annual reporting to the Commission detailing performance. The report must be filed with the Secretary by March 31st and identify whether NRAs or exclusions are applicable during the previous calendar year, that is, for 2022, 2023, and 2024, with the reported results and NRAs applied in Rate Years 1, 2, and 3, respectively.[150]

Discussion

The testimony of both the Company and DPS Staff expressed agreement with respect to the continuation of the electric RPM in the 2019 Rate Order and no party proposed changes.[151] We find that these provisions of the Joint Proposal are within the range of likely litigated outcomes and therefore approve them. In approving these provisions, we note that the overall objective of a reliability performance mechanism is to continue improvement in the Company's performance. Under the Joint Proposal here, the same reliability metrics in place in the two previous three-year rate plans will remain unchanged for

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[150] Joint Proposal, Appendix 13, p. 2. The Joint Proposal requires the annual report to include system-wide performance and the amount of the revenue adjustment, if applicable; and identification of any requested exclusions from the RPM, with an explanation of the applicability of the exclusion, the basis for the requested exclusion, and adequate documentation supporting the exclusion.

[151] DPS Staff Statement in Support, pp. 44-45; Cases 18-E-0067 and 18-G-0068, O&R – Rates, supra, 2019 Rate Order, pp. 82-84; 2019 Joint Proposal, Appendix 13. In the 2019 Joint Proposal adopted in its prior rate case, the Company agreed to continue the electric RPM until the Commission reset rates. Consequently, the Joint Proposal does not add value in the reliability area but continues the status quo.

another three years. As we noted in the 2019 Rate Order, the Company was meeting the targets for the electric reliability metrics that previously had been set under the 2015 Rate Plan.[152] The Company has continued to meet these targets.

2. Gas Safety

The Joint Proposal modifies the existing gas safety performance metrics outlined in the 2019 Rate Order and requires the Company to meet more stringent targets.[153] DPS Staff notes that these modified performance targets will align O&R's performance metrics with other gas utilities operating in New York.[154]

Metrics are established in the following areas: leak management, emergency response, leak prone pipe removal/replacement, gas main replacement, damage prevention, and regulatory non-compliance. Positive revenue adjustments are applicable for exceeding targets and negative revenue adjustments for failing to meet targets in these areas, as detailed below. These metrics and adjustments will remain in effect until the Commission resets rates or otherwise changes them.

No later than 60 days of the end of the calendar year, the Company must report its annual performance in each area for which negative or positive revenue adjustments are applied.[155] If the Company can demonstrate "extenuating circumstances" that

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[152] Cases 18-E-0067 and 18-G-0068, O&R – Rates, 2019 Rate Order, p. 88.

[153] Joint Proposal, p. 25, Appendix 14, pp. 1-15; Cases 18-E-0067 and 18-G-0068, O&R – Rates, supra, 2019 Rate Order, pp. 84-88. The 2019 Rate Order modified the gas safety metrics that previously had been established in the 2015 Rate Order.

[154] DPS Staff Statement in Support, pp. 44-45.

[155] Joint Proposal, Appendix 14, pp. 10-11.

prevented achieving performance metrics, the negative revenue adjustments may be excused by the Commission on a case-by-case basis. The Company's right to seek judicial review of the Commission's determination is preserved.

Under the Joint Proposal, negative revenue adjustments are applicable to leak management, including repairable leaks and year-end leak back logs; emergency response, damage prevention, gas main replacement, and regulatory non-compliance. The leak management targets (Types 1, 2, and 2A) for each rate year are set at less than or equal to 20, with 10 basis points assessed as a negative revenue adjustment if the back log exceeds 20. The leak management, year-end backlog targets (Types 1, 2, 2A, and 3) are set at less than or equal to 50, with 5 basis points assessed as a negative revenue adjustment if greater than 50. The Company will be deemed to meet the targets if achieved by December 31 of each Rate Year.

The emergency response metric requires the Company to respond within 30-minutes to gas leak or odor calls for at least 75 percent of the calls from 2022 to 2024; to respond within 45-minutes to gas leak or odor calls for at least 90 percent of the calls; and to respond within 60-minutes for at least 95 percent of the calls.[156] A twelve basis point negative revenue adjustment is applied for failure to meet these targets, although the Company may seek DPS Staff's consent or Commission approval to exclude gas leak and odor calls resulting from mass area odor complaints, major weather-related occurrences, or major equipment failure within seven days of the date of the event.

For the damage prevention metric, the Joint Proposal requires all damages to be tracked in accordance with the

[156] Joint Proposal, Appendix 14, pp. 3-4.

guidelines in the Annual Gas Safety Performance Measures Report. Negative revenue adjustments of 5, 10, and 20 basis points will apply if the total damages to the Company's gas facilities exceed 2.0, 2.25, and 2.50, respectively, per 1,000 one-call tickets for each calendar year from 2022 to 2024.[157] The Joint Proposal allows the Company to "average" the current year and prior year damage numbers in calculating performance. For example, total damage performance for 2022 would be the average of damage performance in both 2021 and 2022.[158]

The Joint Proposal continues the target for leak prone gas main removal/replacement of 66 miles from 2022 to 2024, and a minimum annual removal/replacement target of 20 miles. These targets will continue after the term of the gas Rate Plan.[159] If the 66-mile target is not achieved, 7.5 basis points will be assessed as a negative revenue adjustment. If the 20-mile minimum annual removal of leak-prone gas main is not achieved, 15 basis points will be assessed as a negative revenue adjustment in 2022 and 2023, and 7.5 basis points assessed in 2024. At the beginning of each calendar year, the Company is required to provide a list of the top five percent of the riskiest pipes.[160] If the pipes on the list are not removed, the Company must provide an explanation. The Company is also required to identify the 5 percent of the riskiest pipes that were not removed in the preceding year.

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157 Joint Proposal, Appendix 14, p. 4.

158 Joint Proposal, Appendix 14, p. 4, n. 7.

159 Joint Proposal, Appendix 14, p. 5. To meet these targets, the Company may remove pipes that are bare steel, aldyl plastic and ineffectively coated steel with high leakage rate if it is in the top five percent of risk. With DPS Staff's consent, the Company may remove ineffectively coated steel pipe outside of the top five percent.

160 Joint Proposal, Appendix 14, p. 11.

For violations of the gas safety regulations identified during DPS Staff field and record audits that pose "high-risk" or "other risk" beginning on January 1, 2022, the Joint Proposal sets negative revenue adjustments of one half and one full basis point for exceeding violation thresholds for the high-risk category, and one-quarter of a basis point for violations in the other risk category.[161]

The violations and occurrences will be identified in a DPS Staff audit letter and will be subject to further discussion at a compliance meeting at which DPS Staff will present its audit findings and violations that are subject to the negative revenue adjustments. The Company is given five days to cure the violations and will not be subject to the adjustment if the violation found is of its work procedure, which exceeds Code 255 or Code 261. The total negative revenue adjustment for this metric cannot exceed 75 basis points. The number of violations is capped at ten for each code section, for purposes of imposing a negative revenue adjustment, but violations in excess of ten will be addressed in a Corrective Action Plan submitted by the Company in response to an audit letter in order to achieve compliance.[162] The Company's failure to implement the corrective action plan will result in imposition of negative revenue adjustments associated with the violations.

The Joint Proposal requires DPS Staff to file its final audit reports with the Secretary and if the Company disputes the results or any findings, or denial of exclusions based on extenuating circumstances, it may appeal to the Commission by filing a petition with a remediation plan to

[161] Joint Proposal, Appendix 14, pp. 5-8.

[162] Joint Proposal, Appendix 14, p. 7.

address the violations.[163] Negative revenue adjustments will not be applied until the Commission issues its final determination on the petition. The Commission in its discretion may provide the Company with an evidentiary hearing prior to a final determination and the Company does not waive its right to seek judicial review of the Commission's determination.

The Joint Proposal provides that negative revenue adjustments shall not exceed 150 basis points for failure to meet any of the metrics in each of the Rate Years.[164] The positive and negative revenue adjustments will be annually reconciled and credited or charged to customers through the Monthly Gas Adjustment surcharge over a 12-month period beginning on June 1. The Company is required to file an annual report with the Secretary reflecting performance and adjustments in each area.

The Joint Proposal also provides for the Company to realize a positive revenue adjustment for meeting targets for leak management year-end backlog, gas main replacement, emergency response and damage prevention.[165] For leak management, the Company will receive positive adjustments between 2 and 6 basis points for reducing year-end total leak backlogs (Types 1, 2, 2A, and 3) and reaching or exceeding the

[163] Joint Proposal, Appendix 14, p. 8.

[164] Joint Proposal, Appendix 14, p. 1, n. 1. The Joint Proposal notes that the NRA is stated on a pre-tax basis and "[t]he revenue requirement equivalents of a ten-basis point on common equity capital per the gas revenue requirements under this Proposal are estimated to be approximately $0.377 million in RY1, $0.405 million in RY2 and $0.433 million in RY3." Joint Proposal, Appendix 14, p. 1, n. 4.

[165] Joint Proposal, Appendix 14, pp. 8-10.

targets.[166]

For each mile in excess of the 23 miles of gas main replacement or removal, the Company will earn a positive revenue adjustment of 2 basis points, capped at 10 basis points or five miles per calendar year.[167] For emergency response, positive revenue adjustments of 2, 4, or 6 basis points (capped at 6 basis points) will be applied if the Company responds to leak or odor calls within 30 minutes for at least 91 percent of the calls.[168] The adjustment applies to each increase of 2 percent beyond the established response time target.

With respect to damage prevention, positive revenue adjustments of between 5 and 10 basis points will be applied if the Company reduces the total damages to its facilities per 1,000 one-call tickets in each calendar year from 2022 to 2024.[169] The targets for each year are greater than 1.25 and less than or equal to 1.50 to earn 5 basis points; and less than or equal to 1.25 to earn 10 basis points.

Discussion

We find these provisions of the Joint Proposal necessary to incentivize the Company's performance in important gas safety areas, while at the same time prioritizing those areas requiring attention by imposing financial penalties. The Joint Proposal's targets and associated revenue adjustments are

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[166] Joint Proposal, Appendix 14, p. 8. For 2022, if the leak backlog is 11 to 20, 2 basis points are applied; if the backlog is 4 to 10, 4 basis point are applied; and if the backlog is 0 to 3, 6 basis point are applied. The leak backlog targets for 2023 and 2024 are 9 to 15, 4 to 8 and 0 to 3 to earn positive revenue adjustments of 2, 4, and 6 basis points, respectively.

[167] Joint Proposal, Appendix 14, p. 9.

[168] Id.

[169] Joint Proposal, Appendix 14, p. 10.

within the range of likely litigated outcomes. We therefore approve the details of the performance mechanisms but with an observation in response to the Company's complaints about the outcome.

In its Statement in Support, the Company identifies the disagreement with DPS Staff regarding the extent to which existing performance mechanisms should be changed and new metrics added.[170] DPS Staff's testimony recommended modest modifications to the existing gas safety performance mechanism established under the 2019 Rate Order.[171] The Company's testimony urged that there should not be any modifications or additional requirements at all.[172] The Company claims that the Joint Proposal's provisions that modified these metrics "were, in particular, a very difficult element" for it to accept except in the context of a comprehensive settlement.[173] The Company asserts that provisions focusing on positive incentives rather than penalties are a more effective mechanism to motivate superior performance. In other words, the Company complains about negative revenue adjustments while at the same time favoring positive ones. In its Statement in Support, the Company argues that "continually tightening standards to match

[170] O&R Statement in Support, p. 23.

[171] Hearing Exhibit 196 (DPS Staff Gas Safety Panel), pp. 13-18, 21-22, 32-33, 41-42, and 47-51. DPS Staff proposed: 1) allowing only the top five percent of pre-1971 ineffectively coated steel mains in the leak prone pipe removal program; 2) returning any earned positive revenue adjustment should O&R fail to achieve the minimum leak prone pipe removal target in any calendar year or cumulatively; 3) adjusting the existing leak management positive revenue adjustment; and 4) adjusting the positive revenue adjustment targets for the emergency response time mechanism.

[172] Hearing Exhibit 66 (O&R Gas Infrastructure and Operations Panel, Rebuttal), pp. 25-32.

[173] O&R Statement in Support, p. 23.

historical performance more closely can be a disincentive to improve, is unnecessary given the Company's demonstrated performance levels, and carries the potential for higher costs to customers to maintain such levels of performance."[174]

We disagree. In setting more stringent targets in the three-year Rate Plans, the objective is for the Company's performance to continue to improve. Some critics of positive revenue adjustments argue that rewarding a utility for doing what is already required to provide safe and reliable service lacks a rational basis and maintaining performance levels should not result in higher costs to ratepayers. Our policy and practice for all major gas utilities is to reward improvement and penalize inadequate performance by setting performance metrics that identify areas in need of attention and establish firm goals. We believe that the Joint Proposal represents a reasonable implementation of our policy and practice.

F. CLCPA Related Efforts

The CLCPA mandates that New York's greenhouse gas emissions be 40 percent below 1990 levels by 2030; 85 percent below 1990 levels by 2050; and economy-wide carbon neutrality achieved by 2050.[175] CLCPA Section 7(2) requires all State agencies to consider whether their administrative approvals and decisions "are inconsistent with or will interfere with the

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[174] Id., p. 23, n. 17.

[175] Environmental Conservation Law (ECL) §75-0107(1). Statewide greenhouse gas emissions levels in 1990 were 409.78 million metric tons of carbon dioxide equivalent. 6 NYCRR §496.4(a). Using a 20-year global warming potential and including upstream emissions from fossil fuels imported into New York, as required by the CLCPA, the statewide greenhouse gas emission limit for 2030 is 245.87 million metric tons of carbon dioxide equivalent (CO_2e) and the emissions limit for 2050 is 61.47 million metric tons of CO_2e. See December 30, 2021 Climate Action Council Draft Scoping Plan, p. 21.

attainment of the statewide greenhouse gas emissions limits" established in Environmental Conservation Law (ECL) Article 75. CLCPA Section 7(3) requires all State agencies to ensure that their decisions will not "disproportionately burden disadvantaged communities."[176] The CLCPA also requires various State agencies, including the Commission, to "promulgate regulations to contribute to achieving the statewide greenhouse gas emissions limits established in Article 75 of the ECL.[177]

The CLCPA establishes the Climate Action Council (CAC), which was required to prepare a draft Scoping Plan by January 1, 2022, and to issue a final Scoping Plan by January 1, 2023, outlining recommendations for attaining statewide greenhouse gas emissions limits. The CAC's Scoping Plan "shall identify and make recommendations on regulatory measures and other state actions that will ensure the attainment of the statewide greenhouse gas emissions limits established" by the CLCPA, with input from the public, subject matter experts, and other stakeholders.[178] On December 30, 2021, the CAC released its draft Scoping Plan for public comment.

In addition, the CLCPA requires the Department of Environmental Conservation, by January 1, 2022 and each year thereafter, to issue a comprehensive report on statewide greenhouse gas emissions, expressed in tons of carbon dioxide equivalents, from all greenhouse gas emission sources in the State, including the relative contribution of each type of greenhouse gas and each type of source to the statewide total.[179] After public workshops, consultation with various groups, and

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[176] CLCPA, L. 2019, ch. 106; ECL §75-0101 et seq.

[177] ECL §75-0109.

[178] ECL §75-0103(11), (13).

[179] ECL §75-0105.

incorporating findings from the CAC's Scoping Plan, the Department of Environmental Conservation must promulgate rules and regulations by January 1, 2024, to ensure compliance with statewide emissions reduction limits and work with other State agencies and authorities to promulgate necessary regulations.[180]

The Joint Proposal states that O&R will undertake environmental sustainability efforts that are designed "to assist in achieving the goals of the CLCPA."[181] As noted above, one of the primary goals of the CLCPA is to reduce statewide greenhouse gas emissions reductions by the established deadlines, the first of which is 2030. As such, O&R's efforts must be aimed at reducing its greenhouse gas emissions, not only during the three-year rate term established in the Joint Proposal, but also in the future.

The Joint Proposal contains provisions identified as "CLCPA-Related Efforts."[182] First, the Joint Proposal requires the Company to undertake an inventory of total system-wide emissions and to report annually on the results of the emissions inventory and the methodology used to calculate emissions.[183] Certain other CLCPA-related provisions in the Joint Proposal require specific actions that are intended to reduce greenhouse gas emissions, including:

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[180] ECL §75-0109.

[181] Joint Proposal, p. 6, Appendix 20.

[182] Joint Proposal, p. 6, Appendix 20.

[183] Id. The Joint Proposal indicates that O&R's emissions inventory "calculation will include publicly available resources, such as EPA's 2019 eGRID table, EPA's greenhouse gases equivalencies calculator, and U.S. Energy Information Administration data." If the Commission takes action in a separate proceeding during the term of these Rate Plans to define the methodology to be used in emissions inventory calculations, that methodology will govern the inventory requirement in the Joint Proposal.

- Lowering emissions from operations by retiring 22 miles of leak prone pipe annually from 2022 to 2029;
- Enhancing public awareness and conducting educational measures related to availability of low carbon heating alternatives, such as ground and air source heat pumps and heat pump water heaters and provide financial incentives to reduce installation costs for those technologies;
- Installing 15,400 natural gas detectors with notification capability to emergency response personnel;
- Proposing in 2022 a Geothermal Neighborhood Project as a Reforming the Energy Vision (REV) Demonstration Project to explore the potential for a geothermal district energy system and thereby avoid construction of additional gas infrastructure;
- Targeting a 0.95 – 3.63 percent annual reduction in peak gas usage by 2024 in all service classes through a Behavioral Demand Response Pilot;
- Advancing customer adoption of clean energy technologies (electric vehicles, heat pumps, etc.) through enrollment in its clean energy program;
- Purchasing new electric vehicles for the Company’s light-duty fleet and transitioning the entire existing light-duty fleet to EVs by 2040;
- Deployment of EV plug-ins;

- Adding 84.6 megawatts (MWs) of energy storage by 2024.[184]

The Company's Statement in Support indicates that it anticipates significant emissions reductions from the CLCPA-Related Efforts and other programs, and lists the "Lifetime CO_2 Reductions" totaling 1.397 million tons in the categories of electric and gas consumption, and electric vehicle and heat pump adoption.[185] The Company notes, however, that these projections are "provided for illustrative purposes only."

In its Reply Statement, O&R indicates that the Joint Proposal "begins to align the Company's gas planning and actions with the CLCPA."[186] Attached to O&R's Reply is a "Sales Volume Emission Impact" chart, which estimates the emissions impacts from 2021 to 2024 that could result based on its electric and gas sales forecasts.[187]

PULP argues in its Statement in Opposition that O&R's CLCPA efforts lag behind other utilities and are tied to prior Consolidated Edison measures requiring use of ratepayer funds to

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184 The Joint Proposal (Appendix 20, pp. 1-2) references measures that the Company is already required to undertake pursuant to the NE:NY order (Case 18-M-0084), such as targeting a 6.6 percent reduction in electric sales volumes and a 1.5 percent reduction in gas sales volumes from 2019 levels through energy efficiency programs. Other listed items are required under separate provisions of the Joint Proposal, some of which are associated with PRAs, including gas performance mechanisms, such as leak prone gas main removal/replacement and leak management.

185 O&R Statement in Support, p. 6.

186 O&R Reply Statement in Support, p. 10.

187 O&R Reply Statement in Support, p. 3, n. 4 and Attachment A. Although the Company indicates that the emission values in Attachment A to its Reply Statement were calculated "[e]mploying the same methodology the Company used to calculate emissions reductions," in its initial Statement in Support (p. 6), that methodology is not set forth.

pay above market rates for non-proven, theoretical measures, such as certified natural gas.[188] PULP asserts that O&R should do more to meet the CLCPA's objectives and should agree to the greenhouse gas reduction measures that its affiliate, Consolidated Edison, has agreed to, including proposing eligibility criteria for NPAs.

AGREE similarly objects to the lack of specificity in the Joint Proposal's CLCPA provisions when compared with other utility rate cases.[189] AGREE asserts that the Joint Proposal's provisions do not comply with the CLCPA and notes that there is little time to comply with the statute's ambitious emissions reductions goals.[190] AGREE notes that although O&R has agreed to inventory its emission in the future, it should have done so in these rate proceedings given the CLCPA's applicability and required Commission findings. AGREE further asserts that the Company has not quantified its emissions in these cases, the Commission has no record upon which to determine how the Company's commitments will align with the CLCPA, including the agreed-upon 1.5 percent reduction target in its service territory.[191]

DPS Staff asserts in its Statement in Support that the CLCPA's requirements must be interpreted with the Commission's statutory duty to ensure safe and adequate service under PSL §65(1). DPS Staff claims that although the Company's projections show increased gas demand, the Joint Proposal is consistent with the CLCPA because its provisions will result in the more efficient use of existing electric and gas service in

[188] PULP Statement in Opposition, p. 5.

[189] AGREE Statement in Opposition, p. 3.

[190] Id., pp. 6-7.

[191] Id., p. 7.

favor of more environmentally friendly alternatives, while also ensuring that the Company provides safe, reliable and adequate service at just and reasonable rates.[192] DPS Staff claims that although the Joint Proposal will increase gas sales in all three Rate Years, O&R will "work to reduce total gas sales from forecasted levels by one and one-half percent" over the three-year Rate Plans.[193] DPS Staff also cites the Company's LPP and NPA programs as contributing to the CLCPA's goals. DPS Staff refers to the Joint Proposal's cost recovery provisions applicable in the New Efficiency: New York (NE:NY) proceeding as furthering the CLCPA's objectives.[194]

In its Reply Statement, DPS Staff points to the Company's commitment to submit a proposal for a Company-owned geothermal system, claiming that it is an NPA project intended to replace fossil fuel heating systems.[195] We find that the Geothermal Neighborhood Project being proposed under the Joint Proposal to be relevant to the CLCPA inquiry only if the Commission approves the proposal and the Company agrees to implement it once approved.

In its Statement in Support, O&R interprets our recent decision in the Niagara Mohawk Power Corporation d/b/a National Grid rate cases[196] to mean that the CLCPA does not override the Commission's "core responsibility" to ensure that O&R provides safe and reliable service at just and reasonable rates.[197] O&R

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[192] DPS Staff Statement in Support, pp. 9-10.

[193] DPS Statement in Support, p. 8.

[194] DPS Statement in Support, pp. 9-10.

[195] DPS Reply Statement in Support, p. 11; Joint Proposal, Appendix 20, p. 1.

[196] Cases 20-E-0380 and 20-G-0381, supra, Niagara Mohawk 2022 Rate Order, pp. 77-78.

[197] O&R Statement in Support, pp. 3-4.

further asserts that disadvantaged communities are not disproportionately burdened by these Rate Plans because they "receive the benefits of safe and reliable service and low-cost natural gas."[198]

Discussion

We find that, in reviewing the Joint Proposal here, the Commission can and should serve the statutory purposes of both the CLCPA to reduce greenhouse gas emissions and PSL §65(1) to ensure that O&R can provide safe and adequate service at just and reasonable rates. The CLCPA recognizes that the provision of safe and adequate service remains paramount during the transition to a clean energy economy and the Commission remains committed to balancing those interests with rate impacts to all customers.[199] The Commission has furthered the CLCPA's objectives and has implemented the State's policy to reduce greenhouse gas emissions in the actions it has taken before and

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[198] Id., p. 4.

[199] PSL §66-p(2), (4).

after the CLCPA's enactment.[200]

The Commission notes that the CLCPA contains no mandates or guidelines with respect to emissions associated with the State's gas distribution system or gas supplied by utilities like O&R. This is in contrast with the specific mandates included within the CLCPA related to the transition to a zero-emission electric grid by 2040 and expressly applicable to the Commission, which are being implemented through the Commission's modification to align the Clean Energy Standard with the CLCPA.[201]

This absence of specific mandates or guidelines with respect to the State's gas distribution system played out in the

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[200] See, e.g., Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015) (Track One Order); Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (Track Two Order) (issued May 19, 2016); Case 15-M-0252, In the Matter of Utility Energy Efficiency Programs, Order Authorizing Utility-Administered Gas Energy Efficiency Portfolios for Implementation Beginning January 1, 2016 (issued June 19, 2015); Case 15-E-0302, Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and Clean Energy Standard, Order Adopting Modifications to the Clean Energy Standard (issued October 15, 2020) (2020 NE:NY Order); Case 20-E-0197, Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act, Order on Phase 1 Local Transmission and Distribution Project Proposals (issued February 11, 2021).

[201] Case 15-E-0302, supra, 2020 NE:NY Order; Case 19-E-0735 - Proceeding on Motion of New York State Energy Research and Development Authority Requesting Additional NY-Sun Program Funding and Extension of Program Through 2025, Order Extending and Expanding Distributed Solar Incentives (issued May 14, 2020) (NY Sun Order); Case 18-E-0130 In the Matter of Energy Storage Deployment Program, Order Establishing Energy Storage Goal and Deployment Policy (issued December 13, 2018) (Energy Storage Order).

rate case before us. While PULP and AGREE argue that O&R is not taking enough action to reduce emissions, the Company notes that the measures itemized in the Joint Proposal only begin to align the Company's gas planning with the CLCPA.

The Commission recognizes the need to reduce the emissions associated with gas delivery systems and, accordingly, initiated the Gas Planning Procedures proceeding, in which it tasked assigned Staff with issuing "a proposal for a modernized gas planning process that is comprehensive, suited to forward-looking system and policy needs, designed to minimize total lifetime costs, and inclusive of stakeholders."[202] Staff subsequently issued a Gas Planning Process Proposal,[203] which has been the subject of a stakeholder forum and two rounds of public comments. The purpose of Staff's proposal is to ensure more thoughtful, strategic, and comprehensive planning for natural gas usage and investments. It also presents a regulatory planning roadmap to enable utilities to maximize the use of energy efficiency, new technologies (such as electric heat pumps) and demand response programs, as well as to minimize —- and potentially eliminate —- new gas infrastructure investments while maintaining safe and reliable service, consistent with the CLCPA.

We thus reject the arguments advanced by both PULP and AGREE that the Joint Proposal is inconsistent with the CLCPA and the Company should be required to do more. The Joint Proposal reflects a result that is within the range of likely litigated outcomes because it sets forth specific actions designed to promote the CLCPA's objectives to reduce emissions over the

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[202] Case 20-G-0131, supra, Gas Planning Order Instituting Proceeding (issued March 19, 2020), p. 7.

[203] Case 20-G-0131, supra, Staff Gas System Planning Process Proposal (February 12, 2021).

three-year Rate Plans, and does so within a legal backdrop that requires O&R to serve its customers. We decline to compare O&R's efforts with those of other utilities, as PULP urges, because of the financial, operational, and other differences among all New York utilities and the parties' good faith efforts to address the CLCPA here.

We find that the Rate Plans proposed here comply with Section 7(2) of the CLCPA and appropriately balance the interests in reliability, public safety, and reasonable rates with emission reductions and clean energy objectives. In addition, the proposed Rate Plans contain provisions similar to those in recent rate plans that the Commission has found to be consistent with the CLCPA,[204] and are an important step in the ongoing process of achieving the CLCPA's greenhouse gas emission limits, one that will be built upon in future rate cases and in other Commission proceedings.

We also find that the programs and projects in the Joint Proposal and proposed Rate Plans will not burden disadvantaged communities disproportionately. No party alleged a disproportionate burden on disadvantaged communities, nor refuted the Company's reliance on our recent findings in the Niagara Mohawk 2022 Rate Order regarding compliance with CLCPA

[204] See, Cases 20-E-0428, Central Hudson Gas & Electric Corporation – Rates, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan (issued November 18, 2021); Cases 19-G-0309, et al., The Brooklyn Union Gas Company d/b/a National Grid NY for Gas Service – Rates, Order Approving Joint Proposal, as Modified, and Imposing Additional Requirements (issued August 12, 2021); Cases 19-E-0378, et al., New York State Electric and Gas Corp. and Rochester Gas and Electric Corp. - Rates, Order Approving Electric and Gas Rate Plans in Accord with Joint Proposal (issued November 19, 2020), pp. 115-120.

Section 7(3) because disadvantaged communities receive the benefits of safe and reliable service.[205]

The Joint Proposal's requirement for O&R to perform a system-wide greenhouse gas emissions inventory and report to the Commission is a critical foundational step that is consistent with our decisions in other recent rate cases, which recognize the need to reduce emissions in complex natural gas delivery systems.[206] The inventory will create a baseline on which the Company's planning measures and operational changes can be based. The Joint Proposal is also consistent with the pending DPS proposal in the Gas Planning Proceeding, including comprehensive usage planning and minimization of new gas infrastructure investments.[207]

Other provisions of the Joint Proposal that require concrete actions also have the potential to result in quantifiable emission reductions, including removing/replacing leak prone pipe, adding energy storage, proposing a geothermal project, targeting annual reductions in peak usage, enrolling customers in the clean energy program to adopt electric vehicles and heat pumps, deploying electric vehicle plug-ins, and purchasing electric fleet vehicles.[208]

Overall, the Joint Proposal's identified CLCPA-Related Efforts advance the CLCPA's objectives. The Joint Proposal

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[205] O&R Statement in Support, p. 4.

[206] See Cases 20-E-0380 and 20-G-0381, supra, Niagara Mohawk 2022 Rate Order, pp. 82-83; Cases 20-E-0428 and 20-G-0429, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric and Gas Service, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan (issued November 18, 2021), pp. 31-32.

[207] Case 20-G-0131, supra, DPS Staff Gas System Planning Proposal (filed February 12, 2021).

[208] Joint Proposal, Appendix 20.

requires O&R to file an emissions inventory, a plan for the development of renewable natural gas (RNG), and a report to the Commission on NPAs in the generic Gas Planning Proceeding. We further clarify the Joint Proposal's reporting requirements. Unless required to do so earlier, in its next rate filing, O&R is additionally required to provide: (1) the 1990 greenhouse gas emissions baseline for its entire gas network, with a description of the methodology used in developing the baseline calculation; (2) a calculation of annual greenhouse gas emissions for its gas network at the time of the filing (or at the time the Commission requires, if earlier), with a description of the methodology used in the calculation; (3) an assessment of the impacts that O&R's specific investments, capital expenditures, programs, and initiatives described in its rate filing will have on its greenhouse gas emissions from its gas network, specifying the potential emissions impacts of each; and, (4) an analysis of NPAs considered for each investment, capital expenditure, program or initiative and a reasoned explanation if such NPA was not selected.

We note that the DPS Gas System Planning Proposal in the Gas Planning Proceeding recommends that the Commission direct New York's gas utilities to file long-term plans every three years, which consider the greenhouse gas emission impacts of new gas infrastructure and the State's reduction goals.[209] That Proposal also recommends that the Commission have a "stringent test" for construction of new gas infrastructure in order to address the State's greenhouse gas reduction goals. The Commission has not yet reached a determination in the Gas Planning Proceeding. In requiring reporting here on O&R's

[209] Case 20-G-0131, supra, DPS Staff Gas System Planning Proposal, p. 26.

CLCPA-Related Efforts, we do not intend to affect the Commission’s actions in that Proceeding.

In approving the CLCPA provisions of the Joint Proposal, we have observations that should guide the Company in its next rate filing. The Joint Proposal reflects increased gas sales over the three-year term of the gas Rate Plans and more should be done in the future to quantify how such increased sales will be mitigated consistent with the CLCPA. As DPS Staff notes, the Company’s forecasts are the best estimate of customer usage that can be expected based on available data and economic variables.”[210] Furthermore, the Company cannot simply refuse gas service in an effort to reduce gas sales because it is required by law to provide gas service to both residential and non-residential applicants upon request where sufficient gas supply exists.[211] The Company should continue to explore additional revisions to its programs, marketing efforts, and incentive structures to mitigate any increased gas expansion.

The Joint Proposal characterizes several measures as “CLCPA-Related Efforts,” but they do not require specific actions by the Company that are likely to result in demonstrable and quantifiable reductions in greenhouse gas emissions to advance the CLCPA’s objectives and do not have a reporting component. For example, the Joint Proposal calls for the Company “to consider non-pipe alternatives instead of LPP replacements;” and “to seek out opportunities for NPAs.”[212] The Joint Proposal also states that O&R will “support efforts that

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[210] DPS Staff Statement in Support, p. 10.

[211] See PSL §31(1), (4); Transportation Corporations Law §12.

[212] Joint Proposal, Appendix 20, pp. 1-2.

explore the use of hydrogen and RNG within the gas system;"[213] will "support the work of the CLCPA's Climate Justice Working Group;" and will "support" customers in adding solar photovoltaics to the electric system.[214] The Joint Proposal further includes on the list of CLCPA-Related Efforts that the Company will update its website to include education about community solar opportunities and "will continue to evaluate its approach to gas depreciation."[215] In the next rate filing, the Company is required to quantify reductions in greenhouse gas emissions expected from all of these proposed CLCPA-Related efforts, programs and projects.

Finally, the Joint Proposal continues to allow declining block rates for gas customers in SC 1, SC 2, SC 6-1A, and SC 6-1B (residential, non-residential, and commercial gas customers. The first block rate is increased from $19.50 to $22.00 for SC 1 and SC 6-1A and the differential between the second and third blocks will be set to equal in Rate Year 3.[216] For SC 2 and SC 6 1B, the first block rate is increased from $30.00 to $33.00 and Appendix 18 of the Joint Proposal indicates that the Company will "file a proposal in its next base rate case to continue the flattening of the block rate structure of these service classes."[217]

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[213] As the Climate Action Council notes in its Draft Scoping Plan (p. 120, n. 156), "The scope of RNG use is limited by available feedstocks and by the need to mitigate statewide emissions from all sectors (since under the Climate Act requirements for emissions accounting, RNG is a low-carbon fuel but it is not zero-emissions)."

[214] Joint Proposal, Appendix 20, pp. 2-3.

[215] Joint Proposal, Appendix 20, p. 2.

[216] Joint Proposal, Appendix 18, p. 3.

[217] Id.

Under a declining block rate structure, the unit cost of energy declines as more energy is used. In other words, the more electricity or gas used, the cheaper the energy cost to customers per kWh or Ccf, which can result in greater usage. As our 2011 Rate Order found with respect to O&R's declining block rates for electricity, this rate structure disincentivizes limiting energy usage.[218] In the 2011 Order, we directed the Company to develop a proposal for its next rate case that would phase out and eliminate declining block rates for electric customers in SC 2 and SC 3.[219]

DPS Staff in these proceedings undertook efforts to move the Company in that direction by agreeing in the Joint Proposal to the elimination of the third block in Rate Year 3 for gas SC 1 and SC 6-1A, and by including the requirement that the Company propose in its next rate case a "continued flattening" of the block rate structure for SC 2 and SC 6-1B.[220] We find that in doing so, DPS Staff has advanced important policy considerations consistent with the CLCPA.

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[218] Case 10-E-0362, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service, Recommended Decision (issued April 4, 2011) (2011 Rate Order), pp. 139-140. The Recommended Decision underlying our 2011 Rate Order proposed that the Company and DPS Staff pursue a collaborative process to transition O&R to a "block-free rate structure." In briefs on exceptions, the Company and DPS Staff indicated that they had insufficient time to propose such a collaborative process, which resulted in the "gradual flattening" approach.

[219] Case 10-E-0362, supra, 2011 Rate Order, p. 91. More than a decade after our 2011 Rate Order, the Joint Proposal here (Appendix 17, pp. 3-4) continues O&R's electric customer declining block rates for SC 2, Secondary Demand Billed Service, after modifying it to eliminate the third block rate.

[220] Joint Proposal, Appendix 18, p. 3.

In adopting the Joint Proposal, we are approving the continuation of the declining block rate structure. At the same time, we express the firm expectation that the Company, in its next gas rate filings, will propose the elimination of any remaining declining block rates for gas customers and foster the incentive to limit gas usage in a manner that avoids excessive bill impacts.

We find that the Joint Proposal is consistent with the CLCPA’s emissions limitations and otherwise takes appropriate steps to mitigate any potential greenhouse gas emissions associated with the Company’s operations. In finding the Joint Proposal to be consistent with the greenhouse gas limits established by the Department of Environmental Conservation, we take notice of the Company’s efforts, along with the State’s other utilities, to comply with the renewables mandates under the CLCPA, which will result in a broad reduction in greenhouse gas emissions associated with its customers’ use of electricity.[221]

G. Major Storm Cost Reserve/Revenue Adjustment Mechanism

The Joint Proposal includes as part of the Company’s annual electric revenue requirements storm reserve funding of $8.0 million in Rate Year 1, $8.2 million in Rate Year 2, and

[221] See, e.g., Case 20-E-0197, Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act, The Utilities’ Coordinated Grid Planning Process and Revised Benefit Cost Analysis Proposals (filed December 17, 2021); Case 20-E-0197, supra, Petition of Niagara Mohawk Power Corporation d/b/a National Grid for Cost Recovery of Phase 1 Local Transmission Projects (filed November 8, 2021).

$8.3 million in Rate Year 3.[222] To the extent that the Company incurs additional storm costs in excess of the annual reserve in any Rate Year, the Joint Proposal provides that the Company will defer on its books of account any excess amounts for future recovery from customers, subject to the limitations outlined below. If on the other hand, the Company incurs major storm costs that are less than the annual reserve amounts in any Rate Year, the Company will defer the unused reserve costs for the benefit of customers.

The Joint Proposal provides that major storm costs related to Pre-Staging and Mobilization, such as employee labor, transportation, meals, lodging and travel time, will be charged to the major storm reserve only as follows:

- Pre-Staging and Mobilization Costs up to $100,000 per event will not be chargeable to the major storm reserve;

- Pre-Staging and Mobilization Costs in excess of $100,000 may be charged to the major storm reserve, with a total cap of $1.75 million per event; and

[222] Joint Proposal, Appendix 9, pp. 8-10; Appendix 6, p. 1. The Joint Proposal also includes in the Company's annual electric revenue requirement $14.9 million in each Rate Year, reflecting a 5.4 year amortization period for previously incurred incremental major storm costs (net of insurance and other recoveries) which are in excess of collections for major storm reserve funding from customers. These costs were related to major storms, such as Winter Storm Toby (resolved in the 2019 Rate Order) and Tropical Storm Isaias.

- Up to 85 percent of Pre-Staging and Mobilization Costs in excess of $1.75 million may be charged to the major storm reserve, and the Company is required to expense the remaining 15 percent of such costs in the year the costs are incurred.[223]

The Joint Proposal further provides that the Company may not charge the storm reserve for (1) any employee overtime for any work occurring more than 60 days following the date on which the Company is able to restore service to customers; and (2) stores handling, engineering, and other overheads costs.

All major storm costs are subject to Staff review and the storm must fall within the regulatory definition of a "major storm" if costs are to be charged to the reserve.[224] The Company may charge to the major storm reserve costs incurred to obtain the assistance of contractors and/or utility companies providing assistance in storm response efforts, as well as Pre-Staging and Mobilization costs, such as incremental employee labor, transportation, meals, lodging, and travel time. Such costs must be incurred in reasonable anticipation that a storm will adversely affect the Company's electric operations and must meet the criteria in 16 NYCRR Part 97.

The Joint Proposal includes a Revenue Adjustment Mechanism (RAM) for actual major storm costs incurred that are

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[223] The Joint Proposal provides that the Company may file a petition with the Commission to defer the remaining 15 percent of such costs in excess of $1.75 million, which shall be subject to the Commission's three-part test regarding deferral accounting treatment. Joint Proposal, Appendix 9, p. 9.

[224] 16 NYCRR Part 97 (defining "major storm" to be a period of adverse weather during which service interruptions affect at least ten percent of customers within an operating area and/or that results in customers being without electric service for at least 24 hours and that exceeds $200,000).

more than $2 million above the reserve in any Rate Year.[225] In that case, the Company may recover the variance between the reserve amount and the actual amount incurred, with a cap of 2.5 percent of annual delivery revenues. The Joint Proposal allows recovery of such costs through the variable ECA.

Discussion

We find the storm reserve amounts for each Rate Year to be reasonable, based on the record, and the limitations and cost recovery mechanism to be consistent with those we have approved in other rate cases. The Joint Proposal lacks an express reporting requirement for recovery under the ECA surcharge as recommended by DPS Staff in its testimony.[226] Accordingly, we include this as an additional requirement. The Company is required to file with the Secretary as a compliance filing details of storm costs to be collected through the variable ECA, which shall be based on actual major storm costs incurred over the 12 months ending December 31 of each prior Rate Year. The filing shall be made 60 days before any new storm costs are recovered through the ECA and shall include the total storm costs incurred per major storm event, backup documentation to support such costs, and workpapers associated with the calculations used to determine the Company's proposed RAM component of the variable ECA by service classification.

H. Additional Electric Programs

The Joint Proposal provides funding for continuing existing electric programs, including REV Demonstration Projects, the Pomona (DRP) Substation Battery Non-Wires Alternative (NWA), the Managed Charging Program for electric vehicles, the Customer-Owned Street Light Program, and the

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[225] Joint Proposal, Appendix 9, p. 10.

[226] Hearing Exhibit 223 (DPS Staff Rates Panel, Exhibit SRP-6).

Little Tor Substation Project. No party objected to the capital expenditures for these additional projects and programs, some of which were included in the revenue requirement and are subject to budget caps and reconciliation of actual costs pursuant to true up targets.

We find that each of the additional electric projects and programs are designed to reduce greenhouse gas emissions and reduce energy usage and therefore are consistent with the CLCPA's goals and the Commission's long-standing energy policy objectives. Accordingly, we find these provisions of the Joint Proposal to be in the public interest, subject to the modifications outlined below. They will be briefly outlined below in the context of the CLCPA and the Commission's policies.

1. REV Demonstration Project Costs

The Joint Proposal calls for O&R's continuation of various REV Demonstration Projects, with actual costs reconciled with the target levels provided in rates and in accordance with the existing reconciliation mechanism, amortized over ten years, subject to continuing reporting requirements.[227] The Joint Proposal recognizes the $10 million project budget cap described in the Commission's REV Track One Order,[228] but preserves the Company's right to file a petition with the Commission if the budget cap is exceeded.

O&R has developed five REV Demonstration Projects, two

[227] Joint Proposal, p. 26; Appendix 9, pp. 1-2, 10; Appendix 6.

[228] Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Adopting Regulatory Policy Framework and Implementation Plan (issued February 26, 2015), pp. 115-117 (permitting deferral until the next rate case of incremental REV demonstration project costs, net of tax and other benefits such as grants, revenues, third party contributions, but limited to 0.5 percent of the delivery service revenue requirement).

that have been completed (Customer Engagement and Marketplace Platform and Optimal Export), two that are ongoing (Innovative Storage Business Models and Smart Home Rates), and one that is still in development (Geothermal Neighborhood).[229] The latter three non-completed projects will continue to be implemented and/or developed during the three-year Rate Plans provided in the Joint Proposal. The true up targets for the three ongoing Projects are $2.59 million in 2022, $3.28 million in 2023, and $3.35 million in 2024.[230]

The Innovative Storage Business Models Project is a ten-year demonstration project being implemented by O&R and Sunrun, Inc., that involves a solar plus storage virtual power plant. The Project is intended to deploy 2.9 MW of rooftop solar and 2.1 MW/4.7 MWh) of leased distributed solar energy storage via Sunrun's "Brightbox" battery technology.[231] The Project uses aggregated collection of behind-the-meter solar energy plus storage systems and is targeting 300 customers in O&R's service territory. The Company claims in its testimony that the Project provides distribution benefits, backup power resiliency, and wholesale revenues. The Company concedes that the Project is not yet financially viable beyond its demonstration status, but it anticipates overall costs to decrease as the market matures. O&R also indicates in testimony that it foresees virtual power plants like Sunrun ultimately

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229 Hearing Exhibit 60 (O&R Electric Infrastructure and Operations Panel), pp. 147-156.

230 Joint Proposal, Appendix 6 (REV Demonstration Project True-Up Targets are $2.58 million for 2022; $3.28 million for 2023; and $3.35 million for 2024).

231 Hearing Exhibit 60 (O&R Electric Infrastructure and Operations Panel), pp. 150-153. O&R filed an implementation plan in June 2020.

being authorized to participate in wholesale electric markets.[232]

O&R's Smart Home Rates demonstration project is a joint effort with affiliate Consolidated Edison designed to demonstrate alternative rate structures and price signals to customers in order to optimize value for both customers and the overall distribution system.[233] Under the project, AMI customers may opt-in to Smart Home Rates and have access to smart home energy management technologies (such as a home smart thermostat) that allow price-responsive home energy management by limiting consumption and reducing peak load. The Company has enrolled approximately 550 customers in the Project, which has an end date of December 2023.

The Geothermal Neighborhood Project is a demonstration project that involves the Company installing and owning ground-source geothermal heat pumps and associated infrastructure across multi-unit, multi-family, residential low-to-moderate income areas.[234] It is intended to foster customer adoption of geothermal heat pumps as a heating source. O&R explains in its testimony that there remain significant economic hurdles for customer adoption, but this Project is intended to provide a model for allocation of infrastructure costs and to explore customer outreach, utility investment, rate design, and recovery models, with a specific focus on disadvantaged customers. Project costs are estimated at $1.8 million and there are additional public funding sources and incentives, such as the New York State Energy Research and Development Authority (NYSERDA) Clean Energy Fund and federal tax credits, that may be

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232 Id.

233 Id., pp. 153-154.

234 Id., pp. 155-157. The Company's testimony indicates that it intended to submit an initial project proposal for the Geothermal Neighborhood demonstration project in early 2021.

available to support the project.[235]

In its testimony, DPS Staff initially disagreed that the Geothermal Neighborhood Project was an appropriate REV Demonstration Project, questioning the funding of such by ratepayers, as well as O&R's ownership of the heat pump infrastructure in the context of the Track One Order. O&R responded in rebuttal testimony that it will continue to pursue additional funding sources for the Project's implementation.[236]

The Joint Proposal incorporates these Company efforts and the inclusion of the Geothermal Neighborhood Project represents a resolution of the issue between DPS Staff and the Company in favor of the Project going forward.[237] As we have recognized in other rate cases, implementation of geothermal heat pumps is expected to result in reductions in natural gas usage and overall energy consumption.[238]

2. Pomona NWA

The Joint Proposal continues O&R's implementation, operation, and maintenance of the Pomona NWA, including the battery storage component. The Joint Proposal includes in the revenue requirement funding for battery storage vendor services, water line and fire hydrant maintenance, and communication

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[235] Id.

[236] Hearing Exhibit 266 (O&R's Rebuttal Electric Infrastructure and Operations Panel), pp. 29-31. O&R indicated that it had filed a grant application with the U.S. Department of Energy and was planning to apply for a second grant from NYSERDA. In addition, the Company notes that DPS Staff was still assessing the Project.

[237] Joint Proposal, p. 26; Appendix 9, p. 10-11; Appendix 6.

[238] See, e.g., Cases 20-E-0380 and 20-G-0381, supra, Niagara Mohawk 2022 Rate Order, pp. 47-51, 85.

network fees.[239] The 2015 Rate Order first approved the Pomona NWA, but did not authorize recovery of ongoing O&M costs for the battery storage system. Consequently, the Joint Proposal recommends approval of O&M costs for battery-related services, water infrastructure maintenance, and communications network fees at an annual cost of $200,000 during 2022-2024.[240] These O&M costs will be amortized and recovered from ratepayers over a ten-year period in the same manner as all other Pomona NWA Project-related costs. The ten-year amortization results in the inclusion of an additional $20,000 cost recovery from ratepayers in each rate year covered by the Joint Proposal.

The Pomona NWA was first approved in the 2015 Rate Order and is a distributed energy resource (DER) and demand-side management (DSM) program combining a battery energy storage system with other programs, including the Small Business Direct Install and C&I Existing Buildings program, the Direct Load Control – Bring Your Own Thermostat program, and the Commercial System Relief and Distribution Load Relief program.[241] The Pomona NWA is intended to delay construction of a major substation and associated facilities and is currently in the

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239 Joint Proposal, p. 26; Appendix 9, p. 11; Appendix 6 (True-Up Targets for 2022: $4.11 million; 2023: $3.81 million; and 2024: $3.49 million); Hearing Exhibit 60 (O&R Electric Infrastructure and Operations Panel), pp. 144-147.

240 Joint Proposal, Appendix 3, p. 1; Hearing Exhibit 60 (O&R Electric Infrastructure and Operations Panel), p. 147; Hearing Exhibit 62 (O&R EIOP-2), p. 17.

241 Case 14-E-0493, Proceeding on Motion of the Commission as to the Rates Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service, Order Adopting Terms of Joint Proposal and Establishing Electric Rate Plan (issued October 16, 2015) (2015 Rate Order). The Commission’s 2015 Rate Order incentivized the Pomona DER Program, allowing O&R to recover through the Energy Cost Adjustment surcharge one basis point for each 0.1 MW of load reduction exceeding 3.0 MW, with a 50-basis point cap.

implementation phase.[242]

The Joint Proposal also contains rate base true up targets for the overall Pomona NWA of $4.11 million in 2022, $3.81 million in 2023, and $3.50 million in 2024, which are the result of the ten-year amortization of battery-related O&M costs and are subject to the reconciliation mechanism outlined in the Joint Proposal.[243] The Joint Proposal provides for total cost recovery for the Pomona NWA Project of $1.86 million over the three-year electric Rate Plans.[244]

O&R indicates that it has achieved 4.1 MW of peak load reduction as a result of the Pomona NWA and the Project costs are within the Commission-established $9.5 million budget cap.[245] The 2015 Rate Order established the budget cap and authorized an incentive if O&R achieved a peak load reduction above 3 MW as a result of the Pomona NWA Project.[246] The Joint Proposal provides for O&R's recovery of an incentive totaling $30,140 for the 1.1 MW peak load reduction achieved above the established 3 MW threshold. The Joint Proposal provides that O&R will recover this incentive through its Earnings Cost Adjustment mechanism, which was also authorized in the 2015 Rate Order.

3. Electric Vehicle (EV) Charging Programs

The Joint Proposal provides for O&R's continued development of its Managed EV Charging Program but does not

242 Hearing Exhibit 60 (O&R Electric Infrastructure and Operations Panel), pp. 144-147.

243 Joint Proposal, Appendix 6, Appendix 9, p. 11.

244 Joint Proposal, Appendix 3, p. 1.

245 Hearing Exhibit 60 (O&R Electric Infrastructure and Operations Panel), p. 145.

246 Case 14-E-0493, 2015 Rate Order, pp. 18-21.

authorize cost recovery in these proceedings.[247] Cost recovery issues are therefore reserved for the Commission's generic EV Make-Ready Proceeding.[248]

In the Commission's generic EV Infrastructure Proceeding, it authorized O&R's proposed price-based, non-peak EV charging program (EV Charging Program), commencing in February 2021, and allowed recovery of annual program costs through an EV Make-Ready Surcharge.[249] In that generic proceeding, O&R initially proposed a three-year EV Charging Program at a cost of $800,000 beginning in 2021, which is designed to encourage EV charging during off-peak energy usage times in order to maintain system reliability. O&R's testimony in these proceedings now proposes a five-year EV Charging Program that will begin in 2022, with incentives available for

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[247] Joint Proposal, p. 26. In the Commission's generic EV Supply Equipment and Infrastructure proceeding (Case 18-E-0138), O&R submitted proposals for managing and implementing an EV charging program in its service territory that called for price-based management techniques to incentivize off-peak charging, including hardware and software technology to monitor location and time of charging and thereby motivate EV owners and operators to charge EVs during off-peak periods.

[248] DPS Staff Statement in Support, pp. 48-49.

[249] Case 18-E-0138, Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure, Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs (issued July 16, 2020) (EV Make-Ready Order), p. 78 (noting that existing rate plans do not account for EV-related costs; authorizing recovery through surcharge; and determining that in future rate filings, utility-owned make-ready work, including work related to future-proofing utility infrastructure, would be treated as capitalized plant-in-service with cost allocation and recovery via traditional ratemaking methodologies); Order Approving Tariff Amendments (issued November 18, 2021) (EV Cost Recovery Order), pp. 7-8 (authorizing on a permanent basis cost recovery of EV programs and implementation of EV surcharge).

the year of enrollment and for the following two years until 2026.[250] Customer enrollment is limited to 100 customers per year through 2024, with a maximum of 300 enrolled vehicles.

O&R indicates that total EV Charging Program costs include the cost of setting up the data tracking system for participant's charging behavior and the license fees paid to the third-party vendor. O&R's testimony indicates that it will retain a third-party technology vendor to deploy cost-effective solutions and monitor the energy consumption of EV-charging customer participants.[251] O&R does not include the specifics of a cost effective EV program, but indicates that it "may include hardware solutions connected directly to the vehicle, or software-based solutions through the use of telematics, smart chargers, application programming interfaces ("APIs"), or AMI" to "track the location, time, and duration of charging."[252] O&R also indicates that it "will provide an enrollment bonus to incentivize participation and cover start-up costs associated with implementing the chosen solution (up to $150 per vehicle)" and additional incentives of up to $500 if a customer's charging

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[250] Joint Proposal, p. 26.

[251] Hearing Exhibit 60 (O&R Electric Infrastructure and Operations Panel), pp. 163-164. The third-party vendor is responsible for participant enrollment and onboarding; management of an online web-portal; quality control and fraud prevention; incentive payment processing and distribution; and development of dashboards and reports for the Company's review.

[252] Id., p. 163.

habits meet the program criteria.[253] O&R does not seek recovery of the EV Charging Program costs in these rate proceedings and recovery is being addressed in the EV Infrastructure Proceeding, through the EV Make-Ready Surcharge.[254]

DPS Staff testified that O&R's EV Program appeared to be in accord with the Commission's EV Make-Ready Order, but did not opine on the Program's merits and noted that cost recovery issues should be addressed in the Commission's EV Infrastructure Proceeding.[255]

The issue of cost recovery for O&R's EV Charging Program is not a part of these rate proceedings. It is already required to implement this Program in the Commission's EV Infrastructure Proceeding. Consequently, we find that O&R is not providing any added value in agreeing in the Joint Proposal to continue its EV Charging Program. We nevertheless find this aspect of the Joint Proposal to be consistent with the CLCPA's emission reduction objectives and it is notable in light of the transportation sector's significant impact on greenhouse gas emissions, which O&R's Program is designed to address.

4. Customer-Owned Street Light Dimming Pilot

The Joint Proposal continues the implementation of O&R's customer-owned light-emitting diode (LED) street light

[253] Id., pp. 163-164. The criteria and associated incentives include: (i) $5.00 per month for active participation, including keeping the solution active and the EV charging in the service territory; (ii) $0.10 per kWh of charging during off-peak hours (off-peak hours are defined as 12:00 a.m.-8:00 a.m. seven days a week); and (iii) $20 per month from June to September for avoiding charging between 2:00 p.m. and 6:00 p.m. on weekdays.

[254] Case 18-E-0138, supra, EV Cost Recovery Order, pp. 7-8.

[255] Hearing Exhibit 131 (DPS Staff Clean Energy Panel), pp. 43-44.

dimming pilot project (Street Light Pilot).[256]

The Street Light Pilot was first approved in the 2019 Rate Order and provided for 25 street lights in two municipalities within SC 6 to be changed to LED dimmable street lights with "smart control nodes" or Network Lighting Control nodes (NLC nodes).[257] The Street Light Pilot is being jointly administered by O&R and the New York Power Authority (NYPA), but implementation was delayed during the last rate term due to Covid-19 as well as procurement and logistical issues, according to NYPA.[258]

NYPA, in partnership with DPS and other State agencies, is leading a statewide Smart Street Lighting NY Initiative to convert 500,000 street lights to energy-saving LED technology by 2025. The O&R Street Light Pilot is part of this Initiative. The Initiative's overall objective is to advance energy efficiency improvements and adoption of such new technologies in municipalities. NYPA facilitates the Initiative by providing financing, educational, technical and acquisition assistance for municipalities, including obtaining LED street lighting systems from utilities and procuring competitive

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[256] Joint Proposal, pp. 31-32.

[257] Cases 18-E-0067 and 18-G-0068, O&R – Rates, supra, 2019 Rate Order, pp. 99-100; 2019 Joint Proposal, pp. 50-51. The functionality of NLC nodes includes energy metering, monitoring, control, and data communications technology. As compared to traditional sensors, NLC nodes have photosensors that activate dimming and measure energy usage and cost savings, but are also "high quality electric meters" that record data in real-time and can be used for billing purposes. Under the terms of the Joint Proposal, they will not be utilized for billing under the Pilot. Hearing Exhibit 248 (NYPA Street Lighting Panel), p. 10.

[258] Hearing Exhibit 248 (NYPA Street Lighting Panel), pp. 8-10. O&R also testified that the Pilot had not been implemented due to circumstances beyond NYPA's control. Hearing Exhibit 100 (O&R Electric Rate Panel), p. 9.

materials.[259] NYPA is working with numerous municipalities across the State to implement the initiative and install LEDs on utility-owned street lights, or to assist municipalities in acquiring, owning, controlling, and implementing dimming LED street lights.

The Joint Proposal's requirement for O&R to file a tariff amendment furthers the objectives of PSL §70-a,[260] and is consistent with the Commission's 2016 order that approved the process for O&R and other utilities to transfer of street lights to municipalities and governmental entities (2016 Street Light Transfer Order).[261] The Commission's 2016 Street Light Transfer Order envisioned tariff amendments that included a reasonable transfer facilitation process, rather than a complex and attenuated one.

The Joint Proposal essentially reiterates the terms of the Street Light Pilot approved in the 2019 Rate Order, with some modifications, and outlines the implementation measures O&R must take. The Joint Proposal requires O&R to file, within 90

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[259] Hearing Exhibit 248 (NYPA Street Lighting Testimony), pp. 2, 4-5, 8. In addition to street light acquisitions from New York utilities, NYPA works with municipalities to design LED conversions and dimmable street lights and thereby realize energy cost savings and extend their useful life. NYPA also performs construction management and on-going maintenance.

[260] See PSL §70-a(4) (mandating that the Commission require utilities to have an effective tariff in place that facilitates the transfer of street lighting systems to municipalities and governmental entities in order to achieve both energy efficiency and cost savings).

[261] Case 15-E-0749, <u>O&R, Tariff filings to Effectuate Amendments to Public Service Law – New §70-a (Transfer of Street Light Systems)</u>, Order Approving Tariff Amendments with Modifications (issued October 14, 2016), p. 28 (approving tariff changes for New York utilities, including O&R, and authorizing implementation of the new street lighting ownership transfer procedures required under PSL §70-a).

days of the Commission's adoption of the Joint Proposal, tariff changes to allow for the installation and prescriptive use of NLC nodes in customer-owned street lights.[262] O&R then must establish the technical requirements for installing NLC nodes on municipally-owned street lights. The NLC nodes will measure energy usage and record data and the Company will continue to measure usage with existing approved meters for billing purposes and to evaluate the accuracy and effectiveness of the NLC nodes.[263]

Prior to NLC node installation, the Joint Proposal requires O&R to undertake a technical and engineering review of all NLC node models, provide municipal customers with progress updates on that review every 45-days, and maintain a list of reviewed NLC models for customers, which is made available upon request. The Joint Proposal further requires O&R to host a "collaborative" with interested parties after 6-months of data collection, at which they will evaluate and discuss (1) the metering accuracy of the NLC nodes as compared to the Company's own meters; and (2) the methodologies that may be used to account for the reduced electric usage associated with municipal-owned dimming street lights and the impacts on SC 6 customer bills, similar to the provisions in the 2019 Rate Order.[264] The Joint Proposal indicates that "if the evidence warrants," the parties may pursue a methodology to account for the reduced usage associated with dimming streetlights that could take effect during the Rate Plans.[265]

Notably, in these rate proceedings, O&R's filing did

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[262] Joint Proposal, pp. 31-32.

[263] Hearing Exhibit 248 (NYPA Street Lighting Panel), p. 8-10.

[264] Case 18-E-0067, O&R – Rates, 2019 Rate Order, pp. 99-100; 2019 Joint Proposal, pp. 50-51.

[265] Joint Proposal, p. 32.

not address the continuation of this Street Light Pilot that had been approved in the 2019 Rate Order.[266] NYPA pressed the continuation of the Pilot and again proposed, as it had in testimony filed in the 2019 rate cases, the use of NLC system nodes with adaptive operating schedules.[267] In its testimony in these rate cases, NYPA urges that this Pilot will allow customers to realize savings while the necessary NLC nodes are meter tested for certification purposes.[268]

NYPA's testimony asserts that the Street Light Pilot is intended to prove the accuracy of the NLC nodes, with energy consumption being monitored for six months to determine the devices' metering accuracy.[269] NYPA concedes that the metering use of NLC nodes is still not a Commission-approved technology,[270] but nevertheless asserts in support of the Joint Proposal that the NLC nodes approach for the Street Light Pilot is reasonable because it is based on a municipality's operating

[266] O&R's filing did propose changes to lighting service classifications by adding LED street light fixtures and dusk-to-dawn luminaries in SCs 4-16; removing certain obsolete luminaires in SCs 4-16; and revising the watt ranges for LEDs. Hearing Exhibit 100 (O&R Electric Rates Panel), pp. 37-39. O&R also offers municipal lighting rebates. These proposals are not designed to promote customer-owned street lighting, however.

[267] Hearing Exhibit 248 (NYPA Street Lighting Panel), pp. 12-14. NYPA proposed that customers could opt into one of four different adaptive operating schedules (0, 30, 50, and 70 percent), as measured by energy use between dusk and dawn. NYPA also proposed maximum flexibility in setting the schedules to allow municipalities to switch between schedules on a quarterly basis and to select customized schedules to enable dimming for a shorter time, for example, in a busy downtown area and a longer time in residential areas.

[268] Hearing Exhibit 248 (NYPA Street Lighting Panel), p. 12.

[269] Id., pp. 12-14.

[270] Id., pp. 11-12.

and dimming schedule.[271]

NYPA's testimony also noted that O&R's current tariff does not recognize lower rates for decreased energy usage resulting from street light dimming.[272] NYPA proposed that, after one-year of the Pilot's operations, O&R should host a technical conference to share the results and make recommendations, followed by a report to the Commission to allow for stakeholder engagement.[273]

In rebuttal testimony, O&R rejected NYPA's position and questioned the benefits of the NLC nodes, their metering accuracy, and the use of adaptive schedules.[274] O&R asserted that until the Street Light Pilot is completed and the results verified, the use of NLC nodes should not be considered. O&R also pointed to multiple standards and requirements that must be reviewed in order to determine if NLC nodes are acceptable for billing purposes. O&R also challenged NYPA's failure to present a cost/benefit analysis to support the asserted cost savings to municipalities and took issue with the "unduly burdensome" tasks in providing such a level of service to municipalities purchasing street lights, which the Company claimed would be subsidized by other customers.[275]

In its Statement in Support, DPS Staff noted that, although the Commission has not approved the NLC node system for metering use in New York, the technology has been used by a

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271 NYPA Statement in Support, p. 5.

272 Hearing Exhibit 248 (NYPA Street Lighting Panel), pp. 10-11.

273 Id., pp. 13-14.

274 Hearing Exhibit 266 (O&R Rebuttal Electric Infrastructure and Operations Panel), pp. 15-21. O&R also questioned NYPA's proposed adaptive schedules and recommended "maximum flexibility" in setting schedules.

275 Id.

California utility and NYPA proposes adaptive dimming schedules from which municipal customers can choose.[276] DPS Staff also noted that the Joint Proposal addresses O&R's concerns about the NLC nodes by requiring technical requirements to be established and met before installation. DPS Staff concludes that these provisions of the Joint Proposal provide a path forward to reduce energy consumption and greenhouse gas emissions, while not impacting lighting quality and public safety.

The Joint Proposal represents a negotiated resolution of the positions advanced by DPS Staff, O&R, and NYPA. We find that the parameters for the Street Light Pilot properly balance NYPA's desire to allow municipalities to implement energy and cost savings lighting measures and operational efficiencies with the Company's responsibilities to assure accurate metering and facilitate customer-owned street lights. The Pilot is sized so that information is obtained without causing substantial rate disruption.

The Joint Proposal's terms address DPS Staff's initial concerns by requiring O&R to separately meter each street light and record actual usage, thereby eliminating any use of the NLC nodes as metering devices for billing purposes. DPS Staff states that the Pilot, as designed, will provide information on the accuracy of the NLC nodes, and whether the nodes can deliver energy efficiency and economic benefits. Finally, we find that this Pilot is consistent with recent Commission decisions related to other investor-owned street lighting tariffs with

[276] DPS Statement in Support, pp. 55-56.

respect to NLC nodes and adaptive lighting schedules.[277]

We find that the Joint Proposal's terms regarding the Pilot warrant clarification for consistency with similar programs. O&R's technical and engineering review of all NLC node system models should be subject to DPS Staff input and oversight in order to effectively manage and oversee implementation of the Pilot, to monitor for consistency with other NLC node uses throughout the State, and to determine potential impacts on customer billing in O&R's service territory. As part of the progress updates the Company is required to provide every 45 days, and before finalizing the NLC node models eligibility list, O&R is required to provide DPS Staff, on notice to NYPA and other interested parties, a summary of the technical and engineering review of the NLC node models evaluated, including (1) identification of the models; (2) the criteria used in approving or disapproving each reviewed model and the decision-modeling applied; and (3) key findings resulting from the review. Staff and interested parties will have 30 days to review this information and provide feedback prior to O&R including an NLC node model on the eligibility list.

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[277] See Cases 20-E-0380 and 20-G-0381, supra, Niagara Mohawk 2022 Rate Order, Joint Proposal, Appendix 2; Cases 20-E-0428 and 20-G-0429, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric and Gas Service, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans (issued November 18, 2021), pp. 52-54;Cases 19-E-0378, 19-G-0379, 19-E-0380, and 19-G-0381, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of New York State Electric & Gas Corporation and Rochester Gas and Electric Corporation for Electric and Gas Service, Order Approving Electric and Gas Rate Plans in Accord With Joint Proposal, With Modifications (issued November 19, 2021), p. 91; Joint Proposal, pp. 35, 65; Appendix N.

O&R is required to sponsor a technical conference after monitoring the results of the technical conference Niagara Mohawk Power Corporation is sponsoring on node model eligibility and other associated issues. O&R is further required to schedule and hold the technical conference 12-months prior to its next rate case filing. In conducting the technical conference, O&R must include the following objectives: streamlining engineering review; developing pre-approvals for standards; limiting field investigations, survey review, and design review of similarly situated Smart City attachments in previously approved locations; identifying optimal locations for attachments; developing a catalog of pre-approved attachments; and identifying the specific criteria and analysis required for each device. O&R is required to use the information gained during the technical conference to prepare a Street Light Replacement Cost Study for filing as part of its next rate case, which must address costs and efficiencies to be realized through a more widespread implementation of municipal street lighting efforts.

In addition, the referenced "collaborative" that O&R will conduct to review the results of the Pilot lacks sufficient details, including a structure and timeline to assure meaningful stakeholder involvement, next steps for Pilot implementation and adaptive scheduling, and facilitation of a more widespread adoption of customer-owned dimmable street lights, if appropriate. O&R must consult with DPS Staff, NYPA, and other interested stakeholders and submit a written plan to the Secretary within 120 days of the date of this Order outlining the collaborative process that will be undertaken (Collaborative Plan). In consulting with DPS Staff, NYPA, and other interested stakeholders, O&R shall, at a minimum, provide each with a draft Collaborative Plan and an opportunity to provide comments prior to O&R's submission of the final Collaborative Plan to the Secretary.

The Collaborative Plan must: provide that all data generated during the Pilot will be made available to interested parties; include a collaborative meeting within 30 days of the end of the Pilot's six-month duration, at which time the data and any other relevant source material may be reviewed and discussed; provide for timely stakeholder input; and require submission to the Commission of recommendations, by consensus or through separate submissions by parties, within 90 days of the close of the collaborative meeting. In addition, O&R shall include in the Collaborative Plan a schedule for the parties' consideration of methodologies to account for reduced usage and the submission of final recommendations to the Commission, by consensus or through separate submissions by the parties. During implementation of the Collaborative Plan, O&R is required to include in the progress reports filed with the Secretary every 45 days (as discussed above) the status and results of the technical conference and the collaborative meeting efforts.

One point of clarification. We take issue with the Joint Proposal's provision that indicates "if the evidence warrants," O&R and other parties "may pursue a methodology to account for the reduced usage associated with dimming street lights that could take effect during the Rate Plan."[278] This language lacks definitive criteria and is not designed to put interested parties on notice about the next steps O&R may take. It also appears to leave O&R with the sole discretion to determine whether the evidence warrants establishing a methodology to account for reduced usage and what that methodology may be. The determination to pursue a methodology

[278] Joint Proposal, p. 32.

to account for reduced usage should be made in consultation with DPS Staff and interested parties. We therefore require such a consultation and the Company shall file the results of same with the Secretary as part of its 45-day progress reports, on notice to all participating parties.

The NLC node system technology has not yet been found to meet the technical requirements for metering set forth in 16 NYCRR Part 93 and consequently has not been approved by the Commission for billing purposes.[279] To be approved, a utility must sponsor the subject device and demonstrate an intention to use it upon Commission approval. The utility must also agree to implement a program with the device that produces energy efficiency and economic benefits and provide a basis for the testing needed to satisfy the Commission's regulations.

The Joint Proposal does not set forth a process to demonstrate the NLC system's compliance with the regulatory requirements of 16 NYCRR Part 93 or expressly recognize the need for Commission's approval of the technology. In adopting these provisions of the Joint Proposal, nothing in this Order is intended to circumvent the petitioning requirements for Commission approval of the NLC node system technology for metering purposes pursuant to 16 NYCRR Part 93.

I. Additional Gas Programs

The Joint Proposal includes several gas programs and pilots that the Company will implement or advance during the three-year gas Rate Plan, including NPAs, Renewable Gas

[279] See 16 NYCRR §93.2, which defines "acceptable meters" for billing purposes to include only types of meters which have been approved by the Commission and provides that the Commission "may approve or reject a type of meter or metering system on the basis of tests required by these rules or such tests as the commission staff may direct."

Standards, Gas Interruptible Rates, Millennium Back-Feed Project, Pipeline Emergency Responders Initiative, Meter Relocation, Certified Gas, Refrigerant Management Initiative, and AMI Natural Gas Detectors. Each of these are addressed below.

1. AMI-Enabled Natural Gas Detectors

The Joint Proposal reflects O&R's agreement to install approximately 15,400 AMI-enabled natural gas detectors (AMI NGDs) over the three-year term of these Rate Plans.[280] The AMI NGDs would be installed at the service line entry point on a customer's property and provide continuous monitoring of methane leaks and report leaks to O&R's centralized Gas Emergency Response Center.[281] The Company will target customers within business districts where there is the potential for larger numbers of people to be present.[282]

O&R originally sought to install only 1,400 AMI NGDs and submitted a program summary estimating a cost of $450 per meter to purchase, install and activate them, with an estimated total capital expenditure of $630,000.[283] The Joint Proposal significantly increases the number of installed AMI NGDs to 15,400. Assuming the same per meter cost to purchase, install and activate, this would increase the estimated total capital costs.

O&R asserts that it can respond to alarms from the AMI

[280] Joint Proposal, pp. 26-27.

[281] Hearing Exhibit 66 (O&R Gas Infrastructure and Operations Panel), pp. 41-42.

[282] Hearing Exhibit 196 (DPS Gas Safety Panel), pp. 57-58.

[283] Hearing Exhibits 66, 67 (O&R Gas Infrastructure and Operations Panel Exhibit GIOP-1), pp. 35-37. The AMI units have a 6-year sensor and battery life that will need to be replaced.

NGD detectors quickly even if a customer is not aware of the methane leak or build up. O&R is currently implementing an AMI NGD pilot program and, along with DPS Staff, recommends expanding the program.[284] In its testimony, DPS Staff supported the program, but recommended that O&R be required to file an annual report including the information that is outlined in the Joint Proposal.[285] The Company agreed to this additional requirement.[286]

The Joint Proposal requires the Company to file an annual report within 90 days of the close of each rate year that, at a minimum, contains: the number of AMI NGDs installed during the year and to-date; the installation costs during the rate year and to-date; the number of alarms received from the detectors by the Company's control center during the rate year; and the activities taken by the Company in response to each alarm received.[287]

It is unclear from the record the total amount of capital costs that may be incurred as a result of the increase of installed AMI detectors from 1,400 (as O&R initially proposed) to 15,400, as agreed in the Joint Proposal. Consequently, as part of O&R's annual report, we require the Company to provide updated estimates of the total cost of installing the 15,400 AMI NGDs, an explanation of how such cost was determined, and the efforts taken to reduce the overall cost. With this additional reporting requirement, we find that the expansion of this pilot program is sound and beneficial to customers. It increases customer and employee safety, fosters

284 Id.

285 Hearing Exhibit 196 (DPS Staff Gas Safety Panel), p. 58.

286 Hearing Exhibit 327 (O&R Rebuttal Gas Infrastructure and Operations Panel), pp. 34-35.

287 Joint Proposal, pp. 26-27.

prompt emergency response, reduces emissions, and mitigates the risks associated with a natural gas leak and accumulation within a structure, including explosions or fires.

2. Review of Gas Interruptible Rates

The Joint Proposal requires the Company to examine the current interruptible discount and recommend adjustment in its next rate case, but only if the Company's analysis supports it.[288] DPS Staff agreed with O&R's proposal to continue the discount because it mitigates infrastructure investment costs for some demand-response customers and elimination would force the Company to serve these customers on peak winter days.[289] But DPS Staff also proposed the review of the discount for a reason, namely, to determine whether it is reasonable and relevant.

We find that the Company alone should not determine whether to recommend an adjustment to the discount in the next rate case "if its analysis supports it." That analysis and the resulting recommendation should be done in coordination with DPS Staff, and it should be completed prior to the Company's next rate case filing, so that the results may be submitted in those cases, if appropriate.

3. Non-Pipes Alternatives

The Joint Proposal provides that O&R will "explore NPAs" for farm taps (or extra-high pressure customer service

[288] Joint Proposal, p. 27.

[289] Hearing Exhibit 202 (DPS Staff Gas Reliability Panel), pp. 17-18.

lines), leak prone pipe (LPP), and other projects.[290] The Company states that it will remove all of the remaining farm taps by 2024, connecting them to a distribution main, for a capital expenditure of $1.2 million. The Company notes that many of the leaks on its system are related to farm tap service lines.[291] The Company also will continue efforts to evaluate and implement applicable aspects of the NPA Framework filed by its affiliate, Consolidated Edison. If the Commission has not approved that NPA Framework as a part of the Gas Planning Proceeding, O&R will file a petition for approval of the Framework within 45 days after the end of Rate Year 1.[292] The NPA Framework will be used to identify capital projects for NPA consideration, resource requirements, a cost recovery mechanism, and include suitability criteria, timing, cost thresholds, and a reporting schedule.

We find that the Company's commitment to continue farm tap removal and to complete removal during the three-year Rate Plans is reasonable because it promotes pipeline safety and eliminates identified methane leaks, resulting in emission reductions consistent with the CLCPA. We also note the Joint Proposal's requirement for the Company to continue to explore other NPAs is designed to result in reduced infrastructure costs and potentially lower greenhouse gas emissions.

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[290] Joint Proposal, pp. 27-28. Farm tap customers' lines are fed from a transmission (rather than distribution) main pipeline operating at 250 pounds per square inch gauge (psig) and represent a safety risk, particularly when in close proximity to structures. Hearing Exhibits 66 and 67/68 (O&R Gas Infrastructure and Operations Panel), pp. 36-37 and (GIOP-1 White Paper), pp. 25-29. Since 2012, O&R has had a program to eliminate farm taps. According to DPS Staff's testimony, the Company has 30 farm taps left to eliminate. Hearing Exhibit 202 (DPS Staff Gas Reliability Panel), pp. 20-21.

[291] Hearing Exhibit 67, 68 (GIOP-1 White Paper), p. 28.

[292] Joint Proposal, pp. 27-28.

4. Renewable Gas Standards

The Joint Proposal provides that, to the extent that the Commission does not provide clear guidance regarding treatment of renewable natural gas (RNG) in the Gas Planning Proceeding, O&R is required to submit a renewable natural gas plan (RNG Plan) to "explore what specifically would be required to bring those sources of energy to O&R customers."[293] The Joint Proposal further provides that, within six months of the Commission's Order in these proceedings or the Commission's action in the Gas Planning Proceeding, whichever is sooner, it will file an RNG Plan with the Secretary.

The 2019 Rate Order approved Joint Proposal provisions that required O&R to develop and evaluate a potential list of RNG sources and providers within the Company's service territory, to determine whether opportunities exist for providing RNG to customers.[294] In the 2019 Rate Order, the Commission noted that the "intended result of this evaluation is that the Company will add a renewable gas interconnection standard to its O&M procedures, including any necessary

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293 Joint Proposal, p. 28. See Case 20-G-0131, supra, Gas Planning Proceeding, Order Instituting Proceeding, p. 2 (providing that gas utilities must "adopt improved planning and operational practices that enable them to meet current customer needs and expectations in a transparent and equitable way while minimizing infrastructure investments and maintaining safe and reliable service" and "be conducted in a manner consistent with the recently enacted Climate Leadership and Community Protection Act (CLCPA)."

294 Cases 18-E-0067 and 18-G-0068, supra, 2019 Rate Order, pp. 97-98; see also Case 99-G-1369, Petition of New York Gas Group for Permission to Establish a Voluntary State Funding Mechanism to Support Medium and Long Term Research and Development (R&D) Programs, Order Concerning Permission to Establish a Voluntary State Funding Mechanism to Support Medium and Long Term Gas Research and Development (issued February 14, 2000).

interconnection fees, allowing it to take advantage of renewable gas supplies in its service territory."[295] The 2019 Rate Order also required O&R to determine the benefits and costs of integrating potential RNG supply sources into the Company's system.

As a result of this requirement in the 2019 Rate Order, O&R submitted a "Renewable Gas Analysis Report" (RNG Analysis Report) that assessed and identified regional RNG potential, estimated production costs and greenhouse gas emissions potential of possible feedstocks, summarized key market and policy drivers affecting RNG development in New York State, identified potential RNG sources, and set forth several conclusions and recommendations.[296] The RNG Analysis Report concluded that "O&R is preparing to integrate RNG into its gas distribution system" and recommended specific kinds of supply sources that are available within and outside of its service territory.[297]

It is unclear from this record what specific next steps O&R will take to explore the measures necessary to bring RNG to its customers in furtherance of the intent of the 2019 Rate Order and consistent with O&R's RNG Analysis Report. In its testimony, O&R indicates that it supports efforts by

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[295] Cases 18-E-0067 and 18-G-0068, supra, 2019 Rate Order, pp. 97-98.

[296] Id., DMM Item No. 176, Navigant "Renewable Gas Analysis Report" (filed March 16, 2020) (RNG Analysis Report).

[297] Id., pp. 26-28 (RNG Analysis Report, Conclusions and Recommendations).

developers in its service territory to pursue RNG,[298] but does not propose any efforts itself. In response to a DPS Staff discovery request, O&R discusses the results of its RNG Analysis Report, noting that it has developed RNG interconnection standards, in conjunction with affiliate Consolidated Edison, and has incorporated them into its Gas Transportation Operating Procedures (GTOP) document. O&R's response further indicates that it "does not currently have a specific plan regarding RNG and has no associated budget or schedule."[299]

DPS Staff's testimony discusses the policy goals of the Gas Planning Proceeding and the need for alternatives to traditional gas infrastructure investment, including RNG investments.[300] DPS Staff notes that, although O&R asserts that its proposed infrastructure investments will position it to better deliver RNG to customers, "[i]t is unclear how these general improvements to the distribution system would allow O&R to integrate RNG into its supply portfolio."[301] DPS Staff's testimony recommends that O&R be required to formulate a plan to provide RNG to customers and to submit a report that includes the details of the plan.[302] In its Statement in Support, DPS

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[298] Hearing Exhibit 66 (O&R Gas Infrastructure and Operations Panel), pp. 12-13, 19-20. O&R also testifies that it will "continue active participation" in the Gas Planning Proceeding and is committed to monitoring the viability and supporting the adoption of RNG, and that its system will be prepared to deliver RNG should projects interconnect to the Company's distribution system.

[299] Hearing Exhibit 195 (DPS Staff Gas Reliability Panel Exhibit, SRGP-1, DPS IR-32-577), pp. 4-5.

[300] Hearing Exhibit 194 (DPS Staff Gas Reliability Panel), pp.

[301] Id., p. 23.

[302] Hearing Exhibit 194 (DPS Staff Gas Reliability Panel), pp. 23-24. DPS Staff also recommended that RNG should be considered an NPA in constrained areas.

Staff indicates that RNG has both environmental and reliability benefits and that O&R has committed to submit a plan regarding how it plans to integrate RNG into its system.[303]

We find that this provision of the Joint Proposal lacks the details and expected results necessary for a useful RNG Plan. Instead, it provides for "continued exploration of RNG."[304] As such, this provision of the Joint Proposal does not appear to further the original intent of the 2019 Rate Order to create a path for RNG implementation in O&R's distribution system and continued exploration of RNG as an energy supply source does not appear to be warranted. O&R has already explored RNG in its RNG Analysis Report and has found a viable RNG resource available. The Commission may provide further direction on this issue in the Gas Planning Proceeding, but RNG is only a subset of the broader purposes of that Proceeding and additional delay while the Commission considers broader action is also not warranted.

Notably, the Company's filings as part of the Joint Local Distribution Companies coalition in the Gas Planning Proceeding express strong support for the development and deployment of RNG resources, as long as incentives and earnings adjustments are made available for reduced carbon gas

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[303] DPS Staff Statement in Support, pp. 50-51.

[304] Joint Proposal, p. 28.

supplies.[305] Furthermore, the CAC Scoping Plan indicates a future role for RNG and biogas, although the extent of that role may be limited.[306]

Thus, we require that O&R develop and file with the Secretary an RNG Implementation Plan, consistent with its RNG Analysis Report, within 180 days of the Commission's issuance of this Order. The RNG Implementation Plan must be developed in consultation with DPS Staff and must outline the specific measures necessary to develop RNG sources with the objective of serving O&R customers, including identifying available and feasible RNG sources, establishing necessary interconnection fees, proposing a timeline for construction of appropriate infrastructure for potential RNG development, deployment, and integration of RNG sources into its transmission and distribution system.

5. Pipeline Emergency Responders Initiative (PERI)

The Joint Proposal calls for the continuation of O&R's training efforts for first responders and fire departments, with participation incentives and annual progress reports to the

[305] Case 20-G-0131, Gas Planning Proceeding, Joint Local Distribution Companies' Comments in Response to the Department of Public Service Staff's Natural Gas Planning Process and Moratorium Management Proposals (filed May 3, 2021), p. 14 (citing December 2019 ICF/American Gas Foundation Study, "Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment"); June 4, 2021 Reply Comments, p. 3, n. 15; pp. 10-12, 17 (noting that the CLCPA's objectives require consideration of all energy resources and "LDCs should, therefore, be unrestricted from pursuing the use of low-carbon resources such as RNG" and RNG should be a significant contributor to decarbonization).

[306] CAC Scoping Plan, supra, p. 245 (favoring "on-site use of biogas captured from waste management and that no significant new transmission infrastructure should be allowed to support additional biogas").

Commission.[307] The training includes preventing, managing and responding to gas incidents and operating specific field devices to reduce response time and the potential for errors. The Joint Proposal also requires the Company's adoption of the PERI principles, which are intended to advance first responders' abilities to manage gas emergencies by improved training, cooperation, and communication.[308] The PERI principles include improved communication among pipeline operators, emergency responders, and other stakeholders; consolidation of existing pipeline emergency response efforts; consistency of training materials; improved emergency response time; and improved media and public relations efforts.

We find this provision of the Joint Proposal to be within the range of a likely litigated outcome, particularly since O&R initially disagreed with the reporting requirement and the adoption of PERI principles that DPS Staff proposed in its testimony.[309] This provision will further gas safety and benefit customers in O&R's service territory.

6. Millennium Back Feed Project

The Joint Proposal requires O&R to expedite efforts to reach an agreement with Millennium Pipeline for the construction of a new interconnection at a preliminary cost of $5.0 million to serve as a second gas feed to an area with a single feed.[310] The Joint Proposal requires O&R to file periodic updates on the

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[307] Joint Proposal, pp. 28-29. The annual PERI progress reports are required to be filed with the Secretary no later than 90 days following the close of each calendar year, beginning at the close of Rate Year 1.

[308] Joint Proposal, pp. 28-29.

[309] DPS Statement in Support, p. 51; Hearing Exhibit 66 (O&R Gas Infrastructure and Operations Panel), pp. 35-36; Hearing Exhibit 196 (DPS Staff Gas Safety Panel), pp. 59-61.

[310] Joint Proposal, p. 29.

status of this Project and meet quarterly with DPS Staff.

O&R's testimony indicates that approximately 45,000 Orange County customers are directly fed natural gas from gate stations connected to the Millennium Pipeline and would be impacted and risk losing service if there was an upstream pipeline interruption due to, for example, pipeline damage, equipment failure, or supply constraints.[311] This Project requires both Millennium Pipeline's and the Algonquin Pipeline's agreement, but O&R has had only preliminary discussions with Millennium. The equipment needed for the Project would be owned and operated by Millennium or Algonquin, but the back feed portion would be funded by ratepayers.[312] O&R's Statement in Support indicates that the Project "will re-establish an important operational mechanism to enhance service reliability."[313]

DPS Staff's testimony was supportive of the Project, but expressed concern about the slow progress of the Back-Feed Project in light of O&R's assertion of reliability concerns.[314] DPS Staff also indicated that the $5 million cost estimate for the Project was preliminary and should be updated once O&R has the appropriate agreements in place to proceed with construction.

It appears that the Millennium Back-Feed Project will address reliability concerns and add needed redundancy in the area, but will not result in expanded gas service to new

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[311] Hearing Exhibit 66 (O&R Gas Infrastructure and Operations Panel), pp. 51-53. O&R testified that once interrupted, service restoration could take days or weeks, depending on the interruption.

[312] Id., p. 53.

[313] O&R Statement in Support, p. 28.

[314] Hearing Exhibit 194 (DPS Staff Gas Reliability Panel), pp. 8-9.

customers and potential increases to greenhouse gas emissions. Consistent with DPS Staff's recommendation, prior to construction of the Project, O&R is required to submit updated cost estimates for the Project in light of the preliminary nature of the $5.0 million estimate the Company provided in these proceedings.[315]

7. Relocating Indoor Meters

Consistent with DPS Staff's recommendation in its testimony, the Joint Proposal calls for O&R to relocate gas meters outside when it performs service line replacements, installs new services, or when the work otherwise can be feasibly performed.[316] It also provides for customers refusing the relocation to be subject to inspection charges and sign acknowledgment of the charges. O&R is required to document the difficulty, limitations, and/or costs associated with relocating meters to outside locations and, in its next rate filing, to address the documented circumstances, including meters that may be too costly to relocate.

As DPS Staff notes in its Statement in Support, relocating meters to outside locations is inherently safer and allows emergency responders to immediately shut off the flow of gas or perform an inspection, without having to enter a building or locate a curb valve in the event of a gas incident.[317] We agree and we find this provision of the Joint Proposal to address important safety considerations for the benefit of both customers and the Company.

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[315] Hearing Exhibit 194 (DPS Staff Gas Reliability Panel), p. 10.

[316] Joint Proposal, p. 29; Hearing Exhibit (DPS Staff Gas Reliability Panel), pp. 65-69.

[317] DPS Statement in Support, p. 52.

8. Certified Gas Purchases Pilot

The Joint Proposal authorizes the Company to establish a new pilot program whereby it may purchase "certified natural gas" (CNG Pilot) that meets certain guidelines and protocols designed to reduce methane emissions for use in its distribution system.[318] The Joint Proposal indicates that the CNG Pilot may start as early as the winter of 2022-2023 and annual expenditures may not exceed $100,000 for commodity costs.

The Joint Proposal requires the Company to file an annual report beginning in May 2023 that (1) calculates the greenhouse gas emissions reductions realized from the certified gas source as compared to traditional natural gas; (2) outlines additional costs to customers and savings to customers if emissions penalties would have been assessed; (3) contains third party provider certification reports, including "items evaluated about the Pilot;" (4) identifies the volume of CNG purchased; (5) recites reliability issues encountered as a result of additional production equipment or processes; and (6) recommends future changes and/or lessons learned from the CNG Pilot for future consideration.[319] The Company is also required to meet with DPS Staff annually to discuss data and information gained during the CNG Pilot and to determine whether it should continue or be terminated.

O&R's Statement in Support clarifies that the Pilot will be conducted jointly with affiliate Consolidated Edison and that it may be modified by filing a petition with the Commission.[320] DPS Staff indicates in its Statement in Support that, although the CNG Pilot was not addressed in testimony, it

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[318] Joint Proposal, pp. 29-30.

[319] Id., p. 30.

[320] O&R Statement in Support, p. 29.

is reasonable because "it directly improves emissions from procurement of natural gas and also limits negative cost implications on customers."[321]

The CNG Pilot appears to have the potential to reduce the Company's emissions, although the emissions associated with CNG as compared to traditional natural gas should be identified. The Company therefore is directed to submit a certification by an independent third-party expert verifying the quantifiable reduced greenhouse gas emissions potential for certified gas as compared to traditional natural gas sources. In addition, the criteria, guidelines, and production protocols that are designed to make CNG a reduced emissions fuel source should be disclosed. We also require the CNG Pilot to commence in the winter of 2022-2023 so that DPS Staff and the Company may evaluate whether it actually results in quantifiable greenhouse gas emissions reductions. We approve the CNG Pilot subject to these additional requirements.

9. Refrigerant Management Initiative

The Joint Proposal requires the Company to evaluate whether to incorporate a Refrigerant Management Initiative into its energy efficiency program during Rate Year 1, including an assessment of the Initiative's suitability, costs, and greenhouse gas emissions reductions.[322] The evaluation will include a benefit-cost analysis under the Commission-approved framework. The Company will integrate the Initiative into its energy efficiency program in Rate Year 2, depending on the results of the evaluation.

DPS Staff notes that it did not file testimony about

[321] DPS Staff Statement in Support, p. 53. DPS Staff does not provide record support for improved emissions and limitations on negative cost implications.

[322] Joint Proposal, p. 31.

the Refrigerant Management Initiative, nor did the Company, but further notes that the testimony of intervenor and Joint Proposal signatory, NYCRM, addressed the energy and emission reduction benefits of such a program.[323] In its testimony, NYCRM's expert noted that hydrofluorocarbon refrigerants used in commercial and industrial building refrigeration systems are "super" greenhouse gas emitters that have an outsized environmentally deleterious effect on climate change because of their chemical composition and because they frequently leak from refrigeration systems into the atmosphere.[324] NYCRM's testimony recited data and information indicating that refrigeration management is a recognized strategy to result in both energy savings and emissions reductions and that such a program is a significant opportunity for O&R to meet mandated electric efficiency requirements. NYCRM's Statement in Support urges that it is in the public interest for O&R to calculate the greenhouse gas emissions impacts from its operations and adopt the best measures to lower emissions, while providing safe and reliable service to customers.[325]

The Joint Proposal appears to leave solely to O&R the decision regarding whether or not to integrate the Refrigerant Management Initiative into the Company's energy efficiency program. It does not provide for DPS Staff's involvement in the Company's evaluation, decision-making, or integration process. Consequently, we require the Company to consult with DPS Staff in conducting the Initiative's benefit-cost analysis and in

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[323] DPS Staff Statement in Support, pp. 54-55.

[324] Hearing Exhibit 246 (NYCRM Witness Ali White), pp. 2-3, 5-12. NYCRM's testimony indicated that New York continues to allow use of hydrofluorocarbon refrigerants in existing equipment and thus measures to address emissions are necessary.

[325] NYCRM Statement in Support, p. 1 (filed November 19, 2021).

evaluating its suitability, overall costs, emissions reductions, and efficient integration into the existing energy efficiency program. This consultation shall be on notice to NYCRM and all interested parties and an opportunity to participate provided.

J. Customer Service

The Joint Proposal continues several of the Company's existing programs, including its Outreach and Education program, same-day electric service reconnections, and digital customer experience (DCX), but also implements additional customer programs such as a customer relationship management system, customer protections during excessive cold and heat, written confirmation of unsigned payment agreements, and an electric reconnection fee waiver.[326] Notably, the Company will forego collection of PRAs associated with terminations during the Covid-19 pandemic in 2020 and 2021. Each of these terms of the Joint Proposal will be briefly summarized below.

1. Outreach and Education. The Joint Proposal establishes an annual date of April 1 on which O&R is required to file its updated Outreach and Education Plan.[327] This is the same date that other utilities must file their respective plans in the Commission's generic Utility Outreach and Education Plans proceeding.[328] As DPS Staff asserts in its Statement in Support, a robust outreach and education program is "a vehicle to disseminate important and timely information to customers."[329]

2. Same-Day Electric Service Reconnections. The Joint Proposal provides that the Company will attempt to achieve 100

[326] Joint Proposal, pp. 32-37.

[327] Joint Proposal, p. 32.

[328] Case 17-M-0475, In the Matter of Utility Outreach and Education Plans.

[329] DPS Staff Statement in Support, p. 57.

percent same-day electric service reconnections for residential electric customers whose service was disconnected at the meter for non-payment.[330] The customer must become eligible for reconnection by 5:00 p.m. Monday-Friday (excluding holidays). DPS Staff notes that this is a benefit for customers who satisfy their unpaid bills. The Company is also required to file a quarterly report on residential same-day reconnections, indicating the number customer reconnections attempted and completed and associated work orders.

3. Recording Calls. The Joint Proposal requires the Company to record inbound and outbound Call Center calls and retain those records for 24 months.

4. Protections During Extreme Temperatures. The Joint Proposal establishes new customer protections against electric and gas terminations during periods of extreme cold or hot temperatures, whereby the Company will refrain from terminating service when temperatures are 32 degrees Fahrenheit or less (November 1 to April 14); or during a heat advisory, when temperatures are 95 degrees Fahrenheit or more for two consecutive days or 100 degrees Fahrenheit or more for one or more consecutive days.[331] The Joint Proposal also provides for a winter moratorium on terminations for elderly, blind, and disabled customers. Although there is no testimony on this issue, DPS Staff notes that these provisions protect customers' health and safety.[332]

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[330] Joint Proposal, p. 33.

[331] Joint Proposal, pp. 34-35. Weather information reflecting that the temperatures are met will be based in O&R's service territory, as reflected on the National Weather Service website, htpps://www.weather.gov.

[332] DPS Statement in Support, p. 57.

5. Confirmation of Unsigned Payment Agreements. The Joint Proposal requires the Company to maintain in customer files a record of oral collection agreements and instruct Call Center personnel to offer to send a written agreement by mail or email.

6. Digital Customer Experience (DCX). In its initial testimony, the Company proposed to continue but expand its existing quarterly DCX program reporting.[333] The aspects of DCX include: 1) ongoing optimization; 2) transitional expansion through self-service offerings; 3) data sharing through the expansion of Green Button Connect; 4) updates for Web Experience Management to maintain high level of reliability; 5) migration of remaining legacy applications to the DCX platform; 6) mobile cell phone updates that include locational, global positioning (GPS) information for reporting an outage and paying bills through Venmo and PayPal; and 7) customer personalization and control through tailored messaging and preferred payment options.[334]

DPS Staff proposed that the Company include in the quarterly reports a breakdown by each DCX function, with actual costs and budgets, and the reasons for any unspent or reallocated funds, and to present future DCX proposals in coordination with affiliate Consolidated Edison.[335] The Joint Proposal continues O&R's DCX reporting requirements, but requires it to make future DCX proposals in concert with affiliate Consolidated Edison, which must include costs and benefits. We agree with DPS Staff's testimony that the future

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[333] Joint Proposal, p. 36.

[334] Hearing Exhibit 79 (O&R Customer Service Panel Exhibit CSP-1), pp. 46-47.

[335] Hearing Exhibit 212 (DPS Staff Information Technology and Common Panel), pp. 31-32.

DCX proposals undertaken with Consolidated Edison should include a breakdown of each DCX feature, with actual costs, benefits, budgets, and the reasons for any unspent or reallocated funds.

7. Customer Relationship Management (CRM) System. The Joint Proposal provides for implementation of the CRM system the Company proposed, but at approximately half the initially proposed investment cost of $5 million.[336] The Company is required to file annual reports detailing the implementation progress including, actual spending and any cost savings realized. DPS Staff did not support the CRM project because it lacked a business plan identifying efficiencies to be gained through implementation.[337] The Company responded to DPS Staff's position by indicating that that CRM systems can lead to adoption of electrification technologies and a positive return on investment, with every dollar spent retuning $8.71.[338]

We see the merit of DPS Staff's position that the CRM System should have a business plan that identifies customer benefits, but we are at the same time satisfied with the Company's response. The Joint Proposal requires annual CRM implementation reporting that should reflect the Company's business planning and actual efficiencies gained from the CRM implementation, in addition to the actual spending and cost savings realized.

8. Residential Termination/Uncollectible Metric. The Joint Proposal provides that for 2020 and 2021, the Company will forego PRAs related to the terminations and uncollectible

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[336] Joint Proposal, p. 36; Hearing Exhibit 78 (O&R Customer Service Panel), pp. 39-42.

[337] Hearing Exhibit 212 (DPS Staff Information Technology and Common Panel), pp. 20-21.

[338] Hearing Exhibit 264 (O&R Customer Service Panel Rebuttal), p. 3 (citing Nucleus Research Study).

metric, and for 2021-2024, to pause the metric (both PRAs and NRAs).[339] As a result of the Covid-19 pandemic and amendments to PSL §32, the Company is subject to a moratorium on termination of residential and certain small business customers. The Joint Proposal provides for reconsideration of this metric in the next rate case.

DPS Staff, UIU, and PULP each presented testimony on this issue, citing the Covid-19 pandemic and associated legislation that significantly changed the Company's collections practices measured by this metric.[340] We find the Joint Proposal's approach to be reasonable in light of the uncertainty that continues to surround Covid-19.

9. Reconnection Fee Waiver. The Joint Proposal provides for the Company to waive reconnection fees for electric customers with AMI meters if the Company can complete the reconnection remotely.[341] Gas reconnection fees will still be assessed because field crews are required to perform that task.

We agree with DPS Staff's position that if the Company has the ability to reconnect a customer remotely via an AMI meter, it is not incurring the costs it otherwise would incur if a field team was necessary to complete the reconnection.[342]

K. Electric and Gas Low-Income Assistance and Affordability Programs

In its initial filings, the Company proposed to

[339] Joint Proposal, p. 36. The terminations/uncollectible metric was authorized in the 2019 Rate Order.

[340] Hearing Exhibit 138 (DPS Staff Consumer Services Panel), pp. 36-40; Hearing Exhibit 256 (UIU Witness Gregg C. Collar), pp. 21-22; Hearing Exhibit 250 (PULP Witness William D. Yates), pp. 39-40.

[341] Joint Proposal, p. 37.

[342] DPS Staff Statement in Support, p. 61.

continue its current Low-Income Discount Programs, which conformed with the Commission's Energy Affordability Policy proceeding.[343] The Company implemented tiered structure monthly discounts, automatic enrollment into budget billing, with an opt-out option, and a reconnection fee waiver program.[344]

DPS Staff testified that the proposals in the Company's filing generally complied with the Energy Affordability Policy, but pointed out that the Commission had commenced Phase 2 or the Energy Affordability Policy in February 2021, and that DPS Staff had issued a White Paper that recommended improvements to certain program elements. In August 2021, the Commission issued the Phase 2 Energy Affordability Order, which made significant improvements to the Energy Affordability Policy, including modifications to the discount calculation methodology, implementation of a statewide self-certification process to improve participation rates and encouraged utilities to target high usage participants with

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[343] Case 14-M-0565, Proceeding on Motion of the Commission to Examine Programs to Address Energy Affordability for Low Income Utility Customers, Order Adopting Low Income Program Modifications and Directing Utility Filings (issued May 20, 2016) (2016 Low-Income Order); Order Approving Implementation Plans with Modifications (issued February 17, 2017); and Order Granting in Part and Denying in Part Requests for Reconsideration and Petitions for Rehearing (issued February 17, 2017); Case 20-M-0266, Proceeding on Motion of the Commission Regarding the Effects of COVID-19 on Utility Service (Energy Affordability Policy Proceeding), Order Adopting Energy Affordability Policy Modifications and Directing Utility Filings (issued August 12, 2021) (Phase 2 Energy Affordability Order). Together, the orders in these proceedings are referred to as the Energy Affordability Policy.

[344] This program allows for a one-time waiver of the reconnection fee for low-income customers that received Home Energy Assistance Program benefits in the previous 12 months and who had their service shut off for non-payment.

energy efficiency measures and programs.[345] The Phase 2 Energy Affordability Order also established an Energy Affordability Policy Working Group where DPS Staff, major utilities and interested stakeholders identify low-income objectives and work together to make improvements to the statewide low-income programs in a collective manner.

Consistent with the Commission's Phase 2 Energy Affordability Order in the generic low-income proceeding, the Joint Proposal (Appendices 6 and 7), continues to provide funding for payment assistance available to O&R's customers who have difficulty paying their utility bills timely due to financial circumstances. The level of funding projected for the bill discount credits, subject to symmetrical deferral, is projected to be $9,988,428 and $5,395,378 in 2022 for electric and gas credits, respectively, based on the current number of customers in each tier.[346] In addition, the Joint Proposal recommends that during the term of the Rate Plans the Company continue to waive its reconnection fee for any customer enrolled in the Company's Low-Income Program.

Discussion

We find that the terms related to the Company's low-income programs effectuate the program framework established in the Energy Affordability Policy proceeding and implement the modifications directed in the Phase 2 Energy Affordability Order. These Joint Proposal provisions also appropriately

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[345] Case 14-M-0565, Proceeding on Motion Regarding Energy Affordability, Order Adopting Energy Affordability Policy Modifications and Directing Utility Filings (issued August 12, 2021).

[346] The specific bill discount credits are set forth in the Company's electric and gas tariffs and are subject to change based on the annual Low-Income Plan the Company is required to file with the Commission with the analysis of customer bills.

consider the long and short-term impacts of the pandemic on the utility, its customers, and the economy in general. Inasmuch as these provisions of the Joint Proposal are reasonable and serve the public interest, they are adopted.

L. Arrears Management

The Joint Proposal does not contain a provision specifically addressing arrears management for low-income customers.[347] In opposing the Joint Proposal, PULP argues that arrears owed by low- and moderate-income customers throughout the State must be resolved "in a manner that does not wreak further harm upon New York's distressed communities," considering the economic strain caused by the Covid-19 pandemic.[348] Acknowledging that DPS Staff recently commenced a public collaborative on arrears resolution, as directed by the Commission in the Phase 2 Energy Affordability Order, PULP nevertheless requests that the Commission require the Company to "mirror any arrearage collaborative language that is arrived at in Con Edison's 2022 rate case and settlement."[349]

DPS Staff and the Company oppose this request, stating, among other things, that it would be improper for the Commission to direct the Company to adhere to the result of an uncertain future event and that, in any event, it is more appropriate for the issue of arrears to be resolved on a generic, statewide basis rather than on an ad hoc basis in

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347 The Joint Proposal, Section H (Customer Service) contains a provision stating that the Company will continue to inform all customers in arrears of the availability of payment agreements through 2022 and continue to permit customers to develop their own payment agreements, within certain parameters.

348 PULP Statement in Opposition, p. 17.

349 PULP Statement in Opposition, p. 17.

separate rate cases.[350]

Discussion

We agree with DPS Staff and the Company that issues related to customer arrears are appropriately addressed and will be resolved within the context of the ongoing stakeholder collaborative and Energy Affordability Policy Working Group (EAP Working Group) that we directed Staff to convene in the Phase 2 Energy Affordability Order.[351]

In that regard, the EAP Working Group filed a status report on February 2, 2022, in which the increase in customer arrears due to the ongoing Covid-19 pandemic and associated moratorium on utility terminations, which expired in December 2021, was identified as a significant priority for the EAP Working Group.[352] The EAP Working Group reported that a multitude of outside speakers had been invited to educate and discuss with the stakeholders various arrears management program design considerations. The EAP Working Group states that it "is actively exploring arrears reduction solutions for the Commission's consideration."[353] Thus, while we share PULP's concerns about the increased level of statewide customer arrears that has accompanied the Covid-19 pandemic, we are satisfied that the issue of arrears management will be appropriately and timely resolved in the generic Energy Affordability Policy proceedings.

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350 DPS Staff Reply Statement, pp. 9-10; Company Reply Statement, p. 13.

351 Case 20-M-0266, supra, (Phase 2 Energy Affordability Order), Clause 2.

352 Case 20-M-0266, supra, EAP Working Group Status Report (filed February 2, 2022), p. 3.

353 Case 20-M-0266, supra, EAP Working Group Status Report, p. 4.

M. Language Access

In its testimony, PULP argued that O&R should provide specific language access assistance to customers who speak Haitian Creole, contending that Haitian Creole is the primary language spoken by "other Indo-European" language speakers in the service area and alleging that Haitian Creole speakers in Orange and Rockland counties "outnumbered Spanish speakers" and "currently represent 14 percent of the population."[354]

In its Statement in Opposition, PULP urges the Commission to "require the Company to translate its web site into Haitian Creole, and its DPA forms, collection notices, bills, and all arrears resolution communications" asserting that "17% of the population of Rockland County speak Haitian Creole as their first language."[355] In so doing, PULP references a Commission regulation that requires utilities that provide service in a county where, according to the most recent Federal census, at least 20 percent of the population regularly speaks a language other than English, to provide messages on its bills and notices in both English and such other language at the request of a customer.[356] In referencing the regulation, PULP acknowledges that the population speaking Haitian Creole does not meet the threshold in the regulation, but argues nevertheless that to do "anything less" than what it proposes would not uphold the State's interest in clear communication during the Covid-19 pandemic.[357]

O&R argued in its testimony that "[d]espite the

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[354] Hearing Exhibit 250 (PULP Witness William D. Yates), pp. 14, 58-59.

[355] PULP Statement in Opposition, pp. 16-17.

[356] PULP Statement in Opposition, p. 16, citing 16 NYCRR §11.17(b).

[357] PULP Statement in Opposition, p. 17.

apparent growth of Haitian Creole-speaking customers in the Company's service territory, there does not appear to be a major need for these services."[358] In testimony, it stated that on average, over a three-year period between 2018 and 2020, it provided translation services to Haitian Creole-speaking customers fewer than 40 times a year while in comparison it provided translation services to Spanish-speaking customers more than 5,360 times a year.[359] In its view, "the record in these proceedings is devoid of evidence supporting PULP's proposal" and states that PULP does not offer a funding source for its proposal.[360]

We share PULP's interest in ensuring that customers can access assistance and critical information about their accounts, regardless of what language they speak. However, the record before us demonstrates that O&R is providing language access services to its customers.[361] As PULP concedes, none of the counties in O&R's service territory satisfy the threshold in our regulation that would require O&R to provide the translation

[358] Hearing Exhibit 264 (O&R Customer Service Panel Rebuttal), p. 28.

[359] Id.

[360] Hearing Exhibit 317, O&R Reply Brief, pp. 12-13; Hearing Exhibit 264 (O&R Customer Service Panel Rebuttal), pp. 28-29.

[361] See Hearing Exhibit 265 (O&R Customer Service Panel Rebuttal Exhibit CSP-2).

services detailed in 16 NYCRR §11.17(b) into Haitian Creole.[362] We therefore decline to direct O&R to expand its language access program at this time but have the expectation that O&R will continue to provide language access assistance to its customers as appropriate.

N. Management and Operations Audit Compliance

Public Service Law §66(19)(c) provides that upon application for a major change in rates, the Commission shall review a utility's compliance with the Commission's directives and recommendations previously made in the most recent management and operations audit report and shall incorporate the findings of such review in its rate order.

DPS Staff's testimony described the most recent management and operations audits of the Company.[363] In 2013, the Commission instituted a proceeding requiring an audit of the internal staffing levels and use of contractors for selected core utility functions at all major New York utilities,

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[362] We also note that while PULP contends U.S. Census Bureau data supports the proposition that 17 percent of the population of Rockland County speaks Haitian Creole as their first language (see Hearing Exhibit 312, PULP Statement in Opposition, p. 16 and Hearing Exhibit 250, PULP Direct Testimony of William D. Yates, p. 59, n. 83), we do not reach the same conclusion based on record evidence. See referenced U.S. Census Bureau data, *American Community Survey (2019-5yr) – Languages Spoken at Home for the Population 5 Years and Over*. https://data.census.gov/cedsci/table?q=language%20spoken%20at%20home&g=0500000US36071,36087&tid=ACSDT5Y2019.C16001

[363] Hearing Exhibit 136 (DPS Staff Witness Angela Morina), p. 2-3 (citing Cases 13-M-0449, 14-M-0001 and 18-M-0013). It does not appear that O&R addressed in testimony the status of implementation and compliance with the management and operations audits referred to in DPS Staff's testimony.

including O&R (Staffing Audit Proceeding).[364] In a February 2017 final audit report, Liberty Consulting Group, made 16 recommendations for O&R's operational improvement (Staffing Audit Report).[365] O&R thereafter submitted an Implementation Plan based on the results of the Staffing Audit Report and the Commission approved it in December 2017 and directed implementation.[366]

O&R timely filed updates to its Implementation Plan, most recently in December 2018, and reviewed the recommendations in resource planning, workforce management and performance measures, internal staffing, overtime, contractor use, and REV efforts.[367] The Company's Updated Implementation Plan indicates that it has completed the implementation of the recommendations in the Staffing Audit Report and further action was not

[364] 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.

[365] Case 13-M-0449, supra, Final Report by The Liberty Consulting Group – Operations Audit of Staffing Levels at the Major New York State Energy Utilities (filed February 21, 2017), pp. ES-45 – ES-48.

[366] Case 13-M-0449, supra, Order Approving Implementation Plans (issued December 15, 2017). DPS Staff's testimony notes that O&R incurred no notable incremental costs from implementing the recommendations and that the savings realized from the implemented recommendations cannot be specifically identified. Hearing Exhibit 136 (DPS Staff – Morina Testimony), p. 8.

[367] Case 13-M-0449, supra, Staffing Audit Implementation Plan Update (filed December 17, 2018) (Updated Implementation Plan). The O&R initial and updated Implementation Plans were filed jointly with affiliate, Consolidated Edison.

required.[368] On April 22, 2019, DPS Staff confirmed completion of O&R's Updated Implementation Plan and the audit recommendations, indicating that all recommendations had been implemented and the Company's updated reports contained sufficient details to reach that conclusion.[369]

We did not address the results of this operations audit in the 2019 Rate Order because it predated DPS Staff's confirmation of O&R compliance. We find that DPS Staff's determination of the Company's completion of the audit consistent with the Liberty Audit Report eliminates any need to address or incorporate those recommendations into this Order.

In a separate audit proceeding, in April 2016, the Commission issued an order adopting recommendations contained in an independent third-party consultant's audit of the accuracy of reported data regarding electric reliability, gas safety, and customer service by all New York utilities (Data Reporting Audit Report).[370] In addition, the audit addressed utility adherence to reporting requirements and the accuracy of systems used to compile compliance data. The Data Reporting Audit Report provided the results of the consultant's audit and contained 426 recommendations designed to improve the accuracy, consistency,

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368 Id., O&R Updated Implementation Plan, pp. 5-6, Appendix A. The details of the Company's Updated Implementation Plan and the status of specific implementation efforts are set forth in Appendix A to the Plan.

369 Hearing Exhibit 136 (DPS Staff Witness Angela Morina), p. 6.

370 Case 13-M-0314, Request for Proposal for an 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 Customer, Order Releasing Report and Providing Guidance on Response (issued April 20, 2016).

and completeness of data reporting of performance metrics.[371] The Commission directed the filing of Implementation Plans to address these recommendations and in a March 2017 order, approved the Plans. On March 1, 2018, DPS Staff found that the Company's Implementation Plan had been implemented and completed its audit.

The Commission commenced a third proceeding requiring a comprehensive management and operations audit of O&R and affiliate, Consolidated Edison.[372] NorthStar Consulting Group conducted the audit and in May 2016, issued a final audit report (NorthStar Audit Report) with recommendations to improve O&R's operations.[373] The Commission required the Company and Consolidated Edison to submit an Implementation Plan to address the recommendations. Following submission, DPS Staff determined that the Company had demonstrated ongoing implementation and compliance with NorthStar's recommendations.[374] DPS Staff testified here that "the implementation phase of this audit is ongoing" because of one outstanding recommendation applicable to

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[371] Hearing Exhibit 136 (DPS Staff Witness Angela Morina), pp. 9.

[372] Case 14-M-0001, Comprehensive Management and Operations Audit of Consolidated Edison Company of New York, Inc. and Orange and Rockland Utilities, Inc., Request for Proposal (issued December 11, 2014).

[373] Hearing Exhibit 136 (DPS Staff Witness Angela Morina), pp. 6-7.

[374] Id.

Consolidated Edison.[375]

Finally, on January 11, 2018, the Commission issued an order commencing a focused operations audit to investigate the income tax accounting of New York State utilities, including O&R (Tax Accounting Audit Proceeding).[376] Specifically, the Tax Accounting Audit Proceeding focuses on determining whether errors in income tax accounting occur with respect to the alleged cost of removal; whether ratepayers receive the benefit of the utilities' lower income tax expenses in rates; and whether correcting adjustments to the errors were accurate, reasonable, and consistent with accounting and tax rules and the Commission's policies.[377] In April 2018, the Commission selected an auditor to investigate the income tax accounting of O&R and other utilities.[378]

As a result of delays associated with the auditor obtaining requested information, the Commission expanded the

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[375] Hearing Exhibit 136 (DPS Staff Witness Angela Morina), pp. 6-7. On November 24, 2021, the Company and Consolidated Edison submitted an Updated Audit Implementation Plan regarding the status of implementation and revision to the December 2021 timeline for completion of the remaining recommendation related to improvements in the Gas Operations' Work Management processes, proposing a new completion date of June 30, 2022. On December 14, 2021, DPS Staff approved the revised timeline.

[376] Case 18-M-0013, In the Matter of a Focused Operations Audit to Investigate the Income Tax Accounting of Certain New York State Utilities, Order Approving and Issuing the Request for Proposals Seeking a Third-Party Consultant to Perform Audits to Investigate the Income Tax Accounting of Certain New York State Utilities (issued January 11, 2018); Hearing Exhibit (DPS Staff – Morina Testimony), pp. 7-8.

[377] Hearing Exhibit 136 (DPS Staff Witness Angela Morina), pp. 7-8.

[378] The Commission selected Schumaker and Company, Inc. as the independent consultant to investigate the income tax accounting issues.

audit scope and increased the audit funding. In August 2019, the auditor submitted a draft report (Draft Tax Audit Report), which is still under review by DPS Staff.[379]

DPS Staff's testimony describes the details of the Tax Accounting Audit Proceeding and indicates that it is ongoing.[380] We have not issued a final determination in that Proceeding.

Our 2019 Rate Order and the underlying Joint Proposal discussed the then-ongoing independent audit and the signatory parties' agreement that the final, non-appealable Commission-ordered findings in the Tax Accounting Audit would be binding, including any Commission-ordered adjustment to the amounts related to the COR error that was embedded in the Company's cost of service forecast (income tax expense and excess deferred federal income tax liability balances) and reconciliation, whether refunded to or collected from customers.

We anticipate that the final Tax Audit Report is likely to be issued during the three-year Rate Plans established under the Joint Proposal in these proceedings, and we expect the Company to file the appropriate Implementation Plan in accordance with PSL §66(19)(b). Subject to the issuance of a final Tax Audit Report and the Company's timely implementation of the recommendations noted, we expect that the Company will be in compliance with the requirements of PSL §66(19)(b) and thereby enable our review of O&R's audit compliance and incorporation of the audit findings in the next rate order pursuant to PSL §66(19)(c).

O. Miscellaneous Provisions

The Joint Proposal contains several miscellaneous

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[379] Case 18-M-0013, supra, Order Adjusting Compensation for the Independent Auditor (issued November 15, 2019), p. 3.

[380] Hearing Exhibit 136 (DPS Staff Witness Angela Morina), p. 8.

provisions that, with two exceptions, represent agreements among the signatories, which are unrelated to our substantive approval of its terms. These provisions address preservation of rights, potential related legislative and regulatory actions and policy proceedings, trade secret protections, separability, assurances, scope, and other procedural terms regarding submission of the Joint Proposal and the Commission's adoption. We therefore decline to adopt those provisions.

The first exception involves the Joint Proposal's terms in Section K(1), that provides for the continuation of its terms after Rate Year 3, including the Rate Year 3 performance targets, until the Commission revises base delivery service rates for electric and/or gas. We adopt this provision.

The second exception involves the Financial Protections terms in Section K(4), which requires, among other things, annual reporting for purposes of evaluating whether ring fencing measures should be implemented. Although included as a "Miscellaneous" provision, this section serves the important purpose of protecting both O&R and ratepayers. In testimony, both DPS Staff and the Company recommended a clarification to the existing ring-fencing criteria, whereby the metric measuring holding company debt to total consolidated debt would exclude non-recourse financing by non-utility entities, an approach that was adopted by the Commission for Consolidated Edison in its last rate order.[381] We adopt this clarification and this

[381] Hearing Exhibit 164 (DPS Staff Finance Panel), pp. 25-30 (citing Cases 19-E-0065 and 19-G-0066, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric and Gas Service, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans (issued January 16, 2020); Joint Proposal, pp. 122-123; Hearing Exhibit 26 (O&R Witness Yukari Saegusa – Cost of Capital), p. 41).

provision of the Joint Proposal.

VII. EVALUATION UNDER PUBLIC INTEREST STANDARD

The Commission will adopt the terms of a joint proposal upon a finding that its terms, when viewed as a whole, produce a result that is in the public interest. Under this public interest standard and applying the Commission's Settlement Guidelines,[382] the terms of a joint proposal must fall within the range of reasonably likely litigate results and, for rate cases, the terms must assure safe and adequate service at just and reasonable rates. A joint proposal should balance protection of consumers with fairness to investors and the long-term viability of the utility. The result of any negotiated proposal also should be consistent with the environmental, social and economic policies of the Commission and the State. These considerations are "themselves elements of the public interest standard."[383]

The Joint Proposal here achieves a fair balance of interests on the issues presented in these electric and gas proceedings and is the product of several negotiation sessions on notice to all participating parties. In addition to O&R and DPS Staff, the Joint Proposal is signed by parties with differing interests, including NYPA, whose street light program is advanced, and by advocates for geothermal heat pump technology and refrigerant use limitations, whose positions are similarly advanced.

The Joint Proposal provides rate mitigation from the

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[382] Cases 90-M-0255 and 92-M-0138, Proceeding on Motion of the Commission Concerning Procedures for Settlement and Stipulation Agreements, C 11175, Opinion, Order and Resolution Adopting Settlement Procedures and Guidelines, Opinion 92-2 (issued March 24, 1992).

[383] Id., pp. 30-31.

economic effects of the Covid-19 pandemic by eliminating a portion of management wage increases, crediting customers with payroll tax credits, establishing productivity adjustments, and shortening the amortization period for excess deferred federal income taxes. The Joint Proposal benefits customers through gas safety and customer service performance metrics that carry positive and negative revenue adjustments to incentivize the Company in meeting established targets. The Joint Proposal benefits ratepayers by including an earnings-sharing mechanism.

The Joint Proposal also institutes fundamental changes to the Company's programs and operations to address the CLCPA. The Joint Proposal strikes the appropriate balance between the need to decrease greenhouse gas emissions and the need for the Company to meet its legal obligations to provide safe and reliable gas service at rate levels that are just and reasonable.

Based on the record, we find that the Joint Proposal strikes an appropriate balance between the interests of the parties, ratepayers, and the Company's long-term viability. We further find that the Joint Proposal meets the criteria in PSL §§65 and 66, the Commission's Settlement Guidelines, and is in the public interest.

VIII. CONCLUSION

Based upon the record as a whole, and as modified by this Order, we find that the Joint Proposal adequately mitigates rate impacts during the term of the three-year rate plans, while providing sufficient funding for the Company to maintain safe and reliable service and attract necessary capital to ensure its long-term viability. The terms of the Joint Proposal comply with our Settlement Guidelines and are consistent with the Commission's and the State's environmental, social, and economic policies, including the CLCPA. Consistent with the discussions contained in this Order, we find that the Rate Plans adopted herein are in the public interest.

The Commission Orders:

1. Subject to the Commission's discussions in this Order and the additional requirements, the terms of the Joint Proposal and associated schedules, dated December 3, 2021, which are appended to this Order as Attachment A, are adopted and incorporated as part of this Order, with the exception of Section K, Miscellaneous Provisions, paragraphs 2-3 and paragraphs 5-13.

2. Orange and Rockland Utilities, Inc. is directed to file cancellation supplements, effective on not less than one day's notice, on or before April 25, 2022, cancelling the tariff amendments and supplements listed in Attachment B to this Order.

3. Orange and Rockland Utilities, Inc. is directed to file, on not less than three-days' notice, to take effect on May 1, 2022, on a temporary basis, such further tariff amendments as are necessary to effectuate the terms of this Order for Rate Year 1, the twelve-month period ending December 31, 2022, and to incorporate any tariff amendments that were previously approved by the Commission since the tariff amendments listed on Attachment B were filed. The Company shall serve copies of its filing on all parties to these cases. Any comments on the compliance filing must be filed within 14 days of service of the Company's proposed amendments. The amendments specified in the compliance filing shall not become effective on a permanent basis until approved by the Commission.

4. Orange and Rockland Utilities, Inc. is directed to file such tariff changes as are necessary to effectuate the

terms of this Order for Rate Years 2 and 3 on not less than 30-days' notice. Such tariff changes shall be effective only on a temporary basis until approved by the Commission.

5. Orange and Rockland Utilities, Inc. is directed to file by December 31, 2022, modifications to its Annual Team Incentive Plan, after consulting with Department of Public Service Staff, as discussed in this Order.

6. Orange and Rockland Utilities, Inc. shall file with the Secretary within 60 days of the effective date of this Order a report regarding the amounts included in the revenue requirement for organization dues, which shall contain the underlying analysis, documentation, and associated workpapers supporting the identified amounts that should be excluded from the revenue requirement (including carrying charges) to be refunded to customers and a proposed treatment to achieve the customer refunds, as discussed in this Order.

7. Orange and Rockland Utilities, Inc. is directed to submit a plan to correct the low-income bill discount program credit error to the Secretary to the Commission within 30 days of the effective date of this Order, consistent with the body of this Order, which shall describe the measures to be taken to address and make whole previously misclassified Low-Income Bill Discount Program participants, including the details of calculations, explanation, analysis, and internal controls. Credits shall be shown on the bills of affected low-income bill discount program participants in their respective billing cycle within 45 days after submittal of the plan, unless Department of Public Service Staff submits a letter to Orange and Rockland Utilities, Inc. indicating that the credit amounts should be adjusted.

8. Orange and Rockland Utilities, Inc. is directed to file in its next rate filing, unless required to do so earlier: (1) the 1990 greenhouse gas emissions baseline for its entire gas system, with a description of the methodology used in developing the baseline calculation; (2) a calculation of annual greenhouse gas emissions for its gas system at the time of the filing, with a description of the methodology used in the calculation; (3) an assessment of how its capital expenditures, programs, and initiatives described in its proposed rate filing (or existing rate plan if done earlier) will impact greenhouse gas emissions from its gas system, specifying the potential emissions impacts of each; and, (4) an analysis of non-pipeline alternatives considered for each capital expenditure, program or initiative on the gas system and a reasoned explanation if such non-pipeline alternatives are not selected.

9. Orange and Rockland Utilities, Inc. shall file, within 90 days after the effective date of this Order, tariff changes to implement the Customer-Owned Street Light Dimming Pilot, which will allow for the installation and prescriptive use of NLC nodes in customer-owned street lights, and otherwise meet the requirements and timeframes set for in the Joint Proposal; shall file progress reports with the Secretary every 45 days in accordance with the terms of this Order; and shall file with the Secretary, a written plan outlining the collaborative process that will be undertaken after consultation with DPS Staff, NYPA, and other interested stakeholders, as discussed in this Order; and is required to otherwise comply with the technical conference, collaborative meeting, reporting, and other requirements set forth in this Order related to the Customer-Owned Street Light Dimming Pilot.

10. Orange and Rockland Utilities, Inc., as part of its annual natural gas detector report under the Joint Proposal to be filed with the Secretary within 90 days of the close of each Rate Year, shall include updated estimates of the total cost for the acquisition and installation of 15,400 Advanced Metering Infrastructure-enabled natural gas detectors, an explanation of how such costs were determined, and the efforts undertaken to reduce and/or limit the overall cost, in accordance with the requirements of this Order.

11. Orange and Rockland Utilities, Inc., shall file a Renewable Natural Gas Plan with the Secretary within six months of the date of this Order in accordance with the requirements of this Order.

12. Orange and Rockland Utilities, Inc. shall file, prior to the construction of the Millennium Back-Feed Project and within 60 days of reaching the appropriate agreements to proceed with the Project, a detailed updated cost estimate for the Millennium Back-Feed Project, an explanation for how the updated cost estimate was derived, and shall provide any associated workpapers.

13. Orange and Rockland Utilities, Inc. shall begin the Certified Natural Gas Pilot in the winter of 2022-2023 and file, a report on May 1, 2023, a certification by an independent third-party expert verifying the quantifiable reduced greenhouse gas emissions potential for certified natural gas, as compared to traditional natural gas sources, and the criteria, guidelines, testing, and production protocols that are designed to demonstrate that certified natural gas is a reduced emissions fuel source, as discussed in this Order.

14. Orange and Rockland Utilities, Inc. shall consult with Department of Public Service Staff and interested parties

on the integration of the Refrigerant Management Initiative into its energy efficiency program, as discussed in this Order.

15. Orange and Rockland Utilities, Inc. shall file quarterly reports beginning on June 30, 2022 that details progress on the redesign of its Digital Customer Experience program, including digital content and services and implementation of new digital services and functionality, and shall make future Digital Customer Experience program proposals with affiliate Consolidated Edison that shall include costs and benefits of the proposals and shall address the timing and impact of presenting the proposals in their respective rate proceedings.

16. Orange and Rockland Utilities, Inc., shall file with the Secretary a Revenue Adjustment Mechanism (RAM) Compliance Filing 60 days before the recovery of any storm costs through the variable ECA, which shall be based on actual major storm costs incurred over the 12 months ending December 31 of each prior Rate Year and shall include the storm costs per major storm event, backup documentation to support such costs, and workpapers associated with the calculations used to determine the Company's proposed RAM component of the variable ECA by service classification. The RAM will continue unless and until changed by Commission order.

17. Orange and Rockland Utilities, Inc., shall file with the Secretary by September 30 of each Rate Year a status report on the Customer Relationship Management System implementation, including actual spending, projected completion date, and any realized costs savings resulting from implementation.

18. The requirement of Public Service Law Section 66(12)(b) that newspaper publication be completed prior to the

effective date of the proposed amendments directed in Clause 3 above is hereby waived for Rate Year 1. The Company is directed to file with the Commission, not later than six weeks following the amendments' effective date, proof that notice to the public of the changes made by the amendments has been published once a week for four successive weeks in daily and weekly newspapers having general circulation in the service territory and areas affected by the amendments. Newspaper notice is not waived for tariff changes necessary to implement the rate plans in Rate Years 2 and 3.

19. 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 justification for the extension, and must be filed at least three days prior to the affected deadline.

20. These proceedings are continued.

By the Commission,

(SIGNED)

MICHELLE L. PHILLIPS
Secretary

ATTACHMENT A

OCTOBER 29, 2021 JOINT PROPOSAL

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 21-G-0073 – Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Gas Service.

CASE 21-E-0074 – Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service.

JOINT PROPOSAL

October 29, 2021

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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 21-G-0073 – Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Gas Service.

CASE 21-E-0074 – Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service.

JOINT PROPOSAL

THIS JOINT PROPOSAL ("Proposal") is made as of the 29th day of October, 2021, by and among Orange and Rockland Utilities, Inc. ("Orange and Rockland" or the "Company"), New York State Department of Public Service Staff ("Staff"), New York Power Authority, New York Geothermal Energy Organization, and New Yorkers For Cool Refrigerant Management, and other parties whose signature pages are or will be attached to this Proposal (collectively referred to herein as the "Signatory Parties").

Introduction

This Proposal sets forth the terms of an electric rate plan for the period January 1, 2022 through December 31, 2024 ("Electric Rate Plan") and a gas rate plan for the period January 1, 2022 through December 31, 2024 ("Gas Rate Plan"). (Collectively, the Electric Rate Plan and the Gas Rate Plan are referred to as the "Rate Plans.") The Rate Plans prescribe agreed-upon rate levels and address operational and accounting matters, as well as various other rate design and revenue allocation issues. The Rate Plans are designed to support the continued reliability, safety, and security of the Company's electric and gas systems at just and reasonable rates.

Among other things, the Electric Rate Plan reflects a revenue requirement based on the adoption of the electric sales and revenue forecast agreed to by the Signatory Parties, the continuation of a revenue decoupling mechanism ("RDM") and various other reconciliations, including a property tax reconciliation, reconciliation of net plant balances in the event that actual average net plant is lower than that reflected in rates, continuation of electric performance metrics and the New York Public Service Commission's ("Commission") enhancement of the low income customer assistance program. The Electric Rate Plan is supportive of and consistent with the goals of the Climate Leadership and Community Protection Act ("CLCPA").

Among other things, the Gas Rate Plan reflects a revenue requirement based on the adoption of the gas sales and revenue forecast agreed to by the Signatory Parties, updates to the interruptible sales benefit imputation, the continuation of an RDM and various other reconciliations, including a property tax reconciliation, reconciliation of net plant balances in the event that actual average net plant is lower than that reflected in rates, provision of additional resources to various gas safety initiatives, continuation and/or enhancement of gas performance metrics, and the Commission's enhancement to the low income customer assistance program. The Gas Rate Plan is supportive of and consistent with the goals of CLCPA and a provides for the continued exploration of potential Non-Pipe Alternatives ("NPA").

Procedural Setting

Orange and Rockland is currently operating under an electric and gas rate order that established electric and gas rates effective January 1, 2019.[1] The 2019 Rate Order established electric and gas base rates for the three years ending December 31, 2021.

On January 29, 2021, Orange and Rockland filed new tariff leaves and supporting testimony for new rates and charges for electric and gas service effective on January 1, 2022, for the 12-month period ending December 31, 2022. In that filing, the Company also included financial information for the two succeeding 12-month periods in order to facilitate development of multi-year rate plans through settlement discussions in the event parties elected to do so.

Two administrative law judges ("ALJs"), Maureen F. Leary and Erika Bergen, were appointed to preside over the rate proceedings. Parties engaged in discovery, with the Company responding to over 900 formal discovery requests on the filings. A procedural conference was held virtually on February 25, 2021. The procedural conference was immediately followed by a technical presentation by the Company on various aspects of the filing.

On February 16, 2021, ALJs Bergen and Leary issued a Ruling Adopting Protective Order. On March 3, 2021, ALJs Bergen and Leary also issued a Ruling on Schedule, providing dates for certain activities in these cases, including an update of the

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[1] Cases 18-E-0067, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Electric Service*; Case 18-G-0068, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities, Inc. for Gas Service*, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans (issued March 14, 2019) ("2019 Rate Order").

Company's filings, Staff and intervenor testimony, rebuttal testimony of the Company's filings, and evidentiary hearings.

On March 31, 2021, the Company provided the parties with revenue requirement updates.

On May 27 through June 1, 2021, six parties filed testimony in response to the Company's filings. On June 18, 2021, the Company filed rebuttal testimony, including the presentation of the Company's formal revenue requirement update. One other party also filed rebuttal testimony.

By notice dated June 11, 2021, Orange and Rockland notified all parties of the commencement of settlement negotiations on June 25, 2021.[2] Settlement negotiations began on June 25, 2021, and continued on July 16, July 29,[3] August 11, August 13, August 20, September 2, September 10, September 24, September 29, October 1, October 15, October 20, and October 26. All settlement negotiations were held virtually and were subject to the Commission's Settlement Rules, 16 NYCRR §3.9, including the provision of appropriate notices for negotiating sessions.

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

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

[3] On June 11, 2021, the Company filed a letter with the Secretary agreeing to a one-month extension of the statutory suspension period in these proceedings subject to a "make-whole" provision that would keep the Company and its customers in the same position they would have been absent the extension. On July 14, 2021, the Company requested a second extension through March 26, 2022. On September 10, 2021, the Company request a third extension through May 26, 2022, if necessary.

A. Term

The Signatory Parties recommend that the Commission adopt a three-year Electric Rate Plan and Gas Rate Plan for Orange and Rockland as set forth herein, effective as of January 1, 2022 and continuing through December 31, 2024.

For the purposes of this Proposal, Rate Year means the 12-month period starting January 1 and ending December 31; Rate Year 1 ("RY1") means the 12-month period starting January 1, 2022 and ending December 31, 2022; Rate Year 2 ("RY2") means the 12-month period starting January 1, 2023 and ending December 31, 2023; and Rate Year 3 ("RY3") means the 12-month period starting January 1, 2024 and ending December 31, 2024.

B. Rates and Revenue Levels

1. Common

a. Rate Mitigation

In order to mitigate customer bill impacts in light of the on-going COVID-19 pandemic, the Company has eliminated funding for senior management (Band 4 and executive) wage increases for the period October 1, 2020 to December 31, 2022. As management wage increases are effective in April of each year, this results in eliminating funding for senior management wage increases for two years.

The Company claimed the COVID-19-related Employee Retention Tax Credit to keep workers employed in the early months of the pandemic when certain activities were suspended. The Company will pass the full $0.975 M benefit of the credit to customers over the term of the Rate Plans.

Moreover, the electric and gas revenue requirements reflected in the Rate Plans contain significant productivity and efficiency-related adjustments. In addition to a one percent productivity adjustment to the cost of direct labor, fringe benefits (*i.e.*, pension, post-employment benefits and employee welfare expenses) and payroll taxes, the revenue requirements also include $2.9 million in COVID-related adjustments over the Rates Plans. The combined productivity and additional adjustments are equivalent to approximately a two percent productivity adjustment for Rate Year 1. In addition, the Company has imputed $19.6 million of forecasted targeted efficiency savings over the term of the Rate Plans. The Company bears the risk of not achieving the targeted efficiency savings as there is no reconciliation.

Finally, this Proposal accelerates pass-back to customers of unprotected excess deferred federal income taxes balances related to the Tax Cuts and Jobs Act of 2017 (*i.e.*, shortened the amortization to six years from 15 years, as set forth in the 2019 Rate Order).

b. CLCPA-Related Efforts

In order to assist in achieving the goals of the CLCPA, the Company will engage in the various environmental sustainability efforts set forth in Appendix 20.

c. Sales Forecasts

The electric and gas sales and delivery revenue forecasts used to determine the revenue requirements for each of RY1, RY2 and RY3 are set forth in Appendices 4 and 5, respectively. For purposes of this Proposal, the sales and delivery revenue forecasts for electric and gas are based on the use of a 10-year normal for the period through December 2020.

d. Annual Team Incentive Program ("ATIP")

During RY1, the Company will confer with Staff to review its ATIP program, particularly how the goals of such program can fully support the customer interest, consistent with Commission policies for safety, reliability, environmental protection and customer service. Based on such review, the Company will modify its ATIP program, as appropriate, for RY2 and RY3. The results of the review and any modifications to be implemented shall be documented in a filing to the Secretary on or before December 31, 2022.

2. Electric

This Proposal recommends changes to the Company's electric delivery service rates and charges designed to produce an additional $4.939 million in revenues on an annual basis starting in RY1, an additional $16.158 million increase in revenues on an annual basis starting in RY2, and an additional $23.129 million increase in revenues on an annual basis starting in RY3. The electric revenue requirement calculations underlying the Proposal are set forth in Appendix 1.

The Signatory Parties recommend that the Commission adopt the option to phase in these three base rate changes on a levelized basis to provide rate stability over the Electric Rate Plan. The annual levelized revenue changes would be an $11.675 million increase in RY1, RY2 and RY3.[4] The revenue changes to each service class associated with the proposed additional revenues are shown in Appendix 17.

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4 The levelized rate changes are inclusive of interest on the deferred rate increase calculated at the 2021 Other Customer-Provided Capital Rate of 1.8 percent. The Company will calculate the change in interest for any change in the Other Customer-Provided Capital Rate in future years and defer the difference for surcharge or credit to customers, as applicable.

The proposed revenue changes for each of RY1, RY2 and RY3 will be effective on the first day of each Rate Year.[5]

The Signatory Parties recognize that levelizing the revenue increases over the three years of the Electric Rate Plan to moderate customer bill impacts will result in lower base delivery rate revenues for the Company at the end of RY3 than would result if the revenue increases were not levelized. To address this circumstance, $20.9 million of the RY3 rate increase will be included in base rates and $9.2 million of the RY3 rate increase will be refunded via a temporary credit through the Energy Cost Adjustment ("ECA"). The major components of the electric revenue requirements underlying this Proposal are set forth in Appendix 1. These revenue requirements are net of the amortizations of various deferred customer credits and charges on the Company's books of account that have previously been deferred by the Company, as well as projections of deferred amounts. The list of deferred customer credits and charges to be applied during the Electric Rate Plan is attached as Appendix 3.

a. Market Supply Charge/Energy Cost Adjustment

The Company will continue to recover all prudently incurred supply and supply-related costs, including, but not limited to, power purchase costs, through the Market Supply Charge ("MSC") and ECA mechanisms.

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[5] If, based on the make whole extension letters referred to in footnote 3, the Commission does not issue an order on this Proposal until after January 1, 2022, the Company will recover shortfalls and refund over-collections that result from the extension of the suspension period in this proceeding through a "make-whole" provision, as detailed in the make whole extension letters. The revenue differences will be recovered or credited, with interest, over the remaining months of 2022 as detailed in Appendices 17 and 18.

b. Revenue Decoupling Mechanism

For the term of the Electric Rate Plan, the Company will continue to implement an RDM, as set forth in the Company's electric tariff, amended to reflect the modifications recommended in this Proposal as outlined in Appendix 21. The RDM, as modified, will continue thereafter until changed by the Commission, except for restating the RDM targets for the Rate Year commencing January 1, 2025, to reflect the expiration of the temporary credit discussed in paragraph B.1 above, if the Company does not file for new base delivery rates to be effective within 15 days after the expiration of RY3.

c. Other Charges

The Signatory Parties agree that, whenever the Company is or will be subject to governmental or regional transmission organization ("RTO") transmission and/or generation-related charges, costs or credits (*e.g.*, FERC, NYISO, PJM, EPA)[6] not already listed in or otherwise covered by the then-effective MSC or ECA tariff language, the Company may make a tariff filing with the Commission providing for recovery of such charges/costs, or application of these credits, through the MSC mechanism, ECA mechanism, and/or comparable adjustment mechanism. The proposed tariff amendment may include charges/costs/credits applicable to the period prior to the effective date of the tariff amendment.

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6 Federal Energy Regulatory Commission ("FERC"), New York Independent System Operator ("NYISO"), PJM Interconnection, L.L.C. ("PJM"), and Environmental Protection Agency ("EPA").

3. Gas

This Proposal recommends changes to the Company's retail gas sales and gas transportation service rates and charges, designed to produce a $0.660 million increase in revenues on an annual basis starting in RY1, an additional $7.395 million increase in revenues on an annual basis starting in RY2, and an additional $9.870 million increase in revenues on an annual basis starting in RY3.[7]

The Signatory Parties recommend that the Commission adopt the option to phase in these three base rate changes on a levelized basis to provide rate stability over the term of the Gas Rate Plan. The annual revenue changes would be a $4.421 million increase in RY1, RY2 and RY3.[8] The revenue changes to each service class associated with the proposed additional revenues are shown in Appendix 18.

The proposed revenue changes for each of RY1, RY2 and RY3, will be effective on the first day of each Rate Year.[9]

The Signatory Parties recognize that levelizing the revenue increases over the three years of the Gas Rate Plan to moderate customer bill impacts will result in lower base delivery rate revenues for the Company at the end of RY3 than would result if the revenue increases were not levelized. To address this circumstance, $9.1 million will be

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[7] Unless specifically stated otherwise in this Proposal, the terms "customers" and "base rate" with respect to gas apply to the Company's firm gas customers who are served under SC Nos. 1, 2, and 6.

[8] The levelized rate changes are inclusive of interest on the deferred rate increase calculated at the 2021 Other Customer-Provided Capital Rate of 1.8 percent. The Company will calculate the change in interest for any change in the Other Customer-Provided Capital Rate in future years and defer the difference for surcharge or credit to customers, as applicable.

[9] *See* footnote 5.

included in base rates in RY3 and $4.7 million will be refunded via a temporary credit through the Monthly Gas Adjustment ("MGA").

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

a. Gas Supply Charge/MGA

The Company will continue to recover all prudently incurred supply and supply-related costs through the Gas Supply Charge ("GSC") and MGA. Costs associated with balancing assets will continue to be recovered from all Service Classification ("SC") Nos. 1, 2, and 6 customers through a common cents per Ccf component in the MGA.[10]

b. Revenue Decoupling Mechanism

For the term of the Gas Rate Plan, the Company will continue to implement an RDM, amended to reflect the modifications recommended in this Proposal as outlined in Appendix 21. The RDM will continue unless and until changed by the Commission, except for restating the RDM targets for the Rate Year commencing January 1, 2025, to reflect the expiration of the temporary credit discussed in paragraph B.2 above, if the

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

Company does not file for new base delivery rates to be effective within 15 days after the expiration of RY3.

c. Base Rate Imputations

The base rate imputation shall increase to $6.45 million in all three Rate Years. These revenue imputations reflect (i) imputations for interruptible benefits[11] of $5.8 million ("Interruptible Benefits Imputation"); and (ii) an imputation of $650,000 for net benefits associated with the delivery of gas to electric generating facilities previously owned by the Company ("Power Generation Imputation") in each Rate Year. Any variances, either positive or negative, between the actual revenue margin and the Interruptible Benefits Imputation, during each Rate Year the Gas Rate Plan is effective, will be shared on an 80% customer/20% Company basis and the 80% customer over-/under-recovery will be credited to/recovered from customers as applicable through the MGA. One hundred percent of any variances, either positive or negative, between the actual revenue margin and the Power Generation Imputation, during each Rate Year the Gas Rate Plan is effective, will be credited to/recovered from customers as applicable through the MGA.

d. Lost and Unaccounted for Gas

The Factor of Adjustment ("FOA"), reflecting lost and unaccounted for ("LAUF") gas, will be reset every November 1 based on the average of the actual FOAs for the previous five 12-month periods ended August 31.

Actual LAUF will be calculated annually as follows:

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[11] Interruptible benefits shall be defined as total interruptible (SC No. 8) and firm withdrawable (SC No. 9) revenues minus any associated gas costs and revenue tax surcharge revenues.

1. Losses = Total Pipeline Receipts less metered deliveries to customers (Retail Sales and Transportation Deliveries + Deliveries to Generators + Gas Used for Company Purposes[12]).

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

3. Line Loss Factor ("LLF") = Adjusted Line Loss divided by Citygate receipts adjusted for generators.

Wholesale generators served under SC No. 14 that have a capacity that is at least 50 MW are to provide 1% of their consumption to cover losses unless the system average is lower. Wholesale generators that are not on a dedicated line but are on a high-pressure transmission line can negotiate a specific LLF, subject to a minimum of 1% of their consumption unless the system average is lower. Wholesale generators that are not served by dedicated lines, and that do not negotiate an LLF, will have the system average LLF applied. The volumes associated with wholesale generators served by dedicated lines shall be excluded from the LLF calculation by deducting the metered amount from the total send out.

In order to determine if the Company receives an incentive or pays a penalty for the annual LLF achieved commencing with the 12-month period ending August 31, 2022, the Company will compare the LLF level for such period to a targeted dead band based on the FOA in effect at the time of the filing of the annual gas cost rate reconciliation

[12] Metered gas for inactive accounts is included in "Gas Used for Company Purposes" and reflected as such in the gas revenue requirement and LAUF calculation. The estimate for Gas Used for Company Purposes used to establish the gas revenue requirement includes an estimated amount for metered gas for inactive accounts based on the Company's gas service termination procedures.

(*i.e.*, based on the average of the prior five-year LLFs through August 31, 2021) ("Target Dead Band"). The Target Dead Band will be reset annually based on the average of the prior five-year LLFs.[13] The Target Dead Band limits are set at minus two standard deviations ("lower limit") and plus two standard deviations ("upper limit") of the FOA in effect. In the event that two standard deviations below the FOA is below 0%, the lower limit will be 0%, and the upper limit will be 0% plus four standard deviations. If the LLF is within the Target Dead Band, no incentive or penalty will arise. If the LLF is greater than the upper limit of the Target Dead Band, a penalty will be assessed according to the tariff. If the LLF is less than the lower limit of the Target Dead Band, an incentive will be provided to the Company according to the tariff. The Company will not earn an incentive on any portion of an LLF below 0.0%.

Appendix 10 provides sample calculations of the determination of the potential benefit or cost to the Company. Appendix 10 also details the calculation of the continuing SPA Mechanism.

If an unforeseeable and uncontrollable event(s) occurs that significantly increases actual line losses, then the Company reserves the right to file a petition with the Commission to modify the annual reconciliation of the GSC in order to reflect such increased line losses. The Company will have the burden of demonstrating the increase in actual line losses and that such increase was not due to the Company's negligent actions or omissions, in the event it makes such a filing.

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[13] The Target Dead Band will also be reset annually for the System Performance Adjustment ("SPA") Mechanism.

C. Computation and Disposition of Earnings

Following each electric and gas Rate Year covered by the Rate Plans, the Company will compute, separately, the earned rate of return on common equity ("ROE") for its electric and gas businesses for the preceding Rate Year. The Company will submit these computations of earnings to the Secretary by no later than March 31 (*i.e.*, within three months after the end of each Rate Year).

1. Earnings Sharing Threshold

The ROE reflected in the revenue requirements for electric for RY1, RY2 and RY3, and for gas for RY1, RY2 and RY3 are set forth in Appendices 1 and 2 (*i.e.*, 9.2 percent). Following each of RY1, RY2 and RY3, the Company will compute, separately, the earned rate of return on common equity for its electric and gas businesses for the preceding Rate Year. If the level of the earned electric ROE for RY1, RY2 or RY3 or of the earned gas ROE for RY1, RY2 or RY3 exceeds 9.7 percent ("Earnings Sharing Threshold"), calculated as set forth below, then the amount in excess of the Earnings Sharing Threshold shall be deemed shared earnings ("Shared Earnings") for the purposes of the Rate Plans.

During the terms of the Rate Plans, one-half of the revenue requirement equivalent of any electric or gas Shared Earnings above 9.7 percent but less than 10.2 percent will be deferred for the benefit of customers and the remaining one-half of any Shared Earnings will be retained by the Company; 75 percent of the revenue requirement equivalent of any electric or gas Shared Earnings equal to or in excess of 10.2 percent but less than 10.7 percent will be deferred for the benefit of customers and the remaining 25 percent of any Shared Earnings will be retained by the Company; and 90 percent of the revenue requirement equivalent of any electric or gas Shared Earnings equal to or in excess of 10.7 percent will be deferred for the benefit of customers and the remaining 10 percent of any Shared Earnings will be retained by the Company.

2. Earnings Calculation Method

For each Rate Year, for purposes of determining the actual earned ROE:

a. The calculation of the actual ROE on common equity capital allocated to New York jurisdictional electric and gas utility operations shall be on a "per books" basis, that is, computed from the Company's books of account for each Rate Year, excluding the effects of: (i) Company incentives and performance-based revenue adjustments (both positive and negative), including incentives for Non-Wires Alternatives ("NWAs") and NPAs, under Earnings Adjustment Mechanisms set forth in Appendix 16, and the performance metrics set forth in Appendices 13, 14 and 15; (ii) the Company's share of property tax refunds earned during the applicable Rate Year; and (iii) any other Commission-approved ratemaking incentives and revenue adjustments in effect during the applicable Rate Year.

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

c. If the Company does not file for new base delivery rates to take effect within 30 days after the expiration of RY3, the Earnings Sharing Threshold and the other earnings sharing thresholds will continue until base delivery rates are reset by the Commission. Such calculation will be performed on an annual basis in the same manner as set forth above.

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

3. Disposition of Shared Earnings

For electric and/or gas Shared Earnings in any Rate Year, the Company will apply 50 percent of its share and the full amount of the customers' share of electric and/or gas Shared Earnings that would otherwise be deferred for the benefit of customers under this Proposal, to reduce respective deferred under-collections of Site Investigation and Remediation ("SIR") costs.

In the event the amount of Shared Earnings for electric and/or gas available to reduce respective deferred under-collections of SIR costs exceeds the amount of such deferred under-collections, the Company will apply the amount of the excess to reduce other deferred costs. The Company's annual earnings report will include the amount, if any, of deferred under-collections of SIR costs written down with the Company's and the customers' respective shares of Shared Earnings. If applicable, the Company's annual earnings report will identify any other deferred costs reduced by application of Shared Earnings and the amount of Shared Earnings used for that purpose.

D. Additional Accounting Provisions

1. Reconciliations and Deferrals

The Company's authorized reconciliations and deferrals are detailed in Appendix 9.

2. Depreciation Rates and Reserves

a. Depreciation Rates (Electric and Gas)

The average services lives, net salvage factors and life tables used in calculating the depreciation reserve and establishing the revenue requirements for electric and gas service are set forth in Appendix 11. Existing pipe to be replaced under the Company's pipe replacement program (mainly cast iron, bare steel and Aldyl-A plastic pipe) is to be depreciated over ten years beginning in Rate Year 3.

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

3. Interest on Deferred Costs

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

4. Property Tax Refunds and Credits

Property tax refunds allocated to electric and/or gas that are not reflected in the respective Rate Plans and that result from the Company's efforts, including credits against tax payments or similar forms of tax reductions (intended to return or offset past overcharges or payments determined to have been in excess of the property tax liability appropriate for Orange and Rockland), will be deferred for future disposition, except for an amount equal to 14 percent of the net refund or credit, which will be retained by the Company. Incremental expenses incurred by the Company to achieve the property tax refunds, credits or reductions in future property tax assessments will be offset against the refund or credit before any allocation of the proceeds is calculated. The 14 percent retention will apply to all such property tax refunds and/or credits against future tax payments actually achieved by Orange and Rockland during the term of the Rate Plans.[14] In addition, the Company is not relieved of the requirements of 16 NYCRR §89.3 with respect to any refunds it receives.

5. Income Taxes and Cost of Removal Audit

On January 11, 2018, the Commission issued an order commencing a focused operations audit to investigate the income tax accounting of Orange and Rockland and

[14] This includes 14 percent of any property tax refunds, finalized during the term of the Rate Plans, but actually received after the end of the term of the Rate Plans (*i.e.*, December 31, 2024).

other New York State utilities in Case 18-M-0013 ("COR Audit").[15] Specifically, the COR Audit focuses on determining whether an error in income tax accounting occurred with respect to cost of removal ("COR") as alleged and whether Orange and Rockland ratepayers received the benefit of the lower income tax expenses in rates as a result of the claimed errors. The COR Audit is currently being performed by an independent auditor selected by the Commission on April 23, 2018.[16] The Signatory Parties agree that the final, non-appealable Commission-ordered findings in the COR Audit are binding on the instant proceedings (*i.e*., any Commission-ordered adjustment to the amounts related to the alleged COR error embedded in the Company's cost of service forecast (income tax expense and excess deferred federal income tax liability balances) in the instant rate filings will be reconciled (*i.e*., refunded to or collected from customers) to any Commission-ordered findings in Case 18-M-0013). The Signatory Parties reserve all of their administrative and judicial rights to take and pursue their respective positions with respect to all issues, rulings and decisions in Case 18-M-0013.

6. Allocation of Common Expenses/Plant

During the term of the Rate Plans and thereafter until revised by the Commission, common expenses and common plant will be allocated according to the following percentages: 66.93% electric operations and 33.07% gas operations. Should the Commission approve different common allocation percentages for electric and/or gas

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

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

service prior to the next base rate case for the electric and/or gas businesses, the resulting annual revenue requirement impacts will be deferred for future recovery from or credit to customers.

E. Revenue Allocation/Rate Design and Other Tariff Changes

1. Electric

The revenue allocation and rate design changes being made as part of this Proposal are set forth in Appendix 17.

a. Embedded Cost of Service ("ECOS") Study

In its next electric rate case, the Company will provide, for illustrative purposes, an alternative ECOS study that excludes T&D components from customer-related costs (*i.e.*, the ECOS study does not make use of the minimum system methodology and poles (FERC Account 364), conductors (FERC Accounts 365, 366, 367) and transformers (FERC Account 368) are classified as entirely demand-related). Following its next electric rate filing, the Company will conduct, for interested parties, a post-filing walk-through of the ECOS study and rate design underlying the proposed electric base delivery rates. Additionally, the Company will provide and review at the walk-through, an explanation of the differences in the ECOS studies filed pursuant to this Proposal, a more detailed explanation of the purpose of each file and cross-references of the underlying data sources, a table of acronyms used, a table of contents, and an index of files.

The Company will study the cost basis for seasonal differentials in its electric tariff. The study is to be completed within one year of the Commission Order adopting the Proposal and circulated to all parties in the case. The Company will schedule a meeting with parties within 60 days of completing the study to discuss the results.

b. Tariff Changes

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

- The Competitive Metering Charges in SC Nos. 2, 3, 9, 20, 21, and 22, and all references to the existing Customer Meter Ownership and Competitive Metering Services provisions in the tariff will be removed. Additionally, the Company will cancel Addendum-MET as part of the RY1 compliance filing made in this case.

- General Information Section Nos. 15 and 16 will contain all supply and delivery-related surcharges.

- The Merchant Function Charge will be labeled as a commodity rate and charge in the tariff (including being a commodity charge for tax-related purposes).

- Standby Service rates will be included in individual service classifications and the Standby Service provisions will be moved to the general information section of the tariff.

- The reconciliation of credit and collections costs and revenues associated with retail access customers whose energy service companies participate in the Company's purchase of receivables program will be amended as described in Appendix 17.

- The ECA will be amended to include provisions for recovery of the following items described in Appendix 9: (1) the Revenue Adjustment Mechanism; (2) the Late Payment Charge reconciliation; and (3) the Covid Uncollectible Expenses Variance. Additional details on these items can also be found in Appendix 17.

- The MSC will be revised to state that the capacity obligation for a customer subject to Mandatory Day Ahead Hourly Pricing cannot be less than zero.

- Updated the Recharge New York bill credit to \$0.00041 per kWh.

- The Company's Economic Development rate under Rider H will be extended for an additional five years.

- New LED options will be added to SC No. 16 and obsolete luminaires will be removed from SC Nos. 4 and 16. Additionally, the wattage ranges on existing LED luminaires will be revised.

- Housekeeping changes will be made to various other provisions of the electric tariff, including the elimination of obsolete provisions as detailed in the direct testimony of the Company Electric Rate Panel.

2. Gas

The revenue allocation and rate design changes being made as part of this Proposal are set forth in Appendix 18.

a. ECOS Study

In its next gas rate case, the Company will provide for illustrative purposes, an alternative ECOS study that excludes T&D components from customer-related costs (*i.e.*, the ECOS study classifies mains (FERC Account 376) as entirely demand-related).

Following its next gas rate filing, the Company will conduct, for interested parties, a walk-through of the ECOS study and rate design underlying the proposed gas base delivery rates. Additionally, the Company will provide and review at the walk-through, an explanation of the differences in the ECOS studies filed pursuant to this Proposal, a more detailed explanation of the purpose of each file and cross-references of the underlying data sources, a table of acronyms used, a table of contents, and an index of files.

b. Marginal Cost Study

The marginal cost study, originally submitted by the Company, forms the basis for the Excelsior Jobs Program ("EJP") discounts shown below, which will be applicable to customers commencing service on the EJP on or after January 1, 2022:

SC Nos. 2 and 6 – RS IB and II	- 47.8 %

c. Interruptible Transportation Rates

SC No. 8 rates will continue to consist of a block rate design and a minimum monthly charge. The minimum monthly charge for 100 Ccf will be set at $131.00 in RY1 and $132.00 in RY2. The monthly minimum charge will then remain at $132.00 until base rates are reset. A Base Charge will continue to be used to determine the block rates for usage greater than 100 Ccf. The Base Charge will be determined each month and shall not exceed 26.8 cents per Ccf during RY1, 27.0 cents per Ccf during RY2, and 27.5 cents per Ccf during RY3 and thereafter until such time as the Commission resets the Company's gas base rates.

d. Tariff Changes

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

- The SBC and RDM provisions will be moved under one general information section.
- The Merchant Function Charge will be labeled as a commodity rate and charge in the tariff (including being a commodity charge for tax-related purposes).
- The reconciliation of credit and collections costs and revenues associated with retail access customers whose energy service companies participate in the Company's purchase of receivables program will be amended as described in Appendix 18.
- The MGA will be amended to include provisions for recovery of the following items described in Appendix 9: (1) the NPA Adjustment Mechanism; (2) the Late Payment Charge reconciliation; and (3) the Covid Uncollectible Expenses Variance. Additional details on these items can also be found in Appendix 18.
- SC No. 5 will be closed, and all language related to the provisions of this SC have been removed from the tariff.

- The definition of the weather normalization adjustment normal heating degree days will be reset to be 4,945 heating degree days, the average for the 30 calendar years ended December 31, 2019.
- The weather normalization adjustment will be added to the Rates – Monthly section of the applicable service classifications.
- The allowance for residential heating customers will be modified from the current entitlement of 200 feet of main and service (in any combination) to 100 feet of main and 100 feet of service and appurtenant facilities.
- Housekeeping changes will be made to various other provisions of the gas tariff, including the elimination of obsolete provisions and changes meant to simplify tariff administration as detailed in the direct testimony of the Company Gas Rate Panel.

F. Performance Metrics

Performance metrics designed to measure various activities that are applicable to the Company's Electric, Gas and Customer Service Operations, and assess negative and/or positive revenue adjustments where performance targets are not met or are exceeded, are set forth in Appendices 13, 14, and 15. Any negative or positive revenue adjustments incurred by the Company during the Rate Plans relating to the performance metrics will be recovered from or credited to customers through the ECA/MGA over a 12-month period commencing June 1. Any negative or positive revenue adjustments are subject to Staff audit and full reconciliation, even after monies have been recovered from or credited to customers through the ECA/MGA. Any such surcharge or credit will be applicable to customers who are subject to the ECA and MGA on a common cents per kWh or cents per Ccf basis, respectively. The Company will perform an annual reconciliation of these revenue adjustments.

G. Additional Gas and Electric Programs

1. REV Demonstration Project Costs

The Company will continue to manage REV Demonstration Projects during the Rate Plans. Costs are to be reconciled in accordance with Appendix 9. The Company acknowledges that the inclusion of a proposed individual demonstration project under this mechanism does not imply endorsement by Staff, nor whether Staff will approve this project under the established REV Demonstration Proposal process.

2. Pomona NWA

The Company's annual operation and maintenance costs include funding for the continued operation and maintenance of the Pomona battery, which is a valuable component of the overall Pomona NWA Program. These costs include battery vendor services, maintenance on a dedicated fire hydrant and water line at the battery site and communication network fees. Costs are to be reconciled in accordance with Appendix 9.

3. Managed Charging Program

The Company agrees to continue to develop and pursue a managed charging program for review in Case 18-E-0138 to encourage EV operations to charge vehicles during off-peak times to maintain system reliability.

4. AMI-Enabled Natural Gas Detectors ("NGDs")

The Company agrees to install approximately 15,400 AMI-enabled NGDs over the term of the Gas Rate Plan. Orange and Rockland will file with the Secretary an annual report no later than 90 days following the close of each Rate Year. The annual report shall include, at a minimum:

(1) number of AMI NGDs installed in the subject Rate Year;

(2) total number of AMI NGDs installed to date;

(3) costs for installations in the subject Rate Year;

(4) costs for installations to date;

(5) alarms received by the control center in the subject Rate Year; and

(6) actions taken by Orange and Rockland in response to each of the alarms received.

5. Review Gas Interruptible Rates

During the term of the Gas Rate Plan, the Company will examine the current interruptible discount and recommend an adjustment in its next gas base rate case filing, if the Company's analysis supports it.

6. Non-Pipes Alternatives

The Company has completed an initial feasibility review of a portion of the Farm Tap customers to see if and how they could be converted. Orange and Rockland will explore NPAs for these projects, and others including leak prone pipe ("LPP"), to minimize or avoid the replacement of gas infrastructure. As explained in Appendix 14, LPP removed from service with an NPA will count toward the removal target for the Company's annual and cumulative LPP targets.

The Company will continue its ongoing efforts to evaluate the NPA Framework filed by Con Edison in Case 19-G-0066, and will implement aspects of that framework, including lessons learned from the Farm Tap NPA effort, above, to the extent they are applicable to Orange and Rockland. The Company will pursue and report upon NPAs in accordance with requirements established under the Gas Planning Proceeding (Case 20-G-0131). In the event that the Commission has not established the framework and reporting requirements associated with NPAs in the Gas Planning Proceeding by the end of RY1, the Company will file a petition with the Commission seeking approval for a proposed NPA Framework within 45 days after the end of RY1. This NPA Framework filing will include, but not be limited to, proposed suitability criteria, timing, cost thresholds and a reporting schedule, which will be used to identify a capital project for NPA consideration, resource requirements and recovery mechanisms.

7. Renewable Gas Standards

To the extent that the Commission does not provide clear guidance on the treatment of RNG in its Gas Planning Proceeding Order (Case 20-G-0131), the Company agrees to submit an RNG Plan that would explore what specifically would be required to bring those sources of energy to O&R customers. If necessary, the Company should file this RNG Plan with the Secretary, within six months of the Commission decision in this rate proceeding or Gas Planning Proceeding Order (Case 20-G-0131), whichever comes first.

8. Pipeline Emergency Responders Initiative ("PERI")

The Company will adopt the principles, as applicable, of the Pipeline Emergency Responders Initiative ("PERI"). On an annual basis, Orange and Rockland will document its outreach to each fire department and other applicable agencies in its service territory for joint drills and/or operational exercises. Costs are to be reconciled in accordance with Appendix 9.

Orange and Rockland will file with the Secretary an annual report no later than 90 days following the close of each Rate Year. The annual report shall include, at a minimum:

(1) date, location, and times of drills and/or operational exercises;

(2) outreach documentation;

(3) number of persons per agency in attendance;

(4) what topics were reviewed; and

(5) any applicable recommendations for improvements.

9. Millennium Back-Feed Project

The Company agrees to accelerate efforts to reach agreement with Millennium Pipeline in order to complete the Millennium Back-Feed Project. The Company agrees to provide Staff with periodic updates on the status of this project at the regular quarterly meetings between Staff and the Company.

10. Relocating Inside Meters

Orange and Rockland will relocate gas meters outside when performing replacements (either by insertion or direct bury), new service installations, and where such work may feasibly be performed. Customers that do not consent to the relocation of their meters outside shall sign an acknowledgement form and shall be subject to charges for future inspection costs. Orange and Rockland will commence documenting (*e.g.*, through inside service line inspections) the difficulty, limitations, and/or costs associated with relocating its remaining inside meters to outside locations. The Company will propose an outside meter program, during its next rate proceeding, to address those inside meters that are more difficult, subject to limitations, and/or cost prohibitive to relocate.

11. Certified Gas

The Company is authorized to contract for and purchase certified gas under a pilot program, subject to the following conditions:

- Starting May 31, 2023, the Company will file an annual report containing the following minimum information:
    - calculated greenhouse gas (“GHG”) emissions savings over traditional procurement process,
    - additional cost to customers,
    - cost savings to customers (if GHG emissions penalties would have been assessed),
    - certification reports by 3rd party provider(s), including items evaluated under the certification,
    - volume,
    - reliability issues as a result of added equipment/processes by the producers, and
    - recommended changes/lessons learned to be considered in the future.
- Maximum annual additional commodity cost to customers may not exceed $100,000 for Orange and Rockland’s share of the joint portfolio with Con Edison.
- The pilot program may start as early as the winter of 2022-2023 and be in place for the duration of this Gas Rate Plan.
- Following the filing of the annual report, the Company will meet with Staff each June to discuss its plan to either continue or terminate the pilot program, based on the data, and make a filing with the Commission if seeking any modifications to the pilot.

12. Little Tor Substation

At the time of this Joint Proposal, the schedule to build Little Tor Substation has not been confirmed and so funding to develop the project is not included in the electric revenue requirement. Notwithstanding the Commission’s adoption of this settlement, the Company may file a petition with the Commission seeking recovery of Little Tor Substation costs via surcharge during the Electric Rate Plan.

13. Refrigerant Management Initiative

During RY1, the Company will evaluate whether a refrigerant management initiative should be incorporated as part of its energy efficiency program. The Company will assess the suitability, potential costs and greenhouse gas emission reductions associated with such an initiative. The Company evaluation will include a benefit-cost analysis under the existing Commission-approved framework. Subject to the results of its evaluation, the Company will seek to integrate the refrigerant management initiative into its energy efficiency program during RY2.

14. Customer-Owned Street Lights

Installation of NLC Nodes for Municipally Owned Street Lights

1. The Company will establish and provide the technical requirements that municipalities must meet to install networked lighting control (NLC) nodes. The technical specifications will allow customers to install and use the NLC Nodes for improved operational efficiency and other applications, but not for billing purposes.

a. The Company must perform an engineering/technical review for all make and model NLC nodes prior to installation. Company will provide customers with progress updates on the review no less than every forty-five (45) days. Once the Company has completed its review of a specific manufacturer's make and model, an engineering/technical review will not be required for that specific NLC node for installations going forward. Company will maintain a list of approved NLC nodes to be shared with customers upon request.

2. The Company will make any required tariff changes to allow for the installation and operation of the NLC nodes within 90 days of a Commission Order adopting this Joint Proposal.

Next Steps for Customer-Owned Street Light Dimming Pilot from Case No. 18-E-0067

1. As described in the Joint Proposal in Case No. 18-E-0067, after obtaining six months of data, the Company will hold a collaborative with interested parties to discuss the results of the pilot. Items to be discussed include but are not limited to: (1) the metering accuracy of the NLC nodes based on a comparison of usage measured by the NLC nodes and usage measured by the Company's revenue grade meters; and (2) methodologies that may be used to account for the reduced usage associated with dimming of municipal-owned streetlights on a SC No. 6 customer's bill. If the evidence warrants, the Parties may pursue a methodology to account for the reduced usage associated with dimming street lights that could take effect during the Rate Plan.

H. Customer Service

1. Outreach and Education

Orange and Rockland will continue to develop and implement outreach and education activities, programs and materials that will aid its customers in understanding their rights and responsibilities as utility customers, as well as provide important safety information. Annually, on April 1 of each calendar year, the Company will file in Case 17-M-0475, an outreach and education plan with the Secretary, along with a summary and assessment of its customer education efforts in the previous year. The annual plan shall include: the goals of the outreach and education program, detailed budgets, the specific outreach campaign messages to be disseminated, the communication vehicles to be used to disseminate them, and the criteria for measuring the program's achievement.

The Company will continue to provide bill messages, email messages and outbound calls to customers in arrears advising them of availability of payment agreements through 2022. The Company will commit to provide through 2022 the same payment agreement terms that have been/are available through the end of 2021 (standard payment agreements have twelve- to twenty-four month terms). Additionally, the Company will continue to allow customers to develop their own payment agreements (within certain parameters) when setting up payment agreements on ORU.com.

2. Same-Day Electric Service Reconnections

a. Weekday Same-Day Reconnections

The Company will exercise reasonable efforts, within the Company's existing staffing levels and budgets, in attempting 100% same-day electric service reconnection for residential electric customers whose service was disconnected for non-payment at the meter and who become eligible for reconnection (*e.g.*, by making payment) by 5:00 p.m. Monday-Friday, excluding Company holidays. This process does not include customers whose meter was removed or service was cut in the street.

b. New Service Connections

The Company will be set up to be able to query the length of time it takes to establish new service connections with remote Advanced Metering Infrastructure ("AMI") capabilities in relation to customer requested start dates. The queried data will be requested as part of Staff's annual service quality metrics audit.

c. Reporting

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

3. Recording Calls

The Company will, to the extent practicable, record outbound and inbound collection calls to and from the Company's call centers. The Company will retain records of such calls for 24 months, after which the Company may delete such records.

4. Voluntary Protections During Periods of Extreme Cold and Heat

The Company will implement the following excessive cold weather protections and excessive heat protections.[17]

a. Cold Weather Protections

The Company commits to the following additional protections for residential customers during the period of November 1 through April 15 ("Cold Weather Period").

[17] Weather information that will trigger these protections, including heat index, heat advisory, temperature and the heat index chart will all be as available on the weather.gov website. Weather information for O&R's Eastern Division will be based on conditions in West Nyack, NY. Weather information for O&R's Northern Division will be based on conditions in Middletown, NY.

i. The Company will accept all regular and/or emergency Home Energy Assistance Program ("HEAP") payments and restore service when necessary upon receipt or guarantee of such a payment. This excludes "Heat Included" benefits for households that pay for heat as a portion of their rental cost as explained in the New York State Office of Temporary and Disability Assistance HEAP Program information outline.

ii. The Company will consider a Regular and Emergency HEAP payment as entitling the applicant to a fair and reasonable payment agreement regardless of any previous payment agreement defaults. The Company will refrain from scheduling residential service terminations on days when the local weather forecast predicts below-freezing temperatures (*i.e.*, 32 degrees Fahrenheit or less).

iii. The Company will establish a voluntary moratorium on winter terminations for customers who are elderly, blind or disabled.

b. Excessive Heat Protections

The Company will suspend residential service terminations during a heat advisory. A heat advisory is in place when the heat index is forecasted at 95 degrees Fahrenheit or more for two or more consecutive days and/or when the heat index is forecasted at 100 degrees Fahrenheit or more for one or more consecutive days.

5. Written Confirmation of Unsigned Payment Agreements

The Company will maintain as part of a customer's account file a record of collection arrangements entered into by oral agreement with the customer. The Company will instruct its call center representatives to offer to send a written summary of such collection arrangements to the customer by mail or email, upon the customer's request.

6. Digital Customer Experience ("DCX")

Beginning in RY1, the Company will file quarterly reports with the Secretary on the DCX program that details progress on the re-design of existing digital content and services, and implementation of new digital services/functionality. The Company and its affiliate Con Edison will make future DCX proposals in a manner that includes both companies' costs and benefits for consistency and transparency and address the timing concern of proposals in individual rate proceedings and the potential impact of such approvals on the other company.

7. Customer Relationship Management ("CRM") System

The Company plans to scope and implement initial CRM system during the Rate Plans. An annual status report on CRM implementation will be filed with the Secretary by September 30 of each year. The report will include actual spending for the project, the projected completion date of the project and any realized costs savings.

8. 2020 and 2021 Residential Termination/Uncollectible Metric

The Company will forego collection of the Positive Revenue Adjustments associated with the terminations and uncollectible metric authorized by the 2019 Rate Order for the Company's performance during 2020 and 2021. In light of the COVID-19 pandemic and Chapters 108 of the Laws of New York of 2020 and 106 of the Laws of New York of 2021, which amended Public Service Law § 32 and imposed moratoriums on termination of service for residential and eligible small business customers, the Company's existing termination and uncollectible metric shall be suspended for the term of the Rate Plans. Reconsideration of the pause on the Termination/Uncollectible metric to be addressed in the next rate proceedings.

9. Reconnection Fee Waiver (Electric)

The Company will waive the reconnection charge for electric customers with remote connect/disconnect capable meters whose service was shut off for non-payment or tampering-related reasons where the Company is able to complete the reconnection of electric service remotely.

I. Electric and Gas Low Income Assistance Programs

1. Monthly Bill Credit

Orange and Rockland's Energy Affordability Program will provide bill discounts to eligible customers consistent with the Commission's Order Adopting Energy Affordability Policy Modifications and Directing Utility Filings issued in Case 14-M-0565 (issued August 12, 2021). The bill discount credits are set forth in the electric and gas tariffs.[18] The level of funding provided for the bill discount credits, subject to symmetrical deferral, is projected to be $9,988,428 and $5,395,378 in 2022 for electric and gas credits, respectively, based on the current number of customers in each tier (and set forth in Appendices 6 and 7).

Income Level	Electric Heating	Electric Non-Heat	Gas Heating	Gas Non-Heat
Tier 1	$48.06	$48.06	$14.84	$3
Tier 2	$57.16	$57.16	$36.64	$3
Tier 3	$76	$76	$53.32	$3
Tier 4	$64.89	$64.89	$44.38	$3

[18] Bill discount credits may change based on the annual Low Income Plan the Company is required to file with analysis of customer bills.

2. Reconnection Fee Waiver

During the term of the Rate Plans, the Company will continue its policy of waiving its reconnection fee for any Orange and Rockland electric and/or gas customer who is enrolled in the Company's Low Income Program, according to the terms set forth in the Company's electric and gas tariffs.

3. Reporting Requirements

The Company will file quarterly Low Income reports as directed by the Commission in the Low Income Order.

J. Earnings Adjustment Mechanisms ("EAMs")

Incentives associated with Electric EAMs will continue to be recovered through the EAM Surcharge component of the Company's ECA Mechanism.

Recovery will be over a 12-month period commencing July 1. Recovery will be on a kWh basis for non-demand customers and on a kW basis for demand customers (on a kW of contract demand basis for standby customers), with rates determined for the following service classification groups:

Group 1: SC Nos. 1 and 19;

Group 2: SC No. 2 Secondary Non-Demand Billed;

Group 3: SC Nos. 2 Secondary and 20;

Group 4: SC Nos. 2 Primary, 3, and 21;

Group 5: SC Nos. 9 and 22; and

Group 6: SC Nos. 4, 5, 6, and 16.

Such collection will be based on the aggregate results of the following allocation methodologies divided by either forecast kWh or kW over the respective recovery period:

- Peak Reduction Metric and Circuit Load Factor Metric will be allocated using the transmission demand allocator (D01);
- Electric Energy Efficiency (Share the Savings) Metric and Cross Commodity Gas/Electric LMI Customer Savings (Electric portion), and Environmentally Beneficial Electrification Metrics (EV Make Ready Share the Savings DC Fast Charger Installations, EV Make Ready Share the Savings Level 2 Installations, EV Adoption and Heat Pump Carbon Reduction) will be allocated using the energy allocator (E01); and
- DER Utilization Metrics (Solar PV and Storage) will be allocated using the following three allocators that will be equally weighted: coincident peak (D01), non-coincident peak (D02), and energy allocator (E01).

These rates will be applied to the energy (kWh) or demand (kW) deliveries, as applicable, on the bills of all customers served under the above-mentioned SC groups.

Recoveries (eleven months actual, one month forecast) will be reconciled to allocable costs for each 12-month recovery period ending June 30, with any over or under recoveries included in the development of the succeeding EAM Surcharge component of the ECA. Reconciliation amounts related to the one month forecast will be included in the next subsequent rates determination.

Incentives associated with the Gas EAMs will continue to be recovered through the EAM Surcharge component of the Company’s MGA Mechanism. Recovery will be over a 12-month period commencing July 1. Recovery will be on a Ccf basis with a uniform factor developed, based on forecast Ccf over the respective recovery period, and applied to all deliveries on the bills of all customers served under SC Nos. 1, 2, and 6. Recoveries (eleven months actual, one month forecast) will be reconciled to allocable costs for each 12-month recovery period ending June 30, with any over or under recoveries included in the development of the succeeding EAM Surcharge component of the MGA. Reconciliation amounts related to the one-month forecast will be included in the next subsequent rates determination.

Orange and Rockland will adopt electric and gas EAMs as of January 1, 2022. Achievement of EAMs will be measured on December 31, 2022 and thereafter on a Rate Year basis over the term of the Rate Plans for all metrics except the Gas Peak Reduction Metric which will be measured from April 2022 through March 2023. There are eight EAM metrics for electric, two EAM metrics for gas and one cross-commodity (both electric and gas) EAM metric. All EAM targets and incentives are set forth in Appendix 16.

K. <u>Miscellaneous Provisions</u>

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

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

Nothing herein precludes Orange and Rockland from filing a new general electric rate case or a new general gas rate case prior to January 1, 2025, for rates to be effective on or after January 1, 2025.

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

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

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

c. The Signatory Parties recognize that the Commission reserves the authority to act on the level of Orange and Rockland's electric and/or gas rates in the event of unforeseen circumstances that, in the Commission's opinion, have such a substantial impact on the range of earnings levels or equity costs envisioned by these

Rate Plans as to render Orange and Rockland's electric and/or gas rates unreasonable or insufficient for the provision of safe and adequate service at just and reasonable rates.

d. Nothing herein will preclude any Signatory Party from petitioning the Commission for approval of new services, the implementation of new service classifications and/or cancellation of existing service classifications, or rate design or revenue allocation changes within or among service classes, which are not contrary to the agreed upon terms and conditions set forth herein. All changes will be implemented on a revenue neutral and earnings neutral basis.

e. The Signatory Parties reserve the right to support or oppose any filings made under this Section.

2. Legislative, Regulatory and Related Actions

a. If at any time the federal government, State of New York and/or other local governments make changes in their tax laws (other than local property taxes, which will be reconciled in accordance with Appendix 9 of this Proposal), that result in a change in the Company's costs[19] in an annual amount, calculated and applied separately for electric and gas, equating to ten basis points of return on common equity or more,[20] and if the Commission does not address the treatment (*e.g.*, through a surcharge or credit) of any such tax law changes, including any new, additional, repealed or reduced federal, State, local government taxes, fees or levies, Orange and Rockland will defer on its books

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

[20] For electric, such amounts are estimated to be $0.679 million in RY1, $0.694 million in RY2 and $0.761 million in RY3. For gas, such amounts are estimated to be $0.377 million in RY1, $0.405 million in RY2 and $0.433 million in RY3.

of account the full change in expense and reflect such deferral as credits or debits to customers in the next base rate change subject to any final Commission determination in a generic proceeding prescribing utility implementation of a specific tax enactment, including a Commission determination of any Company-specific compliance filing made in connection therewith.[21]

b. If at any time any other law, rule, regulation, order, or other requirement or interpretation (or any repeal or amendment of an existing rule, regulation, order or other requirement) of the federal, State, or local government or courts, results in a change in Orange and Rockland's annual electric or gas revenues, costs or expenses not anticipated in the forecasts and assumptions on which the rates in this Proposal are based in an annual amount, calculated and applied separately for electric and gas, equating to ten basis points of return on common equity or more,[22] Orange and Rockland will defer on its books of account the full change in expense, with any such deferrals to be reflected in the next base rate case or in a manner to be determined by the Commission.

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

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

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

3. Recognition of Policy Proceedings

a. The Signatory Parties recognize that the Commission conducts proceedings associated with statewide policy objectives that may impact the Company during the term of the Rate Plans (*e.g.*, the Energy Affordability Program (Case 14-M-0565), the Gas Planning Proceeding (Case 20-G-0131), the Value of DER proceeding (Case 15-E-0751), the REV proceeding (Case 14-M-0101), and energy efficiency proceedings (Cases 15-M-0252 and 18-M-0084)). This Proposal does not limit the Commission's ability to require the Company to implement changes or take certain actions pursuant to these or other policy proceedings during the term of the Rate Plans. The Signatory Parties reserve all of their administrative and judicial rights to take and pursue their respective positions with respect to all issues and Commission proposals and initiatives in these policy proceedings. In the event that Commission determinations in such proceedings cause the Company to incur incremental costs that are not otherwise addressed through cost-recovery mechanisms or a right to defer such costs for future recovery from customers, the Company will defer on its books of account the full change in expense as required by Section K.2.b.

b. Nothing herein will preclude any Signatory Party from (i) petitioning the Commission to extend, modify or establish programs relating to energy efficiency, demand response (including, but not limited to, direct load control) and demand management (including, but not limited to, targeted demand management), and (ii) filing for approval of programs in response to an order(s) or other issuances designed to further the New York State Energy Plan goals, CLCPA implementation[23] or the implementation of REV objectives and principles, including, but not limited to, the Distributed System Platform and demonstration projects; provided that any such petition or filing is not contrary to the agreed upon terms and conditions set forth in this Proposal. All changes will be implemented on a revenue neutral and earnings neutral basis.

4. Financial Protections

Annually, the Company will provide Staff with the five-year earnings forecast for Consolidated Edison Inc. ("CEI") and each direct subsidiary of CEI (*e.g.*, Consolidated Edison Company of New York, Inc., Orange and Rockland, Con Edison Transmission, Inc. and Con Edison Clean Energy Businesses, Inc.). The forecast will include the income statement, balance sheet and cash flow statements for CEI and each above-listed direct subsidiary of CEI. The Company will submit the forecast to Staff no later than 30 calendar days after it is reviewed by the Finance Committee of CEI's Board of Directors. The Company will update Staff when there are material changes to the five-year forecast.

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

[23] Notwithstanding the Commission's adoption of this settlement, the Company may make a tariff filing with the Commission providing for recovery of incremental CLCPA implementation costs via surcharge.

The five-year earnings forecast and actual financial statements will be provided to Staff by filing with the Records Access Officer pursuant to the Commission's trade secret process. The Company reserves the right to object to the use of such confidential information in other proceedings.

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

5. Trade Secret Protection

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

6. Provisions Not Separable

The Signatory Parties intend this Proposal to be a complete resolution of all the issues in Cases 21-E-0074 and 21-G-0073. It is understood that each provision of this Proposal is in consideration and support of all the other provisions, and expressly conditioned upon acceptance by the Commission. Except as set forth herein, none of the Signatory Parties is deemed to have approved, agreed to or consented to any principle, methodology or interpretation of law underlying or supposed to underlie any provision herein. If the Commission fails to adopt this Proposal according to its terms, then the Signatory Parties to this Proposal will be free to pursue their respective positions in this proceeding without prejudice.

7. Provisions Not Precedent

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

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

8. Submission of Proposal

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

9. Procedures in the Event of a Disagreement

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 Signatory Parties, such disagreement will be resolved as follows: the Signatory Parties promptly will confer and in good faith will attempt to resolve such disagreement. If any such disagreement cannot be resolved by the Signatory Parties within 15 business days from notification invoking this process, or a longer period if agreed to by the Signatory Parties, any Signatory Party may petition the Commission for a determination on the disputed matter.

10. Effect of Commission Adoption of Terms of this Proposal

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

11. 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.

12. Scope of Provisions

No term or provision of this Proposal that relates specifically to one but not both electric and gas service, limits any rights of the Company or any Signatory Party to petition the Commission for any purpose with respect to the service not specified in such term or provision.

13. Execution

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

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

ORANGE AND ROCKLAND
UTILITIES, INC.

Dated: October 29, 2021 By: John L. Carley
Associate General Counsel

NEW YORK STATE DEPARTMENT OF
PUBLIC SERVICE

Dated: October 29, 2021

By: Lindsey Overton Orietas
Lindsey Overton Orietas
Staff Counsel

NEW YORK POWER AUTHORITY

Dated: Oct 29, 2021

By: Sarah Salati (Oct 29, 2021 13:34 EDT)

Sarah Salati

NEW YORKERS FOR COOL
REFRIGERANT MANAGEMENT

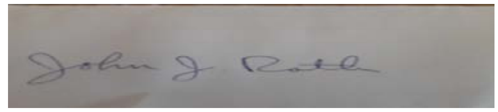
Dated: 10/28/2021

By: Tara Vamos

Tara Vamos
Policy Team Leader

NEW YORK GEOTHERMAL ENERGY ORGANIZATION

Dated: October 29, 2021

By: 

John Rath
Director of Operations

ORANGE AND ROCKLAND UTILITIES, INC.
Case 21-E-0074
Electric Revenue Requirement
For The Twelve Months Ending December 31, 2022
$ 000's

	Rate Year 1 Forecast	Rate Change	Rate Year 1 With Rate Change
Operating revenues			
Sales & deliveries to public	$ 450,883	$ 4,939	$ 455,822
Sales for resale	15,479		15,479
Other operating revenues	12,386	34	12,420
Total operating revenues	478,748	4,973	483,721
Operating expenses			
Purchased power	100,534		100,534
Load Dispatching	504		504
Operations & maintenance expense	173,024	25	173,049
Depreciation	62,001		62,001
Regulatory amortization	11,791		11,791
Taxes other than income taxes	55,572	84	55,656
Total operating expenses	403,426	109	403,535
Operating income before income taxes	75,322	4,864	80,186
New York State income taxes	3,287	353	3,640
Federal income taxes	6,501	947	7,448
Utility operating income	$ 65,535	$ 3,564	$ 69,099
Rate Base	$ 1,021,008		$ 1,021,008
Rate of Return	6.42%		6.77%

ORANGE AND ROCKLAND UTILITIES, INC.
Case 21-E-0074
Electric Revenue Requirement
For The Twelve Months Ending December 31, 2022 and December 31, 2023
$ 000's

Operating revenues	Rate Year 1 With Rate Change	Rate Year 2 Revenue/Expense Rate Base Changes	Rate Change	Rate Year 2 With Rate Change
Sales & deliveries to public	$ 455,822	$ (2,021)	$ 16,158	$ 469,959
Sales for resale	15,479	549	-	16,028
Other operating revenues	12,420	356	111	12,888
Total operating revenues	483,721	(1,116)	16,269	498,875
Operating expenses				
Purchased power	100,534	(961)	-	99,573
Load Dispatching	504	10	-	514
Operations & maintenance expense	173,049	6,968	81	180,098
Depreciation	62,001	3,848	-	65,848
Regulatory amortization	11,791	1,736	-	13,527
Taxes other than income taxes	55,656	1,668	276	57,600
Total operating expenses	403,535	13,268	357	417,160
Operating income before income taxes	80,186	(14,384)	15,912	81,715
New York State income taxes	3,640	(1,144)	1,154	3,650
Federal income taxes	7,448	(2,736)	3,099	7,811
Utility operating income	$ 69,099	$ (10,504)	$ 11,659	$ 70,254
Rate Base	$ 1,021,008	$ 22,625		$ 1,043,633
Rate of Return	6.77%			6.73%

ORANGE AND ROCKLAND UTILITIES, INC.
Case 21-E-0074
Electric Revenue Requirement
For The Twelve Months Ending December 31, 2023 and December 31, 2024
$ 000's

Operating revenues	Rate Year 2 With Rate Change	Rate Year 3 Revenue/Expense Rate Base Changes	Rate Change	Rate Year 3 With Rate Change
Sales & deliveries to public	$ 469,959	$ (4,826)	$ 23,129	$ 488,262
Sales for resale	16,028	64	-	16,092
Other operating revenues	12,888	353	160	13,401
Total operating revenues	498,875	(4,409)	23,289	517,755
Operating expenses				
Purchased power	99,573	(5,407)	-	94,166
Load Dispatching	514	10		524
Operations & maintenance expense	180,098	2,543	116	182,756
Depreciation	65,848	9,121	-	74,969
Regulatory amortization	13,527	1,657	-	15,184
Taxes other than income taxes	57,600	1,805	395	59,800
Total operating expenses	417,160	9,729	511	427,399
Operating income before income taxes	81,714	(14,137)	22,778	90,356
New York State income taxes	3,650	(1,266)	1,651	4,034
Federal income taxes	7,811	(2,824)	4,437	9,424
Utility operating income	$ 70,254	$ (10,047)	$ 16,690	$ 76,897
Rate Base	$ 1,043,633	$ 100,414		$ 1,144,047
Rate of Return	6.73%			6.72%

ORANGE AND ROCKLAND UTILITIES, INC.
Case 21-E-0074
Electric Other Operating Revenues
For The Twelve Months Ending December 31, 2022, December 31, 2023, and December 31, 2024
$ 000's

	Rate Year 1	Rate Year 2 Changes	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Miscellaneous Service & Other Revenues					
AMI/AMR Meter Reading/Change Out Fees	$ 145	$ -	$ 145	$ -	$ 145
Customer Reconnect Fees	23	-	23	-	23
Late Payment Charges	1,450	97	1,547	126	1,673
POR Discount	979	-	979	-	979
Shared Meter Assessment	-	-	-	-	-
Agency Checks Dishonored	1	-	1	-	1
Acceller Inc.	-	-	-	-	-
Bad Check Charge	77	-	77	-	77
Collection Charges	61	-	61	-	61
NYSERDA	2	-	2	-	2
Solar Application Fee	91	-	91	-	91
Other	2	-	2	-	2
Total Miscellaneous Service & Other Revenues	2,830	97	2,928	126	3,054
Rents					
Joint Operating Rents	6,388	319	6,707	335	7,042
Pole Attachment and Parity Billings	2,600	51	2,651	51	2,702
Other Rents	602	-	602	-	602
Total Rents	9,590	370	9,960	387	10,347
Total Other Operating Revenue	$ 12,420	$ 467	$ 12,888	$ 513	$ 13,401

ORANGE AND ROCKLAND UTILITIES, INC.
Case 21-E-0074
Electric Operations & Maintenance Expenses
For The Twelve Months Ending December 31, 2022, December 31, 2023, and December 31, 2024
$ 000's

	Rate Year 1	Rate Year 2 Changes	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Fuel and Purchased Power	$ 100,534	$ (961)	$ 99,573	$ (5,407)	$ 94,167
A & G Health Insurance and Capital Overhead	(968)	(29)	(997)	(35)	(1,032)
Bond Administration & Bank Fees	333	6	340	7	346
Company Labor	62,703	2,459	65,162	2,767	67,929
Customer Billing Postage	1,317	25	1,342	26	1,368
Employee Welfare Expense	9,338	424	9,761	606	10,367
Executive Variable Pay	-	-	-	-	-
Facilities	1,376	26	1,402	27	1,429
Information Technology	5,762	923	6,685	585	7,270
Informational Advertising	319	6	325	6	331
Injuries & Damages/ Workers Compensation	228	(3)	225	18	243
Institutional Dues & Subscription	31	1	32	1	33
Insurance Premium	923	18	941	18	959
Intercompany Shared Services	14,375	(47)	14,327	154	14,481
Legal and Other Professional Services	425	8	433	8	441
Load Dispatching	504	10	513	10	523
Ops - Corporate & Shared Services	6,716	223	6,939	166	7,104
Ops - Customer Operations	5,340	556	5,897	233	6,129
Ops - Electric Operations	24,325	1,840	26,165	695	26,860
Ops - Engineering	1,529	684	2,213	47	2,259
Ops - Substation Operations	1,809	45	1,853	45	1,899
Other Compensation	325	1	326	0	327
Pension and OPEB Costs	2,481	-	2,481	-	2,481
Site Investigation & Remediation	1,442	816	2,258	177	2,435
Regulatory Commission Expense - General and R&D	2,230	43	2,273	44	2,316
Renewable Portfolio Charges	7,099	(153)	6,946	(495)	6,451
Rent	2,336	53	2,389	43	2,432
Research and Development	678	13	691	13	704
Storm Allowance	8,000	154	8,154	157	8,310
System Benefit Charge	13,274	(285)	12,989	(927)	12,062
Uncollectible Reserve - Customer	2,256	70	2,326	92	2,418
Uncollectible Reserve - Sundry	770	-	770	-	770
Worker's Comp NYS Assessment	142	3	144	3	147
Bargaining Unit Contract Cost	70	-	70	-	70
Environmental Affairs	188	-	188	-	188
External Audit Services	419	8	427	8	435
Finance & Accounting Operations	7	0	7	0	7
Other O&M	55	3	58	(1)	57
Business Cost Optimization	(2,964)	(1,230)	(4,194)	(1,857)	(6,051)
Company Labor - Fringe Benefit Adjustment	39	81	119	66	186
Company Labor - Productivity	(1,676)	308	(1,368)	(37)	(1,405)
Total O&M Expenses	$ 274,087	$ 6,098	$ 280,185	$ (2,739)	$ 277,446

ORANGE AND ROCKLAND UTILITIES, INC.
Case 21-E-0074
Electric Taxes Other Than Income Taxes
For The Twelve Months Ending December 31, 2022, December 31, 2023, and December 31, 2024
$ 000's

	Rate Year 1	Rate Year 2 Changes	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Property Taxes					
State, County & Town	$13,489	$641	$14,130	$301	$14,431
Village	2,081	42	2,123	40	2,163
School	27,737	797	28,534	1,321	29,855
Total Property Taxes	43,307	1,480	44,787	1,662	46,449
Payroll Taxes	4,491	251	4,742	248	4,990
Revenue Taxes	7,810	211	8,021	291	8,312
Other Taxes					
Sale & Use Tax	3	-	3	-	3
Other Taxes	46	1	47	-	47
Total Other Taxes	49	1	50	-	50
Total Taxes Other Than Income Taxes	$ 55,657	$ 1,943	$ 57,600	$ 2,201	$ 59,801

ORANGE AND ROCKLAND UTILITIES, INC.
Case 21-E-0074
Electric New York State Income Taxes
For The Twelve Months Ending December 31, 2022, December 31, 2023, and December 31, 2024
$ 000's

	Rate Year 1	Rate Year 2 Changes	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Operating Income Before Income Taxes	$80,186	$ 1,529	$81,715	$ 8,641	$90,356
Interest Expense	(25,873)	(1,406)	(27,279)	(1,679)	(28,958)
Book Income Before State Income Taxes	54,313	123	54,436	6,962	61,398
Tax Computation					
Current State Income Taxes	905	17	922	(645)	277
Deferred State Income Taxes	2,735	(8)	2,727	1,030	3,757
NYS Income Tax Expense	$ 3,640	$ 9	$ 3,649	$ 385	$ 4,034

ORANGE AND ROCKLAND UTILITIES, INC.
Case 21-E-0074
Electric Federal Income Taxes
For The Twelve Months Ending December 31, 2022, December 31, 2023, and December 31, 2024
$ 000's

	Rate Year 1	Rate Year 2 Changes	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Operating Income Before Income Taxes	$80,186	$ 1,529	$81,715	$ 8,641	$90,356
Interest Expense	(25,873)	(1,406)	(27,279)	(1,679)	(28,958)
Book Income Before Income Taxes	54,313	123	54,436	6,962	61,398
Tax Computation					
Current Federal Income Taxes	6,342	(252)	6,090	(1,900)	4,190
Deferred Federal Income Taxes	5,740	390	6,130	3,465	9,595
Excess Deferred Federal Income Tax - Property	(5,913)	226	(5,687)	47	(5,640)
Excess Deferred Federal Income Tax - Non-Property	1,614	-	1,614	-	1,614
R&D Tax Credit	(335)	-	(335)	-	(335)
Federal Income Tax Expense	$ 7,448	$ 364	$ 7,812	$ 1,612	$ 9,424

Orange and Rockland Utilities, Inc.
Rate Case 21-E-0074
Average Electric Rate Base
For Twelve Months Ending December 31, 2022 and December 31, 2023
($000's)

	Rate Year 1	Rate Year 2 Changes	Rate Year 2
Utility Plant			
Electric Plant In Service	$ 1,630,834	$ 56,668	$ 1,687,502
Electric Plant Held For Future Use	8,102	-	$ 8,102
Common Utility Plant (Electric Allocation)	229,440	22,468	$ 251,908
Total	1,868,376	79,136	1,947,512
Utility Plant Reserves:			
Accumulated Reserve for Depreciation - Plant in Service	(575,894)	(45,468)	(621,362)
Accumulated Reserve for Depreciation - Common Plant (Electric Allocation)	(117,866)	(10,596)	(128,462)
Total	(693,760)	(56,064)	(749,824)
Net Plant	1,174,616	23,072	1,197,688
Non-Interest Bearing CWIP	45,122	1,411	46,533
Working Capital - Materials/Supplies, Prepayment and Cash Working Capital	58,301	1,698	59,999
Unamortized Premium & Discount	5,898	132	6,030
Customer Advance Construction	(13,251)	-	(13,251)
Net Deferrals / Credits from Reconciliation Mechanisms	65,839	655	66,495
Accumulated Deferred Income Taxes			
Accumulated Deferred Federal Income Taxes	(205,640)	(1,705)	(207,345)
Accumulated Deferred State Income Taxes	(41,761)	(2,687)	(44,447)
Total	(247,401)	(4,391)	(251,792)
Average Rate Base	1,089,125	22,576	1,111,702
Earnings Base Capitalization Adjustment to Rate Base	(66,434)	-	(66,434)
Isaias Storm Settlement Forecast Earning	(1,683)	49	(1,634)
Total Average Rate Base	$ 1,021,008	$ 22,625	$ 1,043,633

Orange and Rockland Utilities, Inc.
Rate Case 21-E-0074
Average Electric Rate Base
For Twelve Months Ending December 31, 2023 and December 31, 2024
($000's)

	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Utility Plant			
Electric Plant In Service	$ 1,687,502	$ 140,659	$ 1,828,161
Electric Plant Held For Future Use	8,102	-	8,102
Common Utility Plant (Electric Allocation)	251,908	23,485	275,392
Total	1,947,512	164,144	2,111,656
Utility Plant Reserves:			
Accumulated Reserve for Depreciation - Plant in Service	(621,362)	(48,299)	(669,662)
Accumulated Reserve for Depreciation - Common Plant (Electric Allocation)	(128,462)	(9,768)	(138,230)
Total	(749,824)	(58,067)	(807,891)
Net Plant	1,197,688	106,076	1,303,764
Non-Interest Bearing CWIP	46,533	(1,657)	44,876
Working Capital - Materials/Supplies, Prepayment and Cash Working Capital	59,999	935	60,934
Unamortized Premium & Discount	6,030	(30)	6,000
Customer Advance Construction	(13,251)	-	(13,251)
Net Deferrals / Credits from Reconciliation Mechanisms	66,495	1,910	68,405
Accumulated Deferred Income Taxes			
Accumulated Deferred Federal Income Taxes	(207,345)	(3,675)	(211,020)
Accumulated Deferred State Income Taxes	(44,447)	(3,196)	(47,643)
Total	(251,792)	(6,871)	(258,664)
Average Rate Base	1,111,702	100,364	1,212,065
Earnings Base Capitalization Adjustment to Rate Base	(66,434)	-	(66,434)
Isaias Storm Settlement Forecast Earning	(1,634)	50	(1,584)
Total Average Rate Base	$ 1,043,633	$ 100,414	$ 1,144,047

Orange and Rockland Utilities, Inc.
Case 21-E-0074
Average Capital Structure & Cost of Money
For the Twelve Months Ending December 31, 2022, December 31, 2023 and December 31, 2024

RY 1

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre Tax Cost %
Long term debt	51.34%	4.58%	2.35%	2.35%
Customer deposits	0.66%	0.05%	0.00%	0.00%
Subtotal	52.00%		2.35%	2.35%
Common Equity	48.00%	9.20%	4.42%	6.03%
Total	100.00%		6.77%	8.38%

RY 2

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre Tax Cost %
Long term debt	51.34%	4.51%	2.32%	2.32%
Customer deposits	0.66%	0.05%	0.00%	0.00%
Subtotal	52.00%		2.32%	2.32%
Common Equity	48.00%	9.20%	4.42%	6.03%
Total	100.00%		6.73%	8.34%

RY 3

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre Tax Cost %
Long term debt	51.34%	4.49%	2.31%	2.31%
Customer deposits	0.66%	0.05%	0.00%	0.00%
Subtotal	52.00%		2.31%	2.31%
Common Equity	48.00%	9.20%	4.42%	6.03%
Total	100.00%		6.72%	8.33%

Orange and Rockland Utilities, Inc.
Case 21-E-0074
Calculation of Levelized Rate Increase
For the Twelve Months Ending December 31, 2022, December 31, 2023 and December 31, 2024

$ 000's

Other Customer Provided Capital Rate = 1.8%

	Twelve Months Ending December 31, 2022	2023	2024	Cumulative Total
Revenue Requirement				
RY - 1	$4,939	$ 4,939	$ 4,939	$ 14,817
RY - 2		16,158	16,158	32,317
RY - 3			23,129	23,129
Total	$ 4,939	$ 21,097	$ 44,226	$ 70,263
Levelized rate increase without interest				
RY - 1	$ 11,710	$ 11,710	$ 11,710	$ 35,131
RY - 2		$ 11,710	$ 11,710	23,421
RY - 3			$ 11,710	11,710
Total	$ 11,710	$ 23,421	$ 35,131	$ 70,263
Variation	$ (6,771)	$ (2,323)	$ 9,095	$ 0
Interest on Variation (Net of Tax)	$ (45)	$ (106)	$ (61)	$ (211)
Levelized rate increase with interest				
RY - 1	11,675	$ 11,675	$ 11,675	$ 35,026
RY - 2		$ 11,675	$ 11,675	$ 23,351
RY - 3			11,675	$ 11,675
Total	$ 11,675	$ 23,351	$ 35,026	$ 70,052

Orange and Rockland Utilites, Inc.
Case 21-G-0073
Gas Revenue Requirement
For The Twelve Months Ending December 31, 2022
$ 000's

Operating revenues	Rate Year 1 Forecast	Rate Change	Rate Year 1 With Rate Change
Sales revenues	$ 237,929	$ 660	$ 238,589
Other operating revenues	1,757	3	1,760
Total operating revenues	239,686	663	240,348
Operating expenses			
Purchased gas costs	70,117	-	70,117
Operations & maintenance expenses	65,088	3	65,091
Depreciation	28,470	-	28,470
Regulatory amortizations	(845)	-	(845)
Taxes other than income taxes	31,719	11	31,730
Total operating expenses	194,549	14	194,563
Operating income before income taxes	45,137	649	45,786
New York State income taxes	2,135	47	2,182
Federal income taxes	5,186	126	5,312
Utility operating income	$ 37,816	$ 475	$ 38,291
Rate Base	$ 565,784		$ 565,784
Rate of Return	6.68%		6.77%

Orange and Rockland Utilites, Inc.
Case 21-G-0073
Gas Revenue Requirement
For The Twelve Months Ending December 31, 2022 and December 31, 2023
$ 000's

Operating revenues	Rate Year 1 With Rate Change	Rate Year 2 Revenue/Expense Rate Base Changes	Rate Change	Rate Year 2 With Rate Change
Sales revenues	$ 238,589	$ 11,250	$ 7,395	$ 257,234
Other operating revenues	1,760	126	29	1,915
Total operating revenues	240,348	11,376	7,424	259,149
Operating expenses				
Purchased gas costs	70,117	9,694	-	79,811
Operations & maintenance expenses	65,091	2,318	37	67,446
Depreciation	28,470	2,504		30,974
Regulatory amortizations	(845)	194		(652)
Taxes other than income taxes	31,730	682	124	32,536
Total operating expenses	194,563	15,392	161	210,115
Operating income before income taxes	45,785	(4,015)	7,263	49,034
New York State income taxes	2,182	(350)	527	2,359
Federal income taxes	5,312	(901)	1,415	5,826
Utility operating income	$ 38,290	$ (2,764)	$ 5,321	$ 40,848
Rate Base	$ 565,784	$ 41,011		$ 606,795
Rate of Return	6.77%			6.73%

Orange and Rockland Utilites, Inc.
Case 21-G-0073
Gas Revenue Requirement
For The Twelve Months Ending December 31, 2023 and December 31, 2024
$ 000's

Operating revenues	Rate Year 2 With Rate Change	Rate Year 3 Revenue/Expense Rate Base Changes	Rate Change	Rate Year 3 With Rate Change
Sales revenues	$ 257,234	$ (357)	$ 9,870	$ 266,747
Other operating revenues	1,915	99	38	2,052
Total operating revenues	259,149	(258)	9,908	268,799
Operating expenses				
Purchased gas costs	79,811	(253)	-	79,558
Operations & maintenance expenses	67,446	1,524	49	69,019
Depreciation	30,974	3,973		34,947
Regulatory Amortizations	(652)	382		(270)
Taxes other than income taxes	32,536	435	166	33,136
Total operating expenses	210,115	6,060	215	216,390
Operating income before income taxes	49,034	(6,318)	9,693	52,409
New York State income taxes	2,359	(504)	703	2,558
Federal income taxes	5,826	(1,470)	1,888	6,244
Utility operating income	$ 40,848	$ (4,344)	$ 7,103	$ 43,607
Rate Base	$ 606,795	$ 41,974		$ 648,770
Rate of Return	6.73%			6.72%

ORANGE AND ROCKLAND UTILITIES, INC.
Case 21-G-0073
Gas Other Operating Revenues
For The Twelve Months Ending December 31, 2022, December 31, 2023, and December 31, 2024
$ 000's

	Rate Year 1	Rate Year 2 Changes	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Miscellaneous Service & Other Revenues					
AMR/AMI Meter Reading and Change out Fee	$ 44	-	$ 44	$ -	$ 44
Customer Reconnect Fees	12	-	12	-	12
Late Payment Charge Revenues	433	72	506	37	543
POR Discount	541	-	541	-	541
Shared Meter Assessment	(3)	-	(3)	-	(3)
Access Fines	184	55	240	72	312
R&D Ventures	2	-	2	-	2
Total Miscellaneous Service & Other Revenues	1,214	127	1,342	109	1,451
Joint Operating Rents	545	28	573	28	601
Total Other Operating Revenues	$ 1,760	$ 155	$ 1,915	$ 137	$ 2,052

ORANGE AND ROCKLAND UTILITIES, INC.
Case 21-G-0073
Gas Operations & Maintenance Expenses
For The Twelve Months Ending December 31, 2022, December 31, 2023, and December 31, 2024
$ 000's

	Rate Year 1	Rate Year 2 Changes	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Fuel & Purchased Gas Costs	$70,117	$ 9,694	$ 79,811	$ (253)	$ 79,558
A&G Health Insurance and Capital Overhead	(479)	(13)	(492)	(17)	(509)
Bargaining Unit Contract Cost	69	-	69	(0)	69
Bond Administration & Bank Fees	77	1	78	1	80
Company Labor	29,980	1,040	31,020	1,180	32,200
Customer Billing Postage	656	13	669	12	681
Employee Welfare Expense	4,613	209	4,822	299	5,121
Environmental Affairs	102	-	102	-	102
External Audit Services	207	4	211	4	215
Facilities	680	13	693	13	706
Finance & Accounting Operations	3	-	3	-	3
Information Technology	2,715	453	3,168	147	3,315
Informational Advertising	153	3	156	3	159
Injuries & Damages/ Workers Compensation	114	(2)	112	9	121
Institutional Dues & Subscription	7	-	7	1	8
Insurance Premium	456	9	465	9	474
Intercompany Shared Services	7,082	(23)	7,059	76	7,135
Legal and Other Professional Services	195	3	198	4	202
Ops - Corporate & Shared Services	2,226	89	2,315	61	2,376
Ops - Customer Operations	2,196	282	2,478	105	2,583
Ops - Gas Operations	8,713	167	8,880	232	9,112
Ops - Engineering	1,676	40	1,716	184	1,900
Ops - Substation Operations	2	-	2	1	3
Other Compensation	161	-	161	-	161
Pensions and OPEBs	1,226	-	1,226	-	1,226
PERI Initiative	50	(35)	15	-	15
Regulatory Commission Expenses - General and R&D	1,171	23	1,194	23	1,217
Rent	278	6	284	1	285
Research and Development	12	-	12	1	13
Site Investigation & Remediation	712	404	1,116	87	1,203
Uncollectible Reserves	2,151	101	2,252	51	2,303
Worker's Comp NYS Assessment	70	1	71	2	73
Other O&M	28	1	29	-	29
Company Labor - Fringe Benefit Adjustment	15	25	40	18	58
BCO Savings	(1,424)	(608)	(2,032)	(917)	(2,949)
Producitivity	(801)	148	(653)	(16)	(669)
Total O & M Expenses	$ 135,208	$ 12,049	$ 147,256	$ 1,320	$ 148,577

ORANGE AND ROCKLAND UTILITIES, INC.
Case 21-G-0073
Gas Taxes Other Than Income Taxes
For The Twelve Months Ending December 31, 2022, December 31, 2023, and December 31, 2024
$ 000's

	Rate Year 1	Rate Year 2 Changes	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Property Taxes:					
State, County & Town	$7,910	$ 108	$8,018	$ 109	$8,127
Village	1,330	18	1,348	18	1,366
School	16,141	220	16,361	227	16,588
Total Property Taxes	$25,381	$346	$25,727	$354	$26,081
Payroll Taxes	2,228	108	2,336	105	2,441
Revenue Taxes	3,996	350	4,346	138	4,484
Other Taxes					
Sale & Use Tax	-	-	-	-	-
Other Taxes	126	2	128	2	130
Total Other Taxes	$126	$2	$128	$2	$130
Total Taxes Other Than Income Taxes	$31,731	$806	$32,537	$ 599	$33,136

ORANGE AND ROCKLAND UTILITIES, INC.
Case 21-G-0073
Gas New York State Income Taxes
For The Twelve Months Ending December 31, 2022, December 31, 2023, and December 31, 2024
$ 000's

	Rate Year 1	Rate Year 2 Changes	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Operating Income Before Income Taxes	$45,786	$ 3,248	$49,034	$ 3,375	$52,409
Interest Expense	(13,483)	(740)	(14,223)	(784)	(15,007)
Book Income Before Income Taxes	32,303	2,508	34,811	2,591	37,402
Current State Income Taxes	764	144	908	311	1,219
Deferred State Income Taxes	1,419	32	1,451	(113)	1,338
NYS Income Tax Expense	$ 2,183	$ 176	$ 2,359	$ 198	$ 2,557

ORANGE AND ROCKLAND UTILITIES, INC.
Case 21-G-0073
Gas Federal Income Taxes
For The Twelve Months Ending December 31, 2022, December 31, 2023, and December 31, 2024
$ 000's

	Rate Year 1	Rate Year 2 Changes	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Operating Income Before Income Taxes	$45,786	$ 3,248	$49,034	$ 3,375	$52,409
Interest Expense	(13,483)	(740)	(14,223)	(784)	(15,007)
Book Income Before Income Taxes	32,303	2,508	34,811	2,591	37,402
Tax Computation					
Current Federal Income Taxes	4,602	202	4,804	652	5,456
Deferred Federal Income Taxes	2,890	340	3,230	(106)	3,124
Excess Deferred Federal Income Tax - Property	(2,437)	(28)	(2,465)	(128)	(2,593)
Excess Deferred Federal Income Tax - Non-Property	423	-	423	-	423
R&D Tax Credit	(166)	-	(166)	-	(166)
Federal Income Tax Expense	$ 5,312	$ 514	$ 5,826	$ 418	$ 6,244

Orange and Rockland Utilities, Inc.
Case 21-G-0073
Average Gas Rate Base
For Twelve Months Ending December 31, 2022,and December 31, 2023
($000's)

	Rate Year 1	Rate Year 2 Changes	Rate Year 2
Utility Plant			
Gas Plant In Service	$ 987,482	$ 58,925	$ 1,046,406
Gas Plant Held For Future Use	-	-	
Common Utility Plant (Gas Allocation)	101,990	9,601	111,591
Total	1,089,471	68,526	1,157,997
Utility Plant Reserves:			
Accumulated Reserve for Depreciation - Plant in Service	(319,374)	(22,934)	(342,308)
Accumulated Reserve for Depreciation - Common Plant (Gas Allocation)	(50,435)	(4,620)	(55,055)
Total	(369,809)	(27,554)	(397,363)
Net Plant	719,663	40,972	760,634
Non-Interest Bearing CWIP	18,317	626	18,944
Working Capital - Materials/Supplies, Prepayment and Cash Working Capital	25,394	572	25,967
Unamortized Premium & Discount	2,889	(26)	2,863
Customer Advance Construction	(1,868)	-	(1,868)
Net Deferrals / Credits from Reconciliation Mechanisms	11,539	1,260	12,799
Accumulated Deferred Income Taxes			
Accumulated Deferred Federal Income Taxes	(146,491)	(983)	(147,474)
Accumulated Deferred State Income Taxes	(23,398)	(1,410)	(24,808)
Total	(169,889)	(2,393)	(172,282)
Average Rate Base	606,046	41,011	647,057
Earnings Base Capitalization Adjustment to Rate Base	(40,262)	-	(40,262)
Total Average Rate Base	$ 565,784	$ 41,011	$ 606,795

Orange and Rockland Utilities, Inc.
Case 21-G-0073
Average Gas Rate Base
For Twelve Months Ending December 31, 2023 and December 31, 2024
($000's)

	Rate Year 2	Rate Year 3 Changes	Rate Year 3
Utility Plant			
Gas Plant In Service	$ 1,046,406	$ 61,914	$ 1,108,320
Gas Plant Held For Future Use	-	-	
Common Utility Plant (Gas Allocation)	111,591	9,618	$ 121,208
Total	1,157,997	71,531	1,229,528
Utility Plant Reserves:			
Accumulated Reserve for Depreciation - Plant in Service	(342,308)	(25,430)	(367,738)
Accumulated Reserve for Depreciation - Common Plant (Gas Allocation)	(55,055)	(3,938)	(58,993)
Total	(397,363)	(29,368)	(426,731)
Net Plant	760,634	42,163	802,798
Non-Interest Bearing CWIP	18,944	(597)	18,347
Working Capital - Materials/Supplies, Prepayment and Cash Working Capital	25,967	487	26,453
Unamortized Premium & Discount	2,863	(106)	2,757
Customer Advance Construction	(1,868)	-	(1,868)
Net Deferrals / Credits from Reconciliation Mechanisms	12,799	2,450	15,249
Accumulated Deferred Income Taxes			
Accumulated Deferred Federal Income Taxes	(147,474)	(1,052)	(148,526)
Accumulated Deferred State Income Taxes	(24,808)	(1,370)	(26,178)
Total	(172,282)	(2,422)	(174,704)
Average Rate Base	647,057	41,974	689,032
Earnings Base Capitalization Adjustment to Rate Base	(40,262)	-	(40,262)
Total Average Rate Base	$ 606,795	$ 41,974	$ 648,770

Orange and Rockland Utilities, Inc.
Case 21-G-0073
Average Capital Structure & Cost of Money
For the Twelve Months Ending December 31, 2022, December 31, 2023 and December 31, 2024

RY 1

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre Tax Cost %
Long term debt	51.34%	4.58%	2.35%	2.35%
Customer deposits	0.66%	0.05%	0.00%	0.00%
Subtotal	52.00%		2.35%	2.35%
Common Equity	48.00%	9.20%	4.42%	6.03%
Total	100.00%		6.77%	8.38%

RY 2

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre Tax Cost %
Long term debt	51.34%	4.51%	2.32%	2.32%
Customer deposits	0.66%	0.05%	0.00%	0.00%
Subtotal	52.00%		2.32%	2.32%
Common Equity	48.00%	9.20%	4.42%	6.03%
Total	100.00%		6.73%	8.34%

RY 3

	Capital Structure %	Cost Rate %	Cost of Capital %	Pre Tax Cost %
Long term debt	51.34%	4.49%	2.31%	2.31%
Customer deposits	0.66%	0.05%	0.00%	0.00%
Subtotal	52.00%		2.31%	2.31%
Common Equity	48.00%	9.20%	4.42%	6.03%
Total	100.00%		6.72%	8.33%

Consolidated Edison Company of New York, Inc.
Case 21-G-0073
Calculation of Levelized Rate Increase
For the Twelve Months Ending December 31, 2022, December 31, 2023 and December 31, 2024
$ 000's

Other Customer Provided Capital Rate = 1.8%

	Twelve Months Ending			Cumulative
Revenue Requirement	Dec. 31, 2022	Dec. 31, 2023	Dec. 31, 2024	Total
RY - 1	$660	$660	$660	$1,980
RY - 2	-	7,395	7,395	14,790
RY - 3	-	-	9,870	9,870
Total	$ 660	$ 8,055	$ 17,925	$ 26,640
Levelized rate increase without interest				
RY - 1	$ 4,440	$ 4,440	$ 4,440	$ 13,320
RY - 2	-	4,440	4,440	8,880
RY - 3	-	-	4,440	4,440
Total	$ 4,440	$ 8,880	$ 13,320	$ 26,640
Variation	$ (3,780)	$ (825)	$ 4,605	$ -
Interest on Variation (Net of Tax)	$ (25)	$ (56)	$ (31)	$ (111)
Levelized rate increase with interest				
RY - 1	$ 4,421	$ 4,421	$ 4,421	$ 13,264
RY - 2	-	4,421	4,421	8,843
RY - 3	-	-	4,421	4,421
Total	$ 4,421	$ 8,843	$ 13,264	$ 26,529

Orange and Rockland Utilities, Inc.
Case 21-E-0074
Amortization of Electric Regulatory Deferrals (Credits & Debits)
$ 000's

Electric	Amortization Period	Twelve Months Ending December 31, 2022	2023	2024	Total
Regulatory Assets (Debits)					
Storm Deferral (A)	5	$14,855	$14,855	$14,855	$44,565
Pension	3	8,416	8,416	8,416	25,248
Legacy meters	12	1,584	1,584	1,584	4,752
Energy Efficiency Programs	10	766	2,375	3,981	7,122
Late Payment Charges	3	717	717	717	2,151
Pomona DER	10	601	621	641	1,863
Rev Demo Projects	10	470	577	608	1,655
Interest on Storm Reserve	3	435	435	435	1,305
Rate Case Costs	3	179	179	179	537
Other Environmental Sites	3	134	134	134	402
Credit Card Fees	3	105	105	105	315
Sale of Warwick	3	39	39	39	117
NYSIT Rate Change	3	14	14	14	42
Total Regulatory Assets (a)		$ 28,315	$ 30,051	$ 31,708	$ 90,074
Regulatory Liabilities (Credits)					
OPEB	3	$3,602	$3,602	$3,602	$10,806
Low Income	3	3,518	3,518	3,518	10,554
MGP Sites	3	3,002	3,002	3,002	9,006
Property Taxes	3	1,852	1,852	1,852	5,556
Rev Demo Carrying Charges	3	1,112	1,112	1,112	3,336
Plant Reconciliation	3	639	639	639	1,917
Deferred Tax Liabilities Carrying Charge	3	589	589	589	1,767
Customer Portfolio Shared Earnings	3	567	567	567	1,701
Non Officer Management Variable Pay	3	544	544	544	1,632
Settlement of Storms Riley and Quinn	3	289	289	289	867
R&D	3	284	284	284	852
Retention Tax Credit	3	218	218	218	654
Environmental Carrying Charge	3	127	127	127	381
Excess FIT	3	84	84	84	252
Exchange of Easement with Premium Outlets	3	44	44	44	132
Property Tax Refunds	3	24	24	24	72
18A General Assessment Refund 2017 to 2018	3	23	23	23	69
18A Assessment	3	5	5	5	15
Reactive Power	3	2	2	2	6
Total Regulatory Liabilities (b)		$ 16,525	$ 16,525	$ 16,525	$ 49,575
Net Debits (a - b)		$ 11,790	$ 13,526	$ 15,183	$ 40,499

(A) Amortization period is approximately 5.4 years.

Orange and Rockland Utilities, Inc.
Case 21-G-0073
Amortization of Gas Regulatory Deferrals (Credits & Debits)
$ 000's

Gas	Amortization Period	Twelve Months Ending December 31, 2022	2023	2024	Total
Regulatory Assets (Debits)					
Pension	3	$3,603	$3,603	$3,603	$10,809
Pension Phase-in	3	579	579	579	1,737
Plant Reconciliation	3	402	402	402	1,206
Late Payment Charges	3	216	216	216	648
Credit Card Fees	3	66	66	66	198
Other Environmental Sites	3	40	40	40	120
R&D	3	11	11	11	33
Case 05-G-1594 interest on revenue deferral	3	1	1	1	3
Energy Efficiency Programs	10	-	194	576	770
Total Regulatory Assets (a)		$ 4,918	$ 5,112	$ 5,494	$ 15,524
Regulatory Liabilities (Credits)					
OPEB	3	$1,827	$1,827	$1,827	$5,481
Low Income	3	1,657	1,657	1,657	4,971
Property Taxes	3	923	923	923	2,769
MGP Sites	3	519	519	519	1,557
Deferred Tax Liabilities Carrying Charge	3	413	413	413	1,239
Non Officer Management Variable Pay	3	114	114	114	342
Retention Tax Credit	3	107	107	107	321
Environmental Carrying Charge	3	75	75	75	225
Excess FIT	3	74	74	74	222
Rate Case Costs	3	31	31	31	93
NYSIT Rate Change	3	13	13	13	39
18A General Assessment Refund 2017 to 2018	3	8	8	8	24
18A Assessment	3	2	2	2	6
Total Regulatory Liabilities (b)		$ 5,763	$ 5,763	$ 5,763	$ 17,289
Net Credits (a - b)		$ (845)	$ (651)	$ (269)	$ (1,765)

Orange and Rockland Utilities, Inc.
Case 21-E-0074
Forecast of Sales Volume (MWh)
Rate Year 1

	SC 01	SC 19	SC 02 s	SC 20	SC 02 p	SC 03	SC 09	SC 21	SC 22	SC 25	SC 04	SC 05	SC 06	SC 16	PA	Total O&R
Jan-22	136,422	5,889	78,389	7,287	4,538	26,063	41,610	2,762	24,086	339	1,122	173	337	1,268	8,347	338,631
Feb-22	122,134	5,384	69,563	9,803	4,274	24,643	39,594	2,867	24,568	370	931	167	284	1,080	7,382	313,045
Mar-22	103,773	4,643	68,442	7,229	4,123	27,863	35,228	2,468	22,165	191	899	172	292	1,039	7,073	285,600
Apr-22	100,149	4,172	70,062	5,725	3,901	25,638	39,916	2,538	20,374	497	743	170	245	966	7,825	282,923
May-22	94,493	3,884	62,196	8,416	3,985	25,432	40,037	2,364	21,645	413	708	177	234	864	8,378	273,228
Jun-22	117,819	5,020	68,552	8,084	3,597	23,072	47,385	2,693	26,179	334	644	185	205	813	6,585	311,166
Jul-22	176,939	7,838	83,102	9,207	4,292	29,051	49,013	3,344	25,575	387	677	177	234	806	9,643	400,286
Aug-22	189,968	7,572	89,278	7,418	4,798	27,885	48,209	3,509	24,945	394	756	179	253	863	9,803	415,830
Sep-22	157,331	7,005	83,183	6,127	4,199	29,998	44,555	3,379	25,439	184	830	182	203	975	9,956	373,545
Oct-22	112,602	5,186	71,035	6,695	3,928	25,101	45,041	2,369	23,920	341	1,016	171	292	1,015	7,923	306,635
Nov-22	97,679	4,437	68,273	5,465	4,013	25,039	40,655	2,580	24,203	544	1,058	170	303	1,140	7,434	282,995
Dec-22	117,788	5,213	75,600	5,433	4,583	20,674	43,274	2,689	24,409	499	1,113	184	329	1,237	7,465	310,489
Total Billed	1,527,098	66,244	887,677	86,889	50,231	310,460	514,516	33,561	287,508	4,494	10,498	2,105	3,211	12,066	97,814	3,894,371
Net Unbilled	2,164	84	2,669	256	224	6,996	5,666	726	2,245							21,030
RY 1 Total	1,529,262	66,328	890,346	87,145	50,455	317,456	520,182	34,287	289,753	4,494	10,498	2,105	3,211	12,066	97,814	3,915,401

Orange and Rockland Utilities, Inc.
Case 21-E-0074
Forecast of Sales Volume (MWh)
Rate Year 2

	SC 01	SC 19	SC 02 s	SC 20	SC 02 p	SC 03	SC 09	SC 21	SC 22	SC 25	SC 04	SC 05	SC 06	SC 16	PA	Total O&R
Jan-23	134,159	5,791	81,245	7,554	4,703	26,593	44,412	2,817	24,568	337	1,107	170	332	1,252	8,732	343,773
Feb-23	119,785	5,279	72,079	10,161	4,428	25,130	41,331	2,922	25,043	368	918	165	280	1,065	7,723	316,679
Mar-23	101,418	4,537	70,900	7,490	4,271	28,394	37,191	2,514	22,579	191	886	169	288	1,024	7,399	289,251
Apr-23	101,177	4,215	73,337	5,994	4,083	25,635	41,110	2,537	20,367	495	732	168	241	952	7,918	288,960
May-23	95,322	3,918	65,090	8,810	4,170	25,434	41,467	2,364	21,642	395	697	174	230	851	8,477	279,040
Jun-23	119,331	5,084	71,762	8,465	3,765	23,088	48,844	2,694	26,190	329	633	182	202	800	6,663	318,032
Jul-23	176,624	7,823	85,044	9,424	4,392	29,370	50,974	3,379	25,844	373	666	174	230	793	9,833	404,944
Aug-23	189,786	7,564	91,375	7,594	4,910	28,182	50,012	3,545	25,200	393	744	176	249	849	9,996	420,577
Sep-23	156,878	6,984	85,104	6,271	4,296	30,313	47,221	3,413	25,695	183	817	179	200	959	10,152	378,666
Oct-23	113,305	5,218	73,483	6,928	4,064	25,317	45,847	2,389	24,118	340	1,000	168	287	999	8,111	311,572
Nov-23	98,193	4,460	70,611	5,654	4,151	25,252	43,878	2,601	24,400	537	1,041	167	298	1,122	7,611	289,977
Dec-23	118,799	5,257	78,201	5,621	4,740	20,846	44,362	2,710	24,606	497	1,096	181	324	1,218	7,642	316,100
Total Billed	1,524,778	66,130	918,231	89,966	51,974	313,553	536,650	33,886	290,251	4,436	10,339	2,073	3,162	11,884	100,258	3,957,571
Net Unbilled	(8,937)	(349)	(4,491)	(430)	(377)	(3,970)	(3,215)	(412)	(1,274)							(23,455)
RY 2 Total	1,515,841	65,781	913,740	89,536	51,597	309,583	533,435	33,474	288,977	4,436	10,339	2,073	3,162	11,884	100,258	3,934,116

Orange and Rockland Utilities, Inc.
Case 21-E-0074
Forecast of Sales Volume (MWh)
Rate Year 3

	SC 01	SC 19	SC 02 s	SC 20	SC 02 p	SC 03	SC 09	SC 21	SC 22	SC 25	SC 04	SC 05	SC 06	SC 16	PA	Total O&R
Jan-24	133,913	5,780	82,068	7,631	4,751	25,997	43,849	2,756	24,016	333	1,114	172	334	1,259	8,638	342,612
Feb-24	119,308	5,258	72,792	10,261	4,472	24,549	41,721	2,856	24,465	367	923	166	282	1,071	7,640	316,131
Mar-24	100,772	4,508	71,584	7,562	4,312	27,715	38,271	2,455	22,039	190	891	170	289	1,030	7,320	289,109
Apr-24	100,459	4,185	74,344	6,076	4,139	25,250	40,951	2,500	20,058	492	719	165	237	935	7,946	288,457
May-24	94,394	3,879	65,971	8,929	4,227	25,046	41,953	2,329	21,308	375	685	171	226	836	8,508	278,836
Jun-24	118,340	5,041	72,761	8,583	3,817	22,741	50,018	2,655	25,795	324	622	179	198	785	6,687	318,545
Jul-24	174,821	7,743	86,024	9,533	4,443	28,270	49,270	3,255	24,879	357	654	171	225	778	9,544	399,968
Aug-24	188,015	7,493	92,446	7,683	4,968	27,115	49,075	3,413	24,247	391	731	173	245	834	9,702	416,531
Sep-24	155,298	6,914	86,076	6,342	4,345	29,170	46,106	3,286	24,728	183	802	176	196	942	9,854	374,416
Oct-24	108,896	5,015	72,563	6,841	4,013	24,595	45,308	2,322	23,430	338	983	165	282	982	7,932	303,664
Nov-24	94,652	4,299	69,717	5,582	4,098	24,539	41,628	2,529	23,711	528	1,024	164	293	1,103	7,443	281,311
Dec-24	114,823	5,081	77,225	5,551	4,681	20,254	45,004	2,635	23,905	494	1,078	178	319	1,198	7,474	309,899
Total Billed	1,503,693	65,196	923,570	90,573	52,266	305,242	533,153	32,989	282,582	4,372	10,225	2,049	3,127	11,754	98,687	3,919,478
Net Unbilled	7,197	282	5,197	497	436	5,005	4,054	519	1,607							24,794
RY 3 Total	1,510,890	65,478	928,767	91,070	52,702	310,247	537,207	33,508	284,189	4,372	10,225	2,049	3,127	11,754	98,687	3,944,272

Orange and Rockland Utilities, Inc.
Case 21-E-0074
Sales Revenues*
$ 000's

	RY 1	RY 2	RY 3
Delivery**	$ 313,649	$ 313,642	$ 315,136
Competitive Services	14,005	14,058	14,032
Reactive Power	159	159	159
Subtotal	$ 327,813	$ 327,859	$ 329,327
MSC	94,145	92,804	87,719
SBC	19,845	19,405	18,033
Other ***	720	736	818
Tax Recovery Revenue	7,725	7,660	7,555
Total Sales Revenues	$ 450,248	$ 448,463	$ 443,452
Sales for Resale ****	$ 15,469	$ 16,018	$ 16,082
Grand Total Revenues	$ 465,717	$ 464,481	$ 459,533
Rate Relief (Levelized)	11,675	23,351	35,026
Grand Total Revenues with Rate Relief	$ 477,392	$ 487,831	$ 494,559

*At 2021 rates

** Includes Low Income Discount
*** Includes MFC accrual, uncollectibles and other purchased power
**** Includes PSA Fixed Charges and Intercompany Fuel & PSA Bill

Orange and Rockland Utilities, Inc.
Gas Case 21-G-0073
Sales Revenues
$ 000's

	Twelve Months Ending December 31,		
Firm Revenues	2022	2023	2024
Delivery Revenues			
- Non Competitive	159,929	161,204	161,156
- Competitive	1,937	2,006	2,010
Monthly Gas Adjustments	20,713	20,544	19,478
Gas Supply Charge	49,241	59,090	59,870
Revenue Taxes	3,938	4,164	4,137
Subtotal	235,759	247,009	246,652
Interruptible Revenues			
SC 8/13	5,155	5,155	5,155
SC 9	683	683	683
Revenue Taxes	46	46	46
Subtotal	5,884	5,884	5,884
Other Revenues			
System Benefit Charge	-	-	-
Revenue Taxes	-	-	-
Subtotal	-	-	-
Rate Increase	4,421	8,843	13,264
Grand Total	$ 246,064	$ 261,735	$ 265,800

Volumes (MCF)	2022	2023	2024
Total Firm Billed/Unbilled	21,531,566	21,747,030	21,663,228
Total Interruptible	3,573,800	3,573,800	3,573,800
Firm Volume - Billed/Unbilled/Interruptible	25,105,366	25,320,830	25,237,028

Orange and Rockland Utilities, Inc.
Case 21-E-0074
True-Up Targets
$ 000's

Expense Items	Twelve Months Ending December 31, 2022	2023	2024
Research and Development	$ 678	$ 691	$ 704
Contractor Tree Trimming (shortfall true-up only) (a)	10,700	12,100	12,412
Major Storm Cost Reserve	8,000	8,154	8,310
Pension Costs - Qualified Plan	9,580	1,757	3,003
- Non Qualified Plan	1,989	1,900	2,162
OPEB Costs	(3,864)	(4,726)	(4,358)
Total	7,705	(1,069)	807
Property Taxes - State, County & Town	13,489	14,130	14,431
Property Taxes - Village	2,081	2,123	2,163
Property Taxes - School	27,737	28,534	29,855
Total Property Taxes	43,307	44,787	46,449
Non-Officer Management Variable Pay	2,303	2,375	2,458
Environmental Remediation	1,442	2,258	2,435
Uncollectible Expenses	2,256	2,327	2,418
2021 State Tax Law Change	3,640	3,649	4,034
Revenue Item			
Low Income Program (b)	9,988	10,347	10,719
Late Payment Charges	1,450	1,547	1,673
Rate Base True-Ups			
Environmental Remediation	(5,254)	(3,153)	(1,051)
Energy Efficiency	2,527	10,079	19,528
Rev Demo Project Costs	2,585	3,283	3,354
Pomona DRP	4,108	3,807	3,491

(a) Annual over / under expenditures may be netted, true up is cumulative.

(b) This item is handled through rate design (versus base rates)

Orange and Rockland Utilities, Inc.
Case 21-G-0073
True-Up Targets
($000's)

	Twelve Months Ending December 31,		
Expense Items	2022	2023	2024
Property Taxes - State, County & Town	$7,910	$8,018	$8,127
Property Taxes - Village	1,330	1,348	1,366
Property Taxes - School	16,141	16,361	16,588
Total Property Taxes	25,381	25,727	26,081
Pension Costs - Qualified Plan	4,732	868	1,484
- Non Qualified Plan	983	939	1,068
OPEB Costs	(1,909)	(2,335)	(2,153)
Total	3,806	(528)	399
State Tax Law Change	2,183	2,359	2,557
Research and Development	12	12	13
Late Payment Charges	433	506	543
Uncollectible Expenses	1,128	1,229	1,280
Pipeline Emergency Responders Initiatives	50	15	15
Non-Officer Management Variable Pay	1,137	1,171	1,211
Site Investigation & Remediation (True-up target)	712	1,116	1,203
Revenue Item			
Low Income Program (a)	5,359	5,359	5,359
Rate Base True-Up			
Environmental Remediation	(877)	(526)	(175)
Energy Efficiency	-	639	2,467

(a) This item is handled through rate design (versus base rates)

Orange and Rockland Utilities, Inc.
Case 21-E-0074
Electric Net Plant In Service Target Balances - Included in Rate Base
Effective Janaury 1, 2022 - December 31, 2024
$ 000's

MONTH ENDED	**Rate Year 1** Elec. Plant In Service Target	Reserve For Depreciation Target*	Net Plant Target
December 31, 2021 @ 50%	$ 920,528	$ (324,724)	$ 595,804
January	1,843,873	(671,937)	1,171,936
February	1,847,192	(676,327)	1,170,865
March	1,852,846	(680,412)	1,172,435
April	1,856,953	(685,065)	1,171,887
May	1,860,726	(689,724)	1,171,002
June	1,869,530	(694,350)	1,175,180
July	1,873,575	(699,054)	1,174,520
August	1,877,488	(703,739)	1,173,749
September	1,884,175	(708,379)	1,175,795
October	1,888,047	(713,141)	1,174,906
November	1,892,229	(717,805)	1,174,424
December 31, 2022 @ 50%	953,352	(360,453)	592,899
Total	$ 22,420,514	$ (8,325,112)	$ 14,095,401
13 Point Average	$ 1,868,376	$ (693,760)	$ 1,174,616

MONTH ENDED	**Rate Year 2** Elec. Plant In Service Target	Reserve For Depreciation Target*	Net Plant Target
December 31, 2022 @ 50%	$ 953,352	$ (360,453)	$ 592,899
January	1,910,081	(725,753)	1,184,328
February	1,913,463	(730,440)	1,183,023
March	1,919,242	(735,339)	1,183,903
April	1,923,022	(740,230)	1,182,792
May	1,929,146	(744,931)	1,184,215
June	1,939,156	(749,512)	1,189,644
July	1,962,406	(754,490)	1,207,916
August	1,966,663	(759,639)	1,207,024
September	1,977,556	(764,787)	1,212,768
October	1,982,000	(770,059)	1,211,941
November	1,985,354	(774,042)	1,211,312
December 31, 2023 @ 50%	1,008,702	(388,207)	620,495
Total	$ 23,370,143	$ (8,997,883)	$ 14,372,261
13 Point Average	$ 1,947,512	$ (749,824)	$ 1,197,688

MONTH ENDED	**Rate Year 3** Elec. Plant In Service Target	Reserve For Depreciation Target*	Net Plant Target
December 31, 2023 @ 50%	$ 1,008,702	$ (388,207)	$ 620,495
January	2,039,256	(780,974)	1,258,282
February	2,042,862	(786,719)	1,256,143
March	2,048,608	(792,431)	1,256,177
April	2,052,002	(798,153)	1,253,849
May	2,138,378	(803,887)	1,334,491
June	2,144,743	(809,694)	1,335,049
July	2,144,044	(811,446)	1,332,598
August	2,147,534	(817,339)	1,330,195
September	2,154,162	(823,160)	1,331,001
October	2,159,081	(829,141)	1,329,940
November	2,162,618	(834,868)	1,327,750
December 31, 2024 @ 50%	1,097,877	(418,672)	679,205
Total	$ 25,339,866	$ (9,694,690)	$ 15,645,176
13 Point Average	$ 2,111,656	$ (807,891)	$ 1,303,764

* includes Vehicle Depreciation

Orange and Rockland Utilities, Inc.
Case 21-E-0074
Capital True-up Rate - Electric Net Plant Reconciliation
For Twelve Months Ending December 31, 2022, and December 31, 2023, and December 31,2024

Rate Year 1

Electric Carrying Charge - Net Plant	
- Before Tax ROR*	8.38%
- Composite Depreciation Rate	3.56%
	11.94%

Rate Year 2

Electric Carrying Charge - Net Plant	
- Before Tax ROR*	8.34%
- Composite Depreciation Rate	3.65%
	11.99%

Rate Year 3

Electric Carrying Charge - Net Plant	
- Before Tax ROR*	8.33%
- Composite Depreciation Rate	3.91%
	12.24%

* See Appendix 1 page 11 Capital Structure

Orange and Rockland Utilities, Inc.
Case 21-G-0073
Gas Net Plant In Service Target Balances - Included in Rate Base
Effective January 1, 2022 - December 31, 2024
$ 000's

	Rate Year 1		
MONTH ENDED	Gas Plant In Service Target	Reserve For Depreciation Target*	Net Plant Target
December 31, 2021 @ 50%	$ 528,454	$ (178,645)	$ 349,809
January	1,058,907	(358,919)	699,988
February	1,062,109	(360,986)	701,124
March	1,064,930	(362,919)	702,011
April	1,072,868	(365,117)	707,751
May	1,080,876	(367,334)	713,542
June	1,092,457	(369,553)	722,904
July	1,100,179	(371,857)	728,321
August	1,105,161	(374,209)	730,952
September	1,110,338	(376,555)	733,782
October	1,116,716	(378,907)	737,809
November	1,119,417	(381,295)	738,122
December 31, 2022 @ 50%	561,245	(191,408)	369,837
Total	$ 13,073,657	$ (4,437,704)	$ 8,635,953
13 Point Average	$ 1,089,471	$ (369,809)	$ 719,663

	Rate Year 2		
MONTH ENDED	Gas Plant In Service Target	Reserve For Depreciation Target*	Net Plant Target
December 31, 2022 @ 50%	$ 561,245	$ (191,408)	$ 369,837
January	1,125,221	(385,237)	739,984
February	1,127,898	(387,554)	740,343
March	1,130,749	(389,991)	740,757
April	1,138,704	(392,410)	746,294
May	1,146,736	(394,847)	751,890
June	1,154,513	(397,304)	757,209
July	1,169,761	(399,767)	769,994
August	1,176,006	(402,350)	773,656
September	1,183,492	(404,950)	778,542
October	1,190,082	(407,557)	782,525
November	1,192,390	(409,573)	782,817
December 31, 2023 @ 50%	599,167	(205,405)	393,762
Total	$ 13,895,966	$ (4,768,355)	$ 9,127,612
13 Point Average	$ 1,157,997	$ (397,363)	$ 760,634

	Rate Year 3		
MONTH ENDED	Gas Plant In Service Target	Reserve For Depreciation Target*	Net Plant Target
December 31, 2023 @ 50%	$ 599,167	$ (205,405)	$ 393,762
January	1,201,168	(413,614)	787,554
February	1,204,061	(416,426)	787,636
March	1,207,010	(419,243)	787,768
April	1,214,938	(422,043)	792,895
May	1,222,923	(424,861)	798,062
June	1,230,779	(427,654)	803,125
July	1,236,613	(428,454)	808,159
August	1,241,939	(431,302)	810,637
September	1,247,980	(434,175)	813,805
October	1,255,794	(437,056)	818,737
November	1,258,628	(439,850)	818,777
December 31, 2024 @ 50%	633,343	(220,687)	412,655
Total	$ 14,754,342	$ (5,120,770)	$ 9,633,572
13 Point Average	$ 1,229,528	$ (426,731)	$ 802,798

* includes Vehicle Depreciatior

Orange and Rockland Utilities, Inc.
Case 21-G-0073
Capital True-up Rate - Gas Net Plant Reconciliation
For Twelve Months Ending December 31, 2022, December 31, 2023 and December 31, 2024

Rate Year 1

Gas Carrying Charge - Net Plant	
- Before Tax ROR*	8.38%
- Composite Depreciation Rate	2.83%
	11.22%

Rate Year 2

Gas Carrying Charge - Net Plant	
- Before Tax ROR*	8.34%
- Composite Depreciation Rate	2.91%
	11.25%

Rate Year 3

Gas Carrying Charge - Net Plant	
- Before Tax ROR*	8.33%
- Composite Depreciation Rate	3.06%
	11.39%

* See Appendix 2 page 6 Capital Structure

Orange and Rockland Utilities, Inc.
Case 21-E-0074 and 21-G-0073
Calculation of Composite Depreciation Rate for Carrying Charges on Net Plant
($000's)

	Electric	Gas
Rate Year 1		
Depreciation Expense 1/22-12/22:		
-Depreciation Expense	$ 53,476.0	$ 24,591.0
-Allocated portion of Common	12,013.3	5,364.3
Total	$ 65,489.3	$ 29,955.3
Plant Balance @ 12/31/21:		
-Plant Balance	$ 1,615,754.8	$ 956,874.7
-Allocated portion of Common	225,300.9	100,033.6
Total	$ 1,841,055.7	$ 1,056,908.3
Composite Rate	3.56%	2.83%
Rate Year 2		
Depreciation Expense 1/23-12/23:		
-Depreciation Expense	$ 55,694.1	$ 26,479.4
-Allocated portion of Common	13,901.5	6,140.2
Total	$ 69,595.6	$ 32,619.6
Plant Balance @ 12/31/22:		
-Plant Balance	$ 1,670,294.8	$ 1,017,360.9
-Allocated portion of Common	236,410.0	105,129.6
Total	$ 1,906,704.8	$ 1,122,490.6
Composite Rate	3.65%	2.91%
Rate Year 3		
Depreciation Expense 1/24-12/24:		
-Depreciation Expense	$ 62,680.1	$ 29,616.5
-Allocated portion of Common	16,259.4	7,053.2
Total	$ 78,939.5	$ 36,669.7
Plant Balance @ 12/31/23:		
-Plant Balance	$ 1,744,696.9	$ 1,078,325.2
-Allocated portion of Common	272,706.9	120,009.2
Total	$ 2,017,403.8	$ 1,198,334.4
Composite Rate	3.91%	3.06%

Data based on final Net Plant Model (File 212)

Orange and Rockland Utilities, Inc.
Electric Rate Case 21-E-0074
Calculation of Interest on Electric Net Plant
Effective January 1, 2022 - December 31, 2024
($000's)

EXAMPLE 1 - Carrying Charge in December 2024 - end of RY3

As of the end of RY3, the cumulative interest is positive at $367k indicating the actual plant balances are above the target, therefore no interest is accrued to the customer as of the end of the multi-year plan.

	Net Plant Actual (sample)	Net Plant PSC Target	Net Plant Variation	Interest Computed 11.94%	Interest Computed Cumulative	Current Month Interest recorded	Cumulative Interest Accrued to Customer
Dec-21	$ 584,500	$ 595,804	$ (11,304)	$ (112)			
Jan-22	1,170,000	1,171,936	(1,936)	(19)	$ (131)	$ (131)	$ (131)
Feb-22	1,170,000	1,170,865	(865)	(9)	(140)	(9)	(140)
Mar-22	1,171,000	1,172,435	(1,435)	(14)	(154)	(14)	(154)
Apr-22	1,171,000	1,171,887	(887)	(9)	(163)	(9)	(163)
May-22	1,171,000	1,171,002	(2)	-	(163)	-	(163)
Jun-22	1,177,000	1,175,180	1,820	18	(145)	18	(145)
Jul-22	1,177,000	1,174,520	2,480	25	(120)	25	(120)
Aug-22	1,177,000	1,173,749	3,251	32	(88)	32	(88)
Sep-22	1,177,000	1,175,795	1,205	12	(76)	12	(76)
Oct-22	1,177,000	1,174,906	2,094	21	(55)	21	(55)
Nov-22	1,177,000	1,174,424	2,576	26	(29)	26	(29)
Dec-22	589,000	592,899	(3,899)	(39)	(68)	(39)	(68)
Average	$ 1,174,042	$ 1,174,617	$ (575)				

	Net Plant Actual (sample)	Net Plant PSC Target	Net Plant Variation	11.99%			
Dec-22	$ 589,000	$ 592,899	$ (3,899)	$ (39)	$ (107)	$ (39)	$ (107)
Jan-23	1,180,000	1,184,328	(4,328)	(43)	(150)	(43)	(150)
Feb-23	1,181,000	1,183,023	(2,023)	(20)	(170)	(20)	(170)
Mar-23	1,181,000	1,183,903	(2,903)	(29)	(199)	(29)	(199)
Apr-23	1,182,000	1,182,792	(792)	(8)	(207)	(8)	(207)
May-23	1,188,000	1,184,215	3,785	38	(169)	38	(169)
Jun-23	1,193,000	1,189,644	3,356	34	(135)	34	(135)
Jul-23	1,208,000	1,207,916	84	1	(134)	1	(134)
Aug-23	1,208,000	1,207,024	976	10	(124)	10	(124)
Sep-23	1,208,000	1,212,768	(4,768)	(48)	(172)	(48)	(172)
Oct-23	1,208,000	1,211,941	(3,941)	(39)	(211)	(39)	(211)
Nov-23	1,220,000	1,211,312	8,688	87	(124)	87	(124)
Dec-23	610,000	620,495	(10,495)	(105)	(229)	(105)	(229)
Average	$ 1,196,333	$ 1,197,688	$ (1,355)				

	Net Plant Actual (sample)	Net Plant PSC Target	Net Plant Variation	12.24%			
Dec-23	$ 610,000	$ 620,495	$ (10,495)	$ (105)	$ (334)	$ (105)	$ (334)
Jan-24	1,260,000	1,258,282	1,718	18	(87)	247	(87)
Feb-24	1,260,000	1,256,143	3,857	39	(48)	39	(48)
Mar-24	1,261,000	1,256,177	4,823	49	1	48	-
Apr-24	1,261,000	1,253,849	7,151	73	74	-	-
May-24	1,335,000	1,334,491	509	5	79	-	-
Jun-24	1,335,000	1,335,049	(49)	-	79	-	-
Jul-24	1,335,000	1,332,598	2,402	24	103	-	-
Aug-24	1,335,000	1,330,195	4,805	49	152	-	-
Sep-24	1,336,000	1,331,001	4,999	51	203	-	-
Oct-24	1,336,000	1,329,940	6,060	62	265	-	-
Nov-24	1,336,000	1,327,750	8,250	84	349	-	-
Dec-24	681,000	679,205	1,795	18	367	-	-
Average	$ 1,306,750	$ 1,303,765	$ 2,985				

Orange and Rockland Utilities, Inc.
Gas Rate Case 21-G-0073
Calculation of Interest on Gas Net Plant
Effective January 1, 2022 - December 31, 2024
($000's)

EXAMPLE 2 - Carrying Charge in December 2024 - end of RY3

As of the end of RY3, cumulative interest is negative for $113k, indicating the actual plant balances are below the target, therefore the cumulative interest of $116k is accrued to the customer as of the end of the multi-year rate plan.

	Net Plant						
	Actual (sample)	**PSC Target**	**Variation**	Interest Computed **11.22%**	Interest Computed Cumulative	**Current Month Interest recorded**	**Cumulative Interest Accrued to Customer**
Dec-21	$ 351,000	$ 349,809	$ 1,191	$ 11			
Jan-22	702,000	699,988	2,012	19	$ 30	-	-
Feb-22	702,000	701,124	876	8	38	-	-
Mar-22	703,000	702,011	989	9	47	-	-
Apr-22	708,000	707,751	249	2	49	-	-
May-22	714,000	713,542	458	4	53	-	-
Jun-22	723,000	722,904	96	1	54	-	-
Jul-22	725,000	728,321	(3,321)	(31)	23		-
Aug-22	728,000	730,952	(2,952)	(28)	(5)	(5)	(5)
Sep-22	733,000	733,782	(782)	(7)	(12)	(7)	(12)
Oct-22	738,000	737,809	191	2	(10)	2	(10)
Nov-22	740,000	738,122	1,878	18	8	10	-
Dec-22	370,000	369,837	163	2	10		-
Average	$ 719,750	$ 719,663	$ 87				

	Net Plant						
	Actual (sample)	**PSC Target**	**Variation**	**11.25%**			
Dec-22	$ 370,000	$ 369,837	$ 163	$ 2	$ 12		
Jan-23	741,000	739,984	1,016	10	22	-	-
Feb-23	741,000	740,343	657	6	28	-	-
Mar-23	741,000	740,757	243	2	30	-	-
Apr-23	741,000	746,294	(5,294)	(50)	(20)	(20)	(20)
May-23	746,000	751,890	(5,890)	(55)	(75)	(55)	(75)
Jun-23	755,000	757,209	(2,209)	(21)	(96)	(21)	(96)
Jul-23	767,000	769,994	(2,994)	(28)	(124)	(28)	(124)
Aug-23	778,000	773,656	4,344	41	(83)	41	(83)
Sep-23	783,000	778,542	4,458	42	(41)	42	(41)
Oct-23	785,000	782,525	2,475	23	(18)	23	(18)
Nov-23	786,000	782,817	3,183	30	12	18	-
Dec-23	393,000	393,762	(762)	(7)	5	-	-
Average	$ 760,583	$ 760,634	$ (51)				

	Net Plant						
	Actual (sample)	**PSC Target**	**Variation**	**11.39%**			
Dec-23	$ 393,000	$ 393,762	$ (762)	$ (7)	$ (2)	$ (2)	$ (2)
Jan-24	789,000	787,554	1,446	14	12	2	-
Feb-24	789,000	787,636	1,364	13	25	-	-
Mar-24	789,000	787,768	1,232	12	37	-	-
Apr-24	792,000	792,895	(895)	(8)	29	-	-
May-24	794,000	798,062	(4,062)	(39)	(10)	(10)	(10)
Jun-24	800,000	803,125	(3,125)	(30)	(40)	(30)	(40)
Jul-24	806,000	808,159	(2,159)	(20)	(60)	(20)	(60)
Aug-24	809,000	810,637	(1,637)	(16)	(76)	(16)	(76)
Sep-24	814,000	813,805	195	2	(74)	2	(74)
Oct-24	817,000	818,737	(1,737)	(16)	(90)	(16)	(90)
Nov-24	817,000	818,777	(1,777)	(17)	(107)	(17)	(107)
Dec-24	412,000	412,655	(655)	(6)	(113)	(6)	(113)
Average	$ 801,750	$ 802,798	$ (1,048)				

Appendix 9

Orange and Rockland Utilities, Inc.
Cases 21-G-0073 & 21-E-0074

Reconciliations and Deferrals

Table of Contents

A. Net Plant Reconciliation

1. Electric

a. Net Plant Reconciliation

The electric revenue requirements for RY1, RY2 and RY3 reflect the average net plant balances set forth in Appendix 8 ("Electric Net Plant In Service Target Balances").

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

The Company will defer for the benefit of customers the revenue requirement impact (*i.e.*, carrying costs, including depreciation, as identified in Appendix 8) of the amount by which the Company's actual expenditures for electric capital programs and projects result in actual average net plant that is less than the amount included in the Electric Net Plant In Service Target Balances, as set forth in Appendix 8, for RY1, RY2 and RY3 ("target levels"), on a cumulative basis;[1] that is, the carrying charges resulting from the difference (whether representing underspending or overspending) in actual Electric Net Plant In Service Balances and the target levels will carry forward for each of the Rate Years and will be summed at the end of RY3. If at the end of RY3 the cumulative carrying charges represent underspending, the Company will book a regulatory liability for the cumulative underspent carrying charges. If at the end of RY3

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

the cumulative carrying charges represent overspending, no deferrals will be made. Examples of how this reconciliation will work are set forth in Appendix 8.

b. Reporting Requirements

The Company will submit annual reports relating to capital expenditures in the manner set forth in Appendix 19.

c. Non-Wires Alternative Adjustment Mechanism

The costs incurred by the Company for implementation of new NWAs (ones that are not included in base rates or for which the Company has not filed a BCA) during the Electric Rate Plan, including the overall pre-tax rate of return on such costs, will be recovered over ten years. Recovery of these NWA costs during the Electric Rate Plan will be through the ECA. Unamortized NWA costs, including the return, will be incorporated into the Company’s base rates when electric base delivery rates are reset.

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

2. Gas

a. Net Plant Reconciliation

The gas revenue requirements for RY1, RY2 and RY3 reflect the average net plant balances set forth in Appendix 8 (“Gas Net Plant In Service Target Balances”).

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

The Company will defer for the benefit of customers the revenue requirement impact (*i.e.*, carrying costs, including depreciation, as identified in Appendix 8) of the amount by which the Company's actual expenditures for gas capital programs and projects result in average net plant that is less than the amount included in the Gas Net Plant In Service Target Balances as set forth in Appendix 8, for RY1, RY2 and RY3 ("target levels"), on a cumulative basis;[2] that is, the revenue requirement impact resulting from the difference (whether representing underspending or overspending) in actual Gas Net Plant In Service Balances and the target levels will carry forward each of the Rate Years and will be summed at the end of RY3. If at the end of RY3 the cumulative carrying charges represent underspending, the Company will book a regulatory liability for the cumulative underspent carrying charges. If at the end of RY3 the cumulative carrying charges represent overspending, no deferrals will be made. Examples of how this reconciliation will work are set forth in Appendix 8.

b. Reporting Requirements

The Company will provide quarterly and annual reports relating to capital expenditures in the manner set forth in Appendix 19.

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

c. Non-Pipeline Alternative Adjustment Mechanism

The costs incurred by the Company for implementation of new NPAs during the Gas Rate Plan, including the overall pre-tax rate of return on such costs, will be recovered over ten years. Recovery of these NPA costs during the Gas Rate Plan will be through a new component of the MGA, the NPA Adjustment Mechanism. Amortized NPA program costs will be collected on a common cents per Ccf basis from customers served under SC Nos. 1, 2, and 6. Unamortized NPA costs, including the return, will be incorporated into the Company's base rates when gas base delivery rates are reset.

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

B. <u>Non-Plant Reconciliations/Deferrals</u>

The Company will reconcile the following costs and revenues to the levels provided in rates, as set forth in Appendices 6, 7, and 8. Variations subject to recovery from or to be credited to customers will be deferred on the Company's books of account over the term of the Rate Plans, and the revenue requirement effects of such deferred debits and credits, as the case may be, will be addressed in future rate proceedings.

1. Property Taxes (Electric and Gas)

If the level of actual electric or gas expense for property taxes, excluding the effect of property tax refunds (as defined in Section D.4 of the Joint Proposal), varies in any Rate Year from the projected level provided in rates for that service, which levels are set forth in Appendices 6 and 7, 90 percent of the variation will be deferred on the Company's books of account and either recovered from or credited to customers, subject to the following cap: the Company's 10 percent 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 in RY1, 7.5 basis points on common equity in RY2, and 5 basis points on common equity in RY3. The Company will defer on its books of account, for recovery from or credit to customers, 100 percent of the variation above or below the level at which the cap takes effect.

The Company will not be precluded from applying for a greater share of lower than forecasted property tax expenses (including the period beyond RY3) if its extraordinary efforts result in fundamental taxation changes and produce substantial net benefits to customers. The Signatory Parties reserve the right to support or oppose any such filing.

2. Pensions/OPEBs (Electric and Gas)

Pursuant to the Commission's Pension Policy Statement,[3] the Company will reconcile its actual pensions and Other Post-Employment Benefits ("OPEBs") expenses to the levels provided in rates as set forth in Appendices 6 and 7.

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

The Pension Policy Statement provides that companies may seek prospective interest accruals or rate base treatment for amounts funded above the cost recoveries included in rates.[4] During the term of the Rate Plans, the Company may be required to fund its pension plan at a level above the rate allowance pursuant to the annual minimum pension funding requirements contained within the Pension Protection Act of 2006. The Company, its actuary and the parties are unable to predict with certainty if the minimum funding threshold will exceed rate recoveries during the term of the Rate Plans. In lieu of a provision in this Proposal addressing the Company's additional financing requirements should it be required to fund its pension plan above the level provided in rates during the term of these Rate Plans, the Proposal does not preclude the Company from petitioning the Commission to defer the financing costs associated with funding the pension plan at levels above the current rate allowance should funding above the rate allowance be required; the Company's right to obtain authority to defer such financing costs on its books of account will not be subject to requirements respecting materiality.

3. Environmental Remediation (Electric and Gas)

If the level of actual SIR expenditures,[5] including expenditures associated with former manufactured gas plant ("MGP") sites, Superfund sites, and other sites allocated to electric and gas operations, varies in any Rate Year from the levels provided in rates, which are set forth in Appendices 6 and 7, such variation shall be deferred and recovered from or credited to customers. Deferred SIR cost balances varying from the level reflected in rate base during each

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

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

Rate Year, as set forth in Appendices 6 and 7, will accrue a carrying cost at the pre-tax rate of return. The deferred cost balances will be reduced by accruals, insurance and third party recoveries, associated reserves and deferred taxes, and other offsets, if any, obtained by the Company.

4. Non-Officer Management Variable Pay (Electric and Gas)

The electric and gas revenue requirements reflect estimated expense for the Company's Non-Officer Management Variable Pay Program. The Company will defer for future credit to customers, the amount by which the actual expense by service in any Rate Year is less than the amount shown on Appendices 6 and 7 for that service for that Rate Year.

5. Adjustments for Competitive Services (Electric and Gas)

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

6. Low Income Assistance Program (Electric and Gas)

The Company will reconcile actual payments (monthly bill credits) to low-income customers to the levels provided in electric and gas rate designs, as set forth in Appendices 6 and 7.

7. Research and Development Expense (Electric and Gas)

The Company will reconcile its actual Research and Development ("R&D") expenses to the levels provided in electric and gas rates, as set forth in Appendices 6 and 7. The Company shall have the flexibility over the term of the Rate Plans to modify the list, priority, nature and scope of the R&D projects to be undertaken.

8. Energy Efficiency Program (Electric and Gas)

The energy efficiency costs are subject to a cumulative, symmetrical reconciliation over the terms of the Rate Plans subject to the cumulative New Efficiency New York ("NENY") cap. The current NENY cap amounts for each electric and gas are set forth in Appendices 6 and 7. If the Commission modifies the Company's NENY budgets during the rate term, such modifications will be reflected at the time of the cumulative reconciliations. The Company will perform separate reconciliations for its electric and gas portfolios.

To allow the Company flexibility in spending, the NENY funds for the period of 2019 through 2025 will be considered fungible as long as the Company does not exceed the cumulative authorized NENY budget through 2025 for each electric and gas.

9. Major Storm Cost Reserve (Electric)

a. Major Storm Reserve Funding

The Company's annual electric revenue requirements provide funding for the major storm reserve of $8.0 million in RY1, $8.2 million in RY2, and $8.3 million in RY3, as shown in Appendix 6.[6] Except as provided herein, all incremental major storm costs will be charged to the major storm reserve. To the extent that the Company incurs incremental major storm costs in excess of the annual amounts stated above in a Rate Year, the Company will defer on its books of account expenses in excess of the annual amounts stated above for future recovery from

[6] A "major storm" is defined in 16 NYCRR Part 97 as a period of adverse weather during which service interruptions affect at least ten percent of the Company's customers within an operating area and/or results in customers being without electric service for durations of at least 24 hours and exceeds $200,000 in incremental costs.

customers. To the extent that the Company incurs major storm costs less than the annual amounts stated above, the Company will defer any variation less than those amounts for the benefit of customers. All major storm costs are subject to Staff review.

The Company's annual electric revenue requirements provide for $14.9 million in each Rate Year, reflecting a 5.4year amortization of previously incurred incremental major storm costs (net of insurance and other recoveries) due to major storms, including Winter Storm Toby and Tropical Storm Isaias, in excess of collections for major storm reserve funding.

b. Costs Chargeable to the Major Storm Reserve

The Company will be allowed to charge to the major storm reserve for costs incurred to obtain the assistance of contractors and/or utility companies providing mutual assistance, incremental employee labor, transportation, meals, lodging, and travel time (collectively, "Pre-Staging and Mobilization Costs") it incurs in reasonable anticipation that a storm will affect its electric operations to the degree meeting the criteria of a major storm as defined in 16 NYCRR Part 97, but which ultimately does not do so. Pre-Staging and Mobilization Costs up to $100,000 per event will not be chargeable to the major storm reserve. The Company will be allowed to charge to the major storm reserve Pre-Staging and Mobilization Costs in excess of $100,000 per event, up to a total of $1.75 million. For Pre-Staging and Mobilization Costs in excess of $1.75 million, per event, the Company will be allowed to charge 85% of such costs to the major storm reserve, and the Company will expense 15% of such costs in the year incurred. The Company may file a petition to defer the 15% of Pre-Staging and Mobilization Costs in excess of $1.75 million, per event. Each such petition will be subject to the Commission's three-part test traditionally applied to petitions requesting deferral accounting treatment.

The Company will not charge employee overtime to the major storm reserve for overtime work occurring more than 60 days following the date on which the Company is able to restore service to all customers. In addition, the Company will not charge stores handling, engineering, and other overheads costs to the major storm reserve.

c. Revenue Adjustment Mechanism

If the Company's actual major storm costs vary from the rate allowance by more than $2 million in a rate year, the Company will recover the variance, up to a cap of 2.5% of delivery revenues each year as a component of the Variable ECA.

10. Asbestos Workers Compensation Reserve (Electric)

The Company's electric revenue requirements do not reflect asbestos claim payments to the Company's former employees. If the Company incurs any such payments during the term of the Electric Rate Plan, the Company will defer these payments on its books of account for future recovery from customers.

11. Tree Trimming (Electric)

The Company will defer for the benefit of customers any cumulative shortfall over the term of the Electric Rate Plan between actual expenditures for the Company's transmission and distribution ("T&D") tree trimming program, including the danger tree programs and the Three-Phase Clearance Program, and the levels provided in rates, as set forth in Appendix 6. This reconciliation will continue after RY3 on an annual basis or on a pro-rated basis (by month) for any period less than 12 months.

12. REV Demonstration Project Costs (Electric)

The Company's electric revenue requirements include estimated REV Demonstration project costs, amortized over ten years. The Company will reconcile its actual costs for this item with the levels provided in rates, as set forth in Appendix 6. The demonstration project budget cap, regardless of cost recovery mechanism, is the revenue requirement associated with $10 million in capital expenditures, as described in the Track One Order.[7] In the event that demonstration projects would result in the Company exceeding the demonstration project budget cap, the Company may file a petition with the Commission to increase the budget cap.

13. Pomona NWA (Electric)

The Company's electric revenue requirements reflect Pomona NWA program costs to be incurred during the rate period, amortized over ten years, for an NWA solution in the Pomona substation area. The Company will reconcile its actual costs for this item with the levels provided in rates, as set forth in Appendix 6.

14. Platform Service Revenue (Electric)

Revenue generated from the sale of products and services on the Company's MY ORU Store online marketplace, as well as advertising and other program income, will be treated as a platform service revenue ("PSR"). Consistent with the REV Track 2 Order, 80 percent of the PSR will be deferred for customer benefit until base rates are reset and 20 percent will be retained by the Company.

15. Late Payment Charges (Electric and Gas)

The Company's electric and gas revenue requirements have been offset by forecasted revenues from late payment charges. The Company will reconcile its actual revenues for this item with the levels provided in rates, as set forth in Appendices 6 & 7, once the variance, in an annual amount, calculated and applied separately for electric and gas, equates to five (5) basis

[7] Case 14-M-0101, Order Adopting Policy Framework and Implementation Plan (issued February 26, 2015).

points of return on common equity or more. Recovery from, or refund to, customers of the variance will be via surcharge through the variable ECA and a new component of the MGA.[8] When the surcharge/sur-credit threshold has been met, the Company will notify Staff that it intends to begin collecting/refunding late payment charge variance through the ECA/MGA. Once that notification has been made, the Company will provide Staff reports on any late payment charge variance by April 30 of each year.

16. Covid Uncollectible Expenses (Electric and Gas)

The Company's electric and gas revenue requirements included forecasted uncollectible expenses. The Company will defer the difference between its actual uncollectible expense reserve with the level in rates each year, as set forth in Appendices 6 & 7.[9] The deferral amount will be excluded from rate base. The deferral amount will be fully reconciled with the cumulative actual write-offs for the period January 1, 2020 through December 31, 2024. Recovery or refund of the variance in write-offs (less savings for employee training and travel) may begin once the variance, in an annual amount, calculated and applied separately for electric and gas, equates to five (5) basis points of return on common equity or more. Recovery from, or refund to, customers of the variance will be via surcharge through new components of the ECA/MGA. When the surcharge/sur-credit threshold has been met, the Company will notify Staff that it intends to begin collecting/refunding uncollectible write-off variance through the

[8] Actual 2021 late payment fees will be reconciled relative to the level in rates pursuant to the rate plans authorized in Cases 18-E-0067 and 18-G-0068. Recovery from, or refund to, customers of the variance will be via surcharge through the ECA/MGA.

[9] The Company is deferring the change in its uncollectible expense reserve pursuant to the rate plans authorized in Cases 18-E-0067 and 18-G-0068. These deferrals will be included in cumulative reconciliation of actual write-offs in this provision.

ECA/MGA. Once that notification has been made, the Company will provide Staff reports on any uncollectible write-off variance by April 30 of each year.

Final, full reconciliation on uncollectible write-offs will occur at the end of 2024. At that time, any over-collections will be deferred for future ratepayer benefit and the Company may continue to recover against any under-collections via surcharge.

17. 2021 State Tax Law Change (Electric and Gas)

The electric and gas revenue requirements include a 7.25 percent New York State income tax rate. The Company will defer for customer benefit or Company recovery the difference between its actual state incomes taxes with the level in rates in each year, as set forth in Appendices 6 & 7. The deferral will include the Day 1 remeasurement of deferred tax assets and liabilities, the Day 2 impact of the higher NYS state tax rate on current and deferred income taxes and the Day 3 impact of reducing any temporary difference that originated at 7.25 percent, but will reverse after 12/31/2023 when the tax rate returns down to 6.5 percent.

18. Pipeline Emergency Responders Initiative (Gas)

The Company's gas revenue requirements include estimated Pipeline Emergency Responders Initiative costs. These costs are subject to a cumulative reconciliation over the term of the gas rate plan. The Company will defer for future credit to customers, the amount by which the actual expenses is less than the rate plan amounts shown on Appendix 7.

19. Additional Reconciliation/Deferral Provisions

In addition to the foregoing reconciliation provisions, along with all other provisions of this Proposal embodying the use of a reconciliation and/or deferral accounting mechanism, all other applicable existing reconciliations and/or deferral accounting mechanisms will continue in effect through the term of these Rate Plans and thereafter until modified or discontinued by the

Commission, except for those expressly identified in this Proposal for termination. Continuing reconciliation and/or deferral accounting mechanisms include, but are not limited to those for, MTA taxes, New York Public Service Law §18-a regulatory assessment, Renewable Portfolio Standard charges, vacation pay accrual pursuant to ASC 980 Regulated Operations, carrying charges for storage gas, the GSC, MGA, MSC, ECA, and System Benefits Charge ("SBC") mechanisms. The Company will defer any differences between the Company's actual revenues and authorized revenues, as determined by the Company's RDMs. In addition, the Company will defer any carrying costs for projects approved or required by the Commission that are incremental to the Company's capital additions, such as participation in regulated backstop solutions or generation as the provider of last resort.

Appendix 3 sets forth the annual amortization of deferred regulatory assets and liabilities included in the annual revenue requirements.

20. Discontinued Reconciliations

a. Credit Card Payment of Utility Bills (Electric and Gas)

Effective December 31, 2021, the Company will terminate its reconciliation for fees associated with customer usage of credit and debit cards for payment of utility bills. As this is now an established program, forecasted costs are included in the revenue requirements.

b. Tax Cuts and Jobs Act and Bonus Depreciation (Electric and Gas)

Effective December 31, 2021, the Company will terminate its reconciliation for 2017 bonus depreciation under the Tax Cuts and Jobs Act.

c. Pipeline Safety Act (Gas)

Effective December 31, 2021, the Company will terminate its reconciliation for costs to comply with new regulations associated with the Pipeline Safety Act of 2011 as no new regulations are expected.

d. Advanced Meter Infrastructure

Effective December 31, 2021, the Company will terminate its reconciliation for AMI-related net plant costs. The Company has fully reconciled all AMI-implementation costs,

e. Monsey NWA (Electric)

Effective December 31, 2021, the Company will terminate its reconciliation for the Monsey NWA. A subsequent phase of the Monsey NWA program is being developed and costs will be recovered via surcharge in accordance with Section A.1.c above (Non-Wires Alternatives).

f. Carbon Reduction Program (Electric)

Effective December 31, 2021, the Company will terminate its reconciliation for the Carbon Reduction Program.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-G-0073

Calculation of Lost and Unaccounted for Gas ("LAUF") and Dead Band Target
Based on 5 Year Period: 12 ME Aug 2017 to 12 ME Aug 2021

		Aug-21	Aug-20	Aug-19	Aug-18	Aug-17
	Citygate Receipts					
1	**Total Pipeline Receipts**	27,534,802	26,308,861	26,534,355	27,721,302	27,120,146
	Deliveries to Customers					
2	Retail Sales and Transportation Deliveries	24,593,553	24,516,851	25,648,853	25,755,426	24,153,152
3	Gas Used for Company Purposes (Including Inactive Gas Metered Usage)	46,676	42,826	54,867	39,713	22,585
4	Deliveries to Generation	2,288,544	1,513,414	316,922	1,749,745	2,629,526
5	**Total Deliveries (Line 2 - Line 4)**	26,928,774	26,073,091	26,020,642	27,544,883	26,805,262
6	**Losses (Line 1 - Line 5)**	606,028	235,770	513,714	176,419	314,884
7	**Contribution to system line loss from Generation at 1.0% (Line 4 * 0.01)**	22,885	15,134	3,169	17,497	26,295
8	**Adjusted Line Loss (Line 6 - Line 7)**	583,143	220,636	510,544	158,921	288,588
9	**Citygate Receipts adjusted for Generation (Line 1 - Line 7)**	25,223,373	24,780,313	26,214,264	25,954,060	24,464,325
10	***Annual Line Loss Factor (Line 8 / Line 9)***	2.312%	0.890%	1.948%	0.612%	1.180%

DETERMINE LAUF% TARGET & DEAD BAND
Basis: Target & Dead Band are calculated from 5 years of historical data
Dead Band is equal to +/- 2 standard deviations
No Incentive to Be Earned for LAUF % Target < 0

	5-Year Statistics (Aug 17 - Aug 21)	
11	**Mean LAUF% (Average of Line 10)**	1.388%
12	**Std Deviation (Std Deviation of Line 10)**	0.718%
13	**2 Std Deviation (Line 12 * 2)**	1.435%
	Target & Dead Band	
14	**LAUF% Target**	1.388%
15	**Upper Band (Mean + 2 SD)**	2.823%
16	**Lower Band (Mean - 2 SD)**	0.000%

The Fixed FOA will be reset every November 1 based on the average of the actual FOAs for the previous five twelve-month periods ended August 31.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-G-0073
GAS LOST AND UNACCOUNTED FOR

ILLUSTRATIVE CALCULATION OF LINE LOSS INCENTIVE / PENALTY

1	Total Distribution Sendout		25,246,258	Mcf
2	Customer Metered Volumes		24,663,115	Mcf
3	Actual Line Loss -- [(Line 1 - Line 2) / Line 1]		2.364%	
4	Actual Factor of Adjustment -- [1 / (1 - 0.0236)]		1.0242	
5	If Line 4 is ≥ Lower Dead band and ≤ Upper Dead band, equal to line 4 If Line 4 is < Lower Dead band, equal to line 12 If Line 4 is > Upper Dead band, equal to line 11		1.0242	
	Calculation of Benefit / (Shortfall):			
6	Total Cost of Gas 12 months Ended August XX		$75,000,000	
7	(Line 5 Above) -------------------------------- Actual Factor of Adjustment (Line 4 above)	1.0242 ---------- 1.0242	1.000000	
8	Net Adjusted Commodity Cost of Gas (Line 6 x Line 7)		$75,000,000	
9	Company Benefit / (Penalty) due to Line Losses (Line 8 - Line 6)		$0	

** The Fixed FOA for purposes of calculating incentives / penalties based on 1.388% losses equals:

10 $\dfrac{100.0}{(100.0 - 1.388)} = \dfrac{100.0}{98.612} =$ 1.0141

** The maximum "FOA Before Adjustment" based on 2.823% losses equals:

11 $\dfrac{100.0}{(100.0 - 2.823)} = \dfrac{100.0}{97.177} =$ 1.0291

** The minimum "FOA Before Adjustment" based on 0.000% losses equals:

12 $\dfrac{100.0}{(100.0 - 0.000)} = \dfrac{100.0}{100} =$ 1.0000

Note: The Fixed FOA will be reset every November 1 based on the average of the actual FOAs for the previous five twelve-month periods ended August 31.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-G-0073
GAS LOST AND UNACCOUNTED FOR

ILLUSTRATIVE CALCULATION OF
SYSTEM PERFORMANCE ADJUSTMENT ("SPA") MECHANISM

1	Total Distribution Sendout		25,246,258	Mcf
2	Customer Metered Volumes		24,663,115	Mcf
3	Actual Line Loss -- [(Line 1 - Line 2) / Line 1]		2.364%	
4	Actual Factor of Adjustment -- [1 / (1 - 0.0236)]		1.0242	
5	If Line 4 is ≥ Lower Dead band and ≤ Upper Dead band, equal to line 4 If Line 4 is < Lower Dead band, equal to line 14 If Line 4 is > Upper Dead band, equal to line 13		1.0242	
	Calculation of Benefit / (Shortfall):			
6	Total Cost of Gas 12 months Ended August XX		$75,000,000	
7	(Line 5 above) -------------------------------- Fixed Factor of Adjustment (Line 13 Below)	1.0242 ---------- 1.0141	1.009960	
8	Net Adjusted Commodity Cost of Gas (Line 6 x Line 7)		$75,747,000	
9	SPA Dollars to (Credit) / Charge Customers through MGA (Line 8 - Line 6)		$747,000	
10	Forecasted Firm Sales (SC Nos. 1, 2, and 6) (Ccf) for 12 ME Dec 20XX		196,770,000	Ccf
11	SPA Mechanism Rate ($/Ccf) in Monthly Gas Adjustment		$0.00380	

** The Fixed FOA for purposes of calculating incentives / penalties based on 1.388% losses equals:

12 $$\frac{100.0}{(100.0 - 1.388)} = \frac{100.0}{98.612} = 1.0141$$

** The maximum "FOA Before Adjustment" based on 2.823% losses equals:

13 $$\frac{100.0}{(100.0 - 2.823)} = \frac{100.0}{97.177} = 1.0291$$

** The minimum "FOA Before Adjustment" based on 0.000% losses equals:

14 $$\frac{100.0}{(100.0 - 0.000)} = \frac{100.0}{100} = 1.0000$$

Note: The Fixed FOA will be reset every November 1 based on the average of the actual FOAs for the previous five twelve-month periods ended August 31.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-G-0073

Examples of Incentives/Penalties and SPA Mechanism At Various Actual Factor of Adjustments

		Actual FOA Below Dead band	Actual FOA Between Minimum FOA and Fixed FOA	Actual FOA Between Fixed FOA and Maximum FOA	Actual FOA Above Dead band
1	Actual Line Loss Factor	0.762%	1.414%	2.027%	2.560%
2	Actual Factor of Adjustment	1.0077	1.0143	1.0207	1.0263
3	Lower Dead Band	1.0000	1.0000	1.0000	1.0000
4	Upper Dead Band	1.0291	1.0291	1.0291	1.0291
5	Adjustment to Cost of Gas Formula for Line Loss Incentive Penalty Applied to GSC	= 1.0098 / 1.0077	= 1.0151 / 1.0151	= 1.0207 / 1.0207	= 1.0247 / 1.0263
6	Adjustment to Cost of Gas for Line Loss Incentive Penalty Applied to GSC	0.992359	1.000000	1.000000	1.002728
7	Actual Cost of Gas	$75,000,000	$75,000,000	$75,000,000	$75,000,000
8	Cost of Gas Adjustment Factor for Line Loss Incentive / Penalty Applied to GSC	0.99236	1.00000	1.00000	1.00273
9	Net Adjusted Cost of Gas for Line Loss Incentive / Penalty Applied to GSC	$74,426,925	$75,000,000	$75,000,000	$75,204,600
10	Company Benefit / (Penalty) Due to Line Losses Applied to GSC	($573,075)	$0	$0	$204,600
11	Adjustment to Cost of Gas Formula for Line Loss Incentive Penalty Applied to MGA	= 1.0098 / 1.0172	= 1.0151 / 1.0172	= 1.0207 / 1.0172	= 1.0247 / 1.0172
12	Adjustment to Cost of Gas for Line Loss Incentive Penalty Applied to MGA	0.983091	0.997149	1.003441	1.011699
13	Net Adjusted Cost of Gas for Line Loss Incentive / Penalty Applied to MGA	$73,731,825	$74,786,175	$75,258,075	$75,877,425
14	SPA Dollars to (Credit) / Charge Customers through MGA	($1,268,175)	($213,825)	$258,075	$877,425

Note: The Fixed FOA will be reset every November 1 based on the average of the actual FOAs for the previous five twelve-month periods ended August 31.

ORANGE & ROCKLAND UTILITIES
AVERAGE SERVICE LIVES, NET SALVAGE
ANNUAL DEPRECIATION RATES AND LIFE TABLES
(ELECTRIC AND COMMON EFFECTIVE 1/1/2022, GAS EFFECTIVE 1/1/2024)

PSC ACCT NUMBER	ACCOUNT DESCRIPTION	LIFE TABLE	AVERAGE SERVICE LIFE (Years)	NET SALVAGE %	ANNUAL RATE %	
ELECTRIC PLANT						
INTANGIBLE PLANT						
303100	WMS SOFTWARE	SQ	5	-	20.00	(A)
303110	DISTRIBUTION MANAGEMENT SYSTEM	SQ	5	-	20.00	(A)
303120	DISTRIBUTION ENGINEERING SYSTEM (DEW)	SQ	5	-	20.00	(A)
303130	STRAY VOLTAGE SYSTEM	SQ	5	-	20.00	(A)
303140	OUTAGE MANAGEMENT SYSTEM (OMS)	SQ	5	-	20.00	(A)
303150	WEB WMS PHASE 1	SQ	5	-	20.00	(A)
303170	2009 ELECTRIC SOFTWARE ADDITIONS	SQ	5	-	20.00	(A)
303190	2011 ELECTRIC SOFTWARE	SQ	5	-	20.00	(A)
303830	MUNICIPAL ST. LT	SQ	5	-	20.00	(A)
303840	OUTAGE MGMT PH II	SQ	5	-	20.00	(A)
303850	OMS 2014 UPGRADE	SQ	5	-	20.00	(A)
303870	EIMS 2014	SQ	5	-	20.00	(A)
303880	ECC/ACC	SQ	5	-	20.00	(B)
303890	2014 NUCON DG	SQ	5	-	20.00	(A)
303900	ARCOS CREW MANAG	SQ	5	-	20.00	(A)
303920	STORM OUTAGE DASHBOARD	SQ	5	-	20.00	(A)
303940	SOFTWARE 5 YEARS	SQ	5	-	20.00	(B)
303945	SOFTWARE 5 YEARS CLOUD	SQ	5	-	20.00	(B)
TRANSMISSION PLANT						
350000	LAND-EASEMENTS	R3	70	-	1.43	
350100	LAND AND LAND RIGHTS	-	-	-	-	
351000	ENERGY STORAGE EQUIPMENT TRANS	S2.5	15	-	6.67	
352000	STRUCTURES AND IMPROVEMENTS	R1.5	65	(15)	1.77	
353000	STATION EQUIPMENT	R1	45	(20)	2.67	
354000	TOWERS AND FIXTURES	R4	70	(30)	1.86	
355000	POLES AND FIXTURES-WOOD	R3	60	(40)	2.33	
355100	POLES AND FIXTURES-STEEL	R3	60	(40)	2.33	
356000	OVERHEAD CONDUCTORS & DEVICES	R1.5	65	(20)	1.85	
356100	OVERHEAD COND & DEVICES-CLEARING	R1.5	65	0	1.54	
357000	UNDERGROUND CONDUIT	R3	45	-	2.22	
358000	UNDERGROUND COND AND DEVICES	S3	35	(5)	3.00	
359000	ROADS AND TRAILS	R4	70	-	1.43	
DISTRIBUTION PLANT						
360000	LAND-EASEMENTS	S3	70	-	1.43	
360100	LAND AND LAND RIGHTS-FEE	-	-	-	-	
361000	STRUCTURES AND IMPROVEMENTS	R3	55	(15)	2.09	
362000	STATION EQUIPMENT	S0	50	(15)	2.30	
363000	ENERGY STORAGE EQUIPMENT DIST	S2.5	15	-	6.67	
364000	POLES,TOWERS, AND FIXTURES	R0.5	60	(100)	3.33	
365000	OVERHEAD CONDUCTOR AND DEVICES	R1.0	70	(95)	2.79	
365100	O/H COND AND DEVICES-CAPACITORS	R1.5	30	(35)	4.50	
366000	UNDERGROUND CONDUIT	R3	75	(40)	1.87	
367000	UNDERGROUND CONDUCTOR & DEVICES	R4	60	(40)	2.33	
367100	U.G. COND. & DEVICES - CABLE CURE	(A)	-	-	-	
368100	LINE TRANSFORMERS-OVERHEAD	R0.5	50	(20)	2.40	
368200	LINE TRANSFORMERS-O/H INSTALLS	R0.5	50	(20)	2.40	
368300	LINE TRANSFORMERS-UNDERGROUND	R0.5	50	(20)	2.40	
368400	LINE TRANSFORMERS-U/G INSTALLS	R0.5	50	(20)	2.40	
369100	SERVICES-OVERHEAD	R3	65	(105)	3.15	
369200	SERVICES-UNDERGROUND	R3	65	(105)	3.15	
370100	METERS - ELECTRO-MECHANICAL	L0	25	-	4.00	
370110	METERS - SOLID-STATE	S2.5	20	-	5.00	
370120	METERS - AMI METERS	S2	20	-	5.00	
370150	METERS - UNRECOVERED EM PURCHASES	(D)				
370160	METERS - UNRECOVERED SS PURCHASES	(D)				
370200	METER INSTALLATIONS - ELECTRO-MECHANICAL	L0	25	-	4.00	
370210	METER INSTALLATIONS - SOLID-STATE	S2.5	20	-	5.00	
370220	METER INSTALLATIONS - AMI	S2	20	-	5.00	
370250	METERS - UNRECOVERED EM INSTALL	(D)				
370260	METERS - UNRECOVERED SS INSTALL	(D)				
371000	INSTALLATION ON CUSTOMER PREMISES	R0.5	45	-	2.22	
371100	PALISADES MALL METERING	(A)	-	-	-	
373100	STREET LIGHTS-OVERHEAD	R0.5	45	(50)	3.33	
373200	STREET LIGHTS-UNDERGROUND	R0.5	45	(50)	3.33	

ORANGE & ROCKLAND UTILITIES
AVERAGE SERVICE LIVES, NET SALVAGE
ANNUAL DEPRECIATION RATES AND LIFE TABLES

PSC ACCT NUMBER	ACCOUNT DESCRIPTION	LIFE TABLE	AVERAGE SERVICE LIFE (Years)	NET SALVAGE %	ANNUAL RATE %	
ELECTRIC PLANT						
GENERAL PLANT						
389100	LAND AND RIGHTS - FEE	-	-	-	-	
390000	STRUCTURES AND IMPROVEMENTS	S0	45	(30)	2.89	
391100	OFFICE FURN/EQUIP-FURNITURE	SQ	20	-	5.00	(B)
391200	OFFICE FURN/EQUIP-OFFICE MACHINES	SQ	15	-	6.67	(B)
391700	OFFICE FURN/EQUIP-P/C EQUIPMENT	SQ	8	-	12.50	(B)
391800	OFFICE FURN/EQUIP-E.C.C.	SQ	13	-	7.69	(B)
392100	TRANSP EQUIP-PASSENGER CARS	S2.5	12	10	7.50	
392200	TRANSP EQUIP-LIGHT TRUCKS	S1	10	10	9.00	
392300	TRANSP EQUIP-HEAVY TRUCKS	L3	14	5	6.79	
392400	TRANSP EQUIP-TRAILERS/TRAILER MTD EQ.	L3	14	5	6.79	
393000	STORES EQUIPMENT	SQ	20	-	5.00	(B)
394000	TOOLS, SHOP AND WORK EQUIPMENT	SQ	20	-	5.00	(B)
395000	LABORATORY EQUIPMENT	SQ	20	-	5.00	(B)
396000	POWER OPERATED EQUIPMENT	R3	18	15	4.72	
396100	POWER OPERATED EQ - NON FLEET	R3	18	15	4.72	
397000	COMMUNICATION EQUIPMENT	SQ	15	-	6.67	(B)
397100	COMMUNICATION EQUIPT-TELE SYSTEM COMPUTER	SQ	15	-	6.67	(B)
398000	MISCELLANEOUS EQUIPMENT	SQ	20	-	5.00	(B)
PLANT HELD FOR FUTURE USE - TRANSMISSION						
350009	LAND AND LAND RIGHTS-EASEMENTS		0	-	-	
PLANT HELD FOR FUTURE USE - DISTRIBUTION						
360009	LAND AND LAND RIGHTS-EASEMENTS		0	-	-	
360109	LAND AND LAND RIGHTS-EASEMENTS	-	-	-	-	

ORANGE & ROCKLAND UTILITIES
AVERAGE SERVICE LIVES, NET SALVAGE
ANNUAL DEPRECIATION RATES AND LIFE TABLES

PSC ACCT NUMBER	ACCOUNT DESCRIPTION	LIFE TABLE	AVERAGE SERVICE LIFE (Years)	NET SALVAGE %	ANNUAL RATE %	
COMMON PLANT						
INTANGIBLE PLANT						
301000	ORGANIZING	-	-	-	-	
303180	2011 COMMON SOFTWARE ADDITION	SQ	5	-	20.00	(A)
303200	MAPPING SOFTWARE	SQ	5	-	20.00	(A)
303310	EZ VMS SYSTEM	SQ	5	-	20.00	(A)
303320	PEOPLESOFT HR/PR SYSTEM	SQ	15	-	6.67	(B)
303330	PROJECT ONE- GL	SQ	15	-	6.67	(B)
303400	CIMS SYSTEM SOFTWARE	SQ	15	-	6.67	(A)
303401	CIMS SYSTEM SOFTWARE UPGRADE	SQ	5	-	20.00	(A)
303410	CUSTOMER BILLING SYSTEM	SQ	15	-	6.67	(A)
303450	ORACLE STRATEGIC AGREEMENT	SQ	15		6.67	(B)
303500	PLUS SYSTEM SOFTWARE	SQ	5	-	20.00	(A)
303510	POWERPLAN SOFTWARE	SQ	15	-	6.67	(B)
303600	WALKER SYSTEM SOFTWARE	SQ	5	-	20.00	(A)
303700	BUDGET SYSTEM SOFTWARE	SQ	5	-	20.00	(A)
303800	RETAIL ACCESS SOFTWARE	SQ	5	-	20.00	(A)
303810	RETAIL ACCESS SOFTWARE PHASE 4	SQ	5	-	20.00	(A)
303840	FIELD ORDER ROUTE DESIGN SYSTEM	SQ	5	-	20.00	(A)
303870	DATAPIPE SOFTWARE	SQ	5	-	20.00	(A)
303900	NEW BUS PROJ MGMT	SQ	5	-	20.00	(A)
303910	NEW CONSTRUCTION SERVICES (NUCON)	SQ	5	-	20.00	(A)
303911	NUCON ENHANCEMENT	SQ	5	-	20.00	(A)
303920	ROPES	SQ	5	-	20.00	(A)
303930	STORM COMMUNICATION	SQ	5	-	20.00	(A)
303940	COMMON SOFTWARE 5 YEARS	SQ	5	-	20.00	(B)
303945	COMMON SOFTWARE 5 YEARS CLOUD	SQ	5	-	20.00	(B)
303941	COMMON SOFTWARE 15 YEARS	SQ	15		6.67	(B)
303950	PHONE APP	SQ	5	-	20.00	(B)
303960	RETAIL ACCESS 2015	SQ	5	-	20.00	(A)
303970	ROUTE SMART	SQ	5	-	20.00	(A)
303980	EPMS	SQ	5	-	20.00	(A)
303990	WEDSITE REDESIGN	SQ	5	-	20.00	(B)
303991	AMI SOFTWARE	SQ	20	-	5.00	(B)
303998	AMI SOFTWARE CLOUD	SQ	20	-	5.00	(B)
303992	CUSTOMER OUTAGE COMMUNICATION	SQ	5	-	20.00	(B)
303993	FLEET MANAGEMENT	SQ	5	-	20.00	(B)
303994	PI 360	SQ	5	-	20.00	(B)
303995	PRIMATE SITUATIONAL AWARENESS	SQ	5	-	20.00	(A)
GENERAL PLANT EQUIPMENT						
389000	LAND-EASEMENTS	R3	50	-	2.00	
389100	LAND AND LAND RIGHTS -FEES	-	-	-	-	
390000	STRUCTURES AND IMPROVEMENTS	S0	45	(30)	2.89	
390100	LEASEHOLD IMPROVEMENTS-BLUE HILL		-	-	-	(C)
391100	OFFICE FURN/EQUIP-FURNITURE	SQ	20	-	5.00	(B)
391200	OFFICE FURN/EQUIP-OFFICE MACHINES	SQ	15	-	6.67	(B)
391300	OFFICE FURN/EQUIP-CASH EQUIPMENT	SQ	8	-	12.50	(B)
391700	OFFICE FURN/EQUIP-P/C EQUIPMENT	SQ	8	-	12.50	(B)
391710	OFFICE FURN/EQUIP-NON P/C EQUIPMENT	SQ	8	-	12.50	(B)
392100	TRANSP EQUIP-PASSENGER CARS	S2.5	12	10	7.50	
392200	TRANSP EQUIP-LIGHT TRUCKS	S1	10	10	9.00	
392300	TRANSP EQUIP-HEAVY TRUCKS	L3	14	5	6.79	
392400	TRANSP EQUIP-TRAILERS/TRAILER MTD EQ.	L3	14	5	6.79	
393000	STORES EQUIPMENT	SQ	20	-	5.00	(B)
394000	TOOLS, SHOP AND WORK EQUIPMENT	SQ	20	-	5.00	(B)
394200	GARAGE EQUIPMENT	SQ	20	-	5.00	(B)
395000	LABORATORY EQUIPMENT	SQ	20	-	5.00	(B)
396000	POWER OPERATED EQUIPMENT	R3	18	15	4.72	
396100	POWER OPERATED EQ. - NON FLEET	R3	18	15	4.72	
397000	COMMUNICATION EQUIPMENT	SQ	15	-	6.67	(B)
397100	COMMUNICATION EQ.-TELE SYS COMPUTER	SQ	15	-	6.67	(B)
397200	COMMUNICATION EQ.-TELE SYS EQPT	SQ	15	-	6.67	(B)
398000	MISCELLANEOUS EQUIPMENT	SQ	20	-	5.00	(B)

ORANGE & ROCKLAND UTILITIES
AVERAGE SERVICE LIVES, NET SALVAGE
ANNUAL DEPRECIATION RATES AND LIFE TABLES

PSC ACCT NUMBER	ACCOUNT DESCRIPTION	LIFE TABLE	AVERAGE SERVICE LIFE (Years)	NET SALVAGE %	ANNUAL RATE %	
GAS PLANT						
TRANSMISSION PLANT						
367002	GAS MAINS STEEL	R3	70	(35)	1.93	
367003	GAS MAINS PLASTIC	R3	70	(35)	1.93	
367005	LPP MAINS	R3		(35)	4.97	(E)
367322	MAINS - STEEL - STONY POINT		-	-	-	
367502	MAINS - LEDERLE		-	-	-	(A)
DISTRIBUTION PLANT						
374000	LAND & LAND RIGHTS - EASEMENTS	R4	75	-	1.33	
374100	LAND & LAND RIGHTS - FEE	-	-	-	-	
374200	LAND - FEE - CLEVEPAK		-	-	-	(A)
375000	STRUCTURES & IMPROVEMENTS	R2.5	65	(30)	2.00	
375100	ST. & IMPROV. - STONY POINT MAIN		-	-	-	(A)
376000	GAS MAINS PLASTIC	R3	70	(35)	1.93	
376005	LPP MAINS PLASTIC	R3		(35)	6.90	(E)
376100	LPP GAS MAINS CAST IRON	R3		(35)	4.21	(E)
376200	MAINS - CLEVEPAK		-	-	-	(A)
376300	GAS MAINS STEEL	R3	70	(35)	1.93	
376305	LPP MAINS-STEEL	R3		(35)	4.84	(E)
376330	MAINS - TRANSCO		-	-	-	(A)
377000	COMPRESS STATION EQ	S0	35	(20)	3.43	
378000	MEASURING AND REGULATING EQ.	S0	35	(20)	3.43	
378100	MEAS. & REG. EQ. - STONY POINT		-	-	-	(A)
378330	MEAS. & REG. EQ. - TRANSCO		-	-	-	(A)
378340	MEAS. & REG. EQ. - TRANSCO ORDER 63		-	-	-	(A)
380000	SERVICES	R3	65	(90)	2.92	
380005	LPP SERVICES PLASTIC	R3		(90)	8.04	(E)
380006	SERVICES STEEL	R3	65	(90)	2.92	
380007	LPP SERVICES STEEL	R3		(90)	5.21	(E)
381000	METERS	R2	40	-	2.50	
381200	METERS - AMI PURCHASE	S2	20	-	5.00	
382000	METER INSTALLATIONS	R3	55	(15)	2.09	
382200	METER INST. - AMI	S2	20	(15)	5.75	
382400	METER BAR INSTALLATIONS	R3	55	(15)	2.09	
383000	HOUSE REGULATORS	R2	40	-	2.50	
384000	HOUSE REGULATOR INSTALLATIONS	R3	55	(15)	2.09	
385000	INDUSTRIAL MEAS. & REG. EQ.	R4	35	(5)	3.00	
385500	IND. MEAS. & REG. EQ. - LEDERLE		-	-	-	(A)
386300	OTHER PROP. ON CUSTS.' PREM.	S3	20	-	5.00	
GENERAL PLANT EQUIPMENT						
389100	LAND - FEE	-	-	-	-	
390000	STRUCTURES AND IMPROVEMENTS	S0	45	(30)	2.89	
391100	OFFICE FURNITURE & EQ. - FURNITURE	SQ	20	-	5.00	(B)
391200	OFFICE FURNITURE & EQ. - MACHINES	SQ	15	-	6.67	(B)
391700	OFFICE FURNITURE & EQ. - EDP EQ.	SQ	8	-	12.50	(B)
392100	TRANSPORTATION EQ. - PASS. CARS	S2.5	12	10	7.50	
392200	TRANS. EQ. - LIGHT TRUCKS	S1	10	10	9.00	
392300	TRANS. EQ. - HEAVY TRUCKS	L3	14	5	6.79	
392400	TRANS. - TRAILERS	L3	14	5	6.79	
393000	STORES EQUIPMENT	SQ	20	-	5.00	(B)
394000	TOOLS & WORK EQUIPMENT	SQ	20	-	5.00	(B)
395000	LABORATORY EQUIPMENT	SQ	20	-	5.00	(B)
396000	POWER OPERATED EQUIPMENT	R3	18	15	4.72	
396100	POWER OPERATED EQUIPMENT - NON FLEET	R3	18	15	4.72	
397000	COMMUNICATION EQUIPMENT	SQ	15	-	6.67	(B)
397500	COMM EQ NG DETECTOR	SQ	5	-	20.00	
398000	MISCELLANEOUS EQUIPMENT	SQ	20	-	5.00	(B)

ORANGE & ROCKLAND UTILITIES
AVERAGE SERVICE LIVES, NET SALVAGE
ANNUAL DEPRECIATION RATES AND LIFE TABLES
(ELECTRIC AND COMMON EFFECTIVE 1/1/2022, GAS EFFECTIVE 1/1/2024)

PSC ACCT NUMBER	ACCOUNT DESCRIPTION	LIFE TABLE	AVERAGE SERVICE LIFE (Years)	NET SALVAGE %	ANNUAL RATE %	
INTANGIBLE PLANT						
302100	FRANCHISES AND CONSENTS					
302200	FRANCHISES & CONSENTS - AMORT.	SQ	5	-	20.00	(A)
303210	SOFTWARE - ADVANTICA GAS	SQ	5	-	20.00	(A)
303220	GMD AND GIMS 2011	SQ	5	-	20.00	(A)
303830	GAS INSPECTION MGT. SYSTEM	SQ	5	-	20.00	(A)
303850	GAS MOBILE DISPATCH SYSTEM	SQ	5	-	20.00	(A)
303880	GIMS - PHASE 2	SQ	5	-	20.00	(A)
303890	GMD - PH2 GIMS-PH3	SQ	5	-	20.00	(A)
303900	GMD METER ORDERS	SQ	5	-	20.00	(A)
303940	GAS SOFTWARE 5 YEARS	SQ	5	-	20.00	(B)
303945	GAS SW CLOUD	SQ	5	-	20.00	(B)
NONUTILITY PROPERTY						
304100	LAND & LAND RIGHTS - FEE					
304200	LAND & LAND RIGHTS - EASEMENTSTRUCTURES AND					(A)
304300	STRUCTURES AND IMPROVEMENTS					(A)

NOTES:

(A)	**Account is fully recovered**	
(B)	**Amortizable Accounts**	
(C)	**Account is amortizable over the remaining life of the assets.**	
(D)	**Additional accounts are opened to record unrecovered meters. The annual amortization expenses are:**	
	OR - E- 370150 - UNRECOVERED EM PURCHASE	**$437,667**
	OR - E- 370160 - UNRECOVERED SS PURCHASE	**$447,133**
	OR - E- 370250 - UNRECOVERED EM INSTALL	**$166,133**
	OR - E- 370260 - UNRECOVERED SS INSTALL	**$519,533**
		$1,570,466
(E)	**Fixed amortization starting at January 1, 2024 for 10 years. The annual amortization expenses are:**	
	OR-G- 367005 - MAINS LPP	**$29,748**
	OR-G- 376005 - MAINS PLASTIC LPP	**$318,811**
	OR-G- 376100 - GAS MAINS CAST IRON	**$6,921**
	OR-G- 376305 - MAINS STEEL LPP	**$86,947**
	OR-G-380005 - SERVICES PLASTIC LPP	**$288,796**
	OR-G-380007 - SERVICES STEEL LPP	**$20,487**
		$751,710

Orange and Rockland
Cases 21-E-0074 and 21-G-0073
Earnings Sharing Partial Year
Stub Period Starting January 1, 2025
(000's)

Assumption: O&R Files for New Gas Rates Effective January 2025,
but Delays Filing for New Electric Rates for Six Months

Month / Year	Electric Operating Income (1)	
January-25	$ 2,400	
February-25	1,500	
March-25	300	
April-25	1,800	
May-25	2,800	
June-25	10,500	
Total		$ 19,300

	Electric Rate Base (1)	
Projected Rate Base at December 31, 2024	$ 1,000,000	
Projected Rate Base at June 30, 2025	1,020,000	
Total	2,020,000	
Divided by Two	2	
Average Rate Base During Stub Period	$ 1,010,000	
x Ratio of operating income for the six months ended June 2021 to operating income for the 12 months ended December 2021	25.3%	
Rate Base Subject to Earnings Test		$ 255,000
Overall Rate of Return ($ 19,300 / $ 255,000)		7.57%
Return on Equity (Page 2)	10.96%	
Earnings Sharing Threshold	9.70%	
Earnings Above / (Under) Threshold	1.26%	
Equity Earnings Base ($ 255,000 x 48.00%)	$ 122,400	
Equity Earnings Above / (Under) Threshold Subject to Sharing ($ 122,400 x 1.26%)	$ 1,540	

Note: the approach illustrated above would also apply to a delay in filing a gas case.

Orange and Rockland
Cases 21-E-0074 and 21-G-0073
Capital Structure & Cost of Money
Stub Period Starting January 1, 2025

	Capital Structure %	Cost Rate %	Cost of Capital %
Long Term Debt	51.42%	4.49%	2.31%
Customer Deposits	0.58%	0.05%	0.00%
Total Debt	52.00%		2.31%
Common Equity	48.00%	10.96%	5.26%
Total	100.00%		7.57%

Orange and Rockland Utilities, Inc.
Cases 21-G-0073 and 21-E-0074

Electric Reliability Performance Mechanism

Operation of Mechanism:

The Reliability Performance Mechanism ("RPM") includes targets for the frequency and duration of electric service interruption, defined as:

1. Customer Average Interruption Duration Index ("CAIDI") – the average interruption duration time (hours) for those customers that experience an interruption during the year.
2. System Average Interruption Frequency Index ("SAIFI") – the average number of times that a customer is interrupted during a year.

The SAIFI and CAIDI performance targets for Orange and Rockland are 1.20 and 1.85, respectively, with negative revenue adjustments of 20 basis points for failure to meet each target on a calendar year basis. These targets are currently in effect and will continue until reset by the Commission.

Exclusions:

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

1. Any outages resulting from a major storm, as defined in 16 NYCRR Part 97.
2. Any incident resulting from a strike or a catastrophic event beyond the control of the Company, including but not limited to a plane crash, water main break, or natural disasters (*e.g.*, hurricanes, floods, earthquakes).
3. Any incident where problems beyond the Company's control involving generation or the

bulk transmission system is the key factor in the outage, including, but not limited to, NYISO mandated load shedding. This criterion is not intended to exclude incidents that occur as a result of unsatisfactory performance by the Company.

Reporting:

The RPM will be measured on a calendar year basis. Accordingly, the results of the performance measurements, as measured during the calendar year 2022, 2023, and 2024, respectively, will be applied to Rate Years 1, 2, and 3, respectively.

The Company will prepare an annual report(s) on its performance under this reliability mechanism. The annual report(s) will be filed by March 31st of each year with the Secretary to the Commission (*e.g.*, the annual report for 2022 shall be due by March 31, 2023). The report(s) will state the following:

1. Company's annual system-wide performance under the RPM and identify whether a revenue adjustment is applicable and, if so, the amount of the revenue adjustment; and
2. Whether any exclusions should apply, the basis for requesting each exclusion, and adequate support for all requested exclusions.

Orange and Rockland Utilities, Inc.
Cases 21-G-0073

Gas Safety Performance Metrics

The gas safety performance measures described herein will be in effect for the term of the Gas Rate Plan. All gas safety measures and targets (and associated revenue adjustments)[1] for calendar year 2024 remain in effect thereafter unless and until changed by the Commission.[2]

Negative Revenue Adjustments

1. **Leak Management/Emergency Response/Damages**

a. Leak Management – Repairable Leaks

If the repairable leak backlog (types 1, 2 and 2A) exceeds the targets set forth below in calendar year 2022, 2023 and 2024, the following negative rate adjustment will apply for each calendar year that the performance measures noted below are not attained.[3]

2022

Less than or equal to 20	No adjustment
Greater than 20	10 basis points[4]

2023

Less than or equal to 20	No adjustment
Greater than 20	10 basis points

[1] Negative revenue adjustments relating to the Gas Safety Performance metrics in this section shall not exceed 150 basis points in RY1, RY2 or RY3.

[2] The 66 mile replacement target established below, for the three-year period 2022 to 2024, does not remain in effect beyond 2024. However, the 20 miles of main removal per year will remain in effect beyond 2024, unless and until changed by the Commission.

[3] Only "successful elimination" of a leak will be considered a valid leak repair.

[4] The basis point negative rate adjustment associated with each measure is stated on a pre-tax basis. The revenue requirement equivalents of a ten basis point on common equity capital per the gas revenue requirements under this Proposal are estimated to be approximately $0.377 million in RY1, $0.405 million in RY2 and $0.433 million in RY3.

2024

Less than or equal to 20	No adjustment
Greater than 20	10 basis points

Orange and Rockland will be recognized as having met the leak backlog targets if they are achieved between December 21, and December 31 in RY1, RY2 and RY3.

b. Leak Management - Year-End Total Backlog

If the year-end total leak backlog (types 1, 2, 2A and 3) exceeds the targets set forth below in calendar year 2022, 2023 and 2024, the following negative rate adjustment will apply for each calendar year that the performance measures noted below are not attained.[5]

2022

Less than or equal to 50	No adjustment
Greater than 50	5 basis points

2023

Less than or equal to 50	No adjustment
Greater than 50	5 basis points

2024

Less than or equal to 50	No adjustment
Greater than 50	5 basis points

Orange and Rockland will be recognized as having met the leak backlog targets if they are achieved between December 21, and December 31 in RY1, RY2 and RY3.

[5] Only "successful elimination" of a leak will be considered a valid leak repair. In addition, the Company will recheck Type 3 leaks.

c. Emergency Response - 30 Minute Response Time

If Orange and Rockland does not respond to gas leak or odor calls within 30 minutes for at least 75 percent of the calls for calendar years 2022, 2023 and 2024, a negative rate adjustment of twelve basis points will apply for each calendar year that the performance measures are not attained.

The Company may seek the following exclusion to operating performance under this measure:

> Gas leak and odor calls resulting from such events as mass area odor complaints, major weather-related occurrences, or major equipment failure.

Orange and Rockland shall provide notification to safety@dps.ny.gov within seven days of such event that the Company is seeking Staff's consent to the exclusion. Staff will respond whether it consents or does not consent to the requested exclusion.[6] The Company may proceed with filing its request for an exclusion if it has not received a response from Staff within 90 days.

d. Emergency Response - 45 Minute Response Time

If Orange and Rockland does not respond to gas leak or odor calls within 45 minutes for at least 90 percent of the calls for calendar years 2022, 2023 and 2024, a negative rate adjustment of eight basis points will apply for each calendar year that the performance measures are not attained.

e. Emergency Response - 60 Minute Response Time

If Orange and Rockland does not respond to gas leak or odor calls within 60 minutes for at least 95 percent of the calls for calendar years 2022, 2023 and 2024, a negative rate adjustment of five basis points will apply for each calendar year that the performance measures are not attained.

[6] This exclusion, as well as the right to petition the Commission pursuant to the General Provisions section below, also applies to the 45-Minute Response Time and 60-Minute Response Time measures.

f. Damage Prevention

All damages will be tracked, measured and counted following the guidelines for the data reported for the Annual Gas Safety Performance Measures report. Hand damages where notification has been provided will be included in this measure.

If the number of total damages to Company gas facilities made by any party exceeds the targets set forth below per 1,000 one-call tickets in calendar year 2022, 2023 and 2024, the negative rate adjustment associated with such target will apply for each calendar year that the performance measure noted below is not attained.[7]

<u>2022</u>

Greater than 1.50 but less than or equal to 2.00	No adjustment
greater than 2.00 but less than or equal to 2.25	5 basis points
greater than 2.25 but less than or equal to 2.50	10 basis points
greater than 2.50	20 basis points

<u>2023</u>

Greater than 1.50 but less than or equal to 2.00	No adjustment
greater than 2.00 but less than or equal to 2.25	5 basis points
greater than 2.25 but less than or equal to 2.50	10 basis points
greater than 2.50	20 basis points

<u>2024</u>

Greater than 1.50 but less than or equal to 2.00	No adjustment
greater than 2.00 but less than or equal to 2.25	5 basis points
greater than 2.25 but less than or equal to 2.50	10 basis points
greater than 2.50	20 basis points

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

[7] Orange and Rockland will have the option to average the current year and prior year total damage number to calculate the total damages number used to establish the Company's performance for 2022, 2023 and 2024. (*e.g.*, if this option is exercised, the total damage performance for Orange and Rockland in 2022 would be the average of the Company's total damage performance for 2021 and 2022).

The Company will remove from service a minimum of 66 miles of leak-prone gas main[8] during the three calendar year period 2022 to 2024. The Gas Rate Plan establishes minimum replacement targets of 20 miles in 2022, 20 miles in 2023 and 20 miles in 2024. Following the term of the Gas Rate Plan, a minimum of 20 miles of leak-prone gas main will be replaced each year.

If the Company does not meet the annual 20-mile minimum for removal of leak-prone gas main in 2022, 2023 or 2024, the Company will be subject to a negative revenue adjustment equivalent to: fifteen basis points for failing to meet the minimum in 2022 and/or 2023; and seven and one-half basis points for failing to meet the minimum in 2024. If the Company does not remove from service a total of 66 miles of leak-prone pipe over the three-year period, the Company will be subject to a negative rate adjustment equivalent to seven and one-half basis points.

Ineffectively coated steel will be counted if it is in the top 5% riskiest for that year, and Orange & Rockland may request other ineffectively coated steel not in the top 5% to be included as long as proper justification is provided to Staff and Staff consents with the request. Requests shall be submitted to safety@dps.ny.gov.

3. **Gas Regulations Performance Measure**

This metric applies to instances of non-compliance (violations) with the gas safety regulations set forth below that are identified during Staff field and records audits. The categorization of violations hereunder as “High” or “Other” Risk is for administrative purposes of this metric only and do not constitute an admission by the Company as to the level of risk associated with any such regulation or the violation thereunder or that there is any risk associated with a violation.

[8] Bare steel and aldyl plastic will be considered for this measure. The Company may count ineffectively coated steel that is in the top 5% riskiest pipe for that year. Orange and Rockland may request for inclusion of other ineffectively coated steel (e.g., high leakage rates). Staff to respond whether it consents or does not consent with the request.

Only violations identified and included in Staff field and record audit letters may be counted for purposes of this metric. The audit letters cite violations as, for example, "1 violation, ten occurrences," which means one code section has been violated ten times. For the Gas Regulations Performance Measure, this example constitutes ten violations (the number of occurrences is the number of violations).

At the conclusion of each audit, Staff and the Company will have a compliance meeting at which Staff will present its findings to the Company, including which violation(s), if any, that Staff recommends be subject to this metric. The Company will have five business days from the date of the compliance meeting to cure any identified document deficiency. Only official Company records, as defined in the Company's Operating and Maintenance plan, will be considered by Staff as a cure to a document deficiency. In addition, if the Company is found to be in violation of its work procedure, but the work procedure exceeds Code 255 or 261, and the Company is not in violation of the Code requirement, the violation will not be subject to a negative revenue adjustment under this this Safety Violation metric.

Negative revenue adjustments, if any, would be applied as set forth in the following charts:

High Risk **Records** Audit	Other Risk **Records** Audit
Threshold - 0-5 (0 BP) for RY1, RY2, and RY3 RY1 – 6-20 (1/2 BP); 21+ (1 BP) RY2 – 6-20 (1/2 BP); 21+ (1 BP) RY3 – 6-20 (1/2 BP); 21+ (1 BP)	Threshold - 0-15 (0 BP) for RY1, RY2, and RY3 RY1 – 16+ (1/4 BP) RY2 – 16+ (1/4 BP) RY3 – 16+ (1/4 BP)

High Risk **Field** Audit	Other Risk **Field** Audit
RY1 – 1-20 (1/2 BP); 21+ (1 BP) RY2 – 1-20 (1/2 BP); 21+ (1 BP) RY3 – 1-20 (1/2 BP); 21+ (1 BP)	RY1 – 1+ (1/4 BP) RY2 – 1+ (1/4 BP) RY3 – 1+ (1/4 BP)

Any negative revenue adjustments assessed under this metric shall not exceed 75 basis points for 2022, 2023 and 2024 and subsequent calendar years, until changed by the Commission. For any code section, the number of violations will be capped at ten for the negative revenue adjustment determination, for both field and record audits, with the requirement that violations in excess of ten be addressed by a corrective action plan formally submitted to Staff by the Company to achieve compliance going forward. If the Company does not adhere to the corrective action plan, the negative revenue adjustment associated with the violations will be applied. The corrective action plan will be provided in the Company's response to the audit letter.

This metric will be effective as of January 1, 2022 and will be measured on a calendar year basis. For **Field Audits**, only actions performed or required to be performed in the year that the Field Audit is conducted may constitute an occurrence under this metric (*e.g.*, violations arising from 2022 Field Audit findings would count towards any applicable Rate Year 1 (2022) Negative Revenue Adjustments). For **Record Audits**, only documentation required to be performed during the calendar year prior to the year in which the Record Audit is conducted may constitute an occurrence under this metric (*e.g.*, violations arising from 2023 Record Audit findings for activities performed or not performed in 2022 would count towards any applicable Rate Year 2 (2022) Negative Revenue Adjustments).

Staff will submit its final audit reports to the Secretary under Case 21-G-0073. If the Company disputes any of Staff's final audit results, or elects to seek exclusions based on extenuating circumstances, the Company may appeal Staff's finding to the Commission. The Company will include in any such petition a remediation plan addressing such violations. If the Company elects to dispute any of Staff's findings, the Company will not incur a negative revenue adjustment on those Staff findings until such time as the Commission has issued a final decision on the Company's appeal. Upon Company request, the Commission may in its discretion, provide the Company with an evidentiary hearing prior to any final determination. The Company does not waive its right to seek judicial appeal of any Commission determination regarding a violation or penalty under applicable law.

Positive Rate Adjustments

1. Leak Management/Main Replacement/Emergency Response/Damage Protection

a. Leak Management – Year-End Total Backlog

a. Leak Management - Year-End Total Backlog

If the Company successfully reduces the year-end total leak backlog (types 1, 2, 2A and 3) to the targets set forth below in calendar year 2022, 2023 and/or 2024, the Company will receive the following positive rate adjustment for Rate Year 2022, Rate Year 2023 and/or Rate Year 2024, as applicable, up to the following annual maximum amounts.[9]

Basis Points Incentive if Year-End Total Leak Backlog Is:			
	2 BP	4 BP	6 BP
2022	11 to 20	4 to 10	0 to 3
2023	9 to 15	4 to 8	0 to 3
2024	9 to 15	4 to 8	0 to 3

[9] Only "successful elimination" of a leak will be considered a valid leak repair. In addition, the Company will recheck Type 3 leaks.

b. Gas Main Replacement

In the event the Company replaces or eliminates leak-prone pipe[10] in excess of 22 miles in Rate Year 2022, Rate Year 2023, and/or Rate Year 2024, for each whole mile in excess of 23 miles, the Company shall receive a positive revenue adjustment of 2 basis points per additional whole mile, capped at a maximum of 10 basis points (five miles) per calendar year. The Table below shows the basis points available for different mileages of leak-prone pipe replaced for Rate Year 2022, Rate Year 2023 and Rate Year 2024.

Basis Points Incentive if the Miles of LPP Replacement Is:				
2 BP	4 BP	6 BP	8 BP	10 BP
24 to <25	25 to <26	26 to <27	27 to <28	≥ 28

c. Emergency Response - 30 Minute Response Time

If Orange and Rockland responds to gas leak or odor calls within 30 minutes for at least 91 percent of the calls for calendar years 2022, 2023 and/or 2024, the Company shall receive for the applicable year(s) a positive revenue adjustment of 2 basis points for each percentage increase of 2 percent, capped at a maximum of 6 basis points. The Table below shows the basis points available for different response time performance for Rate Year 2022, Rate Year 2023 and Rate Year 2024.

Basis Points Incentive if Emergency Response – 30 Minute Percentage Is:		
2 BP	4 BP	6 BP
91% to <93%	≥93% to <95%	≥ 95%

[10] Bare steel and aldyl plastic will be considered for this measure. The Company may count ineffectively coated steel that is in the top 5% riskiest pipe for that year. Orange and Rockland may request for inclusion of other ineffectively coated steel (e.g., high leakage rates). Staff to respond whether it consents or does not consent with the request.

d. Damage Prevention

If the Company successfully reduces the number of total damages to Company gas facilities made by any party by the targets set forth below per 1,000 one-call tickets in calendar year 2022, 2023 and/or 2024, the Company shall receive for the applicable year(s) a positive revenue adjustment. The Table below shows the basis points available for damage prevention performance for Rate Year 2022, Rate Year 2023 and Rate Year 2024.

Rate Year	Basis Points Incentive if Total Damages per 1000 one-call Tickets Is:	
2022	5 BP	10 BP
	>1.25 to ≤1.50	≤1.25
2023	5 BP	10 BP
	>1.25 to ≤1.50	≤1.25
2024	5 BP	10 BP
	>1.25 to ≤1.50	≤1.25

<u>General Provisions</u>

The Company will report its annual performance in each of the areas set forth in this Appendix to the Secretary no later than 60 days following the end of each calendar year. If a performance metric is not met, the associated negative revenue adjustment will be excused when the Company can demonstrate to the Commission extenuating circumstances that prevented the Company from meeting such performance metric. The determination of whether such circumstances exist will be made on a case-by-case basis by the Commission. The Company does not waive its right to seek judicial appeal of any Commission determination regarding a violation or penalty under applicable law.

With respect to leak-prone pipe replacement, the report shall include material type, mileage, project location, and a summary noting the totals of aldyl plastic, bare steel and ineffectively coated steel that were replaced and what percentage of pipe replaced, in that year, was in the top 5% of riskiest pipe at the start of the calendar year, established by the Company.

The Company will provide, to safety@dps.ny.gov, a list of the top 5% riskiest pipe yet to be replaced at the start of each calendar year. For any pipe on the list for the calendar year that the Company does not plan to replace in that calendar year, the Company will provide a brief explanation. Along with the list, the Company will identify any riskiest pipe on the preceding calendar year's list that was not replaced as planned.

Appendix 14

2022-2024 Cases 21-G-0073 - O&R - Pipeline Safety Measures

Pipeline Safety Measures	Criteria	Unit	NRA (BPs)	PRA (BPs)	CY 2022 Target	NRA (BPs)	PRA (BPs)	CY 2023 Target	NRA (BPs)	PRA (BPs)	CY 2024 Target	NRA (BPs)	PRA (BPs)	Beyond 2024 Target
Leak Backlog or Management [1-2]	Total: Type 1, 2A, 2, and 3	Leaks	5	-	> 50	5	-	> 50	5	-	> 50	5	-	> 50
	Repairable: Type 1, 2A, and 2	Leaks	10	-	> 20	10	-	> 20	10	-	> 20	10	-	> 20
	Total: Type 1, 2A, 2, and 3	Leaks	-	2	11 to 20	-	2	9 to 15	-	2	9 to 15	-	2	9 to 15
	Total: Type 1, 2A, 2, and 3	Leaks	-	4	4 to 10	-	4	4 to 8	-	4	4 to 8	-	4	4 to 8
	Total: Type 1, 2A, 2, and 3	Leaks	-	6	0 to 3	-	6	0 to 3	-	6	0 to 3	-	6	0 to 3
	(1) O&R will be recognized as having met the leak backlog targets if they are achieved between December 21, and December 31. (2) Only "successful elimination" of a leak will be considered a valid leak repair and rechecks are required for Type 3 leaks.													
Leak Prone Pipe (LPP) [3-4-5]	Removal Target [3]	Miles	15	-	< 20	15	-	< 20	7.5	-	< 20 [5]	15	-	< 20
	Removal Target [3]	Miles	-	2	24 to 25	-	2	24 to 25	-	2	24 to 25	-	2	24 to 25
	Removal Target [3]	Miles	-	4	25 to 26	-	4	25 to 26	-	4	25 to 26	-	4	25 to 26
	Removal Target [3]	Miles	-	6	26 to 27	-	6	26 to 27	-	6	26 to 27	-	6	26 to 27
	Removal Target [3]	Miles	-	8	27 to 28	-	8	27 to 28	-	8	27 to 28	-	8	27 to 28
	Removal Target [3]	Miles	-	10	≥ 28	-	10	≥ 28	-	10	≥ 28	-	10	≥ 28
	(3) All leak prone services are to be removed in conjunction with this LPP program. LPP removals resulting from non-pipeline alternative projects may be included in the calendar year total mileage.													
	(4) Annual reporting on the progress of LPP removal is to be submitted by O&R. Inspections should be commensurate with that of the level of leak prone pipe removal. Bare steel, and aldyl-a plastic will be considered for this measure. Ineffectively coated steel allowed if in top 5% riskiest for that year. O&R may request for inclusion of other ineffectively coated steel (e.g. high leakage rates). Staff to respond whether it consents or does not consent with the request.													
	(5) 3-year cumulative target of 66-miles. If not met, an NRA of 7.5 BPs would be applied.													
Emergency Response [6]	Respond within 30 minutes	%	12	-	75	12	-	75	12	-	75	12	-	75
	Respond within 45 minutes	%	8	-	90	8	-	90	8	-	90	8	-	90
	Respond within 60 minutes	%	5	-	95	5	-	95	5	-	95	5	-	95
	Respond within 30 minutes	%	-	2	91 to 93	-	2	91 to 93	-	2	91 to 93	-	2	91 to 93
	Respond within 30 minutes	%	-	4	93 to 95	-	4	93 to 95	-	4	93 to 95	-	4	93 to 95
	Respond within 30 minutes	%	-	6	≥ 95	-	6	≥ 95	-	6	≥ 95	-	6	≥ 95
	(6) Any reports resulting from mass area complaints, major weather-related occurrences, or major equipment failure may be excluded from these counts pending prior Staff approval. Exclusions are considered on a case-by-case basis, must be made via email or in writing, and shall be requested within seven days of such an occurrence. Staff will respond whether it consents or does not consent to the exclusion request. O&R may proceed with the exclusion request if it has not received a response from Staff within 90 days.													
Violations or Non-Compliances [7]	Record Audits: High Risk	Per	1	-	> 20	1	-	> 20	1	-	> 20	1	-	> 20
	Record Audits: High Risk	Per	1/2	-	6 to 20	0.5	-	6 to 20	0.5	-	6 to 20	0.5	-	6 to 20
	Record Audits: High Risk	Per	-	-	0 to 5	-	-	0 to 5	-	-	0 to 5	-	-	0 to 5
	Record Audits: Other Risk	Per	1/4	-	> 15	0.25	-	> 15	0.25	-	> 15	0.25	-	> 15
	Record Audits: Other Risk	Per	-	-	0 to 15	-	-	0 to 15	-	-	0 to 15	-	-	0 to 15
	Field Audits: High Risk	Per	1	-	> 20	1	-	> 20	1	-	> 20	1	-	> 20
	Field Audits: High Risk	Per	1/2	-	1 to 20	0.5	-	1 to 20	0.5	-	1 to 20	0.5	-	1 to 20
	Field Audits: Other Risk	Per	1/4	-	All	0.25	-	All	0.25	-	All	0.25	-	All
	(7) Caps of 10 for record and field audit violations of a single regulation annually. Remediation plans to be filed and adhered to for instances where there are 10 or more violations for a single regulation. If plans not adhered to, NRAs are applied.													
Damage Prevention (per 1,000 one-call tickets) [8]	Total: No Calls, Excavator Error, Company and Company Contractor Error, and Mismarks	Rate	20	-	> 2.50	20	-	> 2.50	20	-	> 2.50	20	-	> 2.50
		Rate	10	-	> 2.25 to ≤ 2.50	10	-	> 2.25 to ≤ 2.50	10	-	> 2.25 to ≤ 2.50	10	-	> 2.25 to ≤ 2.50
		Rate	5	-	> 2.00 to ≤ 2.25	5	-	> 2.00 to ≤ 2.25	5	-	> 2.00 to ≤ 2.25	5	-	> 2.00 to ≤ 2.25
		Rate	-	-	> 1.50 to ≤ 2.00	-	-	> 1.50 to ≤ 2.00	-	-	> 1.50 to ≤ 2.00	-	-	> 1.50 to ≤ 2.00
		Rate	-	5	> 1.25 to ≤ 1.50	-	5	> 1.25 to ≤ 1.50	-	5	> 1.25 to ≤ 1.50	-	5	> 1.25 to ≤ 1.50
		Rate	-	10	≤ 1.25	-	10	≤ 1.25	-	10	≤ 1.25	-	10	≤ 1.25
	(8) Reporting of damage data shall be in compliance with December 11, 2015, guidance. Hand damages where notification has been provided will be included in this measure.													
Total Exposure			150	32		150	32		150	32		150	32	

TABLE 1

Title	Chapter	Subchapter	Part	Section	Subdivision	Description	Risk
16	III	C	255	14	(a)	Conversion to Service Subject to this Part	High
16	III	C	255	14	(b)	Conversion to Service Subject to this Part	Other
16	III	C	255	17	All	Preservation of Records	Other
16	III	C	255	53	All	Materials - General	High
16	III	C	255	65	All	Materials - Transportation of Pipe	High
16	III	C	255	103	All	Pipe Design - General	High
16	III	C	255	143	All	Design of Pipeline Components - General Requirements	High
16	III	C	255	159	All	Design of Pipeline Components - Flexibility	High
16	III	C	255	161	All	Design of Pipeline Components - Supports and Anchors	High
16	III	C	255	163	All	Compressor Stations - Design and Construction	Other
16	III	C	255	165	All	Compressor Stations - Liquid Removal	Other
16	III	C	255	167	All	Compressor Stations - Emergency Shutdown	High
16	III	C	255	169	All	Compressor Stations - Pressure Limiting Devices	High
16	III	C	255	171	All	Compressor Stations - Additional Safety Equipment	Other
16	III	C	255	173	All	Compressor Stations - Ventilation	High
16	III	C	255	179	All	Valves on Pipelines to Operate at 125 PSIG (862 kPa) or More	High
16	III	C	255	181	All	Distribution Line Valves	High
16	III	C	255	183	All	Vaults - Structural Design Requirements	High
16	III	C	255	185	All	Vaults - Accessibility	Other
16	III	C	255	187	All	Vaults - Sealing, Venting, and Ventilation	Other
16	III	C	255	189	All	Vaults - Drainage and Waterproofing	High
16	III	C	255	190	All	Calorimeter or Calorimixer Structures	Other
16	III	C	255	191	All	Design Pressure of Plastic Fittings	Other
16	III	C	255	193	All	Valve Installation in Plastic Pipe	Other
16	III	C	255	195	All	Protection Against Accidental Overpressuring	High
16	III	C	255	197	All	Control of the Pressure of Gas Delivered from High Pressure Distribution Systems	High
16	III	C	255	199	All	Requirements for Design of Pressure Relief and Limiting Devices	High
16	III	C	255	201	All	Required Capacity of Pressure Relieving and Limiting Stations	High
16	III	C	255	203	All	Instrument, Control, and Sampling Piping and Components	Other
16	III	C	255	225	All	Qualification of Welding Procedures	High
16	III	C	255	227	All	Qualification of Welders	High
16	III	C	255	229	All	Limitations On Welders	Other
16	III	C	255	230	All	Quality Assurance Program	Other
16	III	C	255	231	All	Welding - Protection from Weather	High
16	III	C	255	233	All	Welding - Miter Joints	High
16	III	C	255	235	All	Preparation for Welding	High
16	III	C	255	237	All	Welding - Preheating	Other
16	III	C	255	239	All	Welding - Stress Relieving	Other
16	III	C	255	241	(a),(b)	Inspection and Test of Welds	High
16	III	C	255	241	(c)	Inspection and Test of Welds	Other
16	III	C	255	243	(a),(b),(c),(d),(e)	Nondestructive Testing - Pipeline to Operate at 125 PSIG (862 kPa) or More	High
16	III	C	255	243	(f)	Nondestructive Testing - Pipeline to Operate at 125 PSIG (862 kPa) or More	Other
16	III	C	255	244	All	Welding Inspector	High
16	III	C	255	245	All	Welding - Repair or Removal of Defects	High
16	III	C	255	273	All	Joining of Materials other than by Welding - General	High
16	III	C	255	279	All	Joining of Materials other than by Welding - Copper Pipe	High
16	III	C	255	281	All	Joining of Materials other than by Welding - Plastic Pipe	High
16	III	C	255	283	All	Plastic Pipe - Qualifying Joining Procedures	Other
16	III	C	255	285	(a),(b),(d)	Plastic Pipe - Qualifying Persons to make Joints	High
16	III	C	255	285	(c)(e)	Plastic Pipe - Qualifying Persons to make Joints	Other
16	III	C	255	287	All	Plastic Pipe - Inspection of Joints	Other
16	III	C	255	302	All	Notification Requirements	High
16	III	C	255	303	All	Compliance with Construction Standards	High
16	III	C	255	305	All	Inspection - General	High
16	III	C	255	307	All	Inspection of Materials	High
16	III	C	255	309	All	Repair of Steel Pipe	High
16	III	C	255	311	All	Repair of Plastic Pipe	High
16	III	C	255	313	(a),(b),(c)	Bends and Elbows	High
16	III	C	255	313	(d)	Bends and Elbows	Other
16	III	C	255	315	All	Wrinkle Bends in Steel Pipe	High
16	III	C	255	317	All	Protection from Hazards	Other
16	III	C	255	319	All	Installation of Pipe in a Ditch	Other
16	III	C	255	321	All	Installation of Plastic Pipe	High
16	III	C	255	323	All	Casing	Other
16	III	C	255	325	All	Underground Clearance	High
16	III	C	255	327	All	Cover	Other
16	III	C	255	353	All	Customer Meters and Regulators - Location	Other
16	III	C	255	355	All	Customer Meters and Regulators - Protection from Damage	Other
16	III	C	255	357	(a),(b),(c)	Customer Meters and Service Regulators - Installation	Other
16	III	C	255	357	(d)	Customer Meters and Service Regulators - Installation	High
16	III	C	255	359	All	Customer Meter Installations - Operating Pressure	Other
16	III	C	255	361	(a),(b),(c),(d)	Service Lines - Installation	Other
16	III	C	255	361	(e),(f),(g),(h),(i)	Service Lines - Installation	High
16	III	C	255	363	All	Service Lines - Valve Requirements	Other
16	III	C	255	365	(a),(c)	Service Lines - Location of Valves	Other
16	III	C	255	365	(b)	Service Lines - Location of Valves	High
16	III	C	255	367	All	Service Lines - General Requirements for Connections	Other
16	III	C	255	369	All	Service Lines - Connections to Cast Iron or Ductile Iron Mains	Other
16	III	C	255	371	All	Service Lines - Steel	Other
16	III	C	255	373	All	Service Lines - Cast Iron and Ductile Iron	Other
16	III	C	255	375	All	Service Lines - Plastic	Other
16	III	C	255	377	All	Service Lines - Copper	Other
16	III	C	255	379	All	New Service Lines not in Use	Other
16	III	C	255	381	All	Service Lines - Excess Flow Valve Performance Standards	Other
16	III	C	255	455	(a)	External Corrosion Control - Buried or Submerged Pipelines Installed after July 31, 1971	Other
16	III	C	255	455	(d),(e)	External Corrosion Control - Buried or Submerged Pipelines Installed after July 31, 1971	High
16	III	C	255	457	All	External Corrosion Control - Buried or Submerged Pipelines Installed before July 31, 1971	High
16	III	C	255	459	All	External Corrosion Control - Examination of Buried Pipeline when Exposed	Other
16	III	C	255	461	(a),(b),(d),(e),(f),(g)	External Corrosion Control - Protective Coating	Other
16	III	C	255	461	(c)	External Corrosion Control - Protective Coating	High
16	III	C	255	463	All	External Corrosion Control - Cathodic Protection	High
16	III	C	255	465	(a),(e)	External Corrosion Control - Monitoring	High
16	III	C	255	465	(b),(c),(d),(f)	External Corrosion Control - Monitoring	Other
16	III	C	255	467	All	External Corrosion Control - Electrical Isolation	Other
16	III	C	255	469	All	External Corrosion Control - Test Stations	Other
16	III	C	255	471	All	External Corrosion Control - Test Leads	Other
16	III	C	255	473	All	External Corrosion Control - Interference Currents	Other
16	III	C	255	475	All	Internal Corrosion Control - General	Other
16	III	C	255	476	(a),(c)	Internal Corrosion Control - Design and Construction of Transmission Line	High

16	III	C	255	476	(d)	Internal Corrosion Control - Design and Construction of Transmission Line	Other
16	III	C	255	479	All	Atmospheric Corrosion Control - General	Other
16	III	C	255	481	All	Atmospheric Corrosion Control - Monitoring	Other
16	III	C	255	483	All	Remedial Measures - General	High
16	III	C	255	485	(a),(b)	Remedial Measures - Transmission Lines	High
16	III	C	255	485	(c)	Remedial Measures - Transmission Lines	Other
16	III	C	255	487	All	Remedial Measures - Distribution Lines other than Cast Iron or Ductile Iron Lines	Other
16	III	C	255	489	All	Remedial Measures - Cast Iron and Ductile Iron Pipelines	Other
16	III	C	255	490	All	Direct Assessment	Other
16	III	C	255	491	All	Corrosion Control Records	Other
16	III	C	255	503	All	Test Requirements - General	Other
16	III	C	255	505	(a),(b),(c),(d)	Strength Test Requirements for Steel Pipelines to Operate at 125 PSIG (862 kPa) or More	High
16	III	C	255	505	(e),(h),(i)	Strength Test Requirements for Steel Pipelines to Operate at 125 PSIG (862 kPa) or More	Other
16	III	C	255	507	All	Test Requirements for Pipelines to Operate at less than 125 PSIG (862 kPa)	Other
16	III	C	255	511	All	Test Requirements for Service Lines	Other
16	III	C	255	515	All	Environmental Protection and Safety Requirements	Other
16	III	C	255	517	All	Test Requirements - Records	Other
16	III	C	255	552	All	Upgrading / Conversion - Notification Requirements	Other
16	III	C	255	553	(a),(b),(c),(f)	Upgrading / Conversion - General Requirements	High
16	III	C	255	553	(d),(e)	Upgrading / Conversion - General Requirements	Other
16	III	C	255	555	All	Upgrading to a Pressure of 125 PSIG (862 kPa) or More in Steel Pipelines	High
16	III	C	255	557	All	Upgrading to a Pressure Less than 125 PSIG (862 kPa)	High
16	III	C	255	603	All	Operations - General Provisions	High
16	III	C	255	604	All	Operator Qualification	High
16	III	C	255	605	All	Essentials of Operating and Maintenance Plan	High
16	III	C	255	609	All	Change in Class Location - Required Study	High
16	III	C	255	611	(a),(d)	Change in Class Location - Confirmation or Revision of Maximum Allowable Operating Pressure	Other
16	III	C	255	613	All	Continuing Surveillance	Other
16	III	C	255	614	All	Damage Prevention Program	High
16	III	C	255	615	All	Emergency Plans	High
16	III	C	255	616	All	Customer Education and Information Program	High
16	III	C	255	619	All	Maximum Allowable Operating Pressure - Steel or Plastic Pipelines	High
16	III	C	255	621	All	Maximum Allowable Operating Pressure - High Pressure Distribution Systems	High
16	III	C	255	623	All	Maximum and Minimum Allowable Operating Pressure - Low Pressure Distribution Systems	High
16	III	C	255	625	(a),(b)	Odorization of Gas	High
16	III	C	255	625	(e),(f)	Odorization of Gas	Other
16	III	C	255	627	All	Tapping Pipelines Under Pressure	High
16	III	C	255	629	All	Purging of Pipelines	High
16	III	C	255	631	All	Control Room Management	High
16	III	C	255	705	All	Transmission Lines - Patrolling	High
16	III	C	255	706	All	Transmission Lines - Leakage Surveys	High
16	III	C	255	707	(a),(c),(d),(e)	Line Markers for Mains and Transmission Lines	Other
16	III	C	255	709	All	Transmission Lines - Record Keeping	Other
16	III	C	255	711	All	Transmission Lines - General Requirements for Repair Procedures	High
16	III	C	255	713	All	Transmission Lines - Permanent Field Repair of Imperfections and Damages	High
16	III	C	255	715	All	Transmission Lines - Permanent Field Repair of Welds	High
16	III	C	255	717	All	Transmission Lines - Permanent Field Repairs of Leaks	High
16	III	C	255	719	All	Transmission Lines - Testing of Repairs	High
16	III	C	255	721	(b)	Distribution Systems - Patrolling	Other
16	III	C	255	723	All	Distribution Systems -Leakage Surveys and Procedures	High
16	III	C	255	725	All	Test Requirements for Reinstating Service Lines	Other
16	III	C	255	726	All	Inactive Service Lines	Other
16	III	C	255	727	(b),(c),(d),(e),(f),(g)	Abandonment or Inactivation of Facilities	Other
16	III	C	255	729	All	Compressor Stations - Procedures for Gas Compressor Units	High
16	III	C	255	731	All	Compressor Stations - Inspection and Testing of Relief Devices	High
16	III	C	255	732	All	Compressor Stations - Additional Inspections	High
16	III	C	255	735	All	Compressor Stations - Storage of Combustible Materials	Other
16	III	C	255	736	All	Compressor Stations - Gas Detection	High
16	III	C	255	739	(a),(b)	Pressure Limiting and Regulating Stations - Inspection and Testing	High
16	III	C	255	739	(c),(d),(e),(f)	Pressure Limiting and Regulating Stations - Inspection and Testing	Other
16	III	C	255	741	All	Pressure Limiting and Regulating Stations - Telemetering or Recording Gauges	Other
16	III	C	255	743	(a),(b)	Pressure and Limiting and Regulating Stations - Testing of Relief Devices	High
16	III	C	255	743	(c)	Regulator Station MAOP	Other
16	III	C	255	744	All	Service Regulators and Vents - Inspection	Other
16	III	C	255	745	All	Transmission Line Valves	High
16	III	C	255	747	All	Valve Maintenance - Distribution Systems	Other
16	III	C	255	748	All	Valve Maintenance - Service Line Valves	Other
16	III	C	255	749	All	Vault Maintenance	Other
16	III	C	255	751	All	Prevention of Accidental Ignition	High
16	III	C	255	753	All	Caulked Bell and Spigot Joints	Other
16	III	C	255	755	All	Protecting Cast Iron Pipelines	High
16	III	C	255	756	All	Replacement of Exposed or Undermined Cast Iron Piping	High
16	III	C	255	757	All	Replacement of Cast Iron Mains Paralleling Excavations	High
16	III	C	255	801	All	Reports of accidents	Other
16	III	C	255	803	All	Emergency Lists of Operator Personnel	Other
16	III	C	255	805	(a),(b),(e),(g),(h)	Leaks - General	Other
16	III	C	255	807	(a),(b),(c)	Leaks - Records	Other
16	III	C	255	807	(d)	Leaks - Records	High
16	III	C	255	809	All	Leaks - Instrument Sensitivity Verification	High
16	III	C	255	811	(b),(c),(d),(e)	Leaks - Type 1 Classification	High
16	III	C	255	813	(b),(c),(d)	Leaks - Type 2A Classification	High
16	III	C	255	815	(b),(c),(d)	Leaks - Type 2 Classification	High
16	III	C	255	817	All	Leaks - Type 3 Classification	Other
16	III	C	255	819	(a)	Leaks - Follow-Up Inspection	High
16	III	C	255	821	All	Leaks - Nonreportable Reading	High
16	III	C	255	823	(a),(b)	Interruptions of Service	Other
16	III	C	255	825	All	Logging and Analysis of Gas Emergency Reports	Other
16	III	C	255	829	All	Annual Report	Other
16	III	C	255	831	All	Reporting Safety-Related Conditions	Other
16	III	C	255	905	All	High Consequence Areas	High
16	III	C	255	907	All	General (IMP)	Other
16	III	C	255	909	All	Changes to an Integrity Management Program (IMP)	Other
16	III	C	255	911	All	Required Elements (IMP)	High

16	III	C	255	915	All	Knowledge and Training (IMP)	High
16	III	C	255	917	All	Identification of Potential Threats to Pipeline Integrity and Use of the Threat Identification in an Integrity Program (IMP)	High
16	III	C	255	919	All	Baseline Assessment Plan (IMP)	High
16	III	C	255	921	All	Conducting a Baseline Assessment (IMP)	High
16	III	C	255	923	All	Direct Assessment (IMP)	High

Orange and Rockland Utilities, Inc.
Cases 21-G-0073 & 21-E-0074

Customer Service Performance Indicators

The Customer Service Performance Indicators" ("CSPI") described herein will be in effect for the terms of the Rate Plans and thereafter unless and until changed by the Commission.

a) Audited Historic Performance: For the period 2018 through 2020.

In the Company's 2018 annual customer service filing, it reported one Negative Revenue Adjustment ("NRA"): $450,000 for failure to meet the Calls Answer Rate metric target. The $450,000 NRA is credited to customer through the Energy Cost Adjustment/Monthly Gas Adjustment commencing June 1, 2021. Staff conducted an audit of the Companies' 2018, 2019, and 2020 data provided in the Company's reports and confirmed that the Company did not incur any customer service NRA for 2019 and 2020.[1]

b) Operation of Mechanism

The CSPI establishes threshold performance levels for designated aspects of customer service. For all measures the threshold performance levels are detailed on page 4 of this Appendix 15. Failure by the Company to achieve these specified targets will result in a revenue adjustment of up to 23 Basis Points ("BP") for Electric and 16 BP for Gas in Rate Year 1, 24 BP for Electric and 16 BP for Gas in Rate Year 2, and 27 BP for Electric and 18 BP for Gas in Rate Year 3, respectively.[2] The CSPI will be measured on a calendar year basis. Accordingly, the results of the performance measurements, as measured during calendar years 2022, 2023 and 2024, respectively, will be applied to Rate Years 1, 2 and 3, respectively.

[1] Staff also audited the Company's 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 (issued August 4, 2017).

[2] The BP negative rate adjustment associated with each measure is stated on a pre-tax basis. The revenue requirement equivalents of ten BP on common equity capital per the gas revenue requirements under this Proposal are estimated to be approximately $377,400 in RY1, $404,750 in RY2 and $432,750 in RY3. The revenue requirement equivalents of ten BP on common equity capital per the electric revenue requirements under this Proposal are estimated to be approximately $679,160 in RY1, $694,210 in RY2 and $761,010 in RY3.

c) Exclusions

For measurement purposes, results from months having abnormal operating conditions will not be considered. Abnormal operating conditions are deemed to occur during any period of emergency, catastrophe, strike, natural disaster, major storm, or other unusual event not in the Company's control affecting more than ten percent of the customers in an operating area during any month. A "major storm" will have the same definition as set forth in 16 NYCRR Part 97.

d) Reporting

The Company will prepare an annual report on its performance that will be filed with the Secretary by March 1 following each Rate Year (*e.g.*, the annual report for 2022 shall be due by March 1, 2023). Each report will state: (1) the Company's actual performance for the calendar year on each measure; (2) whether a revenue adjustment is applicable and, if so, the amount of the revenue adjustment; and (3) whether any exclusions should apply, the basis for requesting each exclusion, and adequate support for all requested exclusions.

e) Threshold Standards

The Company's threshold performance will be measured based on the Company's cumulative monthly performance for each Rate Year for the following three activities, except as otherwise noted.

i. PSC Complaint Rate

The annual PSC Complaint Rate will be calculated in the manner approved by the Commission in its Order Approving Complaint Rate Targets issued August 26, 2005.[3] In calculating the annual PSC Complaint Rate, (i) duplicative rate consultant complaints, (ii) high commodity prices complaints, and (iii) complaints relating to natural disasters, major storms, or other unusual events not in the Company's control, will be excluded. During the Rate Plans, the PSC Complaint Rate not to exceed targets and associated revenue adjustment levels are set forth in Table 1, below.

ii. Residential Customer Satisfaction Survey

[3] Case 02-G-1553, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules, and Regulations of Orange and Rockland Utilities, Inc. for Gas Service*, and Case 03-E-0797, *In the Matter of Orange and Rockland Utilities, Inc.'s Proposal for an Extension of an Existing Rate Plan, filed in Case 96-E-0900*, Order Approving Complaint Rate Target (issued August 26, 2005).

The Company contracts with a third-party vendor to conduct a monthly Residential Customer Satisfaction Survey. The vendor surveys customers utilizing a 10-point scale to rank customer satisfaction with Company performance based upon a series of questions and one overall customer satisfaction index question:

> "*Using a scale from 1 to 10 where 1 means you were very dissatisfied and 10 means you were very satisfied, how satisfied were you the way the Orange and Rockland's Customer Service Representative handled your recent issue/request?"*

The Company reports the percentage of customers surveyed that responded with a score of 7 – 10 to the overall customer satisfaction index question.

iii. Percent of Calls Answered by a Representative within 30 Seconds

"Percent of Calls Answered by a Representative within 30 Seconds" is the percentage of calls answered by a Company representative within 30 seconds of the customer's request to speak to a representative between the hours of 8:00 AM and 4:30 PM Monday through Friday (excluding holidays). The performance rate is the sum of the system-wide number of calls answered by a representative within 30 seconds divided by the sum of the system-wide number of calls where a customer requests to speak with a representative.

Any negative revenue adjustment earned will be allocated between the Company's electric and gas businesses based on the common cost allocation factor.

Table 1 - Customer Service Performance Indicators Mechanism Targets

	CSPI Performance			Electric	Gas	Electric	Gas	Electric	Gas
Indices	**RY1**	**RY2**	**RY3**	**RY1 (NRA) BPs**	**RY1 (NRA) BPs**	**RY2 (NRA) BPs**	**RY2 (NRA) BPs**	**RY3 (NRA) BPs**	**RY3 (NRA) BPs**
Call Answer Rate									
Target	>60.3	>60.3	>60.3	None	None	None	None	None	None
Minimum	≤60.3	≤60.3	≤60.3	(2)	(2)	(2)	(2)	(3)	(2)
Middle	≤58.0	≤58.0	≤58.0	(3)	(3)	(4)	(3)	(6)	(4)
Max	≤55.7	≤55.7	≤55.7	(5)	(4)	(6)	(4)	(9)	(6)
PSC Complaint Rate									
Target	≤1.0	≤1.0	≤1.0	None	None	None	None	None	None
Minimum	>1.0	>1.0	>1.0	(3)	(2)	(3)	(2)	(3)	(2)
Middle	≥1.1	≥1.1	≥1.1	(6)	(4)	(6)	(4)	(6)	(4)
Max	≥1.2	≥1.2	≥1.2	(9)	(6)	(9)	(6)	(9)	(6)
Transactional Survey									
Target	>92.6	>92.6	>92.6	None	None	None	None	None	None
Minimum	≤92.6	≤92.6	≤92.6	(3)	(2)	(3)	(2)	(3)	(2)
Middle	≤91.8	≤91.8	≤91.8	(6)	(4)	(6)	(4)	(6)	(4)
Max	≤91.0	≤91.0	≤91.0	(9)	(6)	(9)	(6)	(9)	(6)
Total				(23)	(16)	(24)	(16)	(27)	(18)

Appendix 16
Orange and Rockland
Cases 21-E-0074 and 21-G-0073
Earnings Adjustment Mechanisms

Orange and Rockland (“O&R” or the “Company”) will implement electric and gas Earnings Adjustment Mechanisms (“EAM”) as of January 1, 2022 for the term of this Joint Proposal including Rate Year (“RY”)1, RY2, and RY3. Achievement of EAMs will be measured and reported annually. The Company will earn pre-tax earnings adjustments based on its performance relative to established performance targets. For EAM metrics with minimum, midpoint and maximum performance targets, the Company will earn pre-tax earnings adjustments on a prorated basis for performance between minimum and midpoint performance levels, as well as for performance between the midpoint and maximum performance levels.

These EAMs will be in effect during the term of the Rate Plan unless modified by the Commission in a generic proceeding. In the event that NENY budgets and/or targets are modified by the Commission for any year in this Rate Plan, any EAM targets linked to NENY budgets and/or targets will be updated as directed by the Commission.

Tables 1 and 2 (below) list the award opportunities, respectively, for each electric, gas and cross-commodity EAM metric.

Appendix 16
Orange and Rockland
Cases 21-E-0074 and 21-G-0073
Earnings Adjustment Mechanisms

Table 1: Electric EAM Incentives (Basis Points)

Metric	Level	2022	2023	2024
System Efficiency EAM				
Electric Peak Reduction	Minimum	$135,832	$138,842	$152,202
	Mid-Point	$271,664	$277,684	$304,404
	Maximum	$543,328	$555,368	$608,808
Circuit Load Factor Reduction	Minimum	$67,916	$69,421	$76,101
	Mid-Point	$237,706	$242,974	$266,354
	Maximum	$339,580	$347,105	$380,505
DER Utilization (Solar PV)	Minimum	$67,916	$69,421	$76,101
	Mid-Point	$169,790	$173,553	$190,253
	Maximum	$339,580	$347,105	$380,505
DER Utilization (Energy Storage)	Minimum			$228,303
	Mid-Point			$570,758
	Maximum			$1,141,515
Environmentally Beneficial Electrification (EBE) EAM				
Electric Vehicles (EVs)	Minimum	$169,790	$173,553	$190,253
	Mid-Point	$339,580	$347,105	$380,505
	Maximum	$679,160	$694,210	$761,010
Heat Pump Carbon Reduction Count Up	Minimum	$67,916	$69,421	$76,101
	Mid-Point	$135,832	$138,842	$152,202
	Maximum	$339,580	$347,105	$380,505
EVSE DC Fast Charger Installations / EVSE Level 2 Charger Installations – Share the Savings	Determined formulaically (capped at 15 BP for RY1)			
	Maximum	$1,018,740		
Energy Efficiency (EE) EAM				
EE Share-the-Savings – Electric	Determined formulaically – 30% of Savings			

Electric basis point values are $67,916, $69,421, $76,101 in RY1, RY2, RY3

Table 2: Gas EAM Incentives (Basis Points)

Metric	Level	2022	2023	2024
Gas EAMs				
Gas Peak Reduction	Minimum	$37,740	$40,475	$43,275
	Mid-Point	$113,220	$121,425	$129,825
	Maximum	$188,700	$202,375	$216,375
Energy Efficiency (EE) EAM				
EE Share-the-Savings – Gas	Determined formulaically – 30% of Savings			

Gas basis point values are $37,740, $40,475, $43,275 in RY1, RY2, RY3

Table 3: Cross-Commodity EAM Incentives (Basis Points)

LMI Savings – Gas and Electric[1]	Minimum			$119,376
	Mid-Point			$298,440
	Maximum			$596,880

In no event shall the annual monetary award earned from total metrics exceed the value of 100 basis points per gas or electric system.

The EAMs, targets, incentives (earnings adjustments) and measurements are described in the sections that follow.

1.0 Electric EAMs

1.1 Electric System Efficiency EAM

The Electric System Efficiency EAM consists of four metrics: Electric Peak Reduction, Distributed Energy Resources ("DER") Energy Storage Utilization, DER Solar

[1] This is a cross-commodity EAM where the Basis Points are allocated 50/50 between each commodity (i.e., at the maximum 5 BP allocated to gas and 5 BP allocated to electric).

Photovoltaic (“PV)” Utilization, and Circuit Load Factor.

1.1.1 Electric Peak Reduction Metric

The Electric Peak Reduction metric is an outcome-based metric that incentivizes the Company to reduce peak load in its service territory. To the extent the actual weather-normalized peak load for the Company’s service territory is below the minimum target established for the EAM metric, the Company will receive an incentive.

The metric will be based on a reduction in the weather-normalized New York Control Area (“NYCA”) coincident peak load for the Company’s service territory each Rate Year measured in Megawatts (“MW”) as published annually in December by the NYISO through their Business Issues Committee, Load Forecasting Task Force.

Performance targets will be established each year based on the following:

- Baseline for each year will be the adjusted NYCA Coincident Peak Load Forecast for the NYISO portion of the Company’s service territory prior to allocation of Zone G losses as published annually in December in the table “Coincident Peak Forecast for LCR Study, Including BTM:NG Resources” by the NYISO through their Business Issues Committee, Load Forecasting Task Force.

- Adjusted Baseline for each year will be the Baseline less 0.50 percent improvement adjustment.

- Minimum, mid-point, and maximum performance targets for each year will be set, respectively, at the Adjusted Baseline less 0.25, 1.00, and 1.75 times the Standard Error of the regression ("SE").
- The SE will be derived from a regression analysis of the most recent 5-years of Weather-Normalized Peak Load, as derived by the NYISO[2]. For example, Year 1 (Summer 2022) will use the 5-years of Weather Normalized Peak Load from 2017 through 2021. Year 2 (Summer 2023) will use the 5-years from 2018 through 2022.
- The following is a summary of how the targets will be set each Rate Year:

Electric Peak Reduction Targets (MW)	**2022**	**2023**	**2024**
Baseline	Adjusted NYCA Coincident Peak Load Forecast for the NYISO portion of the Company's service territory[3]		
Adjusted Baseline	Baseline + (-0.5%)		
Minimum	Adjusted Baseline – (0.25 x SE of Regression)		
Mid-Point	Adjusted Baseline – (1.00 x SE of Regression)		
Maximum	Adjusted Baseline – (1.75 x SE of Regression)		

Achievement will be determined by the improvement in O&R's Weather Normalized Peak[2] in each year against the targets calculated as described above.

[2] Weather-normalized NYCA coincident peak load for the Company's service territory prior to allocation of Zone G losses for the Current Rate Year as published annually in December in the table "Load Reconciliation", Column Name "Adj. Load Prior to Loss Adjustment" by the NYISO through their Business Issues Committee, Load Forecasting Task Force (as presented in December 2020 or its comparable category in subsequent years).
[3] Adjusted NYCA Coincident Peak Load Forecast for the NYISO portion of the Company's service territory prior to allocation of Zone G losses as published annually in December in the table "Coincident Peak Forecast for LCR Study, Including BTM:NG Resources" by the NYISO through their Business Issues Committee, Load Forecasting Task Force.

1.1.2 DER Solar PV Utilization Metric

The DER Solar PV Utilization metric is an outcome-based metric that incentivizes O&R to work with third parties to expand the use of solar PV in the Company's service territory. This metric will measure the sum of the calculated incremental annualized megawatt hours ("MWh") production in each Rate Year from residential and commercial solar photovoltaic ("PV") installations and Community Distributed Generation ("CDG") installations in O&R's service territory in the measured Rate Year. Solar PV installations will be quantified using reporting from the Company's interconnection application portal, Power Clerk.

The DER Solar PV Utilization metric will be calculated as follows:

$DER\ Utilization$ - $Solar\ (MWh)$=
Residential solar PV MWh annualized production +
Commercial solar PV MWh annualized production +
CDG Solar MWh annualized production

Annualized MWh production for Residential, Commercial and CDG Solar will be calculated as follows:

$$Solar\ PV\ MWh = MW\ Installed \times 8760\ hours \times 13.4\%\ Annual\ Capacity\ Factor$$ [4]

DER Solar PV Utilization Targets (MWh)	2022	2023	2024
Minimum	37,928	41,591	45,307
Mid-Point	40,530	44,193	47,909
Maximum	43,132	46,795	50,511

[4] NYSERDA NY-Sun Initiative Program Manual, p. 10, March 2017.

1.1.3 DER Energy Storage Utilization Metric

The DER Energy Storage Utilization metric is an outcome-based metric that incentivizes O&R to work with third parties to expand the use of electric energy storage resources in the Company's service territory. This metric will measure the Rate Year three (RY3) sum of calculated annualized megawatt hours ("MWh") discharged from incremental electric battery storage unit installations in O&R's service territory in RY1, RY2 and RY3. The incremental battery storage units installed each year will be quantified using reporting from the Company's interconnection application portal, Power Clerk.

The DER Energy Storage Utilization metric will be calculated as follows:

$$DER\ Utilization\ \text{-}\ Storage\ (MWh) = Battery\ storage\ MWh\ annualized\ discharge$$

Annualized discharge for Battery Storage will be calculated as follows:

$$Battery\ Storage\ \text{Utilization}\ MWh = \text{Sum of Daily battery inverter discharge ratings (MWh) for Battery Storage Units installed in RY1, RY2, and RY3} \times [\text{365 days}]$$[5]

DER Battery Storage Utilization Targets (MWh)	2022-2024
Minimum	86,505
Mid-Point	98,863
Maximum	123,579

1.1.4 Circuit Load Factor

The Circuit Load Factor metric (formerly known as the Storage Roadmap metric) is an outcome-based metric which was designed to improve operations and reliability of

[5] DOE/EPRI Electricity Storage Handbook Appendix B, Page B-12.

electric service on certain specified circuits. The metric will measure the year-over-year improvement of the ratio of the Warwick and Blooming Grove circuits' load factors to the overall system load factor. The data required for this calculation will be gathered from circuit amps, bank volts, and power factor readings.

The metric is based on the percentage change in the current year Circuit to System Load Factor ratio (LF Ratio) compared to the prior year calculated as follows:

$$LF\ Ratio\ \% = \frac{LF\ Ratio\ (RY_x) - LF\ Ratio\ (RY_{x-1})}{LF\ Ratio\ (RY_{x-1})}$$

The LF Ratio for each year is the ratio between Circuits Load Factor (CLF) and System Load Factor (SLF) and is calculated as follows:

$$Load\ Factor\ Ratio\ (RY_x) = \frac{Circuits\ Load\ Factor\ (RY_x)}{System\ Load\ Factor\ (RY_x)}$$

Circuits Load Factor (CLF) will be calculated for the Blooming Grove and Warwick Circuits over the June 1 to July 31 period (*i.e.,* 1,464 hours) based upon the top five load hours of Blooming Grove and Warwick Circuits in aggregate.

The CLF is calculated as follows:

$$CLF\ (RY_x) = \frac{Circuits\ Average\ Load\ MWh\ (RY_x)}{Aggregate\ of\ Circuits\ Top\ Five\ Peak\ Loads\ Average\ MW\ (RY_x)}$$

$$Circuits\ Average\ Load\ MWh = \frac{\sum_{June\ 1}^{July\ 31} MW\ for\ all\ circuits_{hourly}}{\sum_{June\ 1}^{July\ 31} Number\ of\ Hours}$$

$$Aggregate\ of\ Circuits\ Top\ Five\ Peak\ Loads\ Average\ MW$$

$$= \frac{\sum_{Peak\ 1}^{Peak\ 5} MW\ of\ aggregrate\ of\ selected\ circuits_{June/July}}{5}$$

The System Load Factor (“SLF”) will be calculated for the entire system over the same June 1 to July 31 period based upon the same top five hours of the aggregate circuit peaks. The SLF is calculated as follows:

$$SLF\ (RY_x) = \frac{System\ Average\ Load\ MWh\ (RY_x)}{System\ Average\ Peak\ Loads\ at\ Aggregrate\ Circuit\ Peaks\ MW(RY_x)}$$

$$System\ Average\ Load\ MWh\ (RY_x) = \frac{\sum_{June\ 1}^{July\ 31}\ MW_{hourly}}{\sum_{June\ 1}^{July\ 31} Number\ of\ Hours}$$

$$System\ Average\ of\ Peak\ Loads\ at\ Aggregrate\ Circuit\ Peaks\ MW\ (RY_x)$$

$$= \frac{\sum_{Peak\ 1}^{Peak\ 5}\ MW_{June/July}}{5}$$

Circuit Load Factor Reduction (%)	**2022**	**2023**	**2024**
Minimum	2.60%	2.60%	2.60%
Mid-Point	3.40%	3.40%	3.40%
Maximum	5.10%	5.10%	5.10%

1.2 Environmentally Beneficial Electrification EAM

The Environmentally Beneficial Electrification EAM is comprised of three metrics: Electric Vehicle (“EV”) Adoption, Heat Pump (“HP”) Carbon Reduction Count Up, EV

Make-Ready Share-the-Savings DC Fast Charger Installation/Level 2 Installation. These metrics incentivize the Company to reduce carbon emissions by facilitating greater penetration of technologies that use electricity rather than traditional fuels that are more carbon-intensive.

1.2.1 EV Adoption metric

The metric will measure the incremental lifetime short tons of avoided carbon dioxide (“CO_2”)[6] from the incremental deployment EVs in the Company’s service territory in a given Rate Year. Eligible EVs consist of battery EVs (“BEVs”) and Plug-in hybrid electric vehicles (“PHEVs”). Incremental lifetime tons of CO_2 will be calculated from the number of incremental vehicle registrations in each year multiplied by per-unit assumptions of avoided CO_2 multiplied by the average vehicle lifetime as set forth below.

Battery Electric Vehicles (“BEV”): BEV registrations × Emissions Reduction per BEV Vehicle × Average Vehicle Lifetime

Plugin Hybrid Electric Vehicles (“PHEV”): PHEV registrations × Emissions Reduction per PHEV Vehicle × Average Vehicle Lifetime

And, where:

Emissions Reduction per BEV Vehicle = 4.91 Tons per year[7]

Emissions Reduction per PHEV Vehicle = 2.65 Tons per year[8]

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[6] US Tons.

[7] Derived from the following sources: https://afdc.energy.gov/data/10310, https://afdc.energy.gov/data/10309, https://www.epri.com/research/products/000000003002006876, https://greet.es.anl.gov/afleet_tool, https://www3.epa.gov/otaq/gvg/learn-more-technology.htm, CALSTART/Alternative Fuels Data Center, U.S. Energy Information Administration Annual Energy Outlook 2019.

[8] Ibid.

Average Vehicle Lifetime = 10 years

Incremental registrations of eligible BEVs and PHEVs in the Company's service territory will be calculated using vehicle registration data as published on the Atlas Public Policy EValuateNY website, a NYSERDA-funded tool, or other equivalent source.

EV Adoption Targets (Incremental Lifetime Tons of CO_2)	**2022**	**2023**	**2024**
Minimum	60,301	120,602	241,225
Mid-Point	82,466	152,044	281,424
Maximum	104,653	183,486	321,601

1.2.2 Heat Pump Carbon Reduction Count Up metric

The Heat Pump Carbon Reduction Count Up ("HPCR") metric will measure the amount of carbon reduction from incremental heat pump technologies and building shell measures using the Company's Clean Heat funds and installed in the Company's service territory each year. The metric will be measured as the incremental lifetime tons of avoided carbon dioxide ("CO_2"),[9] converted from Clean Heat net MMBtu savings, from heat pump technologies and building shell measures calculated by using the current New York Technical Resource Manual (TRM) algorithms and associated EULs from the year in which the savings were achieved. Any energy savings from measures accepted into the NYS Clean Heat Program and reported in the Company's Clean Heat Portfolio will be eligible to count towards the performance of this metric.

[9] US Ton.

Quantification of the HPCR metric will be determined by the net MMBtu savings from heat pumps installed by O&R customers participating in the Clean Heat Program, in the service territory during the Rate Year.

The baseline for each Rate Year will be determined at the end of 2021 by multiplying the NENY Clean Heat MMBtu targets in each Rate Year by the 2021 Baseline Mix CO_2 Tons per MMBtu conversion factor[10] and the 2021 Clean Heat Portfolio EUL to determine the baseline lifetime tons of carbon. The achievement for each Rate Year will be determined by multiplying the actual annual net MMBtu savings as determined by the TRM formula in effect during that Rate Year by the fixed CO_2 Tons per MMBtu conversion factors, provided below, and the Clean Heat Portfolio average EUL from the year in which the savings occurred to determine the actual lifetime tons of carbon reduction achieved. Please refer to below formula:

$$Baseline\ Lifetime\ tons\ of\ Carbon_{RY1,2,3} = NENY\ Annual\ MMBTU\ Target_{\ RY1,2,3} * CO_2 Tons\ per\ MMBTU\ Conversion\ Factor_{2021} * EUL_{\ 2021}$$

Targets will be set at 5%, 25%, and 50% above the baseline to earn the minimum, midpoint, and maximum basis points respectively in each Rate Year.

[10] Baseline Mix will be based off pre-existing baseline fuel mix from the 2021 Clean Heat Portfolio projects and weighted based on MMBtu volume.

$$Actual\ Achievement: Lifetime\ Tons\ of\ Carbon_{RYi}$$

$$= (Company\ Clean\ Heat\ Portfolio\ Natural\ Gas\ MMBTU\ Savings_{RYi} * CO_2 Tons\ per\ Natural\ Gas\ MMBTU\ Conversion\ Factor * EUL_{RYi}) + (Company\ Clean\ Heat\ Portfolio\ Propane\ MMBTU\ Savings_{RYi} * CO_2 Tons\ per\ Propane\ MMBTU\ Conversion\ Factor * EUL_{RYi}) + (Company\ Clean\ Heat\ Portfolio\ \#2\ Oil\ MMBTU\ Savings_{RYi} * CO_2 Tons\ per\ \#2\ Oil\ MMBTU\ Conversion\ Factor * EUL_{RYi}) + (Company\ Clean\ Heat\ Portfolio\ Electric\ MMBTU\ Savings_{RYi} * CO_2 Tons\ per\ Electric\ MMBTU\ Conversion\ Factor * EUL_{RYi})$$

Pre-Existing Fuel: Greenhouse Gas Conversion Factors	
Natural Gas (Tons CO2e/MMBtu)	.0586
#2 Oil (Tons CO2e/MMBtu)	.0815
Propane (Tons CO2e/MMBtu)	.0681
Electric (Tons CO2e/MMBtu)	.1324

1.2.3 EVSE Make-Ready – Share-the-Savings

The EVSE (Electric Vehicle Supply Equipment) Share-the-Savings metric consists of two components: EVSE Make-Ready Share-the-Savings DC Fast Charger Installations and EV Make-Ready Share-the-Savings Level 2 Installations. These metrics promote performance within O&R’s EV Make-Ready Program (“MR Program”) to support the development of electric infrastructure and equipment necessary to accommodate increased deployment of EVs within New York State by reducing the upfront costs of building charging stations. Through the MR Program, third parties seeking to install or participate in the installation of Level 2 (“L2”) and/or Direct-Current Fast Charging (“DCFC”) chargers can earn incentives that will offset a large portion of, or in some cases, all of the infrastructure costs associated with preparing a site for EV charger installation.

Performance will be based on the number of EVSE L2 and DCFC plugs that received an incentive under the MR Program and the average incentive per plug paid for each plug type.

Performance will be determined at two distinct milestones: at the MR Program’s midpoint review (which coincides with RY 1), and at the end of MR Program review, as described within the EVSE Make-Ready Program Order and subsequent Errata Notice. Achievement at each milestone will be determined as detailed below:

Level 2 Metric Award Calculation[11]

$$
\begin{aligned}
EAM\ Award = \Bigg\{\Bigg[&\left(\frac{\$\ incentive}{plug}_{Public,baseline}\right)\left(Plugs\ Incented_{Public,actual}\right) \\
&+ \left(\frac{\$\ incentive}{plug}_{Non-Public,baseline}\right)\left(Plugs\ Incented_{Non-Public,actual}\right) \\
&+ \left(\frac{\$\ incentive}{plug}_{DAC,baseline}\right)\left(Plugs\ Incented_{DAC,actual}\right)\Bigg] \\
&- \Big[\left(\$\ Incentive_{Public,actual}\right) + \left(\$\ Incentive_{Non-Public,actual}\right) \\
&+ \left(\$\ Incentive_{DAC,actual}\right)\Big]\Bigg\}\ (30\%)
\end{aligned}
$$

Where:

$\frac{\$\ incentive}{plug}_{Public,baseline}$	\$5,400 per Plug
$\frac{\$\ incentive}{plug}_{Non-Public,baseline}$	\$3,000 per Plug
$\frac{\$\ incentive}{plug}_{DAC,baseline}$	\$6,000 per Plug
$Plugs\ Incented_{Public,actual}$	The number of qualifying public L2 plugs installed under the program, outside of disadvantaged communities, during the applicable program period.[12]
$Plugs\ Incented_{Non-Public,actual}$	The number of L2 plugs installed under the program in non-public spaces, outside of disadvantaged communities, during the applicable program period.
$Plugs\ Incented_{DAC,actual}$	The number of L2 plugs installed under the program within disadvantaged communities during the applicable program period.
$\$\ Incentive_{Public,actual}$	Total incentives paid qualifying public L2 plugs outside of disadvantaged communities during the applicable period.
$\$\ Incentive_{Non-Public,actual}$	Total incentives paid for non-public L2 plugs outside of disadvantaged communities during the applicable period.
$\$\ Incentive_{DAC,actual}$	Total incentives paid for plugs within disadvantaged communities during the applicable period.
Minimum Number of Plugs Required to earn Mid-point EAM	569
Minimum Number of Plugs Required to earn End of Program EAM	2,845

[11] Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs, issued July 16, 2020, in Case 18-E-0138, Appendix C and Errata Notice.

[12] Applicable program period refers to program start through mid-point or mid-point through program end.

Disadvantaged Communities (DAC)	Includes environmental justice and low- and moderate-income communities as well as additional areas to be determined later.

DCFC Metric Award Calculation[13]

$$\begin{aligned} EAM\ Award = \Bigg\{\Bigg[&\left(\frac{\$\ incentive}{kW}_{Public,baseline}\right)\left(kW\ Incented_{Public,actual}\right) \\ &+ \left(\frac{\$\ incentive}{plug}_{Non-Public,baseline}\right)\left(Plugs\ Incented_{Non-Public,actual}\right) \\ &+ \left(\frac{\$\ incentive}{kW}_{DAC,baseline}\right)\left(kW\ Incented_{DAC,actual}\right)\Bigg] \\ &- \left[\left(\$\ Incentive_{Public,actual}\right) + \left(\$\ Incentive_{DAC,actual}\right)\right]\Bigg\}\ (30\%) \end{aligned}$$

Where:

$\frac{\$\ incentive}{kW}_{Public,baseline}$	\$330 per kW
$\frac{\$\ incentive}{kW}_{DAC,baseline}$	\$183 per kW
$kW\ Incented_{Public,actual}$	Total public kW plug capacity installed outside of disadvantaged communities for the applicable program period.
$kW\ Incented_{DAC,actual}$	Total kW plug capacity installed within disadvantaged communities for the applicable program period.
$\$\ Incentive_{Public,actual}$	Total incentives paid for all public plugs outside of disadvantaged communities for the applicable program period.
$\$\ Incentive_{DAC,actual}$	Total incentives paid for all plugs within disadvantaged communities for the applicable program period.
Minimum Number of Plugs Required to earn Mid-point EAM	14
Minimum Number of Plugs Required to earn End of Program EAM	71

[13] Ibid.

2.0 Gas EAMs

2.1 Gas Peak Reduction Metric

The Gas Peak Reduction metric is an outcome-based metric that incentivizes the Company to reduce gas peak load in its service territory. To the extent the gas peak load for the Company's service territory is less than the minimum target established for the EAM metric, the Company will receive an incentive. The metric is based on a reduction in the "Heating Factor", derived by dividing heating-related peak demands ("HPD") by heating degree days ("HDD") (together "HPD/HDD"). The HPD for each period is calculated as the difference between the average of the top 3 winter season (October through June) firm peak demands and the average of the top 3 summer season (July through September) firm peak demands.[14]

The HPD/HDD or Heating Factor for each year is determined through the following formula:

$$\frac{HPD}{HDD} \text{ or Heating Factor}$$

$$= \frac{\overline{Top\ 3\ Winter\ Peak\ Day\ Demands_Y} - \overline{Top\ 3\ Summer\ Peak\ Day\ Demands_Y}}{\overline{Top\ 3\ Winter\ Peak\ Day\ HDDs_Y}}$$

Where:

Y	A given year with winter and summer seasons. The summer seasons start from July 1 through September 30 of the current year, and the winter seasons start from October 1 of current year through June 30 of the following year. For example, 2021-2022 year includes summer season from

[14] Only those days during the summer season that have an average temperature above 63 degrees will be considered.

	July 1, 2021 through September 30, 2021, and winter season from October 1, 2022 through June 30, 2022.
$\overline{Top\ 3\ Winter\ Peak\ Day\ Demands}_y$	Average of top 3 peak day demands during the winter season in year Y (as defined above)
$\overline{Top\ 3\ Summer\ Peak\ Day\ Demands}_y$	Average of top 3 peak day demands during the summer season in year Y (as defined above)
$\overline{Top\ 3\ Winter\ Peak\ Day\ HDDs}_y$	Average of heating degree days from the top 3 peak demand days during the winter season in year Y (as defined above)

Performance targets will be established each year based on the following:

- Baseline will be set each year based on a trendline derived from a linear regression of the most recent 5-year historical HPD/HDD or Heating Factors. For example, the RY1 (2022-23) baseline will be based on the five-year historical period from July 2017 through June 2022.
- Adjusted Baseline will be set each year at Baseline less 0.50 percent improvement factor.
- Minimum, mid-point, and maximum performance targets for each Rate Year will be set, respectively, at the Adjusted Baseline less 0.25, 1.00, and 1.75 times the Standard Error of the linear regression (SE).
- The SE will be based on the standard error of the linear regression model.
- The following is a summary of how the targets will be set each Rate Year:

Gas Peak Reduction Targets (Dth)	**2022**	**2023**	**2024**
Baseline	Trendline based on Linear Regression of the most recent 5-year historical HPD/HDD		
Adjusted Baseline	Baseline + (-0.50%)		
Minimum	Adjusted Baseline – (0.25 x SE of Regression)		
Mid-Point	Adjusted Baseline – (1.00 x SE of Regression)		
Maximum	Adjusted Baseline – (1.75 x SE of Regression)		

The Company will receive an incentive if the actual HPD/HDD or Heating Factor for a given year is less than the minimum performance targets described above, with linear scaling between minimum and midpoint, and between midpoint and maximum earnings adjustments.

3.0 Energy Efficiency EAMs

The Energy Efficiency EAMs consists of one electric metric, one gas metric, and one cross commodity metric: Electric Energy Efficiency (“EE”) Share-the-Savings (“STS”), Gas EE STS, and Cross Commodity EE LMI Savings.

3.1 Energy Efficiency Share-the-Savings Metrics

The STS metrics are designed to promote unit cost reductions for O&R’s non-LMI electric energy efficiency, and non-LMI gas energy efficiency portfolios. Performance will be measured based on O&R’s implementation of energy efficiency programs and the resulting reductions in the unit cost of lifetime energy savings as compared with the targets as approved by the Public Service Commission[15], as well as the overall level of energy savings achieved.

Under the STS metrics, the Company will be awarded 30% of unit cost savings realized from O&R's lifetime acquired and verified gross savings (VGS) once O&R has met the minimum annual threshold savings targets. The calculation is subject to verified gross savings policy, as described in Clean Energy Guidance Document #8, "Gross Savings Verification Guidance."[16]

The Share-the-Savings metrics are computed formulaically based on annualized energy savings achieved, Commission approved budgets and targets, weighted average EUL, and expenditures associated with each respective portfolio.

First year annualized energy savings and weighted average EUL will be computed in accordance with the TRM where applicable.[17] Expenditures will be tracked and reported by O&R.

Share-the-Savings achievement will be calculated as follows:

Electric Energy Efficiency Share-the-Savings:

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[15] Case 18-M-0084, *In the Matter of a Comprehensive Energy Efficiency Initiative. Order Authorization Utility Energy Efficiency and Building Electrification Portfolios through 2025, Issued and effective January 16, 2020.*

[16] New York State Department of Public Service Office of Markets and Innovation, Clean Energy Guidance (CE-08), Gross Savings Verification Guidance, August 23, 2019.

[17] If a specific algorithm is not included in the TRM, the Company will estimate using technology specific industry research and/or data.

$$Non-LMI\ Electric\ EE\ STS\ EAM\ Award = \left[\left(\frac{Budget_{Authorized}}{MWh_{Authorized} \times EUL_{Baseline}}\right) - \left(\frac{Expenditures_{Actual}}{MWh_{Actual} \times EUL_{Actual}}\right)\right] \times MWh_{Actual} \times EUL_{Actual} \times 30\%$$

Gas Energy Efficiency Share-the-Savings

$$Non-LMI\ Gas\ EE\ STS\ EAM\ Award = \left[\left(\frac{Budget_{Authorized}}{MMBtu_{Authorized} \times EUL_{Baseline}}\right) - \left(\frac{Expenditures_{Actual}}{MMBtu_{Actual} \times EUL_{Actual}}\right)\right] \times MMBtu_{Actual} \times EUL_{Actual} \times 30\%$$

Where:

$EUL_{Baseline}$	Weighted average Non-LMI Gas or Electric portfolio EUL based on the actual mix of measures acquired during the prior year, computed using EULs from the Technical Resource Manual version that is in effect at the end of the current year for those measures. This baseline mechanism is designed to eliminate impacts from TRM changes which occur during the current (measurement) year.
EUL_{Actual}	Actual weighted average portfolio EUL for the current year.
$MWh_{Authorized}$ $MMBtu_{Authorized}$	O&R's January 2020 NENY authorized portfolio energy annual savings targets (less January 2020 LMI NENY Targets) as detailed below.
MWh_{Actual} $MMBtu_{Actual}$	Total gross verified first year annualized portfolio energy savings achieved during the year.
$Budget_{Authorized}$	O&R's January 2020 NENY authorized portfolio annual budgets (less January 2020 LMI NENY budgets) as detailed below.
$Expenditures_{Actual}$	O&R Gas or Electric portfolio expenditures during the current year.
Minimum Annual STS Threshold Targets	Calculated by applying the cumulative over-or-under performance using the 2018 O&R Rate Case Joint Proposal EE targets for 2019-2020 and the January 2020 NENY Order for 2021-2025 to the 2022-2025 annual NENY targets. The cumulative over-or-under-performance from prior years will be divided by the remaining number of years through 2025.

Authorized budgets and targets are detailed in tables below.

Authorized Budgets and Targets	2022	2023	2024
Non-LMI Electric EE Portfolio			
$MWh_{Authorized}$	64,191	66,044	67,711
$Budget_{Authorized}$	$11,940,181	$12,280,211	$12,586,238
Non-LMI Gas EE Portfolio			
$MMBtu_{Authorized}$	56,438	72,469	89,470
$Budget_{Authorized}$	$1,851,941	$2,400,359	$2,981,977

3.2 Cross Commodity LMI EE Savings Metric

The LMI EE metric is designed to promote gas and electric energy savings of the LMI customer segment. This metric will measure O&R's performance in delivering savings to qualifying customers. Eligibility and program delivery structures have been developed in accordance with, and may continue to evolve within, the context of the NENY proceeding. Eligibility and program delivery structures for LMI customers are further detailed within the 2020 LMI Implementation Plan.[18] This calculation is subject to the verified gross savings policy, as described in Clean Energy Guidance Document #8, Gross Savings Verification Guidance.

The LMI EE metric is based on total lifecycle energy savings achieved within O&R's LMI Energy Efficiency portfolio. Actual lifecycle energy savings will be based on first year annualized energy savings and multiplied by the weighted average EUL of the

[18] Cases 18-M-0084, 14-M-0094, Statewide Low and Moderate Income Portfolio Implementation Plan, filed July 27, 2020.

respective energy efficiency portfolio for the year in which energy savings were achieved (i.e., the EUL used to determine actual lifetime energy savings achieved in RY 3 should be the respective EE portfolio weighted EUL average from 2024). The savings will be computed in accordance with the TRM Programs where applicable.[19]

The targets are based on electric and gas MMBtu achieved cumulatively between January 1, 2022, and December 31, 2024. To determine achievement, lifecycle energy savings will be compared against the cumulative target as computed below, following the end of 2024. Additionally, the Company is required to meet the cumulative 3-year annual minimum lifetime MMBtu target[20] identified below for both of its electric and gas energy efficiency portfolios before it can have the opportunity to earn a monetary award for this metric.

$$LMI\ Energy\ Savings\ Target$$

$$= \sum_{i=2022}^{2024} \left[\left(Baseline\ Target_{e,i}\ \times EUL_{e,2021} \times 3.412 \right) + \left(Baseline\ Target_{g,i}\ \times EUL_{g,2021} \right) \right] \times Performance\ Multiplier$$

[19] If a specific algorithm is not included in the TRM, the Company will estimate using technology specific industry research and/or data.

[20] Cumulative 3-year annual minimum lifetime thresholds will be determined individually for the electric and gas targets by summing the product of the NENY first year annual MMBtu targets multiplied by the respective 2021 EUL for each portfolio.

$$Actual\ LMI\ Savings = \sum_{i=2022}^{2024} \left(Verified\ LMI\ First\ Year\ MWh\ Savings_{e,i} \times EUL_{e,i} \times 3.412\right) + \left(Verified\ LMI\ First\ Year\ MMBtu\ Savings_{g,i} \times EUL_{g,i}\right)$$

Where:

$Baseline\ Target_{e,i}$	2022: 415 MWh 2023: 530 MWh 2024: 646 MWh
$Baseline\ Target_{g,i}$	2022: 5,167 MMBtu 2023: 6,606 MMBtu 2024: 8,044 MMBtu
$EUL_{e,2021}$	Weighted average portfolio EUL for O&R electric portfolio in 2021.
$EUL_{g,2021}$	Weighted average portfolio EUL for O&R gas portfolio in 2021.
$EUL_{e,i}$	Weighted average electric portfolio EUL for year in which first year savings were achieved.
$EUL_{g,i}$	Weighted average gas portfolio EUL for year in which first year savings were achieved.
$Performance\ Multiplier$	Minimum Targets: 105%, Mid-Point Targets: 125%, Maximum Targets: 150%

4.0 EAM Reporting Requirements

The Company will file an annual EAM report with the Secretary no later than April 30 following each Rate Year demonstrating the Company’s performance relative to each EAM metric target and the calculations for incentives earned, including proration of any incentives related to metric achievement between the minimum, midpoint, and maximum target levels, and Share-the-Savings calculations if applicable. In addition, the Company will file quarterly reports with the Secretary in these proceedings to report progress on both the EAM metrics and scorecard metrics. The reports should be filed

60 days after the end of the first three quarters and should describe the Company's progress toward the metric targets and the actions the Company has taken during the quarter to achieve its targets. Annual reports should describe any EM&V activities applicable to EAM performance. The Company will also detail the application of VGS policy to certain EAMs. In addition, the reports should include a forecast of whether the Company believes it is on track to meet the annual or cumulative targets.

Orange and Rockland Utilities, Inc.
Cases 21-E-0074 & 21-G-0073

ELECTRIC REVENUE ALLOCATION AND RATE DESIGN

1. Revenue Allocation

Two adjustments were made to the incremental revenue requirement before allocating it among customer classes. The first adjustment to the incremental revenue requirement for each Rate Year ("RY")[1] is the subtraction of amounts included for New York State Gross Receipts and Franchise Tax surcharge revenues, Municipal Tax surcharge revenues and Metropolitan Transportation Authority Business Tax surcharge revenues. The second adjustment was made to adjust the revenue requirement to offset the incremental credits that are projected to be paid to low income residential customers in each RY.[2]

For each RY, before the adjusted incremental revenue requirement was applied to each customer class, the RY delivery revenues for each class were realigned in a revenue neutral manner to reduce interclass deficiencies and surpluses as indicated by the embedded cost of service ("ECOS") study. In each RY, deficiency and surplus indications have been reduced by one-third. The RY delivery revenue increase was then allocated among the Service Classifications ("SC") in proportion to the relative contribution made by each SC's realigned RY delivery revenue to the total realigned RY delivery revenue. The delivery revenue changes by SC for each RY were mitigated in a manner such that each SC did not

[1] RY1 is defined as the 12 months ending December 31, 2022, RY2 is defined as the 12 months ending December 31, 2023, and RY3 is defined as the 12 months ending December 31, 2024.
[2] This adjustment was a decrease of $174,572 in RY1 with an incremental increase of $358,756 in RY2 and an incremental increase of $371,640 in RY3.

receive a revenue change that was no more than 1.2 times or less than 0.3 times the overall RY delivery revenue change.

2. <u>Rate Design (Excluding Standby Service and Buyback Service)</u>

The rate design process for each RY for all classes except for Rider J – Smart Home Rate consists of the following six steps:

- Determine revised customer charges and a revised Reactive Power Demand Charge ("RPDC") and associated delivery revenue changes.
- Determine revised competitive service charges and associated delivery revenue changes.
- Adjust class-specific delivery revenue increases to determine non-competitive delivery revenue increases excluding customer charges and the RPDC ("adjusted non-competitive delivery revenue increases").
- Calculate class-specific adjusted non-competitve delivery revenue changes for a historical period.
- Implement intraclass rate structure changes for certain SCs.
- Apply adjusted non-competitve delivery revenue increases within each SC.

a. <u>Revised Customer Charges and RPDC and Associated Delivery Revenue Changes</u>

(i) The following summarizes the customer charges in each RY.

SC	RY1	RY2	RY3
SC No. 1*	$20.50	$21.50	$22.00
SC Nos. 2 Sec NDB Unmtd & 16 EO Unmtd	18.00	19.00	20.00
SC No. 2 Sec NDB Mtd	20.00	22.00	24.00
SC No. 2 Sec DB (Non-Standby)	23.00	25.00	27.00
SC No. 2 Pri (Non-Standby)	37.00	39.00	41.00
SC No. 3 (Non-Standby)	100.00	80.00	60.00
SC No. 21 (Non-Standby)	133.00	103.00	73.00

* These charges are also applicable to Rider J – Smart Home Rate.

For all other SCs (except for Standby Service and Buyback Service), the customer charges will remain at their current levels.

(ii) The RPDC will be increased to $0.85/kVAr of billable reactive power demand.

b. Revised Competitive Service Charges and Associated Delivery Revenue Changes

The competitive delivery components include: the billing and payment processing ("BPP") charge; the merchant function charge ("MFC") fixed components, that is the MFC procurement and credit and collections ("C&C") components; the purchase of receivables ("POR") C&C component; and metering charges. The revised competitive service charge revenue levels for each RY were compared with competitive service charge revenues determined based on competitive service charges for the previous RY to determine the change in competitive service revenues.

(i) Based on ECOS study indications, the BPP charge has been increased in RY1 from $1.30 to $1.50. The incremental revenue associated with the change in the BPP charge was based on the number of forecasted bills times the incremental BPP charge.

(ii) The revised revenue levels for the MFC fixed components and the POR C&C component were based on percentages of delivery revenue as determined in the ECOS study.

(iii) The revised revenue level for the metering charges was set to zero due to the elimination of these competitive service charges beginning in RY1.

c. Determination of Class-Specific Adjusted Non-competitive Delivery Revenues

For each RY, the revenue changes associated with the competitive service charges, customer charges, and RPDC were used to adjust the class-specific delivery revenue increases to determine class-specific adjusted non-competitive delivery revenue increases.[3]

d. <u>Determination of Class-Specific Adjusted Non-Competitive Delivery Revenue Increases for a Historical Period</u>

Class-specific revenue ratios were developed for each RY by dividing (a) adjusted non-competitive delivery revenues for each class based on billing data for the historical period (*i.e.*, the twelve months ended December 31, 2019) and rates for the previous RY by (b) adjusted non-competitive delivery revenues for each class based on RY billing data and rates for the previous RY. These revenue ratios for each class were applied to each RY's adjusted non-competitive delivery revenue increase to determine each class's adjusted non-competitive delivery revenue increase for that historic year.

e. <u>Intraclass Rate Structure Changes</u>

The following rate structure changes were made in a revenue neutral manner before applying the adjusted non-competitive delivery revenue increases within each of the affected SCs.

<u>SC No. 2 – Secondary Demand Billed</u>

For SC No. 2 Secondary Demand Billed service, in RY1, the existing three block kWh usage rate structure will be changed to a two block usage rate structure (*i.e.*, the new two block structure will consist of separate rates for the first 4,920 kWh of monthly usage and for monthly usage over 4,920 kWh). Additionally, in each RY, 5% of kWh usage related delivery revenue was shifted from usage charges to demand charges on a

[3] For ECOS Study indications, revenue allocation, and rate design, SC No. 19 is and will continue to be treated as a separate class from SC No. 1.

seasonal basis. The class-specific increase was then applied on a common percentage basis to the demand charges.

SC No. 20

For SC No. 20, in each RY, 25% of kWh usage related revenue was shifted from usage charges to demand charges for Periods I and II. The class-specific increase was then applied on a common percentage basis to the demand charges.

f. Application of Adjusted Non-Competitive Delivery Revenue Increase Within Each SC

For all remaining demand billed classes, the Company applied the adjusted non-competitive delivery revenue increase for the historical period to the demand rates on a common percentage basis.

For all other SCs, each class-specific adjusted non-competitive delivery revenue increase, determined as set forth above, was divided by the total of the kWh usage related revenue or luminaire related revenue at the previous RY's rate levels, to establish an average class-specific percentage by which non-competitive delivery rates excluding the customer charges were increased.

g. Rider J – Smart Home Rate

The rates for Rider J – Smart Home Rate were developed in a manner consistent with that used to develop the current Rider J rates. For both Rate I and Rate II,[4] a portion of transmission and distribution ("T&D") related revenue was allocated to be recovered through T&D event charges. That revenue was then assigned to be recovered through

[4] The Company separately filed with the Commission on October 22, 2021 a proposal to eliminate Rider J – Rate II. Upon Commission approval of the Company's proposal, Rate II will not be included in the compliance filings in this proceeding.

T&D events in a way that mirrors the overall T&D proportional allocations of the delivery charge in the revenue requirement.

For Rate I, the delivery revenue that is not recovered through the customer charge and is not designed to be recovered through T&D event charges was assigned to be recovered through the daily demand charges. For Rate II, the delivery revenue that is not recovered through the customer charge and is not designed to be recovered through T&D event charges was assigned to be recovered through the subscription charge.

3. Unbundled Charges

a. Merchant Function Charge

For the term of the Electric Rate Plan, the Company will continue to implement the MFC, as set forth in the Company's electric tariff**.** The MFC fixed component monthly targets for each RY are set forth in Schedule 4 of this Appendix.

b. Transition Adjustment for Competitive Services

For the term of the Electric Rate Plan, the Company will continue to implement the Transition Adjustment for Competitive Services ("TACS"), as set forth in the Company's electric tariff, modified as follows.

The Company will no longer reconcile the difference between the POR C&C revenue target and the POR C&C actual revenue through the TACS mechanism and will instead do so through the POR Discount. The TACS section of the electric tariff will be amended to remove the POR C&C reconciliation commencing with the TACS that will become effective January 1, 2023, since the TACS effective January 1, 2022 will be reconciling the POR C&C revenue target and actual revenue for RY 3 of the current rate plan.

c. POR Discount

For the term of the Electric Rate Plan, the Company will continue to implement the POR discount, as set forth in the Company's electric tariff, modified as follows.

The Company will collect the difference between the POR C&C revenue target and actual revenue as a component of the POR discount (*i.e.*, on a percentage basis applicable to ESCOs rather than on a $/kWh basis applicable to customers). The POR C&C reconciliation has been added as a component of the POR discount percentage commencing with the POR discount percentage effective January 1, 2023. The POR C&C component monthly targets for each RY are set forth in Schedule 4 of this Appendix.

d. BPP Charge

The Company's BPP charge will increase from $1.30 per bill to $1.50 per bill.

e. Metering Charges

The Company's Metering Charges will be eliminated beginning in RY1.

4. Rate Design – Standby Service and Buyback Service[5]

The standby rate design is consistent with the guidelines set forth in the Commission's Opinion 01-04, Opinion and Order Approving Guidelines for the Design of Standby Service Rates, issued October 26, 2001 in Case 99-M-1470. The billing determinants used to design standby rates were based on those used in the formulation of the proposed rates for the otherwise applicable non-standby SCs. The cost allocation matrix contained in Appendix B

[5] The Company filed on September 23, 2019 proposed changes to the Standby Service rate design in compliance with the Commission's Order on Standby and Buyback Service Rate Design and Establishing Optional Demand-Based Rates, issued May 16, 2019, in Case No. 15-E-0751. Should the Commission approve the Company's filing or require changes to the proposed filing during the course of the rate plan, the Company will revise its proposed Standby Service rates accordingly.

of the March 11, 2003 Joint Proposal adopted by the Commission in its Order Establishing Electric Standby Rates, issued July 29, 2003, in Case Nos. 02-E-0780 and 02-E-0781 also was used. This matrix shows the percentage allocation of costs between the as-used demand charge and the contract demand charge, at various service levels.

The class revenue requirements to be recovered through the contract demand charges were developed by applying the percentages applicable to the contract demand from the cost allocation matrix to the portions of the revenue requirement applicable to transmission, substation, primary, and secondary costs. The contract demand revenue requirements were divided by the applicable estimated standby contract demand billing determinants, which were developed based on a ratio reflecting the relationship between contract demand and monthly billing demands. This resulted in the contract demand charges.

The class revenue requirements to be recovered through the as-used daily demand charges were developed by applying the percentages applicable to as-used demand charges from the cost allocation matrix to the portions of the revenue requirement applicable to transmission, substation, primary, and secondary costs. The as-used daily demand charge revenue requirements were divided by the applicable estimated as-used daily demand billing determinants to develop the as-used daily demand charges.

The customer charges for standby service were based on the otherwise applicable SC customer costs as outlined in the ECOS study.

The MFC, BPP, and RPDC for Standby Service rates are equal to that of the otherwise applicable SC.

The Buyback Service Contract Demand rates and customer charges have been set equal to the Standby Service contract demand rates and customer charges for the applicable class.

5. Additional Items for Collection through the Energy Cost Adjustment

As set forth in Appendix 9, the Energy Cost Adjustment ("ECA") will be amended to include recovery for the following items: (1) the Revenue Adjustment Mechanism; (2) the Late Payment Charge Reconciliation; and (3) the COVID Uncollectible Expenses Variance. These three items will become components of the Variable ECA and collections or credits to customers through such mechanism will occur once results are known after the end of each RY. Such collection amounts will be spread equally over a 12-month period.

6. Make Whole Provisions

If the Commission makes rates effective for RY1 after January 1, 2022, the Company will implement a make whole provision. Differences in non-competitive delivery service revenues that result from the extension of the Case 21-E-0073 suspension period plus interest at the Commission's Other Customer Capital Rate will be collected via the implementation of a Delivery Revenue Surcharge ("DRS").[6] The DRS will be in effect on the date rates become effective in this case through the remainder of RY1. The unit amount to be collected from customers will be shown by SC on the Statement of Delivery Revenue Surcharge.[7] Any difference between amounts required to be collected and actual amounts collected will be charged or credited to customers in a subsequent DRS Statement that will become effective March 1, 2023.

[6] Competitive services' revenue differences associated with the extension of the Case 21-E-0073 suspension period will be reconciled and surcharged or recovered through the TACS.

[7] Standby Service customers will be charged on a per-kW of contract demand basis while all other customers will be charged on a per-kWh basis.

7. Tariff Filing Dates

By January 1, 2022, 2023 and 2024 the Company will file tariff revisions implementing the rate changes for RY1, RY2, and RY3, respectively,[8] unless the Commission makes rates effective for RY1 after January 1, 2022 in this proceeding, at which time the Company will place RY1 rates into effect on another date subject to the make whole provisions described above.

[8] The tariff filings for RY2 and RY3 will be made at least 30 days prior to the effective date of new rates.

ORANGE AND ROCKLAND UTILITIES, INC.

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Appendix 17 - Electric Revenue Allocation and Rate Design

Index of Schedules

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-E-0074

Impact of Proposed Rate Change on Total Revenue - No Temporary Surcharge
For the Rate Year Twelve Months Ending December 31, 2022 (1) (2)
(Based on Billed Sales and Revenues)

Based on Levelized Revenue Requirement

Service Classification	Rate Year Billed Sales (MWH)	Customers	Revenue At Current Rates ($000s)	Revenue At Proposed Rates ($000s)	Change ($000s)	Percent Change
SC1	1,527,098	203,697	294,740	302,958	8,218	2.8%
SC19	66,244	3,198	11,638	11,924	286	2.5%
Total Res	1,593,342	206,896	306,378	314,882	8,505	2.8%
SC2 Sec	846,575	24,174	136,309	138,049	1,740	1.3%
SC2 Sec Heat	24,293	296	2,755	2,801	46	1.7%
SC2 Sec ND & UM	16,808	4,938	3,420	3,491	71	2.1%
SC20	86,889	461	10,795	10,945	150	1.4%
Total Secondary	974,566	29,868	153,279	155,286	2,007	1.3%
SC2 Pri	50,231	186	5,760	5,851	90	1.6%
SC3	310,460	261	36,765	37,077	312	0.9%
SC21	33,561	27	4,025	4,077	52	1.3%
Total Primary	394,252	474	46,550	47,004	454	1.0%
Total Sec & Pri	1,368,818	30,342	199,829	202,290	2,461	1.2%
SC9 (Commercial)	514,516	51	50,526	50,835	308	0.6%
SC22 (Industrial)	292,002	33	28,901	29,082	181	0.6%
Total SC9 & SC22	806,518	84	79,428	79,917	489	0.6%
SC4	10,498	66	2,989	3,082	93	3.1%
SC5	2,105	508	348	357	9	2.6%
SC6	3,211	0	470	474	5	1.0%
SC 16 -dusk-to-dawn	9,489	2,220	3,316	3,426	110	3.3%
SC 16 - energy only	2,577	436	507	519	12	2.4%
SC16 - Total	12,066	2,656	3,823	3,945	122	3.2%
Total Lighting	27,880	3,230	7,630	7,859	228	3.0%
Total	3,796,558	240,551	593,264	604,948	11,684	2.0%

Notes:
1. For comparison purposes, an estimated electric supply charge for retail access customers has been included in total revenues. This is equivalent, on a per unit basis, to the cost of electric supply included in full service customer revenues.
2. Revenue at Current Rates excludes temporary surcharge revenues from Rate Year 3 of Case 18-E-0067

ORANGE AND ROCKLAND UTILITIES, INC.

Case No. 21-E-0074

Calculation of Incremental Revenue Requirement for Rate Year 1

Based on Levelized Revenue Requirement

a.	Incremental Revenue Requirement for Rate Year Including Gross Receipts/MTA Taxes (1)	$11,675,285
b.	Gross Receipts/MTA Tax Included in Incremental Revenue Requirement (2)	199,000
c.	Incremental Revenue Requirement for Rate Year Excluding Gross Receipts/MTA Taxes (a - b)	$11,476,285
d.	Low Income Incremental Funding	($174,572)
e.	Total Revenue Reqirement + Low Income Incremental Funding	$11,301,713
f.	Rate Year Bundled Delivery Revenues	$334,869,993
g.	Rate Year Percentage Increase in Delivery Revenues (e / f)	3.37496%
h.	Rate Year Overall Percentage Increase in Delivery Revenues Less Low Income Incremental Funding (c/f)	3.42709%

Note:
1. Twelve months ending December 31, 2022
2. GRT/MTA Gross Up Included in Rev Req = 1.71%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-E-0074

Allocation of Incremental Revenue Requirement Among Customer Classes for Rate Year 1

Based on Levelized Revenue Requirement

Class	Bundled Rate Yr. Delivery Rev ($)	Surplus/ Deficiency ($)	Adj. Rate Yr. Delivery Revenue ($)	Proposed Rate Yr. Incr. @ 3.37496% ($)	Rate Yr. Bundled Delivery Rev. at 'Proposed Rate Level ($)	Proposed RY Increase Incl. (Sur)/Def ($)	Mitigation Adjustment ($)	Adjusted Rate Yr. Increase Including Mitigation Adj ($)	Rate Yr. Bundled %
SC1	195,025,100	3,850,329	198,875,429	6,711,966	205,587,395	10,562,295	(2,663,876)	7,898,419	4.0%
SC19	6,948,100	27,000	6,975,100	235,407	7,210,507	262,407	71,917	281,395	4.0%
Total Res	201,973,200	3,877,329	205,850,529	6,947,373	212,797,902	10,824,702	(2,591,959)	8,179,814	4.0%
SC2 Sec	76,821,098	(1,633,665)	75,187,433	2,537,546	77,724,979	903,881	775,220	1,710,310	2.2%
SC2 Sec Heating	1,121,746	147,667	1,269,413	42,842	1,312,255	190,509	(145,078)	45,431	4.0%
SC2 Sec ND	1,717,649	32,667	1,750,316	59,072	1,809,388	91,739	(22,175)	69,564	4.0%
SC20	4,727,800	(61,000)	4,666,800	157,503	4,824,303	96,503	48,117	146,557	3.1%
Total Sec	84,388,293	(1,514,332)	82,873,962	2,796,963	85,670,925	1,282,631	656,084	1,971,861	2.3%
SC2 Pri	2,237,000	(11,000)	2,226,000	75,127	2,301,127	64,127	22,951	88,002	3.9%
SC3	15,191,900	(795,333)	14,396,567	485,878	14,882,445	(309,455)	611,707	308,228	2.0%
SC21	1,688,800	(23,333)	1,665,467	56,209	1,721,676	32,876	17,172	50,739	3.0%
Total Pri	19,117,700	(829,666)	18,288,034	617,214	18,905,248	(212,452)	651,830	446,969	2.3%
Total Sec & Pri	103,505,993	(2,343,998)	101,161,996	3,414,177	104,576,173	1,070,179	1,307,914	2,418,830	2.3%
Total SC9 (Com)	15,024,000	(973,999)	14,050,001	474,182	14,524,183	(499,817)	796,796	302,811	2.0%
Total SC22 (Mfg)	8,787,000	(648,666)	8,138,334	274,666	8,413,000	(374,000)	546,878	176,256	2.0%
Total SC 9 & SC 22	23,811,000	(1,622,665)	22,188,335	748,848	22,937,183	(873,817)	1,343,674	479,067	2.0%
SC4	2,233,000	34,000	2,267,000	76,510	2,343,510	110,510	(20,075)	90,435	4.0%
SC5	198,000	17,667	215,667	7,279	222,946	24,946	(16,927)	8,019	4.0%
SC6	234,000	(24,000)	210,000	7,087	217,087	(16,913)	21,447	4,621	2.0%
SC 16 -dusk-to-dawn	2,618,000	29,667	2,647,667	89,358	2,737,025	119,025	(12,997)	106,028	4.0%
SC 16 - energy only	296,800	32,000	328,800	11,097	339,897	43,097	(31,077)	12,020	4.0%
SC16 - Total	2,914,800	61,667	2,976,467	100,455	3,076,922	162,122	(44,074)	118,048	4.0%
Total Lights	5,579,800	89,333	5,669,133	191,331	5,860,464	280,664	(59,629)	221,122	4.0%
Total	334,869,993	0	334,869,993	11,301,729	346,171,722	11,301,729	0	11,298,834	3.4%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-E-0074

Determination of Non-Competitive Delivery Revenue Increases for Rate Year 1

Based on Levelized Revenue Requirement

		Incremental Competitive Service, Customer Charge, and RPDC Revenues									
Class	Adj. Rate Yr. Incr. Incl. (Sur)/Def Incl. Mitigation Adj./Incr A ($)	MFC Supply Related Rev B ($)	MFC PP WC Related Rev C ($)	MFC Credit & Collections Related Rev D ($)	POR Credit & Collections Related Rev E ($)	Competitive Metering Related Rev F ($)	Customer Charge Rev G ($)	Reactive Power Demand Charge Rev H ($)	BPP Charge Rev I ($)	Total Rate Yr. Incremental Comp. Services Rev J = ∑ (A to I) ($)	Non-Competitive Rate Yr. Delivery Revenue Incr K = A - J ($)
SC1	7,898,419	(1,671,309)	(73,010)	(168,855)	(404,567)	0	2,367,777	0	329,854	379,890	7,518,530
SC19	281,395	(56,222)	(2,456)	(5,680)	(23,656)	0	(464)	0	4,794	(83,684)	365,079
Total Res	8,179,814	(1,727,531)	(75,466)	(174,535)	(428,223)		2,367,313	0	334,648	296,206	7,883,608
SC2 Sec Dmd	1,710,310	(349,872)	(23,808)	(40,500)	(1,772)	(4,867,637)	580,178	3,320	42,541	(4,657,549)	6,367,859
SC2 Sec Heating	45,431	(5,863)	(399)	(679)	(350)	(59,076)	0	0	0	(66,367)	111,798
SC2 Sec ND	69,564	(13,845)	(942)	(1,603)	674	(521,840)	90,575	0	8,689	(438,291)	507,855
SC20	146,557	(13,791)	(938)	(1,597)	(125)	(129,501)	256	554	872	(144,269)	290,826
Total Sec	1,971,861	(383,370)	(26,087)	(44,379)	(1,573)	(5,578,054)	671,009	3,874	52,103	(5,306,477)	7,278,338
SC2 Pri	88,002	(6,720)	(1,519)	(727)	3,085	(61,399)	4,757	653	1,746	(60,124)	148,126
SC3	308,228	(12,995)	(2,939)	(1,405)	17,344	(143,963)	(60,800)	33,889	518	(170,350)	478,579
SC21	50,739	(481)	(108)	(52)	474	(12,976)	(9,708)	4,794	50	(18,007)	68,746
Total Pri	446,969	(20,196)	(4,566)	(2,184)	20,903	(218,338)	(65,751)	39,336	2,314	(248,482)	695,451
Total Sec & Pri	2,418,830	(403,566)	(30,653)	(46,563)	19,330	(5,796,392)	605,258	43,210	54,418	(5,554,958)	7,973,789
Total SC9 (Com)	302,811	(24,458)	(5,533)	(2,644)	12,326	(76,279)	0	61,660	112	(34,816)	337,627
Total SC22 (Mfg)	176,256	(19,794)	(4,478)	(2,140)	10,819	(49,357)	0	90,747	79	25,876	150,380
Total SC 9 & SC 22	479,067	(44,252)	(10,011)	(4,784)	23,145	(125,636)	0	152,406	191	(8,940)	488,007
SC4	90,435	(1,656)	(113)	(192)	(319)	0	0	0	0	(2,280)	92,715
SC5	8,019	(477)	(33)	(56)	(52)	0	0	0	89	(529)	8,548
SC6	4,621	(3,034)	(207)	(351)	117	0	(3,024)	0	0	(6,499)	11,120
SC 16 -dusk-to-dawn	106,028	(8,504)	(579)	(985)	322	0	0	0	54	(9,692)	115,720
SC 16 - energy only	12,020	(2,311)	(157)	(268)	96	0	936	0	790	(914)	12,934
SC16 - Total	118,048	(10,815)	(736)	(1,253)	418	0	936	0	844	(10,606)	128,654
Total Lights	221,122	(15,982)	(1,088)	(1,852)	164	0	(2,088)	0	933	(19,914)	241,036
Total	11,298,834	(2,191,331)	(117,218)	(227,734)	(385,584)	(5,922,028)	2,970,483	195,616	390,189	(5,287,607)	16,586,441

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-E-0074

Monthly Billing Comparison - Summer
Reflecting Proposed Rate Change

SC No. 1 Residential

Based on Levelized Revenue Requirement for Rate Year 1

Monthly Summer Usage (kWh)		Bill at Present Rates	Bill at Proposed Rates	Change Amount	Change %	% of Bills in this Usage Range
Usage >	Usage ≤					
	50	$29.53	$30.79	$1.26	4.3	8.3
50	100	37.78	39.09	1.31	3.5	1.6
100	150	46.04	47.34	1.30	2.8	2.3
150	200	54.26	55.62	1.36	2.5	3.0
200	250	62.52	63.91	1.39	2.2	3.5
250	300	71.89	73.37	1.48	2.1	3.8
300	350	81.22	82.81	1.59	2.0	3.9
350	400	90.62	92.28	1.66	1.8	4.1
400	450	99.97	101.73	1.76	1.8	4.0
450	500	109.36	111.21	1.85	1.7	4.0
500	550	118.70	120.64	1.94	1.6	3.8
550	600	128.05	130.09	2.04	1.6	3.7
600	650	137.45	139.56	2.11	1.5	3.6
650	700	146.78	149.02	2.24	1.5	3.5
700	750	156.15	158.46	2.31	1.5	3.3
750	800	165.53	167.93	2.40	1.4	3.2
800	850	174.88	177.38	2.50	1.4	3.0
850	900	184.25	186.84	2.59	1.4	2.8
900	950	193.61	196.29	2.68	1.4	2.6
950	1,000	202.98	205.74	2.76	1.4	2.5
1,000	1,050	212.34	215.19	2.85	1.3	2.3
1,050	1,100	221.70	224.67	2.97	1.3	2.1
1,100	1,150	231.07	234.10	3.03	1.3	2.0
1,150	1,200	240.43	243.56	3.13	1.3	1.8
1,200	1,250	249.80	253.03	3.23	1.3	1.7
1,250	1,300	259.15	262.48	3.33	1.3	1.5
1,300	1,350	268.51	271.91	3.40	1.3	1.4
1,350	1,400	277.90	281.39	3.49	1.3	1.3
1,400	1,450	287.24	290.84	3.60	1.3	1.2
1,450	1,500	296.62	300.32	3.70	1.2	1.1
1,500	1,550	305.99	309.75	3.76	1.2	1.0
1,550	1,600	315.32	319.21	3.89	1.2	0.9
1,600	1,650	324.70	328.67	3.97	1.2	0.8
1,650	1,700	334.07	338.13	4.06	1.2	0.8
1,700	1,750	343.43	347.56	4.13	1.2	0.7
1,750	1,800	352.80	357.04	4.24	1.2	0.7
1,800	1,850	362.15	366.49	4.34	1.2	0.6
1,850	1,900	371.52	375.95	4.43	1.2	0.5
1,900	1,950	380.89	385.40	4.51	1.2	0.5
1,950	2,000	390.25	394.86	4.61	1.2	0.5
2,000	2,050	399.60	404.30	4.70	1.2	0.4
2,050	2,100	408.97	413.78	4.81	1.2	0.4
2,100	2,150	418.33	423.21	4.88	1.2	0.4
2,150	2,200	427.69	432.67	4.98	1.2	0.3
2,200	2,250	437.08	442.14	5.06	1.2	0.3
2,250	2,300	446.43	451.60	5.17	1.2	0.3
2,300	2,350	455.78	461.03	5.25	1.2	0.2
2,350	2,400	465.15	470.50	5.35	1.2	0.2
2,400	2,450	474.51	479.95	5.44	1.1	0.2
2,450	2,500	483.89	489.43	5.54	1.1	0.2

* The bills for each range are calculated at the upper band
(e.g., the impact shown for 0 - 50 kWh band is based on the 50 kWh).
** There are an additional 3% of customers with usage above 2,500 kWh.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-E-0074

Monthly Billing Comparison - Winter
Reflecting Proposed Rate Change

SC No. 1 Residential

Based on Levelized Revenue Requirement for Rate Year 1

Monthly Winter Usage (kWh) Usage >	Usage ≤	Bill at Present Rates	Bill at Proposed Rates	Change Amount	Change %	% of Bills in this Usage Range
	50	$29.53	$30.79	$1.26	4.3	10.9
50	100	37.78	39.09	1.31	3.5	2.3
100	150	46.04	47.34	1.30	2.8	4.2
150	200	54.26	55.62	1.36	2.5	5.2
200	250	62.52	63.91	1.39	2.2	5.6
250	300	70.77	72.19	1.42	2.0	5.9
300	350	79.00	80.46	1.46	1.8	6.0
350	400	87.27	88.75	1.48	1.7	5.8
400	450	95.51	97.03	1.52	1.6	5.6
450	500	103.77	105.32	1.55	1.5	5.3
500	550	111.99	113.58	1.59	1.4	4.8
550	600	120.24	121.86	1.62	1.3	4.3
600	650	128.50	130.15	1.65	1.3	3.9
650	700	136.74	138.43	1.69	1.2	3.4
700	750	144.99	146.70	1.71	1.2	3.0
750	800	153.25	154.99	1.74	1.1	2.7
800	850	161.48	163.27	1.79	1.1	2.4
850	900	169.72	171.54	1.82	1.1	2.1
900	950	177.98	179.82	1.84	1.0	1.8
950	1000	186.21	188.10	1.89	1.0	1.6
1000	1050	194.46	196.37	1.91	1.0	1.4
1050	1100	202.71	204.68	1.97	1.0	1.2
1100	1150	210.96	212.93	1.97	0.9	1.1
1150	1200	219.19	221.20	2.01	0.9	0.9
1200	1250	227.46	229.51	2.05	0.9	0.8
1250	1300	235.69	237.77	2.08	0.9	0.7
1300	1350	243.92	246.05	2.13	0.9	0.7
1350	1400	252.20	254.33	2.13	0.8	0.6
1400	1450	260.43	262.61	2.18	0.8	0.5
1450	1500	268.69	270.91	2.22	0.8	0.5
1500	1550	276.94	279.17	2.23	0.8	0.4
1550	1600	285.17	287.46	2.29	0.8	0.4
1600	1650	293.42	295.73	2.31	0.8	0.3
1650	1700	301.67	304.01	2.34	0.8	0.3
1700	1750	309.90	312.28	2.38	0.8	0.3
1750	1800	318.17	320.58	2.41	0.8	0.2
1800	1850	326.40	328.86	2.46	0.8	0.2
1850	1900	334.65	337.12	2.47	0.7	0.2
1900	1950	342.90	345.41	2.51	0.7	0.2
1950	2000	351.16	353.69	2.53	0.7	0.2
2000	2050	359.39	361.96	2.57	0.7	0.1
2050	2100	367.63	370.26	2.63	0.7	0.1
2100	2150	375.89	378.51	2.62	0.7	0.1
2150	2200	384.12	386.79	2.67	0.7	0.1
2200	2250	392.39	395.09	2.70	0.7	0.1
2250	2300	400.63	403.37	2.74	0.7	0.1
2300	2350	408.86	411.64	2.78	0.7	0.1
2350	2400	417.11	419.92	2.81	0.7	0.1
2400	2450	425.36	428.19	2.83	0.7	0.1
2450	2500	433.63	436.49	2.86	0.7	0.1

* The bills for each range are calculated at the upper band
(e.g., the impact shown for 0 - 50 kWh band is based on the 50 kWh).
** There are an additional 1.2% of customers with usage above 2,500 kWh.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-E-0074

Impact of Proposed Rate Change on Total Revenue
For the Rate Year Twelve Months Ending December 31, 2023 (1)
(Based on Billed Sales and Revenues)

Based on Levelized Revenue Requirement

Service Classification	Rate Year Billed Sales (MWH)	Customers	Revenue At Current Rates ($000s)	Revenue At Proposed Rates ($000s)	Change ($000s)	Percent Change
SC1	1,524,778	205,444	300,789	308,855	8,066	2.7%
SC19	66,130	3,137	11,777	12,075	298	2.5%
Total Res	1,590,908	208,581	312,566	320,930	8,364	2.7%
SC2 Sec	875,760	24,739	140,813	142,664	1,851	1.3%
SC2 Sec Heat	25,203	285	2,855	2,904	49	1.7%
SC2 Sec ND & UM	17,268	4,697	3,462	3,552	89	2.6%
SC20	89,966	462	11,163	11,322	159	1.4%
Total Secondary	1,008,197	30,182	158,294	160,442	2,148	1.4%
SC2 Pri	51,974	190	6,023	6,120	97	1.6%
SC3	313,553	261	36,933	37,245	312	0.9%
SC21	33,886	27	4,060	4,113	53	1.3%
Total Primary	399,413	478	47,016	47,478	462	1.0%
Total Sec & Pri	1,407,610	30,660	205,310	207,919	2,610	1.3%
SC9 (Commercial)	536,650	51	51,836	52,141	305	0.6%
SC22 (Industrial)	294,690	33	28,804	28,979	175	0.6%
Total SC9 & SC22	831,339	84	80,640	81,121	480	0.6%
SC4	10,339	66	3,020	3,115	95	3.1%
SC5	2,073	508	350	358	8	2.3%
SC6	3,162	0	458	463	5	1.1%
SC 16 -dusk-to-dawn	9,346	2,198	3,240	3,348	108	3.3%
SC 16 - energy only	2,538	434	502	514	12	2.4%
SC16 - Total	11,884	2,632	3,742	3,862	120	3.2%
Total Lighting	27,458	3,206	7,570	7,798	228	3.0%
Total	3,857,315	242,531	606,087	617,768	11,682	1.9%

Notes:

1. For comparison purposes, an estimated electric supply charge for retail access customers has been included in total revenues. This is equivalent, on a per unit basis, to the cost of electric supply included in full service customer revenues.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-E-0074

Calculation of Incremental Revenue Requirement for Rate Year 2

Based on Levelized Revenue Requirement

a.	Incremental Revenue Requirement for Rate Year Including Gross Receipts/MTA Taxes (1)	$11,675,285
b.	Gross Receipts/MTA Tax Included in Incremental Revenue Requirement (2)	199,000
c.	Incremental Revenue Requirement for Rate Year Excluding Gross Receipts/MTA Taxes (a - b)	$11,476,285
d.	Low Income Incremental Funding	$358,756
e.	Total Revenue Reqirement + Low Income Incremental Funding	$11,835,041
f.	Rate Year Bundled Delivery Revenues	$349,235,600
g.	Rate Year Percentage Increase in Delivery Revenues (e / f)	3.38884%
h.	Rate Year Overall Percentage Increase in Delivery Revenues Less Low Income Incremental Funding (c/f)	3.28612%

Note:
1. Twelve months ending December 31, 2023
2. GRT/MTA Gross Up Included in Rev Req = 1.71%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-E-0074

Allocation of Incremental Revenue Requirement Among Customer Classes for Rate Year 2

Based on Levelized Revenue Requirement

Class	Bundled Rate Yr. Delivery Rev ($)	Surplus/ Deficiency ($)	Adj. Rate Yr. Delivery Revenue ($)	Proposed Rate Yr. Incr. @ 3.38884% ($)	Rate Yr. Bundled Delivery Rev. at 'Proposed Rate Level ($)	Proposed RY Increase Incl. (Sur)/Def ($)	Mitigation Adjustment	Adjusted Rate Yr. Increase Including Mitigation Adj	Rate Yr. Bundled %
SC1	203,791,400	3,850,329	207,641,729	7,036,646	214,678,375	10,886,975	(2,599,574)	8,287,401	4.1%
SC19	7,193,600	27,000	7,220,600	244,695	7,465,295	271,695	69,216	292,536	4.1%
Total Res	210,985,000	3,877,329	214,862,329	7,281,341	222,143,670	11,158,670	(2,530,358)	8,579,937	4.1%
SC2 Sec	80,232,746	(1,633,665)	78,599,081	2,663,597	81,262,678	1,029,932	753,445	1,812,050	2.3%
SC2 Sec Heating	1,146,393	147,667	1,294,059	43,854	1,337,913	191,521	(144,901)	46,620	4.1%
SC2 Sec ND	2,183,761	32,667	2,216,428	75,111	2,291,539	107,778	(18,973)	88,805	4.1%
SC20	5,017,000	(61,000)	4,956,000	167,951	5,123,951	106,951	47,508	156,267	3.1%
Total Sec	88,579,900	(1,514,332)	87,065,568	2,950,513	90,016,081	1,436,181	637,079	2,103,741	2.4%
SC2 Pri	2,438,300	(11,000)	2,427,300	82,257	2,509,557	71,257	23,268	95,410	3.9%
SC3	15,559,400	(795,333)	14,764,067	500,331	15,264,398	(295,002)	594,713	305,097	2.0%
SC21	1,751,200	(23,333)	1,727,867	58,555	1,786,422	35,222	16,563	52,415	3.0%
Total Pri	19,748,900	(829,666)	18,919,234	641,143	19,560,377	(188,523)	634,544	452,922	2.3%
Total Sec & Pri	108,328,800	(2,343,998)	105,984,802	3,591,656	109,576,458	1,247,658	1,271,623	2,556,663	2.4%
Total SC9 (Com)	15,501,000	(973,999)	14,527,001	492,297	15,019,298	(481,702)	778,548	302,146	1.9%
Total SC22 (Mfg)	8,822,000	(648,666)	8,173,334	276,981	8,450,315	(371,685)	539,723	171,020	1.9%
Total SC 9 & SC 22	24,323,000	(1,622,665)	22,700,335	769,278	23,469,613	(853,387)	1,318,271	473,166	1.9%
SC4	2,283,000	34,000	2,317,000	78,519	2,395,519	112,519	(19,678)	92,841	4.1%
SC5	206,000	17,667	223,667	7,580	231,247	25,247	(16,869)	8,378	4.1%
SC6	234,000	(24,000)	210,000	7,117	217,117	(16,883)	21,275	4,469	1.9%
SC 16 -dusk-to-dawn	2,577,000	29,667	2,606,667	88,336	2,695,003	118,003	(13,206)	104,797	4.1%
SC 16 - energy only	298,800	32,000	330,800	11,210	342,010	43,210	(31,059)	12,151	4.1%
SC16 - Total	2,875,800	61,667	2,937,467	99,546	3,037,013	161,213	(44,265)	116,948	4.1%
Total Lights	5,598,800	89,333	5,688,133	192,762	5,880,895	282,095	(59,537)	222,635	4.0%
Total	349,235,600	0	349,235,600	11,835,037	361,070,637	11,835,037	0	11,832,402	3.4%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-E-0074

Determination of Non-Competitive Delivery Revenue Increases for Rate Year 2

Based on Levelized Revenue Requirement

		Incremental Competitive Service, Customer Charge, and RPDC Revenues									
Class	Adj. Rate Yr. Incr. Incl. (Sur)/Def Incl. Mitigation Adj./Incr A ($)	MFC Supply Related Rev B ($)	MFC PP WC Related Rev C ($)	MFC Credit & Collections Related Rev D ($)	POR Credit & Collections Related Rev E ($)	Competitive Metering Related Rev F ($)	Customer Charge Rev G ($)	Reactive Power Demand Charge Rev H ($)	BPP Charge Rev I ($)	Total Rate Yr. Incremental Comp. Services Rev J = ∑ (A to I) ($)	Non-Competitive Rate Yr. Delivery Revenue Incr K = A - J ($)
SC1	8,287,401	81,442	1,640	14,971	14,453	0	2,465,224	0	0	2,577,730	5,709,671
SC19	292,536	2,778	56	511	623	0	53	0	0	4,020	288,516
Total Res	8,579,937	84,220	1,696	15,482	15,076		2,465,277	0	0	2,581,750	5,998,187
SC2 Sec Dmd	1,812,050	3,751	554	(884)	6,189	0	593,732	0	0	603,342	1,208,708
SC2 Sec Heating	46,620	63	9	(15)	159	0	0	0	0	216	46,403
SC2 Sec ND	88,805	148	22	(35)	116	0	84,619	0	0	84,870	3,935
SC20	156,267	150	22	(35)	254	0	(381)	0	0	10	156,257
Total Sec	2,103,741	4,112	608	(969)	6,718	0	677,970	0	0	688,439	1,415,303
SC2 Pri	95,410	(334)	36	(57)	280	0	4,522	0	0	4,447	90,963
SC3	305,097	(631)	68	(108)	1,134	0	(62,680)	0	0	(62,217)	367,315
SC21	52,415	(24)	3	(4)	33	0	(9,828)	0	0	(9,820)	62,235
Total Pri	452,922	(989)	106	(169)	1,447	0	(67,986)	0	0	(67,591)	520,513
Total Sec & Pri	2,556,663	3,123	714	(1,138)	8,165	0	609,984	0	0	620,847	1,935,816
Total SC9 (Com)	302,146	(1,381)	148	(236)	1,154	0	0	0	0	(315)	302,461
Total SC22 (Mfg)	171,020	(959)	103	(164)	897	0	0	0	0	(124)	171,144
Total SC 9 & SC 22	473,166	(2,340)	251	(400)	2,051	0	0	0	0	(438)	473,604
SC4	92,841	17	3	(4)	78	0	0	0	0	94	92,747
SC5	8,378	5	1	(1)	17	0	0	0	0	22	8,356
SC6	4,469	32	5	(7)	29	0	576	0	0	634	3,835
SC 16 -dusk-to-dawn	104,797	88	13	(21)	84	0	0	0	0	164	104,633
SC 16 - energy only	12,151	23	4	(6)	21	0	1,332	0	0	1,374	10,777
SC16 - Total	116,948	111	17	(27)	105	0	1,332	0	0	1,537	115,411
Total Lights	222,635	164	24	(39)	229	0	1,908	0	0	2,287	220,349
Total	11,832,402	85,167	2,685	13,905	25,521	0	3,077,169	0	0	3,204,446	8,627,956

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-E-0074

Monthly Billing Comparison - Summer
Reflecting Proposed Rate Change

SC No. 1 Residential

Based on Levelized Revenue Requirement for Rate Year 2

Monthly Summer Usage (kWh)		Bill at Present Rates	Bill at Proposed Rates	Change Amount	Change %	% of Bills in this Usage Range
Usage >	Usage ≤					
	50	$30.71	$31.92	$1.21	3.9	8.3
50	100	38.93	40.33	1.40	3.6	1.6
100	150	47.11	48.71	1.60	3.4	2.3
150	200	55.31	57.09	1.78	3.2	3.0
200	250	63.52	65.50	1.98	3.1	3.5
250	300	72.91	75.11	2.20	3.0	3.8
300	350	82.28	84.71	2.43	3.0	3.9
350	400	91.66	94.32	2.66	2.9	4.1
400	450	101.04	103.94	2.90	2.9	4.0
450	500	110.42	113.56	3.14	2.8	4.0
500	550	119.79	123.16	3.37	2.8	3.8
550	600	129.17	132.78	3.61	2.8	3.7
600	650	138.56	142.40	3.84	2.8	3.6
650	700	147.93	152.00	4.07	2.8	3.5
700	750	157.32	161.64	4.32	2.7	3.3
750	800	166.70	171.25	4.55	2.7	3.2
800	850	176.05	180.84	4.79	2.7	3.0
850	900	185.44	190.44	5.00	2.7	2.8
900	950	194.84	200.08	5.24	2.7	2.6
950	1,000	204.20	209.69	5.49	2.7	2.5
1,000	1,050	213.57	219.30	5.73	2.7	2.3
1,050	1,100	222.98	228.94	5.96	2.7	2.1
1,100	1,150	232.33	238.52	6.19	2.7	2.0
1,150	1,200	241.70	248.12	6.42	2.7	1.8
1,200	1,250	251.10	257.76	6.66	2.7	1.7
1,250	1,300	260.48	267.37	6.89	2.6	1.5
1,300	1,350	269.85	276.98	7.13	2.6	1.4
1,350	1,400	279.23	286.59	7.36	2.6	1.3
1,400	1,450	288.61	296.21	7.60	2.6	1.2
1,450	1,500	298.00	305.82	7.82	2.6	1.1
1,500	1,550	307.36	315.43	8.07	2.6	1.0
1,550	1,600	316.74	325.05	8.31	2.6	0.9
1,600	1,650	326.13	334.66	8.53	2.6	0.8
1,650	1,700	335.52	344.27	8.75	2.6	0.8
1,700	1,750	344.88	353.89	9.01	2.6	0.7
1,750	1,800	354.26	363.50	9.24	2.6	0.7
1,800	1,850	363.64	373.11	9.47	2.6	0.6
1,850	1,900	373.01	382.71	9.70	2.6	0.5
1,900	1,950	382.40	392.34	9.94	2.6	0.5
1,950	2,000	391.77	401.94	10.17	2.6	0.5
2,000	2,050	401.15	411.55	10.40	2.6	0.4
2,050	2,100	410.55	421.20	10.65	2.6	0.4
2,100	2,150	419.90	430.79	10.89	2.6	0.4
2,150	2,200	429.28	440.38	11.10	2.6	0.3
2,200	2,250	438.67	450.02	11.35	2.6	0.3
2,250	2,300	448.05	459.62	11.57	2.6	0.3
2,300	2,350	457.42	469.23	11.81	2.6	0.2
2,350	2,400	466.81	478.86	12.05	2.6	0.2
2,400	2,450	476.17	488.46	12.29	2.6	0.2
2,450	2,500	485.57	498.08	12.51	2.6	0.2

* The bills for each range are calculated at the upper band
(e.g., the impact shown for the 0 - 50 kWh band is based on the 50 kWh)
** There are an additional 3% of customers with usage above 2,500 kWh.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-E-0074

Monthly Billing Comparison - Winter
Reflecting Proposed Rate Change

SC No. 1 Residential

Based on Levelized Revenue Requirement for Rate Year 2

Monthly Winter Usage (kWh) Usage >	Usage ≤	Bill at Present Rates	Bill at Proposed Rates	Change Amount	Change %	% of Bills in this Usage Range
	50	$30.71	$31.92	$1.21	3.9	10.9
50	100	38.93	40.33	1.40	3.6	2.3
100	150	47.11	48.71	1.60	3.4	4.2
150	200	55.31	57.09	1.78	3.2	5.2
200	250	63.52	65.50	1.98	3.1	5.6
250	300	71.73	73.87	2.14	3.0	5.9
300	350	79.93	82.27	2.34	2.9	6.0
350	400	88.13	90.65	2.52	2.9	5.8
400	450	96.33	99.07	2.74	2.8	5.6
450	500	104.54	107.44	2.90	2.8	5.3
500	550	112.73	115.83	3.10	2.7	4.8
550	600	120.94	124.23	3.29	2.7	4.3
600	650	129.15	132.64	3.49	2.7	3.9
650	700	137.34	141.00	3.66	2.7	3.4
700	750	145.55	149.42	3.87	2.7	3.0
750	800	153.77	157.81	4.04	2.6	2.7
800	850	161.94	166.18	4.24	2.6	2.4
850	900	170.15	174.56	4.41	2.6	2.1
900	950	178.36	182.97	4.61	2.6	1.8
950	1000	186.56	191.36	4.80	2.6	1.6
1000	1050	194.76	199.74	4.98	2.6	1.4
1050	1100	202.98	208.16	5.18	2.6	1.2
1100	1150	211.15	216.52	5.37	2.5	1.1
1150	1200	219.36	224.92	5.56	2.5	0.9
1200	1250	227.58	233.33	5.75	2.5	0.8
1250	1300	235.77	241.71	5.94	2.5	0.7
1300	1350	243.98	250.09	6.11	2.5	0.7
1350	1400	252.18	258.50	6.32	2.5	0.6
1400	1450	260.37	266.89	6.52	2.5	0.5
1450	1500	268.59	275.28	6.69	2.5	0.5
1500	1550	276.78	283.66	6.88	2.5	0.4
1550	1600	285.00	292.06	7.06	2.5	0.4
1600	1650	293.19	300.45	7.26	2.5	0.3
1650	1700	301.40	308.84	7.44	2.5	0.3
1700	1750	309.60	317.24	7.64	2.5	0.3
1750	1800	317.80	325.63	7.83	2.5	0.2
1800	1850	326.00	334.01	8.01	2.5	0.2
1850	1900	334.19	342.38	8.19	2.5	0.2
1900	1950	342.41	350.81	8.40	2.5	0.2
1950	2000	350.60	359.18	8.58	2.4	0.2
2000	2050	358.80	367.56	8.76	2.4	0.1
2050	2100	367.03	375.98	8.95	2.4	0.1
2100	2150	375.20	384.35	9.15	2.4	0.1
2150	2200	383.41	392.74	9.33	2.4	0.1
2200	2250	391.62	401.15	9.53	2.4	0.1
2250	2300	399.83	409.53	9.70	2.4	0.1
2300	2350	408.02	417.92	9.90	2.4	0.1
2350	2400	416.22	426.32	10.10	2.4	0.1
2400	2450	424.42	434.70	10.28	2.4	0.1
2450	2500	432.63	443.10	10.47	2.4	0.1

* The bills for each range are calculated at the upper band
(e.g., the impact shown for the 0 - 50 kWh band is based on the 50 kWh)
** There are an additional 1.2% of customers with usage above 2,500 kWh.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-E-0074

Impact of Proposed Rate Change on Total Revenue
For the Rate Year Twelve Months Ending December 31, 2023 (1) (2)
(Based on Billed Sales and Revenues)

Based on Levelized Revenue Requirement

Service Classification	Rate Year Billed Sales (MWH)	Customers	Revenue At Current Rates ($000s)	Revenue At Proposed Rates ($000s)	Change ($000s)	Percent Change
SC1	1,503,693	207,271	301,808	310,991	9,183	3.0%
SC19	65,196	3,077	11,742	12,069	327	2.8%
Total Res	1,568,889	210,348	313,550	323,059	9,510	3.0%
SC2 Sec	880,897	25,061	141,297	142,853	1,555	1.1%
SC2 Sec Heat	25,423	273	2,859	2,913	55	1.9%
SC2 Sec ND & UM	17,250	4,698	3,514	3,617	103	2.9%
SC20	90,573	463	11,149	11,292	142	1.3%
Total Secondary	1,014,143	30,494	158,820	160,675	1,856	1.2%
SC2 Pri	52,266	194	6,063	6,155	93	1.5%
SC3	305,242	261	35,437	35,414	(22)	-0.1%
SC21	32,989	27	3,910	3,956	46	1.2%
Total Primary	390,497	482	45,410	45,526	116	0.3%
Total Sec & Pri	1,404,639	30,976	204,230	206,201	1,972	1.0%
SC9 (Commercial)	533,153	51	50,343	50,315	(27)	-0.1%
SC22 (Industrial)	286,955	33	27,458	27,443	(15)	-0.1%
Total SC9 & SC22	820,108	84	77,801	77,758	(43)	-0.1%
SC4	10,225	66	3,042	3,148	106	3.5%
SC5	2,049	508	347	357	10	2.9%
SC6	3,127	0	445	445	0	0.0%
SC 16 -dusk-to-dawn	9,246	2,175	3,168	3,285	117	3.7%
SC 16 - energy only	2,508	436	494	507	13	2.7%
SC16 - Total	11,754	2,611	3,662	3,792	130	3.6%
Total Lighting	27,156	3,185	7,496	7,742	246	3.3%
Total	3,820,792	244,593	603,076	614,761	11,685	1.9%

Notes:

1. For comparison purposes, an estimated electric supply charge for retail access customers has been included in total revenues. This is equivalent, on a per unit basis, to the cost of electric supply included in full service customer revenues.

2. Revenue at proposed rates includes the RY3 temporary credit.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-E-0074

Calculation of Incremental Revenue Requirement for Rate Year 3

Based on Levelized Revenue Requirement

a.	Incremental Revenue Requirement for Rate Year Including Gross Receipts/MTA Taxes (1)	$20,875,640
b.	Gross Receipts/MTA Tax Included in Incremental Revenue Requirement (2)	356,000
c.	Incremental Revenue Requirement for Rate Year Excluding Gross Receipts/MTA Taxes (a - b)	$20,519,640
d.	Low Income Incremental Funding	$371,640
e.	Total Revenue Reqirement + Low Income Incremental Funding	$20,891,280
f.	Rate Year Bundled Delivery Revenues	$359,042,800
g.	Rate Year Percentage Increase in Delivery Revenues (e / f)	5.81860%
h.	Rate Year Overall Percentage Increase in Delivery Revenues Less Low Income Incremental Funding (c/f)	5.71510%

Note:
1. Twelve months ending December 31, 2024
2. GRT/MTA Gross Up Included in Rev Req = 1.71%

ORANGE AND ROCKLAND UTILITIES, INC.

Case No. 21-E-0074

Allocation of Incremental Revenue Requirement Among Customer Classes for Rate Year 3

Based on Levelized Revenue Requirement

Class	Bundled Rate Yr. Delivery Rev ($)	Surplus/ Deficiency ($)	Adj. Rate Yr. Delivery Revenue ($)	Proposed Rate Yr. Incr. @ 5.8186% ($)	Rate Yr. Bundled Delivery Rev. at 'Proposed Rate Level ($)	Proposed RY Increase Incl. (Sur)/Def ($)	Mitigation Adjustment	Adjusted Rate Yr. Increase Including Mitigation Adj	Rate Yr. Bundled %
SC1	210,424,000	3,850,329	214,274,329	12,467,766	226,742,095	16,318,095	(1,625,618)	14,692,477	7.0%
SC19	7,390,500	27,000	7,417,500	431,595	7,849,095	458,595	48,286	506,881	6.9%
Total Res	217,814,500	3,877,329	221,691,829	12,899,361	234,591,190	16,776,690	(1,577,332)	15,199,358	7.0%
SC2 Sec	82,684,635	(1,633,665)	81,050,970	4,716,032	85,767,002	3,082,367	527,616	3,609,983	4.4%
SC2 Sec Heating	1,201,619	147,667	1,349,286	78,510	1,427,796	226,177	(142,276)	83,901	7.0%
SC2 Sec ND	2,280,746	32,667	2,313,412	134,608	2,448,020	167,275	(8,026)	159,249	7.0%
SC20	5,202,000	(61,000)	5,141,000	299,134	5,440,134	238,134	33,466	271,600	5.2%
Total Sec	91,369,000	(1,514,332)	89,854,668	5,228,284	95,082,952	3,713,952	410,780	4,124,732	4.5%
SC2 Pri	2,610,600	(11,000)	2,599,600	151,260	2,750,860	140,260	16,923	157,183	6.0%
SC3	15,442,900	(795,333)	14,647,567	852,283	15,499,850	56,950	307,969	364,919	2.4%
SC21	1,750,600	(23,333)	1,727,267	100,503	1,827,770	77,170	11,244	88,414	5.1%
Total Pri	19,804,100	(829,666)	18,974,434	1,104,046	20,078,480	274,380	336,136	610,516	3.1%
Total Sec & Pri	111,173,100	(2,343,998)	108,829,102	6,332,330	115,161,432	3,988,332	746,916	4,735,248	4.3%
Total SC9 (Com)	15,661,000	(973,999)	14,687,001	854,578	15,541,579	(119,421)	488,404	368,983	2.4%
Total SC22 (Mfg)	8,774,000	(648,666)	8,125,334	472,781	8,598,115	(175,885)	381,935	206,050	2.3%
Total SC 9 & SC 22	24,435,000	(1,622,665)	22,812,335	1,327,359	24,139,694	(295,306)	870,339	575,033	2.4%
SC4	2,338,000	34,000	2,372,000	138,017	2,510,017	172,017	(8,770)	163,247	7.0%
SC5	211,000	17,667	228,667	13,305	241,972	30,972	(16,239)	14,733	7.0%
SC6	232,000	(24,000)	208,000	12,103	220,103	(11,897)	17,301	5,404	2.3%
SC 16 -dusk-to-dawn	2,538,000	29,667	2,567,667	149,402	2,717,069	179,069	(1,857)	177,212	7.0%
SC 16 - energy only	301,200	32,000	333,200	19,388	352,588	51,388	(30,357)	21,031	7.0%
SC16 - Total	2,839,200	61,667	2,900,867	168,790	3,069,657	230,457	(32,214)	198,243	7.0%
Total Lights	5,620,200	89,333	5,709,533	332,215	6,041,748	421,548	(39,922)	381,626	6.8%
Total	359,042,800	0	359,042,800	20,891,265	379,934,065	20,891,265	0	20,891,266	5.8%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-E-0074

Determination of Non-Competitive Delivery Revenue Increase for Rate Year 3

Based on Levelized Revenue Requirement

		Incremental Competitive Service, Customer Charge, and RPDC Revenues									
Class	Adj. Rate Yr. Incr. Incl. (Sur)/Def Incl. Mitigation Adj./Incr A ($)	MFC Supply Related Rev B ($)	MFC PP WC Related Rev C ($)	MFC Credit & Collections Related Rev D ($)	POR Credit & Collections Related Rev E ($)	Competitive Metering Related Rev F ($)	Customer Charge Rev G ($)	Reactive Power Demand Charge Rev H ($)	BPP Charge Rev I ($)	Total Rate Yr. Incremental Comp. Services Rev J = ∑ (A to I) ($)	Non-Competitive Rate Yr. Delivery Revenue Incr K = A - J ($)
SC1	14,692,477	94,504	2,272	24,785	14,850	0	1,243,548	0	0	1,379,959	13,312,519
SC19	506,881	3,266	79	857	756	0	(22)	0	0	4,936	501,945
Total Res	15,199,358	97,770	2,351	25,642	15,606		1,243,526	0	0	1,384,895	13,814,464
SC2 Sec Dmd	3,609,983	6,033	783	(305)	7,710	0	601,464	(0)	0	615,685	2,994,298
SC2 Sec Heating	83,901	101	14	(6)	241	0	0	0	0	350	83,551
SC2 Sec ND	159,249	239	31	(12)	43	0	84,513	0	0	84,815	74,434
SC20	271,600	244	32	(12)	320	0	128	0	0	713	270,887
Total Sec	4,124,732	6,617	860	(335)	8,314	0	686,105	(0)	0	701,562	3,423,171
SC2 Pri	157,183	(185)	52	(213)	255	0	4,760	0	0	4,669	152,514
SC3	364,919	(338)	93	(390)	1,643	0	(62,860)	0	0	(61,851)	426,771
SC21	88,414	(13)	3	(14)	43	0	(9,948)	(0)	0	(9,928)	98,342
Total Pri	610,516	(535)	149	(617)	1,941	0	(68,048)	0	0	(67,110)	677,626
Total Sec & Pri	4,735,248	6,082	1,009	(952)	10,255	0	618,057	0	0	634,451	4,100,797
Total SC9 (Com)	368,983	(795)	220	(917)	1,025	0	0	(0)	0	(467)	369,450
Total SC22 (Mfg)	206,050	(515)	143	(593)	887	0	0	(0)	0	(78)	206,128
Total SC 9 & SC 22	575,033	(1,309)	363	(1,510)	1,912	0	0	(1)	0	(545)	575,578
SC4	163,247	27	3	(1)	135	0	0	0	0	164	163,082
SC5	14,733	8	1	0	26	0	0	0	0	35	14,698
SC6	5,404	50	6	(2)	20	0	576	0	0	650	4,754
SC 16 -dusk-to-dawn	177,212	141	17	(7)	55	0	0	0	(0)	206	177,005
SC 16 - energy only	21,031	38	5	(2)	12	0	432	0	(3)	482	20,549
SC16 - Total	198,243	179	23	(9)	67	0	432	0	(3)	688	197,554
Total Lights	381,626	264	33	(12)	248	0	1,008	0	(3)	1,538	380,088
Total	20,891,266	102,807	3,756	23,168	28,021	0	1,862,591	(1)	(3)	2,020,339	18,870,927

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-E-0074

Monthly Billing Comparison - Summer
Reflecting Proposed Rate Change

SC No. 1 Residential

Based on Levelized Revenue Requirement for Rate Year 3

Monthly Summer Usage (kWh) Usage >	Usage ≤	Bill at Present Rates	Bill at Proposed Rates	Change Amount	%	% of Bills in this Usage Range
	50	$31.79	$32.55	$0.76	2.4	8.3
50	100	40.05	41.09	1.04	2.6	1.6
100	150	48.29	49.58	1.29	2.7	2.3
150	200	56.54	58.10	1.56	2.8	3.0
200	250	64.81	66.61	1.80	2.8	3.5
250	300	74.30	76.45	2.15	2.9	3.8
300	350	83.77	86.30	2.53	3.0	3.9
350	400	93.25	96.15	2.90	3.1	4.1
400	450	102.71	105.99	3.28	3.2	4.0
450	500	112.20	115.84	3.64	3.2	4.0
500	550	121.67	125.66	3.99	3.3	3.8
550	600	131.15	135.51	4.36	3.3	3.7
600	650	140.63	145.36	4.73	3.4	3.6
650	700	150.10	155.19	5.09	3.4	3.5
700	750	159.58	165.03	5.45	3.4	3.3
750	800	169.07	174.88	5.81	3.4	3.2
800	850	178.54	184.73	6.19	3.5	3.0
850	900	188.00	194.55	6.55	3.5	2.8
900	950	197.49	204.40	6.91	3.5	2.6
950	1,000	206.97	214.24	7.27	3.5	2.5
1,000	1,050	216.45	224.08	7.63	3.5	2.3
1,050	1,100	225.93	233.94	8.01	3.5	2.1
1,100	1,150	235.40	243.78	8.38	3.6	2.0
1,150	1,200	244.87	253.62	8.75	3.6	1.8
1,200	1,250	254.34	263.45	9.11	3.6	1.7
1,250	1,300	263.84	273.28	9.44	3.6	1.5
1,300	1,350	273.31	283.13	9.82	3.6	1.4
1,350	1,400	282.79	292.98	10.19	3.6	1.3
1,400	1,450	292.27	302.83	10.56	3.6	1.2
1,450	1,500	301.75	312.67	10.92	3.6	1.1
1,500	1,550	311.22	322.51	11.29	3.6	1.0
1,550	1,600	320.69	332.36	11.67	3.6	0.9
1,600	1,650	330.17	342.20	12.03	3.6	0.8
1,650	1,700	339.65	352.03	12.38	3.6	0.8
1,700	1,750	349.12	361.86	12.74	3.6	0.7
1,750	1,800	358.61	371.71	13.10	3.7	0.7
1,800	1,850	368.08	381.56	13.48	3.7	0.6
1,850	1,900	377.55	391.40	13.85	3.7	0.5
1,900	1,950	387.04	401.26	14.22	3.7	0.5
1,950	2,000	396.52	411.09	14.57	3.7	0.5
2,000	2,050	405.99	420.92	14.93	3.7	0.4
2,050	2,100	415.48	430.77	15.29	3.7	0.4
2,100	2,150	424.94	440.61	15.67	3.7	0.4
2,150	2,200	434.41	450.46	16.05	3.7	0.3
2,200	2,250	443.90	460.30	16.40	3.7	0.3
2,250	2,300	453.37	470.13	16.76	3.7	0.3
2,300	2,350	462.86	479.97	17.11	3.7	0.2
2,350	2,400	472.33	489.82	17.49	3.7	0.2
2,400	2,450	481.81	499.67	17.86	3.7	0.2
2,450	2,500	491.30	509.51	18.21	3.7	0.2

* The bills for each range are calculated at the upper band
(e.g., the impact shown for the 0 - 50 kWh band is based on the 50 kWh)
** There are an additional 3% of customers with usage above 2,500 kWh.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-E-0074

Monthly Billing Comparison - Winter
Reflecting Proposed Rate Change

SC No. 1 Residential

Based on Levelized Revenue Requirement for Rate Year 3

Monthly Summer Usage (kWh) Usage >	Usage ≤	Bill at Present Rates	Bill at Proposed Rates	Change Amount	%	% of Bills in this Usage Range
	50	$31.79	$32.55	$0.76	2.4	10.9
50	100	40.05	41.09	1.04	2.6	2.3
100	150	48.29	49.58	1.29	2.7	4.2
150	200	56.54	58.10	1.56	2.8	5.2
200	250	64.81	66.61	1.80	2.8	5.6
250	300	73.06	75.12	2.06	2.8	5.9
300	350	81.33	83.64	2.31	2.8	6.0
350	400	89.58	92.16	2.58	2.9	5.8
400	450	97.83	100.67	2.84	2.9	5.6
450	500	106.09	109.19	3.10	2.9	5.3
500	550	114.35	117.69	3.34	2.9	4.8
550	600	122.59	126.21	3.62	3.0	4.3
600	650	130.86	134.73	3.87	3.0	3.9
650	700	139.10	143.23	4.13	3.0	3.4
700	750	147.36	151.75	4.39	3.0	3.0
750	800	155.63	160.27	4.64	3.0	2.7
800	850	163.88	168.79	4.91	3.0	2.4
850	900	172.13	177.28	5.15	3.0	2.1
900	950	180.37	185.80	5.43	3.0	1.8
950	1000	188.64	194.30	5.66	3.0	1.6
1000	1050	196.89	202.82	5.93	3.0	1.4
1050	1100	205.16	211.34	6.18	3.0	1.2
1100	1150	213.40	219.85	6.45	3.0	1.1
1150	1200	221.67	228.38	6.71	3.0	0.9
1200	1250	229.91	236.87	6.96	3.0	0.8
1250	1300	238.18	245.39	7.21	3.0	0.7
1300	1350	246.43	253.90	7.47	3.0	0.7
1350	1400	254.70	262.42	7.72	3.0	0.6
1400	1450	262.94	270.93	7.99	3.0	0.5
1450	1500	271.20	279.46	8.26	3.0	0.5
1500	1550	279.46	287.96	8.50	3.0	0.4
1550	1600	287.70	296.48	8.78	3.1	0.4
1600	1650	295.96	304.98	9.02	3.0	0.3
1650	1700	304.21	313.50	9.29	3.1	0.3
1700	1750	312.47	322.00	9.53	3.0	0.3
1750	1800	320.72	330.52	9.80	3.1	0.2
1800	1850	329.00	339.05	10.05	3.1	0.2
1850	1900	337.24	347.55	10.31	3.1	0.2
1900	1950	345.51	356.08	10.57	3.1	0.2
1950	2000	353.75	364.58	10.83	3.1	0.2
2000	2050	362.00	373.08	11.08	3.1	0.1
2050	2100	370.26	381.60	11.34	3.1	0.1
2100	2150	378.51	390.11	11.60	3.1	0.1
2150	2200	386.77	398.64	11.87	3.1	0.1
2200	2250	395.04	407.16	12.12	3.1	0.1
2250	2300	403.28	415.65	12.37	3.1	0.1
2300	2350	411.53	424.16	12.63	3.1	0.1
2350	2400	419.80	432.67	12.87	3.1	0.1
2400	2450	428.04	441.20	13.16	3.1	0.1
2450	2500	436.32	449.73	13.41	3.1	0.1

* The bills for each range are calculated at the upper band
(e.g., the impact shown for the 0 - 50 kWh band is based on the 50 kWh)
** There are an additional 1.2% of customers with usage above 2,500 kWh.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-E-0074

**Temporary Credit to be Refunded through
Energy Cost Adjustment in Rate Year 3**

Class	Bundled Rate Yr. 3 Delivery Rev. (1) ($)	Rate Yr. 3 Incr. -2.51875% ($)	Rate Yr. 3 Sales (MWh)	Temporary ECA Credit ($/kWh)
SC1	210,424,000	(5,300,055)	1,503,693	(0.00352)
SC19	7,390,500	(186,148)	65,196	(0.00286)
Total Res	217,814,500	(5,486,203)	1,568,889	
SC2 Sec	82,684,635	(2,082,619)	880,897	(0.00236)
SC2 Sec Heating	1,201,619	(30,266)	25,423	(0.00119)
SC2 Sec ND & UM	2,280,746	(57,446)	17,250	(0.00333)
SC20	5,202,000	(131,025)	90,573	(0.00145)
Total Sec	91,369,000	(2,301,356)	1,014,143	
SC2 Pri	2,610,600	(65,754)	52,266	(0.00126)
SC3	15,442,900	(388,968)	305,242	(0.00127)
SC21	1,750,600	(44,093)	32,989	(0.00134)
Total Pri	19,804,100	(498,815)	390,497	
Total Sec & Pri	111,173,100	(2,800,171)	1,404,639	
Total SC9 (Com)	15,661,000	(394,461)	533,153	(0.00074)
Total SC22 (Mfg)	8,774,000	(220,995)	286,955	(0.00077)
* Includes SC25 Rate IV				
Total SC 9 & SC 22	24,435,000	(615,456)	820,108	
SC4	2,338,000	(58,888)	10,225	(0.00576)
SC5	211,000	(5,315)	2,049	(0.00259)
SC6	232,000	(5,844)	3,127	(0.00187)
SC 16 -dusk-to-dawn	2,538,000	(63,926)	9,246	(0.00691)
SC 16 - energy only	301,200	(7,586)	2,508	(0.00302)
SC16 - Total	2,839,200	(71,512)	11,754	
Total Lights	5,620,200	(135,715)	27,156	
Total	359,042,800	(9,037,545)	3,820,792	

Notes:

RY 3 ECA Increase	($9,200,355)
Revenue Taxes	(156,954)
Increase Less Revenue Taxes	(9,043,401)
RY 3 Delivery Revenues	359,042,800
% Decrease	-2.51875%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-E-0074

Summary of MFC Monthly Targets
For Rates Effective January 1, 2022, January 1, 2023 and January 1, 2024

Based on Levelized Revenue Requirement

For Rates Effective January 1, 2022	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Supply Related Component*	$238,115	$214,583	$188,287	$183,312	$172,210	$208,048	$295,125	$313,541	$267,691	$201,477	$179,903	$209,630	$2,671,922
Credit and Collections Related Component	45,883	41,194	35,800	34,735	32,583	39,703	57,442	61,223	51,761	38,323	33,884	39,958	512,489
POR Discount Related Component	37,926	34,444	31,324	30,675	28,940	33,706	45,704	48,486	42,453	33,516	30,527	34,515	432,216
Total	$321,924	$290,221	$255,411	$248,722	$233,733	$281,457	$398,271	$423,250	$361,905	$273,316	$244,314	$284,103	$3,616,627

For Rates Effective January 1, 2023	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Supply Related Component*	$242,894	$218,297	$191,285	$190,952	$179,214	$217,236	$303,700	$322,731	$275,507	$208,658	$186,803	$217,535	$2,754,812
Credit and Collections Related Component	46,871	41,977	36,397	36,315	34,028	41,610	59,330	63,271	53,425	39,862	35,258	41,649	529,993
POR Discount Related Component	39,718	36,010	32,721	32,623	30,728	35,873	47,972	50,925	44,532	35,445	32,268	36,557	455,372
Total	$329,483	$296,284	$260,403	$259,890	$243,970	$294,719	$411,002	$436,927	$373,464	$283,965	$254,329	$295,741	$3,740,177

For Rates Effective January 1, 2024	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Supply Related Component*	$254,846	$228,895	$200,399	$199,779	$187,258	$227,345	$315,785	$336,150	$286,633	$211,546	$189,322	$221,814	$2,859,772
Credit and Collections Related Component	49,408	44,189	38,255	38,144	35,670	43,683	62,048	66,245	55,892	40,570	35,938	42,612	552,654
POR Discount Related Component	42,623	38,576	34,984	34,959	32,872	38,409	51,143	54,338	47,467	36,933	33,676	38,217	484,197
Total	$346,877	$311,660	$273,638	$272,882	$255,800	$309,437	$428,976	$456,733	$389,992	$289,049	$258,936	$302,643	$3,896,623

* MFC Supply Related Component Includes purchased power working capital.

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 1

Service Classification No. 1

		Present Summer	Present Winter	Proposed Summer	Proposed Winter
Customer Charge:	per month	$19.50	$19.50	$20.50	$20.50
Delivery Charges:					
First 250 kWh	¢ per kWh	8.711	8.711	9.176	9.176
Over 250 kWh	¢ per kWh	10.894	8.711	11.475	9.176
Minimum Charge:					
Monthly*	monthly	$19.50		$20.50	
Per Contract	per contract	117.00		123.00	
Merchant Function Charge					
Supply Related	¢ per kWh	0.339		0.166	
Purch Pwr Wrking Cap	¢ per kWh	0.057		0.052	
Credit & Collections	¢ per kWh	0.062		0.046	
Uncollectibles	¢ per kWh	Variable		Variable	
Plus:				Plus:	
Energy Cost Adjustment				Please refer to Present Rates	
System Benefits Charge				"	
Renewable Portfolio Standard Charge				"	
Transition Adjustment for Competitive Services				"	
Revenue Decoupling Mechanism Adjustment				"	
Increase in Rates and Charges				"	
Market Supply Charge				"	
Billing and Payment Processing Charge			$1.30	$1.50	

* Plus any applicable billing and payment processing charges.

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 1

Service Classification No. 2 Secondary - Non-Demand Billed Customers

		Present Summer	Present Winter	Proposed Summer	Proposed Winter
Customer Charge:					
Metered Service	per month	$18.00	$18.00	$20.00	$20.00
Unmetered Service	per month	17.00	17.00	18.00	18.00
Delivery Charge:					
Usage Charge					
All kWh	¢ per kWh	4.263	3.150	8.109	5.992
Space Heating:					
Delivery	¢ per kWh	12.045	3.010	13.407	3.350
Minimum Charge		Customer Charge*		Customer Charge*	
Merchant Function Charge					
Supply Related	¢ per kWh	0.198		0.092	
Purch Pwr Wrking Cap	¢ per kWh	0.057		0.052	
Credit & Collections	¢ per kWh	0.033		0.022	
Uncollectibles	¢ per kWh	Variable		Variable	
Metering Charges					
(Applicable to Metered Service Only)					
Ownership	per bill	$2.60		N/A	
Service Provider	per bill	11.07		N/A	
Data Service Provider	per bill	2.99		N/A	
Plus:				Plus:	
Energy Cost Adjustment				Please refer to Present Rates	
System Benefits Charge				"	
Renewable Portfolio Standard Charge				"	
Transition Adjustment for Competitive Services				"	
Revenue Decoupling Mechanism Adjustment				"	
Increase in Rates and Charges				"	
Market Supply Charge				"	
Billing and Payment Processing Charge			$1.30	$1.50	

* Plus any applicable metering and/or billing and payment processing charges.

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 1

Service Classification No. 2 Secondary Demand Billed

		Present Summer	Present Winter	Proposed Summer	Proposed Winter
Standard Rates					
Customer Charge:					
Metered Service	per month	$21.00	$21.00	$23.00	$23.00
Delivery Charge:					
Demand Charge					
First 5 kW	per kW	$3.10	$1.83	$3.65	$2.15
Over 5 kW	per kW	20.39	11.85	23.99	13.95
Usage Charge					
First 1,250 kWh	¢ per kWh	4.758	3.673	4.758	3.673
Second Block	¢ per kWh	2.977	2.868	3.084	2.970
Third Block	¢ per kWh	4.041	3.860	N/A	N/A
Minimum Charge		Customer Charge plus the demand charges*		Customer Charge plus the demand charges*	
Standby Rates (Presently Listed in Tariff as SC No. 25 - Rate 1)					
Customer Charge:	per month	$36.00	$36.00	$38.00	$38.00
Delivery Charges:					
Contract Demand Charge	per kW	$5.10	$5.10	$5.54	$5.54
As Used Daily Demand Charge	per kW	$0.7797	$0.5477	$0.8938	$0.6167

* Plus any applicable metering and/or billing and payment processing charges.
** Plus any applicable billing and payment processing charges.

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 1

Service Classification No. 2 Secondary Demand Billed (Continued)

Charges Applicable to Both Standard and Standby Service Rates

		Present	Proposed
Merchant Function Charge			
Supply Related	¢ per kWh	0.198	0.092
Purch Pwr Wrking Cap	¢ per kWh	0.057	0.052
Credit & Collections	¢ per kWh	0.033	0.022
Uncollectibles	¢ per kWh	Variable	Variable
Metering Charges			
Non-MDAHP:			
Ownership	per bill	$2.60	N/A
Service Provider	per bill	11.07	N/A
Data Service Provider	per bill	2.99	N/A
Subject to MDAHP:			
Ownership	per bill	$12.84	N/A
Service Provider	per bill	34.28	N/A
Data Service Provider	per bill	15.51	N/A
Reactive Power Demand Charge (if applicable)			
	per KVAr	$0.40	$0.85
Plus:			Plus:
Energy Cost Adjustment			Please refer to Present Rates
System Benefits Charge			"
Renewable Portfolio Standard Charge			"
Transition Adjustment for Competitive Services			"
Revenue Decoupling Mechanism Adjustment			"
Increase in Rates and Charges			"
Market Supply Charge			"
Billing and Payment Processing Charge			$1.30	$1.50

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 1

Service Classification No. 2 Primary

		Present		Proposed	
		Summer	Winter	Summer	Winter
Standard Rates					
Customer Charge:	per month	$35.00	$35.00	$37.00	$37.00
Delivery Charge:					
Demand Charge	per kW	$17.12	$9.50	$18.63	$10.34
Usage Charge	¢ per kWh	0.786	0.786	0.786	0.786
Minimum Charge		Customer Charge plus the demand charges*		Customer Charge plus the demand charges*	
Standby Rates (Presently Listed in Tariff as SC No. 25 - Rate 1)					
Customer Charge:	per month	$50.00	$50.00	$40.00	$40.00
Delivery Charges:					
Contract Demand Charge	per kW	$4.97	$4.97	$5.51	$5.51
As Used Daily Demand Charge	per kW	$0.6040	$0.4163	$0.6447	$0.4424

* Plus any applicable metering and/or billing and payment processing charges.

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 1

Service Classification No. 2 Primary (Continued)

Charges Applicable to Both Standard and Standby Service Rates

		Present	Proposed
Merchant Function Charge			
Supply Related	¢ per kWh	0.071	0.049
Purch Pwr Wrking Cap	¢ per kWh	0.057	0.052
Credit & Collections	¢ per kWh	0.009	0.008
Uncollectibles	¢ per kWh	Variable	Variable
Metering Charges			
Non-MDAHP:			
Ownership	per bill	$4.49	N/A
Service Provider	per bill	19.12	N/A
Data Service Provider	per bill	2.97	N/A
Subject to MDAHP:			
Ownership	per bill	$12.84	N/A
Service Provider	per bill	34.28	N/A
Data Service Provider	per bill	15.51	N/A
Reactive Power Demand Charge (if applicable)			
	per KVAr	$0.40	$0.85
Plus:			Plus:
Energy Cost Adjustment			Please refer to Present Rates
System Benefits Charge			"
Renewable Portfolio Standard Charge			"
Transition Adjustment for Competitive Services			"
Revenue Decoupling Mechanism Adjustment			"
Increase in Rates and Charges			"
Market Supply Charge			"
Billing and Payment Processing Charge		$1.30	$1.50

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 1

Service Classification No. 3

		Present		Proposed	
		Summer	Winter	Summer	Winter
Standard Rates					
Customer Charge:	per month	$120.00	$120.00	$100.00	$100.00
Delivery Charge:					
Demand Charge	per kW	$22.32	$12.63	$23.17	$13.11
Usage Charge	¢ per kWh	0.696	0.696	0.696	0.696
Minimum Charge:		$120.00	plus the demand charges*	$100.00	plus the demand charges*
Standby Rates (Presently Listed in Tariff as SC No. 25 - Rate 2)					
Customer Charge:	per month	$85.00	$85.00	$60.00	$60.00
Delivery Charges:					
Contract Demand Charge	per kW	$9.24	$9.24	$9.50	$9.50
As Used Daily Demand Charge	per kW	$0.7142	$0.4788	$0.7525	$0.5084
Charges Applicable to Both Standard and Standby Service Rates					
Merchant Function Charge					
Supply Related	¢ per kWh	0.071		0.049	
Purch Pwr Wrking Cap	¢ per kWh	0.057		0.052	
Credit & Collections	¢ per kWh	0.009		0.008	
Uncollectibles		Variable		Variable	

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 1

Service Classification No. 3 (Continued)

Charges Applicable to Both Standard and Standby Service Rates (Continued)

Metering Charges				
(Applicable to Metered Service Only)				
Non-MDAHP:				
Ownership	per bill	$4.17		N/A
Service Provider	per bill	17.74		N/A
Data Service Provider	per bill	1.50		N/A
Subject to MDAHP:				
Ownership	per bill	$12.84		N/A
Service Provider	per bill	34.28		N/A
Data Service Provider	per bill	15.51		N/A
Reactive Power Demand Charge (if applicable)				
	per KVAr	$0.40		$0.85
Plus:				Plus:
Energy Cost Adjustment				Please refer to Present Rates
System Benefits Charge				"
Renewable Portfolio Standard Charge				"
Transition Adjustment for Competitive Services				"
Revenue Decoupling Mechanism Adjustment				"
Increase in Rates and Charges				"
Market Supply Charge				"
Billing and Payment Processing Charge			$1.30	$1.50

* Plus any applicable metering and/or billing and payment processing charges.

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 1

Service Classification No. 4

Luminaries Charge, per month

Nominal Lumens	Luminaires Type	Watts	Total Wattage	Present Delivery Charge	Proposed Delivery Charge
Street Lighting Luminaires					
5,800	Sodium Vapor	70	108	$11.19	$11.66
9,500	Sodium Vapor	100	142	12.21	12.72
16,000	Sodium Vapor	150	199	14.50	15.11
27,500	Sodium Vapor	250	311	19.39	20.20
46,000	Sodium Vapor	400	488	27.16	28.29
Off-Roadway Luminaires					
27,500	Sodium Vapor	250	311	$25.14	$26.19
46,500	Sodium Vapor	400	488	31.07	32.37
LED Street Lighting Luminaires					
3,000	LED	15-29	23	$9.96	$10.38
3,900	LED	30-39	35	10.07	10.49
5,000	LED	40-59	50	10.18	10.60
7,250	LED	60-89	68	11.24	11.71
12,000	LED	90-129	103	11.84	12.33
16,000	LED	130-169	140	13.01	13.55
22,000	LED	170-220	200	17.73	18.47

The following luminaires will no longer be installed. Charges are for existing luminaires only.

Nominal Lumens	Luminaires Type	Watts	Total Wattage	Present Delivery Charge	Proposed Delivery Charge
600	Open Bottom Inc	52	52	$5.53	$5.76
1,000	Open Bottom Inc	92	92	7.54	7.85
4,000	Mercury Vapor PB	100	127	8.88	9.25
4,000	Mercury Vapor	100	127	10.04	10.46
7,900	Mercury Vapor PB	175	215	10.90	11.35
7,900	Mercury Vapor	175	211	12.18	12.69
12,000	Mercury Vapor	250	296	15.95	16.62
22,500	Mercury Vapor	400	459	20.39	21.24
59,000	Mercury Vapor	1,000	1,105	40.04	41.71
130,000	Sodium Vapor	1,000	1,120	57.16	59.55

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 1

Service Classification No. 4 (Continued)

The following luminaires will no longer be installed. Charges are for existing luminaires only.

Luminaries Charge, per month

Nominal Lumens	Luminaires Type	Watts	Total Wattage	Present Delivery Charge	Proposed Delivery Charge
5,890	LED	70	74	$12.23	$12.74
9,365	LED	100	101	13.87	14.45
3,400	Induction	40	45	12.20	12.71
12,750	Induction	150	160	16.65	17.34

		Present	Proposed
Additional Charge:			
UG Svc- Customer owned and maintained duct	per month	$4.67	$4.86
15 Foot Brackets	$ per month	0.40	0.42
Merchant Function Charge			
Supply Related	¢ per kWh	0.198	0.092
Purch Pwr Wrking Cap	¢ per kWh	0.057	0.052
Credit & Collections	¢ per kWh	0.033	0.022
Uncollectibles	¢ per kWh	Variable	Variable
Plus:			Plus:
Energy Cost Adjustment			Please refer to Present Rates
System Benefits Charge			"
Renewable Portfolio Standard Charge			"
Transition Adjustment for Competitive Services			"
Revenue Decoupling Mechanism Adjustment			"
Increase in Rates and Charges			"
Market Supply Charge			"
Billing and Payment Processing Charge		$1.30	$1.50

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 1

Service Classification No. 5

		Present	Proposed
		Year-round	Year-round
Delivery Charge:	¢ per kWh	9.462	9.870
Merchant Function Charge			
Supply Related	¢ per kWh	0.198	0.092
Purch Pwr Wrking Cap	¢ per kWh	0.057	0.052
Credit & Collections	¢ per kWh	0.033	0.022
Uncollectibles	¢ per kWh	Variable	Variable
Plus:			Plus:
Energy Cost Adjustment			Please refer to Present Rates
System Benefits Charge			"
Renewable Portfolio Standard Charge			"
Transition Adjustment for Competitive Services			"
Increase in Rates and Charges			"
Market Supply Charge			"
Billing and Payment Processing Charge		$1.30	$1.50

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 1

Service Classification No. 6

		Present Year-round	Proposed Year-round
Delivery Charges for Service Types A & B:	¢ per kWh	7.739	8.113
Delivery Charges for Service Type C:			
Customer Charge		$24.00	$24.00
Delivery Charge	¢ per kWh	6.726	7.051
Merchant Function Charge			
Supply Related	¢ per kWh	0.198	0.092
Purch Pwr Wrking Cap	¢ per kWh	0.057	0.052
Credit & Collections	¢ per kWh	0.033	0.022
Uncollectibles	¢ per kWh	Variable	Variable
Plus:			Plus:
Energy Cost Adjustment			Please refer to Present Rates
System Benefits Charge			"
Renewable Portfolio Standard Charge			"
Transition Adjustment for Competitive Services			"
Revenue Decoupling Mechanism Adjustment			"
Increase in Rates and Charges			"
Market Supply Charge			"
Billing and Payment Processing Charge		$1.30	$1.50

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 1

Service Classification No. 9

				Present Year-round	Proposed Year-round
Standard Rates					
Customer Charge:			per month	$500.00	$500.00
Delivery Charges:					
Primary:					
Demand Charge					
	Period A	All kW @	per kW	$24.08	$24.70
	Period B	All kW @	per kW	11.31	11.60
	Period C	All kW @	per kW	No Charge	No Charge
Usage Charge					
	Period A	All kWh @	¢ per kWh	0.441	0.441
	Period B	All kWh @	¢ per kWh	0.441	0.441
	Period C	All kWh @	¢ per kWh	0.164	0.164
Substation:					
Demand Charge					
	Period A	All kW @	per kW	$17.41	$17.86
	Period B	All kW @	per kW	7.87	8.07
	Period C	All kW @	per kW	No Charge	No Charge
Usage Charge					
	Period A	All kWh @	¢ per kWh	0.244	0.244
	Period B	All kWh @	¢ per kWh	0.244	0.244
	Period C	All kWh @	¢ per kWh	0.150	0.150
Transmission:					
Demand Charge					
	Period A	All kW @	per kW	$8.59	$8.81
	Period B	All kW @	per kW	5.85	6.00
	Period C	All kW @	per kW	No Charge	No Charge
Usage Charge					
	Period A	All kWh @	¢ per kWh	0.139	0.139
	Period B	All kWh @	¢ per kWh	0.139	0.139
	Period C	All kWh @	¢ per kWh	0.131	0.131

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 1

Service Classification No. 9 (Continued)

		Present	Proposed
Standby Rates (Presently Listed in Tariff as SC No. 25 - Rate 3)			
Customer Charge:	per month	$500.00	$500.00
Delivery Charges:			
Primary:			
Contract Demand Charge	per kW	$6.76	$7.11
As Used Daily Demand Charge (S)	per kW	$0.7091	$0.7201
As Used Daily Demand Charge (W)	per kW	$0.4004	$0.3973
Substation:			
Contract Demand Charge	per kW	$4.32	$4.69
As Used Daily Demand Charge	per kW	$0.5000	$0.4945
As Used Daily Demand Charge (W)	per kW	$0.3414	$0.3359
Transmission:			
Contract Demand Charge	per kW	$1.50	$1.59
As Used Daily Demand Charge	per kW	$0.3922	$0.3860
As Used Daily Demand Charge (W)	per kW	$0.2953	$0.2867
Minimum Charge		Sum of the Customer Charge, Min. Monthly Demand Charge, contract demand charge, the reactive power demand charge, and any applicable metering and/or billing and payment processing charges.	Sum of the Customer Charge, Min. Monthly Demand Charge, contract demand charge, the reactive power demand charge, and any applicable billing and payment processing charges.
Min. Monthly Demand Charge		$53.13	$51.18
Contract Demand Charge - Pri	per kW of CD	$3.86	$3.72
Contract Demand Charge - Sec	per kW of CD	$6.34	$6.11

Orange and Rockland Utilities, Inc.
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Rates in Brief - Rate Year 1

Service Classification No. 9 (Continued)

		Present	Proposed
Charges Applicable to Both Standard and Standby Service Rates			
Merchant Function Charge			
Supply Related	¢ per kWh	0.071	0.049
Purch Pwr Wrking Cap	¢ per kWh	0.057	0.052
Credit & Collections	¢ per kWh	0.009	0.008
Uncollectibles	¢ per kWh	Variable	Variable
Metering Charges:			
Ownership	per bill	$20.77	N/A
Service Provider	per bill	88.36	N/A
Data Service Provider	per bill	15.51	N/A
Reactive Power Demand Charge (if applicable)			
	per KVAr	$0.40	$0.85
Plus:			Plus:
Energy Cost Adjustment			Please refer to Present Rates
System Benefits Charge			"
Renewable Portfolio Standard Charge			"
Transition Adjustment for Competitive Services			"
Revenue Decoupling Mechanism Adjustment			"
Increase in Rates and Charges			"
Market Supply Charge			"
Billing and Payment Processing Charge		$1.30	$1.50

Definition of Rating Periods:

Period A - 8:00 a.m. to 11:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.

Period B - 8:00 a.m. to 11:00 p.m. prevailing time, Monday through Friday, except holidays, October through May.

Period C - 11:00 p.m. to 8:00 a.m. prevailing time, Monday through Friday, all hours on Saturday, Sunday and holidays, all months.

Orange and Rockland Utilities, Inc.
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Rates in Brief - Rate Year 1

Service Classification No. 15

		Present Year-round	Proposed Year-round
Customer Charge - For customers who take service under SC No. 15 and another SC			
Primary Voltage with CD < 1,000 kW	per month	$153.69	See Below
Primary Voltage with CD ≥ 1,000 kW	per month	$116.99	See Below
Secondary Voltage	per month	$14.44	See Below
Customer Charge - For customers who take service only under SC No. 15			
Primary Voltage with CD < 1,000 kW	per month	$159.87	See Below
Primary Voltage with CD ≥ 1,000 kW	per month	$123.17	See Below
Secondary Voltage	per month	$28.69	See Below
Customer Charge*:			
SC Nos. 2 Secondary and 20	per month	See Above	$38.00
SC No. 2 Primary	per month	See Above	$40.00
SC Nos. 3 and 21	per month	See Above	$60.00
SC No. 9	per month	See Above	$500.00
SC No. 22	per month	See Above	$500.00
Contract Demand Charge*			
SC Nos. 2 Secondary and 20	per kW	$6.93	$5.54
SC No. 2 Primary	per kW	$4.22	$5.51
SC Nos. 3 and 21	per kW	$4.22	$9.50
SC No. 9 - Primary	per kW	$4.22	$7.11
SC No. 9 - Substation	per kW	$4.22	$4.69
SC No. 9 - Transmission	per kW	$4.22	$1.59
SC No. 22 - Primary	per kW	$4.22	$5.93
SC No. 22 - Substation	per kW	$4.22	$3.31
SC No. 22 - Transmission	per kW	$4.22	$1.38
Reactive Power Demand Charge (if applicable)			
	per KVAr	$0.40	$0.85

* Based on what the customer's otherwise applicable service classification is.

Plus:	Plus:
Increase in Rates and Charges	Please refer to Present Rates

Orange and Rockland Utilities, Inc.
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Rates in Brief - Rate Year 1

Service Classification No. 16

Luminaries Charge, per month

Nominal Lumens	Luminaires Type	Watts	Total Wattage	Present Delivery Charge	Proposed Delivery Charge
Power Bracket Luminaires					
5,800	Sodium Vapor	70	108	$20.64	$21.56
9,500	Sodium Vapor	100	142	22.06	23.05
16,000	Sodium Vapor	150	199	25.94	27.10
Street Lighting Luminaires					
5,800	Sodium Vapor	70	108	$22.59	$23.60
9,500	Sodium Vapor	100	142	24.09	25.17
16,000	Sodium Vapor	150	199	27.87	29.12
27,500	Sodium Vapor	250	311	35.53	37.12
46,000	Sodium Vapor	400	488	48.78	50.96
3,000	LED	15-29	23	N/A	10.88
3,900	LED	30-39	35	N/A	11.00
5,000	LED	40-59	50	N/A	11.12
7,250	LED	60-89	68	N/A	12.28
12,000	LED	90-129	103	N/A	12.93
16,000	LED	130-169	140	N/A	14.21
22,000	LED	170-220	200	N/A	19.37
Flood Lighting Luminaires					
27,500	Sodium Vapor	250	311	$35.53	$37.12
46,000	Sodium Vapor	400	488	48.78	50.96
15,000	LED	100-159	125	N/A	13.91
27,000	LED	160-249	205	N/A	16.40
37,500	LED	230-320	290	N/A	18.91

The following luminaires will no longer be installed. Charges are for existing luminaires only.

Nominal Lumens	Luminaires Type	Watts	Total Wattage	Present Delivery Charge	Proposed Delivery Charge
Power Bracket Luminaires					
4,000	Mercury Vapor	100	127	$18.95	$19.80
7,900	Mercury Vapor	175	215	21.94	22.92
22,500	Mercury Vapor	400	462	31.51	32.92
3,950	LED	25-39	35	N/A	9.23
5,550	LED	44-55	50	N/A	9.30
7,350	LED	56-70	65	N/A	9.39
Street Lighting Luminaires					
21,250	Induction	250	263	42.34	44.23
4,000	Mercury Vapor	100	127	$20.77	21.70
7,900	Mercury Vapor	175	211	24.05	25.12
12,000	Mercury Vapor	250	296	30.28	31.63
22,500	Mercury Vapor	400	459	37.29	38.96
40,000	Mercury Vapor	700	786	55.18	57.65
59,000	Mercury Vapor	1,000	1,105	68.86	71.94
1,000	Incandescent	92	92	16.50	17.24
5,890	LED	70	74	30.07	31.41
9,365	LED	100	101	32.51	33.96

Orange and Rockland Utilities, Inc.
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Rates in Brief - Rate Year 1

Service Classification No. 16 (Continued)

Nominal Lumens	Luminaires Type	Watts	Total Wattage	Present Delivery Charge	Proposed Delivery Charge
The following luminaires will no longer be installed. Charges are for existing luminaires only.					
Flood Lighting Luminaires					
12,000	Mercury Vapor	250	296	$30.28	$31.63
22,500	Mercury Vapor	400	459	37.29	38.96
40,000	Mercury Vapor	700	786	55.18	57.65
59,000	Mercury Vapor	1,000	1,105	68.86	71.94
15 Foot Brackets			$ per month	0.70	0.73
Delivery Charges for Service Type C:					
Customer Charge (Metered)			per month	$24.00	$24.00
Customer Charge (Unmetered)			per month	17.00	18.00
Delivery Charge			¢ per kWh	6.726	7.220
Merchant Function Charge					
Supply Related			¢ per kWh	0.198	0.092
Purch Pwr Wrking Cap			¢ per kWh	0.057	0.052
Credit & Collections			¢ per kWh	0.033	0.022
Uncollectibles			¢ per kWh	Variable	Variable
Plus:					Plus:
Energy Cost Adjustment					Please refer to Present Rates
System Benefits Charge					"
Renewable Portfolio Standard Charge					"
Transition Adjustment for Competitive Services					"
Increase in Rates and Charges					"
Market Supply Charge					"
Billing and Payment Processing Charge				$1.30	$1.50

Orange and Rockland Utilities, Inc.
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Rates in Brief - Rate Year 1

Service Classification No. 19

				Present Year-round	Proposed Year-round
Customer Charge:			per month	$32.00	$32.00
Delivery Charges:					
	Period I	All kWh @	¢ per kWh	34.539	36.833
	Period II	All kWh @	¢ per kWh	12.358	13.179
	Period III	All kWh @	¢ per kWh	12.358	13.179
	Period IV	All kWh @	¢ per kWh	2.224	2.372
Merchant Function Charge					
Supply Related			¢ per kWh	0.339	0.166
Purch Pwr Wrking Cap			¢ per kWh	0.057	0.052
Credit & Collections			¢ per kWh	0.062	0.046
Uncollectibles			¢ per kWh	Variable	Variable
Minimum Charge:			per contract (not less than) plus applicable billing and payment processing charges	$384.00	$384.00
Plus:					Plus:
Energy Cost Adjustment					
System Benefits Charge					
Renewable Portfolio Standard Charge					Please refer to Present Rates
Transition Adjustment for Competitive Services					"
Revenue Decoupling Mechanism Adjustment					"
Increase in Rates and Charges					"
Market Supply Charge					"
Billing and Payment Processing Charge				$1.30	$1.50

Definition of Rating Periods:

Period I -	12:00 p.m. to 7:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.
Period II -	10:00 a.m. to 12:00 p.m. and 7:00 p.m. to 9:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.
Period III -	10:00 a.m. to 9:00 p.m. prevailing time, Monday through Friday, except holidays, October through May.
Period IV -	9:00 p.m. to 10:00 a.m. prevailing time, Monday through Friday, all hours on Saturday, Sunday and holidays, all months.

Orange and Rockland Utilities, Inc.
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Rates in Brief - Rate Year 1

Service Classification No. 20

			Present Year-round	Proposed Year-round
Standard Rates				
Customer Charge:		per month	$40.00	$40.00
Delivery Charges:				
Demand Charge				
Period I	All kW @	per kW	$30.24	$32.51
Period II	All kW @	per kW	12.94	13.91
Period III	All kW @	per kW	0.45	0.57
Usage Charge				
Period I	All kWh @	¢ per kWh	3.592	3.592
Period II	All kWh @	¢ per kWh	0.863	0.863
Period III	All kWh @	¢ per kWh	0.115	0.086
Minimum Charge:			Sum of the Customer Charge and $120.00 plus any applicable metering and/or billing and payment processing charges.	Sum of the Customer Charge and $120.00 plus any applicable billing and payment processing charges.
Standby Rates (Presently Listed in Tariff as SC No. 25 - Rate 1)				
Customer Charge:		per month	$36.00	$38.00
Delivery Charges:				
Contract Demand Charge		per kW	$5.10	$5.54
As Used Daily Demand Charge (S)		per kW	$0.7797	$0.8938
As Used Daily Demand Charge (W)		per kW	$0.5477	$0.6167

Orange and Rockland Utilities, Inc.
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Rates in Brief - Rate Year 1

Service Classification No. 20 (Continued)

Charges Applicable to Both Standard and Standby Service Rates

Merchant Function Charge			
Supply Related	¢ per kWh	0.198	0.092
Purch Pwr Wrking Cap	¢ per kWh	0.057	0.052
Credit & Collections	¢ per kWh	0.033	0.022
Uncollectibles	¢ per kWh	Variable	Variable
Metering Charges			
Non-MDAHP:			
Ownership	per bill	$3.96	N/A
Service Provider	per bill	16.85	N/A
Data Service Provider	per bill	2.28	N/A
Subject to MDAHP:			
Ownership	per bill	$12.84	N/A
Service Provider	per bill	34.28	N/A
Data Service Provider	per bill	15.51	N/A
Reactive Power Demand Charge (if applicable)			
	per KVAr	$0.40	$0.85
Plus:			Plus:
Energy Cost Adjustment			
System Benefits Charge			
Renewable Portfolio Standard Charge			Please refer to Present Rates
Transition Adjustment for Competitive Services			"
Revenue Decoupling Mechanism Adjustment			"
Increase in Rates and Charges			"
Market Supply Charge			"
Billing and Payment Processing Charge		$1.30	$1.50

Definition of Rating Periods:

Period I -	1:00 p.m. to 7:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.
Period II -	10:00 a.m. to 9:00 p.m. prevailing time, Monday through Friday, except holidays, October through May.
Period III -	7:00 p.m. to 1:00 p.m. prevailing time, Monday through Friday, June through September; 9:00 p.m. to 10:00 a.m. prevailing time, Monday through Friday, October through May; all hours on Saturday, Sunday and holidays, all months.

Orange and Rockland Utilities, Inc.
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Rates in Brief - Rate Year 1

Service Classification No. 21

			Present Year-round	Proposed Year-round
Customer Charge:		per month	$163.00	$133.00
Delivery Charges:				
Demand Charge				
Period I	All kW @	per kW	$30.52	$32.02
Period II	All kW @	per kW	10.76	11.29
Period III	All kW @	per kW	No Charge	No Charge
Usage Charge				
Period I	All kWh @	¢ per kWh	1.553	1.553
Period II	All kWh @	¢ per kWh	1.553	1.553
Period III	All kWh @	¢ per kWh	0.136	0.136
Minimum Charge:			Sum of the Customer Charge and any applicable metering and/or billing and payment processing charges.	Sum of the Customer Charge and any applicable billing and payment processing charges.

Standby Rates (Presently Listed in Tariff as SC No. 25 - Rate 2)

		Present Year-round	Proposed Year-round
Customer Charge:	per month	$85.00	$60.00
Delivery Charges:			
Contract Demand Charge	per kW	$9.24	$9.50
As Used Daily Demand Charge (S)	per kW	$0.7142	$0.7525
As Used Daily Demand Charge (W)	per kW	$0.4788	$0.5084

Orange and Rockland Utilities, Inc.
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Rates in Brief - Rate Year 1

Service Classification No. 21 (Continued)

Charges Applicable to Both Standard and Standby Service Rates

Merchant Function Charge			
Supply Related	¢ per kWh	0.071	0.049
Purch Pwr Wrking Cap	¢ per kWh	0.057	0.052
Credit & Collections	¢ per kWh	0.009	0.008
Uncollectibles	¢ per kWh	Variable	Variable
Metering Charges			
Non-MDAHP:			
Ownership	per bill	$2.82	N/A
Service Provider	per bill	11.98	N/A
Data Service Provider	per bill	0.93	N/A
Subject to MDAHP:			
Ownership	per bill	$12.84	N/A
Service Provider	per bill	34.28	N/A
Data Service Provider	per bill	15.51	N/A
Reactive Power Demand Charge (if applicable)			
	per KVAr	$0.40	$0.85
Plus:			Plus:
Energy Cost Adjustment			
System Benefits Charge			
Renewable Portfolio Standard Charge			Please refer to Present Rates
Transition Adjustment for Competitive Services			"
Revenue Decoupling Mechanism Adjustment			"
Increase in Rates and Charges			"
Market Supply Charge			"
Billing and Payment Processing Charge		$1.30	$1.50

Definition of Rating Periods:

Period I -	1:00 p.m. to 7:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.
Period II -	10:00 a.m. to 9:00 p.m. prevailing time, Monday through Friday, except holidays, October through May.
Period III -	7:00 p.m. to 1:00 p.m. prevailing time, Monday through Friday, June through September; 9:00 p.m. to 10:00 a.m. prevailing time, Monday through Friday, October through May; all hours on Saturday, Sunday and holidays, all months.

Orange and Rockland Utilities, Inc.
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Rates in Brief - Rate Year 1

Service Classification No. 22

			Present	Proposed
			Year-round	Year-round
Standard Rates				
Customer Charge:		per month	$500.00	$500.00
Delivery Charges:				
Primary:				
Demand Charge				
Period A	All kW @	per kW	$18.31	$18.69
Period B	All kW @	per kW	10.45	10.67
Period C	All kW @	per kW	No Charge	No Charge
Usage Charge				
Period A	All kWh @	¢ per kWh	0.710	0.710
Period B	All kWh @	¢ per kWh	0.710	0.710
Period C	All kWh @	¢ per kWh	0.126	0.126
Substation:				
Demand Charge				
Period A	All kW @	per kW	$11.77	$12.01
Period B	All kW @	per kW	6.49	6.62
Period C	All kW @	per kW	No Charge	No Charge
Usage Charge				
Period A	All kWh @	¢ per kWh	0.298	0.298
Period B	All kWh @	¢ per kWh	0.298	0.298
Period C	All kWh @	¢ per kWh	0.126	0.126
Transmission:				
Demand Charge				
Period A	All kW @	per kW	$6.76	$6.90
Period B	All kW @	per kW	5.91	6.03
Period C	All kW @	per kW	No Charge	No Charge
Usage Charge				
Period A	All kWh @	¢ per kWh	0.126	0.126
Period B	All kWh @	¢ per kWh	0.126	0.126
Period C	All kWh @	¢ per kWh	0.126	0.126
Minimum Charge			Sum of the Customer Charge, Min. Monthly Demand Charge, contract demand charge, the reactive power demand charge, and any applicable metering and/or billing and payment processing charges.	Sum of the Customer Charge, Min. Monthly Demand Charge, contract demand charge, the reactive power demand charge, and any applicable billing and payment processing charges.
Min. Monthly Demand Charge			$53.13	$51.18
Contract Demand Charge		per kW of CD	$3.86	$3.72
Contract Demand Charge		per kW of CD	$6.34	$6.11

Orange and Rockland Utilities, Inc.
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Rates in Brief - Rate Year 1

Service Classification No. 22 (Continued)

		Present	Proposed
Standby Rates (Presently Listed in Tariff as SC No. 25 - Rate 4)			
Customer Charge:	per month	$500.00	$500.00
Delivery Charges:			
Primary:			
Contract Demand Charge	per kW	$5.94	$5.93
As Used Daily Demand Charge (S)	per kW	$0.6288	$0.6349
As Used Daily Demand Charge (W)	per kW	$0.4396	$0.4377
Substation:			
Contract Demand Charge	per kW	$3.21	$3.31
As Used Daily Demand Charge	per kW	$0.4284	$0.4158
As Used Daily Demand Charge (W)	per kW	$0.2882	$0.2746
Transmission:			
Contract Demand Charge	per kW	$1.34	$1.38
As Used Daily Demand Charge	per kW	$0.3487	$0.3287
As Used Daily Demand Charge (W)	per kW	$0.3187	$0.2980

Orange and Rockland Utilities, Inc.
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Rates in Brief - Rate Year 1

Service Classification No. 22 (Continued)

		Present Year-round	Proposed Year-round
Charges Applicable to Both Standard and Standby Service Rates			
Merchant Function Charge			
Supply Related	¢ per kWh	0.071	0.049
Purch Pwr Wrking Cap	¢ per kWh	0.057	0.052
Credit & Collections	¢ per kWh	0.009	0.008
Uncollectibles	¢ per kWh	Variable	Variable
Metering Charges:			
Ownership	per bill	$20.77	N/A
Service Provider	per bill	88.36	N/A
Data Service Provider	per bill	15.51	N/A
Reactive Power Demand Charge (if applicable)			
	per KVAr	$0.40	$0.85
Plus:			Plus:
Energy Cost Adjustment			Please refer to Present Rates
System Benefits Charge			"
Renewable Portfolio Standard Charge			"
Transition Adjustment for Competitive Services			"
Revenue Decoupling Mechanism Adjustment			"
Increase in Rates and Charges			"
Market Supply Charge			"
Billing and Payment Processing Charge		$1.30	$1.50

Definition of Rating Periods:

Period A - 8:00 a.m. to 11:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.

Period B - 8:00 a.m. to 11:00 p.m. prevailing time, Monday through Friday, except holidays, October through May.

Period C - 11:00 p.m. to 8:00 a.m. prevailing time, Monday through Friday, all hours on Saturday, Sunday and holidays, all months.

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Rates in Brief - Rate Year 1

Rider J - Smart Home Rate

		Present	Proposed
Customer Charge:	per month	$19.50	$20.50
Rate I - Delivery Charges:			
Daily Demand Charges	per kW	$1.13	$1.15
Distribution Event Charge	per kW	$1.82	$1.76
Transmission Event Charge	per kW	$0.46	$0.44
Rate II - Delivery Charges:			
Subscribed Demand Chg	per kW	$19.35	$19.25
Distribution Event Charge	per kW	$21.27	$19.88
Transmission Event Charge	per kW	$5.32	$4.97
Merchant Function Charge			
Supply Related	¢ per kWh	0.339	0.166
Purch Pwr Wrking Cap	¢ per kWh	0.057	0.052
Credit & Collections	¢ per kWh	0.062	0.046
Uncollectibles	¢ per kWh	Variable	Variable
Plus:			Plus:
Energy Cost Adjustment			
System Benefits Charge			Please refer to Present Rates
Renewable Portfolio Standard Charge			"
Transition Adjustment for Competitive Services			"
Revenue Decoupling Mechanism Adjustment			"
Increase in Rates and Charges			"
Market Supply Charges			"
Billing and Payment Processing Charge		$1.30	$1.50

* Plus any applicable billing and payment processing charges.

Orange and Rockland Utilities, Inc.
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Rates in Brief - Rate Year 2

Service Classification No. 1

		Present Summer	Present Winter	Proposed Summer	Proposed Winter
Customer Charge:	per month	$20.50	$20.50	$21.50	$21.50
Delivery Charges:					
First 250 kWh	¢ per kWh	9.176	9.176	9.529	9.529
Over 250 kWh	¢ per kWh	11.475	9.176	11.917	9.529
Minimum Charge:					
Monthly*	monthly	$20.50		$21.50	
Per Contract	per contract	123.00		129.00	
Merchant Function Charge					
Supply Related	¢ per kWh	0.166		0.176	
Purch Pwr Wrking Cap	¢ per kWh	0.052		0.052	
Credit & Collections	¢ per kWh	0.046		0.048	
Uncollectibles	¢ per kWh	Variable		Variable	

Plus:	Plus:
Energy Cost Adjustment	Please refer to Present Rates
System Benefits Charge	"
Renewable Portfolio Standard Charge	"
Transition Adjustment for Competitive Services	"
Revenue Decoupling Mechanism Adjustment	"
Increase in Rates and Charges	"
Market Supply Charge	"
Billing and Payment Processing Charge	"

* Plus any applicable billing and payment processing charges.

Orange and Rockland Utilities, Inc.
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Rates in Brief - Rate Year 2

Service Classification No. 2 Secondary - Non-Demand Billed Customers

		Present		Proposed	
		Summer	Winter	Summer	Winter
Customer Charge:					
Metered Service	per month	$20.00	$20.00	$22.00	$22.00
Unmetered Service	per month	18.00	18.00	19.00	19.00
Delivery Charge:					
Usage Charge					
All kWh	¢ per kWh	8.109	5.992	8.138	6.013
Space Heating:					
Delivery	¢ per kWh	13.407	3.350	13.958	3.488
Minimum Charge		Customer Charge*		Customer Charge*	
Merchant Function Charge					
Supply Related	¢ per kWh	0.092		0.094	
Purch Pwr Wrking Cap	¢ per kWh	0.052		0.052	
Credit & Collections	¢ per kWh	0.022		0.022	
Uncollectibles	¢ per kWh	Variable		Variable	

Plus:	Plus:
Energy Cost Adjustment	Please refer to Present Rates
System Benefits Charge	"
Renewable Portfolio Standard Charge	"
Transition Adjustment for Competitive Services	"
Revenue Decoupling Mechanism Adjustment	"
Increase in Rates and Charges	"
Market Supply Charge	"
Billing and Payment Processing Charge	"

* Plus any applicable billing and payment processing charges.

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Rates in Brief - Rate Year 2

Service Classification No. 2 Secondary Demand Billed

		Present Summer	Present Winter	Proposed Summer	Proposed Winter
Standard Rates					
Customer Charge:					
Metered Service	per month	$23.00	$23.00	$25.00	$25.00
Delivery Charge:					
Demand Charge					
First 5 kW	per kW	$3.65	$2.15	$3.75	$2.21
Over 5 kW	per kW	23.99	13.95	24.66	14.34
Usage Charge					
First 1,250 kWh	¢ per kWh	4.758	3.673	4.758	3.673
Over 1,250 kWh	¢ per kWh	3.084	2.970	3.084	2.970
Minimum Charge		Customer Charge plus the demand charges*		Customer Charge plus the demand charges*	
Standby Rates (Presently Listed in Tariff as SC No. 25 - Rate 1)					
Customer Charge:	per month	$38.00	$38.00	$38.00	$38.00
Delivery Charges:					
Contract Demand Charge	per kW	$5.54	$5.54	$5.68	$5.68
As Used Daily Demand Charge	per kW	$0.8938	$0.6167	$0.9174	$0.6326

* Plus any applicable billing and payment processing charges.

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 2

Service Classification No. 2 Secondary Demand Billed (Continued)

Charges Applicable to Both Standard and Standby Service Rates

		Present	Proposed
Merchant Function Charge			
Supply Related	¢ per kWh	0.092	0.094
Purch Pwr Wrking Cap	¢ per kWh	0.052	0.052
Credit & Collections	¢ per kWh	0.022	0.022
Uncollectibles	¢ per kWh	Variable	Variable
Reactive Power Demand Charge (if applicable)			
	per KVAr	$0.85	$0.85
Plus:			Plus:
Energy Cost Adjustment			Please refer to Present Rates
System Benefits Charge			"
Renewable Portfolio Standard Charge			"
Transition Adjustment for Competitive Services			"
Revenue Decoupling Mechanism Adjustment			"
Increase in Rates and Charges			"
Market Supply Charge			"
Billing and Payment Processing Charge			"

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 2

Service Classification No. 2 Primary

		Present		Proposed	
		Summer	Winter	Summer	Winter
Standard Rates					
Customer Charge:	per month	$37.00	$37.00	$39.00	$39.00
Delivery Charge:					
Demand Charge	per kW	$18.63	$10.34	$19.51	$10.83
Usage Charge	¢ per kWh	0.786	0.786	0.786	0.786
Minimum Charge		Customer Charge plus the demand charges*		Customer Charge plus the demand charges*	
Standby Rates (Presently Listed in Tariff as SC No. 25 - Rate 1)					
Customer Charge:	per month	$40.00	$40.00	$40.00	$40.00
Delivery Charges:					
Contract Demand Charge	per kW	$5.51	$5.51	$5.74	$5.74
As Used Daily Demand Charge	per kW	$0.6447	$0.4424	$0.6720	$0.4602

* Plus any applicable billing and payment processing charges.

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 2

Service Classification No. 2 Primary (Continued)

Charges Applicable to Both Standard and Standby Service Rates

		Present	Proposed
Merchant Function Charge			
Supply Related	¢ per kWh	0.049	0.048
Purch Pwr Wrking Cap	¢ per kWh	0.052	0.052
Credit & Collections	¢ per kWh	0.008	0.008
Uncollectibles	¢ per kWh	Variable	Variable
Reactive Power Demand Charge (if applicable)			
	per KVAr	$0.85	$0.85
Plus:			Plus:
Energy Cost Adjustment			Please refer to Present Rates
System Benefits Charge			"
Renewable Portfolio Standard Charge			"
Transition Adjustment for Competitive Services			"
Revenue Decoupling Mechanism Adjustment			"
Increase in Rates and Charges			"
Market Supply Charge			"
Billing and Payment Processing Charge			"

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 2

Service Classification No. 3

		Present Summer	Present Winter	Proposed Summer	Proposed Winter
Standard Rates					
Customer Charge:	per month	\$100.00	\$100.00	\$80.00	\$80.00
Delivery Charge:					
Demand Charge	per kW	\$23.17	\$13.11	\$23.82	\$13.48
Usage Charge	¢ per kWh	0.696	0.696	0.696	0.696
Minimum Charge:		\$100.00	plus the demand charges*	\$80.00	plus the demand charges*
Standby Rates (Presently Listed in Tariff as SC No. 25 - Rate 2)					
Customer Charge:	per month	\$60.00	\$60.00	\$60.00	\$60.00
Delivery Charges:					
Contract Demand Charge	per kW	\$9.50	\$9.50	\$9.71	\$9.71
As Used Daily Demand Charge	per kW	\$0.7525	\$0.5084	\$0.7697	\$0.5188
Charges Applicable to Both Standard and Standby Service Rates					
Merchant Function Charge					
Supply Related	¢ per kWh	0.049		0.048	
Purch Pwr Wrking Cap	¢ per kWh	0.052		0.052	
Credit & Collections	¢ per kWh	0.008		0.008	
Uncollectibles		Variable		Variable	

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 2

Service Classification No. 3 (Continued)

Charges Applicable to Both Standard and Standby Service Rates (Continued)

Reactive Power Demand Charge (if applicable)			
	per KVAr	$0.85	$0.85
Plus:			Plus:
Energy Cost Adjustment			Please refer to Present Rates
System Benefits Charge			"
Renewable Portfolio Standard Charge			"
Transition Adjustment for Competitive Services			"
Revenue Decoupling Mechanism Adjustment			"
Increase in Rates and Charges			"
Market Supply Charge			"
Billing and Payment Processing Charge			"

* Plus any applicable billing and payment processing charges.

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 2

Service Classification No. 4

Luminaries Charge, per month

Nominal Lumens	Luminaires Type	Watts	Total Wattage	Present Delivery Charge	Proposed Delivery Charge
Street Lighting Luminaires					
5,800	Sodium Vapor	70	108	$11.66	$12.13
9,500	Sodium Vapor	100	142	12.72	13.24
16,000	Sodium Vapor	150	199	15.11	15.72
27,500	Sodium Vapor	250	311	20.20	21.02
46,000	Sodium Vapor	400	488	28.29	29.44
Off-Roadway Luminaires					
27,500	Sodium Vapor	250	311	$26.19	$27.25
46,500	Sodium Vapor	400	488	32.37	33.69
LED Street Lighting Luminaires					
3,000	LED	15-29	23	$10.38	$10.80
3,900	LED	30-39	35	10.49	10.92
5,000	LED	40-59	50	10.60	11.03
7,250	LED	60-89	68	11.71	12.19
12,000	LED	90-129	103	12.33	12.83
16,000	LED	130-169	140	13.55	14.10
22,000	LED	170-220	200	18.47	19.22

The following luminaires will no longer be installed. Charges are for existing luminaires only.

Nominal Lumens	Luminaires Type	Watts	Total Wattage	Present Delivery Charge	Proposed Delivery Charge
600	Open Bottom Inc	52	52	$5.76	$5.99
1,000	Open Bottom Inc	92	92	7.85	8.17
4,000	Mercury Vapor PB	100	127	9.25	9.63
4,000	Mercury Vapor	100	127	10.46	10.89
7,900	Mercury Vapor PB	175	215	11.35	11.81
7,900	Mercury Vapor	175	211	12.69	13.21
12,000	Mercury Vapor	250	296	16.62	17.30
22,500	Mercury Vapor	400	459	21.24	22.10
59,000	Mercury Vapor	1,000	1,105	41.71	43.41
130,000	Sodium Vapor	1,000	1,120	59.55	61.97

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 2

Service Classification No. 4 (Continued)

The following luminaires will no longer be installed. Charges are for existing luminaires only.

Luminaries Charge, per month

Nominal Lumens	Luminaires Type	Watts	Total Wattage	Present Delivery Charge	Proposed Delivery Charge
5,890	LED	70	74	$12.74	$13.26
9,365	LED	100	101	14.45	15.04
3,400	Induction	40	45	12.71	13.23
12,750	Induction	150	160	17.34	18.04

		Present	Proposed
Additional Charge:			
UG Svc- Customer owned and maintained duct	per month	$4.67	$4.86
15 Foot Brackets	$ per month	0.42	0.44
Merchant Function Charge			
Supply Related	¢ per kWh	0.092	0.094
Purch Pwr Wrking Cap	¢ per kWh	0.052	0.052
Credit & Collections	¢ per kWh	0.022	0.022
Uncollectibles	¢ per kWh	Variable	Variable

Plus:	Plus:
Energy Cost Adjustment	Please refer to Present Rates
System Benefits Charge	"
Renewable Portfolio Standard Charge	"
Transition Adjustment for Competitive Services	"
Revenue Decoupling Mechanism Adjustment	"
Increase in Rates and Charges	"
Market Supply Charge	"
Billing and Payment Processing Charge	"

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 2

Service Classification No. 5

		Present Year-round	Proposed Year-round
Delivery Charge:	¢ per kWh	9.87	10.270
Merchant Function Charge			
Supply Related	¢ per kWh	0.092	0.094
Purch Pwr Wrking Cap	¢ per kWh	0.052	0.052
Credit & Collections	¢ per kWh	0.022	0.022
Uncollectibles	¢ per kWh	Variable	Variable
Plus:			Plus:
Energy Cost Adjustment			Please refer to Present Rates
System Benefits Charge			"
Renewable Portfolio Standard Charge			"
Transition Adjustment for Competitive Services			"
Increase in Rates and Charges			"
Market Supply Charge			"
Billing and Payment Processing Charge			"

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 2

Service Classification No. 6

		Present Year-round	Proposed Year-round
Delivery Charges for Service Types A & B:	¢ per kWh	8.113	8.246
Delivery Charges for Service Type C:			
Customer Charge		$24.00	$24.00
Delivery Charge	¢ per kWh	7.220	7.338
Merchant Function Charge			
Supply Related	¢ per kWh	0.092	0.094
Purch Pwr Wrking Cap	¢ per kWh	0.052	0.052
Credit & Collections	¢ per kWh	0.022	0.022
Uncollectibles	¢ per kWh	Variable	Variable
Plus:			Plus:
Energy Cost Adjustment			Please refer to Present Rates
System Benefits Charge			"
Renewable Portfolio Standard Charge			"
Transition Adjustment for Competitive Services			"
Revenue Decoupling Mechanism Adjustment			"
Increase in Rates and Charges			"
Market Supply Charge			"
Billing and Payment Processing Charge			"

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 2

Service Classification No. 9

			Present Year-round	Proposed Year-round
Standard Rates				
Customer Charge:		per month	$500.00	$500.00
Delivery Charges:				
Primary:				
Demand Charge				
Period A	All kW @	per kW	$24.70	$25.24
Period B	All kW @	per kW	11.60	11.85
Period C	All kW @	per kW	No Charge	No Charge
Usage Charge				
Period A	All kWh @	¢ per kWh	0.441	0.441
Period B	All kWh @	¢ per kWh	0.441	0.441
Period C	All kWh @	¢ per kWh	0.164	0.164
Substation:				
Demand Charge				
Period A	All kW @	per kW	$17.86	$18.25
Period B	All kW @	per kW	8.07	8.25
Period C	All kW @	per kW	No Charge	No Charge
Usage Charge				
Period A	All kWh @	¢ per kWh	0.244	0.244
Period B	All kWh @	¢ per kWh	0.244	0.244
Period C	All kWh @	¢ per kWh	0.150	0.150
Transmission:				
Demand Charge				
Period A	All kW @	per kW	$8.81	$9.00
Period B	All kW @	per kW	6.00	6.13
Period C	All kW @	per kW	No Charge	No Charge
Usage Charge				
Period A	All kWh @	¢ per kWh	0.139	0.139
Period B	All kWh @	¢ per kWh	0.139	0.139
Period C	All kWh @	¢ per kWh	0.131	0.131

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 2

Service Classification No. 9 (Continued)

		Present	Proposed
Standby Rates (Presently Listed in Tariff as SC No. 25 - Rate 3)			
Customer Charge:	per month	$500.00	$500.00
Delivery Charges:			
Primary:			
Contract Demand Charge	per kW	$7.11	$7.26
As Used Daily Demand Charge (S)	per kW	$0.7201	$0.7349
As Used Daily Demand Charge (W)	per kW	$0.3973	$0.4050
Substation:			
Contract Demand Charge	per kW	$4.69	$4.78
As Used Daily Demand Charge	per kW	$0.4945	$0.5023
As Used Daily Demand Charge (W)	per kW	$0.3359	$0.3437
Transmission:			
Contract Demand Charge	per kW	$1.59	$1.62
As Used Daily Demand Charge	per kW	$0.3860	$0.3934
As Used Daily Demand Charge (W)	per kW	$0.2867	$0.2922
Minimum Charge		Sum of the Customer Charge, Min. Monthly Demand Charge, contract demand charge, the reactive power demand charge, and any applicable billing and payment processing charges.	Sum of the Customer Charge, Min. Monthly Demand Charge, contract demand charge, the reactive power demand charge, and any applicable billing and payment processing charges.
Min. Monthly Demand Charge		$51.18	$49.38
Contract Demand Charge - Pri	per kW of CD	$3.72	$3.59
Contract Demand Charge - Sec	per kW of CD	$6.11	$5.90

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 2

Service Classification No. 9 (Continued)

		Present	Proposed
Charges Applicable to Both Standard and Standby Service Rates			
Merchant Function Charge			
Supply Related	¢ per kWh	0.049	0.048
Purch Pwr Wrking Cap	¢ per kWh	0.052	0.052
Credit & Collections	¢ per kWh	0.008	0.008
Uncollectibles	¢ per kWh	Variable	Variable
Reactive Power Demand Charge (if applicable)			
	per KVAr	$0.85	$0.85
Plus:			Plus:
Energy Cost Adjustment			Please refer to Present Rates
System Benefits Charge			"
Renewable Portfolio Standard Charge			"
Transition Adjustment for Competitive Services			"
Revenue Decoupling Mechanism Adjustment			"
Increase in Rates and Charges			"
Market Supply Charge			"
Billing and Payment Processing Charge			"

Definition of Rating Periods:

Period A - 8:00 a.m. to 11:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.

Period B - 8:00 a.m. to 11:00 p.m. prevailing time, Monday through Friday, except holidays, October through May.

Period C - 11:00 p.m. to 8:00 a.m. prevailing time, Monday through Friday, all hours on Saturday, Sunday and holidays, all months.

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 2

Service Classification No. 15

		Present Year-round	Proposed Year-round
Customer Charge*:			
SC Nos. 2 Secondary and 20	per month	$38.00	$38.00
SC No. 2 Primary	per month	$40.00	$40.00
SC Nos. 3 and 21	per month	$60.00	$60.00
SC No. 9	per month	$500.00	$500.00
SC No. 22	per month	$500.00	$500.00
Contract Demand Charge*			
SC Nos. 2 Secondary and 20	per kW	$5.54	$5.68
SC No. 2 Primary	per kW	$5.51	$5.74
SC Nos. 3 and 21	per kW	$9.50	$9.71
SC No. 9 - Primary	per kW	$7.11	$7.26
SC No. 9 - Substation	per kW	$4.69	$4.78
SC No. 9 - Transmission	per kW	$1.59	$1.62
SC No. 22 - Primary	per kW	$5.93	$6.05
SC No. 22 - Substation	per kW	$3.31	$3.38
SC No. 22 - Transmission	per kW	$1.38	$1.41
Reactive Power Demand Charge (if applicable)			
	per KVAr	$0.85	$0.85

* Based on what the customer's otherwise applicable service classification is.

Plus:	Plus:
Increase in Rates and Charges	Please refer to Present Rates

Orange and Rockland Utilities, Inc.
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Rates in Brief - Rate Year 2

Service Classification No. 16

Luminaries Charge, per month

Nominal Lumens	Luminaires Type	Watts	Total Wattage	Present Delivery Charge	Proposed Delivery Charge
Power Bracket Luminaires					
5,800	Sodium Vapor	70	108	$21.56	$22.45
9,500	Sodium Vapor	100	142	23.05	24.00
16,000	Sodium Vapor	150	199	27.10	28.21
Street Lighting Luminaires					
5,800	Sodium Vapor	70	108	$23.60	$24.57
9,500	Sodium Vapor	100	142	25.17	26.20
16,000	Sodium Vapor	150	199	29.12	30.32
27,500	Sodium Vapor	250	311	37.12	38.64
46,000	Sodium Vapor	400	488	50.96	53.05
3,000	LED	15-29	23	10.88	10.88
3,900	LED	30-39	35	11.00	11.00
5,000	LED	40-59	50	11.12	11.12
7,250	LED	60-89	68	12.28	12.28
12,000	LED	90-129	103	12.93	12.93
16,000	LED	130-169	140	14.21	14.21
22,000	LED	170-220	200	19.37	19.37
Flood Lighting Luminaires					
27,500	Sodium Vapor	250	311	$37.12	$38.64
46,000	Sodium Vapor	400	488	50.96	53.05
15,000	LED	100-159	125	13.91	13.91
27,000	LED	160-249	205	16.40	16.40
37,500	LED	230-320	290	18.91	18.91

The following luminaires will no longer be installed. Charges are for existing luminaires only.

Nominal Lumens	Luminaires Type	Watts	Total Wattage	Present Delivery Charge	Proposed Delivery Charge
Power Bracket Luminaires					
4,000	Mercury Vapor	100	127	$19.80	$20.61
7,900	Mercury Vapor	175	215	22.92	23.86
22,500	Mercury Vapor	400	462	32.92	34.27
3,950	LED	25-39	35	9.23	9.23
5,550	LED	44-55	50	9.30	9.30
7,350	LED	56-70	65	9.39	9.39
Street Lighting Luminaires					
21,250	Induction	250	263	$44.23	$46.05
4,000	Mercury Vapor	100	127	21.70	22.59
7,900	Mercury Vapor	175	211	25.12	26.15
12,000	Mercury Vapor	250	296	31.63	32.93
22,500	Mercury Vapor	400	459	38.96	40.56
40,000	Mercury Vapor	700	786	57.65	60.02
59,000	Mercury Vapor	1,000	1,105	71.94	74.89
1,000	Incandescent	92	92	17.24	17.95
5,890	LED	70	74	31.41	32.70
9,365	LED	100	101	33.96	35.35

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 2

Service Classification No. 16 (Continued)

Nominal Lumens	Luminaires Type	Watts	Total Wattage	Present Delivery Charge	Proposed Delivery Charge
The following luminaires will no longer be installed. Charges are for existing luminaires only.					
Flood Lighting Luminaires					
12,000	Mercury Vapor	250	296	$31.63	$32.93
22,500	Mercury Vapor	400	459	38.96	40.56
40,000	Mercury Vapor	700	786	57.65	60.02
59,000	Mercury Vapor	1,000	1,105	71.94	74.89
15 Foot Brackets			$ per month	0.73	0.76
Delivery Charges for Service Type C:					
Customer Charge (Metered)			per month	$24.00	$24.00
Customer Charge (Unmetered)			per month	18.00	19.00
Delivery Charge			¢ per kWh	7.220	7.657
Merchant Function Charge					
Supply Related			¢ per kWh	0.092	0.094
Purch Pwr Wrking Cap			¢ per kWh	0.052	0.052
Credit & Collections			¢ per kWh	0.022	0.022
Uncollectibles			¢ per kWh	Variable	Variable

Plus:	Plus:
Energy Cost Adjustment	Please refer to Present Rates
System Benefits Charge	"
Renewable Portfolio Standard Charge	"
Transition Adjustment for Competitive Services	"
Increase in Rates and Charges	"
Market Supply Charge	"
Billing and Payment Processing Charge	"

Orange and Rockland Utilities, Inc.
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Rates in Brief - Rate Year 2

Service Classification No. 19

				Present	Proposed
				Year-round	Year-round
Customer Charge:			per month	$32.00	$32.00
Delivery Charges:					
	Period I	All kWh @	¢ per kWh	36.833	38.649
	Period II	All kWh @	¢ per kWh	13.179	13.829
	Period III	All kWh @	¢ per kWh	13.179	13.829
	Period IV	All kWh @	¢ per kWh	2.372	2.489
Merchant Function Charge					
Supply Related			¢ per kWh	0.166	0.176
Purch Pwr Wrking Cap			¢ per kWh	0.052	0.052
Credit & Collections			¢ per kWh	0.046	0.048
Uncollectibles			¢ per kWh	Variable	Variable
Minimum Charge:			per contract (not less than) plus applicable billing and payment processing charges	$384.00	$384.00
Plus:					Plus:
Energy Cost Adjustment					
System Benefits Charge					
Renewable Portfolio Standard Charge					Please refer to Present Rates
Transition Adjustment for Competitive Services					"
Revenue Decoupling Mechanism Adjustment					"
Increase in Rates and Charges					"
Market Supply Charge					"
Billing and Payment Processing Charge					"

Definition of Rating Periods:

Period I -	12:00 p.m. to 7:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.
Period II -	10:00 a.m. to 12:00 p.m. and 7:00 p.m. to 9:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.
Period III -	10:00 a.m. to 9:00 p.m. prevailing time, Monday through Friday, except holidays, October through May.
Period IV -	9:00 p.m. to 10:00 a.m. prevailing time, Monday through Friday, all hours on Saturday, Sunday and holidays, all months.

Orange and Rockland Utilities, Inc.
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Rates in Brief - Rate Year 2

Service Classification No. 20

				Present Year-round	Proposed Year-round
Standard Rates					
Customer Charge:			per month	$40.00	$40.00
Delivery Charges:					
Demand Charge					
	Period I	All kW @	per kW	$32.51	$33.69
	Period II	All kW @	per kW	13.91	14.42
	Period III	All kW @	per kW	0.57	0.65
Usage Charge					
	Period I	All kWh @	¢ per kWh	3.592	3.592
	Period II	All kWh @	¢ per kWh	0.863	0.863
	Period III	All kWh @	¢ per kWh	0.086	0.064
Minimum Charge:				Sum of the Customer Charge and $120.00 plus any applicable billing and payment processing charges.	Sum of the Customer Charge and $120.00 plus any applicable billing and payment processing charges.
Standby Rates (Presently Listed in Tariff as SC No. 25 - Rate 1)					
Customer Charge:			per month	$38.00	$38.00
Delivery Charges:					
Contract Demand Charge			per kW	$5.54	$5.68
As Used Daily Demand Charge (S)			per kW	$0.8938	$0.9174
As Used Daily Demand Charge (W)			per kW	$0.6167	$0.6326

Orange and Rockland Utilities, Inc.
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Rates in Brief - Rate Year 2

Service Classification No. 20 (Continued)

Charges Applicable to Both Standard and Standby Service Rates

Merchant Function Charge			
Supply Related	¢ per kWh	0.092	0.094
Purch Pwr Wrking Cap	¢ per kWh	0.052	0.052
Credit & Collections	¢ per kWh	0.022	0.022
Uncollectibles	¢ per kWh	Variable	Variable
Reactive Power Demand Charge (if applicable)			
	per KVAr	$0.85	$0.85
Plus:			Plus:
Energy Cost Adjustment			Please refer to Present Rates
System Benefits Charge			"
Renewable Portfolio Standard Charge			"
Transition Adjustment for Competitive Services			"
Revenue Decoupling Mechanism Adjustment			"
Increase in Rates and Charges			"
Market Supply Charge			"
Billing and Payment Processing Charge			"

Definition of Rating Periods:

Period I -	1:00 p.m. to 7:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.
Period II -	10:00 a.m. to 9:00 p.m. prevailing time, Monday through Friday, except holidays, October through May.
Period III -	7:00 p.m. to 1:00 p.m. prevailing time, Monday through Friday, June through September; 9:00 p.m. to 10:00 a.m. prevailing time, Monday through Friday, October through May; all hours on Saturday, Sunday and holidays, all months.

Orange and Rockland Utilities, Inc.
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Rates in Brief - Rate Year 2

Service Classification No. 21

			Present Year-round	Proposed Year-round
Customer Charge:		per month	$133.00	$103.00
Delivery Charges:				
Demand Charge				
Period I	All kW @	per kW	$32.02	$33.37
Period II	All kW @	per kW	11.29	11.76
Period III	All kW @	per kW	No Charge	No Charge
Usage Charge				
Period I	All kWh @	¢ per kWh	1.553	1.553
Period II	All kWh @	¢ per kWh	1.553	1.553
Period III	All kWh @	¢ per kWh	0.136	0.136
Minimum Charge:			Sum of the Customer Charge and any applicable billing and payment processing charges.	Sum of the Customer Charge and any applicable billing and payment processing charges.

Standby Rates (Presently Listed in Tariff as SC No. 25 - Rate 2)

		Present	Proposed
Customer Charge:	per month	$60.00	$60.00
Delivery Charges:			
Contract Demand Charge	per kW	$9.50	$9.71
As Used Daily Demand Charge (S)	per kW	$0.7525	$0.7697
As Used Daily Demand Charge (W)	per kW	$0.5084	$0.5188

Orange and Rockland Utilities, Inc.
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Rates in Brief - Rate Year 2

Service Classification No. 21 (Continued)

Charges Applicable to Both Standard and Standby Service Rates

Merchant Function Charge			
Supply Related	¢ per kWh	0.049	0.048
Purch Pwr Wrking Cap	¢ per kWh	0.052	0.052
Credit & Collections	¢ per kWh	0.008	0.008
Uncollectibles	¢ per kWh	Variable	Variable
Reactive Power Demand Charge (if applicable)			
	per KVAr	$0.85	$0.85
Plus:			Plus:
Energy Cost Adjustment			Please refer to Present Rates
System Benefits Charge			"
Renewable Portfolio Standard Charge			"
Transition Adjustment for Competitive Services			"
Revenue Decoupling Mechanism Adjustment			"
Increase in Rates and Charges			"
Market Supply Charge			"
Billing and Payment Processing Charge			"

Definition of Rating Periods:

Period I -	1:00 p.m. to 7:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.
Period II -	10:00 a.m. to 9:00 p.m. prevailing time, Monday through Friday, except holidays, October through May.
Period III -	7:00 p.m. to 1:00 p.m. prevailing time, Monday through Friday, June through September; 9:00 p.m. to 10:00 a.m. prevailing time, Monday through Friday, October through May; all hours on Saturday, Sunday and holidays, all months.

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 2

Service Classification No. 22

				Present	Proposed
				Year-round	Year-round
Standard Rates					
Customer Charge:			per month	$500.00	$500.00
Delivery Charges:					
Primary:					
Demand Charge					
Period	A	All kW @	per kW	$18.69	$19.12
Period	B	All kW @	per kW	10.67	10.91
Period	C	All kW @	per kW	No Charge	No Charge
Usage Charge					
Period	A	All kWh @	¢ per kWh	0.710	0.710
Period	B	All kWh @	¢ per kWh	0.710	0.710
Period	C	All kWh @	¢ per kWh	0.126	0.126
Substation:					
Demand Charge					
Period	A	All kW @	per kW	$12.01	$12.28
Period	B	All kW @	per kW	6.62	6.77
Period	C	All kW @	per kW	No Charge	No Charge
Usage Charge					
Period	A	All kWh @	¢ per kWh	0.298	0.298
Period	B	All kWh @	¢ per kWh	0.298	0.298
Period	C	All kWh @	¢ per kWh	0.126	0.126
Transmission:					
Demand Charge					
Period	A	All kW @	per kW	$6.90	$7.06
Period	B	All kW @	per kW	6.03	6.17
Period	C	All kW @	per kW	No Charge	No Charge
Usage Charge					
Period	A	All kWh @	¢ per kWh	0.126	0.126
Period	B	All kWh @	¢ per kWh	0.126	0.126
Period	C	All kWh @	¢ per kWh	0.126	0.126
Minimum Charge				Sum of the Customer Charge, Min. Monthly Demand Charge, contract demand charge, the reactive power demand charge, and any applicable billing and payment processing charges.	Sum of the Customer Charge, Min. Monthly Demand Charge, contract demand charge, the reactive power demand charge, and any applicable billing and payment processing charges.
Min. Monthly Demand Charge				$51.18	$49.38
Contract Demand Charge			per kW of CD	$3.72	$3.59
Contract Demand Charge			per kW of CD	$6.11	$5.90

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 2

Service Classification No. 22 (Continued)

		Present	Proposed
Standby Rates (Presently Listed in Tariff as SC No. 25 - Rate 4)			
Customer Charge:	per month	$500.00	$500.00
Delivery Charges:			
Primary:			
Contract Demand Charge	per kW	$5.93	$6.05
As Used Daily Demand Charge (S)	per kW	$0.6349	$0.6477
As Used Daily Demand Charge (W)	per kW	$0.4377	$0.4463
Substation:			
Contract Demand Charge	per kW	$3.31	$3.38
As Used Daily Demand Charge	per kW	$0.4158	$0.4246
As Used Daily Demand Charge (W)	per kW	$0.2746	$0.2801
Transmission:			
Contract Demand Charge	per kW	$1.38	$1.41
As Used Daily Demand Charge	per kW	$0.3287	$0.3359
As Used Daily Demand Charge (W)	per kW	$0.2980	$0.3044

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 2

Service Classification No. 22 (Continued)

		Present Year-round	Proposed Year-round
Charges Applicable to Both Standard and Standby Service Rates			
Merchant Function Charge			
Supply Related	¢ per kWh	0.049	0.048
Purch Pwr Wrking Cap	¢ per kWh	0.052	0.052
Credit & Collections	¢ per kWh	0.008	0.008
Uncollectibles	¢ per kWh	Variable	Variable
Reactive Power Demand Charge (if applicable)			
	per KVAr	$0.85	$0.85
Plus:			Plus:
Energy Cost Adjustment			Please refer to Present Rates
System Benefits Charge			"
Renewable Portfolio Standard Charge			"
Transition Adjustment for Competitive Services			"
Revenue Decoupling Mechanism Adjustment			"
Increase in Rates and Charges			"
Market Supply Charge			"
Billing and Payment Processing Charge			"

Definition of Rating Periods:
Period A - 8:00 a.m. to 11:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.
Period B - 8:00 a.m. to 11:00 p.m. prevailing time, Monday through Friday, except holidays, October through May.
Period C - 11:00 p.m. to 8:00 a.m. prevailing time, Monday through Friday, all hours on Saturday, Sunday and holidays, all months.

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 2

Rider J - Smart Home Rate

		Present	Proposed
Customer Charge:	per month	$20.50	$21.50
Rate I - Delivery Charges:			
Daily Demand Charges	per kW	$1.15	$1.18
Distribution Event Charge	per kW	$1.76	$1.80
Transmission Event Charge	per kW	$0.44	$0.45
Rate II - Delivery Charges:			
Subscribed Demand Chg	per kW	$19.25	$19.64
Distribution Event Charge	per kW	$19.88	$20.43
Transmission Event Charge	per kW	$4.97	$5.11
Merchant Function Charge			
Supply Related	¢ per kWh	0.166	0.166
Purch Pwr Wrking Cap	¢ per kWh	0.052	0.052
Credit & Collections	¢ per kWh	0.046	0.046
Uncollectibles	¢ per kWh	Variable	Variable
Plus:			Plus:
Energy Cost Adjustment			Please refer to Present Rates
System Benefits Charge			"
Renewable Portfolio Standard Charge			"
Transition Adjustment for Competitive Services			"
Revenue Decoupling Mechanism Adjustment			"
Increase in Rates and Charges			"
Market Supply Charges			"
Billing and Payment Processing Charge			"

* Plus any applicable billing and payment processing charges.

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 3

Service Classification No. 1

		Present		Proposed	
		Summer	Winter	Summer	Winter
Customer Charge:	per month	$21.50	$21.50	$22.00	$22.00
Delivery Charges:					
First 250 kWh	¢ per kWh	9.529	9.529	10.363	10.363
Over 250 kWh	¢ per kWh	11.917	9.529	12.960	10.363
Minimum Charge:					
Monthly*	monthly	$21.50		$22.00	
Per Contract	per contract	129.00		132.00	
Merchant Function Charge					
Supply Related	¢ per kWh	0.176		0.190	
Purch Pwr Wrking Cap	¢ per kWh	0.052		0.053	
Credit & Collections	¢ per kWh	0.048		0.052	
Uncollectibles	¢ per kWh	Variable		Variable	
Plus:				Plus:	
Energy Cost Adjustment				Please refer to Present Rates	
System Benefits Charge				"	
Renewable Portfolio Standard Charge				"	
Transition Adjustment for Competitive Services				"	
Revenue Decoupling Mechanism Adjustment				"	
Increase in Rates and Charges				"	
Market Supply Charge				"	
Billing and Payment Processing Charge				"	

* Plus any applicable billing and payment processing charges.

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 3

Service Classification No. 2 Secondary - Non-Demand Billed Customers

		Present		Proposed	
		Summer	Winter	Summer	Winter
Customer Charge:					
Metered Service	per month	$22.00	$22.00	$24.00	$24.00
Unmetered Service	per month	19.00	19.00	20.00	20.00
Delivery Charge:					
Usage Charge					
All kWh	¢ per kWh	8.138	6.013	8.683	6.416
Space Heating:					
Delivery	¢ per kWh	13.958	3.488	14.943	3.734
Minimum Charge		Customer Charge*		Customer Charge*	
Merchant Function Charge					
Supply Related	¢ per kWh	0.094		0.099	
Purch Pwr Wrking Cap	¢ per kWh	0.052		0.053	
Credit & Collections	¢ per kWh	0.022		0.023	
Uncollectibles	¢ per kWh	Variable		Variable	
Plus:				Plus:	
Energy Cost Adjustment				Please refer to Present Rates	
System Benefits Charge				"	
Renewable Portfolio Standard Charge				"	
Transition Adjustment for Competitive Services				"	
Revenue Decoupling Mechanism Adjustment				"	
Increase in Rates and Charges				"	
Market Supply Charge				"	
Billing and Payment Processing Charge				"	

* Plus any applicable billing and payment processing charges.

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 3

Service Classification No. 2 Secondary Demand Billed

		Present Summer	Present Winter	Proposed Summer	Proposed Winter
Standard Rates					
Customer Charge:					
Metered Service	per month	$25.00	$25.00	$27.00	$27.00
Delivery Charge:					
Demand Charge					
First 5 kW	per kW	$3.75	$2.21	$4.00	$2.36
Over 5 kW	per kW	24.66	14.34	26.30	15.29
Usage Charge					
First 1,250 kWh	¢ per kWh	4.758	3.673	4.758	3.673
Over 1,250 kWh	¢ per kWh	3.084	2.970	3.084	2.970
Minimum Charge		Customer Charge plus the demand charges*		Customer Charge plus the demand charges*	
Standby Rates (Presently Listed in Tariff as SC No. 25 - Rate 1)					
Customer Charge:	per month	$38.00	$38.00	$38.00	$38.00
Delivery Charges:					
Contract Demand Charge	per kW	$5.68	$5.68	$5.97	$5.97
As Used Daily Demand Charge	per kW	$0.9174	$0.6326	$0.9672	$0.6634

* Plus any applicable billing and payment processing charges.

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 3

Service Classification No. 2 Secondary Demand Billed (Continued)

Charges Applicable to Both Standard and Standby Service Rates

		Present	Proposed
Merchant Function Charge			
Supply Related	¢ per kWh	0.094	0.099
Purch Pwr Wrking Cap	¢ per kWh	0.052	0.053
Credit & Collections	¢ per kWh	0.022	0.023
Uncollectibles	¢ per kWh	Variable	Variable
Reactive Power Demand Charge (if applicable)			
	per KVAr	$0.85	$0.85
Plus:			Plus:
Energy Cost Adjustment			Please refer to Present Rates
System Benefits Charge			"
Renewable Portfolio Standard Charge			"
Transition Adjustment for Competitive Services			"
Revenue Decoupling Mechanism Adjustment			"
Increase in Rates and Charges			"
Market Supply Charge			"
Billing and Payment Processing Charge			"

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 3

Service Classification No. 2 Primary

		Present		Proposed	
		Summer	Winter	Summer	Winter
Standard Rates					
Customer Charge:	per month	$39.00	$39.00	$41.00	$41.00
Delivery Charge:					
Demand Charge	per kW	$19.51	$10.83	$20.94	$11.62
Usage Charge	¢ per kWh	0.786	0.786	0.786	0.786
Minimum Charge		Customer Charge plus the demand charges*		Customer Charge plus the demand charges*	
Standby Rates (Presently Listed in Tariff as SC No. 25 - Rate 1)					
Customer Charge:	per month	$40.00	$40.00	$40.00	$40.00
Delivery Charges:					
Contract Demand Charge	per kW	$5.74	$5.74	$6.09	$6.09
As Used Daily Demand Charge	per kW	$0.6720	$0.4602	$0.7157	$0.4882

* Plus any applicable billing and payment processing charges.

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 3

Service Classification No. 2 Primary (Continued)

Charges Applicable to Both Standard and Standby Service Rates

		Present	Proposed
Merchant Function Charge			
Supply Related	¢ per kWh	0.048	0.050
Purch Pwr Wrking Cap	¢ per kWh	0.052	0.053
Credit & Collections	¢ per kWh	0.008	0.008
Uncollectibles	¢ per kWh	Variable	Variable
Reactive Power Demand Charge (if applicable)			
	per KVAr	$0.85	$0.85
Plus:			Plus:
Energy Cost Adjustment			Please refer to Present Rates
System Benefits Charge			"
Renewable Portfolio Standard Charge			"
Transition Adjustment for Competitive Services			"
Revenue Decoupling Mechanism Adjustment			"
Increase in Rates and Charges			"
Market Supply Charge			"
Billing and Payment Processing Charge			"

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 3

Service Classification No. 3

		Present Summer	Present Winter	Proposed Summer	Proposed Winter
Standard Rates					
Customer Charge:	per month	$80.00	$80.00	$60.00	$60.00
Delivery Charge:					
Demand Charge	per kW	$23.82	$13.48	$24.60	$13.92
Usage Charge	¢ per kWh	0.696	0.696	0.696	0.696
Minimum Charge:		$80.00	plus the demand charges*	$60.00	plus the demand charges*
Standby Rates (Presently Listed in Tariff as SC No. 25 - Rate 2)					
Customer Charge:	per month	$60.00	$60.00	$60.00	$60.00
Delivery Charges:					
Contract Demand Charge	per kW	$9.71	$9.71	$9.97	$9.97
As Used Daily Demand Charge	per kW	$0.7697	$0.5188	$0.7915	$0.5323
Charges Applicable to Both Standard and Standby Service Rates					
Merchant Function Charge					
Supply Related	¢ per kWh	0.048		0.050	
Purch Pwr Wrking Cap	¢ per kWh	0.052		0.053	
Credit & Collections	¢ per kWh	0.008		0.008	
Uncollectibles		Variable		Variable	

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 3

Service Classification No. 3 (Continued)

Charges Applicable to Both Standard and Standby Service Rates (Continued)

Reactive Power Demand Charge (if applicable)			
	per KVAr	$0.85	$0.85
Plus:			Plus:
Energy Cost Adjustment			Please refer to Present Rates
System Benefits Charge			"
Renewable Portfolio Standard Charge			"
Transition Adjustment for Competitive Services			"
Revenue Decoupling Mechanism Adjustment			"
Increase in Rates and Charges			"
Market Supply Charge			"
Billing and Payment Processing Charge			"

* Plus any applicable billing and payment processing charges.

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 3

Service Classification No. 4

Luminaries Charge, per month

Nominal Lumens	Luminaires Type	Watts	Total Wattage	Present Delivery Charge	Proposed Delivery Charge
Street Lighting Luminaires					
5,800	Sodium Vapor	70	108	$12.13	$12.98
9,500	Sodium Vapor	100	142	13.24	14.16
16,000	Sodium Vapor	150	199	15.72	16.82
27,500	Sodium Vapor	250	311	21.02	22.49
46,000	Sodium Vapor	400	488	29.44	31.49
Off-Roadway Luminaires					
27,500	Sodium Vapor	250	311	$27.25	$29.15
46,500	Sodium Vapor	400	488	33.69	36.04
LED Street Lighting Luminaires					
3,000	LED	15-29	23	$10.80	$11.55
3,900	LED	30-39	35	10.92	11.68
5,000	LED	40-59	50	11.03	11.80
7,250	LED	60-89	68	12.19	13.04
12,000	LED	90-129	103	12.83	13.73
16,000	LED	130-169	140	14.10	15.08
22,000	LED	170-220	200	19.22	20.56

The following luminaires will no longer be installed. Charges are for existing luminaires only.

Nominal Lumens	Luminaires Type	Watts	Total Wattage	Present Delivery Charge	Proposed Delivery Charge
600	Open Bottom Inc	52	52	$5.99	$6.41
1,000	Open Bottom Inc	92	92	8.17	8.74
4,000	Mercury Vapor PB	100	127	9.63	10.30
4,000	Mercury Vapor	100	127	10.89	11.65
7,900	Mercury Vapor PB	175	215	11.81	12.63
7,900	Mercury Vapor	175	211	13.21	14.13
12,000	Mercury Vapor	250	296	17.30	18.51
22,500	Mercury Vapor	400	459	22.10	23.64
59,000	Mercury Vapor	1,000	1,105	43.41	46.44
130,000	Sodium Vapor	1,000	1,120	61.97	66.29

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 3

Service Classification No. 4 (Continued)

The following luminaires will no longer be installed. Charges are for existing luminaires only.

Luminaries Charge, per month

Nominal Lumens	Luminaires Type	Watts	Total Wattage	Present Delivery Charge	Proposed Delivery Charge
5,890	LED	70	74	$13.26	$14.19
9,365	LED	100	101	15.04	16.09
3,400	Induction	40	45	13.23	14.15
12,750	Induction	150	160	18.04	19.30
Additional Charge:					
UG Svc- Customer owned and maintained duct			per month	$4.67	$5.00
15 Foot Brackets			$ per month	0.44	0.47
Merchant Function Charge					
Supply Related			¢ per kWh	0.094	0.099
Purch Pwr Wrking Cap			¢ per kWh	0.052	0.053
Credit & Collections			¢ per kWh	0.022	0.023
Uncollectibles			¢ per kWh	Variable	Variable
Plus:					Plus:
Energy Cost Adjustment					Please refer to Present Rates
System Benefits Charge					"
Renewable Portfolio Standard Charge					"
Transition Adjustment for Competitive Services					"
Revenue Decoupling Mechanism Adjustment					"
Increase in Rates and Charges					"
Market Supply Charge					"
Billing and Payment Processing Charge					"

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 3

Service Classification No. 5

		Present Year-round	Proposed Year-round
Delivery Charge:	¢ per kWh	10.270	10.985
Merchant Function Charge			
Supply Related	¢ per kWh	0.094	0.099
Purch Pwr Wrking Cap	¢ per kWh	0.052	0.053
Credit & Collections	¢ per kWh	0.022	0.023
Uncollectibles	¢ per kWh	Variable	Variable
Plus:			Plus:
Energy Cost Adjustment			Please refer to Present Rates
System Benefits Charge			"
Renewable Portfolio Standard Charge			"
Transition Adjustment for Competitive Services			"
Increase in Rates and Charges			"
Market Supply Charge			"
Billing and Payment Processing Charge			"

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 3

Service Classification No. 6

		Present Year-round	Proposed Year-round
Delivery Charges for Service Types A & B:	¢ per kWh	8.246	8.415
Delivery Charges for Service Type C:			
Customer Charge		$24.00	$24.00
Delivery Charge	¢ per kWh	7.657	7.814
Merchant Function Charge			
Supply Related	¢ per kWh	0.094	0.099
Purch Pwr Wrking Cap	¢ per kWh	0.052	0.053
Credit & Collections	¢ per kWh	0.022	0.023
Uncollectibles	¢ per kWh	Variable	Variable
Plus:			Plus:
Energy Cost Adjustment			Please refer to Present Rates
System Benefits Charge			"
Renewable Portfolio Standard Charge			"
Transition Adjustment for Competitive Services			"
Revenue Decoupling Mechanism Adjustment			"
Increase in Rates and Charges			"
Market Supply Charge			"
Billing and Payment Processing Charge			"

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 3

Service Classification No. 9

			Present Year-round	Proposed Year-round
Standard Rates				
Customer Charge:		per month	$500.00	$500.00
Delivery Charges:				
Primary:				
Demand Charge				
Period A	All kW @	per kW	$25.24	$25.91
Period B	All kW @	per kW	11.85	12.16
Period C	All kW @	per kW	No Charge	No Charge
Usage Charge				
Period A	All kWh @	¢ per kWh	0.441	0.441
Period B	All kWh @	¢ per kWh	0.441	0.441
Period C	All kWh @	¢ per kWh	0.164	0.164
Substation:				
Demand Charge				
Period A	All kW @	per kW	$18.25	$18.73
Period B	All kW @	per kW	8.25	8.47
Period C	All kW @	per kW	No Charge	No Charge
Usage Charge				
Period A	All kWh @	¢ per kWh	0.244	0.244
Period B	All kWh @	¢ per kWh	0.244	0.244
Period C	All kWh @	¢ per kWh	0.150	0.150
Transmission:				
Demand Charge				
Period A	All kW @	per kW	$9.00	$9.24
Period B	All kW @	per kW	6.13	6.29
Period C	All kW @	per kW	No Charge	No Charge
Usage Charge				
Period A	All kWh @	¢ per kWh	0.139	0.139
Period B	All kWh @	¢ per kWh	0.139	0.139
Period C	All kWh @	¢ per kWh	0.131	0.131

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 3

Service Classification No. 9 (Continued)

		Present	Proposed
Standby Rates (Presently Listed in Tariff as SC No. 25 - Rate 3)			
Customer Charge:	per month	$500.00	$500.00
Delivery Charges:			
Primary:			
Contract Demand Charge	per kW	$7.26	$7.43
As Used Daily Demand Charge (S)	per kW	$0.7349	$0.7533
As Used Daily Demand Charge (W)	per kW	$0.4050	$0.4145
Substation:			
Contract Demand Charge	per kW	$4.78	$4.90
As Used Daily Demand Charge	per kW	$0.5023	$0.5119
As Used Daily Demand Charge (W)	per kW	$0.3437	$0.3533
Transmission:			
Contract Demand Charge	per kW	$1.62	$1.66
As Used Daily Demand Charge	per kW	$0.3934	$0.4030
As Used Daily Demand Charge (W)	per kW	$0.2922	$0.2990
Minimum Charge		Sum of the Customer Charge, Min. Monthly Demand Charge, contract demand charge, the reactive power demand charge, and any applicable billing and payment processing charges.	Sum of the Customer Charge, Min. Monthly Demand Charge, contract demand charge, the reactive power demand charge, and any applicable billing and payment processing charges.
Min. Monthly Demand Charge		$51.18	$50.56
Contract Demand Charge - Pri	per kW of CD	$3.72	$3.68
Contract Demand Charge - Sec	per kW of CD	$6.11	$6.04

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 3

Service Classification No. 9 (Continued)

		Present	Proposed
Charges Applicable to Both Standard and Standby Service Rates			
Merchant Function Charge			
Supply Related	¢ per kWh	0.048	0.050
Purch Pwr Wrking Cap	¢ per kWh	0.052	0.053
Credit & Collections	¢ per kWh	0.008	0.008
Uncollectibles	¢ per kWh	Variable	Variable
Reactive Power Demand Charge (if applicable)			
	per KVAr	$0.85	$0.85
Plus:			Plus:
Energy Cost Adjustment			Please refer to Present Rates
System Benefits Charge			"
Renewable Portfolio Standard Charge			"
Transition Adjustment for Competitive Services			"
Revenue Decoupling Mechanism Adjustment			"
Increase in Rates and Charges			"
Market Supply Charge			"
Billing and Payment Processing Charge			"

Definition of Rating Periods:

Period A - 8:00 a.m. to 11:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.

Period B - 8:00 a.m. to 11:00 p.m. prevailing time, Monday through Friday, except holidays, October through May.

Period C - 11:00 p.m. to 8:00 a.m. prevailing time, Monday through Friday, all hours on Saturday, Sunday and holidays, all months.

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 3

Service Classification No. 15

		Present Year-round	Proposed Year-round
Customer Charge*:			
SC Nos. 2 Secondary and 20	per month	$38.00	$38.00
SC No. 2 Primary	per month	$40.00	$40.00
SC Nos. 3 and 21	per month	$60.00	$60.00
SC No. 9	per month	$500.00	$500.00
SC No. 22	per month	$500.00	$500.00
Contract Demand Charge*			
SC Nos. 2 Secondary and 20	per kW	$5.68	$5.97
SC No. 2 Primary	per kW	$5.74	$6.09
SC Nos. 3 and 21	per kW	$9.71	$9.97
SC No. 9 - Primary	per kW	$7.26	$7.43
SC No. 9 - Substation	per kW	$4.78	$4.90
SC No. 9 - Transmission	per kW	$1.62	$1.66
SC No. 22 - Primary	per kW	$6.05	$6.20
SC No. 22 - Substation	per kW	$3.38	$3.47
SC No. 22 - Transmission	per kW	$1.41	$1.44
Reactive Power Demand Charge (if applicable)			
	per KVAr	$0.85	$0.85

* Based on what the customer's otherwise applicable service classification is.

Present	Proposed
Plus:	Plus:
Increase in Rates and Charges	Please refer to Present Rates

Orange and Rockland Utilities, Inc.
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Rates in Brief - Rate Year 3

Service Classification No. 16

Luminaries Charge, per month

Nominal Lumens	Luminaires Type	Watts	Total Wattage	Present Delivery Charge	Proposed Delivery Charge
Power Bracket Luminaires					
5,800	Sodium Vapor	70	108	$22.45	$24.03
9,500	Sodium Vapor	100	142	24.00	25.69
16,000	Sodium Vapor	150	199	28.21	30.20
Street Lighting Luminaires					
5,800	Sodium Vapor	70	108	$24.57	$26.30
9,500	Sodium Vapor	100	142	26.20	28.05
16,000	Sodium Vapor	150	199	30.32	32.46
27,500	Sodium Vapor	250	311	38.64	41.37
46,000	Sodium Vapor	400	488	53.05	56.79
3,000	LED	15-29	23	10.88	10.88
3,900	LED	30-39	35	11.00	11.00
5,000	LED	40-59	50	11.12	11.12
7,250	LED	60-89	68	12.28	12.28
12,000	LED	90-129	103	12.93	12.93
16,000	LED	130-169	140	14.21	14.21
22,000	LED	170-220	200	19.37	19.37
Flood Lighting Luminaires					
27,500	Sodium Vapor	250	311	$38.64	$41.37
46,000	Sodium Vapor	400	488	53.05	56.79
15,000	LED	100-159	125	13.91	13.91
27,000	LED	160-249	205	16.40	16.40
37,500	LED	230-320	290	18.91	18.91

The following luminaires will no longer be installed. Charges are for existing luminaires only.

Nominal Lumens	Luminaires Type	Watts	Total Wattage	Present Delivery Charge	Proposed Delivery Charge
Power Bracket Luminaires					
4,000	Mercury Vapor	100	127	$20.61	$22.06
7,900	Mercury Vapor	175	215	23.86	25.54
22,500	Mercury Vapor	400	462	34.27	36.69
3,950	LED	25-39	35	9.23	9.23
5,550	LED	44-55	50	9.30	9.30
7,350	LED	56-70	65	9.39	9.39
Street Lighting Luminaires					
21,250	Induction	250	263	$46.05	$49.30
4,000	Mercury Vapor	100	127	22.59	24.18
7,900	Mercury Vapor	175	211	26.15	27.99
12,000	Mercury Vapor	250	296	32.93	35.25
22,500	Mercury Vapor	400	459	40.56	43.42
40,000	Mercury Vapor	700	786	60.02	64.25
59,000	Mercury Vapor	1,000	1,105	74.89	80.17
1,000	Incandescent	92	92	17.95	19.22
5,890	LED	70	74	32.70	35.01
9,365	LED	100	101	35.35	37.84

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 3

Service Classification No. 16 (Continued)

Nominal Lumens	Luminaires Type	Watts	Total Wattage	Present Delivery Charge	Proposed Delivery Charge
The following luminaires will no longer be installed. Charges are for existing luminaires only.					
Flood Lighting Luminaires					
12,000	Mercury Vapor	250	296	$32.93	$35.25
22,500	Mercury Vapor	400	459	40.56	43.42
40,000	Mercury Vapor	700	786	60.02	64.25
59,000	Mercury Vapor	1,000	1,105	74.89	80.17
15 Foot Brackets			$ per month	0.76	0.81
Delivery Charges for Service Type C:					
Customer Charge (Metered)			per month	$24.00	$24.00
Customer Charge (Unmetered)			per month	19.00	20.00
Delivery Charge			¢ per kWh	7.657	8.541
Merchant Function Charge					
Supply Related			¢ per kWh	0.094	0.099
Purch Pwr Wrking Cap			¢ per kWh	0.052	0.053
Credit & Collections			¢ per kWh	0.022	0.023
Uncollectibles			¢ per kWh	Variable	Variable

Plus:	Plus:
Energy Cost Adjustment	Please refer to Present Rates
System Benefits Charge	"
Renewable Portfolio Standard Charge	"
Transition Adjustment for Competitive Services	"
Increase in Rates and Charges	"
Market Supply Charge	"
Billing and Payment Processing Charge	"

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 3

Service Classification No. 19

				Present Year-round	Proposed Year-round
Customer Charge:			per month	$32.00	$32.00
Delivery Charges:					
	Period I	All kWh @	¢ per kWh	38.649	41.846
	Period II	All kWh @	¢ per kWh	13.829	14.973
	Period III	All kWh @	¢ per kWh	13.829	14.973
	Period IV	All kWh @	¢ per kWh	2.489	2.695
Merchant Function Charge					
Supply Related			¢ per kWh	0.176	0.190
Purch Pwr Wrking Cap			¢ per kWh	0.052	0.053
Credit & Collections			¢ per kWh	0.048	0.052
Uncollectibles			¢ per kWh	Variable	Variable
Minimum Charge:		per contract (not less than) plus applicable billing and payment processing charges		$384.00	$384.00
Plus:					Plus:
Energy Cost Adjustment					Please refer to Present Rates
System Benefits Charge					"
Renewable Portfolio Standard Charge					"
Transition Adjustment for Competitive Services					"
Revenue Decoupling Mechanism Adjustment					"
Increase in Rates and Charges					"
Market Supply Charge					"
Billing and Payment Processing Charge					"

Definition of Rating Periods:

Period I -	12:00 p.m. to 7:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.
Period II -	10:00 a.m. to 12:00 p.m. and 7:00 p.m. to 9:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.
Period III -	10:00 a.m. to 9:00 p.m. prevailing time, Monday through Friday, except holidays, October through May.
Period IV -	9:00 p.m. to 10:00 a.m. prevailing time, Monday through Friday, all hours on Saturday, Sunday and holidays, all months.

Orange and Rockland Utilities, Inc.
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Rates in Brief - Rate Year 3

Service Classification No. 20

			Present Year-round	Proposed Year-round
Standard Rates				
Customer Charge:		per month	$40.00	$40.00
Delivery Charges:				
Demand Charge				
Period I	All kW @	per kW	$33.69	$35.72
Period II	All kW @	per kW	14.42	15.29
Period III	All kW @	per kW	0.65	0.73
Usage Charge				
Period I	All kWh @	¢ per kWh	3.592	3.592
Period II	All kWh @	¢ per kWh	0.863	0.863
Period III	All kWh @	¢ per kWh	0.064	0.048
Minimum Charge:			Sum of the Customer Charge and $120.00 plus any applicable billing and payment processing charges.	Sum of the Customer Charge and $120.00 plus any applicable billing and payment processing charges.
Standby Rates (Presently Listed in Tariff as SC No. 25 - Rate 1)				
Customer Charge:		per month	$38.00	$38.00
Delivery Charges:				
Contract Demand Charge		per kW	$5.68	$5.97
As Used Daily Demand Charge (S)		per kW	$0.9174	$0.9672
As Used Daily Demand Charge (W)		per kW	$0.6326	$0.6634

Orange and Rockland Utilities, Inc.
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Rates in Brief - Rate Year 3

Service Classification No. 20 (Continued)

Charges Applicable to Both Standard and Standby Service Rates

Merchant Function Charge			
Supply Related	¢ per kWh	0.094	0.099
Purch Pwr Wrking Cap	¢ per kWh	0.052	0.053
Credit & Collections	¢ per kWh	0.022	0.023
Uncollectibles	¢ per kWh	Variable	Variable
Reactive Power Demand Charge (if applicable)			
	per KVAr	$0.85	$0.85
Plus:			Plus:
Energy Cost Adjustment			Please refer to Present Rates
System Benefits Charge			"
Renewable Portfolio Standard Charge			"
Transition Adjustment for Competitive Services			"
Revenue Decoupling Mechanism Adjustment			"
Increase in Rates and Charges			"
Market Supply Charge			"
Billing and Payment Processing Charge			"

Definition of Rating Periods:

Period I -	1:00 p.m. to 7:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.
Period II -	10:00 a.m. to 9:00 p.m. prevailing time, Monday through Friday, except holidays, October through May.
Period III -	7:00 p.m. to 1:00 p.m. prevailing time, Monday through Friday, June through September; 9:00 p.m. to 10:00 a.m. prevailing time, Monday through Friday, October through May; all hours on Saturday, Sunday and holidays, all months.

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Rates in Brief - Rate Year 3

Service Classification No. 21

			Present Year-round	Proposed Year-round
Customer Charge:		per month	$103.00	$73.00
Delivery Charges:				
Demand Charge				
Period I	All kW @	per kW	$33.37	$35.56
Period II	All kW @	per kW	11.76	12.53
Period III	All kW @	per kW	No Charge	No Charge
Usage Charge				
Period I	All kWh @	¢ per kWh	1.553	1.553
Period II	All kWh @	¢ per kWh	1.553	1.553
Period III	All kWh @	¢ per kWh	0.136	0.136
Minimum Charge:			Sum of the Customer Charge and any applicable billing and payment processing charges.	Sum of the Customer Charge and any applicable billing and payment processing charges.

Standby Rates (Presently Listed in Tariff as SC No. 25 - Rate 2)

		Present	Proposed
Customer Charge:	per month	$60.00	$60.00
Delivery Charges:			
Contract Demand Charge	per kW	$9.71	$9.97
As Used Daily Demand Charge (S)	per kW	$0.7697	$0.7915
As Used Daily Demand Charge (W)	per kW	$0.5188	$0.5323

Orange and Rockland Utilities, Inc.
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Rates in Brief - Rate Year 3

Service Classification No. 21 (Continued)

Charges Applicable to Both Standard and Standby Service Rates

Merchant Function Charge			
Supply Related	¢ per kWh	0.048	0.050
Purch Pwr Wrking Cap	¢ per kWh	0.052	0.053
Credit & Collections	¢ per kWh	0.008	0.008
Uncollectibles	¢ per kWh	Variable	Variable
Reactive Power Demand Charge (if applicable)			
	per KVAr	$0.85	$0.85
Plus:			Plus:
Energy Cost Adjustment			Please refer to Present Rates
System Benefits Charge			"
Renewable Portfolio Standard Charge			"
Transition Adjustment for Competitive Services			"
Revenue Decoupling Mechanism Adjustment			"
Increase in Rates and Charges			"
Market Supply Charge			"
Billing and Payment Processing Charge			"

Definition of Rating Periods:

Period I -	1:00 p.m. to 7:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.
Period II -	10:00 a.m. to 9:00 p.m. prevailing time, Monday through Friday, except holidays, October through May.
Period III -	7:00 p.m. to 1:00 p.m. prevailing time, Monday through Friday, June through September; 9:00 p.m. to 10:00 a.m. prevailing time, Monday through Friday, October through May; all hours on Saturday, Sunday and holidays, all months.

Orange and Rockland Utilities, Inc.
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Rates in Brief - Rate Year 3

Service Classification No. 22

				Present Year-round	Proposed Year-round
Standard Rates					
Customer Charge:			per month	$500.00	$500.00
Delivery Charges:					
Primary:					
Demand Charge					
Period	A	All kW @	per kW	$19.12	$19.65
Period	B	All kW @	per kW	10.91	11.21
Period	C	All kW @	per kW	No Charge	No Charge
Usage Charge					
Period	A	All kWh @	¢ per kWh	0.710	0.710
Period	B	All kWh @	¢ per kWh	0.710	0.710
Period	C	All kWh @	¢ per kWh	0.126	0.126
Substation:					
Demand Charge					
Period	A	All kW @	per kW	$12.28	$12.62
Period	B	All kW @	per kW	6.77	6.96
Period	C	All kW @	per kW	No Charge	No Charge
Usage Charge					
Period	A	All kWh @	¢ per kWh	0.298	0.298
Period	B	All kWh @	¢ per kWh	0.298	0.298
Period	C	All kWh @	¢ per kWh	0.126	0.126
Transmission:					
Demand Charge					
Period	A	All kW @	per kW	$7.06	$7.25
Period	B	All kW @	per kW	6.17	6.34
Period	C	All kW @	per kW	No Charge	No Charge
Usage Charge					
Period	A	All kWh @	¢ per kWh	0.126	0.126
Period	B	All kWh @	¢ per kWh	0.126	0.126
Period	C	All kWh @	¢ per kWh	0.126	0.126
Minimum Charge				Sum of the Customer Charge, Min. Monthly Demand Charge, contract demand charge, the reactive power demand charge, and any applicable billing and payment processing charges.	Sum of the Customer Charge, Min. Monthly Demand Charge, contract demand charge, the reactive power demand charge, and any applicable billing and payment processing charges.
Min. Monthly Demand Charge				$51.18	$50.56
Contract Demand Charge			per kW of CD	$3.72	$3.68
Contract Demand Charge			per kW of CD	$6.11	$6.04

Orange and Rockland Utilities, Inc.
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Rates in Brief - Rate Year 3

Service Classification No. 22 (Continued)

		Present	Proposed
Standby Rates (Presently Listed in Tariff as SC No. 25 - Rate 4)			
Customer Charge:	per month	$500.00	$500.00
Delivery Charges:			
Primary:			
Contract Demand Charge	per kW	$6.05	$6.20
As Used Daily Demand Charge (S)	per kW	$0.6477	$0.6638
As Used Daily Demand Charge (W)	per kW	$0.4463	$0.4567
Substation:			
Contract Demand Charge	per kW	$3.38	$3.47
As Used Daily Demand Charge	per kW	$0.4246	$0.4355
As Used Daily Demand Charge (W)	per kW	$0.2801	$0.2873
Transmission:			
Contract Demand Charge	per kW	$1.41	$1.44
As Used Daily Demand Charge	per kW	$0.3359	$0.3447
As Used Daily Demand Charge (W)	per kW	$0.3044	$0.3127

Orange and Rockland Utilities, Inc.
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Rates in Brief - Rate Year 3

Service Classification No. 22 (Continued)

		Present Year-round	Proposed Year-round
Charges Applicable to Both Standard and Standby Service Rates			
Merchant Function Charge			
Supply Related	¢ per kWh	0.048	0.050
Purch Pwr Wrking Cap	¢ per kWh	0.052	0.053
Credit & Collections	¢ per kWh	0.008	0.008
Uncollectibles	¢ per kWh	Variable	Variable
Reactive Power Demand Charge (if applicable)			
	per KVAr	$0.85	$0.85
Plus:			Plus:
Energy Cost Adjustment			Please refer to Present Rates
System Benefits Charge			"
Renewable Portfolio Standard Charge			"
Transition Adjustment for Competitive Services			"
Revenue Decoupling Mechanism Adjustment			"
Increase in Rates and Charges			"
Market Supply Charge			"
Billing and Payment Processing Charge			"

Definition of Rating Periods:

Period A - 8:00 a.m. to 11:00 p.m. prevailing time, Monday through Friday, except holidays, June through September.

Period B - 8:00 a.m. to 11:00 p.m. prevailing time, Monday through Friday, except holidays, October through May.

Period C - 11:00 p.m. to 8:00 a.m. prevailing time, Monday through Friday, all hours on Saturday, Sunday and holidays, all months.

Orange and Rockland Utilities, Inc.
Case 21-E-0074

Rates in Brief - Rate Year 3

Rider J - Smart Home Rate

		Present	Proposed
Customer Charge:	per month	$21.50	$22.00
Rate I - Delivery Charges:			
Daily Demand Charges	per kW	$1.18	$1.24
Distribution Event Charge	per kW	$1.80	$1.89
Transmission Event Charge	per kW	$0.45	$0.47
Rate II - Delivery Charges:			
Subscribed Demand Chg	per kW	$19.64	$20.69
Distribution Event Charge	per kW	$20.43	$21.36
Transmission Event Charge	per kW	$5.11	$5.34
Merchant Function Charge			
Supply Related	¢ per kWh	0.176	0.190
Purch Pwr Wrking Cap	¢ per kWh	0.052	0.053
Credit & Collections	¢ per kWh	0.048	0.052
Uncollectibles	¢ per kWh	Variable	Variable
Plus:			Plus:
Energy Cost Adjustment			Please refer to Present Rates
System Benefits Charge			"
Renewable Portfolio Standard Charge			"
Transition Adjustment for Competitive Services			"
Revenue Decoupling Mechanism Adjustment			"
Increase in Rates and Charges			"
Market Supply Charges			"
Billing and Payment Processing Charge			"

* Plus any applicable billing and payment processing charges.

Orange and Rockland Utilities, Inc.
Case 21-G-0073

GAS REVENUE ALLOCATION AND RATE DESIGN

1. Revenue Allocation

Two adjustments were made to the incremental revenue requirement before allocating it among customer classes. The first adjustment to the incremental revenue requirement for each Rate Year ("RY")[1] is the subtraction of amounts included for New York State Gross Receipts and Franchise Tax surcharge revenues, Municipal Tax surcharge revenues and Metropolitan Transportation Authority Business Tax surcharge revenues. The second adjustment was made to offset the incremental credits that are projected to be paid to low income residential customers in each RY.[2]

For each RY, before the adjusted incremental revenue requirement was applied to each customer class, the RY delivery revenues for each class were realigned in a revenue neutral manner to reduce interclass deficiencies and surpluses as indicated by the embedded cost of service ("ECOS") study. In each RY, deficiency and surplus indications have been reduced by one-third. The RY delivery revenue increase was then allocated among the Service Classifications ("SC") in proportion to the relative contribution made by each SC's realigned RY delivery revenue to the total realigned RY delivery revenue. The delivery revenue changes by SC for each RY were mitigated in a manner such that each SC did not receive a revenue change that was no more than 1.2 times or less than 0.3 times the overall RY delivery revenue change.

[1] RY 1 is defined as the 12 months ending December 31, 2022, RY2 is defined as the 12 months ending December 31, 2023, and RY3 is defined as the 12 months ending December 31, 2024.
[2] This adjustment was $1,644,485 in RY1 with no incremental increases in RY2 and RY3.

2. **Rate Design**

The rate design process for each RY for firm rates consists of the following five steps:

- Determine revised competitive service charges and associated delivery revenue changes.
- Adjust class-specific delivery revenue increases to determine non-competitive delivery revenue increases.
- Determine first block charges and associated changes in delivery revenue.
- Implement intraclass rate structure changes.
- Adjust class-specific non-competitive delivery revenue increases for revenue changes associated with increases in first block charges; and apply non-competitive delivery revenue increases, adjusted for revenue changes associated with increases in first block charges, on a common percentage basis to the per-Ccf charges within each SC.

a. Revised Competitive Service Charges and Associated Delivery Revenue Changes

(i) The competitive delivery components include the billing and payment processing ("BPP") charge; the Merchant Function Charge ("MFC") fixed components, that is the MFC procurement and credit and collections components; and the purchase of receivables ("POR") credit and collections ("C&C") component. For each RY, revised revenue levels for the MFC fixed components and the POR C&C component were based on percentages of delivery revenue as determined in the ECOS study. Based on ECOS study indications, the BPP charge has been increased in RY1 from $1.30 to $1.50. The incremental revenue associated with the change in the BPP charge was based on the number of forecasted bills times the incremental BPP charge.

The revised competitive service charge revenue levels for each RY were compared with competitive service charge revenues determined based on competitive service charges for the previous RY to determine the change in competitive service revenues.

b. Determination of Class-Specific Non-Competitive Delivery Revenue Increases

For each RY, the revenue changes associated with the competitive service charges were used to adjust the class-specific delivery revenue increases to determine class-specific non-competitive delivery revenue increases.

c. Intraclass Rate Structure Changes

The following rate structure changes were made in a revenue neutral manner before applying the non-competitive delivery revenue increase within each of the affected SCs.

- For SC No. 1 and SC No. 6 1A, in each RY, the Company reduced the differential between the 2nd and 3rd rate block such that in Rate Year 3, the rates for the 2nd and 3rd block were set equal.
- For SC No. 2 and SC No. 6 IB, in each RY, the Company began a gradual process to flatten the block rates. The Company will file a proposal in its next base rate case to continue the flattening of the block rate structure for these classes.

d. Revised First Block Charges and Associated Delivery Revenue Changes

The following summarizes the first block charges in each RYU

SC	RY1	RY2	RY3
SC1 / SC6 1A	$20.00	$21.00	$22.00
SC2 / SC6 1B	31.00	32.00	33.00

e. Application of Delivery Revenue Increase Adjusted for Revenue Associated with First Block Charges Within Each Service Classification

For RY1, the remaining incremental revenue requirement in each class, after subtracting any revenue associated with changes in the first block charges as described above, was applied to all rate block charges, except the first block charges, on an equal percentage basis. The revenue impacts of the rate design changes on firm customers are summarized in Schedule 1 of this Appendix.

3. Unbundled Charges

a. Merchant Function Charge

For the term of the Gas Rate Plan, the Company will continue to implement the MFC, as set forth in the Company's gas tariff**.** The MFC fixed component monthly targets (commodity procurement and credit and collections) for RY1, RY2 and RY3 are set forth in Schedule 4 of this Appendix.

b. Transition Adjustment for Competitive Services

For the term of the Gas Rate Plan, the Company will continue to implement the Transition Adjustment for Competitive Services ("TACS"), as set forth in the Company's gas tariff, modified as follows.

The Company will no longer reconcile the difference between the POR C&C revenue target and the POR C&C actual revenue through the TACS mechanism and will instead do so through the POR Discount. The TACS section of the gas tariff will be amended to remove the POR C&C reconciliation commencing with the TACS that will become effective January 1, 2023, since the TACS effective January 1, 2022 will be reconciling the POR C&C revenue target and actual revenue for RY 3 of the current rate plan.

c. POR Discount

For the term of the Gas Rate Plan, the Company will continue to implement the POR discount, as set forth in the Company's gas tariff, modified as follows.

The Company will collect the difference between the POR C&C revenue target and actual revenue as a component of the POR discount (*i.e.*, on a percentage basis applicable to ESCOs rather than on a $/Ccf basis applicable to firm customers). The POR C&C reconciliation has been added as a component of the POR discount percentage commencing with the POR discount percentage effective January 1, 2023. The POR C&C component monthly targets for each RY are set forth in Schedule 4 of this Appendix.

d. BPP Charge

The Company's BPP charge will increase from $1.30 per bill to $1.50 per bill.

4. Distributed Generation Rates

The rates for service under Rider B (non-residential DG rate) and Rider C (residential DG rate) have been increased at the percentage increases in per Ccf delivery service revenues for the otherwise applicable service classification (i.e., SC No. 2 for Rider B and SC No. 1 for Rider C).

5. Additional Items for Collection through the Monthly Cost Adjustment

As set forth in Appendix 9, the Monthly Gas Adjustment ("MGA") will be amended to include recovery for the following items: (1) the NPA Adjustment Mechanism; (2) the Late Payment Charge Reconciliation; and (3) the COVID Uncollectible Expenses Variance.

These three items will become separate components of the MGA and collections or credits to firm customers through such mechanism will occur once results are known after the end of each RY. Recovery will be over a 12-month period. Recovery will be on a Ccf basis with a uniform factor developed, based on forecast Ccf over the respective recovery period, and applied to all deliveries on the bills of all customers served under SC Nos. 1, 2, and 6. Recoveries (eleven months actual, one month forecast) will be reconciled to allocable costs for each 12-month recovery period, with any over- or under-recoveries included in the development of the succeeding components of the MGA. Reconciliation amounts related to the one-month forecast will be included in the next subsequent rates determination.

6. Make Whole Provisions

If the Commission makes rates effective for RY1 after January 1, 2022, the Company will implement a make whole provision. Differences in non-competitive delivery service revenues that result from the extension of the Case 21-G-0073 suspension period plus interest at the Commission's Other Customer Capital Rate will be collected via the implementation of a Delivery Revenue Surcharge ("DRS").[3] The DRS will be in effect on the date rates become effective in this case through the remainder of RY1. The unit amount to be collected from customers will be shown by SC on the Statement of Delivery Revenue Surcharge. Any difference between amounts required to be collected and actual amounts collected will be charged or credited to customers in a subsequent DRS Statement that will become effective March 1, 2023.

[3] Competitive services' revenue differences associated with the extension of the Case 21-G-0073 suspension period will be reconciled and surcharged or recovered through the TACS.

6. Tariff Filing Dates

By January 1, 2022, 2023 and 2024, the Company will file tariff revisions implementing the rate changes for RY1, RY2, and RY3, respectively,[4] unless the Commission makes rates effective for RY1 after January 1, 2022 in this proceeding, at which time the Company will place RY1 rates into effect on another date subject to the make whole provisions described above.

[4] The tariff filings for RY2 and RY3 will be made at least 30 days prior to the effective date of new rates.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-G-0073

Appendix 18 - Gas Revenue Allocation and Rate Design

Index of Schedules

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-G-0073

Impact of Proposed Rate Change on Total Firm Revenue - Company Impact - No Temporary Credit
For the Rate Year Twelve Months Ending December 31, 2022 (1) (2)
(Based on Billed Sales and Revenues)

Based on Levelized Revenue Requirement

Service Classification	Type of Service	Total Sales (Mcf)	Customers	Revenue At Current Rates ($000's)	Revenue At Proposed Rates ($000's)	Change ($000's)	Percent Change
1 / 6 IA	Residential	14,696,813	128,632	$ 197,138.5	$ 200,855.7	$ 3,717.2	1.9%
1 / 6 1A	Non Residential	1,060,144	6,186	13,766.3	14,179.3	413.0	3.0%
2 / 6 IB	Commercial	4,419,648	5,865	42,992.9	43,238.8	245.9	0.6%
6 II	Large Commercial	1,226,494	96	11,205.4	11,251.1	45.7	0.4%
	Total Firm	21,403,099	140,779	$ 265,103.1	$ 269,524.9	$ 4,421.8	1.7%

1. For comparison purposes, an estimated cost of gas supply has been included in the SC No. 6 revenue. This is equivalent on a per unit basis, to the cost of gas supply included in SC No. 1 and 2 revenues.
2. Revenue at Current Rates excludes temporary credit revenues from Rate Year 3 of Case 18-G-0068.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-G-0073

Calculation of Incremental Revenue Requirement for Rate Year 1

Based on Levelized Revenue Requirement

a.	Incremental Revenue Requirement for the Rate Year Including Gross Receipts/MTA Taxes (1)	$4,421,433
b.	Less Gross Receipts/MTA Tax Included in Incremental Revenue Requirement (2)	$74,000
c.	Incremental Revenue Requirement for the Rate Year Excluding Gross Receipts/MTA Taxes (a - b)	$4,347,433
d.	Low Income Credits	$1,644,845
e.	Total Revenue Requirement + Low Income Credits (c + d)	$5,992,278
f.	Rate Year Bundled Delivery Revenues for the Rate Year for Firm Service Classification Nos. 1, 2, and 6	$160,901,233
g.	Rate Year Overall Percentage Increase in Delivery Revenues (e / f)	3.72420%
h.	RY Overall Percentage Increase in Del Revenues less Low Income Credits (c / f)	2.70193%

Note:

1. Twelve months ending December 31, 2022
2. GRT/MTA Gross Up Included in Rev Req = 1.68%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-G-0073

Allocation of Incremental Revenue Requirement Among Customer Classes for Rate Year 1

Based on Levelized Revenue Requirement

	(1)	(2)	(3)=(1)+(2)	(4)	(5)=(3)+(4)	(6)=(2)+(4)	(7)	(8)	(9)	(10)=(6)+(8)+(9)	(11)=(1)+(10)	(12)=(10)/(1)
Class	Rate Year Bundled Delivery Rev. ($)	(Surplus)/ Deficiency (a) ($)	Adjusted Rate Year Del Revenue ($)	Rate Increase 3.724% ($)	Adj Delivery Rev incl Rate Incr at Rate Yr Rate Level ($)	Rate Year Increase Incl. (Sur)/Def ($)	Rate Year % Increase	Mitigation Adj (b) ($)	Mitigation Increase ($)	Adj. Rate Year Incl. (Sur)/Def Incl. Mit. Adj./Dec. ($)	Adj RY Bundled Del Revenue At RY Level ($)	Adjusted Rate Year % Increase
SC Nos. 1 & 6 RS IA	135,235,720	1,497,652	136,733,372	5,092,224	141,825,596	6,589,876	4.87%	(546,137)	(338,205)	5,705,533	140,941,253	4.22%
SC Nos. 2 & 6 RS 1B & II	25,665,513	(1,497,652)	24,167,862	900,060	25,067,922	(597,592)	-2.33%	884,342	0	286,751	25,952,264	1.12%
Total	160,901,233	0	160,901,233	5,992,284	166,893,517	5,992,284		338,205	(338,205)	5,992,284	166,893,517	3.724%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-G-0073

Determination of Non-Competitive Delivery Revenue Increases for Rate Year 1

Based on Levelized Revenue Requirement

	(1)	(2)	(3)	(4)	(5)=(1)-(2)-(3)-(4)
		Incremental Competitve Svc Revenues			
Service Class	Adj Rate Year Incr. Incl (Surplus)/Deficiency Incl Mitigation Adj. Delivery Rev. (a)	MFC Fixed Component Related Revenue (b)	BPP Component Related Revenue (c)	POR Credit & Collections Related Revenue (d)	Non-Competitive Rate Year Delivery Revenue Increase
	($)	($)	($)	($)	($)
SC Nos. 1 & 6 RS IA	5,705,533	664,592	164,593	182,403	4,693,945
SC Nos. 2 & 6 RS 1B & II	286,751	54,236	7,601	29,818	195,095
Total	5,992,284	718,828	172,194	212,221	4,889,041

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-G-0073

**Monthly Billing Comparison
Reflecting Proposed Rate Change**

SC1 Residential and Space Heating

Based on Levelized Revenue Requirement for Rate Year 1

Monthly Use (ccf) Usage >	Usage ≤	Monthly Bill @ Present Rate	Monthly Bill @ Proposed Rate	Change Amount	Change Percent	% of Bills in this Usage Range
0	3	$22.65	$23.40	$0.75	3.3%	2.1%
3	5	24.99	25.80	0.81	3.2%	1.4%
5	10	30.83	31.79	0.97	3.1%	4.4%
10	30	54.18	55.78	1.60	2.9%	23.7%
30	50	77.53	79.76	2.23	2.9%	14.4%
50	70	100.36	103.37	3.01	3.0%	9.5%
70	90	123.19	126.99	3.80	3.1%	7.4%
90	110	146.02	150.61	4.59	3.1%	6.1%
110	130	168.85	174.23	5.38	3.2%	5.1%
130	150	191.67	197.84	6.17	3.2%	4.4%
150	170	214.50	221.46	6.96	3.2%	3.9%
170	190	237.33	245.08	7.74	3.3%	3.4%
190	210	260.16	268.69	8.53	3.3%	2.8%
210	230	282.99	292.31	9.32	3.3%	2.3%
230	250	305.82	315.93	10.11	3.3%	1.9%
250	270	328.65	339.54	10.90	3.3%	1.5%
270	290	351.48	363.16	11.69	3.3%	1.2%
290	310	374.30	386.78	12.48	3.3%	0.9%
310	330	397.14	410.40	13.26	3.3%	0.7%
330	350	419.96	434.01	14.05	3.3%	0.5%
350	370	442.79	457.63	14.84	3.4%	0.4%
370	390	465.62	481.25	15.63	3.4%	0.3%
390	410	488.45	504.86	16.42	3.4%	0.3%
410	430	511.28	528.48	17.20	3.4%	0.2%
430	450	534.11	552.10	17.99	3.4%	0.2%
450	470	556.93	575.71	18.78	3.4%	0.1%
470	490	579.76	599.33	19.57	3.4%	0.1%
490	510	602.59	622.95	20.36	3.4%	0.1%
510	530	625.42	646.57	21.15	3.4%	0.1%
530	550	648.25	670.18	21.93	3.4%	0.1%
550	570	671.08	693.80	22.72	3.4%	0.1%
570	590	693.91	717.42	23.51	3.4%	0.0%
590	600	705.32	729.23	23.91	3.4%	0.0%

* The bills for each range are calculated at the upper band (e.g., the impact shown for the 0 - 3 Ccf. band is based on the 3 Ccf)

** There are an additional 0.5% of bills with usage above 600 Ccf.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-G-0073

Impact of Proposed Rate Change on Total Firm Revenue - Company Impact
For the Rate Year Twelve Months Ending December 31, 2023 (1)
(Based on Billed Sales and Revenues)

Based on Levelized Revenue Requirement

Service Classification	Type of Service	Total Sales (Mcf)	Customers	Revenue At Current Rates ($000's)	Revenue At Proposed Rates ($000's)	Change ($000's)	Percent Change
1 / 6 IA	Residential	14,965,621	130,124	$ 199,341.3	$ 203,285.7	$ 3,944.4	2.0%
1 / 6 1A	Non Residential	1,123,696	6,259	14,573.5	14,842.8	269.2	1.8%
2 / 6 IB	Commercial	4,536,827	5,894	42,760.2	42,924.3	164.1	0.4%
6 II	Large Commercial	1,258,988	96	11,108.9	11,154.2	45.4	0.4%
	Total Firm	21,885,133	142,373	267,783.9	272,207.0	4,423.0	1.7%

1. For comparison purposes, an estimated cost of gas supply has been included in the SC No. 6 revenue. This is equivalent on a per unit basis, to the cost of gas supply included in SC No. 1 and 2 revenues.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-G-0073

Calculation of Incremental Revenue Requirement for Rate Year 2

a.	Incremental Revenue Requirement for the Rate Year Including Gross Receipts/MTA Taxes (1)	$4,421,433
b.	Less Gross Receipts/MTA Tax Included in Incremental Revenue Requirement (2)	$74,000
c.	Incremental Revenue Requirement for the Rate Year Excluding Gross Receipts/MTA Taxes (a - b)	$4,347,433
d.	Low Income Credits	$0
e.	Total Revenue Requirement + Low Income Credits (c + d)	$4,347,433
f.	Rate Year Bundled Delivery Revenues for the Rate Year for Firm Service Classification Nos. 1, 2, and 6	$169,190,608
g.	Rate Year Overall Percentage Increase in Delivery Revenues (e / f)	2.56955%
h.	RY Overall Percentage Increase in Del Revenues less Low Income Credits (c / f)	2.56955%

Note:

1. Twelve months ending December 31, 2023
2. GRT/MTA Gross Up Included in Rev Req = 1.68%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-G-0073

Allocation of Incremental Revenue Requirement Among Customer Classes for Rate Year 2

Based on Levelized Revenue Requirement

	(1)	(2)	(3)=(1)+(2)	(4)	(5)=(3)+(4)	(6)=(2)+(4)	(7)	(8)	(9)	(10)=(6)+(8)+(9)	(11)=(1)+(10)	(12)=(10)/(1)
Class	Rate Year Bundled Delivery Rev. ($)	(Surplus)/ Deficiency (a) ($)	Adjusted Rate Year Del Revenue ($)	Rate Increase 3.724% ($)	Adj Delivery Rev incl Rate Incr at Rate Yr Rate Level ($)	Rate Year Increase Incl. (Sur)/Def ($)	Rate Year % Increase	Mitigation Adj (b) ($)	Mitigation Increase ($)	Adj. Rate Year Incl. (Sur)/Def Incl. Mit. Adj./Dec. ($)	Adj RY Bundled Del Revenue At RY Level ($)	Adjusted Rate Year % Increase
SC Nos. 1 & 6 RS IA	142,697,958	1,497,652	144,195,609	3,705,178	147,900,787	5,202,830	3.65%	(802,795)	(256,821)	4,143,213	146,841,171	2.90%
SC Nos. 2 & 6 RS 1B & II	26,492,650	(1,497,652)	24,994,998	642,259	25,637,257	(855,393)	-3.23%	1,059,617	0	204,224	26,696,874	0.77%
Total	169,190,608	0	169,190,608	4,347,437	173,538,045	4,347,437		256,821	(256,821)	4,347,437	173,538,045	2.570%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-G-0073

Determination of Non-Competitive Delivery Revenue Increases for Rate Year 2

Based on Levelized Revenue Requirement

	(1)	(2)	(3)	(4)	(5)=(1)-(2)-(3)-(4)
		Incremental Competitve Svc Revenues			
Service Class	Adj Rate Year Incr. Incl (Surplus)/Deficiency Incl Mitigation Adj. Delivery Rev. (a) ($)	MFC Fixed Component Related Revenue (b) ($)	BPP Component Related Revenue (c) ($)	POR Credit & Collections Related Revenue (d) ($)	Non-Competitive Rate Year Delivery Revenue Increase ($)
SC Nos. 1 & 6 RS IA	4,143,213	42,426	0	18,100	4,082,687
SC Nos. 2 & 6 RS 1B & II	204,224	4,211	0	4,410	195,603
Total	4,347,437	46,638	0	22,510	4,278,289

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-G-0073

Monthly Billing Comparison
Reflecting Proposed Rate Change

SC1 Residential and Space Heating

Based on Levelized Revenue Requirement for Rate Year 2

Monthly Use (ccf) Usage >	Usage ≤	Monthly Bill @ Present Rate	Monthly Bill @ Proposed Rate	Change Amount	Change Percent	% of Bills in this Usage Range
0	3	$23.31	$24.33	$1.02	4.4%	2.1%
3	5	25.65	26.70	1.05	4.1%	1.4%
5	10	31.49	32.60	1.11	3.5%	4.4%
10	30	54.87	56.23	1.36	2.5%	23.7%
30	50	78.24	79.85	1.61	2.1%	14.4%
50	70	101.25	103.23	1.98	2.0%	9.5%
70	90	124.27	126.61	2.34	1.9%	7.4%
90	110	147.28	149.99	2.71	1.8%	6.1%
110	130	170.29	173.36	3.07	1.8%	5.1%
130	150	193.30	196.74	3.44	1.8%	4.4%
150	170	216.31	220.12	3.80	1.8%	3.9%
170	190	239.33	243.49	4.17	1.7%	3.4%
190	210	262.34	266.87	4.53	1.7%	2.8%
210	230	285.35	290.25	4.90	1.7%	2.3%
230	250	308.36	313.63	5.26	1.7%	1.9%
250	270	331.37	337.00	5.63	1.7%	1.5%
270	290	354.39	360.38	6.00	1.7%	1.2%
290	310	377.40	383.76	6.36	1.7%	0.9%
310	330	400.41	407.14	6.73	1.7%	0.7%
330	350	423.42	430.51	7.09	1.7%	0.5%
350	370	446.44	453.89	7.46	1.7%	0.4%
370	390	469.45	477.27	7.82	1.7%	0.3%
390	410	492.46	500.65	8.19	1.7%	0.3%
410	430	515.47	524.02	8.55	1.7%	0.2%
430	450	538.48	547.40	8.92	1.7%	0.2%
450	470	561.49	570.78	9.28	1.7%	0.1%
470	490	584.51	594.16	9.65	1.7%	0.1%
490	510	607.52	617.53	10.01	1.6%	0.1%
510	530	630.53	640.91	10.38	1.6%	0.1%
530	550	653.54	664.29	10.74	1.6%	0.1%
550	570	676.55	687.66	11.11	1.6%	0.1%
570	590	699.57	711.04	11.47	1.6%	0.0%
590	600	711.07	722.73	11.66	1.6%	0.0%

* The bills for each range are calculated at the upper band (e.g., the impact shown for the 0 - 3 Ccf. band is based on the 3 Ccf)

** There are an additional 0.5% of customers with usage above 600 Ccf.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-G-0073

Impact of Proposed Rate Change on Total Firm Revenue - Company Impact
For the Rate Year Twelve Months Ending December 31, 2024 (1) (2)
(Based on Billed Sales and Revenues)

Based on Levelized Revenue Requirement

Service Classification	Type of Service	Total Sales (Mcf)	Customers	Revenue At Current Rates ($000's)	Revenue At Proposed Rates ($000's)	Change ($000's)	Percent Change
1 / 6 IA	Residential	14,800,853	131,220	$ 201,600.5	$ 206,471.9	$ 4,871.4	2.4%
1 / 6 1A	Non Residential	1,145,353	6,318	15,108.0	15,474.2	366.2	2.4%
2 / 6 IB	Commercial	4,499,364	5,917	42,591.4	41,958.2	(633.2)	-1.5%
6 II	Large Commercial	1,249,094	97	11,063.7	10,884.9	(178.8)	-1.6%
	Total Firm	21,694,664	143,551	270,363.7	274,789.3	4,425.6	1.6%

1. For comparison purposes, an estimated cost of gas supply has been included in the SC No. 6 revenue. This is equivalent on a per unit basis, to the cost of gas supply included in SC No. 1 and 2 revenues.
2. Revenue at Proposed Rates reflects the RY3 temporary credit.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-G-0073

Calculation of Incremental Revenue Requirement for Rate Year 3

a.	Incremental Revenue Requirement for the Rate Year Including Gross Receipts/MTA Taxes	$9,082,133
b.	Less Gross Receipts/MTA Tax Included in Incremental Revenue Requirement (2)	$153,000
c.	Incremental Revenue Requirement for the Rate Year Excluding Gross Receipts/MTA Taxes (a - b)	$8,929,133
d.	Low Income Credits	$0
e.	Total Revenue Requirement + Low Income Credits (c + d)	$8,929,133
f.	Rate Year Bundled Delivery Revenues for the Rate Year for Firm Service Classification Nos. 1, 2, and 6	$172,545,997
g.	Rate Year Overall Percentage Increase in Delivery Revenues (e / f)	5.17493%
h.	RY Overall Percentage Increase in Del Revenues less Low Income Credits (c / f)	5.17493%

Note:

1. Twelve months ending December 31, 2024
2. GRT/MTA Gross Up Included in Rev Req = 1.68%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-G-0073

Allocation of Incremental Revenue Requirement Among Customer Classes for Rate Year 2

Based on Levelized Revenue Requirement

	(1)	(2)	(3)=(1)+(2)	(4)	(5)=(3)+(4)	(6)=(2)+(4)	(7)	(8)	(9)	(10)=(6)+(8)+(9)	(11)=(1)+(10)	(12)=(10)/(1)
	Rate Year Bundled Delivery Rev.	(Surplus)/ Deficiency (a)	Adjusted Rate Year Del Revenue	Rate Increase 3.724%	Adj Delivery Rev incl Rate Incr at Rate Yr Rate Level	Rate Year Increase Incl. (Sur)/Def	Rate Year % Increase	Mitigation Adj (b)	Mitigation Increase	Adj. Rate Year Incl. (Sur)/Def Incl. Mit. Adj./Dec.	Adj RY Bundled Del Revenue At RY Level	Adjusted Rate Year % Increase
Class	($)	($)	($)	($)	($)	($)		($)	($)	($)	($)	
SC Nos. 1 & 6 RS IA	146,042,555	1,497,652	147,540,207	7,635,102	155,175,309	9,132,754	6.25%	(63,628)	(551,452)	8,517,673	154,560,228	5.83%
SC Nos. 2 & 6 RS 1B & II	26,503,442	(1,497,652)	25,005,791	1,294,032	26,299,823	(203,620)	-0.77%	615,080	0	411,461	26,914,903	1.55%
Total	172,545,997	0	172,545,997	8,929,134	181,475,131	8,929,134		551,452	(551,452)	8,929,134	181,475,131	5.175%

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-G-0073

Determination of Non-Competitive Delivery Revenue Increases for Rate Year 3

Based on Levelized Revenue Requirement

	(1)	(2)	(3)	(4)	(5)=(1)-(2)-(3)-(4)
		Incremental Competitve Svc Revenues			
Service Class	Adj Rate Year Incr. Incl (Surplus)/Deficiency Incl Mitigation Adj. Delivery Rev. (a) ($)	MFC Fixed Component Related Revenue (b) ($)	BPP Component Related Revenue (c) ($)	POR Credit & Collections Related Revenue (d) ($)	Non-Competitive Rate Year Delivery Revenue Increase ($)
SC Nos. 1 & 6 RS IA	8,517,673	52,046	0	22,596	8,443,031
SC Nos. 2 & 6 RS 1B & II	411,461	2,953	0	4,439	404,069
Total	8,929,134	54,998	0	27,036	8,847,100

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-G-0073

Monthly Billing Comparison
Reflecting Proposed Rate Change

SC1 Residential and Space Heating

Based on Levelized Revenue Requirement for Rate Year 3

Monthly Use (ccf) Usage >	Usage ≤	Monthly Bill @ Present Rate	Monthly Bill @ Proposed Rate	Change Amount	Change Percent	% of Bills in this Usage Range
0	3	$24.33	$25.29	$0.96	3.9%	2.1%
3	5	26.70	27.69	0.99	3.7%	1.4%
5	10	32.60	33.67	1.07	3.3%	4.4%
10	30	56.23	57.62	1.39	2.5%	23.7%
30	50	79.85	81.56	1.71	2.1%	14.4%
50	70	103.23	105.51	2.28	2.2%	9.5%
70	90	126.61	129.46	2.85	2.2%	7.4%
90	110	149.99	153.40	3.42	2.3%	6.1%
110	130	173.36	177.35	3.99	2.3%	5.1%
130	150	196.74	201.30	4.56	2.3%	4.4%
150	170	220.12	225.24	5.12	2.3%	3.9%
170	190	243.49	249.19	5.69	2.3%	3.4%
190	210	266.87	273.14	6.26	2.3%	2.8%
210	230	290.25	297.08	6.83	2.4%	2.3%
230	250	313.63	321.03	7.40	2.4%	1.9%
250	270	337.00	344.97	7.97	2.4%	1.5%
270	290	360.38	368.92	8.54	2.4%	1.2%
290	310	383.76	392.87	9.11	2.4%	0.9%
310	330	407.14	416.81	9.68	2.4%	0.7%
330	350	430.51	440.76	10.25	2.4%	0.5%
350	370	453.89	464.71	10.81	2.4%	0.4%
370	390	477.27	488.65	11.38	2.4%	0.3%
390	410	500.65	512.60	11.95	2.4%	0.3%
410	430	524.02	536.54	12.52	2.4%	0.2%
430	450	547.40	560.49	13.09	2.4%	0.2%
450	470	570.78	584.44	13.66	2.4%	0.1%
470	490	594.16	608.38	14.23	2.4%	0.1%
490	510	617.53	632.33	14.80	2.4%	0.1%
510	530	640.91	656.28	15.37	2.4%	0.1%
530	550	664.29	680.22	15.94	2.4%	0.1%
550	570	687.66	704.17	16.50	2.4%	0.1%
570	590	711.04	728.11	17.07	2.4%	0.0%
590	600	722.73	740.09	17.36	2.4%	0.0%

* The bills for each range are calculated at the upper band (e.g., the impact shown for the 0 - 3 Ccf. band is based on the 3 Ccf)

** There are an additional 0.5% of customers with usage above 600 Ccf.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-G-0073

**Temporary Credit to be Refunded through
Monthly Gas Adjustment in Rate Year 3**

Temp Surcharge/(Credit)	($4,660,700)	
Less GRT/MTA Tax	($78,464)	
Net	($4,582,236)	
Rate Year Sales (CCF)	216,946,641	
MGA Surcharge	($0.02112)	per CCF

ORANGE & ROCKLAND UTILITIES, INC.

Case 21-G-0073

Summary of MFC Monthly Targets
For Rates Effective January 1, 2022, January 1, 2023 and January 1, 2024

Based on Levelized Revenue Requirement

For Rates Effective January 1, 2022	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Supply Related Component	$190,627	$192,743	$171,819	$124,995	$72,805	$46,458	$34,259	$28,849	$31,384	$40,288	$79,549	$152,020	$1,165,796
Credit and Collections Related Component	57,947	58,606	52,208	38,012	22,211	14,136	10,347	8,738	9,508	12,225	24,158	46,185	354,282
POR Discount Related Component	32,108	32,778	29,468	21,110	13,098	8,096	5,910	5,299	5,574	7,260	13,987	25,560	200,248
Total	$280,682	$284,127	$253,495	$184,117	$108,115	$68,691	$50,515	$42,886	$46,466	$59,773	$117,694	$223,765	$1,720,326

For Rates Effective January 1, 2023	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Supply Related Component	$186,496	$200,414	$185,810	$134,427	$76,513	$49,235	$34,928	$29,491	$32,054	$40,884	$83,759	$158,200	$1,212,210
Credit and Collections Related Component	56,725	60,964	56,475	40,894	23,349	14,989	10,555	8,937	9,717	12,410	25,443	48,079	368,536
POR Discount Related Component	31,523	34,106	31,821	22,630	13,712	8,558	6,016	5,409	5,678	7,379	14,667	26,573	208,072
Total	$274,744	$295,484	$274,106	$197,951	$113,574	$72,781	$51,498	$43,836	$47,448	$60,673	$123,870	$232,851	$1,788,818

For Rates Effective January 1, 2024	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Supply Related Component	$201,960	$210,911	$192,090	$142,868	$80,847	$51,372	$37,144	$31,226	$33,899	$40,515	$83,482	$161,339	$1,267,652
Credit and Collections Related Component	61,454	64,190	58,414	43,485	24,688	15,650	11,231	9,469	10,282	12,301	25,373	49,058	385,595
POR Discount Related Component	34,064	35,868	32,891	24,004	14,470	8,926	6,361	5,684	5,958	7,319	14,723	27,118	217,385
Total	$297,477	$310,968	$283,396	$210,356	$120,005	$75,948	$54,736	$46,379	$50,138	$60,135	$123,578	$237,516	$1,870,632

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-G-0073

Present and Proposed Rates in Brief - Rate Year 1

Based on Levelized Revenue Requirement

Present S.C. No. 1 (Monthly)
(Residential and Space Heating)

Delivery Charges:

Delivery:

First	3	Ccf or less	$19.50	
Next	47	Ccf	68.220	¢/Ccf
All over	50	Ccf	65.661	¢/Ccf

Other Charges:

Merchant Function Charge:

Fixed Procurement	0.439	¢/Ccf
Credit and Collections	0.114	¢/Ccf
Storage WC (supply related)	0.069	¢/Ccf
Uncollectibles	Variable	

Plus: Gas Supply Charge
Plus: Monthly Gas Adjustment
Plus: RDM Adjustment
Plus: System Benefits Charge
Plus: Unauthorized Use of Gas
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge

Minimum Charge* - $19.50 per month

Proposed S.C. No. 1 (Monthly)
(Residential and Space Heating)

Delivery Charges:

Delivery:

First	3	Ccf or less	$20.00	
Next	47	Ccf	70.264	¢/Ccf
All over	50	Ccf	68.485	¢/Ccf

Other Charges:

Merchant Function Charge:

Fixed Procurement	0.974	¢/Ccf
Credit and Collections	0.299	¢/Ccf
Storage WC (supply related)	0.069	¢/Ccf
Uncollectibles	Variable	

Plus: Gas Supply Charge
Plus: Monthly Gas Adjustment
Plus: RDM Adjustment
Plus: System Benefits Charge
Plus: Unauthorized Use of Gas
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge

Minimum Charge* - $20.00 per month

Present S.C. No. 2 (Monthly)
(General Service)

Delivery Charges:

First	3	Ccf or less	$30.00	
Next	47	Ccf	44.645	¢/Ccf
Next	4,950	Ccf	42.866	¢/Ccf
All over	5,000	Ccf	37.906	¢/Ccf

Other Charges:

Merchant Function Charge:

Fixed Procurement	0.156	¢/Ccf
Credit and Collections	0.036	¢/Ccf
Storage WC (supply related)	0.069	¢/Ccf
Uncollectibles	Variable	

Plus: Gas Supply Charge
Plus: Monthly Gas Adjustment
Plus: RDM Adjustment
Plus: System Benefits Charge
Plus: Unauthorized Use of Gas
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge

Minimum Charge* - $30.00 per month

Proposed S.C. No. 2 (Monthly)
(General Service)

Delivery Charges:

Delivery:

First	3	Ccf or less	$31.00	
Next	47	Ccf	44.643	¢/Ccf
Next	4,950	Ccf	43.041	¢/Ccf
All over	5,000	Ccf	38.253	¢/Ccf

Other Charges:

Merchant Function Charge:

Fixed Procurement	0.430	¢/Ccf
Credit and Collections	0.113	¢/Ccf
Storage WC (supply related)	0.069	¢/Ccf
Uncollectibles	Variable	

Plus: Gas Supply Charge
Plus: Monthly Gas Adjustment
Plus: RDM Adjustment
Plus: System Benefits Charge
Plus: Unauthorized Use of Gas
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge

Minimum Charge* - $31.00 per month

* Minimum charge set at the first block charge.

ORANGE AND ROCKLAND UTILITIES, INC.
Case 21-G-0073
Present and Proposed Rates in Brief - Rate Year 1

Based on Levelized Revenue Requirement

Present S.C. No. 6 (Monthly)
(Firm Transportation Service)

Rate Schedule IA - Residential:

Delivery Charges:

First	3	Ccf or less	$19.50	
Next	47	Ccf	68.220	¢/Ccf
All over	50	Ccf	65.661	¢/Ccf

Other Charges:

Plus: Monthly Gas Adjustment
Plus: RDM Adjustment
Plus: System Benefits Charge
Plus: Winter Bundled Sales Service
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge*

Rate Schedule IB - Non-Residential:

Delivery Charges:

First	3	Ccf or less	$30.00	
Next	47	Ccf	44.645	¢/Ccf
Next	4,950	Ccf	42.866	¢/Ccf
All over	5,000	Ccf	37.906	¢/Ccf

Other Charges:

Plus: Monthly Gas Adjustment
Plus: RDM Adjustment
Plus: System Benefits Charge
Plus: Winter Bundled Sales Service
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge*

Rate Schedule II:

Delivery Charges:

First	100	Ccf or less	$255.18	
Over	100	Ccf	37.906	¢/Ccf

Other Charges:

Plus: Monthly Gas Adjustment
Plus: RDM Adjustment
Plus: System Benefits Charge
Plus: Winter Bundled Sales Service
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge*

Proposed S.C. No. 6 (Monthly)
(Firm Transportation Service)

Rate Schedule IA - Residential:

Delivery Charges:

Delivery:

First	3	Ccf or less	$20.00	
Next	47	Ccf	70.264	¢/Ccf
All over	50	Ccf	68.485	¢/Ccf

Other Charges:

Plus: Monthly Gas Adjustment
Plus: RDM Adjustment
Plus: System Benefits Charge
Plus: Winter Bundled Sales Service
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge*

Rate Schedule IB - Non-Residential:

Delivery Charges:

Delivery:

First	3	Ccf or less	$31.00	
Next	47	Ccf	44.643	¢/Ccf
Next	4,950	Ccf	43.041	¢/Ccf
All over	5,000	Ccf	38.253	¢/Ccf

Other Charges:

Plus: Monthly Gas Adjustment
Plus: RDM Adjustment
Plus: System Benefits Charge
Plus: Winter Bundled Sales Service
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge*

Rate Schedule II:

Delivery Charges:

Delivery:

First	100	Ccf or less	$255.18	
Over	100	Ccf	38.253	¢/Ccf

Other Charges:

Plus: Monthly Gas Adjustment
Plus: RDM Adjustment
Plus: System Benefits Charge
Plus: Winter Bundled Sales Service
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge*

* Assessed on customers receiving a utility single bill

ORANGE AND ROCKLAND UTILITIES, INC.
Case 21-G-0073
Present and Proposed Rates in Brief - Rate Year 1

Based on Levelized Revenue Requirement

Present Rider B - Rate Schedule I Rate IA

Delivery Charges (Summer):

First	3 Ccf or less	$153.51	
All over	3 Ccf	23.712	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$153.51	
All over	3 Ccf	29.435	¢/Ccf

Minimum Charge - $153.51 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Proposed Rider B - Rate Schedule I Rate IA

Delivery Charges (Summer):

First	3 Ccf or less	$155.23	
All over	3 Ccf	23.840	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$155.23	
All over	3 Ccf	29.593	¢/Ccf

Minimum Charge - $155.23 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Present Rider B - Rate Schedule I Rate IB

Delivery Charges (Summer):

First	3 Ccf or less	$260.68	
All over	3 Ccf	23.712	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$260.68	
All over	3 Ccf	29.435	¢/Ccf

Minimum Charge - $260.68 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Proposed Rider B - Rate Schedule I Rate IB

Delivery Charges (Summer):

First	3 Ccf or less	$263.59	
All over	3 Ccf	23.812	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$263.59	
All over	3 Ccf	29.593	¢/Ccf

Minimum Charge - $263.59 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Present Rider B - Rate Schedule I Rate IC

Delivery Charges (Summer):

First	3 Ccf or less	$396.82	
All over	3 Ccf	23.712	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$396.82	
All over	3 Ccf	29.435	¢/Ccf

Minimum Charge - $396.82 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

* Excluding the RDM Adjustment

Proposed Rider B - Rate Schedule I Rate IC

Delivery Charges (Summer):

First	3 Ccf or less	$401.25	
All over	3 Ccf	23.840	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$401.25	
All over	3 Ccf	29.593	¢/Ccf

Minimum Charge - $401.25 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

* Excluding the RDM Adjustment

ORANGE AND ROCKLAND UTILITIES, INC.
Case 21-G-0073
Present and Proposed Rates in Brief - Rate Year 1

Based on Levelized Revenue Requirement

Present Rider B - Rate Schedule I Rate ID

Delivery Charges (Summer):

First	3 Ccf or less	$503.99	
All over	3 Ccf	23.712	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$503.99	
All over	3 Ccf	29.435	¢/Ccf

Minimum Charge - $503.99 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Proposed Rider B - Rate Schedule I Rate ID

Delivery Charges (Summer):

First	3 Ccf or less	$509.62	
All over	3 Ccf	23.840	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$509.62	
All over	3 Ccf	29.593	¢/Ccf

Minimum Charge - $509.62 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Present Rider B - Rate Schedule II

Delivery Charges (Summer):

First	3 Ccf or less	$57.93	
All over	3 Ccf	4.742	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$57.93	
All over	3 Ccf	5.888	¢/Ccf

Contract Demand - $41.93 per Ccf of Contract Demand

Minimum Charge - $57.93 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Proposed Rider B - Rate Schedule II

Delivery Charges (Summer):

First	3 Ccf or less	$58.58	
All over	3 Ccf	4.767	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$58.58	
All over	3 Ccf	5.920	¢/Ccf

Contract Demand - $42.16 per Ccf of Contract Demand

Minimum Charge - $58.58 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Present Rider C

Delivery Charges:

First	3 Ccf or less	$37.07	
All over	3 Ccf	24.088	¢/Ccf

Minimum Charge - $37.07 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Proposed Rider C

Delivery Charges:

First	3 Ccf or less	$38.63	
All over	3 Ccf	25.007	¢/Ccf

Minimum Charge - $38.63 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

* Excluding the RDM Adjustment

* Excluding the RDM Adjustment

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-G-0073
Present and Proposed Rates in Brief - Rate Year 2

Based on Levelized Revenue Requirement

Present S.C. No. 1 (Monthly)
(Residential and Space Heating)

Delivery Charges:

Delivery:

First	3	Ccf or less	$20.00	
Next	47	Ccf	70.264	¢/Ccf
All over	50	Ccf	68.485	¢/Ccf

Other Charges:

Merchant Function Charge:

Fixed Procurement	0.974	¢/Ccf
Credit and Collections	0.299	¢/Ccf
Storage WC (supply related)	0.069	¢/Ccf
Uncollectibles	Variable	

Plus: Gas Supply Charge
Plus: Monthly Gas Adjustment
Plus: RDM Adjustment
Plus: System Benefits Charge
Plus: Unauthorized Use of Gas
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge

Minimum Charge* - $20.00 per month

Proposed S.C. No. 1 (Monthly)
(Residential and Space Heating)

Delivery Charges:

Delivery:

First	3	Ccf or less	$21.00	
Next	47	Ccf	71.471	¢/Ccf
All over	50	Ccf	70.251	¢/Ccf

Other Charges:

Merchant Function Charge:

Fixed Procurement	0.991	¢/Ccf
Credit and Collections	0.304	¢/Ccf
Storage WC (supply related)	0.069	¢/Ccf
Uncollectibles	Variable	

Plus: Gas Supply Charge
Plus: Monthly Gas Adjustment
Plus: RDM Adjustment
Plus: System Benefits Charge
Plus: Unauthorized Use of Gas
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge

Minimum Charge* - $21.00 per month

Present S.C. No. 2 (Monthly)
(General Service)

Delivery Charges:

First	3	Ccf or less	$31.00	
Next	47	Ccf	44.643	¢/Ccf
Next	4,950	Ccf	43.041	¢/Ccf
All over	5,000	Ccf	38.253	¢/Ccf

Other Charges:

Merchant Function Charge:

Fixed Procurement	0.430	¢/Ccf
Credit and Collections	0.113	¢/Ccf
Storage WC (supply related)	0.069	¢/Ccf
Uncollectibles	Variable	

Plus: Gas Supply Charge
Plus: Monthly Gas Adjustment
Plus: RDM Adjustment
Plus: System Benefits Charge
Plus: Unauthorized Use of Gas
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge

Minimum Charge* - $31.00 per month

Proposed S.C. No. 2 (Monthly)
(General Service)

Delivery Charges:

Delivery:

First	3	Ccf or less	$32.00	
Next	47	Ccf	44.633	¢/Ccf
Next	4,950	Ccf	43.210	¢/Ccf
All over	5,000	Ccf	38.606	¢/Ccf

Other Charges:

Merchant Function Charge:

Fixed Procurement	0.435	¢/Ccf
Credit and Collections	0.114	¢/Ccf
Storage WC (supply related)	0.069	¢/Ccf
Uncollectibles	Variable	

Plus: Gas Supply Charge
Plus: Monthly Gas Adjustment
Plus: RDM Adjustment
Plus: System Benefits Charge
Plus: Unauthorized Use of Gas
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge

Minimum Charge* - $32.00 per month

* Minimum charge set at the first block charge.

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-G-0073

Present and Proposed Rates in Brief - Rate Year 2

Based on Levelized Revenue Requirement

Present S.C. No. 6 (Monthly) (Firm Transportation Service)

Rate Schedule IA - Residential:

Delivery Charges:

First	3	Ccf or less	$20.00	
Next	47	Ccf	70.264	¢/Ccf
All over	50	Ccf	68.485	¢/Ccf

Other Charges:

Plus: Monthly Gas Adjustment
Plus: RDM Adjustment
Plus: System Benefits Charge
Plus: Winter Bundled Sales Service
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge*

Rate Schedule IB - Non-Residential:

Delivery Charges:

First	3	Ccf or less	$31.00	
Next	47	Ccf	44.643	¢/Ccf
Next	4,950	Ccf	43.041	¢/Ccf
All over	5,000	Ccf	38.253	¢/Ccf

Other Charges:

Plus: Monthly Gas Adjustment
Plus: RDM Adjustment
Plus: System Benefits Charge
Plus: Winter Bundled Sales Service
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge*

Rate Schedule II:

Delivery Charges:

First	100	Ccf or less	$255.18	
Over	100	Ccf	38.253	¢/Ccf

Other Charges:

Plus: Monthly Gas Adjustment
Plus: RDM Adjustment
Plus: System Benefits Charge
Plus: Winter Bundled Sales Service
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge*

Proposed S.C. No. 6 (Monthly) (Firm Transportation Service)

Rate Schedule IA - Residential:

Delivery Charges:

Delivery:

First	3	Ccf or less	$21.00	
Next	47	Ccf	71.471	¢/Ccf
All over	50	Ccf	70.251	¢/Ccf

Other Charges:

Plus: Monthly Gas Adjustment
Plus: RDM Adjustment
Plus: System Benefits Charge
Plus: Winter Bundled Sales Service
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge*

Rate Schedule IB - Non-Residential:

Delivery Charges:

Delivery:

First	3	Ccf or less	$32.00	
Next	47	Ccf	44.633	¢/Ccf
Next	4,950	Ccf	43.210	¢/Ccf
All over	5,000	Ccf	38.606	¢/Ccf

Other Charges:

Plus: Monthly Gas Adjustment
Plus: RDM Adjustment
Plus: System Benefits Charge
Plus: Winter Bundled Sales Service
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge*

Rate Schedule II:

Delivery Charges:

Delivery:

First	100	Ccf or less	$255.18	
Over	100	Ccf	38.606	¢/Ccf

Other Charges:

Plus: Monthly Gas Adjustment
Plus: RDM Adjustment
Plus: System Benefits Charge
Plus: Winter Bundled Sales Service
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge*

* Assessed on customers receiving a utility single bill

ORANGE AND ROCKLAND UTILITIES, INC.
Case 21-G-0073
Present and Proposed Rates in Brief - Rate Year 2

Based on Levelized Revenue Requirement

Present Rider B - Rate Schedule I Rate IA

Delivery Charges (Summer):

First	3 Ccf or less	$155.23	
All over	3 Ccf	23.840	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$155.23	
All over	3 Ccf	29.593	¢/Ccf

Minimum Charge - $155.23 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Present Rider B - Rate Schedule I Rate IB

Delivery Charges (Summer):

First	3 Ccf or less	$263.59	
All over	3 Ccf	23.812	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$263.59	
All over	3 Ccf	29.593	¢/Ccf

Minimum Charge - $263.59 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Present Rider B - Rate Schedule I Rate IC

Delivery Charges (Summer):

First	3 Ccf or less	$401.25	
All over	3 Ccf	23.840	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$401.25	
All over	3 Ccf	29.593	¢/Ccf

Minimum Charge - $401.25 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

* Excluding the RDM Adjustment

Proposed Rider B - Rate Schedule I Rate IA

Delivery Charges (Summer):

First	3 Ccf or less	$156.43	
All over	3 Ccf	23.964	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$156.43	
All over	3 Ccf	29.748	¢/Ccf

Minimum Charge - $156.43 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Proposed Rider B - Rate Schedule I Rate IB

Delivery Charges (Summer):

First	3 Ccf or less	$265.62	
All over	3 Ccf	23.912	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$265.62	
All over	3 Ccf	29.748	¢/Ccf

Minimum Charge - $265.62 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Proposed Rider B - Rate Schedule I Rate IC

Delivery Charges (Summer):

First	3 Ccf or less	$404.34	
All over	3 Ccf	23.964	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$404.34	
All over	3 Ccf	29.748	¢/Ccf

Minimum Charge - $404.34 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

* Excluding the RDM Adjustment

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-G-0073
Present and Proposed Rates in Brief - Rate Year 2

Based on Levelized Revenue Requirement

Present Rider B - Rate Schedule I Rate ID

Delivery Charges (Summer):

First	3 Ccf or less	$509.62	
All over	3 Ccf	23.840	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$509.62	
All over	3 Ccf	29.593	¢/Ccf

Minimum Charge - $509.62 per month

Other Charges:

Rates and other provisions of the customer’s otherwise applicable service classification*

Proposed Rider B - Rate Schedule I Rate ID

Delivery Charges (Summer):

First	3 Ccf or less	$513.55	
All over	3 Ccf	23.964	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$513.55	
All over	3 Ccf	29.748	¢/Ccf

Minimum Charge - $513.55 per month

Other Charges:

Rates and other provisions of the customer’s otherwise applicable service classification*

Present Rider B - Rate Schedule II

Delivery Charges (Summer):

First	3 Ccf or less	$58.58	
All over	3 Ccf	4.767	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$58.58	
All over	3 Ccf	5.920	¢/Ccf

Contract Demand - $42.16 per Ccf of Contract Demand

Minimum Charge - $58.58 per month

Other Charges:

Rates and other provisions of the customer’s otherwise applicable service classification*

Proposed Rider B - Rate Schedule II

Delivery Charges (Summer):

First	3 Ccf or less	$59.03	
All over	3 Ccf	4.792	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$59.03	
All over	3 Ccf	5.951	¢/Ccf

Contract Demand - $42.38 per Ccf of Contract Demand

Minimum Charge - $59.03 per month

Other Charges:

Rates and other provisions of the customer’s otherwise applicable service classification*

Present Rider C

Delivery Charges:

First	3 Ccf or less	$38.63	
All over	3 Ccf	25.007	¢/Ccf

Minimum Charge - $38.63 per month

Other Charges:

Rates and other provisions of the customer’s otherwise applicable service classification*

Proposed Rider C

Delivery Charges:

First	3 Ccf or less	$39.75	
All over	3 Ccf	25.573	¢/Ccf

Minimum Charge - $39.75 per month

Other Charges:

Rates and other provisions of the customer’s otherwise applicable service classification*

* Excluding the RDM Adjustment

* Excluding the RDM Adjustment

ORANGE AND ROCKLAND UTILITIES, INC.

Case 21-G-0073
Present and Proposed Rates in Brief - Rate Year 3

Based on Levelized Revenue Requirement

Present S.C. No. 1 (Monthly) (Residential and Space Heating)

Delivery Charges:

Delivery:

First	3	Ccf or less	$21.00	
Next	47	Ccf	71.471	¢/Ccf
All over	50	Ccf	70.251	¢/Ccf

Other Charges:

Merchant Function Charge:

Fixed Procurement	0.991	¢/Ccf
Credit and Collections	0.304	¢/Ccf
Storage WC (supply related)	0.069	¢/Ccf
Uncollectibles	Variable	

Plus: Gas Supply Charge
Plus: Monthly Gas Adjustment
Plus: RDM Adjustment
Plus: System Benefits Charge
Plus: Unauthorized Use of Gas
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge

Minimum Charge* - $21.00 per month

Proposed S.C. No. 1 (Monthly) (Residential and Space Heating)

Delivery Charges:

Delivery:

First	3	Ccf or less	$22.00	
All over	3	Ccf	75.079	¢/Ccf

Other Charges:

Merchant Function Charge:

Fixed Procurement	1.044	¢/Ccf
Credit and Collections	0.321	¢/Ccf
Storage WC (supply related)	0.069	¢/Ccf
Uncollectibles	Variable	

Plus: Gas Supply Charge
Plus: Monthly Gas Adjustment
Plus: RDM Adjustment
Plus: System Benefits Charge
Plus: Unauthorized Use of Gas
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge

Minimum Charge* - $22.00 per month

Present S.C. No. 2 (Monthly) (General Service)

Delivery Charges:

First	3	Ccf or less	$32.00	
Next	47	Ccf	44.633	¢/Ccf
Next	4,950	Ccf	43.210	¢/Ccf
All over	5,000	Ccf	38.606	¢/Ccf

Other Charges:

Merchant Function Charge:

Fixed Procurement	0.435	¢/Ccf
Credit and Collections	0.114	¢/Ccf
Storage WC (supply related)	0.069	¢/Ccf
Uncollectibles	Variable	

Plus: Gas Supply Charge
Plus: Monthly Gas Adjustment
Plus: RDM Adjustment
Plus: System Benefits Charge
Plus: Unauthorized Use of Gas
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge

Minimum Charge* - $32.00 per month

Proposed S.C. No. 2 (Monthly) (General Service)

Delivery Charges:

Delivery:

First	3	Ccf or less	$33.00	
Next	47	Ccf	45.014	¢/Ccf
Next	4,950	Ccf	43.757	¢/Ccf
All over	5,000	Ccf	39.314	¢/Ccf

Other Charges:

Merchant Function Charge:

Fixed Procurement	0.460	¢/Ccf
Credit and Collections	0.121	¢/Ccf
Storage WC (supply related)	0.069	¢/Ccf
Uncollectibles	Variable	

Plus: Gas Supply Charge
Plus: Monthly Gas Adjustment
Plus: RDM Adjustment
Plus: System Benefits Charge
Plus: Unauthorized Use of Gas
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge

Minimum Charge* - $33.00 per month

* Minimum charge set at the first block charge.

ORANGE AND ROCKLAND UTILITIES, INC.
Case 21-G-0073
Present and Proposed Rates in Brief - Rate Year 3

Based on Levelized Revenue Requirement

Present S.C. No. 6 (Monthly)
(Firm Transportation Service)

Rate Schedule IA - Residential:

Delivery Charges:

First	3	Ccf or less	$21.00	
Next	47	Ccf	71.471	¢/Ccf
All over	50	Ccf	70.251	¢/Ccf

Other Charges:

Plus: Monthly Gas Adjustment
Plus: RDM Adjustment
Plus: System Benefits Charge
Plus: Winter Bundled Sales Service
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge*

Rate Schedule IB - Non-Residential:

Delivery Charges:

First	3	Ccf or less	$32.00	
Next	47	Ccf	44.633	¢/Ccf
Next	4,950	Ccf	43.210	¢/Ccf
All over	5,000	Ccf	38.606	¢/Ccf

Other Charges:

Plus: Monthly Gas Adjustment
Plus: RDM Adjustment
Plus: System Benefits Charge
Plus: Winter Bundled Sales Service
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge*

Rate Schedule II:

Delivery Charges:

First	100	Ccf or less	$255.18	
Over	100	Ccf	38.606	¢/Ccf

Other Charges:

Plus: Monthly Gas Adjustment
Plus: RDM Adjustment
Plus: System Benefits Charge
Plus: Winter Bundled Sales Service
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge*

Proposed S.C. No. 6 (Monthly)
(Firm Transportation Service)

Rate Schedule IA - Residential:

Delivery Charges:

Delivery:

First	3	Ccf or less	$22.00	
All over	3	Ccf	75.079	¢/Ccf

Other Charges:

Plus: Monthly Gas Adjustment
Plus: RDM Adjustment
Plus: System Benefits Charge
Plus: Winter Bundled Sales Service
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge*

Rate Schedule IB - Non-Residential:

Delivery Charges:

Delivery:

First	3	Ccf or less	$33.00	
Next	47	Ccf	45.014	¢/Ccf
Next	4,950	Ccf	43.757	¢/Ccf
All over	5,000	Ccf	39.314	¢/Ccf

Other Charges:

Plus: Monthly Gas Adjustment
Plus: RDM Adjustment
Plus: System Benefits Charge
Plus: Winter Bundled Sales Service
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge*

Rate Schedule II:

Delivery Charges:

Delivery:

First	100	Ccf or less	$255.18	
Over	100	Ccf	39.314	¢/Ccf

Other Charges:

Plus: Monthly Gas Adjustment
Plus: RDM Adjustment
Plus: System Benefits Charge
Plus: Winter Bundled Sales Service
Plus: Increase in Rates and Charges
Plus: Billing and Payment Processing Charge*

* Assessed on customers receiving a utility single bill

ORANGE AND ROCKLAND UTILITIES, INC.
Case 21-G-0073
Present and Proposed Rates in Brief - Rate Year 3

Based on Levelized Revenue Requirement

Present Rider B - Rate Schedule I Rate IA

Delivery Charges (Summer):

First	3 Ccf or less	$156.43	
All over	3 Ccf	23.964	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$156.43	
All over	3 Ccf	29.748	¢/Ccf

Minimum Charge - $156.43 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Present Rider B - Rate Schedule I Rate IB

Delivery Charges (Summer):

First	3 Ccf or less	$265.62	
All over	3 Ccf	23.912	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$265.62	
All over	3 Ccf	29.748	¢/Ccf

Minimum Charge - $265.62 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Present Rider B - Rate Schedule I Rate IC

Delivery Charges (Summer):

First	3 Ccf or less	$404.34	
All over	3 Ccf	23.964	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$404.34	
All over	3 Ccf	29.748	¢/Ccf

Minimum Charge - $404.34 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

* Excluding the RDM Adjustment

Proposed Rider B - Rate Schedule I Rate IA

Delivery Charges (Summer):

First	3 Ccf or less	$158.86	
All over	3 Ccf	24.299	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$158.86	
All over	3 Ccf	30.163	¢/Ccf

Minimum Charge - $158.86 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Proposed Rider B - Rate Schedule I Rate IB

Delivery Charges (Summer):

First	3 Ccf or less	$269.75	
All over	3 Ccf	24.212	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$269.75	
All over	3 Ccf	30.163	¢/Ccf

Minimum Charge - $269.75 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Proposed Rider B - Rate Schedule I Rate IC

Delivery Charges (Summer):

First	3 Ccf or less	$410.62	
All over	3 Ccf	24.299	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$410.62	
All over	3 Ccf	30.163	¢/Ccf

Minimum Charge - $410.62 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

* Excluding the RDM Adjustment

ORANGE AND ROCKLAND UTILITIES, INC.
Case 21-G-0073
Present and Proposed Rates in Brief - Rate Year 3

Based on Levelized Revenue Requirement

Present Rider B - Rate Schedule I Rate ID

Delivery Charges (Summer):

First	3 Ccf or less	$513.55	
All over	3 Ccf	23.964	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$513.55	
All over	3 Ccf	29.748	¢/Ccf

Minimum Charge - $513.55 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Proposed Rider B - Rate Schedule I Rate ID

Delivery Charges (Summer):

First	3 Ccf or less	$521.52	
All over	3 Ccf	24.299	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$521.52	
All over	3 Ccf	30.163	¢/Ccf

Minimum Charge - $521.52 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Present Rider B - Rate Schedule II

Delivery Charges (Summer):

First	3 Ccf or less	$59.03	
All over	3 Ccf	4.792	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$59.03	
All over	3 Ccf	5.951	¢/Ccf

Contract Demand - $42.38 per Ccf of Contract Demand

Minimum Charge - $59.03 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Proposed Rider B - Rate Schedule II

Delivery Charges (Summer):

First	3 Ccf or less	$59.95	
All over	3 Ccf	4.859	¢/Ccf

Delivery Charges (Winter):

First	3 Ccf or less	$59.95	
All over	3 Ccf	6.034	¢/Ccf

Contract Demand - $42.97 per Ccf of Contract Demand

Minimum Charge - $59.95 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

Present Rider C

Delivery Charges:

First	3 Ccf or less	$39.75	
All over	3 Ccf	25.573	¢/Ccf

Minimum Charge - $39.75 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

* Excluding the RDM Adjustment

Proposed Rider C

Delivery Charges:

First	3 Ccf or less	$42.07	
All over	3 Ccf	27.160	¢/Ccf

Minimum Charge - $42.07 per month

Other Charges:

Rates and other provisions of the customer's otherwise applicable service classification*

* Excluding the RDM Adjustment

Orange and Rockland Utilities, Inc.
Cases 21-G-0073 & 21-E-0074

Electric, Gas, Common Capital Program Expenditure Reporting Requirements

The Company will file a quarterly report within 45 days after the end of each of the first three quarters of each Rate Year (*e.g.*, the report for the quarter January – March 2022 would be due by May 15, 2022). The annual report will be due 60 days after the end of the last quarter in each rate year (*e.g.*, by March 1, 2023 for Rate Year 1). The quarterly and annual reports will include the information outlined below. The quarterly reports will support the capital projects and blankets, and will reflect cumulative expenditures[1] and plant additions[2] during the Rate Year. The reports will explain any significant changes in project timelines or changes in cost estimates exceeding 15%, as well as an explanation of any new priority capital projects budgeted over $1.0 million for Electric, and over $0.5 million for Gas and Common. In addition, the Company will highlight all new non-blanket gas projects in the quarterly capital expenditure reports and will provide additional information in response to Staff requests.

Quarterly and Annual Reports will include:

- Summary of Capital Expenditures - Blankets, Regular Projects, and All Other

- Summary of Plant Additions - Blankets, Regular Projects, and All Other

- Capital Projects over $1.0 million (Electric); over $0.5 million (Gas and Common)
    - Rate Case – In-service date
    - Projected in-service date
    - Breakdown of expenditures (*e.g.*, payroll, accounts payable, and materials and supplies categories)
    - Comparison of rate year budgeted vs. rate year actual to date
    - Narrative on cost deltas exceeding 15%
    - Narrative on project design, permitting and or construction status (including a detailed construction schedule for each project).
    - Inclusion of any new projects exceeding $1.0 million (Electric), $0.5 million (Gas and Common)
    - Capital project documentation for any projects exceeding $1.0 million (Electric), $0.5 million (Gas and Common) that were authorized during the previous quarter.

- Annual Five-year capital budget for the projects and programs in the categories noted above and for Gas in the same format as Staff's Exhibit SGIOP-2.

[1] Expenditures – this includes all charges to active and on-going construction projects.
[2] Plant Additions – the increase in plant-in-service resulting from a transfer of costs from ongoing construction projects to plant-in-service upon completion of the project.

- Annual Leak Prone Pipe Program Report that includes the location (specific location of each section of leak prone pipe removed or abandoned), risk priority score of section(s) replaced, length and type of leak prone pipe replaced, Length and type of material replaced/installed, and number of leak prone services replaced. The Annual Leak Prone Pipe Program Report will be in the following format:

Company Name											
Date											
		Length Installed		Length Removed per Material (ft)						Number of Services Replaced	
Location	Risk Priority	Plastic	Steel	Plastic	Prot. Steel	Bare Steel	Cast Iron	Wrought Iron	Universal		Category
Smith St, NY	2	3510	1020	1408	3378	1335	2135	0	0	256	LPP Replacement
Total Footage (ft)		45100	119,830	14,186	24,681	59,435	28,437	9,610	2,083	256	
Miles		8.5	22.7	2.7	4.7	11.3	5.4	1.8	0.4		

- Gas R&D Expenditure Reports (Quarterly Only)

Orange and Rockland Utilities, Inc.
Cases 21-E-0074 and 21-G-0073
CLCPA-Related Efforts

1. O&R will inventory its emissions (in accordance with applicable state standards) and file its results and methodology on an annual basis.[1] Emissions inventory results will be filed within 90 days after the end of each rate year.
2. The Company's current and proposed commitments to address New York State emissions reduction targets and CLCPA goals include the following:
   - O&R will reduce the carbon intensity of gas transmission and distribution by lowering emissions from operations. This reduction will be driven by retirement of 22 miles of leak prone pipe ("LPP") annually from 2022-2029.[2]
   - O&R will consider NPAs for LPP replacement projects, as well as other projects including Farm Taps. Any LPP retired as a result of implementing an NPA will count toward the Company's annual and cumulative LPP targets.
   - O&R will enhance awareness and education of low carbon heating alternatives, including ground source heat pumps, air source heat pumps and heat pump water heaters and provide incentives to reduce the upfront costs of installing these technologies through the implementation of the Clean Heat program and/or potential future Non-Pipes Alternative ("NPA") efforts. Orange and Rockland will include online materials addressing heat pump guides, customer facing Heating and Cooling Comparison Calculator[3] and contractor awareness programs.
   - O&R will install and maintain 15,400 Natural Gas Detectors (NGDs) that will detect inside and outside leaks and automatically send notification to our gas emergency response center for immediate response. Immediate leak detection will reduce the amount of methane emissions from these leaks.
   - O&R will propose a Geothermal Neighborhood Project as a REV Demonstration Project in 2022 to study the potential for geothermal district energy systems to reduce emissions from heating, lower costs for customers through new business models and avoid additional gas infrastructure.
   - O&R is targeting approximately 6.6% reduction in electric sales volumes over the rate plan from 2019 levels. These reductions will result primarily from the Company's energy efficiency program.[4]

[1] The Company's calculation will include publicly available resources, such as EPA's 2019 eGRID table, EPA's greenhouse gases equivalencies calculator, and U.S. Energy Information Administration data.
[2] The Company currently anticipates completing its LPP program by 2029.
[3] https://www.oru.com/es/save-money/estimate-your-energy-usage/heating-calculator
[4] The Company reports on its results under Case 18-M-0084.

- O&R is targeting approximately 1.5% reduction in gas sales volumes over the rate plan from 2019 levels. These reductions will result primarily from the Company's energy efficiency program.[5]
- O&R is supporting efforts that will lower emissions by shifting electric consumption to periods of lower carbon intensity. This will be accomplished through the Behavioral Demand Response Pilot, Non-Wires Alternatives ("NWA") and the Innovative Storage Business Models ("ISBM") demonstration project, which involves the Company deploying behind the meter residential battery energy storage.
- O&R is targeting approximately a 0.95 – 3.63% annual reduction[6] in peak day gas usage across commercial, industrial, and residential customers by 2024 through the use of Earnings Adjustment Mechanisms. This reduction will result primarily from the Company's proposed Behavioral Demand Response Pilot and may defer the need for additional gas infrastructure to serve peak demand.
- O&R will modify its natural gas tariff to reduce the maximum regulatory required allowances for residential heating customers from 200ft. of main and service (in any combination) to 100ft. of main and 100ft. of service and appurtenant facilities.
- The Company will continue to evaluate its approach to gas depreciation in light of CLCPA.
- O&R will seek out opportunities for NPAs. The Company is closely following the NPA Framework filing submitted by Con Edison (Case 19-G-0066) and will implement aspects of that framework, to the extent they are applicable to the Company. The Company will pursue and report upon NPAs in accordance with requirements established under the Gas Planning Proceeding (Case 20-G-0131).
- O&R will support efforts by developers in the service territory to pursue renewable natural gas ("RNG") as a complement to energy efficiency / electrification and has established a standard gas system interconnection process for RNG facilities. The Company will file a plan with the Secretary to the Commission detailing how this source of gas can be incorporated into O&R's system.
- The Parties recognize that the Company is authorized to contract for and purchase certified gas. The Parties further acknowledge that such purchases may be more costly than conventional gas supplies.
- O&R through its R&D Spending Plan will continue to support efforts that explore the use of hydrogen and RNG within the gas system.
- O&R will advance customer adoption of emerging clean energy technologies such as electric vehicles ("EV"), EV supply equipment, air-source heat pumps, ground-

[5] The Company reports on its results under Case 18-M-0084.
[6] EAM targets for gas peak reduction are calculated formulaically each year, therefore this is an estimate. Actual annual targets will vary.

source heat pumps, and heat pump water heaters. This will be accomplished by facilitating enhanced customer enrollment and participation in the Company's clean energy programs.

- Starting in 2021, one hundred percent of new light-duty vehicles purchased will be electrified, and the Company will transition 100% of its existing fleet of light-duty vehicles to EV by 2040. The Company also will explore opportunities and alternative technologies to reduce the use of fossil fuels for its medium- and heavy-duty trucks.
- Through EV infrastructure and managed charging programs, O&R aims to deploy approximately 3,000 EV plugs which the Company anticipates will support up to 33,866 EVs, resulting in 1,583,236 avoided tons of carbon from transportation sources by 2025.
- O&R is targeting adding 84.6MW of energy storage by 2024. This will be accomplished through the bulk solicitation, NWA projects, support for customer-owned storage, and direct procurement of energy storage as needed to support the Company's electric system.
- O&R anticipates the addition of approximately 120 MW of solar PV to its electric system by year end 2024. The Company will accomplish this by supporting its customers through an efficient interconnection process and customer/developer outreach. The Company will continue to improve the interconnection process by identifying gaps between performance and best practices including lessons learned. This may include more efficient communication with developers and customers, offering tools/resources, enhancing internal procedures for efficiencies, and streamlining/standardization of processes.
- O&R will pursue distribution system and multi-value transmission infrastructure investments that will increase the Company's ability to integrate large-scale renewable resources including those identified in the Company's section of the CLCPA Utility Study. These activities align with the State, Company and Commission goals to enable the development of clean energy resources.
- O&R will support real-time electric operations across a diverse resource mix including traditional assets and DERs, and other large-scale intermittent renewable generation connected to the bulk electric power system. The Company's role as the Distributed System Platform provider supports the coordination between wholesale and distribution markets, while continuing to deliver reliable and resilient energy to customers.
- O&R will continue to support and facilitate customers participation in clean energy programs through its Customer Engagement Marketplace Platform ("CEMP") (www.myorustore.com) and enhance its marketplace by expanding its offerings to low and moderate income ("LMI") customers. The Company will also consider offering rebates for induction stoves through the CEMP pending applicability to the New Efficiency New York ("NENY") portfolio. Specific LMI offerings on the CEMP will include free energy efficiency kits. These kits will include lighting, weatherization and water efficiency measures.

- O&R will continue to partner with NYSERDA and other NY utilities to implement a low-income direct install program to its LMI community to help reduce their energy bills and increase energy affordability by investing over $5 million in energy efficiency offerings. The Company will strive to achieve 50% above the NENY targets. The Company will provide higher incentives to disadvantaged communities[7] under the Make Ready Program and the Company is seeking to locate its Geothermal Neighborhood demonstration project in a disadvantaged community or low-income area.
- O&R will commit to updating its website to include additional consumer education about community solar opportunities. This will include frequently asked questions, tips, information on billing including consolidating billing. It may also include links to other available resources such as NYSERDA's "Find a Community Solar Project."
- The Company has modified its website to remove "convert to natural gas" pages. The Company also commits to remove the promotion of converting to natural gas through customer mailings, emails, and marketing material. The Company will continue to promote programs and incentives available to customers for opportunities to reduce gas use or consider alternate forms of heating such as electric heat pumps and geothermal loops.
- The Company has discontinued any existing neighborhood expansion promotional or oil to gas rebate programs and will not institute any such new programs during the term of the Rate Plan. References to the terminated programs on the Company's websites have been removed.
- The Company has been and will continue to support the work of the CLCPA's Climate Justice working group to define and identify disadvantaged communities in O&R's service territory.

[7] As defined in the Commission's September 9, 2021, Clean Energy Fund Order (Case 14-M-0094).

Cases 21-G-0073 & 21-E-0074

REVENUE DECOUPLING MECHANISM

I. Electric Revenue Decoupling Mechanism

The Electric Revenue Decoupling Mechanism ("RDM") will continue to be based on a total delivery revenue methodology for customer groups that are included in the RDM, as set forth in the Company's electric tariff, modified commencing with the effective date of the Electric Rate Plan as follows:

- Standby Service customers have been added to the RDM where their RDM group will be that of the otherwise applicable class.
- Customers who move from individually negotiated contracts to an RDM class will have revenues excluded from the RDM until base rates and RDM targets are reset. Customers moving from an RDM class to individually negotiated contracts will have their revenues excluded from the RDM calculation (both the revenues and the target) until RDM targets and base rates are reset.
- If the Company does not file for new base delivery rates to take effect within 15 days upon the expiration of RY3, the RDM will remain in effect and the delivery revenue targets effective January 1, 2024 will continue, but will be restated to reflect the expiration of the temporary credit that is being collected through the Energy Cost Adjustment in RY3.
- If new base delivery rates take effect on a date other than January 1, 2024, the sum of the monthly delivery revenue excess/shortfalls for each month of the partial year, for each customer group, will be refunded/surcharged to customers through customer group-specific RDM Adjustments applicable during the

subsequent 12-month period commencing one month after new base delivery rates take effect.

The Electric RDM targets for each Rate Year are detailed in Schedule 1 to this Appendix.

II. Gas Revenue Decoupling Mechanism

The Gas Revenue Decoupling Mechanism ("RDM") will continue to be based on a total delivery revenue methodology for customer groups that are included in the RDM, as set forth in the Company's gas tariff, modified commencing with the effective date of the Gas Rate Plan as follows:

- If the Company does not file for new base delivery rates to take effect within 15 days upon the expiration of RY3, the RDM will remain in effect and the delivery revenue targets effective January 1, 2024 will continue, but will be restated to reflect the expiration of the temporary credit that is being collected through the Monthly Gas Adjustment in RY3.

The Gas RDM targets for each Rate Year are detailed in Schedule 2 to this Appendix.

III. Provisions Applicable to Both Electric and Gas

a. Filing of Statements

RDM Statements will be filed three calendar days before the effective date of a change in the RDM Adjustments, both for an annual filing and for an interim filing.

b. Partial Rate Year Reconciliation

If new base delivery rates in a subsequent case take effect on a date other than January 1, 2024, the sum of the monthly delivery revenue excess/shortfalls for each month of the partial year, for each customer group, will be refunded/surcharged to customers through customer group-specific RDM Adjustments applicable during the subsequent 12-month period commencing one month after new base delivery rates take effect.

c. Adjustments to RDM Targets

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

d. Make Whole Provisions

For the Company's annual RDM reconciliation for RY1 for both electric and gas, the revenue targets to which actual revenues are compared for the period January 1, 2022 until the date rates become effective as a result of the extension of the Case Nos. 21-E-0064 and 21-G-0063 suspensions will be equal to the monthly targets under the existing Case Nos. 18-E-0067 and 18-G-0068 rate plans. The targets for the remainder of RY1 will be the monthly targets as contained in Schedules 1 and 2 to this Appendix.

Orange and Rockland Utilities Inc.

Case 21-E-0074

Summary of Monthly Electric RDM Targets - RY 1
Revenue Targets for Rate Year Ending December 31, 2022 - (Thousand $)

	Residential SC 1/19	Secondary SC 2/20	SC 2p/3/21	Primary SC 9	SC 22	Lighting	TOTAL Billed	Unbilled	O&R
Jan-22	$17,081	$6,062	$1,262	$713	$544	$212	$25,874	($696)	$25,178
Feb-22	$15,785	$5,830	$1,244	$711	$528	$221	$24,319	($970)	$23,349
Mar-22	$14,099	$5,735	$1,412	$632	$490	$215	$22,583	$1,330	$23,913
Apr-22	$13,746	$5,852	$1,330	$736	$498	$207	$22,369	$359	$22,728
May-22	$13,223	$5,689	$1,382	$768	$545	$209	$21,816	$1,600	$23,416
Jun-22	$16,130	$6,977	$1,920	$1,631	$890	$205	$27,753	($60)	$27,693
Jul-22	$23,819	$9,991	$2,349	$1,753	$843	$209	$38,964	($448)	$38,516
Aug-22	$25,100	$10,078	$2,278	$1,810	$853	$217	$40,336	$1,200	$41,536
Sep-22	$21,731	$9,693	$2,450	$1,565	$865	$215	$36,519	($1,244)	$35,275
Oct-22	$16,110	$7,550	$1,386	$1,337	$549	$224	$27,156	$351	$27,507
Nov-22	$13,564	$5,909	$1,321	$794	$549	$216	$22,353	$133	$22,486
Dec-22	$15,416	$5,990	$1,076	$762	$575	$203	$24,022	($416)	$23,606
RY ending Dec 2022	$205,804	$85,356	$19,410	$13,212	$7,729	$2,553	$334,064	$1,139	$335,203

Orange and Rockland Utilities Inc.

Case 21-E-0074

Summary of Monthly Electric RDM Targets - RY 2
Revenue Targets for Rate Year Ending December 31, 2023 - (Thousand $)

	Residential SC 1/19	Secondary SC 2/20	SC 2p/3/21	Primary SC 9	SC 22	Lighting	TOTAL Billed	Unbilled	O&R
Jan-23	$17,601	$6,342	$1,326	$748	$568	$217	$26,802	($158)	$26,644
Feb-23	$16,245	$6,115	$1,309	$748	$549	$225	$25,191	($1,007)	$24,184
Mar-23	$14,494	$6,018	$1,483	$662	$509	$221	$23,387	$623	$24,010
Apr-23	$14,450	$6,162	$1,376	$756	$508	$211	$23,463	($55)	$23,408
May-23	$13,889	$6,007	$1,434	$793	$558	$213	$22,894	$1,326	$24,220
Jun-23	$16,993	$7,439	$1,992	$1,686	$914	$210	$29,234	($916)	$28,318
Jul-23	$24,787	$10,487	$2,457	$1,827	$874	$213	$40,645	($313)	$40,332
Aug-23	$26,131	$10,576	$2,385	$1,883	$885	$222	$42,082	$1,138	$43,220
Sep-23	$22,601	$10,172	$2,563	$1,631	$898	$219	$38,084	($1,693)	$36,391
Oct-23	$16,848	$7,918	$1,449	$1,381	$566	$229	$28,391	$774	$29,165
Nov-23	$14,213	$6,183	$1,380	$824	$566	$221	$23,387	($833)	$22,554
Dec-23	$16,184	$6,259	$1,124	$791	$591	$208	$25,157	($656)	$24,501
RY ending Dec 2023	$214,436	$89,678	$20,278	$13,730	$7,986	$2,609	$348,717	($1,770)	$346,947

Orange and Rockland Utilities Inc.

Case 21-E-0074

Summary of Monthly Electric RDM Targets - RY 3
Revenue Targets for Rate Year Ending December 31, 2024 - (Thousand $)

	Residential SC 1/19	Secondary SC 2/20	SC 2p/3/21	Primary SC 9	SC 22	Lighting	TOTAL Billed	Unbilled	O&R
Jan-24	$18,374	$6,455	$1,305	$723	$550	$225	$27,632	($14)	$27,618
Feb-24	$16,928	$6,244	$1,288	$724	$599	$226	$26,009	($132)	$25,877
Mar-24	$15,071	$6,154	$1,456	$640	$562	$230	$24,113	$714	$24,827
Apr-24	$15,018	$6,312	$1,366	$832	$567	$216	$24,311	$69	$24,380
May-24	$14,408	$6,174	$1,424	$863	$616	$219	$23,704	$1,150	$24,854
Jun-24	$17,739	$7,780	$1,997	$1,864	$1,022	$215	$30,617	($1,028)	$29,589
Jul-24	$25,842	$10,925	$2,417	$1,966	$962	$219	$42,331	($45)	$42,286
Aug-24	$27,266	$11,003	$2,348	$2,021	$972	$228	$43,838	$1,332	$45,170
Sep-24	$23,561	$10,591	$2,519	$1,777	$984	$225	$39,657	($1,478)	$38,179
Oct-24	$17,192	$8,090	$1,426	$1,439	$616	$232	$28,995	$2,029	$31,024
Nov-24	$14,482	$6,262	$1,349	$887	$615	$224	$23,819	($12)	$23,807
Dec-24	$16,512	$6,312	$1,097	$851	$640	$209	$25,621	($601)	$25,020
RY ending Dec 2024	$222,393	$92,302	$19,992	$14,587	$8,705	$2,668	$360,647	$1,984	$362,631

O&R Gas RDM Targets

(in $000s)

	Billed SC1	SC2 (w/o Rider B)	Total Billed	UnBilled	TOTAL
Jan-22	20,334.72	3,660.00	23,994.72	1,900.49	25,895.20
Feb-22	20,573.40	3,759.45	24,332.85	(2,160.89)	22,171.96
Mar-22	18,511.35	3,496.99	22,008.34	(1,940.59)	20,067.74
Apr-22	14,161.30	2,546.65	16,707.95	(3,676.96)	13,031.00
May-22	9,399.53	1,615.40	11,014.93	(1,555.06)	9,459.87
Jun-22	6,770.30	1,212.29	7,982.59	(2,278.84)	5,703.75
Jul-22	5,455.22	1,133.52	6,588.74	462.63	7,051.37
Aug-22	5,030.10	1,013.83	6,043.93	289.65	6,333.58
Sep-22	5,270.69	1,014.28	6,284.97	508.56	6,793.53
Oct-22	6,117.01	1,208.14	7,325.15	3,800.31	11,125.46
Nov-22	9,801.19	1,958.71	11,759.90	5,251.28	17,011.18
Dec-22	16,645.39	3,073.22	19,718.61	808.32	20,526.93
TOTAL	138,070.19	25,692.48	163,762.67	1,408.91	165,171.58

O&R Gas RDM Targets

(in $000s)

	Billed SC1	SC2 (w/o Rider B)	Total Billed	UnBilled	TOTAL
Jan-23	20,219.92	3,586.63	23,806.55	3,175.15	26,981.71
Feb-23	21,562.45	3,895.32	25,457.77	(2,314.85)	23,142.92
Mar-23	20,066.86	3,751.13	23,817.98	(3,091.84)	20,726.15
Apr-23	15,265.45	2,699.45	17,964.90	(4,473.41)	13,491.49
May-23	9,938.89	1,680.48	11,619.37	(1,720.43)	9,898.94
Jun-23	7,208.71	1,268.50	8,477.21	(2,698.51)	5,778.70
Jul-23	5,685.93	1,144.98	6,830.91	538.60	7,369.51
Aug-23	5,256.50	1,027.44	6,283.95	264.83	6,548.78
Sep-23	5,500.74	1,024.96	6,525.70	499.17	7,024.87
Oct-23	6,333.54	1,227.21	7,560.75	3,794.55	11,355.30
Nov-23	10,365.51	2,040.76	12,406.27	4,603.08	17,009.35
Dec-23	17,447.62	3,174.60	20,622.22	727.76	21,349.99
TOTAL	144,852.12	26,521.47	171,373.59	(695.88)	170,677.70

O&R Gas RDM Targets

(in $000s)

	Billed SC1	SC2 (w/o Rider B)	Total Billed	UnBilled	TOTAL
Jan-24	21,440.17	3,561.89	25,002.05	2,841.81	27,843.87
Feb-24	22,309.53	3,765.37	26,074.90	(1,676.14)	24,398.76
Mar-24	20,436.96	3,573.45	24,010.41	(2,435.10)	21,575.31
Apr-24	15,912.25	2,631.74	18,543.99	(4,678.97)	13,865.02
May-24	10,323.95	1,628.77	11,952.72	(1,770.39)	10,182.33
Jun-24	7,430.73	1,219.32	8,650.04	(2,691.34)	5,958.70
Jul-24	5,936.51	1,115.81	7,052.32	521.62	7,573.94
Aug-24	5,478.34	996.88	6,475.22	295.79	6,771.01
Sep-24	5,729.00	993.18	6,722.19	569.84	7,292.02
Oct-24	6,328.83	1,146.05	7,474.88	4,546.02	12,020.90
Nov-24	10,293.18	1,905.45	12,198.63	5,217.10	17,415.73
Dec-24	17,565.73	2,996.96	20,562.69	(447.51)	20,115.18
TOTAL	149,185.17	25,534.87	174,720.04	292.73	175,012.77

ATTACHMENT B

TARIFF AMENDMENTS

SUBJECT: Filings by ORANGE AND ROCKLAND UTILITIES, INC.

Amendments to Schedule P.S.C. No. 3 – Electricity

Original Leaves Nos. 220.2, 220.3, 221.1-221.26, 270.1, 276.1, 309.1, 331.1, 356.1
First Revised Leaves Nos. 71-76, 81, 83, 105, 107, 121, 123, 124, 174, 185.4.1, 185.5.1, 185.14, 189.3, 220.1, 221, 234, 235, 252.3, 255.1, 259.1, 263.1, 263.2, 263.3, 280, 349, 353, 354, 378, 380, 383.1, 386, 394, 395, 396, 398
Second Revised Leaves Nos. 12, 13, 108, 113, 169.2, 180.1.1, 181.6, 185.3, 254.1, 254.2, 262.1, 273, 283.1, 308, 379, 381-385, 393, 397
Third Revised Leaves Nos. 7, 68, 114, 116, 143, 155.1, 162, 185.5, 217, 249.1, 252.2, 263, 279, 291, 311, 334, 370, 371
Fourth Revised Leaves Nos. 6, 8, 90, 147, 148.1, 151, 161, 348, 387, 391, 392
Fifth Revised Leaves Nos. 164, 177, 180.4, 182, 254, 256, 265, 296, 342, 343, 390
Sixth Revised Leaves Nos. 156.1, 157, 157.1, 169.1, 215, 252.1, 253, 255, 257, 258, 261, 262, 335, 377, 388
Seventh Revised Leaves Nos. 155, 156, 181.1, 214, 216, 218, 220, 277, 376, 389
Eighth Revised Leaves Nos. 5, 249, 250, 259, 260, 266, 271, 286, 346, 351, 357
Ninth Revised Leaves Nos. 168, 251, 252
Tenth Revised Leaf No. 219
Eleventh Revised Leaves Nos. 264, 270, 312, 321, 322, 331, 332, 336, 356, 359, 373, 374, 375
Twelfth Revised Leaves Nos. 269, 274, 276, 284, 341, 345, 350, 372
Thirteenth Revised Leaves Nos. 272, 278, 283, 309, 310, 347, 352, 358
Fifteenth Revised Leaves Nos. 285, 290, 295, 333
Sixteenth Revised Leaf No. 89

Suspension Supplement Nos. 45, 47, 49

Amendments to Schedule P.S.C. No. 4 – Gas

Original Leaves Nos. 80.3.10, 112.1-112.10
First Revised Leaves Nos. 89.1, 90.6, 90.7, 113.5
Second Revised Leaves Nos. 87, 128.1
Third Revised Leaves Nos. 80.3.9, 84, 85, 88, 89, 90-90.5
Fourth Revised Leaf No. 113.3
Fifth Revised Leaves Nos. 86, 128
Sixth Revised Leaves Nos. 4.1, 93, 113.4
Seventh Revised Leaf No. 126
Eighth Revised Leaves Nos. 5, 79.2, 94.11, 113.1
Ninth Revised Leaf No. 113.2
Tenth Revised Leaves Nos. 79.1, 80.3.1, 80.4, 113
Eleventh Revised Leaves Nos. 80.3.2, 127
Thirteenth Revised Leaves Nos. 81.1, 132
Fifteenth Revised Leaves Nos. 4, 34, 137.2
Sixteenth Revised Leaves Nos. 112, 117
Seventeenth Revised Leaves Nos. 94.9, 94.10
Eighteenth Revised Leaves Nos. 80, 115
Nineteenth Revised Leaf No. 80.1
Twentieth Revised Leaf No. 94.16
Twenty-Third Revised Leaf No. 33.3
Twenty-Ninth Revised Leaf No. 133
Thirtieth Revised Leaves Nos. 114, 130
Thirty-Third Revised Leaf No. 116

Suspension Supplement Nos. 78, 79, 80