CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

DIRECT TESTIMONY – ACCOUNTING PANEL

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I. INTRODUCTION

Q. Would the members of the Accounting Panel please state their names and business address?

A. Joseph Miller, Kelly McLaughlin-Martini, and Wenqi Wang. We are each employed by Consolidated Edison Company of New York, Inc. ("Con Edison," the "Company" or "CECONY"). Our business address is 4 Irving Place, New York, NY 10003.

Q. What are your current positions and general responsibilities with Con Edison?

A. (**Miller**) I am the Vice President and Controller. In this position I am the Company's chief accounting officer with the overall responsibility for the development and maintenance of the Company's financial accounting records.

(**McLaughlin**) I am the Assistant Controller responsible for the Regulatory Accounting & Policy, Accounts Payable and Payroll.

(**Wang**) I hold the position of Department Manager of Regulatory Accounting and Revenue Requirements.

Q. Please explain your educational background and work experience.

A. **(Miller)** In June 1984, I received a Bachelor of Business Administration Degree in Accounting from Baruch College and in January 1990, I received a Master of Business Administration in Finance from Baruch College. I began my employment with Con Edison in July 1984 as a Management Intern. I worked in the Corporate Accounting Department from July 1985 until January 2001 primarily between the Accounting Research and Procedures ("ARP") and the

General Accounts (“GA”) sections starting as a Staff Accountant, then Supervisor and ultimately reaching the Department Manager level in both sections. In 2001, I worked as a Department Manager within the Corporate Planning Department and then in 2002, I became the Department Manager of our Financial Reporting section. In 2004, I became an Assistant Controller and then a Director of Treasury’s Risk Management section. From 2006 through 2012, I was an Assistant Controller for the Financial Reporting Sections, which ultimately included ARP, GA, Commodity and Derivative Accounting, Account Reconciliations and Financial Reporting. From 2013 through 2017, I was the Assistant Controller responsible for the Regulatory Accounting & Policy, Accounts Payable, Payroll and Account Reconciliation sections. From 2018 to 2021, I returned to the Assistant Controller position for the Financial Reporting Sections which by that time included ARP, GA, and Financial Reporting. I became Vice President and Controller in 2021.

(McLaughlin-Martini) I graduated from Fordham University in 1997 with a Bachelor of Science Degree in Accounting and Finance and received my Master of Business Administration, also from Fordham University, in 2004. I am a Certified Public Accountant. After five years working predominately as an auditor and accountant, I joined Con Edison in 2003 as an Accountant in the Corporate Accounting department. I assumed positions of increasing responsibility over the years, including Senior Accountant and Department Manager in Corporate Accounting, Financial Accounting & Reporting. In September 2014, I assumed the position of Department Manager O&R Financial Services and in November 2016, I was promoted to Director, Corporate Financial Planning and Analysis. I assumed the position of Assistant Controller, Corporate Accounting in April 2021.

(**Wang**) In June 1999, I received a Bachelor of Science Degree in Accounting from the University at Albany, State University of New York. I began my employment with Con Edison in July 1999 as a Management Intern. I worked in the Corporate Accounting Department from July 2000 until April 2014, primarily in the General Accounts section starting as a Staff Accountant, then Supervisor and ultimately reaching the Department Manager level. In May 2014, I assumed my current position as Department Manager of Regulatory Accounting and Revenue Requirements.

Q. Have any members of the Accounting Panel previously testified before the New York State Public Service Commission ("PSC" or the "Commission")?

A. Yes. All members of the Accounting Panel have previously submitted testimony before the Commission on behalf of CECONY and/or its affiliate, Orange and Rockland Utilities, Inc. ("O&R"), in previous electric, gas and/or steam proceedings.

II. PURPOSE OF TESTIMONY

Q. Please summarize your testimony.

A. The Accounting Panel testimony covers the following topics:

- An overview of the costs driving the proposed electric and gas revenue requirements for the twelve months ending December 31, 2023 (the "Rate Year" or "RY1"),
- Historic financial statements and statistical data required by the Commission;
- The development of the Rate Year electric and gas revenue requirements;
- The proposed overall rate of return and capital structure for the Rate Year;
- Sources and uses of funds and interest coverage ratios;
- The Company's proposals related to certain deferral accounting and reconciliation mechanisms;
- The Company's forecasted financial information for the two annual periods beyond the Rate Year to provide a basis for settlement discussions regarding multi-year electric and gas rate plans; and
- The Commission's Management and Operations Audits involving the Company.

III. ORGANIZATION OF TESTIMONY

Q. Please describe your testimony and how it is organized.

A. The Accounting Panel testimony covers the below-listed topics and exhibits. All of these exhibits were prepared under our supervision and direction, but rely on input from other Company witnesses. Certain projections will be updated based on the latest information available during the course of these proceedings.

Exhibit Title and Description	Exh. No.	E, G*
Historic Financial and Statistical Data	AP-1	E, G
Rate Base	AP-2	E, G
Operating Income/Revenue Requirement	AP-3	E, G
Estimated Net Plant and Capital Expenditures	AP-4	E, G
Capital Structure/Cost of Capital	AP-5	E, G
Allocation of Electric Rate Increase	AP-6	E

* The numbering convention for exhibits indicates whether the exhibits address electric or gas (E, G) service as follows: AP-E1, AP-E2, etc. for electric exhibits and AP-G1, AP-G2, etc. for gas exhibits. For ease of presentation, the exhibits are often referenced without the commodity designation. Please note that AP-6 is only applicable to electric service.

The Company is not proposing a multi-year rate plan for electric or gas in its filing. However, in addition to providing projections for the Rate Year, in order to facilitate the negotiation of multi-year electric and gas rate plans, the Company has included forecasted financial information for two annual periods beyond the Rate Year, *i.e.*, the twelve-month periods ending December 31, 2024 and December 31, 2025 (which we and other Company witnesses will refer to as "RY2" and "RY3," respectively).

IV. PROPOSED REVENUE REQUIREMENTS

Q. What revenue requirement increases is the Company requesting in its electric and gas rate filings?

A. For electric, the Company is requesting an increase of approximately $1,199 million for the Rate Year. That amount equates to approximately an 11.2% overall increase in customer bills and approximately a 17.6% increase on a delivery bill basis.

For gas, the Company is requesting an increase of approximately $503 million for the Rate Year. That amount equates to approximately a 18.2% overall increase in customer bills and approximately a 28.1% increase on a delivery bill basis.

Q. What are the primary drivers of the requested electric and gas rate increases?

A. The primary drivers for the requested increases are summarized in Table 1. The table is separated into two categories: 'New Investments and Others,' representing drivers initiated by the Company in this proceeding, and 'Legacy Costs and Other Obligations,' representing the revenue requirement effects of factors outside of the Company's control in this proceeding. Additional detail regarding the components of each driver is set forth in the AP-3 exhibits and additional commentary regarding the most significant drivers is included in the table below.

Table 1 ($millions)		
Driver	**Electric**	**Gas**
New Investments and Others		
New infrastructure investment	250	161
ROE / Capital structure	201	77
Operations and maintenance expenses	79	32
Depreciation	15	64
Income taxes	12	12
Other Operating revenues	12	7
Legacy Costs and Other Obligations		
Sales revenues	259	77
Amortization of net deferred credits/costs (*e.g.*, storm deferrals, prior rate plan property taxes)	191	(1)
Property and other taxes	180	74
Total	**$1,199**	**$503**

A. New Investments and Others

New Infrastructure Investment

Q. Please discuss the impact of new infrastructure investment on the Company's rate base.

A. The Company has a statutory obligation to maintain safe and reliable electric and gas systems in a changing climate. As discussed by the Company's Electric Infrastructure and Operations Panel ("EIOP"), Gas Infrastructure, Operations and Supply Panel ("GIOSP"), Storm Response and Resiliency Panel, Climate Leadership and Community Protection Act ("CLCPA") Panel and other Company witnesses, the projected level of spending reflects the investments determined to be necessary to install and replace infrastructure and manage risk, meet current customer needs, plan for future customer needs and enable the transition to a clean energy system. The Company makes capital spending decisions following its extensive and rigorous analysis, including an optimization assessment that is guided by our long- and short-term planning processes and takes into account State and local policy objectives and potential climate change impacts. As the witnesses explain, the Company's strategy is to invest in infrastructure enhancements only when less expensive alternative solutions are not available to sustain existing reliability levels, provide for localized delivery capacity needs, provide for employee and public safety, and enable the clean energy transition. And for gas, the Company's capital investment strategy is focused on making the system safer.

The expanding need for capital investment, much of which is related to resiliency and clean energy enablement for electric, and safety for gas, contributes to the increase in the carrying cost on rate base relative to current RY3 rate levels by approximately $250 million for electric and $161 million for gas, which includes additional depreciation expense of $59 million for electric and $47 million for gas on the higher plant investment at the Company's currently-authorized depreciation rates.

ROE/Capital Structure

Q. Please discuss the increase in financing costs for both electric and gas services as shown in Table 1.

A. The overall effect of the change in financing costs amounts to $201 million for electric and $77 million for gas. The primary factor contributing to this increase is the proposed return on equity ("ROE") of 10.00 percent (as compared to the ROE in RY 3 of the current rate plan). Other factors include increasing the equity ratio from 48.00 percent to 50.00 percent, partially offset by a decrease in the cost of debt from 4.63 percent to 4.28 percent and a decrease in the customer deposit rate from 2.45 percent to 0.05 percent.

Q. Why is the Company proposing an ROE of 10.00 percent in this rate filing?

A. As discussed in her direct testimony, Company witness Villadsen is recommending an ROE range between 10.0 and 10.50 percent for the Company. The Company is filing with the lower 10.00 percent ROE in order to facilitate the resolution of the issues in these proceedings.

Operations and Maintenance ("O&M") Expenses

Q. Please explain the increases in electric and gas O&M expenses as shown in Table 1 above.

A. Increases in O&M expenses result from a variety of normalizations of Historic Year/Test Year (*i.e*., October 1, 2020 through September 30, 2021) costs and program changes described later in this testimony and in the testimony of various Company witnesses. In addition, the Company escalated Historic Year expenses using labor and non-labor escalation factors to arrive at Rate Year amounts, as described later in this testimony.

For electric, the $79 million overall increase in O&M expense includes, in addition to general inflation and wage awards, funding of a number of operational enhancements, including maintenance of various Information Technology ("IT") projects such as the new Customer Service System ("CSS") system. There are also increases related to facilities and field services as well as interference. These increases are partially offset by certain reductions, most notably savings driven by reduced Pension and other Post-Employment Benefit ("OPEB") costs, as well as Employee Welfare Expenses.

For gas, the $32 million overall increase in O&M expense is driven in part by increased spending on IT support and higher spending on gas interference. In addition, this increase includes the effect of moving gas service line inspection costs from surcharge to base rates. These increases are partially offset by certain reductions to Pension and OPEB costs.

Depreciation

Q. Please explain the increases in depreciation expense for electric and gas.

A. The increases in electric and gas expenses are driven by a proposal for increased depreciation rates, partially mitigated by a decrease in the depreciation reserve deficiency. As discussed by the Company's Depreciation Panel, the increase in gas depreciation expense is also driven by the Company's proposal to reduce certain gas service lives in alignment with the requirements of CLCPA.

B. Legacy Costs and Other Obligations

Sales Revenue

Q. Please explain the sales revenue effect on the revenue requirement shown in Table 1 above.

A. With regard to the electric sales revenue forecast contained in its current rate plan, the Company is projecting a revenue requirement increase of $259 million relative to projected revenues in RY3 of the current rate plan. Using a similar comparison for gas, the Company is projecting a revenue requirement increase of $77 million.

Amortization of Net Deferred Credits/Costs

Q. Please discuss the increases related to the amortization of net deferred credits/costs as shown in Table 1 above.

A. The increase in the electric amortization of deferrals was $191 million, while gas was relatively flat. Approximately $130 million of the electric increase is due to the expiration of one of the credits associated with the refund of the 2018 tax savings resulting from the reduction in the corporate tax rate from 35% to 21%, pursuant to the Tax Cuts and Jobs Act of 2017. Two other major contributors to the electric increase are increases to the major storm and pension/OPEB deferrals of approximately $53 million and $57 million, respectively.

Property and Other Taxes

Q. Please discuss the increases related to property and other taxes for electric and gas services as shown in Table 1 above.

A. The total increase in property and other taxes is $180 million for electric and $74 million for gas, representing approximately 15% of the requested increase for both electric and gas. The increases in property taxes relative to the current rate allowances are attributable to higher projected property taxes in New York City ("NYC"), partially offset by lower projected property taxes in the County of Westchester and other municipalities, as addressed in the testimony of the Company's Property Tax Witness.

V. HISTORIC FINANCIAL AND STATISTICAL DATA (Exhibits AP-1)

Q. Are you familiar with the Company's accounting books and records?

A. Yes.

Q. Are the accounts of the Company kept in accordance with the Uniform System of Accounts prescribed by the Commission?

A. Yes.

Q. Does this filing include historical financial and statistical data as required by the Commission for major rate filings?

A. Yes. The required information is included in the AP-1 exhibits. Exhibits AP-1, Schedules 1-10, consist of an index and supporting schedules (*i.e.*, ten for electric and nine for gas) containing financial data and the results of operations for the particular utility service. The balance sheets are shown as of December 31 for the years 2017 through 2020, and as of September 30, 2021, the end of the Historic Year. Details of the income statement accounts are shown for the calendar years 2018 through 2020, and the Historic Year. Exhibits AP-1, Schedules 1-10 are:

- Schedule 1 – Balance Sheets;
- Schedule 2 – Income Statements;
- Schedule 3 – Unappropriated Retained Earnings;
- Schedule 4 – Utility Operating Income;
- Schedule 5 – Operating Revenues;
- Schedule 6 – Statement of Commodity Supplied and Revenue Billed
- Schedule 7 – Other Operating Revenues;
- Schedule 8 – Operation and Maintenance Expenses;
- Schedule 9 – Taxes Other Than Income Taxes; and
- Schedule 10 – Power Production Expenses (electric only).

All of the financial information in Exhibits AP-1, Schedules 1-10, are from the books and records of the Company, except statistical information in cents per kWh and dekatherm, which were computed based on the data contained in the exhibits.

VI. HISTORIC FEDERAL AND STATE INCOME TAXES (Exhibits AP-1, Schedule 11)

Q. Have you included a presentation of federal and state income taxes for the Historic Year in your exhibits?

A. Yes. The first part of Exhibits AP-1, Schedule 11, sets forth the calculation of federal income tax for electric and gas operations, including accruals, deferrals and amortizations of deferrals for the Historic Year. The second part of those exhibits show the calculation of New York State ("NYS") income tax for electric and gas operations for the same twelve-month period.

VII. HISTORIC BOOK COST OF UTILITY PLANT (Exhibits AP-1, Schedule 12)

Q. Have you included a presentation of the historic book cost of utility plant in your exhibits?

A. Yes. Exhibits AP-1, Schedule 12, contain historic balances of the book cost of utility plant, by utility plant account, and the balances of construction work in progress ("CWIP") for electric and gas as of the end of the Historic Year and as of the end of the preceding four calendar years taken directly from the books and records of the Company. The utility plant accounts are maintained in balance with the continuing property records, which show the original cost of the existing property classified in accordance with established continuing property record units.

VIII. HISTORIC ACCUMULATED PROVISION FOR DEPRECIATION OF UTILITY PLANT (Exhibits AP-1, Schedule 13)

Q. Have you included a presentation of the historic balances of the accumulated provision for depreciation of utility plant in your exhibits?

A. Yes. Exhibits AP-1, Schedule 13, contain historic balances of the accumulated provision for depreciation as of the end of the Historic Year and as of the end of the preceding four calendar years. The amounts shown in Exhibits AP-1, Schedule 13, were taken from the books and records of the Company. We will address projected changes to the accumulated provision for depreciation below in this testimony.

IX. RATE BASE (Exhibits AP-2)

Q. Turning to rate base, do your exhibits include an itemization of the components of electric and gas rate base?

A. Yes, that information for the Historic Year and the Rate Year is presented in Exhibits AP-2.

Q. Please describe your presentation of rate base in Exhibits AP-2.

A. The presentation approach is the same for the electric and gas rate base exhibits. There are a total of six pages in Exhibits AP-2. Page 1 summarizes the overall rate base calculation for the Historic Year and Rate Year. Page 2 shows the details of the forecasted net plant and non-interest bearing CWIP calculation, as shown on page 1, lines 1 to 11 for electric (lines 1 to 10 for gas). Page 3 provides the details of the working capital, unamortized premium & discount, unamortized preferred stock expense, and customer advance construction figures, as shown on page 1, lines 12, 13, 14, and 15 for electric (lines 11, 12, 13, and 14 for gas). Page 4 provides the details of the projected deferred balances from reconciliation mechanisms contained in the current rate plan as shown on page 1, line 16 for electric (line 15 for gas). Page 5 shows the details of accumulated deferred federal and state tax balances, as shown on page 1, lines 17 to 20 for electric (lines 16 to 19 for gas). Page 6 provides a detailed calculation of the Earnings Base Capitalization Adjustment amount, as shown on page 1, line 22 for electric (line 21 for gas).

Q. Are there any remaining rate base items on page 1 of Exhibits AP-2 that are not detailed on pages 2 - 6 of Exhibits AP-2?

A. Yes. Pension/OPEB Reduction on line 23 (line 22 for gas), and Former Employee/Contractor Proceeding Rate Base Reduction on line 24 (line 23 for gas), 2018 Sales and Use Tax Refund on line 26 (line 24 for gas), Isaias Storm Settlement on line 25 are the remaining rate base items that are shown on page 1 of Exhibits AP-2.

For the Pension/OPEB Reduction, without waiving its right to modify its position in future rate proceedings, the Company made an adjustment for prepaid pensions based on a decision in Case 07-E-0523.

Regarding the Former Employee/Contractor Proceeding Rate Base Reduction, the Company made this adjustment in compliance with the Commission-adopted Joint Proposal in Cases 09-M-0114 and 09-M-0243. In the Joint Proposal, the Company agreed to forgo earning any return after January 1, 2017 on certain capital expenditures and to limit the return on certain other capital expenditures after January 1, 2017 until December 31, 2044 to the Company's embedded cost of long-term debt.

The Isaias Storm Settlement refers to the settlement agreement that fully resolved issues with respect to four events described in Cases 21-E-0372, 20-E-0422, 20-E-0586, 20-E-0587, 20-E-0588, 20-E-0643, and 18-S-0448. In that settlement, the Company agreed to forgo recovery from customers of $25 million associated with the return on existing storm hardening assets over a period of 35 years. As such, the Company has removed the undepreciated plant balances for the storm hardening assets from rate base in this electric base rate filing.

For the Sales and Use Tax Refund received in 2018, the Company agreed in Case 19-E-0065 and 19-G-0066 to reflect the refund as cost of service adjustment in rate base and depreciation, amortized over 24 years ending December 31, 2043.

C. Net Plant Rate Base (Exhibits AP-2, Page 2)

Q. What rate base items related to net plant investment are included on page 2 of Exhibits AP-2?

A. Page 2 of Exhibits AP-2 includes projected net plant and the portion of CWIP not subject to Allowance for Funds Used During Construction ("AFUDC"). Net plant includes utility plant in service, the allocated portion of common utility plant, plant held for future use, Oracle agreement payment liability and the accumulated provision for depreciation at proposed depreciation rates, including proposed recovery of reserve deficiencies. Rate Year plant and accumulated depreciation forecasts are based on capital budget models and a thirteen-point average methodology. A description on how the Company developed the forecasted amounts of these items for the Rate Year is included in Section XIII of this testimony. In this filing, the Company is projecting Rate Year CWIP to remain at the Historic Year level. As the Company further reviews its capital forecast, it will refine the Rate Year CWIP projection and incorporate the projection into the Update filing.

D. Detailed Development of Working Capital, Unamortized Premium & Discount, and Customer Advance Construction (Exhibits AP-2, page 3)

Q. Please explain the rate base component labeled "Working Capital" on page 1 of Exhibits AP-2.

A. The detailed elements of working capital rate base are shown on page 3 of Exhibits AP-2. Working capital rate base contains three categories: Materials and Supplies, Prepayments, and Cash Working Capital.

1. Materials and Supplies

Q. How did you determine the average balance of Materials and Supplies rate base for the Rate Year shown on page 3 of Exhibits AP-2?

A. As in past Company rate cases, the Rate Year forecast of Materials and Supplies inventory generally represents the Historic Year amount escalated using the general escalation factor.

An exception with respect to gas, however, but also consistent with the practice in past Company gas rate cases, is that we excluded from rate base the inventory balances of both gas stored underground and Liquefied Natural Gas in storage. As discussed later, we have also eliminated from sales revenues the effects of gas in storage (as well as other items) to reflect only pure base revenues on which the revenue requirement should be based. This elimination would match our adjustment to revenues.

2. Prepayments

Q. What is included in the "Prepayments" category of working capital rate base on page 3 of Exhibits AP-2?

A. The prepayment component of working capital rate base includes local property tax, computer maintenance and software support, insurance, Commission assessment, NYS Gross Receipts Tax, rents and other items.

Q. Please explain how you developed the Rate Year rate base amount for the prepayment items.

A. All prepayments except for the prepaid property taxes were projected at the Historic Year level and escalated by general inflation. Prepaid property taxes are forecasted to increase at the same rate as property taxes. The Company's Property Tax witness in her direct testimony provides further explanation of the Company's property tax forecasts.

3. Cash Working Capital

Q. Please explain the allowance for the cash working capital component of working capital rate base on page 3 of Exhibits AP-2.

A. We determined the cash working capital component of working capital rate base following well-established Commission practice including application of the 1/8 FERC Working Capital Formula. As such, we performed separate calculations of the rate base amount for electric and gas. For each, we started with projected total O&M expenses from Schedule 6 of Exhibits AP-3. Continuing with the established approach, we eliminated certain expenses from the O&M expense amounts to arrive at the level of O&M expenses that would be subject to the 1/8 FERC Working Capital Formula.

For electric, we eliminated purchased power and fuel expenses, amortization of energy efficiency programs and energy efficiency surcharges, amortization of Manufactured Gas Plant ("MGP")/Superfund Site, interdepartmental rents, East River Repowering Project ("ERRP") rent, System Benefit Charge and uncollectible accounts expense. For gas, we eliminated purchased gas expenses, interdepartmental rents, amortization of MGP/Superfund Site, System Benefit Charge and uncollectible accounts expense for that purpose.

The amounts for gas are the final cash working capital amounts, but there is an additional element of the cash working capital allowance for electric related to the fuel and purchased power expenses previously eliminated from the calculation. The cash working capital allowance related to fuel and purchased power is calculated based on a time lag between fuel costs included in customer bills and when payments are collected from customers, as customarily applied by the Commission. This additional element of the cash working capital allowance adds

$113 million to the cash working capital rate base for electric as shown on page 3 of Exhibit AP-E2.

4. Unamortized Premium & Discount, Unamortized Preferred Stock Expense, and Customer Advance for Construction

Q. Please explain the unamortized premium/discount expense, unamortized preferred stock expense, and customer advance for construction on page 3 of Exhibits AP-2.

A. The unamortized premium/discount and expense reflects the unamortized balance of debt discounts, premiums and expenses, as additions to rate base. Unamortized Preferred Stock Expense reflects the unamortized preferred stock expense as additions to rate base. The Commission directed this rate base treatment in its Order on Rehearing in Case 27353. Customer advance for construction represents the amount billed to customers and others for the construction necessary to provide utility service to their premises (rather than for general system service) and represent a reduction to rate base. The Historic Year levels of these items were carried forward to the Rate Year.

E. **Net Deferrals/Credits from Reconciliation Mechanism (Exhibits AP-2, page 4)**

Q. Are deferral balances net of deferred income taxes?

A. Yes.

Q. Please explain each item on Exhibit AP-2, page 4.

A. For detail on lines 1-52 of Exhibit AP-E2, page 4, and lines 1-39 of Exhibit AP-G2, page 4, please refer to Section XVI (Reconciliations & Deferred Accounting) of this testimony.

Line 46 (G), Underground Gas Storage – Noncurrent, represents the Company's investment in the non-current portion of cushion gas stored underground. The Historic Year levels of underground gas storage were carried forward to the Rate Year.

Line 58 (E)/Line 45 (G), Unbilled Revenues, represents the unbilled revenue deferral that was established to allow the Company to recover a portion of the deferred World Trade Center ("WTC") related costs. The electric amount included in rate base, $94 million, was approved by the Commission as part of Case 08-E-0539. The amount included in gas rate base, $46 million, was approved by the Commission in Case 06-G-1332.

Line 59 (E), Deferred Fuel - Net of Tax, is the average balance of deferred fuel, net of taxes. Deferred fuel is comprised of deferred Market Supply Charge ("MSC")/MAC costs.

F. Detailed Development of Accumulated Deferred Income Taxes (Exhibits AP-2, page 5)

Q. How did the Company develop Accumulated Deferred Federal Income Taxes on page 5 of Exhibits AP-2?

A. The Company developed Accumulated Deferred Federal Income Taxes for plant-related items using data from its capital budget and tax depreciation models. The

Company calculates the rate base impact for federal deferred income taxes by using a proration methodology that is required by the Internal Revenue Service ("IRS") for any revenue requirement calculation that employs a future test period. The Company developed non-plant related deferred taxes by escalating the historic balances.

Q. How did the Company develop the Accumulated Deferred State Income Taxes on page 5 of Exhibits AP-2?

A. The Company developed Accumulated Deferred State Income Taxes using data from the Company's capital budget and tax depreciation models. The forecasted Rate Year balance is based on 50% of beginning and 50% of ending forecasted balance.

Q. Please explain the line items pertaining to federal and state deferred income taxes.

A. Below are detailed descriptions of the line items common to federal and state deferred income taxes. For figures for each line item, please see page 5 of Exhibits AP-2.

Statutory Tax Deduction, represents the deferred income taxes resulting from the normalization of federal/state tax depreciation. The Company developed the average balance of accumulated deferred taxes for the Rate Year by starting with the actual balance at the end of the Historic Year and increasing it each month through the Rate Year if forecasted deferred income taxes generated by tax depreciation normalization exceeded the amortization of such amounts previously deferred.

Change in Accounting Section 263A, represents deferred income taxes for capitalized overheads deducted on the Company's tax returns under Section 263A of the IRS Code.

Repair Allowance, represents deferred income taxes for repair allowance deductions claimed in lieu of tax depreciation on new plant.

Cost of Removal, reflects deferred income taxes associated with the timing differences between financial accounting and accounting for income tax purposes related to removal costs.

Materials and Supplies Deduction, represents deferred income taxes for non-incidental materials and supplies costs claimed in lieu of the tax depreciation that would be otherwise claimed on new plant.

Vested Vacation (non-plant portion), reflects the amount of accumulated deferred federal/state income taxes on the vested vacation pay deduction.

Prepaid Insurance Expense, reflects the amount of accumulated deferred federal/state income taxes on prepaid insurance expenses.

Unbilled Revenues, represents the deferred balance of taxes paid on unbilled revenues. The Commission, in its Statement of Policy on Accounting and Ratemaking Procedures to Implement Requirements of the Tax Reform Act of 1986 ("TRA-86"), issued July 8, 1989 in Case 29465, directed utilities to normalize the effect of unbilled revenues in taxable income. This line also reflects the effects of the unbilled revenue change previously mentioned in this section.

Call Premiums, is the deferred federal/state income tax effect resulting from the payment of call premiums when redeeming long-term debt issues prior to their maturity dates. The call premiums paid are a current deduction for federal/state income tax purposes, but amortized over the remaining lives of the redeemed issues, in accordance with Commission policy.

G. Rate Base Over/Under Capital Adjustment (Exhibits AP-2, page 6)

Q. Please explain the rate base over/under capitalization adjustment ("EB/Cap Adjustment") on Exhibits AP-2, page 6.

A. The rate base over/under capitalization adjustment on Exhibits AP-2, page 6, reflects the required adjustment to rate base to make earnings base equal to capitalization. The Commission has required this EB/Cap Adjustment in past proceedings to synchronize rate base plus interest bearing items (together, "Earnings Base") with the total capitalization employed in utility service. Line 54 on Exhibits AP-2, page 6, shows the EB/Cap adjustment amount to each electric and gas rate base. The Company calculates the EB/Cap adjustment amount by taking the total capitalization amount on line 53, less the rate base balance on line 31.

X. REVENUES AND OPERATING EXPENSE DATA (Exhibits AP-3)

Q. Have you included a presentation of the Historic Year and projected Rate Year revenues and expenses in your exhibits?

A. Yes. Historic Year levels and Rate Year levels of revenues and expenses are presented in Exhibits AP-3.

Each of Exhibits AP-3 contains extensive detail regarding elements or components of revenue and expense on which the Company's rate request is based. The first page of Exhibits AP-3 is an index of the 17 schedules included in the exhibits.

- Schedule 1 presents the major cost drivers of the proposed revenue requirement increase.
- Schedule 2 presents the summary of the proposed revenue requirement increase.
- Schedule 3 presents the total revenues at current rates used to develop the revenue requirement.
- Schedule 4 presents projected amortizations of deferred debits and credits.
- Schedule 5 presents projected other operating revenues.
- Schedule 6 shows projected O&M expenditures.
- Schedule 7.1 presents depreciation at current rates with no additional recovery of the reserve deficiency and Schedule 7.2 presents depreciation at proposed rates and adjusting the annual recovery of the reserve deficiency.
- Schedule 8 presents projected taxes other than income taxes.
- Schedules 9 and 10 present projected state and federal income taxes.
- Schedule 11 projects Rate Year interest expense for purposes of reflecting the interest deduction included in Schedules 9 and 10. The schedule applies the weighted cost of debt from the Company's capitalization

schedules to forecasted rate base inclusive of interest bearing CWIP in order to derive the projected interest deduction.

- Schedule 12 presents projected fund requirements and sources.
- Schedule 13 presents interest coverage ratios.
- Schedule 14 shows how the general escalation factor was derived.
- Schedule 15 presents underlying calculations supporting the labor escalator.
- Schedule 16 summarizes normalizations, program changes, and other Rate Year adjustments.
- Schedule 17 lists cost elements and other items that the Company expects to update during these proceedings, and the sponsoring witnesses. In addition, any adjustments identified during discovery will be updated as well.

A. Sales Delivery and Net Revenue Margins (Exhibits AP-3, Schedule 3)

Q. How did the Company develop the sales revenues and associated fuel, purchased power and purchased gas costs, as applicable, for the Rate Year shown on Schedule 3 of Exhibits AP-3?

A. The Company's Electric and Gas Forecasting Panels provided the sales revenue forecast for each commodity shown in Exhibits AP-3, Schedule 3. The methodology used to derive sales revenue forecasts is addressed in the direct testimony of those Company witnesses.

The Company developed fuel and purchased power costs as follows:

- Electric fuel and purchased power costs were developed by Company witness Kimball – Electricity Supply. We adjusted the electric fuel costs to an accounting basis to reflect the deferred accounting for these costs prescribed by the Commission as implemented through the MAC and the MSC.
- Purchased gas costs were developed by the GIOSP. We adjusted the purchased gas costs to an accounting basis to reflect the deferred accounting for these costs prescribed by the Commission as implemented through the Gas Cost Factor (“GCF”) and the Monthly Rate Adjustment (“MRA”).

B. Amortization of Regulatory Deferrals (Exhibits AP-3, Schedule 4)

Q. Please explain the amortizations of regulatory deferrals as shown on Exhibits AP-3, Schedule 4.

A. These adjustments reflect the Company’s proposals for crediting or charging customers for a variety of deferred credits or deferred charges. The Company projects the balance of deferred charges at the beginning of the Rate Year by obtaining the deferral balances as of September 30, 2021 and projecting any additional deferrals and amortizations from October 2021 to December 2022. In the preliminary update, the Company will update this exhibit with the December 31, 2021 deferral balances and revise its 2022 projections of deferrals and amortizations as appropriate.

Q. Do these proposals and adjustments result in a net credit to or net charge to customers in the Rate Year?

A. For electric, the result is a net collection from customers of $213,368,000 in the Rate Year.

For gas, the result is a net collection from customers of $37,871,000 in the Rate Year.

Q. What amortization period is the Company proposing for these deferred credits and deferred charges?

A. For most items, the Company proposes an amortization period of three years starting at the beginning of the Rate Year (*i.e.*, January 1, 2023). With regard to electric, the Company proposes longer amortizations for the REV Demonstration Projects, BQDM, NENY EE, Electric Vehicle Smart Charge, Electric Vehicle Power Ready, NENY Heat Pumps (Clean Heat), Heating Electrification Make Ready, EE Information Systems and Operational Software Upgrades, Legacy Meters, Non-Wire Alternative programs, Storage Dispatch General Expenses, System Peak Reduction programs, and Site Investigation and Remediation ("SIR") costs. With a few exceptions explained by the Company's CES Panel, the extended amortization periods were directed or previously approved by the Commission. For gas, the amortization period for EE extends beyond three years. Additionally, the Company is recovering costs of the Meadowlands Heaters Projects from gas customers over the remaining nine years of the fifteen-year amortization period approved by the Commission in Case 16-G-0061. The relevant amortization periods for all deferred balances are noted within Schedule 4 of AP-3.

Q. Are the deferred credit and deferred charge balances the Company is proposing to amortize, projected balances as of the start of the Rate Year?

A. Yes, the amounts shown on Schedule 4 of Exhibits AP-3 are based on projected deferred balances as of the start of the Rate Year. In the Company's Update filing, the Company will refine its projections to reflect additional deferral activity in the intervening months, as well as any new information that impacts the deferral projection.

Q. Please identify and explain the deferred credit and deferred charge items included in the amortization of regulatory deferrals on Schedule 4 of Exhibits AP-3.

A. Below are detailed descriptions of each item and a designation to which commodity (ies) it applies (E- Electric, G-Gas).

1. Electric and Common Items

Line 1, Additional 18a Assessment: (E, G) As result of the PSC 18A audit review, the Department of Public Service ("DPS") Staff advised the Company to defer the 2017-2018 fiscal period general assessment for future refund. The DPS Staff reasoned that the Company had recovered the 2017-2018 fiscal period general assessment under-collection amount in 18A assessment surcharge based on the estimated payment amount. Therefore, the difference between final and estimated general assessment payment should be deferred to the regulatory deferral account for customer's benefit.

Line 2, AMI Customer Engagement: (E, G) Reflects a refund over three years of residual AMI Customer Engagement under-spending during prior rate plans (16-E-0060 and 16-G-0061).

Line 3, Carrying Charges (Net Plant Reconciliation): (E, G) Reflects a refund to customers over three years of carrying charges on net plant reconciliations, inclusive of AMI, during the current rate plans.

Line 4, Carrying Cost – SIR Deferred Balances: (E, G) Reflects refunds to electric customers and gas customers over three years of carrying charges accrued on the variation between the forecasted balance of deferred SIR costs reflected in rate base under the Company's current rate plans and the actual deferred balances.

Line 5, Customer Cash Flow Benefits- Bonus Depreciation: (E, G) Reflects a refund for electric and a recovery from gas customers over three years related to reconciliations of bonus depreciation.

Line 6, Energy Efficiency: (E, G) This item represents the amounts to collect from customers for Energy Efficiency program costs. The Company's proposed methodology to reconcile the revenue requirement effect of its energy efficiency spending is discussed in Section XVI.A.7 of this direct testimony.

Line 7, Energy Efficiency Carrying Charge: (E, G) This item represents interest to refund to customers on energy efficiency program spending under-runs in accordance with the energy efficiency program reconciliation mechanism.

Line 8, Federal Tax Reform Transition Period: (E, G) This item represents residual amounts to collect from customers associated with the federal income tax difference between the level previously embedded in rates at 35 percent and the federal tax rate of 21 percent effective for calendar year 2018 under the Tax Cuts and Jobs Act of 2017.

Line 9, Former Employees/Contractor Proceeding: (E, G) Reflects a refund over a three-year period of residual amounts involving the Former Employees/Contractor Proceeding in accordance with the Joint Proposal adopted in Cases 09-M-0114 and 09-M-0243.

Line 10, Interest on Rate Case Deferrals: (E, G) Reflects recovery from electric and gas customers over a three-year period of interest on various regulatory asset and liability balances.

Line 11, Interest Rate True-Up (Auction Rate/ LT Debt): (E, G) Reflects the refund to electric customers and gas customers over three years of variable rate debt interest cost reconciliations.

Line 12, Interference: (E, G) Reflects the recovery over a three-year period of electric and gas interference costs in accordance with the interference program expense reconciliation mechanism.

Line 13, Management Variable Pay: (E, G) Reflects the refund to electric customers and gas customers over a three-year period of the difference between the Company's actual expense for non-officer management variable pay and the targeted amounts in rates.

Line 14, NYSIT Rate Change: (E, G) Reflects a residual recovery from electric customers and refunds to gas customers over a three-year period due to the effect of a change in the NYS income tax rate.

Line 15, Pensions/OPEBs: (E, G) Reflects a recovery from electric customers and gas customers over a three-year period of pensions/OPEBs costs. The electric deferred pension and OPEB regulatory asset at September 30, 2021 of $296.2 million is projected to decrease to a regulatory asset of $214.2 million by the start of the Rate Year. The gas deferred pension and OPEB regulatory asset at September 30, 2021 of $49.3 million is projected to decrease to a regulatory asset of $36.9 million by the start of the Rate Year. Deferral accounting for pension and OPEB costs is provided for by the Commission's Statement of Policy and Order Concerning the Accounting and Ratemaking Treatment for Pensions and Postretirement Benefits Other Than Pensions issued September 7, 1993 in Case 91-M-0890.

Line 16, Prop Tax Refund (City): (E, G) Reflects a refund over a three-year period of the residual balance at September 30, 2021 for deferred property tax refunds.

Line 17, Property Tax Deferrals: (E, G) Reflects a recovery of undercollection from electric customers and refund of overcollection to gas customers over three years of the amount under the reconciliation mechanisms included in the Company's current electric and gas rate plans.

Line 18, Sales and Use Tax Refund: (E, G) Reflects a residual refund to electric and gas customers over three years related to sales and use tax refunds received during the previous rate plan.

Line 19, SIR net of Shared Earnings: (E, G) Reflects the recovery from electric customers and gas customers over five years for SIR Expenditures including MGP, Superfund, Appendix B, Astoria, Underground Storage Tank, and Other remediation sites. The amounts presented in this amortization reflect both the amortization of the projected deferral balance in the account as of December 2022 (inclusive of any shared earnings deferrals recorded prior to September 2021), as well as amortization of projected spending during the Rate Year.

Line 20, BQDM & REV Demo Carrying Charge Deferral: (E) Reflects forecasted refunds to electric customers over three years of carrying charges on BQDM & REV Demonstration project costs that underran the rate base target during the current rate plans.

Line 21, Brooklyn Queens Demand Management Program (“BQDM”): (E) Reflects the recovery from electric customers over a five-year period for BQDM. The five-year recovery reflects the average remaining recovery period for the deferred charges inclusive of new charges projected during the linking period (*i.e.*, October 1, 2021 through December 31, 2022) and Rate Year. The Company estimates that it will have $31.7 million in unrecovered expenditures by the beginning of the Rate Year.

Line 22, Capital Expense Carrying Charge: (E) Reflects a refund to the customer over a three-year period representing residual carrying charges from previous rate plans.

Line 23, DSM Liquidated: (E) Reflects refunds to electric customers over three years of the terminated Demand Side Management ("DSM") contract liquidation payments received by CECONY and associated accrued interest.

Line 24, Electric Service Reliability Rate Adjustment (CAIDI/ SAIFI): (E) This line item will be removed in in the Update filing. It reflects charges that are refunded to customers via a surcharge mechanism and should not be included in the schedule.

Line 25, Electric Vehicle Rate Incentive Expense True Up: (E) Reflects refunds of residual underspend on Electric Vehicles Rate Incentive Expense from Case 16-E-0060 to electric customers over three years.

Line 26, Electric Vehicle Smart Charge: (E) Reflects the recovery from electric customers over a ten-year period for the Smart Charge Electric Vehicle Program. Pursuant to the Commission's rate order in Case 16-E-0060, electric rates are designed for the Company to recover the costs of the equipment portion of Smart Charge Program over ten years, including the overall pre-tax rate of return on such costs. Therefore, the revenue requirement reflects recovery of these costs over ten years through base rates.

Line 27, Emergency Low Income Credit: (E) Reflects recovery from electric customers over the remaining three-years of a five-year amortization authorized by the Commission for the 2020 summer cooling credit program for low income customers during the COVID-19 pandemic.

Line 28, Interest on Revenue Requirement Service Change: (E) Reflects recovery from electric customers over a three-year period relating to the interest on the phase-in of electric base rates under Case 16-E-0060.

Line 29, Legacy Meters: As per Case 16-E-0060, the Company will begin amortizing unrecovered legacy meter costs after the implementation of AMI. The Company expects to complete AMI deployment in RY1. The Company estimates approximately $427M in unrecovered legacy meter costs at the beginning of RY2. The unrecovered amount is currently classified as an accumulated reserve for depreciation. However, per the terms of the 2016 Rate Order, once AMI is fully deployed, the Company is to defer as a separate regulatory asset the remaining undepreciated investment in legacy meters and recover it over a 15-year period. Because the Company projects AMI to be fully deployed by December 2023, the Company expects to reclassify the $427 million in estimated unrecovered costs from accumulated reserve for deprecation to a regulatory asset in RY2. For further discussion, see the Depreciation Panel testimony.

Line 30, MTA work: (E) Reflects the residual recovery from electric customers over a three-year period for Commission-ordered work on the MTA system.

Line 31, Non Wire Solutions Projects (NWS): (E) This item represents costs to recover from customers over ten years associated with NWS projects.

Line 32, Prop Tax Refund Town: (E, G) Reflects a refund over a three-year period of the residual balance at September 30, 2021 for deferred property tax refunds.

Line 33, REV Demonstration Projects: (E) Reflects the recovery from electric customers over a six-year period for REV Demonstration Projects. The Commission's December 17, 2015 Order in Case 15-E-0229 directed the Company to recover REV Demonstration costs in a manner similar to its recovery of BQDM costs (*i.e.*, recovery over ten years). The six-year recovery reflects the average remaining recovery period for the deferred charges inclusive of new charges projected during the Rate Year.

Line 34, Settlement of Storms Riley and Quinn: (E) This item reflects the amounts to return to customers due to the settlement agreement reached between the Company and the DPS Staff to resolve all issues in Case 19-E-0107.

Line 35, Gain on Sale of North First Street: (E) This amortization reflects refunding the customers' residual share of the gain on this property sale over three years.

Line 36, Gain on Sale of Kent Ave: (E) This amortization reflects refunding the customers' residual share of the gain on this property sale over three years.

Line 37, Storage Dispatch General Expenses - 10 Years: Pursuant to the Commission's order in Case 18-E-0130, this item represents spending on dispatch rights for bulk-level energy storage systems for contracts up to ten years.

Line 38, Storage Dispatch General Expenses - 7 Years: Pursuant to the Commision's order in Case 18-E-0130, this item represents spending on dispatch rights for bulk-level energy storage systems for contracts up to seven years.

Line 39, Storm Deferral: This item represents amounts to be recovered from customers under the major storm costs reconciliation mechanism.

Line 40, System Peak Reduction: (E) Reflects the recovery from electric customers over a ten-year period for System Peak Reduction Projects. Pursuant to the Commission's rate order in Case 16-E-0060, electric rates are designed for the Company to recover the costs of the system peak reduction projects over ten years, including the overall pre-tax rate of return on such costs. Therefore, the revenue requirement reflects recovery of these costs over ten years through base rates.

Line 41, WTC Incident System Restoration Interest Accrued: (E) Reflects a residual recovery from electric customers over three years for interest accrued on WTC Incident System Restoration costs.

2. Additional Gas Only Items

Q. Please identify and explain the items of deferred credit and deferred charge items on Exhibit AP-3, Schedule 4 that pertain only to gas.

A. The items are as follows:

Line 20, Building Meter Conversion Study: (G) Reflects a recovery over a three-year period of the residual regulatory asset balance related to this item.

Line 21, Gas Service Line: (G) Reflects the recovery from gas customers over a three-year period for costs deferred for incremental inspection and repair work incurred as a result of the DPS Staff's directives related to the change in the definition of "Gas Service Line." Incremental costs incurred under the current rate case (19-G-0066) are being recovered through the MRA. Such recovery is capped at $99.79 million (cumulative over RY1- RY3). The Company expects to defer approximately $42 million in excess of the capped threshold due to changes it made in its inspection plan to comply with the DPS Staff's directives interpreting the Commission's Gas Service Line inspection order. The Company accordingly deferred these costs as authorized by the "new laws" provisions of its current rate plan. The Company is proposing that such costs, in addition to the residual balance from Case 16-G-0061, be recovered through base rates. See the Gas Infrastructure, Operation, and Supply Panel testimony for further discussion on this deferral.

Line 22, Inside Gas Meters: (G) Reflects the refund to gas customers over a three-year period for over-recovery of deferred balances, partially offset by additional deferred charges incurred during the current rate plan, to relocate and install gas meters that are located inside a customer's premises outside.

Line 23, Meadowlands Heaters: (G) Reflects the recovery from gas customers over a nine-year period the remaining balance for Meadowlands Heaters Projects. Pursuant to the Commission's rate order in Case 16-G-0061, the Company is required to defer the cost as a regulatory asset and recover the cost over the 15-year period that began January 1, 2017.

Line 24, Penalties on Off-Peak/ Interruptible Customers: (G) Reflects the refund to gas customers over three years of penalties assessed to off-peak and interruptible customers for not switching to alternative fuel sources when required.

Line 25, Pipeline Integrity: (G) Reflects the residual refund to gas customers over three years related to the annual reconciliation of KeySpan pipeline integrity costs allocable to the Company pursuant to the New York Facilities Agreement.

Line 26, Pipeline Upgrade Projects: (G) Reflects recovery from gas customers over a three-year period for the White Plains Gate Station. These represent the costs of the project exceeding $11 million, which is the cap for collection through the MRA.

Line 27, Positive Incentive Revenue Adjustments: (G) This item reflects residual amounts to refund to customers as a result of an overcollection of financial incentives achieved under a previous rate plan (Case 16-G-0061).

Line 28, R and D Recon: (G) Reflects the recovery from gas customers over a three-year period for the reconciliation of Gas Research and Development (“R&D”) costs.

Line 29, Transition Gas Adjustment: (G) This residual balance is proposed to be refunded to customers over a three-year period.

Line 30, Unauthorized Use Charge: (G) This residual balance is proposed to be refunded to customers over a three-year period.

C. Other Operating Revenues (Exhibits AP-3, Schedule 5)

Q. Is the Accounting Panel presenting data on Other Operating Revenues of the Company?

A. Yes. Schedule 5 of Exhibits AP-3 shows the detail of Other Operating Revenues in the Historic Year and the Rate Year.

Q. Please briefly explain what is meant by Other Operating Revenues and how they affect the amount of the revenue requirement.

A. Other Operating Revenues include revenue collected by the Company from customers or third parties such as late payment charges and facility rents. Increases in such revenues serve to reduce the Company's base rate revenue requirement and decreases in such revenues serve to increase the Company's base revenue requirement.

Q. Please summarize the projected net changes to the level of Other Operating Revenues from the Historic Year to the Rate Year.

A. For electric, the Historic Year level of $740 million is forecast to decrease by $534 million, for a Rate Year level of $206 million.

For gas, the Historic Year level of $197 million is forecast to decrease by $161 million, for a Rate Year level of $36 million.

The line items included in these totals, and their corresponding figures, are specified on Exhibits AP-3, Schedule 5. Note that while Other Operating

Revenues in this schedule show significant decreases, much of that decrease is driven by normalizations of items that do not have an effect on the Company's revenue requirement. Such items are discussed below and can be seen within AP-3, Schedule 5. Excluding the effect of normalized items (e.g., eliminating the impact of surcharge activity; resetting deferrals/amortizations for a new rate case), Other Operating Revenues are expected to increase, with the largest driver for both electric and gas being projected increases in late payment charges relative to the Historic Year.

Q. Are the types of Other Operating Revenues the same for electric and gas?

A. No, although there are some types that apply to both commodities. Below are detailed descriptions of each type of expense and a designation to which commodity(ies) it applies (E- Electric, G- Gas). For the Historic Year amount, any adjustments, and the Rate Year forecast for each line item, please see Exhibits AP-3, Schedule 5.

1. Electric and Common Revenue Types

Q. Please explain the items of Other Operating Revenues that pertain to electric or are common to electric and gas shown on Schedule 5 of Exhibits AP-3.

A. The items are as follows:

Note that Lines 1 through 5 are various charges to customers resulting from miscellaneous tariff charges. The Rate Year forecasts are based on corporate budgets.

Line 1, AMI Opt Out Fees: (E,G) This line represents revenues that the

Company receives from customers who opt-out of the AMI program.

Line 2, Field Collection: (E) This line represents charges that are assessed on commercial customers when the Company sends employees to the field to collect overdue balances.

Line 3, Meter Recovery: (E, G- Line 2) This line represents charges to active customers for payments made by the Company to apply for a court order to recover the customer's meter.

Line 4, No Access Charge: (E, G- Line 3) This line represents monies collected from customers because the Company was unable to access meters.

Line 5, Miscellaneous Service Revenues: (E, G- Line 4) This represents the Company's forecast of various charges to customers other than AMI opt out fees, field collection, meter recovery, and no access charge, which are broken out separately in Lines 1 to 4 for electric and 1 to 3 for gas.

Line 6, Transmission of Energy: (E) This represents revenues from the transmission of energy under bundled "grandfathered" firm transmission agreements with the New York Power Authority ("NYPA") and the Long Island Power Authority ("LIPA"). The forecast remains at the current level, as approved in the Company's 2019 electric rate case.

Line 7, Transmission Service Charges ("TSC"): (E) This represents daily transmission wheeling transactions scheduled through the New York Independent System Operator ("NYISO"). The Rate Year forecast reflects the current level that was approved in the Company's 2019 electric rate case.

Line 8, Maintenance of Interconnection Facilities: (E) This reflects a projection for the net reimbursement of certain expenses the Company incurs for interconnecting customers to the Con Edison system. The Rate Year forecast remains at the Historic Year level.

Line 9, Excess Distribution Facilities: (E) This represents tariff payments from customers for distribution facilities provided by the Company in excess of those normally provided. The Rate Year forecast is the average of these revenues for the prior three years (*i.e.*, October 1, 2018 through September 30, 2021).

Line 10, Late Payment Charges: (E, G- Line 7) This includes revenues from residential and non-residential customers. Due to the COVID-19 pandemic and associated laws, the Company did not assess late payments charges for the majority of the Historic Year. As such, the Rate Year forecast is based on the level that was approved by the Commission in the Company's 2019 electric rate case. The Company applied the factor that was also approved in the Company's 2019 electric rate case to the Rate Year sales revenue forecast to arrive at late payment charges at the proposed rate. The Company's proposal to reconcile these revenues is discussed in Section XVI.

Line 11, NYSERDA On-Bill Recovery Financing Program: (E) When homeowners obtain a loan from the New York State Energy Research and Development Authority ("NYSERDA"), they can repay the loan through their utility bill by using the on-bill recovery financing program. The Company then remits the money to NYSERDA. NYSERDA pays the Company a one-time fee of $100 for each loan and a fee of one percent of the amount of each loan to defray costs directly associated with implementing the program The Rate Year forecast is the average of these revenues for the prior three years (*i.e.*, October 1, 2018 through September 30, 2021).

Line 12, Revenues From The Learning Center: (E, G- Line 8) These revenues result from providing training and conference services to outside parties. The Rate Year forecast is based on the Company's 2021 budget for such revenues with a 2% escalation per year.

Line 13, Wholesale Distribution Service: (E) This line item represents revenues the Company receives for delivery service under the Wholesale Distribution Service pursuant to the Open Access Transmission Tariff ("OATT"). The Rate Year forecast remains at the Historic Year level.

Line 14, Proceeds from Sales of TCCs: (E) This represents projected auction proceeds from the sale of Transmission Congestion Contracts ("TCC"). The Rate Year forecast is based on the current level that was approved by the Commission in the Company's 2019 electric rate case. Variances between the actual amount of revenues achieved and the levels included in rates are surcharged or passed back to customers through an existing tariff mechanism in the MAC.

Line 15, POR Discount: (E, G-Line 9) This represents the discount on receivables purchased by the Company from energy services companies ("ESCOs"). The Company's proposal to reconcile these revenues is discsued in Section XVI. The Rate Year forecast reflects the current Historic Year level.

Line 16, Substation Operation Services (E) These are revenues associated with work done for third parties. The Rate Year forecast is the average of these revenues for the prior three years (*i.e.*, October 1, 2018 through September 30, 2021).

Please note that the Company performs accommodation billings pursuant to General Rule 17.2 of the Company's electric tariff based on the elements of cost identified in General Rule 17.3. The Electric Rate Panel has updated a number of tariffs that outline the overhead rates currently applied to accommodation billings. If the updated overhead calculations and associated tariff are approved by the Commission, the Company would reflect these updates effective at the start of the Rate Year.

Q. Would you like to make additional comments regarding the electric accommodation work that the Company performs for third parties?

A. General Rule 17.3 of the Company's electric tariff lists the elements of cost charged for special services performed by the Company pursuant to General Rule 17.2.

The Company is modifying the percentages to be applied to certain cost elements based on the average of work performed for the 12 months ended 2019, the 12 months ended 2020 and the 11 months ended November 2021. The stores handling rate will increase from 11 percent to 13 percent; the overhead rate for Electric Engineering and Administrative and General ("A&G") will increase from 15 percent to 17 percent; the overhead rate for A&G only will increase from 1 percent to 3 percent; and when Construction Management Oversight ("CMO") is required, the overhead rate for CMO, Electric Engineering and A&G will increase from 19 percent to 35 percent.

As indicated in the Electric Rate Panel's testimony, the tariff leaf for General Rule 17.3 (Leaf 126) has been updated to reflect these new percentages.

Q. What additional comments would you like to make regarding the gas accommodation work that the Company performs for third parties?

A. General Information IV. 2 of the Company's gas tariff lists the elements of cost charged for special services performed by the Company.

The Company is modifying the percentages to be applied to certain cost elements based on the average of work performed for the 12 months ended 2019, the 12 months ended 2020, and the 11 months ended November 2021. The stores handling rate will increase from 11 percent to 13 percent; the overhead rate for Gas Engineering and A&G will increase from 7 percent to 10 percent; the overhead rate for A&G only will increase from 1 percent to 3 percent; and when CMO oversight is required, the overhead rate for CMO, Gas Engineering and A&G will increase from 13 percent to 23 percent.

As indicated in the Gas Rate Panel's testimony, the tariff leaf for General Information IV. 2 (Leaf 117) has been updated to reflect these new percentages.

Line 17, Management Fees: (E) This line represents revenues the Company receives for administration work performed pertaining to its Areawide Public

Utilities Contracts. The Rate Year forecast reflects the current Historic Year level.

Line 18, Net Unbilled Revenues: (E, G-Line 10) This item represents the change in the unbilled revenue level recorded on the Company's books and records during the 12 months ended September 30, 2021. The accounting for unbilled revenues has no impact on the revenue requirement.

Line 19, Reconnection Fee: (E, G- Line 6) This represents reconnection fees applied to customers who require service restoration. The Rate Year forecast is described in the testimony of the Customer Operations Panel.

Line 20, Reconnection Fee Waiver: (E, G- Line 5) This line represents waiver of reconnection fees for low income customers who require service restoration. The Rate Year amount represents targets developed by Customer Operations. Refer to Customer Operations Panel's testimony for discussion of such targets.

Line 21, DG Project Application Fees: (E) This line represents the revenues the Company receives for solar applications. The Rate Year forecast is set at the Historic Year level.

Line 22, Miscellaneous: (E, G- Line 13) This line includes various small items. For gas, the Company did not include a Rate Year forecast for revenues it receives for penalties assessed on interruptible customers who failed to submit affidavits, since it is difficult to forecast the activities for this item and there was no activity in the Historic Year. The Rate Year forecast for other items in this line is based on the Historic Year level.

Line 23, Rent from Electric Property: (E) This represents amounts billed by the Company to third parties for their use of Company property such as poles, easements, and transmission and distribution facilities. The forecast of revenue reflects an analysis of the terms of the Company's rental agreements.

Line 24, Interdepartmental Rents: (E, G-Line 15) This represents carrying charges billed to one department of the Company for its use of facilities by another department of the Company. Joint use facilities include the head house at Hell Gate Station (electric and gas); facilities at the East River station (electric and steam); the Ravenswood Tunnel, Flushing Tunnel, and Astoria Tunnel (electric and gas); and the Hudson Avenue Tunnel (electric and steam). Carrying charges include components of rate of return on net plant investment, depreciation, and taxes. Changes in revenues for one department are offset by changes in interdepartmental rent expense for other departments.

Note for Following Line Items: Lines 25 through 31 (E, G- Lines 20 through 37), are offset in other places on the income statement, such as sales revenues or included in the MSC / MAC. Lines 32 through 44 (E, G- Lines 38 through 50) are deferrals/reconciliations. Unless otherwise noted, no activity is projected for these items for the Rate Year.

Line 25, RDM Reconciliation: (E, G-Line 27) This represents the accounting adjustments recorded by the Company to implement the Revenue Decoupling Mechanism ("RDM") in place under its current electric and gas rate plans. It relates to the deferral of the variation between the actual delivery revenues billed and the established target level.

Line 26, Indian Point Energy Center Programs: (E) This represents the carrying cost on the deferred expenditures related to the Indian Point Energy Center programs. This cost was recovered through the MAC.

Line 27, NEIL Dividend: (E) This item reflects the Nuclear Electric Insurance Limited ("NEIL") dividend received by the Company. This item is refunded to customers through the MAC.

Line 28, MFC – Lost Supply Revenues: (E) This represents the variation between the level of Merchant Function Charge ("MFC") supply revenues collected from full service customers and the actual amounts received during the Historic Year. The variation is the result of customers switching to ESCOs, who provide energy to those customers.

Line 29, Hedging Program Interest: (E, G- Line 24) This line reflects Historic Year reclassification of interest assessed on funds advanced for the program to interest income.

Line 30, Price Guarantee Program: (E) This line represents collections related to the program. The Company developed the Commission-approved Innovative Pricing Pilot to test new rate designs. Such collections are recovered through MAC.

Line 31, ESCO/Marketers – Bill Charges: (E, G- Line 25) These are billing and payment processing charges the Company collects from ESCOs for consolidated billing services. These revenues were excluded from the Rate Year forecast of Other Operating Revenues and are included in Sales Revenue.

Line 32, Interest Rate True-Up: (E, G- Line 49) This represents the net variation between the cost of variable rate long-term debt reflected in rates and the Company's actual cost during the Historic Year. The interest rates for variable rate long-term debt will be reset in this case and, as a result, this variation is assumed to be zero in the Rate Year.

Line 33, Net Plant Carrying Charges: (E, G-Line 41) This represents amounts deferred for credit to customers resulting from net additions to utility plant being less than reflected in rates.

Line 34, Interference Reconciliation: (E, G-Line 48) This represents the deferrals for interference reconciliation as compared to target levels reflected in rates.

Line 35, Amortization of Deferrals: (E, G-Line 39) This reflects the amortization of various deferred costs that were amortized under the current rate plan.

Line 36, Management Variable Pay ("MVP"): (E, G-Line 50) This item represents revenues deferred under the MVP reconciliation mechanism included in the current rate plans.

Line 37, Accounting Reserve: (E, G-Line 40) This item represents reserves set up by the Company for various purposes, including shared earnings accruals.

Line 38, Emergency Low Income Credit: (E) This item represents deferrals and related interest for temporary emergency financial relief for low-income bill discount program customers.

Line 39, Federal Tax Reform Transition Period: (E, G-Line 47) This item represents the deferrals of over-refund of tax sur credits to the customers.

Line 40, ERRP Major Maintenance: (E) The Company's current electric rate plan reflects $8.798 million for the ERRP maintenance costs per year. This item represents accounting entries related to the reconciliation of actual ERRP maintenance costs with the amount included in rates.

Line 41, Carrying Charge on Energy Efficiency Programs: (E, G-Line 45) These lines represent deferrals resulting from reconciling actuals to target levels set in the current rate plan for Energy Efficiency related programs, SmartCharge Program, the BQDM program, and REV demonstration projects.

Line 42, Climate Study: (E, G-Line 46) This represents expenses incurred for the Climate Change Vulnerability Study that is collected through the MAC.

Line 43, GRT Public Utility Tax: (E & G – Line 38) This line reflects gross receipts taxes on revenues other than the sale of gas. No activity is projected for the Rate Year.

Line 44, Revenue Imputation - Cases 09-M-0114 and 09-M-0243: (E & G – Line 51) This represents the revenues recorded by the Company to offset the revenue requirement effect of certain capital expenditures in order to limit recovery to the level approved by the Commission in its April 20, 2016 Order in

Cases 09-M-0114 and 09-M-0243. The Company will adjust this amount on Update, if and to the extent necessary and appropriate, consistent with Commission's Order.

Line 45, NYPA Related Revenue: (E, G - Line 52) This line represents NYPA related revenues that are forecasted in sales revenues. Therefore, the Historic Year level of this item is normalized in this schedule.

2. Additional Gas Only Revenues Types

Q. Please explain the items of Other Operating Revenues representing revenue collected by the Company from customers or third parties that pertain only to gas shown on Schedule 5 of Exhibit AP-G3.

A. They are as follows:

Line 11, Reimbursement To National Grid – Governor's Island: (G) This represents National Grid's share of the revenues earned from gas sales to the United States Coast Guard in accordance with the Governors' Island agreement and serves to offset the gross amount (including National Grid's share) recorded in sales revenues. Embedded in the sales forecast is the historic level of revenue from National Grid. The Rate Year forecast was kept at the Historic Year level.

Line 12, R&D Ventures: (G) This represents royalties the Company receives from other gas utilities. The Rate Year forecast is the average of these revenues for the prior three years (*i.e.*, October 1, 2018 through September 30, 2021).

Line 16, New York Facilities: (G) This represents carrying charges billed by Con Edison to National Grid in accordance with the provisions of the New York Facilities Agreement The Rate Year forecast is at the Historic Year level.

Line 17, Real Estate Rents: (G) This revenue primarily represents the gas department's share of rental income from leasing property at the Company's central headquarters building.

Line 18, NYPA Variable and Maintenance and Line 19, Steam Department – ERRP Incremental Charges: (G) These two items, which are grouped under the heading "transmission system reinforcement recoveries" represent recoveries of CECONY's share of gas transmission facilities reinforcement costs from the generators that use gas that is delivered by the Company. Line 18 represents payments from generators for variable operating costs and upkeep of the Hunts Point Compressor. The Rate Year forecast is the average of these revenues for the prior three years (*i.e.*, October 1, 2018 through September 30, 2021). Line 19 represents recoveries of reinforcement costs from the Steam Department. There are no additional recoveries from the Steam Department projected. As a result, the Rate Year forecast for these revenues remains at the Historic Year level.

Note for Following Line Items: Lines 20 through 37 are offset in other places on the income statement, such as sales revenues or included in the MSC / MAC. Lines 38 through 50 are deferrals/reconciliations. Unless otherwise noted, no activity is projected for these items for the Rate Year.

Lines 20-22, Non-Firm Revenues: (G) These revenues are generated from serving non-firm customers and from efforts to maximize the value of assets obtained to meet the Company's firm customer requirements. These revenues are currently subject to the non-firm revenue sharing mechanism set forth in the current gas rate plan, which the Company is proposing to continue without change. The Company's filing reflects a $65 million imputation in base rates.

- Line 20, Gas Purchased from Transportation Customers: This line represents "cash out" transactions with gas marketers.
- Line 21, Gas Penalties – Off Peak/Interruptible: This line represents penalties assessed to off-peak and interruptible customers for not switching to alternative fuel sources when required.
- Line 22, Non-firm Interruptible Sales Credit: This line represents service fees related to off-system gas sales.

Line 23, Asset Management Revenue: (G) This item reflects revenues received for capacity releases. We do not reflect a Rate Year amount for this item in Other Operating Revenues because it is included as part of the non-firm revenue target.

Line 26, R&D True-Up and Surcharge (Millennium Fund): (G) This line reflects the deferrals related to the R&D reconciliation that was implemented as part of the current gas rate plan. Such deferrals were normalized from the Historic Year. The line also contains deferral and matching of revenues collected from customers through the MRA to fund certain gas R&D projects pursuant to the Commission's order dated April 4, 2000 in Case 99-G-1369 with projected

R&D expenses. The revenues are referred to as the "Millennium Fund." The Rate Year forecast for such items is zero.

Line 28, Low Income Program: (G) This line represents the accounting entries related to the deferral of low income discounts under the current gas rate plan.

Line 29, Gas In Storage Reconciliation: (G) This line represents the reconciliation of actual working capital for gas in storage compared to the level set under the current gas rate plan. Working capital on gas in storage is recovered volumetrically through the MFC and the MRA, instead of through base delivery rates. The revenues derived for working capital on gas in storage is calculated using the Company's allowed rate of return on the "base" or lowest inventory level of gas in storage during the year and the current other cost of capital rate on the average balances above the base amounts. In order to eliminate any impact on the Company's revenue requirement resulting from differences on the carrying cost of gas in storage, we have eliminated both the gas in storage surcharge revenues from the forecast and the historic level of storage gas from rate base as shown in Exhibit AP-G2.

Line 30, Credits and Collections: (G) This line represents the accounting entries related to the deferral of the MFC Credits and Collections charges under the current gas rate plan.

Line 31, Gas SBC Revenue Deferral: (G) This line represents an accounting entry related to the gas System Benefit Charge. The accounting entries record any over/under collection from customers for amounts expensed.

Line 32, Supply Related Charge Revenue: (G) This line represents the accounting entries related to the deferral of the difference between target and actual amounts collected for MFC-related charges approved by the Commission.

Line 33, Gas Daily Delivery Service: (G) This line represents the accounting entries related to the Gas Daily Delivery Service Program passed through the GCF.

Line 34, SBU Balancing Charges: (G) This line reflects the revenues recorded for gas transportation and balancing service to the Company's Steam Business Unit.

Line 35, Gas Adjustment Clause ("GAC") Interest: (G) The balance represents the accrued interest applicable to the GAC surcharge/refund. If the cost of gas to the Company that is recoverable from firm customers exceeds or falls below the total amount actually recovered through both the base rates and GAC revenues, the difference between the recoverable amount and the amount actually recovered is deferred, and is subsequently charged or refunded to customers, as appropriate. Pursuant to 16 New York Codes Rules & Regulations ("NYCRR") Section 720-6.5, interest is accrued on these balances in the deferral accounts.

Line 36, Gas Service Line Cost Recovery: (G) This line represents actual costs and associated carrying costs incurred above those reflected in the revenue requirement for gas service lines that are recovered through the MRA.

Line 37, Prior Gas Supplier Interest Refund: (G) This line represents refunds of the excess charges paid to the gas suppliers due to rate changes. Such refunds are recovered through the MRA.

Line 42, Incentive for NY Facilities Agreement: (G) This line represents incentives and associated interests that are returned back to the customers associated with the NY Facilities Agreement that are passed through the MRA.

Line 43, Interest Accrual on Deferred Leak Prone Pipe O&M: (G) This line represents the carrying costs for leak prone pipe O&M expenses deferred under the Safety and Reliability Surcharge Mechanism ("SRSM") that are recovered through the MRA. SRSM allows the Company to recover the carrying costs on incremental capital expenditures and O&M expenses associated with the replacement of leak prone pipe above the levels established under the current Gas Rate Plan, and incremental O&M expenses associated with lowering the Company's leak backlog.

Line 44, Pipeline Recovery: (G) This line represents the deferral of pipeline costs and associated carrying costs under the Pipeline Facilities Adjustment component of the MRA.

D. O&M Expenses (Exhibits AP-3, Schedule 6)

Q. Please explain the development of O&M Expenses shown on Schedule 6 of Exhibits AP-3.

A. Detailed calculations of the O&M amounts are shown on Schedule 6 of Exhibits AP-3. This page shows the derivation of the projected expenses in the Rate Year from the Historic Year expense. Various Company witnesses, including the Accounting Panel, will explain any adjustments.

Q. Please summarize the projected net changes to the level of O&M Expenses during the Historic Year to the Rate Year.

A. For electric, the Historic Year level of $3,839 million is forecasted to decrease by $341 million for a Rate Year level of $3,498 million.

For gas, the Historic Year level of $865 million is forecasted to increase by $450 million for a Rate Year level of $1,315 million.

Please note that these figures represent overall electric and gas O&M expenses, which include fuel and purchase power and that normalizes a number of other types of reconciled costs in the Rate Year that do not impact the revenue requirement. For gas, $421 million of the increase is attributable to fuel costs. For both electric and gas services, the non-reconciled portions of O&M expenses are increasing from the Historic Year to the Rate Year.

1. Development of O&M

Q. How did the Company develop O&M costs for the Rate Year?

A. The Company began with Historic Year O&M costs and then made adjustments to bring the costs forward to the Rate Year. Adjustments made to expense levels were due to normalizations, program changes, wage escalation, and general escalation. The Company's approach to each adjustment is described below beginning with how we developed general and labor escalation factors.

a. General Escalation (Exhibits AP-3, Schedule 14)

Q. Please describe how you escalated costs due to inflation.

A. The general escalation rate is applied to costs anticipated to increase at the rate of inflation as measured by the Gross Domestic Product ("GDP") price deflator. The labor component was removed from each element of expense and then the residual amounts were escalated using the GDP price deflator for most elements of expense subject to escalation. For certain expenses, the escalation factor is specifically tailored to the particular expense item, such as medical insurance costs, as addressed by the Company's Compensation and Benefits Panel. Additional detail on generally escalated costs is included in Schedule 14 of Exhibits AP-3.

Q. Please describe how the Company applied the general escalation rate in developing projected revenue requirements.

A. The GDP deflator published by the U.S. Bureau of Economic Analysis, used to escalate various non-labor elements of the cost of service as addressed throughout our direct testimony and the direct testimony of other witnesses, are based on actual data through the third quarter of 2021. The forecast for the fourth quarter of 2021 and the annual forecasts for 2022, 2023 and forward are from the Blue Chip Economic Indicators dated November 2021. Using these forecasts, the projected cumulative effect of inflation for the 27 months from the Historic Year to the Rate Year is 8.31 percent (approximately 3.5 percent annually over the linking period and RY1).

Q. Is the Company proposing a reconciliation of the costs associated with inflation in this case?

A. Yes; please refer to Section XVI of testimony for a discussion of the Company's proposed reconciliation.

b. Labor Escalation (Exhibits AP-3, Schedules 15.1-15.3)

Q. Please describe the labor cost escalation factor used to develop Rate Year labor cost.

A. The development of the labor escalation factor is presented in Schedules 15.1, 15.2, and 15.3 of Exhibits AP-3 for RY1-3, respectively. We applied the calculated labor escalation factor to Historic Year labor expense amounts, labor expense normalizations, and labor expense program changes to determine the total Rate Year level of labor expense for electric and gas services.

Q. How was the labor escalation factor calculated?

A The labor escalation factor is meant to reflect the labor expense increase associated with an average employee from the Historic Year to the Rate Year, independent of the effects of normalizations and program changes. As shown in the exhibits, the labor escalation factor is the weighted average of increase in management and weekly average straight time salaries and wages from the Historic Year to the Rate Year. For weekly employees, we included a general wage increase of 3.0 percent effective in July of each year. Semi-annual progression increases of 0.4 percent in October and February of each year are also included, but applied to only 56.8 percent of total weekly employees. The annual and progression wage increase rates are all pursuant to the collective bargaining agreements with union employees. The 56.8 percent figure is based on a five-year (2017-2021) average of the actual number of weekly employees that received progression increases as employees already at the maximum pay rate for their job title do not receive progressions. For management employees, we assumed annual 3.0 percent merit increases in April of each year.

Q. Did the Company apply a one percent productivity adjustment?

A. Yes, the Company reduced the labor escalation factor by 2.24% for Rate Year 1 and 1% each year for Rate Year 2 and Rate Year 3.

c. Normalization (Exhibits AP-3, Schedule 16)

Q. Please describe the normalization of O&M costs for the Rate Year.

A. The Company eliminated from the elements of expense ("EOE") those amounts that are nonrecurring, out of period, or for which the Company has decided to not seek recovery in this proceeding. The Company also annualized amounts that were not fully recognized in the Historic Year in order to develop Rate Year costs. Additional detail on normalized costs is found within Schedule 16 of Exhibits AP-3.

d. Program Changes (Exhibits AP-3, Schedule 16)

Q. Please describe how the Company adjusted O&M costs to reflect program changes.

A. The Company adjusted O&M costs based on documented, planned program changes that are driven by the business needs of the Company. Estimated costs associated with these programs and additional detail regarding these costs are included in Schedule 16 of Exhibits AP-3.

e. Common Expense Allocation

Q. Please explain how common O&M costs are allocated among electric, gas, and steam services for the Rate Year.

A. The Company used existing allocation factors the Commission adopted in the Company's current rate plans. Customer Operations and Customer Services expenses were allocated 84 percent to electric and 16 percent to gas. A&G expenses were allocated 77.60 percent to electric, 15.95 percent to gas, and 6.45 percent to steam.

Q. How did you allocate common expenses among electric, gas and steam services if they applied to O&R as well as CECONY?

A. The Company used the existing common expense split between CECONY and O&R, which is 92.45 percent allocated to CECONY and 7.55 percent allocated to O&R. This rate is updated annually by the Company using a three-part formula of revenues, assets, and payroll. To calculate the common expense allocation among electric, gas and steam services if they applied to O&R as well as CECONY, we took CECONY's existing allocation factor for each service (*i.e.*, Customer Operations and Customer Service expense – 84 percent electric, 16 percent gas; A&G expense – 77.60 percent electric, 15.95 percent gas, 6.45 percent steam) and multiplied it by CECONY's share of 92.45 percent. This resulted in Customer Operations and Customer Service expenses being allocated

77.66 percent to CECONY electric, 14.79 percent to CECONY gas, with the remaining 7.55 percent allocated to O&R, and A&G expenses being allocated 71.74 percent to CECONY electric, 14.75 percent to CECONY gas, 5.96 percent to CECONY steam, with the remaining 7.55 percent allocated to O&R.

Q. What is the Company's methodology for allocating common expenses incurred at the parent company, Consolidated Edison, Inc. ("CEI"), and passed down to its subsidiaries?

A. Common expenses incurred by CEI, which are not directly charged services, are allocated under a three-factor formula to its subsidiaries. As agreed upon in the current rate plan, the Company allocates expenses for these intercompany shared services for each Rate Year under a three-factor allocation using forecasted operating revenue, segment payroll, and assets for each CEI subsidiary. If a CEI subsidiary has equity method investments, the revenue factor for that subsidiary will include a proportionate share of its equity method investments' revenues.

2. Line Item Descriptions (Exhibits AP-3, Schedule 6)

Q. Please describe the various line items set forth in Exhibits AP-3, Schedule 6.

A. We set forth below detailed descriptions of each type of expense and a designation to which commodity(ies) it applies (E- Electric, G-Gas). For those line items that include common expenses, we indicate the total Company common expense amount and the portion allocated to electric and gas services. The remaining unstated amounts are allocated to steam service. For the Historic Year amount, any adjustments, and the Rate Year forecast for each line item, please see page 3 of Schedule 1.

Line 1, Fuel and Purchased Power: (E, G) This item tracks projected fuel and purchased power costs. The Rate Year forecast includes program changes discussed in detail in the direct testimony of the Electric and Gas Volume and Revenue Forecasting Panels.

Line 2, A&G, Health Ins. Cap: (E, G) This line represents the capitalized portion of A&G overhead costs applicable to construction activities, including general office salaries and expenses, and health insurance premiums. The Company escalated the Historic Year expense adjusted by a normalization for COVID-related activity by the labor escalation factor to arrive at the Rate Year level.

Line 3, Advanced Metering Infrastructure: (E, G) This item represents historic costs and program changes reflecting the implementation and maintenance of the AMI systems and communications infrastructure. Expenses and program changes also reflect customer engagement expenses covering the AMI deployment period. Further discussion of the AMI program changes can be found within the Customer Energy Solutions ("CES") Panel testimony. We then escalated the Historic Year expense and program changes by the general escalation factor to arrive at the Rate Year amount.

Line 4, Bargaining Unit Contract Cost: (E, G) This item represents a program change for annualized costs associated with negotiation and strike contingency efforts discussed in detail in the direct testimony of the Shared Services Panel. We then escalated the Historic Year expense and program changes by the general escalation factor to arrive at the Rate Year amount.

Line 5, Bond Administration & Bank Fees: (E, G) This item includes expenses for charges such as bank fees, revolving credit fees, line of credit fees, and credit rating agencies fees. The Historic Year expense is escalated by the general escalation factor to arrive at the Rate Year level.

Line 6, Company Labor- Advanced Metering Infrastructure: (E, G) This item reflects labor charges related to the Company's AMI program (non-labor AMI costs are discussed above on Line 3). The Rate Year forecast for electric and gas include program changes discussed in detail in the direct testimony of the CES Panel. We then escalated the Historic Year expense and program changes by the labor escalation factor to arrive at the Rate Year amount.

Line 7, Company Labor- Central Engineering: (E) This item reflects labor charges related to the Company's Central Engineering departments. We escalated the Historic Year expense by the labor escalation factor to arrive at the Rate Year amount.

Line 8, Company Labor- Construction Management: (E, G) This item reflects labor charges related to the Company's Construction Management departments. We escalated the Historic Year expense by the labor escalation factor to arrive at the Rate Year amount.

Line 9, Company Labor - Corporate & Shared Services: (E, G) The Company's Corporate & Shared Services departments include, among others, Finance, Environmental Health & Safety, Emergency Management, Energy Management, Facilities & Field Services, Government Relations, Human Resources, Information Technology, Learning & Inclusion, Legal Services, Public Affairs, Office of the Secretary, President & Staff, R&D, Security, Strategic Planning and Supply Chain.

The total Rate Year forecast includes a number of program changes, which are discussed in detail in the direct testimony of the Shared Services Panel. We then escalated the Historic Year expense and program changes by the labor escalation factor to arrive at the Rate Year amount.

Line 10, Company Labor – Customer Energy Solutions (E, G)

This item reflects labor charges related to the Company's Customer Energy Solutions group. The Rate Year forecast includes program changes for positions in programs such as NYNE EE, NYNE Heat Pumps (Clean Heat), and energy storage. This line item also includes a normalization to reflect a full year of salary for newly added employees. Further discussion of the program changes can be found in the direct testimony of the CES Panel. We then escalated the Historic Year expense, program changes, and normalization by the labor escalation factor to arrive at the Rate Year amount.

Line 11, Company Labor – Customer Information System (E, G)

This item reflects labor charges related to the Company's new CSS. We then escalated the Historic Year expense by the labor escalation factor to arrive at the Rate Year amount.

Line 12, Company Labor - Customer Operations: (E, G) This item reflects labor charges related to the Company's Customer Operations departments. The Rate Year forecast for electric and gas include a number of program changes discussed in detail in the direct testimony of the Customer Operations Panel. We then escalated the Historic Year expense and program changes by the labor escalation factor to arrive at the Rate Year amount.

Line 13, Company Labor- Electric Operations: (E, G) This item relates to labor charges related to the Company's Electric Operations departments. The Rate Year forecast for electric includes program changes discussed in detail in the direct testimony of the EIOP. We then escalated the Historic Year expense and program changes by the labor escalation factor to arrive at the Rate Year amount.

Line 14, Company Labor- Gas Operations: (E, G) This item relates to labor charges related to the Company's Gas Operations departments. The Rate Year forecast for gas includes program changes discussed in detail in the direct testimony of the GIOSP. We escalated the Historic Year expense and program changes by the labor escalation factor to arrive at the Rate Year amount.

Line 15, Company Labor- Production: (E) This item relates to labor charges related to the Company's Production departments. We escalated the Historic Year expense by the labor escalation factor to arrive at the Rate Year amount.

Line 16, Company Labor- Substation Operations ("SSO"): (E) This item relates to labor charges related to the Company's SSO departments. We then escalated the Historic Year expense by the labor escalation factor to arrive at the Rate Year amount.

Line 17, Company Labor- System & Transmission Operations ("STO"): (E) This item relates to labor charges related to the Company's STO departments. We escalated the Historic Year expense and the program changes by the labor escalation factor to arrive at the Rate Year amount. The program changes are explained in further detail within the EIOP testimony.

Line 18, Corporate and Shared Services: (E, G) This item relates to non-labor charges for the Company's Corporate & Shared Services departments that are not already covered in another line item (*e.g.*, Line 25, Environmental Affairs, Line 29, Facilities & Field Services, Line 30, Finance & Accounting Operations, Line 32, Information Technology, Line 60, Research & Development, and Line 61, Security).

The Rate Year forecast for electric and gas reflects a program change related to the Diversity & Inclusion's DE&I Employee Survey, which is discussed in the direct testimony of the Shared Services Panel. The Rate Year forecast for electric and gas also reflects a program change related to Emergency Preparedness related to Weather Monitoring Stations (NYC Micronet) which is discussed in the direct testimony of Shared Services Panel. The electric and and gas rate year forecast also reflects a program change from the Finance department which is related to

Climate Risk and Resiliency program and is discussed in detail in the direct testimony of Storm Response and Resiliency Panel.

Additionally, the Rate Year forecast for gas also reflects a program change related to implementing a Gas Distribution Forecasting Model which is discussed in the direct testimony of the GIOSP.

We escalated the Historic Year expense and program changes discussed above by the general escalation factor to arrive at the Rate Year amount.

Line 19, Corporate Fiscal Expense: (E, G) This item includes costs of annual reporting services and meeting, trustee and committee fees including equity grants, as well as stock transfer agent fees and stock exchange registration fees. We escalated the Historic Year expense by the general escalation factor to arrive at the Rate Year amount.

Line 20, Customer Energy Solutions: (E, G) This item relates to non-labor charges for the Company’s Customer Energy Solutions departments (e.g., Demonstration Projects, EE, Rate Engineering, and Utility of the Future) that are not otherwise reflected in Line 21 (Customer Information System). This item includes a number of program changes discussed further in the CES Panel’s direct testimony. This line also includes a normalization of one-time charges occurring in the Historic Year.

We escalated the Historic Year expense, program changes, and normalization by the general escalation factor to arrive at the Rate Year amount.

Line 21, Customer Information System: (E, G) This line item represents O&M costs associated with implementing the Company's new CSS. The program change is discussed further within the Customer Operations Panel.

Line 22, Dynamic Load Management Programs: (E) The Rate Year forecast is normalized to remove from the revenue requirement an expense that is recovered through surcharge. The Company's filing does not include any projected recovery of the cost of dynamic load management programs through surcharge, thus there is no impact on the Company's revenue requirement.

Line 23, Duplicate Misc. Charges: (E, G) This item is comprised of credits for charges made to operating expenses or other accounts for the Company's own use of utility service. The Rate Year amount was held constant at the Historic Year expense.

Line 24, Employee Welfare Expense: (E, G) In its direct testimony, the Company's Compensation and Benefits Panel discuss costs and programs totaling $166 million in the Rate Year ($138 million allocated to electric and $28 million allocated to gas). In addition to the amounts supported by the Compensation and Benefits Panel, other employee welfare related fees such as service awards and administration support are included in this line and escalated using the labor escalation factor. In addition, costs associated with the Deferred Income Plan are normalized out of the historic period because this pertains to officers' benefits. The Company is not seeking to recover these costs through rates in this proceeding, but the Company reserves its rights to seek the recovery of such costs in future rate proceedings.

Line 25, Environmental Affairs: (E, G) This item relates to the non-labor charges related to the Company’s Environmental Health & Safety departments. We escalated the Historic Year expense by the general escalation factor to arrive at the Rate Year amount.

Line 26, ERRP Major Maintenance: (E) ERRP Major Maintenance costs are fully reconciled. The Rate Year expense of $4.385 million represents the current forecast of annual major maintenance expenses. The Company recorded a normalization to present both the cost and reconciliation to rate level of ERRP major maintenance as expense rather than partially as a reduction to other operating revenue. The Company will revisit the five-year forecast for major maintenance expenses during the preliminary update to determine whether refinement of the annual allowance is appropriate.

Line 27, Executive MVP: (E, G) The Company normalized the Rate Year forecast to eliminate the cost of the executive variable pay plan and long-term equity grants. The Company is not seeking to recover these costs through rates in this proceeding, but reserves its rights to seek the recovery of such costs in future rate proceedings.

Line 28, External Audit Services: (E, G) The Company contracts for services provided by PwC, such as auditing, research, and training. The Rate Year forecast includes a normalization due to a change in the external auditor’s billing cycle which understated total expense in the Historic Year, and a program change to reflect the latest audit fee schedule available. We then escalated the Historic Year expense and program changes by the general escalation factor to arrive at the Rate Year amount.

Line 29, Facilities and Field Services: (E, G) This item relates to the non-labor charges related to the Company's Facilities and Field Services departments, such as contracts for building maintenance and janitorial services. We normalized the Historic Year expense for COVID-19 related costs and escalated the Historic Year expense by a program change to account for the Prevailing Wage Law , which impacts building services workers (and is discussed by the Shared Services Panel), and the general escalation factor to arrive at the Rate Year amount.

Line 30, Finance & Accounting Operations: (E, G) This item relates to the non-labor charges related to the Company's Finance and Accounting Operations departments and select other corporate charges. We escalated the Historic Year expense by the general escalation factor to arrive at the Rate Year amount.

Line 31, Indian Point Contingency: (E) The Indian Point Contingency plan addressed the potential reliability concerns that may arise upon the retirement of electric generation facilities, notably the Indian Point Energy Center. In response to the Commission's request, on February 1, 2013, the Company and NYPA filed a joint proposal to conduct Energy Efficiency/Demand Reduction/Combined Heat and Power programs. Pursuant to the Commission's Order, the Company is authorized to recover all costs through the MAC over a ten-year period. This normalization adjustment removes the amortization costs for the Historic Year.

Line 32, Information Technology: (E, G) This item relates to the non-labor charges related to the Company's IT departments, such as technology support, software maintenance and application services, as well as mainframe computers in general. The total Rate Year forecast includes program changes including, but not limited to, funding for programs such as Obsolete Oracle GRC Replacement, Budget Systems Enhancement, CECONY REV/DER/EEDM Forecasting Tool, Allegro Replacement, ISOs Revenue Metering Validation and Reporting Software Phase, and Work and Asset Management Mobility Solution. These program changes are all discussed in detail in the direct testimony of the IT Panel. The Company also normalized expenses due to the timing of Oracle billings understating expense during the Historic Year. We then escalated the Historic Year expense, normalization, and program changes by the general escalation factor to arrive at the Rate Year amount.

Line 33, Informational Advertising: (E, G) This item relates to informational advertising directed to customers. The Historic Year expense was adjusted by a program change to reflect advertising as a percentage of sales revenues at the percentage historically accepted by the Commission (0.08%) and escalated by the general escalation factor to arrive at the Rate Year amount.

Line 34, Injuries & Damages/ Workers Compensation: (E, G) In accordance with prior practice in rate case filings, the Company forecasted the Rate Year level of injuries and damages and workers compensation expenditures based on the average net claim payments for the most recent three-year period (*i.e.*, October 2018 through September 2021), escalated using the general escalation factor.

Line 35, Institutional Dues & Subscription: (E, G) This item includes membership fees paid and association dues. Consistent with New York State law, the Company excluded from its proposed revenue requirements all fees paid to the American Gas Association and Edison Electric Institute as they engage in lobbying activites. We then escalated the Historic Year expense and normalization by the general escalation factor to arrive at the Rate Year amount.

Line 36, Insurance Premium: (E, G,) This item includes insurance premiums the Company incurs for items such as property insurance, liability insurance, Directors and Officers insurance, and cyber security insurance. A program change was recorded to align expenses with the latest premiums and then we escalated using the general escalation factor.

Line 37, Intercompany Shared Services: (E, G) This item reflects intercompany billing between the Company and CEI. A normalization adjustment eliminates the Company's portion of the insurance premiums expense from the Historic Year, so such expense, which is included in Line 36, Insurance Premiums, in this section of the testimony, is only included once. We then escalated the Historic Year expense and normalization by the general escalation factor to arrive at the Rate Year amount.

Line 38, Load Dispatching and PJM TEC: (E) This item represents refunds to customers associated with a settlement approved by FERC on PJM Transmission Enhancement Charges in Docket No. EL05-121-009. The amounts are passed back outside of base rates through surcharge; as such, in this filing, the Company has normalized all activity that occurred in the Historic Year.

Line 39, New York Facilities: (G) On July 27, 1950, the Company, Brooklyn Union Gas Company and Long Island Lighting Company, (which are now known as KEDNY and KEDLI, respectively) executed the New York Facilities Agreement to facilitate the introduction of natural gas into the New York area. The agreement was last updated on October 18, 2018. The New York Facilities Agreement provides, among other things, for the apportionment of costs for participants' use of other participants' facilities. We maintained the Historic Year level of costs for the Rate Year.

Line 40, Ops-Central Engineering: (E) This item relates to the non-labor charges related to the Company's Central Engineering departments. We escalated the Historic Year expense by the general escalation factor to arrive at the Rate Year amount.

Line 41, Ops-Construction Management: (E, G) This item relates to the non-labor charges related to the Company's Construction Management departments. We escalated the Historic Year expense by the general escalation factor to arrive at the Rate Year amount.

Line 42, Ops-Customer Operations: (E, G) This item relates to the non-labor charges of the Company's Customer Operations departments. The Rate Year forecast includes program changes discussed in the direct testimony of the Customer Operations Panel, including changes to the manner in which the Company collects the costs of credit card payment of utility bills. Further program changes request funding to enhance the Dynamic Customer Experience ("DCX"), customer outreach, collection agency fees, customer analytics, credit modeling, privacy readiness, revenue protection, and replevin. The Company also recorded a normalization to adjust for COVID-related reductions in collection agency fees. We then escalated the Historic Year expense, program changes, and normalization by the general escalation factor to arrive at the Rate Year amount.

Line 43, Ops-Electric Operations: (E, G) This item relates to non-labor charges related to the Company's Electric Operations departments. The Rate Year forecast for electric includes program changes discussed in detail in the direct testimony of the EIOP, including program changes for Safety Inspection Program, AMI meter testing, emergency response, tree trimming, and structures/poles. We then escalated the Historic Year expense and program changes by the general escalation factor to arrive at the Rate Year amount.

Line 44, Ops-Gas Operations: (E, G) This item relates to non-labor charges related to the Company's Gas Operations departments. The Rate Year forecast for gas includes program changes discussed in detail in the direct testimony of the GIOSP including costs related to additional inspections and repairs due to an amendment to the definition of “gas service line,” a gas outage management system, and the inspection and repair of distribution and transmission natural gas piping at expansion joints, on bridges, and through submarine river crossings. We then escalated the Historic Year expense and program changes by the general escalation factor to arrive at the Rate Year amount.

Line 45, Ops-Interference: (E, G) The Company has an extensive system of electric and gas infrastructure within the streets of its service territory. As discussed in the direct testimony of the Municipal Infrastructure Support Panel, when a municipality plans to perform work and is unable to complete the proposed plan absent our relocating Company facilities that are “in the way,” the Company bears all the costs to locate, move, support, protect and/or relocate the facilities affected by the municipality’s construction activity. These costs are referred to as “interference costs.” The Rate Year forecast includes a program change discussed in the direct testimony of the Municipal Infrastructure Support Panel. We then escalated the Historic Year expense and the program change by the general escalation factor to arrive at the Rate Year amount.

Line 46, Ops-Production: (E) This item relates to non-labor charges related to the Company’s Production departments. The Rate Year forecast includes a program change related to an overhaul of East River Unit No. 6, which is discussed in further detail within the EIOP Panel. This line also includes a program change to reflect the projected Rate Year amount of other fuel charges for electric. We then escalated the Historic Year expense and program changes by the general escalation factor to arrive at the Rate Year amount.

Line 47, Ops-Substation Operations ("SSO"): (E) This item relates to non-labor charges related to the Company's SSO departments. We escalated the Historic Year expense by the general escalation factor to arrive at the Rate Year amount.

Line 48, Ops-System & Transmission Operations ("STO"): (E) This item relates to non-labor charges related to the Company's STO departments. The Rate Year also reflects program changes related to licensing fees and ongoing maintenance for vehicle purchases due to increased headcount for storm response, which are explained in further detail within the EIOP testimony. The rate year also reflects a normalization to adjust for one-time expenditures incurred in the Historic Year. We escalated the Historic Year expense adjusted for program changes and normalizations by the general escalation factor to arrive at the Rate Year amount.

Line 49, Other Compensation (Long-Term Equity): (E, G) This line includes the executive variable pay plan and officer and non-officer long-term equity grants, which is made up of time based and performance based restricted stock expenses. The Rate Year program change for non-officer time based and performance based restricted stock expenses are based on the stock price of $78.77 and the number of outstanding shares of 270,450 at November 15, 2021.

We escalated the program changes by the general escalation factor to arrive at Rate Year amounts.

We normalized the Rate Year amount to reflect elimination of costs associated with the executive variable pay plan and long-term equity grants. The Company is not seeking to recover these eliminated costs through rates in this proceeding, but, as noted above, reserves its rights to seek the recovery of such costs in future rate proceedings.

Line 50, Outside Legal Services (E, G) This item includes the cost of outside legal counsel. The Company normalized this line item to reflect a three-year average of expenditures. We escalated the Historic Year expense and normalization by the general escalation factor to arrive at the Rate Year estimate.

Line 51, Pension and OPEB: (E, G) This line reflects the actuarially determined level of expenses for employee pensions and OPEBs, which was based on two studies performed by the Company's actuary, Buck Consultants, dated May 2021 for pensions (updated by the Company for changes in assumptions through November 2021) and dated December 2021 for OPEBs. The studies incorporate the Company's actual historical experience supplemented by assumptions of future activity through November 2021. Assumptions used in the forecast of pensions were a discount rate of 2.85 percent and an expected return on plan assets of 7.0 percent. OPEB projections were based on a discount rate of 2.65 percent, return on assets of 7.0 percent for the 401(h) account, 7.6 percent for the

Management Life Insurance VEBA, 7.1 percent for the Management Health VEBA and 6.6 percent for the Weekly Health VEBA.

Q. Please summarize the estimate of the Rate Year employee pensions/OPEBs expense.

A. The amount of the actuarially determined level of expense for employee pensions/OPEBs and other payments, net of capitalization and regulatory deferrals, for all three commodities for the Historic Year is $83.7 million, with $56.1 million allocable to electric and $11.5 million allocable to gas. The Rate Year estimated cost for all three commodities is a credit of $283 million (($220) million allocable to electric and ($45) million allocable to gas). This $366.8 million decrease ($275.7 million allocable to electric and $56.7 million allocable to gas) in accounting cost is attributed to multiple factors. One key driver for the decrease in the accounting cost from the Historic Year to the Rate Year is the change in the discount rate. The pension discount rate was 3.35% for the three months ended December 31, 2020, and was 2.55% for the nine months ended September 30, 2021. For the Rate Year, the projected pension discount rate is 2.85%. Future pension cost projections have also declined due to stronger than anticipated investment returns in 2021 (approximately 8% actual returns relative to a 7% assumed return on pension assets), and the continued roll-off of actuarial losses related to the 2008 market downturn.

Q. Does this line item include Supplemental Retirement Income Plan (“SRIP”) costs?

A. Yes. Officer and non-officer SRIP costs are included in this line item, as they relate to the Company's long-term performance-based compensation for management employees.

Line 52, RCA- Amort. of MGP/Superfund: (E, G) Expenses recorded in the Historic Year are normalized as the Rate Year costs associated with this program are already reflected in the Company's deferral amortization schedule. The SIR program, inclusive of MGP/Superfund, is addressed by the Environmental Health and Safety Panel.

Line 53, RCA- Amort. of Energy Efficiency Programs: (E, G) These expenses recorded in the Historic Year are normalized as the Rate Year costs associated with this program are already reflected in the Company's deferral amortization schedule. The energy efficiency program is addressed by the Customer Energy Solutions Panel.

Line 54, Regional Gas Greenhouse Initiative ("RGGI"): (E) We normalized the Rate Year forecast to remove the Historic Year expense because recovery for this program is collected through the MAC.

Line 55, Regulatory Commission Expense-All Other: (E, G) This item includes costs of participating in regulatory proceedings (*e.g.*, consultants, outside legal counsel). The Rate Year forecast reflects a three-year average of costs escalated by the general escalation factor to arrive at the Rate Year amount.

Line 56, Regulatory Commission Expense-General and R&D: (E, G) We forecasted the Rate Year Commission Assessment based on the latest

Commission Assessment letter dated August 2021, excluding refunds, for the 2021-2022 State fiscal year ending March 31, 2022. We then escalated it by using the general escalation factor to arrive at the Rate Year forecast. The Company will update this element of expense based on any additional Commission Assessment letters received during these proceedings.

Line 57, Rents – ERRP: (E) This expense, which is recovered through the MAC, is an interdepartmental rent that is offset in steam's Other Operating Revenues. Because the Company is not filing for new steam rates to be effective January 1, 2023 concurrent with the electric and gas filings, the $77.218 million of revenues in steam rates, reflected in RY3 of the current steam rate plan, will continue to be reflected in steam rates. Under the current electric rate plan, the Commission authorized the Company to defer the impact of the change in expense to steam, starting in 2017 and annually thereafter (until steam base rates are reset), whether positive or negative, to continue the "earnings neutral" nature of these revenues to the Company.

Line 58, Rents-General: (E, G) This item represents general rents paid to lease various properties or land on which the Company operates. We escalated the Historic Year expense by the general escalation factor to arrive at the Rate Year estimate.

Line 59, Rents-Interdepartmental: (E, G) The Rate Year forecast for electric includes a program change primarily attributable to increases to the book costs of the Ravenswood and Astoria tunnels, which are part of Gas Plant, and an increase to the book cost of the Hudson Avenue Tunnel, which is part of Steam Plant.

Line 60, Research & Development: (E, G) This item relates to non-labor charges related to the Company's R&D department. The line includes additional expenses for program changes, which are discussed within the direct testimony of the Company's Shared Service Panel. The line also includes a normalization to exclude expenses related to the Millenium Fund because such expenses are collected through surcharge rather than base rates. We escalated the Historic Year expense level adjusted for normalizations and program changes using the general escalation factor to arrive at the Rate Year amount.

Line 61, Security: (E, G) This item relates to non-labor charges related to the Company's Corporate Security department. We escalated the Historic Year expense by the general escalation factor to arrive at the Rate Year amount.

Line 62, Storm Reserve: (E) The Company is proposing to maintain the Historic Year level of storm reserve expenditures, as increased by the general escalation factor, to arrive at the Rate Year amount. Please also see the Deferrals and Reconciliation section for additional detail on the major storm reserve target and associated proposed reconciliation method.

Line 63, System Benefit Charge: (E, G) For electric, the System Benefit Charge is adjusted to match the level in sales revenue projections. For gas, this expense will be corrected and normalized in the preliminary update because the System Benefit Charge is collected as a separate surcharge.

Line 64, Uncollectible Reserve-Customer: (E, G) This item represents an allowance for the recovery of write-offs of customer accounts receivable. Historic Year uncollectible expenses were greatly impacted by the COVID-19 pandemic and associated laws. As such, the Company proposes to set the Rate Year uncollectibles at the levels approved for RY3 under the current Rate Plans. For electric, this amount is $42,847,000, a reduction of $12,579,000 from the Test Year before accounting for the proposed rate increase. For gas, this amount is $12,895,000, a reduction of $2,315,000 from the Test Year before accounting for the proposed rate increase. The Company's proposal to reconcile uncollectible write-offs is discussed in Section XVI.

Line 65, Uncollectible Reserve-Sundry: (E, G) This item represents a provision and write-off of miscellaneous accounts receivables which are not expected to be collected by the Company. The Rate Year amount includes a program change to reflect a three-year annualized average for the period October 2018 through September 2021.

Line 66, Worker's Comp NYS Assessment: (E, G) This line item represents assessment payments by employers to the NYS Workers' Compensation Board ("WCB"). The assessment rates are determined by the WCB each year and the Company estimates its expenses based on the latest available rates and projected payroll levels. The Company recorded a program change to reflect the latest available estimates as of the time of the filing. We then escalated the Historic

Year expense and program changes by the general escalation factor to arrive at the Rate Year amount.

Line 67, All Other: (E, G) This line item includes miscellaneous and general expenses that did not fit into other categories of expense discussed above. Included within this line item are also costs that were normalized, including certain deferrals and related amortizations for deferred balances such as Meadowlands heaters, gas service line deferrals, and interference. Additionally, oil to gas expenditures were also normalized from the test year as they are recovered outside of base rates. We then escalated the Historic Year expense adjusted for normalizations by the general escalation factor to arrive at the Rate Year amount.

Line 68, Company Labor – Fringe Benefit Adjustment: (E, G) This adjustment represents the increase or decrease in employee welfare expenses and workers' compensation related to the increase or decrease in employees through program changes as sponsored by various Company witnesses. We escalated the program change by the general escalation factor to arrive at the Rate Year amount.

Line 69, Business Cost Optimization ("BCO"): (E, G) This line item reflects the customer savings associated with the Company's BCO Program. Beginning in 2017, the Company implemented a multi-year BCO program to improve processes, functions, and tasks in order to identify and achieve savings. The savings reflected in this line item represent the Company's projected incremental BCO efficiencies to be achieved between the end of the Historical Year and the beginning of the Rate Year. Additionally, embedded within the Historical Year are over $150 million in O&M savings achieved since the inception of the program.

The Company is completing the program and is transitioning from focusing on an independent BCO program to integrating optimization approaches developed under BCO to normal business planning and operation. These types of cost savings are embedded in program costs in this case (*e.g.*, GIOSP discusses how aligning gas service line inspection work with installing AMI-enabled natural gas detectors is expected to result in significant savings in the Rate Year).

E. **Depreciation and Amortization (Exhibits AP-3, Schedule 7.1 & 7.2)**

Q. Please describe Schedules 7.1 and 7.2 of Exhibits AP-3 relating to Depreciation and Amortization.

A. Schedule 7.1 shows the depreciation and amortization amounts at current depreciation rates, with no change to the reserve deficiency recovery for the period from September 2021 to December 2025. Schedule 7.2 shows the depreciation and amortization amounts at proposed depreciation rates with adjustments made to the reserve deficiency recovery for the same period.

Rate Year depreciation and amortization is based on projected plant balances through the Rate Year and composite depreciation rates for current plant accounts. Both are discussed in detail in the Depreciation Panel's testimony.

Q. Please summarize the projected net changes to the level of Depreciation and Amortization from the Historic Year to the Rate Year as shown in Schedule 7.1.

A. For electric, the Historic Year level of $1,276 million is forecast to increase by $144 million for a Rate Year level of $1,420 million.

For gas, the Historic Year level of $319 million is forecast to increase by $88 million for a Rate Year level of $407 million.

Q. Please summarize the projected net changes to the level of Depreciation and Amortization from the Historic Year to the Rate Year as shown in Schedule 7.2.

A. For electric, the Historic Year level of $1,276 million is forecast to increase by $159 million for a Rate Year level of $1,435 million.

For gas, the Historic Year level of $319 million is forecast to increase by $150 million for a Rate Year level of $469 million.

Q. Please summarize the Company's proposed depreciation and amortization expense.

A. These figures reflect proposed electric and gas depreciation rates, $2 million decrease in recovery of reserve deficiencies for electric and $15 million increase in recovery of reserve deficiencies for gas, as explained by the Depreciation Panel.

Q. Are the gas depreciation rates used to develop revenue requirement those recommended by the Company's Depreciation Panel?

A. No. The Gas Depreciation Panel recommended a ten-year decrease in the average service lives of longer-lived gas accounts. In order to mitigate customer bill impacts, the Company's gas revenue requirement uses a five-year decrease, which is the lowest reduction the Company views as appropriate in light of CLCPA requirements.

F. **Taxes Other than Income Taxes (Exhibits AP-3, Schedule 8)**

Q. How did you calculate the Property Taxes component of Taxes Other Than Income Taxes for the Rate Year shown on Schedule 8 of Exhibits AP-3?

A. Historic Year property taxes consist of NYC real estate and special franchise taxes and Westchester County and other upstate county property taxes. The Rate Year forecasts were provided to us by the Company's Property Tax Witness and are described in her direct testimony.

Also shown on Schedule 8 of Exhibits AP-3 are amounts representing the reconciliation of actual property taxes to the levels established in base rates during the Historic Year under the Company's current electric and gas rate plans, which are normalized for the Rate Year.

Q. How did you calculate the Payroll Taxes component of Taxes Other than Income Taxes as set forth on Schedule 8 of Exhibits AP-3?

A. We determined the payroll taxes by applying the employer payroll tax rate to the forecasted direct labor increases.

Q. How did you calculate the Revenue Tax component of Taxes Other Than Income Taxes for the Rate Year shown on Schedule 8 of Exhibits AP-3?

A. We determined the Revenue Taxes based on the estimated revenue for gas and electric multiplied by the effective tax rate (provided by the Company's Electric and Gas Forecasting Panels).

Q. Please explain the Sales and Use Tax component of Taxes Other Than Income Taxes shown on Schedule 8 of Exhibits AP-3.

A. These are the state and local sales and use taxes paid by the Company when acquiring a broad range of goods and services. The amount shown is the portion of such taxes chargeable to expense as opposed to being capitalized. We have escalated the Historic Year amounts to recognize general inflation in the cost of goods and services. The forecast does not assume any change in sales tax rates.

Q. Please describe the All Other Taxes component of Taxes Other Than Income Taxes shown on Schedule 8 of Exhibits AP-3.

A. All Other Taxes represents minor taxes such as commercial rent and occupancy tax, motor vehicle taxes, state gasoline tax, state highway use tax, federal diesel and gasoline taxes, the NYS tax on insurance premiums and hazardous waste. The Company estimates the Rate Year level for such taxes to be the Historic Year amount plus escalation at the general inflation factor.

G. State and Federal Income Taxes (Exhibits AP-3, Schedules 9 and 10)

Q. Please describe the calculation of income taxes shown on Schedules 9 and 10 of Exhibits AP-3.

A. Schedule 9 details the NYS income tax computation. In April 2021, New York State passed a law that increased the corporate franchise tax rate on business income from 6.5% to 7.25%, retroactive to January 1, 2021, for taxpayers with taxable income greater than $5 million for tax years 2021, 2022 and 2023. Because the Company will carryforward NYS Net Operating Losses into RY1 (*i.e.*, tax year 2023), the Company is not impacted by the temporary higher NYS tax rate of 7.25%. Therefore, we calculated the NYS income tax expense using a 6.5% tax rate for all rate years.

Schedule 10 details the federal income tax computation. The federal income taxes are computed using the 21 percent tax rate in the Tax Cuts and Jobs Act of 2017. The Schedule shows the amortization of excess deferred federal income tax ("EDFIT") broken out in the following four categories: protected plant, unprotected plant, accelerated unprotected plant and non-plant. The EDFIT represents the difference in the amounts the Company collected from its customers at a 35 percent tax rate to pay future income taxes, and the Company's future tax liabilities at a 21 percent tax rate. The Company proposes to refund the protected component over the remaining lives of the underlying plant assets and the unprotected and non-plant components over the remaining two years of the five year amortization approved in the Company's current rate plans.

Schedule 10 also reflects a credit to customers for an estimated amount of an R&D tax credit that reduces the Company's federal income tax expense in the Rate Year.

XI. FUND REQUIREMENTS AND SOURCES (Exhibits AP-3, Schedule 12)

Q. Please describe Exhibits AP-3, Schedule 12.

A. This schedule reflects the Company's forecast of capital fund requirements and sources of capital funds, as well as certain financial statistics, for the Rate Year.

We have determined that capital funds required during the Rate Year will exceed internal sources by $1,936 million.

Q. Please describe the items contained in the schedule under the heading "Internal Sources of Funds."

A. The first item is estimated retained earnings. For the Rate Year, net income for common stock is projected at $1,804 million and new issuances are projected at $800 million, offset by projected common stock dividends of $1,128 million. The second item is depreciation. The third item is the amortization of net accounting credits. The fourth item is net working capital requirements. The fifth item, deferred tax accruals, are funds provided principally by the use of tax depreciation subject to normalization. In total, our projections show internal sources of funds will provide $3,408 million.

Q. Please describe the next section of the schedule.

A. The next section, "External Sources of Funds," shows the Company's projected debt issuances and changes to short-term borrowings for the Rate Year. These external sources of funds will provide $1,936 million.

Q. Please describe the items contained in the schedule under the heading "Use of Funds."

A. The first item, requiring the largest amount of capital funds, is Construction Expenditures of $5,344 million. This amount is consistent with the Company's five-year forecast of construction expenditures, as set forth in Exhibits AP-4.

The second item shows there are no long-term debt maturities during the Rate Year, consistent with what is shown in Exhibits AP-5.

XII. INTEREST COVERAGE – S.E.C. BASIS PER BOOKS (Exhibits AP-3, Schedule 13)

Q. Is the Accounting Panel sponsoring an exhibit to show the calculation of interest coverage ratio for the interest paid on long-term debt and other items?

A. Yes, we are sponsoring Schedule 13 of Exhibits AP-3. The schedules contain identical information because the information is presented on a corporate rather than a commodity basis.

Q. Please describe these exhibits.

A. Schedule 13 of Exhibits AP-3 show the ratio of the Company's earnings before interest and taxes to the amount of fixed charges it had to pay for each of the prior five years.

Fixed charges includes interest on long-term debt, amortization of debt discount and expense, the interest component of rentals and "other interest," which is comprised of interest paid on customer deposits, commercial paper, customer overpayments and other miscellaneous items.

Q. Does the Company currently have available lines of credit?

A. Yes. The Company, along with CEI and O&R, has agreements with various banks for revolving credit lines totaling $2,250 million. Assuming that CEI and O&R have not used their assigned portions of this credit, $1,000 million and $200 million, respectively, the Company can use the entire $2,250 million.

XIII. NET PLANT INVESTMENT (EXHIBITS AP-4)

A. Projected Net Plant Balances (Exhibits AP-4, Schedules 1 & 2)

Q. Has the Accounting Panel prepared projections of net plant balances from the end of the Historic Year (*i.e.*, September 30, 2021) through the Rate Year (*i.e.*, December 31, 2023) appraising the impact of the current construction and retirement programs on electric and gas rate base?

A. Yes, that information is presented in Exhibits AP-4.

Q. What is shown on Schedule 1 of Exhibits AP-4?

A. Schedule 1 of these exhibits contains three pages. Page 1 of Schedule 1 shows projected net plant balances for the Rate Year, with the depreciation reserve reflecting accruals at currently effective rates. Page 2 of Schedule 1 shows projected net plant balances for the Rate Year, with the depreciation reserve reflecting accruals at the proposed rates inclusive of adjustments to the reserve deficiencies recovery. Page 3 of Schedule 1 shows the projected monthly net plant balances from the end of the Historic Year to the start of the Rate Year, which served as a basis for our Rate Year projections.

Using projected capital expenditures provided to us by various witnesses in these proceedings, we estimated transfers to plant in service. We then added the estimated transfers to the actual plant in service account balances at September 30, 2021 and deducted the projected book cost of plant retired to give us a book cost of plant. In order to develop net plant balance, we deducted accumulated depreciation from book cost of plant.

Q. What is shown on Schedule 2 of Exhibits AP-4?

A. Schedule 2 of these exhibits shows average CWIP in rate base for the twelve-months ended September 2021. In this filing, the Company is projecting Rate Year CWIP to remain at the Historic Year level. As the Company further reviews its capital forecast, it will refine the Rate Year CWIP projection and incorporate the projection into the update filing.

Q. Are the net plant and non-interest bearing CWIP rate base amounts in Exhibits AP-4 reflected in the total rate base amounts shown in Exhibits AP-2?

A. Yes.

Q. What is shown on Schedule 3 of Exhibits AP-4?

A. Schedule 3 shows the capital expenditure projections for calendar years 2022 through 2026 reflected in our net plant and CWIP forecasts.

B. Allocation of Common Plant Investment (Exhibits AP-4, Schedule 3)

Q. How is the cost of common plant allocated between Con Edison and its affiliate O&R?

A If a common plant project benefits O&R, the portion of the project applicable to O&R will be charged to an O&R capital account through the affiliate billing process. If there is not another basis to allocate costs, the intercompany shared services percentage discussed above will be used.

Q. Do the net plant rate base amounts for electric and gas include amounts related to common net plant?

A. Yes. Con Edison's portion of common plant is allocated 83 percent to electric operations and 17 percent to gas operations. Steam operations is charged an interdepartmental rent charge for common plant used in steam operations. That charge to steam operations is credited to the electric and gas departments.

XIV. RATE OF RETURN (EXHIBIT AP-5)

Q. Is the Accounting Panel sponsoring an exhibit regarding the required rate of return?

A. Yes, along with Company witness Saegusa, we are sponsoring Exhibits AP-5. These exhibits contain identical information for electric and gas because the information is presented on a corporate rather than a commodity basis.

Q. Please describe Schedule 1 of Exhibits AP-5.

A. Schedule 1 of these exhibits shows the actual capital structure for the Company as of the end of the Historic Year, the average cost rate for each component of the capital structure and the related cost of capital. The Company's overall weighted cost of capital at the end of the Historic Year was 6.46 percent for both electric and gas.

Q. Please describe Schedules 2, 3 and 4 of Exhibits AP-5.

A. These schedules show the projected average capital structure, the average cost rate for each component of the capital structure and the related cost of capital for the Rate Year and the two following twelve-month periods ending December 31, 2024 and 2025, respectively.

Q. What capital structure is the Company proposing to use for the Rate Year?

A. The Company proposes a 50.00 percent common equity ratio for the Rate Year. Witness Saegusa explains in her testimony that this equity ratio is appropriate and necessary to address the negative outlook of credit rating agencies and the Company's weakened cash flow profile.

Q. How did you derive the amount of average long-term debt for each period?

A. To derive the average long-term debt for the each of the Rate Years presented in this filing, we determined the amount of long-term debt outstanding at the end of each month from the end of the Historic Year through December 31, 2025. We then used these figures to calculate the average balance of long-term debt outstanding for each period.

Q. How was the amount of long-term debt outstanding each month determined?

A. We estimated changes in the outstanding amount of debt each month from the end of the Historic Year forward based on the forecasted funding requirements. Schedules 5, 6, 7, and 8 of Exhibits AP-5 list the actual long-term debt balance as of the end of the Historic Year and the projected monthly balances. The forecasted average amount of long-term debt for the Rate Year is $19,733 million as shown on Schedule 6 of Exhibits AP-5.

Q. Please explain how you derived the average customer deposit amounts, set forth on Schedules 2, 3 and 4 of Exhibits AP-5.

A. With respect to customer deposits, we started with the actual average balance during the Historic Year of $284 million. From there, the Company applied the annual growth rate in customer deposits observed during the Historic Year, which brought the average balance of customer deposits for the Rate Year to $352 million.

Q. Please explain the average balance for common equity for each of the periods.

A. As explained by Company witness Saegusa and as set forth in Exhibits AP-5, Schedule 2, the forecasted capital structure for the thirteen months ending December 31, 2023 includes a common stock equity ratio of 48.20 percent. Schedules 3 and 4 of Exhibits AP-5 show that the Company's equity ratio would increase to 48.54 and 49.25 percent for the twelve-month periods ending December 2024 and 2025, respectively. To the extent that the recommended equity ratio of 50.00 percent is agreed upon, the Company would modify its debt and equity issuances to work toward achieving that ratio.

Q. What average cost rate for long-term debt is reflected in the overall rate of return?

A. Con Edison's long-term debt consists of tax-exempt debt issued through NYSERDA and debenture bonds. The average annual cost rate of this debt is calculated by dividing the annual interest requirements for all long-term debt issues, including the annual amortization of the net amount of any premiums or discounts realized when the securities were sold and the cost and expense of issuance, by the amount of long-term debt outstanding. As shown on Schedules 6 through 8 of Exhibits AP-5, the average cost of long-term debt for the Rate Year is 4.30 percent, 4.32 percent for the twelve months ending December 31, 2024 and 4.35 percent for the twelve months ending December 31, 2025.

Q. What cost rate for customer deposits is reflected in the overall rate of return?

A. We reflected the current rate as set by the Commission of 0.05 percent. The Commission reviews this rate annually.

Q. What rate of return on common equity is reflected in the overall rate of return?

A. As noted above, we have used a return on common equity of 10.00 percent to calculate the overall rate of return. For the Rate Year, the overall rate of return is 7.10 percent, which we used in determining the revenue requirement for the Rate Year.

Q. Will the rate of return be updated in this proceeding?

A. The Company may update the rate of return as part of the Company's rebuttal and update testimony if financial conditions at that time warrant such an update.

XV. ALLOCATION OF ELECTRIC RATE INCREASE (Exhibit AP-6)

Q. Did the Accounting Panel determine how much of the total increase in the electric revenue requirement of $1,199 million was allocable to delivery service and how much was allocable to the MAC?

A. Yes. Exhibit AP-E6 reflects this allocation.

Q. Please describe this exhibit.

A. Exhibit AP-E6 includes four schedules. Schedule 1 summarizes the proposed $1,199 million increase as allocated between delivery service rates and the MAC. The required increase in delivery service revenues is $1,190 million; the accompanying increase in required MAC revenues is $9 million. Schedule 2 summarizes the production proposed rate increase. Schedule 3 presents the state and federal income taxes related to the production function. Schedule 4 shows the average rate base allocated between the delivery and the MAC components.

XVI. RECONCILIATIONS AND DEFERRED ACCOUNTING

Q. Does the Company currently employ deferred accounting as permitted under Accounting Standards Codification 980, Regulated Operations?

A. Yes. The Commission has authorized the Company to employ deferred accounting to match the recognition of expenditures with the recovery of certain costs when they are either beyond the Company's direct control and therefore not subject to reasonable estimation, the timing of the actual expenditure is not certain, or in furtherance of State and/or Commission policy objectives. The Commission similarly employs deferred accounting regarding the Company's actual, potential or unexpected receipts of various revenues and credits. The approach is intended to protect the interests of customers and investors by avoiding a "windfall" for one or the other and the approach of amortizing the costs over subsequent periods serves the purpose of minimizing rate volatility.

Q. What is the Company proposing regarding the use of deferral accounting and reconciliation mechanisms?

A. The Company is proposing to continue all deferral accounting and reconciliation mechanisms that are in effect during the current electric and gas rate plans unless otherwise noted below. The deferral and reconciliation mechanisms that are proposed to continue include, but are not limited to, the existing supply rider provisions (*e.g.*, MSC, MAC, GCF, MRA) and deferral and reconciliation mechanisms for such items as pensions and OPEBs, SIR costs, East River station maintenance costs and East River interdepartmental rent, non-officer management variable pay, New York Facilities Agreement, adjustments for competitive services, other transmission revenues (*e.g.*, Transmission Congestion Contracts), NEIL dividends, Brownfield Tax Credits, proceeds from the sale of SO_2 allowances, congestion tolling, Non-Wire Solutions and Non-Pipeline Solutions, White Plains Gate Station, REV demonstration projects, BQDM, Prospective Sales and Use Tax Refunds/Assessments, low income discounts, and gas research and development (internal program) expenses.

The Company is also proposing to implement new deferral accounting or reconciliation mechanisms, as addressed below.

Q. Why is the Company proposing the continuation of the existing reconciliation mechanisms?

A. Those reconciliation mechanisms are related to costs that are significant, highly variable even in the near term, and not subject to reasonable estimation, protect the interests of customers and investors and are appropriate. We note in that regard that the Company is subject to the Commission's Policy Statement on Pensions and Other Post-Employment Benefits and is required to true-up its annual pension and OPEB costs to the levels provided in base rates. Others, such as those related to the Low Income customer charge discounts, are in furtherance of public policy objectives. Moreover, continuing these true-ups in connection with a one-year rate determination could enable the Company to delay the need for rate relief at the expiration of the Rate Year.

A. Modified Deferral or Reconciliation Mechanisms

1. Electric and Gas Net Plant

Q. Please describe electric and gas net plant reconciliation under the Company's current rate plans.

A. The revenue requirement impact of actual electric and gas net plant (excluding AMI and CSS) is subject to downward reconciliation, with the possibility of limited upward reconciliation of certain municipal infrastructure support (interference) costs as specified in the rate plans. The rate plans also include an adjustment to the electric and gas net plant reconciliation to account for certain NWS and NPA programs implemented during the rate plans.

Q. What is the Company's proposal regarding net plant reconciliation for the Rate Year?

A. The Company proposes that the current electric and gas net plant reconciliation mechanisms continue, each with a modification to fully reconcile all interference capital. In addition, the Company is proposing an adjustment mechanism so that spending for the Reliable Clean City ("RCC") Projects will not exceed $780 million unless otherwise authorized by the Commission.

Q. Please explain why the Company is proposing to reconcile interference capital.

A. As explained by the Municipal Infrastructure Support Panel, interference costs are mandatory expenditures incurred to support local and state government projects.

As such, they are beyond the Company's direct control. New York City's Capital Infrastructure Improvement Program is the primary driver of the Company's forecasted interference expenditures, but Westchester County municipalities, and NYS are also planning projects that will cause the Company to incur interference costs in the upcoming years. These project plans are still under development and have the potential to significantly change, further hampering the Company's ability to reasonably forecast its interference costs. It is clear from the scope of the projects that these costs will be substantial. Accordingly, a change in a project plan could have a significant impact on the Company's overall capital spending plan. In order to avoid a situation where this impairs the Company's ability to manage its portfolio of capital projects effectively, the Commission should permit the Company to reconcile fully its interference capital costs.

Q. Please explain how your proposal for full reconciliation for interference capital would operate within the context of a single overall net plant target for electric and gas.

A. If actual aggregate net plant including actual interference net plant is at or below the aggregate net plant target, there would be no separate reconciliation of interference net plant. If capital expenditures resulting from interference costs above the forecasted amount cause the Company to exceed its aggregate net plant target, the Company would be permitted to recover carrying charges on the amount of net plant that exceeds the aggregate net plant target through a surcharge. Surcharge recovery is further detailed in the direct testimony of the Company's Electric and Gas Rate Panels.

Q. Please explain the Company's proposed adjustment mechanism for RCC costs within electric net plant.

A. Pursuant to the Commission's *Order Regarding Transmission Investment Petition* in Case 19-E-0065, the Company is authorized to spend $780 million on three RCC Projects to enable the retirement of peaker generation units and provide new delivery pathways for renewable power to reach customers. Consistent with the Order and subsequent discussions with Staff, the Company will cap the net plant impact of its spend on these projects to $780 million unless otherwise authorized by the Commission.

Mechanically, in the event the Company spends in excess of $780 million (unless otherwise authorized by the Commission) and also exceeds its overall electric net plant targets, the Company would not be permitted to defer carrying charges on the amount of net plant that exceeds the aggregate net plant target due to excess RCC project spending.

2. AMI Net Plant (Electric and Gas)

Q. Please describe AMI net plant reconciliation under the Company's current rate plans.

A. Net plant reconciliation for AMI capital expenditures is currently implemented for a single category of AMI capital expenditures that includes amounts allocated to both electric and gas customers, and is subject to a $1.285 billion overall project cap. The Company had forecasted, pre-pandemic, that AMI deployment would be completed during the current rate plan.

Q. What is the Company's proposal regarding net plant reconciliation of AMI-related expenditures for the Rate Year?

A. As described in the testimony of the Customer Energy Solutions Panel, the Company currently expects to complete AMI deployment in 2023. As such, the Company proposes to continue the current AMI reconciliation mechanism without modification.

3. New Customer Service System ("CSS") (Electric and Gas)

Q. Please describe the CSS net plant reconciliation under the Company's current rate plans.

A. The new CSS was not projected to be placed into service in the current rate plan, so the revenue requirement does not reflect any carrying costs associated with the new CSS. However, in the event a portion of the new CSS is placed into service, the Company is allowed to defer the associated revenue requirement impact in a manner similar to the AMI program. The CSS system implementation is also subject to a $421 million overall project cap.

Q. What is the Company's proposal regarding net plant reconciliation of CSS-related capital expenditures for the Rate Year?

A. The Company proposes that the current reconciliation mechanism continue without modification. In the Company's revenue requirement model, the new CSS system is expected to be placed in service in 2023 and the projected revenue requirement impact associated with the project would be compared to the revenue requirement associated with the actual expenditures and in-service date in a manner similar to the AMI program.

Q. What is the Company's proposal with respect to the new CSS-related O&M expenditures for the Rate Year?

A. In the current rate plan, the Company is reconciling the three year cumulative O&M targets to actual expenditures and deferring any over-collection to be applied to expenditures incurred above the O&M targets over the remaining CSS implementation period. The current rate plan also states that any deferral amount at the end of the new CSS implementation is to be credited to customers in the manner determined by the Commission. The Company proposes that the current reconciliation mechanism continue without modification.

4. Non-Wires Solutions ("NWS") and Non-Pipeline Alternatives ("NPA") (Electric and Gas)

Q. Please describe how cost recovery for NWS and NPA are structured under the Company's current electric and gas rate plans.

A. Under the Company's current electric and gas rate plans, costs of any new electric NWS or gas NPA (*i.e.*, those not included in rate base) are recovered as a regulatory asset. Recovery occurs via surcharge through the MAC and NYPA OTH Statement for electric or MRA for gas until base rates are reset. The rate plans further provides that to the extent an NWS or NPA results in the Company displacing a capital project included in its electric or gas net plant target, the

Company nets the carrying charge associated with the displaced capital project against the surcharge recovery of the NWS/NPA project. Any remaining credit is deferred for the benefit of customers.

Q. Is the Company proposing to modify either of these mechanisms for the Rate Year?

A. Yes. The Company is required by its current gas rate plan to propose an amortization period for NPAs.[1] The Company recently filed a petition in Case 19-G-0066 seeking approval of certain NPAs and proposing an amortization period of 20 years for the regulatory asset. The Company also clarified that in the event an NPA portfolio is not viable, it will continue to treat the spending associated with the project up to that point as a regulatory asset. The Company proposes to modify the NPA deferral in this case to be consistent with the clarifications in its petition.

5. Property Tax Reconciliation & Refund Sharing (Electric and Gas)

Q. Does the Company propose modifications to the Property Tax Reconciliation Mechanism?

A. Yes. The Company proposes a full and symmetrical reconciliation of property taxes applicable separately to electric and gas. Such a reconciliation for property taxes is needed regardless of whether a single year rate order or multi-year rate

[1] The Company's current rate plans provided that NWS costs are amortized over a 10-year term.

plan is adopted by the Commission in these proceedings. In addition, the Company proposes recovery through surcharge. Surcharge recovery is further detailed in the direct testimony of the Company's Electric and Gas Rate Panels.

Q. Please explain the basis for the modifications.

A. The Company's Property Tax Witness explains at length why property taxes are not subject to reasonable estimation and why a full reconciliation is appropriate. The Company's property taxes are subject to, among other things, the vagaries of municipal fiscal practices and economic circumstances.

Moreover, surcharge recovery is appropriate because of the magnitude of the variations between the Company's actual property taxes and the rate plan targets, particularly with regard to NYC property taxes. For instance, in the Company's current electric rate plan, undercollected property taxes from the previous rate plan represent the Company's second largest regulatory asset, requiring annual recovery of over $29 million. Conversely, in the previous rate plan (16-E-0060), overcollected property taxes from the prior rate plan represented the Company's largest regulatory liability, requiring refund to customers of over $42 million annually. These result in sharp rate increases or decreases for customers in each rate case and, when property taxes are undercollected, put pressure on the Company's cash flow between rate cases. Having more current collections for the Company/customer via surcharge/sur-credit, respectively, would spread out the rate impact associated with property tax increases and reduce both customer rate volatility and Company financing pressure.

Q. What do you propose regarding the sharing between the Company and its customers of any property tax savings the Company might obtain?

A. The Commission should continue the 86% customer / 14% Company sharing mechanism for property tax refunds, including credits against tax payments or similar forms of tax reductions (intended to return or offset past overcharges or payments determined to have been in excess of the property tax liability appropriate for Con Edison), net of costs incurred to achieve them, that exists under the current electric and gas rate plans with one modification. In many instances, the Company determines it is less costly (and thus better for customers) to negotiate future assessment reductions in a property tax settlement because a municipality is unable or unwilling to provide a cash refund or credit. The alternative is to pursue lengthy litigation in an attempt to obtain a refund award that could strain the municipality's finances. The nature of these reductions are fundamentally the same as cash refunds, to which the sharing mechanism plainly applies. As such, as explained by the Company's Property Tax Witness, the sharing mechanism should be modified to include costs to achieve reductions in future assessments.

6. Interference O&M Reconciliation (Electric and Gas)

Q. Does the Company propose a modification to the existing reconciliation mechanisms for interference O&M expense?

A. Yes. For the reasons explained in the direct testimony of the Company's Municipal Infrastructure Support Panel, the Company is proposing that a full and symmetrical reconciliation mechanism replace the partial and asymmetrical reconciliation mechanism currently in effect under the Company's rate plans for Municipal Infrastructure Support O&M expenses.

Q. Is the current interference reconciliation mechanism flawed?

A. Yes. As discussed in the direct testimony of Municipal Infrastructure Support Panel, interference costs are outside the Company's direct control and cannot be reasonably forecasted. Moreover, the current NYC projects expected are notably large and changes in their project plan could have a significant impact on costs that the Company must incur. As a result, the Company proposes that O&M costs be fully reconciled to protect both the Company and customers from any windfalls resulting from deviations from current cost projections, at the expense of the other. As the Company's Municipal Infrastructure Support Panel explains, the Company has historically sought to minimize its interference expenses and that continues on an ongoing basis – it is a normal course of business for the Company, even during times when a full reconciliation was in effect.

7. NENY Energy Efficiency ("EE") (Electric and Gas)

Q. Is the Company proposing to modify the reconciliation for its NENY EE program?

A. Yes. The Company is proposing changes to its EE reconciliation in light of the Commission's New Efficiency: New York ("NE:NY") Order, which was issued after the Commission adopted its current rate plan.

Q. How does the Company reconcile EE program costs under its current rate plans?

A. The ratemaking framework established in the Company's current electric and gas rate plans provide for the recovery of forecasted EE costs over ten years using the overall pre-tax rate of return. The revenue requirement associated with combined electric and gas costs for Low-Moderate Income ("LMI") and Non-Low-Moderate Income ("Non-LMI") EE Programs are subject to a downward-only reconciliation on a cumulative basis over the term of the current rate plan. There is also contingent flexibility across commodities for the Non-LMI EE Program when derived lifetime savings targets under the Commission's NE:NY Order have been met in any Rate Year.

Q. What modification is the Company proposing for its EE programs?

A. The Company is proposing a single cumulative EE reconciliation target that encompasses three programs (Non-LMI EE program, LMI EE program, and Heat Pump (Clean Heat) program) and is subject to an overall EE program cap. The Company will have the ability to transfer costs across programs and commodities as detailed in the NE:NY Order, which is discussed by the Company's CES Panel.

As discussed further in the direct testimony of the Company's CES Panel, the Company anticipates a change in the NE:NY funding cap prior to RY3. The Company intends to propose surcharge recovery in that proceeding. To the extent the NE:NY funding cap is increased subsequent to the rate plan being finalized and no surcharge mechanism is authorized in the NE:NY proceeding, the Company proposes that reconciliation targets in this case will be automatically adjusted to the updated cap.

Q. Does the Company propose any changes to amortization periods?

A. Yes. The Company seeks to change the recovery period for the Heat Pump (Clean Heat) program to fifteen years to match the useful life of the measures that are implemented as part of the program. This proposal is discussed further in the direct testimony of the Company's CES Panel. The Company is not proposing to change the ten-year amortization associated with the LMI EE and Non-LMI EE programs.

8. Smart Charge Electric Vehicles ("EV") (Electric)

Q. Is the Company proposing to modify the reconciliation mechanism for the regulatory asset associated with its Smart Charge EV program?

A. Yes. The ratemaking framework established in the Company's current electric rate plan provides for the recovery of forecasted EV costs over ten years using the overall pre-tax rate of return. The EV costs are subject to a downward-only reconciliation on a cumulative basis over the term of the rate plan.

As discussed further in the direct testimony of the Company's CES Panel, although there is no funding request for Smart Charge in this case, the Company anticipates additional funding to be approved in the Case 18-E-0138 ("Make Ready proceeding") prior to RY3. The Company intends to propose surcharge recovery in that proceeding. To the extent that funding is increased subsequent to the rate plan being finalized and no surcharge mechanism is authorized in the Make Ready proceeding, the Company proposes deferral treatment of any authorized spending.

9. Major Storm Reserve (Electric)

Q. Are you proposing to update the target, or base rate allowance level, for the major storm cost reserve applicable to electric operations?

A. Yes. The Company is proposing to maintain the Historic Year level of storm reserve expenditures, as increased by the general escalation factor, to arrive at the Rate Year amount.

Q. Does the Company propose a modification to the existing framework for major storm reserve costs?

A. Yes. The Company is proposing a number of changes. Under the current electric rate plan, the Company is 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 anticipation that a potential major storm will affect its electric operations, but which ultimately does not do so. In the current rate plan, the Company incurs a deductible expense of up to $500,000 per event for Pre-Staging and Mobilization Costs. Additionally, for events with costs exceeding $2.5 million, the Company absorbs further costs (i.e., incurs expense of 15% of such excess costs). For the reasons discussed in the testimony of the Storm Response and Resilience Panel, the Company is proposing to defer all Pre-Stage and Mobilization Costs as they are driven by events outside the Company's control.

For major storms that do materialize, the Company's current plan includes a two percent deductible for eligible expenses. The Company proposes to eliminate this deductible for reasons discussed in the testimony of the Storm Response and Resilience Panel. If there were negotiations for a multi-year settlement, the Company would be willing to consider an annual combined cap on deductibles for major storms and pre-staging and mobilizations.

Q. Is the Company proposing a surcharge mechanism for recovery of major storm costs?

A. Yes. The Company's deferral balance at the end of the Historic Year for storm costs is over $150 million. To avoid the future build up of a large deferral balance, the Company proposes the same surcharge that was proposed by Staff in its direct testimony (and agreed to by parties to the Joint Proposal) in O&R's recent rate case proceedings in Cases 21-G-0073 and 21-E-0074. Specifically, the Company proposes to surcharge actual major storm costs that vary from the rate allowance by more than $7 million in a given year. Once the $7 million variance is triggered, the Company would be allowed to recover the entire variance up to 2.5% of delivery revenues each year through surcharge. Surcharge recovery is further detailed in the direct testimony of the Company's Electric Rate Panel.

Q. Why is the Company proposing a $7 million variance trigger?

A. The threshold in the O&R rate cases was set at $2 million, which was 25% of the reserve allowance. The Company's proposes to use the same percentage and set is variance threshold at $7 million, which is approximately 25% of its proposed reserve allowance.

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

Q. Is the Company proposing to modify the reconciliation of the costs associated with its long term debt?

A. Yes. In the current rate plan, the Company is allowed to true-up its actual weighted average cost of Variable Rate Debt (i.e., the Company's portfolio of floating rate debt, including tax-exempt and taxable debt), including costs associated with retirement and refinancing of the Variable Rate Debt, to the cost rates reflected in the rate plan. As discussed in the direct testimony of Witness Saegusa (Cost of Capital), in light of recent disturbances in the financial markets, which have resulted in an unsettled and volatile interest rate environment, forecasting the cost rates associated with future debt issues is increasingly difficult. The Company proposes to true-up the entirety of its weighted average cost of long term debt to the rate reflected in Exhibit AP-5 (i.e. 4.28%).

Q. Is there precedent for the Commission allowing the Company reconciliation for both fixed and variable rate debt?

A. Yes; subsequent to the 2008 disruption in the financial markets, the Company was granted reconciliation for the entirety of its weighted average cost of long term debt for the period covering April 2010 through March 2013 in Case 09-E-0428. The economic circumstances in the instant cases, while different from the 2008 disruption, also warrant such a reconciliation. While they are different, we are currently experiencing the highest inflation in 40 years, which creates significant uncertainty for interest rates.

11. Legislative, Regulatory and/or Related Actions (Electric and Gas)

Q. Please describe the Company's deferral authorization under the Legislative, Regulatory and/or Related Actions provision of its current rate plan.

A. The current plan provides that the Company may defer costs or expenses resulting from laws, rules, regulations, orders or other requirements or interpretations of law if the amounts were not anticipated in the forecasts and assumptions on which rates are based after a ten (10) basis points of return on common equity has been met.

Q. Is the Company proposing to clarify the provision?

A. Yes. The Company proposes to clarify that it may defer "costs or expenses or revenues not anticipated in the forecasts and assumptions on which the authorized rates are based." Under Generally Accepted Accounting Principles, different treatment is afforded to deferrals of costs and expenses than deferrals of revenues. As such, the Company is seeking to be more precise in the deferral language authorized by the Commission to avoid any potential issues with appropriately recognizing its deferrals on its balance sheet. The Company also seeks to clarify that in the case of revenue deferals, it is a deferral for surcharge recovery and not until the next base rate case.[2]

12. Prevailing Wage Law (Electric and Gas)

Q. Under the current electric and gas rate plans, the Company is allowed to defer any incremental expenses incurred to comply with a State Prevailing Wage Law that was anticipated at the time of settlement. Is the Company proposing to continue this reconciliation going forward?

A. Yes. Although the Company has included forecasted costs to comply with the 2020 Prevailing Wage Law in its revenue requirements for two sites (the West End and East River facilities), there is an open legal question on whether the scope of the law will be broadened to cover building service workers at additional locations. As discussed by the Company's Shared Services Panel, application of this law to the West End and East River facilities has doubled the costs of certain service costs. The Company expects a comparable increase if the law is interpreted to include additional facilities. These costs would be significant and outside the Company's control. As such, the Company is proposing to continue to defer incremental expenses associated with compliance with the Prevailing Wage Law.

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[2] Deferred revenue related to alternative revenue programs may not be recorded for GAAP reporting until the collection is determined to be within 24 months from the end of the annual period in which they are recognized. Thus, to be consistent with GAAP rules, sur-credit/surcharge mechanisms should be utilized for revenues unless recovery through a deferral is imminent.

13. Pipeline Safety Acts (Gas)

Q. Does the Company propose to continue its reconciliations for incremental costs incurred to comply with the Pipeline Safety Act of 2011 and the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2019?

A. Yes, as discussed by the GIOSP, reconciliation is still necessary because of uncertainties with pending regulations.

Q. Under its current gas rate plan, how is the Company authorized to recover incremental costs incurred to comply with the Pipeline Safety Acts?

A. The Company is allowed to defer incremental O&M costs incurred to comply with the Pipeline Safety Acts. The Company may recover carrying charges (including depreciation) associated with incremental capital to comply with the Pipeline Safety Acts through the MRA.

Q. Is the Company proposing to modify its recovery going forward?

A. Yes. The Company is proposing to recover incremental O&M costs via surcharge to avoid a potential large deferral build-up prior to the next rate case filing. The Company proposes that carrying charges associated with incremental capital costs continue to be recovered through surcharge. Surcharge recovery is further detailed in the direct testimony of the Company’s Gas Rate Panel.

B. New Deferral Or Reconciliation Mechanisms

Q. Does the Company propose to establish any new deferral or reconciliation mechanisms?

A. Yes. The Company proposes the new deferrals or reconciliations detailed below.

1. COVID Uncollectible Reconciliation (Electric and Gas)

Q. What is the Company's proposed accounting treatment for uncollectible expenses in this case?

A. The Company proposes a full and symmetrical reconciliation of uncollectible expenses.

Q. Why does the Company believe that a full and symmetrical reconciliation is warranted?

A. The Company is unable to make an acceptable estimate of uncollectible expenses given the continued uncertainty around the financial health of the Company's customers. The Company continues to see significant growth in its aged accounts receivables balances since the onset of the COVID-19 pandemic when New York issued its 'on PAUSE' and other executive orders. When and whether those receivables will ultimately be collected is dependent on the strength of the economic recovery in the greater New York area and whether there is a statewide program addressing customer arrearages and is thus outside of the Company's control.

Q. How does the Company propose to perform the reconciliation calculation?

A. The Company's electric and gas revenue requirements include forecasted uncollectible expenses. The Company proposes to defer the difference between its actual uncollectible expense reserve and the level in rates each year. The deferral amount will be excluded from rate base and accrue interest at the Other Customer Provided Capital Rate. The deferral amount will be fully reconciled with the cumulative actual write-offs for the period January 1, 2020 through December 31,

2025. Recovery from, or refund to, customers of the annual variance for uncollectible write-offs will be via surcharge. The Company will provide Staff reports on any uncollectible write-off variance by April 30 of each year and begin collecting/refunding uncollectible write-off variance no earlier than 30 days after that notification. Final, full reconciliation on uncollectible write-offs will occur at the end of 2025. 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. Surcharge recovery is further detailed in the direct testimony of the Company's Electric and Gas Rate Panels.

2. Late Payment Fees (Electric and Gas)

Q. What is the Company's proposed accounting treatment for late payment fees in this case?

A. Pursuant to the Commission's *Order Authorizing Alternative Recovery Mechanism for Unbilled Fees* in Cases 19-E-0065 and 19-G-0066, the Company is reconciling late payment and other fees under its current rate plans via sur-credit/surcharge. Receipt of late payment fees is driven primarily by customer circumstances and is thus outside the Company's control. The COVID-19 pandemic has demonstrated that these revenues can be highly variable. Rather than regress to the pre-pandemic status quo where the Company forecasted late payment fees and then managed any over or under recovery, the Company proposes to continue full, symmetric reconciliation of late payment fees via sur-credit/surcharge.[3] From a policy perspective, this is a more appropriate approach as it eliminates risk to customers or the Company from variations in late payment fee collections and removes the counter-productive incentive for the Company to increase late payment charge revenues during a rate plan. Surcharge recovery is further detailed in the direct testimony of the Company's Electric and Gas Rate Panels.

3. Purchase of Receivables ("POR") (Electric and Gas)

Q. What is the Company's proposed accounting treatment for POR revenues?

A. The Company is proposing to reconcile actual POR-related revenues against the level included in the revenue requirement. Because ESCO can opt in or out of the POR program depending on the annual rate, their actions drive variability in the POR discount revenue collected. POR revenues have become a source of significant financial variability (for example, the POR revenue collected during the Historic Year for electric was approximately $18 million whereas the revenue target in rates for the Historic Year approximated $27 million. A similar variance can be observed in gas, where actual collections of POR revenues were $3 million versus $9 million assumed in rates). As this variability is outside of the Company's control, a new annual reconciliation with refund/recovery via sur-

[3] *See supra* n. 2.

credit/surcharge is appropriate.[4] Surcharge recovery is further detailed in the direct testimony of the Company's Electric and Gas Rate Panels.

4. Inflation (Electric and Gas)

Q. What is the Company's proposed accounting treatment for inflation in this case?

A. The Company proposes reconciliation for inflation to the extent that actual inflation exceeds the inflation rates assumed in the revenue requirement by a specified threshold.

Q. Why does the Company believe that reconciliation of inflation is appropriate in this case?

A. Current inflation rates are high relative to recent historical trends (the highest in 40 years) and it is unclear how long inflationary conditions will last. This renders the Company unable to make a reasonable estimate of inflation in its revenue requirement model. According to the U.S. Department of Commerce, Bureau of Economic Analysis ("BEA")[5], in Q2 and Q3 of 2021, the total annualized GDP price index in the United States was 6.1% and 5.9%, respectively. These are the highest annualized rates in 40 years. Further, it is unclear what, if any, steps will be taken to curtail inflation and what effects those steps will have on the inflation rate over the next several years. The Company's revenue requirement calculation,

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4 *Id.*

5 https://apps.bea.gov/iTable/iTable.cfm?reqid=19&step=3&isuri=1&1921=survey&1903=11#reqid=19&step=3&isuri=1&1921=survey&1903=11

which, as noted above is based on data from Blue Chip Economic Indicators, projects linking period inflation of 8.3% and inflation of 3.4% in RY2 and RY3, but actions outside of the Company's control will significantly affect whether these projections approximate actual future conditions.

Q. How does the Company propose to implement an inflation reconciliation?

A. If the general inflation rate exceeds 5.0% ("Inflation Threshold") in any of the rate years during the Electric and Gas Rate Plans and the Company's electric or gas earnings are less than the authorized ROE (as determined in our excess earnings calculation) applicable to that rate year, the Company will be allowed to request authorization from the Commission to defer actual inflationary increases above the Inflation Threshold applicable to the expenses subject to general escalation as indicated with a "Y" in the General Escalation column of the O&M expense table within Exhibits AP-3 Schedule 6. Any such request will not be subject to the Company meeting the Commission's deferral materiality threshold for the impact of these cost increases.

The deferral will be based on the lower of the following:

(a) Inflationary increases above the Inflation Threshold, determined using Price Index numbers for GDP published by the BEA applicable to the Inflation Pool; or

(b) Actual costs incurred by the Company for the expenses, contained in the Inflation Pool, above the Inflation Threshold.

As an example of how the mechanism would work, if during RY2, the inflation rate according to the BEA is 6.1%, as compared to the 3.4% increase in the expenses contained in the Inflation Pool used for purposes of establishing the revenue requirements for the Electric and Gas Rate Plans, the deferral would be equal to 2.7% (*i.e*., 6.1% less the 3.4% threshold) of the Inflation Pool, provided that the Company's earned ROE, as calculated pursuant to Section 10 of the Proposal was less than 10.0%.

Q. Is there precedent for the Commission granting the Company a reconciliation for the effects of inflation?

A. Yes; as an example, in Cases 08-G-1398 and 11-E-0408, the Commission authorized a similar inflation reconciliation for O&R because there were volatile inflation environments at the time of those cases.

5. Regulatory Commission Assessment (Electric and Gas)

Q. Is the Company introducing a reconciliation related to the regulatory commission assessment?

A. Yes. The Company is proposing a full and symmetrical reconciliation of regulatory commission General Assessment costs.

Q. What is the Company's rationale for requesting this reconciliation?

A. The regulatory commission assessment represents a significant expense for the Company and estimates of the expense in the Company's revenue requirement are based on assessment letters provided by the state commission. The estimates provided to the Company tend to be higher than actual costs. Although this results in relatively low risk for the Company and high risk for customers, the

Company believes it is appropriate to fully reconcile these costs as they are outside the Company's control.

6. Power Ready Electric Vehicles (Electric)

Q. Is the Company introducing a reconciliation related to the Power Ready Program?

A. Yes. The Company's proposed electric revenue requirement reflects regulatory asset amounts for the Power Ready Electric Vehicles program implementation costs amortized over 5 years. As further discussed in the testimony fo the CES Panel, the Company proposes a cumulative reconciliation of the revenue requirement effect of the actual level of costs incurred against the three-year targets (RY1 to RY3).

As discussed further in the direct testimony of the Company's CES Panel, the Company anticipates a potential change in the this program funding cap prior to RY3. The Company intends to propose surcharge recovery in the Make Ready proceeding. To the extent the funding cap is increased subsequent to the rate plan being finalized and no surcharge mechanism is authorized in the Make Ready proceeding, the Company proposes that reconciliation targets in this case will be automatically adjusted to the updated cap.

C. Terminated Deferral or Reconciliation Mechanism

Q. Does the Company propose to terminate any deferral or reconciliation mechanisms?

A. Yes. The Company proposes to terminate the deferral or reconciliation mechanisms discussed below.

1. Sales and Use Tax Refunds 2019

Q. The current rate plans have a reconciliation in place to address sales and use tax refunds related to the June 1, 2015 through May 31, 2018 audit period. Is the Company proposing to terminate this mechanism going forward?

A. Yes. The refunds related to this audit period have been received during the current rate plan and the associated deferral is included within this filing. No further action is needed and, as a result, the reconciliation is no longer necessary. Note that the Company is proposing to continue, without modification, the sales and use tax reconciliation for future assements/refunds.[6]

2. Taxes on Health Insurance

Q. Under the current electric and gas rate plans, the Company reconciles the difference between the estimate and actual excise taxes that were scheduled to become effective under the Affordable Care Act. Is the Company proposing to terminate this mechanism going forward?

A. Yes. The excise tax under the Affordable Care Act was repealed by the federal government in 2019. As a result, this mechanism is no longer necessary.

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[6] Under this provision, the Company has reflected a sales and use tax refund to customers of approximately $3.9 million received during its current rate plan in its proposed revenue requirements.

3. NYC Local Law 97

Q. Under the current electric and gas rate plans, the Company is allowed to defer incremental costs incurred to bring the Company's buildings into compliance with NYC Local Law 97. Is the Company proposing to terminate this reconciliation going forward?

A. Yes. The Company now has an understanding of the work necessary to comply with Local Law 97 and is able to reflect costs within its forecasts going forward. None were forecast for this rate plan. As such, the reconciliation is no longer necessary.

4. Gas Service Lines

Q. Under the current gas rate plan, the Company is allowed to defer for surcharge recovery certain incremental costs associated with inspection and maintenance of gas service lines. Is the Company proposing to terminate this reconciliation going forward?

A. Yes. After receiving clarification on survey/inspection intervals in Case 15-G-0244, and a Staff directive how to implement the inspections, the Company is now able to estimate the costs of compliance within the revenue requirement in this filing. As such, the reconciliation is no longer necessary.

XVII. MULTI-YEAR RATE PLAN

Q. Has the Company included forecasted financial information for periods beyond the Rate Year in its filing?

A. Yes. The Company has included, for illustrative purposes only, financial information for two annual periods beyond the Rate Year. Details of the revenue requirement for the Rate Year and the two following twelve-month periods, ending December 31, 2024, and December 31, 2025, are presented within Exhibits AP-3.

Q. What is the basis of the financial information presented in Exhibits AP-3?

A. Various Company witnesses have presented forecasts extending beyond the Rate Year. There are also proposals by various witnesses, including the Accounting Panel, which would affect periods beyond the Rate Year, such as amortization periods for deferred costs and credits.

Q. Is the Company proposing a multi-year rate plan for adoption by the Commission?

A. No. This filing seeks Commission approval of what is commonly referred to as "one-year rates" for electric and gas services. The Company is, however, interested in pursuing, through settlement discussions with Staff and interested parties, multi-year rate plans.

XVIII. MANAGEMENT AND OPERATIONS AUDITS

Q. Please discuss any developments in Commission-initiated management and operations audits since the Company's last base rate cases.

A. At the time of the Company's last base rate filings, the Company had three open management and operation audits.

First, Case 14-M-0001 was a comprehensive management and operations audit of Con Edison and O&R pursuant to Public Service Law §66(19). At the time, the Company had completed 35 of 36 recommendations and Staff had accepted and closed 32 of 36 recommendations. In December 2021, Staff granted a change to the implementation timeline and allowed the Company until June 30, 2022 to implement the final recommendation.

Second, Case 13-M-0449 was an internal staffing audit. Although the Company had implemented all 24 recommendations at the time of its last base rate filing, a number of those recommendations were pending Staff review and closeout. Staff closed all 36 recommendations in April 2019.

Third, Case 18-M-0013 was an income tax accounting audit. The audit report was pending at the time of the Company's last base rate filing. The report is currently still pending.

Q. Has the Commission commenced any new Commission-initiated management and operations audits since the Company's last base rate cases?

A. Yes. In Case 21-M-0193, the Commission commenced a comprehensive management and operations audit of Con Edison and O&R pursuant to Public Service Law §66(19). The final report is currently expected by August 2022.

Q. Does that conclude your direct testimony?

A. Yes, it does.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

DIRECT TESTIMONY OF

GAS RATE PANEL

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I. INTRODUCTION

Q. Would the members of the Gas Rate Panel ("Panel") please state their names and business addresses.

A. William Atzl, Yan Flishenbaum, Lucy Villeta and Alla Warner, 4 Irving Place, New York, New York 10003.

Q. By whom are you employed and in what capacity?

A. **(Atzl)** I am employed by Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company") as the Director of the Rate Engineering Department.

(Flishenbaum) I am employed by Con Edison as the Department Manager of the Load Research and Cost Analysis sections in the Rate Engineering Department.

(Villeta) I am employed by Con Edison as the Department Manager of the Gas Rates section in the Rate Engineering Department.

(Warner) I am employed by Con Edison as a Senior Rate Analyst in the Gas Rates section in the Rate Engineering Department.

Q. Please summarize your educational background and business experience.

A. **(Atzl)** In 1983, I graduated from the State University of New York at Stony Brook with a Bachelor of Engineering degree in Mechanical Engineering. In 1989, I graduated from Pace University, White Plains, New York with a Master of Business Administration degree in Management Information Systems. I am a Licensed Professional Engineer in the State of New York. My first employment was with the Long Island Lighting Company in 1983 where I held the position of Assistant Engineer in the New Business Department. In 1984, I joined Orange and Rockland Utilities, Inc. ("Orange and Rockland," or "O&R") as a Commercial and Industrial Representative in the Commercial Operations Department. At Orange and Rockland, I also held the positions of Commercial and Industrial Engineer, Program Administrator - Demand-Side Management, Manager - Demand-Side Management Operations, Manager - Energy Services and Pricing, and Manager – Regulatory Affairs. In October 1999, I joined Con Edison and held the position of Department Manager – Electric and Gas Rate Design – O&R and Director prior to my present position.

(Flishenbaum) I received a Bachelor of Business Administration Degree in Economics from Pace University in 2001 and a Master of Business Administration Degree in Finance and Economics from New York University in 2008. In 2001, I began my employment with Con Edison in the Cost Analysis Area of the Rate Engineering Department. In 2003, I was promoted to Analyst, mainly involved in the development of the costing methodologies related to unbundling. I was promoted to Senior Analyst in 2005. In 2008, I was promoted to Senior Rate Analyst responsible for developing the Company’s cost-of-service models. In 2013 I was promoted to Section Manager of the Electric Rates area of the Rate Engineering Department. I have been in my current position since September 2016.

(Villeta) I received a Bachelor of Business Administration Degree in Finance with a minor in Management Information Systems from Pace University in September 1989. In October 1989, I began my employment with Con Edison as a Management Intern with rotational assignments in Forecasting and Economic Analysis, Accounting Research and Procedures (“ARP”) and Power Generation Services. In June 1990, I accepted my permanent assignment as an Associate Accountant in ARP. In 1995, I was promoted to Budget Analyst in Central Customer Service. In 1998, I was promoted to Senior Analyst in Customer Operations responsible for managing the Call Center and Service Center budget. In 2001, I was promoted to Financial Manager of Staten Island and Electric Services. In 2005 I was promoted to Section Manager of Cost Analysis section of the Rate Engineering Department responsible for the development of fully unbundled embedded and marginal cost of service studies. I have been in my current position since December 2021.

(Warner)I am a Senior Rate Analyst in the Gas Rates section in the Rate Engineering Department. I received a Bachelor of Arts Degree and a Master of Business Administration Degree in Finance from Russian State Economics University. In 2014, I received a Bachelor of Arts Degree in Financial Economics from Columbia University. My employment thereafter was as a Rate Analyst at SUEZ from 2015 to 2017. I joined Con Edison in 2017 as a Senior Analyst in the Gas Rates section of the Rate Engineering Department. In December 2021, I was promoted to my current position.

Q. Have any members of the Gas Rate Panel previously testified before the New York State Public Service Commission ("PSC" or the "Commission")?

A. This is Alla Warner's first time testifying before the Commission. All other members of the Panel have previously testified before the Commission.

II. PURPOSE OF TESTIMONY

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

A. Our testimony presents the Company's:

(1) Gas embedded cost of service ("ECOS") study, including the development of unbundled costs associated with competitive services;

(2) Gas marginal transmission and distribution cost analysis;

(3) Proposed revenue allocation and rate design;

(4) Revenue and bill impacts showing the projected number of bill increases and decreases, and typical monthly bills, by class;

(5) Other tariff changes; and

(6) Computer System Enhancement Programs.

III. <u>EMBEDDED COST-OF-SERVICE STUDY</u>

Q. Did you perform an ECOS study for this proceeding including the development of unbundled costs associated with competitive services?

A. Yes, we did. Exhibit __ (GRP-1) is entitled "Consolidated Edison Company of New York, Inc. – Embedded Cost-of-Service Study – Gas Department – Year 2019."

Q. Please describe the exhibit.

A. The ECOS study and unbundled cost components analysis exhibit consists of three schedules. The first schedule, entitled Exhibit ___ (GRP-1), Schedule 1 "Consolidated Edison Company of New York, Inc. – Embedded Cost-of-

Service Study – Gas Department – Year 2019 – Rates in Effect January 1, 2022," shows the results of the ECOS study. The second schedule entitled Exhibit ___ (GRP-1), Schedule 2, "Merchant Function," shows the Merchant Function Charge ("MFC") calculations. The third schedule, entitled Exhibit ___(GRP-1), Schedule 3 "Billing & Payment Processing," shows the unbundled costs for printing and mailing a bill and receipts processing functions.

Q. Please provide a general description of the ECOS study.

A. The ECOS study (Schedule 1) analyzes, on a class basis and for a past period, revenues and book (accounting) costs for specific cost categories.

Q. What cost categories are analyzed in the ECOS study you are presenting?

A. The ECOS study analyzes costs and revenues associated with the Company's transmission, storage and distribution operations. It also includes the competitive cost categories related to the gas merchant function, the receipts processing function and the printing and mailing a bill functions. Competitive revenues included in the study are the MFC revenues associated with commodity procurement and credit and collections, as well as billing and payment processing ("BPP") revenues. The Gas Cost Factor ("GCF") revenues, Monthly Rate Adjustment ("MRA") revenues and associated expenses are not included in the ECOS study. Revenues and expenses associated with the uncollectible component of the MFC and System Benefits Charge ("SBC") have also been excluded from the study. Revenues and gas costs are presented as if there were no interruptible customers.

Q. What time period does the ECOS study cover?

A. It covers Con Edison's gas operations for the calendar year 2019.

Q. Why did the Company select 2019 as the historical test year for its ECOS study in this case?

A. The Company determined that 2020 does not represent a reasonable test year given abnormal disruptions to customer behavior due to the COVID-19 pandemic. 2019 was selected as the test year, since it represents a calendar year more closely resembling conditions expected to occur during the rate plan contemplated in this case. For instance, many restrictions in place during 2020 are not expected to be in place in 2023 and beyond. These include severe disruptions to the hospitality industry, such as closures of restaurants and hotels; as well as restrictions on entertainment and sports venues.

Q. What gas revenues are reflected in the ECOS study?

A. Gas revenues reflect current delivery rates, which went into effect January 1, 2022 ("current rates"). In addition, non-competitive T&D revenues include weather normalization adjustment ("WNA") revenues, which is a change from the ECOS study in our last rate case submission.

Q. What customer classes are analyzed in the ECOS study?

A. The ECOS study analyzes Con Edison's four firm classes: Service Classification ("SC") 1, SC 2 Rate I (including customers served under SC 13), SC 2 Rate II, and SC 3. For the purposes of the ECOS study and rate design, we combined firm transportation classes with their otherwise applicable firm sales service classes.

Q. How are the results of the ECOS study expressed?

A. The results of the ECOS study are expressed as Total Company ("total system") and class-by-class rates of return.

Q. What is the total system rate of return shown in the ECOS study?

A. The total system rate of return is 12.22% as shown on Table 1, Page 1, Column (1), Line 17 of the ECOS study.

Q. What are the class rates of return shown in the ECOS study?

A. The following class rates of return are shown on Table 1, Page 1, Line 17 of the ECOS study:

SC 1: 17.13%

SC 2 RATE I: 15.23%

SC 2 RATE II: 11.09%

SC 3: 11.29%

Q. Has the Commission historically employed "tolerance bands" around the system rate of return in developing class revenue responsibilities?

A. Yes. Based on past practice, class revenue responsibility has been measured with respect to a ±10% tolerance band around the total system rate of return. Classes would not be considered "surplus" or "deficient" if the class ECOS rate of return falls within this tolerance band. Classes that fall outside this range would be either surplus or deficient by the revenue amount, including appropriate state and federal income taxes, necessary to bring the realized return to the upper or lower level of the band. We propose to continue this practice in this case.

Q. Based on the application of the ±10% tolerance band around the calculated total system rate of return of 12.22%, what are the ECOS study class surpluses and deficiencies?

A. These results are shown on Table 1 of Schedule 1, lines 26 and 27 respectively. SC 1 is surplus by $36,230,127, SC 2

Rate I is surplus by $13,660,064, SC2 Rate II and SC3 are within the tolerance band.

Q. What is the significance, for example, of the SC 1 surplus?

A. The surplus is the amount of revenue decrease, at current rates, required to bring the SC 1 return to the upper level of the tolerance band around the system rate of return.

Q. Please describe what is shown on Table 1A, which is the last page of Exhibit__(GRP-1).

A. Due to the application of a 10% tolerance band around the system rate of return, the ECOS study in this case produces a net system surplus. To ensure that ECOS study indications are revenue neutral to the Company, Table 1A adjusted all SCs to offset the net system surplus.

Q. Let us now turn to the methodology used in developing the ECOS study. Please describe the procedures followed in the preparation of this study.

A. There are two main steps in the preparation of the ECOS study: (1) functionalization and classification of costs to operating functions, such as gas supply, distribution, customer accounting and customer service (with further division into sub-functions, such as distribution-demand component (mains) and distribution-services), and (2) allocation of these functionalized costs to customer classes.

Q. Please describe the functionalization and classification step.

A. The functionalization and classification step assigns the broad accounting-based cost categories to the more detailed categories used in the ECOS study. This breakdown is required, for example, to differentiate distribution-demand related costs from distribution-customer related costs. This allows for the proper allocation of these costs to the classes based on cost causation.

Q. Please continue.

A. During the process of functionalization, all costs are classified as being demand-related, commodity-related, or customer-related. Demand-related costs are fixed costs created by the on-peak hourly loads placed on the various components of the gas system. Commodity-related costs are variable costs caused by the total quantities of gas delivered during the year. Customer-related costs are fixed costs caused by the presence of customers connected to the system, regardless of any customer's particular level of usage.

Q. Please describe the allocation step.

A. This step allocates the functionalized and classified costs to the customer classes based on the appropriate demand, commodity (sales) or customer allocation factors, which are shown on Table 7 of the ECOS study.

Q. Please explain the general organization of the ECOS study.

A. The ECOS study begins with explanatory notes detailing sources of data and methods used in the preparation of the study followed by seven tables of cost data.

Q. Does the ECOS study contain an analysis of customer costs by class of service?

A. Yes. Please refer to Table 6, Page 1, Line 14 of the ECOS study. The monthly customer costs by class are as follows:

SC 1:	$26.54
SC 2 RATE I:	$93.20
SC 2 RATE II:	$137.64
SC 3:	$149.11

Q. What do customer costs include?

A. Customer costs include: a distribution-customer component, services, meters and house regulators, customer installation, payment processing, printing and mailing a bill, customer accounting, uncollectibles and customer service.

Q. Does the ECOS study present unbundled functional costs for competitive services as set forth in the Commission's *Statement of Policy on Unbundling and Order Directing*

Tariff Filings, issued August 25, 2004, in Case 00-M-0504 ("Unbundling Policy Statement")?

A. Yes. The ECOS study separately identifies the following competitive functions: gas merchant function, receipts processing, and printing and mailing a bill.

Q. What costs are included in the gas merchant function?

A. The gas merchant function contains costs associated with procuring the gas commodity, including an allocation of customer care-related activities, customer service-related activities and Information Technology ("IT").

Q. What costs are included in the allocation of customer care and customer service-related activities?

A. The customer care allocation includes costs associated with the Company's call centers, service centers, and credit and collection/theft activities. The customer service allocation also includes an assignment of education and outreach costs.

Q. How were these costs allocated to the gas merchant function?

A. Pursuant to the Unbundling Policy Statement, customer care and customer service-related costs were allocated to the gas merchant function on the basis of total revenues (i.e., including commodity revenues and SBC revenues).

Q. How were IT costs allocated to the gas merchant function?

A. Pursuant to the Unbundling Policy Statement, IT costs were allocated on the basis of total revenues with 50 percent of the resultant allocation included in the gas merchant function.

Q. Have you further unbundled the gas merchant function for use in developing rate components for competitive services?

A. Yes. The ECOS study includes the development of separate supply-related and credit and collection-related MFC components to recover the costs for these commodity-related competitive services from two categories of customers. The supply-related MFC component consists of the costs associated with procuring commodity, and an allocation of IT and education and outreach associated with commodity. The credit and collection-related MFC component consists of costs associated with credit and collection/theft. Only full service customers will pay for these MFC components. The costs for credit and collection services associated with the Purchase of Receivables ("POR") program have been identified separately and are reflected in a component of the POR discount applicable to marketers serving firm transportation customers receiving utility consolidated bills.

Q. How are these components allocated to the service classifications within the study?

A. One hundred percent of gas procurement activity costs and 25 percent of credit and collection/theft, IT, and education and outreach costs were allocated on a per-therm basis. The remaining 75 percent of credit and collection/theft, IT, and education and outreach costs were allocated on a per-customer basis.

Q. Why were the customer care-type costs, such as credit and collection/theft, allocated predominantly on the basis of number of customers, while the gas procurement activity was allocated entirely on a volumetric (i.e., therm consumption) basis?

A. The Company followed basic cost causation principles and determined that customer care-type activities are predominantly driven by the existence of customers on the system as opposed to their usage characteristics. On the other hand, the functional cost of purchasing commodity is aligned with sales volumes. This allocation is consistent with the *Order Adopting Unbundled Rates and Backout Credits and Specifying Terms for the Recovery of Revenues Lost As a Result of Such Rates and Credits*, issued April 15, 2005, in Case 04-E-0572, approving Con Edison's unbundled rates.

Q. Is the allocation of the MFC components to various groups of customers shown on Exhibit __ (GRP-1)?

A. Yes. Schedule 2 of Exhibit __ (GRP-1), pages 1 and 2, shows the allocation of the competitive supply-related MFC cost components and the competitive credit and collection-related MFC cost components to the residential and commercial categories of customers. The exhibit presents these two components as percentages of total revenues, which is the sum of the T&D and competitive revenues (i.e., MFC, BPP and POR Discount Credit and Collection revenues) used in the ECOS study. Separate percentages are shown for the residential and commercial groups of customers for use in the development of the MFC.

Q. Is the allocation of unbundled costs for printing and mailing a bill and receipts processing functions shown on Exhibit __ (GRP-1)?

A. Yes. Schedule 3 of Exhibit __ (GRP-1) shows the unbundled costs for printing and mailing a bill and receipts processing functions. The printing and mailing a bill function and the receipts processing function consist of the customer accounting expense of accepting customer payments and billing customers, including both direct costs and an allocation for call center and walk-in center operations based on a detailed study of those activities.

Credit and collection, education and outreach, and uncollectible expenses were allocated to these functions on the basis of functional revenues. The unbundled average unit cost for receipts processing is 46 cents per bill. The average unit cost for printing and mailing a bill is 74 cents per bill. The costs for these two functions combined yield $1.20 in unbundled costs associated with billing and payment processing. The costs associated with billing and payment processing do not vary by SC and, thus, the system-wide $1.20 in unbundled costs is applicable to all service classifications.

IV. GAS MARGINAL T&D COST ANALYSIS

Q. Did you perform an analysis of the marginal cost of delivering an additional therm of gas on the transmission and distribution system?

A. Yes. The analysis is shown in Exhibit __ (GRP-2), titled "Consolidated Edison Company of New York, Inc. – Marginal Cost Analysis."

Q. Please describe the exhibit.

A. Exhibit __ (GRP-2), Schedule 1, shows the steps in the calculation of the marginal cost of delivering an additional therm of gas on Con Edison's gas transmission and distribution system. Exhibit __ (GRP-2), Schedule 2 presents a comparison of marginal costs developed in Schedule 1 to current T&D revenues.

Q. What period was used to calculate marginal costs?

A. We used the forecast period of five years from January 1, 2022 through December 31, 2026. This period includes the twelve months ending December 31, 2023 ("Rate Year").

Q. Please define marginal T&D costs.

A. Marginal T&D costs are the costs associated with additions and modifications to the T&D system infrastructure that result from increased throughput due to increased sales. This does not include costs associated with service piping or any equipment inside the customer's premises.

Q. How did you estimate the marginal T&D costs for this study?

A. First, we identified capital costs incurred for the T&D system to maintain reliable service under peak design conditions as a result of increased sales. As discussed in the testimony of the Company's Gas Infrastructure, Operations and Supply Panel ("GIOSP"), the Company is not actively pursuing growth in the gas business, consistent with its clean energy commitment and the Climate Leadership and Community Protection Act ("CLCPA"). However, the Company does have an obligation to serve eligible customers who decline gas alternatives or for whom gas alternatives are not feasible. For purposes of this marginal cost study, only mains investment associated with customer connections was identified as marginal. Line 1 in Exhibit __ (GRP-2), Schedule 1, shows the projected average annual capital investment in the T&D system for the years 2022-2026 that results from increased sales associated with customer connections. Next, we calculated the annualized costs associated with the average annual capital costs by applying a carrying charge of 8.46%, plus an additional 1.80% in annual O&M, to Line 1. The final step in our analysis was to compute the average T&D capital costs per unit of increased sales associated with customer connections by dividing the incremental annualized capital costs by the projected increase in annual sales and escalating the result to bring it to Rate Year dollars. Line 6 of Exhibit __ (GRP-2), Schedule 1, shows the computed projected increase in sales (in therms); Line 7 shows the general escalation factor; and Line 8 shows the resultant total average marginal T&D cost per unit of increased sales.

Q. How do the marginal T&D costs compare to what is currently being recovered in rates?

A. Exhibit __ (GRP-2), Schedule 2, shows that marginal costs are less than what is being recovered in delivery rates for both SC 2 Rate I and SC2 Rate II. The ratio by which marginal costs are less than what is being recovered in delivery rates is the basis for the discounts participating customers receive under Rider D – Excelsior Jobs Program ("EJP"), which is further discussed in detail below. If marginal costs exceed what is being recovered in delivery rates, no discount under EJP is warranted.

V. <u>REVENUE ALLOCATION AND RATE DESIGN</u>

Q. Did the Company's Accounting Panel provide you with the increased delivery revenue requirement for the Rate Year?

A. Yes, the increase in the delivery revenue requirement for the Rate Year, which is proposed to be obtained from firm sales and firm transportation customers in SCs 1, 2, 3, 9 and 13, amounted to $502.650 million including gross receipts taxes.

Q. Please describe how you determined the Rate Year delivery revenue increase applicable to each class.

A. We performed the following steps in allocating the increased delivery revenue requirement:

- Gross receipts taxes of $12.991 million were deducted from the total Rate Year increased delivery revenue requirement of $502.650 million to derive the delivery revenue increase in the Rate Year of $489.659 million excluding taxes.

- Prior to allocating the proposed delivery revenue increase excluding taxes, we increased it by $10.744 million to reflect a projected increase in credits to be paid to low income residential customers in the Rate Year (the current funding level for the low income program credits is $24.649 million and the projected Rate Year funding level for the low income program credits is $35.393). This results in an adjusted delivery revenue increase of $500.403 million excluding taxes.
- Rate Year delivery revenues at the current level for SC 1, SC 2 Rates I and Rate II, and SC 3 were then realigned to eliminate the deficiency and surplus indications from Exhibit __ (GRP-1), Schedule 1, Table 1A. To address the need to eliminate the surpluses and deficiencies while considering the impacts on customers in the deficient SC 2 Rate II and SC 3 classes, we applied one third of the class-specific deficiency and surplus indications (“revenue adjustments”) from the ECOS study in a revenue neutral manner prior to applying the revenue increases. This approach allows us to address revenue and cost imbalances while

considering customer bill impacts. Our intent is to reduce further any deficiencies and surpluses in subsequent years.

- The Rate Year delivery revenue increase was then allocated to each class by applying the overall Rate Year delivery revenue percentage increase to Rate Year delivery revenues as realigned for the ECOS study surplus and deficiency indications as described above. The Rate Year delivery revenue percentage increase of 28.78% was developed by dividing the proposed delivery rate increase by the total Rate Year delivery revenues.
- We then determined the total Rate Year delivery revenue increase for each class by adding the revenue adjustments we proposed based on Table 1A of the ECOS study to the delivery revenue increase allocated to each class.

Q. Please explain how you designed firm gas delivery rates for each SC.

A. The rate design process consisted of the following steps:

- determining the amount of the revenue increase applicable to the competitive charges;
- determining the remaining amount of the revenue increase to be applied to non-competitive charges; and

- designing rates for non-competitive charges.

Q. Please explain how you determined the amount of the delivery revenue increase attributable to the competitive charges.

A. The amount of the delivery revenue increase attributable to the competitive charges is determined by taking the difference between the competitive service revenues at the proposed rates, designed in accordance with the Unbundling Policy Statement, and the competitive service revenues at current rates. The change in competitive delivery revenues reflects changes in the MFC fixed components. For reasons we will discuss later in this testimony, we are not proposing any changes to the BPP charge.

Q. Please describe the MFC fixed components.

A. The MFC fixed components consist of: a supply-related component, a credit and collections-related ("C&C") component, and a POR C&C component. Separate MFCs were calculated for the following MFC groups: (1) residential customers (SCs 1 and 3); and (2) commercial customers (SCs 2 Rate I, 2 Rate II and 13).

Q. Please describe how you designed the MFC.

A. As shown on Exhibit __ (GRP-1), Schedule 2, Page 1, the costs associated with the supply-related component are:

(1) 0.17627% of total delivery revenues for residential customers; and

(2) 0.06332% of total delivery revenues for commercial customers.

To determine the Rate Year revenue requirement associated with these costs for each MFC group, the respective percentages were applied to the total Rate Year revenue requirement at the proposed rate level. The resulting Rate Year revenue requirement for the supply-related portion of the MFC for each MFC group was then divided by the combined Rate Year sales for SC 1 and SC 3 full service customers and the combined Rate Year sales for SC 2 Rate I, SC 2 Rate II and SC 13 full service customers, respectively, to determine the $/therm supply-related component of the MFC for each MFC group.

Q. Please continue.

A. As shown on Exhibit __ (GRP-1), Schedule 2, Page 2, the total costs associated with the credit and collections-related component of the MFC are 0.34940 percent of total Con Edison delivery revenues at current rates.

To determine the Rate Year C&C–related revenue requirement, this percentage was applied to the total Rate Year delivery revenue requirement at the proposed level. The total Rate Year C&C-related revenue requirement was then split between full service and POR customers based on the respective split of full service and POR forecasted Rate Year volumes. The portion of the C&C-related Rate Year revenue requirement to be recovered from full service customers through separate MFC rate components was further allocated among: (1) SC 1 and SC 3 customers; and (2) SC 2 Rate I, SC 2 Rate II and SC 13 customers based on the breakdown of relative class percentages for full service customers' portion of C&C costs as shown on Exhibit__ (GRP-1), Schedule 2, Page 2. The resulting Rate Year revenue requirements for the C&C-related portion of the MFC for each MFC group were then divided by the respective Rate Year volumes for full service customers to determine the $/therm C&C-related component of the MFC. The residual Rate Year C&C-related revenue requirement will be recovered through a percentage adder to the POR discount rate.

Q. Have you changed the BPP charge?

A. No. Under the current Electric and Gas Rate Plans established in Cases 19-E-0065 and 19-G-0066, in order to have a consistent BPP charge applicable to gas and electric service, the BPP charge was set at $1.28. As noted in Section III, the unbundled cost for gas billing and payment processing is $1.20 per bill. As noted by the

Electric Rate Panel, the Electric ECOS study determined that the unbundled cost for electric billing and payment processing is $1.21 per bill. The Electric Rate Panel adjusted this cost based on the Gross Domestic Product Implicit Price Deflator index, resulting in an adjusted billing and payment processing cost of $1.27, which is extremely close to the current level of $1.28. The Electric Rate Panel therefore proposes to keep the electric BPP at the current level. Likewise, we are proposing to keep the gas BPP charge at its current level of $1.28 per bill to maintain a consistent BPP charge for electric and gas service.

Q. How will the BPP charge be applied?

A. Single service gas customers purchasing both commodity and delivery from the Company and single service retail access customers receiving separate bills from the Company and a Marketer will pay $1.28 per bill, which is also unchanged.

Q. Will dual service customers pay the same BPP charge as single service customers?

A. Yes, but half of the charge is treated as a gas charge under the Company’s gas rate schedule and the other half as an electric charge under the Company’s electric rate schedule.

Q. Please describe the next step in the rate design process.

A. The revenue increase to be applied to the non-competitive charges for each class was determined by adjusting the total revenue increase for the variation between the competitive charges by class at current rates and competitive charges by class for the Rate Year.

Q. Please describe how you designed the non-competitive charges to collect the Rate Year non-competitive delivery revenue increase.

A. The minimum charges, which include delivery of the first three therms of gas, were increased for the firm SCs. The minimum charge for SC 1 was increased from $27.70 to $31.00 as explained below. The minimum charge for SC 2 Rate I and SC 2 Rate II was increased from $34.80 to $44.90 and the minimum charge for SC 3 was increased from $23.80 to $31.00 to make movement toward the ECOS study customer cost indications. The SC 13 minimum charge also increased since it’s a function of the SC 2 minimum charge in that it recovers the same annual minimum charge revenue over a 7 month period, i.e., the number of months that customers can take service under SC 13, instead of over a 12-month period.

Q. Please explain why the minimum charge for SC 1 was increased.

A. The majority of SC 1 customers use 5 therms or less per month and the vast majority of SC 1 delivery revenue is associated with the minimum charge. Therefore, applying the revenue increase solely to the volumetric charge would disproportionally affect customers using more than 5 therms per month.

Q. Please continue to describe the rate design for the non-competitive charges.

A. After considering the amount of the delivery revenue increase attributable to changes in the minimum charges, the remaining non-competitive delivery revenue increase within each class was allocated to the block rates as follows:

- The charges for the per therm rate block for SC 1 (i.e., for all usage over 3 therms per month) was designed to collect the balance of the revenue increase assigned to SC 1.
- For SC 2 and SC 3, the Company began a gradual process to flatten the declining block rate structures to promote energy efficiency.
    - First, the charges for the three volumetric rate blocks within SC 3 (i.e., for usage from 4 to 90 therms, for usage from 91 to 3,000 therms and for usage greater than 3,000 therms) were

changed to begin to flatten the declining block rate structure in a revenue neutral manner. Then the remaining revenue increase for this class, after deducting the changes in annual revenues attributable to the minimum charge and to the air conditioning rates (as explained below), was applied to the volumetric charges on an equal percentage basis.

- o The charges for the three volumetric rate blocks within SC 2 Rate I and Rate II (i.e., for usage from 4 to 90 therms, for usage from 91 to 3,000 therms and for usage greater than 3,000 therms) were changed to begin to flatten the declining block rate structure in a revenue neutral manner. Then the remaining revenue increases for SC 2 Rate I and Rate II, after deducting the change in annual revenues attributable to the minimum charge and to the air conditioning rates (as explained below), were applied to the volumetric charges on an equal percentage basis.

- After accounting for the change in revenues to be collected through the SC 13 minimum charge, the two volumetric rate blocks for SC 13 were assigned the balance of the rate increase assigned to SC 13 on an equal percentage basis. Consistent with our current rate design, the SC 2 and SC 3 air-conditioning rates were set equal to the proposed block rates in SC 13, because the air-conditioning rates apply to seasonal off-peak firm gas usage as SC 13 rates do.

Q. Are you proposing any changes to the distributed generation ("DG") rates under Riders H and J?

A. Yes, we are proposing to increase the non-competitive delivery rates for Riders H and J as follows:

- The Rider H minimum charges (which include the first 3 therms of gas use), per therm rates and the contract demand rate were increased on a uniform percentage basis, by the SC 2 Rate I non-competitive rate change percentage.
- The Rider J minimum charge applicable to SC 1 and equivalent SC 9 customers was increased by the same percentage increase as the SC 1 minimum charge. The per therm rate for Rider J, Rate I, applicable to SC 1 and equivalent SC 9 customers, was increased by the same percentage increase as applied to the SC 1 non-competitive per therm delivery rate.
- The Rider J minimum charge and per therm rate, applicable to SC 3 and equivalent SC 9 customers in buildings with four or less dwelling units, were

increased on a uniform percentage basis by the SC 3 Rider J non-competitive rate change percentage.

Q. Did you allocate any of the delivery revenue increase to Firm Bypass customers in SC 9 or customers in SC 14?

A. No. Firm Bypass customers in SC 9 were not allocated any portion of the rate increase because bypass rates are set by contract based on the bypass customer’s competitive alternatives. SC 14, the rate for natural gas used in vehicles, was not allocated any portion of the rate increase because SC 14 customers are charged either fixed rates set by contract or market-based rates reflecting the competitive price of gasoline.

Q. Are you proposing any other rate changes?

A. Yes, we are proposing to update the discounts for customers who commence service under Rider D, EJP, on or after January 1, 2023.

Q. How did you determine the discounts for Rider D?

A. Exhibit ___ (GRP-2), Schedule 2, shows the ratio of marginal costs to what is currently being recovered in delivery rates. The rate discounts were based on one minus the ratio of the marginal costs to the corresponding revenue requirement for the respective class. This results in a discount of 53% for SC 2 Rate I and a discount of 40% for SC 2 Rate II. For customers commencing service under Rider D beginning on or after January 1, 2023, this percentage reduction would be applicable to their delivery rates. EJP discount percentages have been rounded to the nearest whole percentage.

Q. Are you proposing any changes to rates of the interruptible service class?

A. We are not proposing to change the methodology for determining delivery rates for interruptible customers taking service under SC 12 Rate 1 and SC 9 Rate B. In accordance with the Commission's January 16, 2020 *Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan* in Cases 19-E-0065 and 19-G-0066, we have set the rates for the volumetric rate blocks at 70% of each of the SC 2 Rate II volumetric block rates for non-residential customers and 70% of each of the SC 3 volumetric block rates for residential customers.

Q. Are you proposing any changes to rates of off-peak firm customers taking service under SC 12 Rate 2 and SC 9 Rate C?

A. We are not proposing any changes to off-peak firm delivery rates at this time.

Q. Are you proposing any other changes?

A. Yes. The Company is eliminating Rider G (New York State Economic Development Zones Act) and Rider I (Gas Manufacturing Incentive Rate) because these Riders expired on December 31, 2020. The Company currently does not have any customers under these Riders.

VI. REVENUES AND BILL IMPACTS

Q. Having computed revised rates for each SC, have you prepared exhibits showing what the estimated impact on customers' bills would be under the proposed rates?

A. Yes, we prepared Exhibit __ (GRP-3), the first page of which is entitled "CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. – RATE DESIGN – GAS DEPARTMENT – RATE YEAR 2023."

Q. Please continue.

A. Exhibit __ (GRP-3) includes four schedules that compare present and proposed revenue levels and rates and show the estimated impacts on customers' bills resulting from the proposed rates.

Q. Please explain each schedule.

A. Exhibit __ (GRP-3), Schedule 1, shows, by service classification, the Rate Year annual service class revenues at current January 1, 2022 rates, the Rate Year annual service class revenues at the proposed rates, and the resulting change in Rate Year service class revenues. Also shown is the number of customer bills that would have been increased, decreased and remain unchanged in the Rate Year based upon customer data for the 12-month period ended December 31, 2019. The revenues reflect an estimated gas cost for both full service and transportation customers.

Exhibit __ (GRP-3), Schedule 2, shows a comparison of the current firm rates and charges, effective January 1, 2022, with the proposed firm rates and charges, for SCs 1, 2, 3, 9, 13, and for distributed generation rates under Riders H and J.

Exhibit __ (GRP-3), Schedule 3, shows bill comparisons by service class, at the current January 1, 2022 rates and at the proposed rates. It consists of tables that show comparisons of monthly bills at various usage levels under the current rates and charges and under the proposed rates and charges.

The revenues and bill impacts shown in Exhibit __ (GRP-3), Schedules 1 and 3 include the same gas cost, SBC and MRA rates, at the forecasted Rate Year level, in the revenues and bill amounts at the current revenue level and proposed revenues and bill amounts in order to demonstrate the impact of the change in delivery rates on a customer's total bill amount.

Q. Have you prepared any analyses that show the change in total firm customers' bills taking into account both the increase in proposed delivery rates and projections for other charges, such as commodity charges?

A. Yes. We prepared Exhibit __ (GRP-3), Schedule 4, entitled "Consolidated Edison Company of New York, Inc. Projected Gas Bills." In this schedule, we show a comparison of average monthly bills by service class at proposed rates and charges for three 12-month periods. In these comparisons, the commodity and delivery-related portions are also shown. The commodity charges reflect the effect of projected gas costs. The delivery charges consist of projected non-competitive and competitive delivery charges based on three years of projected delivery revenue requirements provided by the Accounting Panel. Delivery charges also include projections for various other charges, such as the MRA and SBC, for each of the three Rate Years.

VII. OTHER TARIFF CHANGES

Q. Are you making any tariff changes resulting from program changes proposed by other Company panels in this case?

A. Yes. The Panel is sponsoring tariff changes associated with program changes being proposed by the Accounting Panel and the GIOSP.

Q. Please specify the tariff changes associated with program changes being proposed by the Accounting Panel.

A. There are various program changes in the Accounting Panel testimony that require tariff changes as follows:

- The Company has updated the handling cost and corporate overheads in General Information Sections IV.2.(B) and (F), respectively, which list elements of costs charged for special services performed by the Company.
- The Company has added the Reconciliation of Interference Costs to General Information Section IX.4. to recover carrying charges associated with interference costs that cause an exceedance of the net gas plant target. The Municipal Infrastructure Support Panel also further describes this change.
- The Company has added the Reconciliation of Property Taxes mechanism to General Information Section IX.31. to charge or credit customers the amount by which actual annual property taxes differ from Commission approved levels in base rates.

- The Company has added the Unbilled Fees Adjustment to General Information Section IX.6. The Company proposes to recover the reconciliation of the actual late payment fee revenues with Commission approved levels included in base rates in 2023 and future years and charge or credit any variance over a subsequent twelve-month period as authorized by the Commission. In addition, the Panel has included in the Unbilled Fees Adjustment mechanism recovery related to unbilled fees that were approved for recovery through the MRA pursuant to the Commission's *Order Authorizing Alternative Recovery Mechanism for Unbilled Fees*, issued and effective November 18, 2021, in Cases 19-E-0065 and 19-G-0066, for clarity.
- The Company has added the Uncollectible Bill Expense Adjustment to General Information Section IX.32. The Company will recover the difference, plus interest, between the actual annual uncollectible expense and Commission approved levels in rates for the period January 1, 2020 through December 31, 2025. After that time, the Company may recover any under-collections. Additionally, the Company proposes to include the reconciliation of the non-C&C related portion of the POR Discount reconciliation.

Q. Please specify the tariff changes associated with program changes being proposed by the GIOSP.

A. The Panel is also sponsoring the following tariff changes associated with the program changes being proposed in the GIOSP testimony:

- Added language to recover the cost of replacing damaged gas meters under General Information Section III.8.(X).
- Updated the inside piping survey/inspection fees under General Information Sections III.5.(C)(3)(ii)(a) and (b).
- Added language under General Information Section III.8.(C)(2) to: (1) collect the denial of access penalty for service line inspection for every billing period until access is gained; and (2) allow for recovery of all costs from the customer associated with legal action, including payments to law enforcement personnel, in regards to gaining access to the Company's gas meter;
- Modified the main and service allotment for residential heating customers to match the allotment for other customer types/usage (i.e., 100 feet of combined main and service) under General Information Section III.3.(B)(3).

- Removed the 100’ of main entitlement aggregation language for customers seeking service at the same time under General Information Section III.3.(B)(3)(b).
- Removed, under General Information Sections III.3.(C)(1) and (2), the revenue test (adjusted gas revenue exceeds 40 percent of cost) used to determine whether a surcharge is imposed or terminated and also removed the 50% percent of adjusted gas revenue reduction to monthly surcharges.
- Added the definition of Local RNG Production in General Information Section II and added language throughout the tariff to reflect the inclusion of Local RNG Production gas purchased by ESCOs into gas distribution operations.
- Removed the Pipeline Safety Acts Surcharge and added the Surcharge for Gas Safety Compliance under General Information Section IX.28. The Company proposes to recover currently unknown costs associated with specified federal, state and/or local gas safety requirements.
- We added additional pipelines to the market pricing language for the Gas Service Curtailments provisions of General Information Section III.(E) to correspond

with similar language in the Company's Gas Sales and Transportation Operating Procedures ("GTOP").

The following tariff changes related to Advanced Metering Infrastructure ("AMI") were made:

- Language was removed that required Interval Metering for Rider H customers. Language was also removed that required Rider H customers to provide, install and maintain all communications to the meter at their expense, and that required Rider H customers to maintain a dedicated telephone line to enable the Company to obtain remote readings.
- Language was added that exempts Rider H customers participating in the AMI program from being assessed a fee if their communications equipment fails.
- The term "telephone lines" was replaced with "communications equipment" throughout the tariff.
- Language was added to SC 12, Section (E) Customer Responsibility, stating that a Customer with AMI metering will not be required to install and maintain associated communication equipment.

Q. What changes are being proposed related to the period for which uncollectible bill ("UB") percentages are determined?

A. We propose to change various references to UB experiences for electric and gas customers based on the 12-month periods ending each September. This change would affect the POR discount in Miscellaneous Provision (P) of SC 20, which is currently based on the 12 months ending November. General Information Sections IX.8. and IX.11., related to the MFC and MRA, respectively, would also need to be updated in subsequent compliance filings to reflect the annual updates to the UB rates and percentages.

Q. Why are you proposing this change?

A. The main driver for the proposal is to better reflect changes in UB levels during the course of a rate plan. For the reconciliation of the MFC and MRA, a UB level set at the onset of a multi-year rate plan could change significantly up or down during the term of a rate plan and allowing the UB factors to refresh annually would provide rate recovery more consistent and timely with actual UB experiences. The change in the UB determination period for the POR discount from 12 months ending November to 12 months ending September would provide consistency with the changes to the MFC and MRA provisions. Since the UB factors for the MFC and MRA provisions would be included in compliance tariff filings, which are typically filed in early December, for each rate year, the 12-month period through September will allow the updates for all three tariff provisions to be included with each compliance tariff filing.

Q. What other tariff changes are being sponsored by the Gas Rate Panel?

A. The following additional Gas Rate Panel sponsored tariff changes are summarized below:

- We have updated General Information Section IX.14. to include interest on the monthly accrual and deferral balance for the purpose of calculating the RDM Adjustment. The interest will be calculated at the Other Customer Capital rate. This change is consistent with the Company's determination of the electric RDM Adjustment. This section was also revised to eliminate past period RDM revenue targets and to add the framework for a list of RDM revenue targets for the period January through December 2023. These targets have been shown as "TBD" since they have not yet been calculated.
- As discussed in the Rate Design section above, tariff changes have been made to specify the revised EJP discounts we are proposing under Rider D and their effective dates.
- The Low Income Reconciliation Adjustment, under General Information Section IX.10., has been updated

to conform to the Energy Affordability Program ("EAP") Budget of $35.393 million (an increase of $10.7 million from the current level in rates of $24.6 million) adopted in the Commission's *Order Adopting Energy Affordability Policy Modifications and Directing Utility Filings*, in Cases 14-M-0565 and 20-M-0266, issued August 12, 2021.

Q. Please describe any housekeeping changes you are making.

A. The housekeeping changes are as follows:

- We eliminated the tariff provisions and references related to the Interruptible Temperature Control option in SC 12 and the equivalent transportation SC (i.e., SC 9) as approved in Case 19-G-0066.
- We eliminated the tariff provisions regarding the annual interruptible reconciliation of the Interruptible Rate 1 customers for SC 12 and the equivalent transportation SC (i.e., SC 9) as approved in Case 19-G-0066.
- We eliminated delivery rates that have expired and are no longer being offered under SC 12 Rate 2 and the equivalent transportation SC (i.e., SC 9).
- On Leaf 378, we added the days of exclusion to the pricing of the Cashout Credit and Charges for Interruptible Daily Balancing in SC 20 similar to the

pricing of the Cashout Credit and Charges for Interruptible Monthly Balancing.

- Because Rider E – Low Income Program, is available to qualifying residential customers, including those taking service under Rider J, Residential Distributed Generation Rate, we have revised the applicability section of Rider E to include customers taking service under Rider J Rates I and II and SC 9 Rate (A)(10). We also added the Low Income Discount to the lists of rates in Rider J, Rates I and II.
- For clarification, on Leaf 349, we add language referencing all charges applicable in the determination of the penalty rate under SC 13 Seasonal Off-Peak Firm Service.
- On Leaves 232 and 241, we added language to the Reconciliation of Minimum Charge provisions applicable to Dual Fuel Firm Service in SCs 2 and 3 to clarify that, in no event shall the customer be charged less than the amount based on their actual consumption during the 12-month period.
- For clarification, on Leaves 230, 235 and 235.1, we added exemptions to the SC 2 ratio calculation that were previously approved in Case 16-G-0061.

- For clarification, we added the WNA to the list of charges applicable to SC 2 Rate II, SC 3, Rider D and Rider J Rate II, where applicable. Since the WNA is applicable to SC 3 customers, including those taking service under Rider J, Residential Distributed Generation Rate, references to the WNA were added to the list of rates under Rider J Rate II. In addition, changes were made to Special Adjustment IX., Weather Normalization Adjustment, to clarify the penultimate pure base rate to be used in the WNA calculation for Rider J Rate II customers.
- In SC 12, we made clarifying edits to the delivery and commodity rate descriptions under Interruptible Base Rate (Rate 1) on Leaf 332, and to the commodity rate description under Off-Peak Firm Rate (Rate 2) on Leaf 333.
- In SC 20 (Leaf 378), we made a clarifying edit to the description of the cost of gas used to determine cashout charges for interruptible daily balancing service to conform to language existing in the GTOP.
- We eliminated Rider G (New York State Economic Development Zones Act) and Rider I (Gas Manufacturing Incentive Rate) and references to these riders

throughout the tariff because these Riders expired on December 31, 2020.

- We modified the reconnection fee waiver language in General Information Section III.8.(V) to continue the requirement for the Company to notify parties if the target cost will be reached in any rate year. A reference to a specific case number was replaced with "in its most recent gas rate plan."
- We eliminated in General Information Sections VII.(A)1.(a)(i) and VII.(A)2.(a)(vi) obsolete references to revenue resulting from rates in effect prior to October 1, 2010.
- We eliminated in General Information Section IX.7. an obsolete reference to the Transition Adjustment for Competitive Services in effect prior to January 1, 2019.

Q. Are you recommending any housekeeping changes to General Information Section IX Special Adjustments of the tariff?

A. Yes. The Panel is recommending the following obsolete Special Adjustments be removed from General Information Section IX of the tariff along with any references throughout the tariff to such Special Adjustments:

- General Information Section IX.4., Transition Surcharge for Capacity Costs;

- General Information Section IX.6., Load Following Charge;
- General Information Section IX.17., Tax Sur-credit;
- General Information Section IX.20., Delivery Revenue Surcharge; and,
- General Information Section IX.31., Manhattan Transmission Project Surcharge.

Also, General Information Section IX.19., Other Non-Recurring Adjustments, is being updated to remove the reference associated with the credit resulting from Case 10-G-0100 and approved by the Commission in Case 09-G-0795.

Q. Are you updating the line loss factor and Factor of Adjustment at this time?

A. No. Since the Factor of Adjustment is updated each January based upon the average of actual line losses for the preceding five 12-month periods ending August, we do not have the values at this time. This will be updated at a later stage in this proceeding. We therefore revised General Information Section VII.(A)1.(d) to remove a specific reference to Case 19-G-0066 and a specific factor of adjustment.

VIII. RATE CASE ENHANCEMENTS PROJECT

Q. Is the Panel proposing any systems initiatives?

A. Yes, as discussed in the testimony of the Demand Analysis and Costs of Service Panel filed in the Company's electric rate case, the Customer Usage System ("CUS") project is common to both gas and electric services. As discussed in the whitepaper, this project provides gas-related load research and rate design benefits. For example, additional customer interval data made available through the gas AMI program will enable the retrieval and analysis of billing determinants for the design and evaluation of potential alternate gas rate structures.

Q. Does this conclude your direct testimony?

A. Yes, it does.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

GAS FORECASTING PANEL

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CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

GAS FORECASTING PANEL

I. INTRODUCTION

Q. Would the members of the Gas Forecasting Panel please state their names and business address?

A. John Catuogno, Patrick F. Hourihane, Robert Downes, and Johan Tolosa, 4 Irving Place, New York, New York 10003.

Q. By whom are you employed, in what capacity, what are your professional backgrounds and qualifications, and describe your current responsibilities?

A. (**Catuogno**)

We are employed by Consolidated Edison Company of New York, Inc. (“Con Edison” or the “Company”). I am Director of Commodity Forecasting in Energy Management. I graduated from Polytechnic University with a Bachelor of Science degree in Mechanical Engineering in 1991 and with a Master of Science degree in Management in 2002. I have also completed the Siemens PTI power system transmission course/certification.

I am a licensed Professional Engineer in the State of New York and an Adjunct Assistant Professor in the Mechanical Engineering Department of Manhattan College, where I present graduate lectures on energy and sustainability.

I joined Con Edison in 1991 as a Management Intern and have held various positions of increasing responsibility in the Fossil Power, Nuclear Power Engineering, Energy Management, and Steam Operations Departments. Since December 2013, I have been the Director of Energy Management's Commodity Forecasting Department. My responsibilities include oversight of daily peak, annual peak, monthly/annual energy revenue and volume forecasts for the electric, gas, and steam systems; and technical and analytical support for long range plans, strategies, and industry trends and issues that affect the Company.

(**Hourihane)** I am Section Manager of Gas and Steam Forecasting of Commodity Forecasting Department in Energy Management. My background is as follows: I received a Bachelor of Arts Degree in History from Saint Meinrad in 1974 and a Master's Degree in Energy Management from New York Institute of Technology in 2000. In 1975, I joined Con Edison in the Customer Service Department. Between 1978 and 2005, I worked in positions of increasing responsibility in the Customer Service and Energy Management Departments working on such projects as the electric governmental forecast and gas sales forecast. In 2005, I transferred to the Rate Engineering Department. In December 2006, I was promoted to Section Manager of Electric Volume and Revenue Forecasting. In July 2017, I assumed my present position. My responsibilities include overseeing the development of the gas delivery volume and revenue forecast.

(Downes) I am a Senior Planning Analyst of Gas and Steam Forecasting in Energy Management. My background is as follows: I received a Bachelor's degree in Economics from East Carolina University in 2009. I also received a Master of Science in Economics degree from East Carolina University in 2010. Prior to joining Con Edison, I worked at Seattle City Light where I was responsible for producing the utility's electric volume and peak forecasts as well as forecasts of the local economy. In 2016, I joined Con Edison gas forecasting where I work on developing econometric time series models and gas forecasts for Con Edison.

(Tolosa) I am a Senior Planning Analyst of Gas and Steam Forecasting in Energy Management. My background is as follows: I graduated from the City College of New York with a Bachelor of Engineering degree in Mechanical Engineering in 2009. I also received a Master of Science degree in Finance from Pace University in 2016. I joined Con Edison in 2009 as a management intern (GOLD associate) where I had assigments in the Steam and the Electric Operations departments. After graduating the program, I took a permanent position as an Associate

Engineer in Central Engineering supporting Steam Operations from 2011 to 2015. In June 2015, I became an Operating Supervisor for the Gas Conversions group in Gas Operations where I worked until the end of 2017. I joined and assumed my current position in the Energy Management department in Decemeber 2017 where I have had various roles. My responsibilities include the production of a long term, firm peak demand forecast for natural gas in Con Edison; the preparation of technical and anayltical studies related to natural gas in our service territory; and feasibility studies of different technologies in our service territory along with their impact on our natural gas system.

Q. Have you previously submitted testimony to the New York State Public Service Commission ("Commission")?

A. **(Catuogno)** I submitted testimony in Case Nos. 21-G-0073, 21-E-0074, 19-E-0065, 19-G-0066, 18-E-0067, 18-G-0068, 16-E-0060, 16-G-0061, 13-S-0032, 09-S-0794, 09-S-0029, and 07-S-1315.

(Hourihane) I testified in Case Nos. 13-E-0030, 10-E-0362, 08-E-0539, and 07-E-0523 and submitted testimony in Case Nos. 21-G-0073, 19-G-0066, 18-G-0068, 16-E-0060, 15-E-0050, 11-E-0408, 09-E-0428, and 07-E-0949.

(Downes) I submitted testimony in Case No. 19-G-0066.

(Tolosa) No.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of the Gas Forecasting Panel’s testimony in this proceeding?

A. The Gas Forecasting Panel’s testimony presents the Company’s forecast of gas delivery volumes (both full service and transportation combined), and revenues for the 12 months ending December 31, 2023 (“Rate Year”) also known as (“RY1”), and two additional 12-month periods ending December 31, 2024 and December 31, 2025 (which we refer to as “RY2” and “RY3,” respectively). The testimony explains the development of these forecasts starting from the 12 months ending September 30, 2021 (“Historic Year” or “Base Period”), and the key factors expected to impact future delivery volumes through the end of RY3.

Q. What was the adjusted actual and weather normalized firm delivery volume for the 12 months ending September 2021?

A. The adjusted actual firm delivery volume for the 12 months ending September 2021 was 158,086 thousand dekatherms (“MDt”). The weather and water normalized firm delivery volume for this same period was 164,901 MDt.

Q. Will you please summarize, in aggregate form, your firm delivery volume forecast?

A. The firm delivery volume forecast for the three months ending December 2021 is 39,871 MDt. The firm delivery volume forecast for the 12 months ending December 2022 is 167,528 MDt. The firm delivery volume forecast are 171,522 MDt for 12 months ending December 2023 (i.e., RY1), 173,019 MDt for the 12 months ending 2024 (i.e., RY2), and 171,445 MDt for the 12 months ending 2025 (i.e., RY3). The drivers of the changes in the forecasted volumes are discussed further in Section IV.

Q. What is the purpose of the delivery volume and sendout forecast?

A. The firm delivery volume forecast is used to determine the revenue forecast. The sendout forecast is also used by Company witness Kathleen Trischitta to develop a gas supply cost forecast.

Q. Do you have any exhibits that accompany this testimony?

A. Yes, we are presenting four exhibits, Exhibit ___(GFP-1) through Exhibit ___ (GFP-4).

Q. Were these four exhibits prepared under the Panel’s direction and supervision?

A. Yes. We describe each of these exhibits below in our testimony.

III. DELIVERY VOLUMES BY SERVICE CLASSIFICATION

Q. Which customers are included in the delivery volume forecast?

A. Both firm and non-firm customers are included in the delivery volume forecast. Firm customer classes include:

- SC-1 – Residential and religious customers;
- SC-2 – Rate 1 (General commercial and industrial customers);
- SC-2 – Rate 1 Rider H (General commercial and industrial customers);
- SC-2 – Rate 2 (General commercial and industrial customers);
- SC-3 – Residential (1 to 4 family dwelling units);
- SC-3 – Residential Rider J (1 to 4 family dwelling units);
- SC-3 – Residential (>4 family dwelling units);
- SC-13 – Seasonal off-peak water heating;
- SC-14 – Natural gas vehicles; and
- Special Contract Customers.

Non-firm (Interruptible) customer classes include:

- SC-9 – Transportation service customers who would otherwise take SC-12 service;
- SC-12 Rate 1 – Non-firm (interruptible) customers; and

- SC-12 Rate 2 – Off-peak firm customers.

IV. FIRM VOLUME FORECAST

Q. What are the key factors expected to impact future gas delivery volume?

A. The key factors expected to impact future gas delivery volume in the various service classifications are:

- Historic Year volume;
- The assumption of normal weather conditions;
- The assumption of an annual climate change impact to the normal weather conditions used for the first year of the forecast;
- The assumption of normal water temperature;
- The number of annual billing days;
- New Business – including oil-to-gas conversions;
- Energy Efficiency including both programmatic and organic;
- Electrification of heating load;
- Electrification of non-heating natural gas load; and
- COVID impact.

Q. Were any adjustments made to the Historic Year volume?

A. Yes. The Historic Year volume was adjusted for:

- Normalizing the impact of actual weather conditions to a 30-year average condition measured in Heating Degree

Days;

- Normalizing the impact of actual water temperature to a historical average of water temperature condition measured as an average cycle water temperatures;
- Transferring of customers between non-firm service and firm service;
- Theft of service;
- Seasonal adjustment of A/C volumes;
- Manual adjustments of large volumes to account for cancellation and rebilling from prior periods; and
- Billing days.

Q. Please explain why each of these adjustments is made.

A. The weather normalization adjustment is performed to adjust volumes to the 30 years ending 2020 normal level of Heating Degree Days. The Company used a 30-year normal of Heating Degree Days in accordance with the Commission’s requirement in the *Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal*, in Case 16-G-0061, *et al*. We calculated the monthly impact on firm delivery volume for firm heating service classifications by multiplying the variation between normal and actual Heating Degree Days, measured on a billing cycle basis, by a use per heating degree-day per bill factor times the actual number of bills by applicable service classification.

Q. How is average weather normalized use per bill calculated?

A. Con Edison calculates the average weather normalized use per bill by dividing monthly volume in the Historic Year by the monthly number of bills during the Historic Year. This is then divided by the number of billing days in the month.

Q. What did you do next with the Heating Degree Day calculation?

A. We used a regression analysis of the adjusted actual monthly billed volumes per customer per billing day versus actual monthly billing cycle heating degree days per billing day to determine the factors by service classification.

- We performed the water normalization adjustment to the Base Period volume for deviations from normal average water temperatures to the actual average water temperatures to adjust for the impact on water heating requirements. The Adjustment for SC-1 and SC-2 rate 1 is for all 12 months. The water adjustments for SC-2 rate 2 and SC-3 cover the three summer months July – September that are outside the weather normalization discussed above for these two service classes. We determined the usage per degree of average water temperature factors for the average customer of each class by regression analysis, which demonstrated a correlation between sales and water temperature. We applied these factors in a similar manner as the space heating factors were applied in the weather normalization adjustment to derive the water normalization adjustment.

- We made adjustments to account for customers transferring from non-firm to firm service during the Base Period. We performed this adjustment to annualize the transfers occurring in the historic period. These customers moved either electively or because their gas usage did not meet interruptible tariff terms.
- We performed adjustments to remove theft of service volumes from the Historic Year.
- We performed seasonal adjustments for air conditioning volumes where billing is outside the cooling season.
- We performed billing adjustments that smooth out large billing cancellations and re-billings to reflect what the actual volumes would have been on a monthly basis.

Q. Please discuss the adjustment to billing days.

A. We performed the adjustment for the number of billing days to account for the difference between the number of days billed in the Historic Year versus the number of expected billing days in each forecast Year.

Q. Please discuss the adjustment to the 30-year normal to reflect the impact of Climate Change.

A. After using the 30-year normal ending 2020 to adjust volumes for the test year, we reviewed the Company's industry-leading proactive Climate Change Vulnerability Study (conducted in 2019) and determined the annual rate of climate change to get to the Study's 2030 normal. Using that change, we adjusted the normal used for the test and bridge years to reflect a new climate normal for RY1 (2023), RY2 (2024), RY3 (2025), and continued for years 2026 and 2027 to complete the Company six-year forecast.

Q. Please explain the electrification of heating.

A. The adjustment reflects the Company's estimated impact of gas customers converting their heating systems to use electric service in support of the initiatives outlined in the Climate Leadership and Community Protection Act and Local Law 97. Commercial SC-2R2 customers and associated volumes along with Residential Heating SC-11 and SC-31 customers and associated volumes are adjusted in the forecast to reflect the loss of gas heating as customer switch to electrify their heating.

Q. Please explain the electrification of non-heating.

A. This adjustment reflects the Company’s estimated impact of gas customers that will convert their gas stoves, gas dryers, and gas water heaters to use electric service in support of the initiatives to reduce greenhouse gas emissions. Commercial SC-2R1 customers and Residential SC-1 customers are adjusted to reflect the loss of forecasted non-heating gas customers and associated volumes for the electricification of appliances.

Q. Does COVID–19 have any impact on the customer and delivery volume forecast?

A. Yes. The effects of COVID-19 are adjusted in the Company’s customer and volume forecast. The Company’s adjustment is necessary because the base year (12 months ending September 2021) still reflects much of the impact of customers leaving the service territory and changing service classes. From March 2020 through May 2021, SC-1 Residential non-heating was reduced by more than 26,000 customers. The Commercial SC-2R1 increased by more than 13,000 customers for this period as the landlord (if known) is placed on record as the responsible party until the vacant unit is occupied and returned to SC-1 Residential non-heating. In the period June 2021 through September 2021, the Company has seen a gradual reversal as potential new customers move back into the service territory and customers originally in SC-1 Residential convert away from SC2-R1 Commercial back to their original service class. The Company's forecast continued this movement, returning these two service classes to their pre-pandemic number of customers during the three month forecast for October 2021 through December 2021 and the bridge year 2022.

Q. Were there any other adjustments related to the effects of the COVID-19 pandemic?

A. Yes. The panel also adjusted rate class specific monthly average use per customer when forecasting the volume impact of customer growth and an adjustment for the base period's usage. Instead of using the average use per customer witnessed during the forecast's base period, the pre-pandemic (April 2019 – March 2020) monthly average use per customer was used in forecasting the volume impact of customer growth by service classification. The second COVID adjustment using average usage per customer was made to the SC-2 rate 1 and SC-2 rate 2 customer classes to account for the decline of average use experienced in these commercial service classifications due to the pandemic. Upward adjustments to volumes were made in both of these service classes by taking the difference of the average usage per customer that pre-dated the pandemic from the base period's average usage per customer for each service class. This was then multiplied by the number of customers in the service class. These volume impacts were phased in at 50% for 12 months ending 2022 and fully implemented commencing with RY1 (2023).

Q. Does that conclude the Company's attempts to account for the impact of the COVID-19 pandemic?

A. No. The panel also accounted for COVID-19's impact on customer growth in its regression equation used to forecast customer growth for the SC2 R2 commercial heating service classification. A dummy variable using Google mobility data was deemed statistically significant in estimating the equation used to forecast these customers. Please reference testimony from the Electric Forecasting Panel 22-E-XXXX for further details on this data.

Q. Have you prepared an exhibit showing the RY1 firm gas volumes?

A. Yes, we prepared a three-page Exhibit ___ (GFP-1), the first page of which is titled "CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. - DEVELOPMENT OF 12 MONTHS ENDING DECEMBER 31, 2023 - FORECASTED FIRM GAS VOLUMES (MDts)" with this information.

MARK FOR IDENTIFICATION AS EXHIBIT ___ (GFP-1)

Q. Please describe page 1, line 1 of Exhibit ___ (GFP-1).

A. Page 1, line 1 of Exhibit ___ (GFP-1) shows the adjusted actual firm gas volumes recorded during the Historic Year on a service classification basis.

Q. Please describe page 1, line 2 of Exhibit ___ (GFP-1).

A. Page 1, line 2 of Exhibit ___ (GFP-1) shows the adjusted volumes associated from the weather normalization.

Q. Please describe page 1, line 3 of Exhibit ___ (GFP-1).

A. Page 1, line 3 of Exhibit ___ (GFP-1) shows the adjusted volumes associated from the water normalization. Water temperatures during the Historic Year were warmer than normal. As a result, the Historic Year delivery volumes were lower than they otherwise would have been under normal conditions. This resulted in an upward adjustment to firm volumes of 281 MDt.

Q. Please explain the annualization adjustment labeled “Transfers From Interruptible Service” on line 5.

A. The delivery volumes on line 5 reflects the net of delivery volumes of customer movement between firm and interruptible service during the Historic Year.

Q. Please explain line 6 “Billing Schedule Adjustment.”

A. The Billing Schedule Adjustement represents the variations in the meter reading schedule from Historic Year to the rate years.

Q. What does line 7, “Base Estimate” represent?

A. The Base Estimate represents the Historic Year volume with the adjustments described previously in this section. The Base Estimate is the starting point for the Rate Year’s firm delivery volume forecast. We then apply the adjustments described below to develop the firm delivery volume forecast.

Q. Please explain the “Oil to Gas Conversions” forecast shown on line 8.

A. The Oil to Gas Conversions forecast are forecasted volumes for anticipated new business from customers converting to natural gas from heating oils.

Q. What is the New Business forecast on line 9?

A. The forecast on line 9:

(1) annualizes the volumes associated with customers added or lost during the Historic Year that were not fully realized in the Historic Year and customers that have switched from one service class to another as mentioned previously in this testimony; and

(2) estimates the expected volume to be realized in the Rate Year associated with new construction.

Q. Please explain how the New Business forecast was developed.

A. The New Business volume forecast begins with a forecast of the number of customers for SC-1, SC-2 rate 1, SC-2 rate 2, and SC-3 split between 1 to 4 dwelling units and greater than 4 dwelling units.

As mentioned previously in this testimony, we also used the weather-normalized average use per customer during the period of April 2019 – March 2020. This period was used to reflect average use not impacted by changing customer behavior during the COVID-19 Pandemic. We multiplied the weather-normalized average use by the forecast of the number of customers resulting in the New Business forecast.

Q. In developing the New Business volume forecast, how was the forecast of customers developed?

A. We developed the forecast of customers primarily based on time-series econometric regression models using customer count history. Regression models were used to forecast customers for service classifications SC-1 – Residential and religious customers, SC-2 rate 1 (General commercial and industrial customers), SC-2 rate 2 (General commercial and industrial customers), SC-3 – Residential (1 to 4 family dwelling units), and SC-3 – Residential (>4 family dwelling units). These regressions by service classification used historical customer data as dependent variables. We adjusted the historical customer counts for historical oil-to-gas conversions in service classifications SC-2 rate 2 (General commercial and industrial customers), SC-3 – Residential (1 to 4 family dwelling units), and SC-3 – Residential (>4 family dwelling units) to account for the Company’s programs that provide incentives to customers who convert from heating oils. Additionally, we accounted for inactive accounts in service classification SC-2 rate 1 (General commercial and industrial customers).

Q. Explain how you developed the 30-day bills forecast.

A. We created the 30-day bills forecast in this filing by converting the customer forecast as mentioned previously in the description of the New Business Forecast in this section. We developed an analysis of the historical relationship between customers and 30-day bills. We used this analysis to create the 30-day bills forecast.

Q. What is the “Energy Efficiencies” forecast shown on line 10?

A. The Company’s Energy Efficiency Department develops the Energy Efficiency forecast. This forecast reflects the expected impact of energy efficiency plans and programs as well as forecasted non-programmatic organic conservation by customers in the service territory.

Q. Please explain the basis of the “Energy Efficiencies” forecast shown on line 10.

A. The Company develops the forecast based on programs and plans that include: New Efficiency: New York (NE:NY) and Clean Heat programs. In addition, the forecast includes expected savings from the New York State Energy Research and Development Authority. These programs provide resources and incentives to the residential (1 to 4 dwelling units), multi-family and commercial customer segments to promote energy efficiency. The Company also develops a forecast of organic, or non-programmatic energy efficiency that customers pursue without the aid of the programs mentioned previously.

Q. Please explain the basis of the “Electrification” forecast shown on line 11.

A. The Electrification on line 11 forecasts the Company’s forecasted reduction in gas delivery volume related to existing and future customers switching from gas to electric service for both heating and non-heating purposes.

Q. Did the Company consider the recently enacted New York City legislation that generally bans the submission of applications for new natural gas connections within city limits beginning on January 1, 2024?

A. Yes. However, the Company does not expect this legislation will have a material effect on forecasts for this rate plan period. The Company will continue to examine the impact of this legislation and will adjust its forecast in the update, if necessary.

Q. Please explain the basis of the “Climate Change” forecast shown on line 12.

A. The Climate Change forecast on line 12 represents changes to normal weather as climate change impacts the region. The expected decrease in future heating degree days is represented in this portion of the Panel’s forecast and is detailed in a prior section of this testimony.

Q. Please explain the basis of the “COVID Adjustment” forecast shown on line 13.

A. As mentioned previously in this testimony, the Company has made an adjustment to account for the change in the average usage per customer in the SC-2 rate 1 and SC-2 rate 2 customer classes to account for the decline of average use experienced in these commercial service classifications due to the pandemic. Upward adjustments to volumes were made in both of these service classes by taking the difference of the average usage per customer that pre-dated the pandemic from the base period’s average usage per customer for each service class. This was then multiplied by the number of customers in the service class. These volume impacts were phased in at 50% for 12 months ending 2022 and fully implemented commencing with RY1 (2023).

Q What do pages two and three of Exhibit (GFP-1) show?

A. These pages quantify the impacts that the forecast drivers previously discussed in this section are expected to have on RY2 and RY3, respectively.

Q. Based on page one of Exhibit __ (GFP-1), what are the projected firm delivery volumes for the Rate Year?

A. Line 14 on page one of Exhibit __ (GFP-1) summarizes the firm delivery volume forecast for the Rate Year. Firm delivery volume is estimated to total 171,522 MDt. This represents an increase of 7,890 MDt over the Historic Year’s volume adjusted to normal weather, water, transfers to and from interruptible, and billing schedule adjustments.

Q. Are the volumes shown by service classification and in total on page one of Exhibit __ (GFP-1) the volumes the Panel is recommending to be used for rate setting forecasting?

A. Yes. These are the service class delivery volumes for this rate filing.

V. NON-FIRM (INTERRUPTIBLE) VOLUME FORECAST

Q. How was the volume projected for SC-12 rate 1 Non-Firm (Interruptible) and SC-12 rate 2 Off-Peak Firm developed?

A. We developed the forecast of the future volume for SC-12 rate 1 Non-Firm (Interruptible) and SC-12 rate 2 Off-Peak Firm by making adjustments to the Historic Year volumes. These adjustments include:

(1) a weather adjustment that was computed in a manner similar to the weather normalization adjustments for the weather sensitive firm rate classifications;

(2) an adjustment for the service interruptions that occurred within the Historic Year for the interruptible service classes; and

(3) an adjustment for the transfer of customers between interruptible and firm service discussed earlier.

Q. Based on Exhibit __ (GFP-3), described later, what are the projected non-firm sendout volumes for the Rate Year?

A. Line 13 of Exhibit __ (GFP-3 page 1) summarizes the non-firm sendout volume forecast for the Rate Year. We forecast that Non-Firm sendout volume will be 24,753 MDt.

VI. REVENUE FORECAST

Q. Was Exhibit ___ (GFP-2)and (GFP-3), which is entitled “CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. –

FORECSATED GAS VOLUMES AND REVENUES,” prepared under the Gas Forecasting Panels supervision and direction?

A. Yes. They were.

MARK FOR IDENTIFICATION AS EXHIBIT ___ (GFP-2) and (GFP-3)

Q. Please explain what page 1 of Exhibit ___ (GFP-2)shows?

A. Page 1 shows forecasted volumes and revenues for the three months ended December 31, 2021 at January 1, 2021 rates.

Q. What does column 1 “Gas Delivery Volumes (MDt)” of this exhibit show?

A. Column 1 shows by service classification grouping the gas volumes forecasted for the three months ending December 31, 2021.

The firm gas service classifications are:

- SC-1 - Residential and Religious;
- SC-2R1 – General Commercial and Industrial;
- SC-2R1 – Rider H - General Commercial and Industrial (customer using gas service for on site Distributed Generation);
- SC-2R1 – Contract General Commercial and Industrial (non-heating);
- SC-2R2 – General Commercial and Industrial (heating);

- SC-3 - Residential and Religious (heating);
- SC-3 – Rider J - Residential and Religious (customer using gas service for on site generation);
- SC-13 – Seasonal Off Peak Water Heating; and
- SC-14 – Natural Gas Vehicles.

Column 1 also shows projected SC 12 Rate 1 Non-Firm and SC-12 rate 2 Off-Peak Firm volumes for the three months ending December 31, 2021.

Q. Please explain how the Base Revenues, shown in column 2 on page 1, for firm related volumes were determined.

A. For SC-1, SC-2 rate 1, SC-2 rate 2, SC-3, and SC-13, we computed the forecasted Base Revenues by month on a billing determinant basis. The forecast is the product of three steps:

(1) the estimated number of 30-day bills associated with the forecasted usage is multiplied by the minimum charge rate to obtain minimum charge revenues;

(2) the forecast usage is broken down into usage by rate block and multiplied by the associated rates as they appear in the Company’s gas rate leafs for each rate block; and

(3) the minimum charge revenues and block charge revenues are summed to obtain total Base Revenues.

The air conditioning volumes of certain customers within these service classifications are charged lower rates for associated incremental volumes and were priced separately. Volumes to distributed generation customers and contract customers were priced according to their appropriate rate/contract terms. The volumes related to SC-14 were priced at the rate in effect at the time the forecast was developed.

Q. Please explain how the Base Revenues related to the projected volumes for SC-12 rate 1 Non-Firm were determined.

A. SC-12 rate 1 Non-Firm Base Revenue was calculated by separating the service classification customers into commercial and residential. Volumes were then broken down into usage by rate block and multiplied by the associated rates as they appear in the Company's gas rate leafs for each rate block.

Q. Please explain how the Base Revenues, shown in column 2, related to the projected volumes for SC-12 rate 2 Off-Peak Firm, were determined.

A. SC-12 rate 2 Non–Firm Base Revenue was provided by Accounting reflecting the base period's actual revenue.

Q. Please describe the revenues shown in columns 3,4,5,6, and 7 on page 1.

A. Column 3 on page 1 shows Competitive Charges, which are the associated Merchant Function charges for Supply, Credit and Collections, plus Billing and Payment Processing revenues. Column 4 through 7 on page 1 are revenues supplied by Financial Planning and Analysis for this Exhibit. Column 4 that is listed as “Other Charges” include various complonents of Monthly Rate Adjustment, Uncollectibe Bills, Purchase of Receivables. Column 5 is System Benefit Charges. Column 6 is the Gas Cost revenues. Column 7 is the revenue taxes associated with columns 2 through 6, and column 8 shows the total revenues of column 2 through column 7.

Q. Please explain what page 2 of Exibit ___ (GFP-2)shows?

A. Page 2 in the same format shows forecasted volumes and revenues for the 12 months that lead up to the Rate Year, 12 months ending December 31, 2022 at January 1, 2022 rates.

Q. Please explain Exhibit ___ (GFP-3)?

A. GFP-3 is similar to Exhibit ___ GFP-2 as it shows the Gas Delivery Volume and Revenues for the Rate Year, RY2, and RY3 at current rates. The Rate Year shown on page 1 of Exhibit GFP-3 has three additional columns, columns 9, 10, and 11, to include the Proposed Rate Increase and additional Revenue tax. Column 9 is the proposed change in non-competitive revenues. Column 10 is the proposed change in competitive revenues. Column 11 additional taxes and column 12 is the grand total of the proposed rate increase and associated taxes added to the Total Revenues at current rates shown in colum 8.

Q. What is the firm rate increase proposed in the Company's rate filing?

A. The total proposed firm rate increase inclusive of revenue tax and low income discount is $502.6 million.

Q. You stated above that you developed the Rate Year base revenue forecast by using billing determinants. Did you develop exhibits summarizing the details of the billing determinant forecast?

A. Yes. This data is shown for the three rate years on a three-page exhibit, the first page of which is entitled "CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. – FORECASTED GAS VOLUMES AND BASE REVENUES - 12 MONTHS ENDING DECEMBER 31, 2023 AT CURRENT RATES BY BILLING DETERMINANTS."

MARK FOR IDENTIFICATION AS EXHIBIT ___ (GFP-4)

Q. Please describe what this exhibit shows.

A. This exhibit shows, where applicable, the firm volumes by billing determinant. The volumes by billing determinant were developed using actual billing determinant volumes for the Historic Year, modified to reflect the impact of the variables previously discussed. The allocation of the impact of each of those variables on billing determinant volumes was assessed on an individual basis. For example, the impact of adjustments related to weather has a relatively greater impact on penultimate and terminal billing determinant usage than that of smaller size new business customers.

We based the forecast of firm delivery revenues from tariff customers (other than special contract customers and SC-14) based on billing determinants. Firm delivery revenues from special contract customers were based on their current contract terms. We developed the firm delivery revenues SC-14 revenues by using prices in effect during the Historic Year.

Q. Does this conclude the Gas Forecasting Panel’s testimony?

A. Yes. It does.

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I. INTRODUCTION

A. Introduction and Qualifications of Panel Members

Q. Would the members of the Gas Infrastructure, Operations and Supply Panel ("GIOSP" or "Panel") please state your names and business addresses?

A. Our names are Katherine Boden, Nicholas Inga, Amr Hassan, Robert Massoni, Christine Cummings, Ivan Kimball and Kathleen Trischitta.

Our business address is 4 Irving Place, New York, New York 10003.

Q. By whom are you employed and in what capacity?

A. We are all employed by Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company").

(Boden) I am the Senior Vice President of Gas Operations.

(Hassan) I am the Vice President of Gas Engineering.

(Inga) I am the Vice President of Gas Operations.

(Cummings) I am the General Manager of Project Management and Customer Programs.

(Massoni) I am the General Manager of Manhattan Gas Operations.

(Kimball) I am the Vice President of Energy Management.

(Trischitta) I am the Director of Commodity Operations.

Q. Please state your educational background.

A. (**Boden**) I hold a bachelor's degree in Electrical Engineering from Polytechnic University, and a Master of Business Administration in Management from Hofstra University. I have also completed PTI's Power Technology Course, PTI's Electric Distribution System Engineering Course, and Gas Technology Institute's ("GTI") Registered Gas Distribution Professional Course.

(Hassan) I hold a bachelor's degree in Mechanical Engineering from the Cooper Union, and a Master of Business Administration in Finance from NYU Stern. I have also completed GTI's Registered Gas Distribution Professional Course.

(Inga) I hold a Bachelor of Science Degree in Mechanical Engineering from Polytechnic University, and a Master of Business Administration Degree in Corporate Finance from Fordham University. I have also completed PTI's Power Technology Transmission and Distribution Systems programs, and a Project Management certificate course through the Company's program with Stony Brook University.

(**Cummings**) I hold a Bachelor of Science degree in Economics from Queens College. I have also completed GTI's Registered Gas Distribution Professional Course.

(Massoni) I hold a bachelor's degree in Business Management from the University of Phoenix.

(**Kimball)** I hold a Bachelor of Science degree and a Master of Science degree in Nuclear Engineering from Rensselaer Polytechnic Institute.

(Trischitta) I hold a bachelor's degree in Electrical Engineering from the State University of New York at Stony Brook.

Q. Please describe your work experience.

A. (**Boden)** I joined Consolidated Edison in 1990 as a Management Intern. I have held various positions of increasing responsibility in Construction, Operations, and Engineering in Electric Operations. In 2005, I was promoted to Vice President Manhattan Electric Operations a position that I held through 2010. In 2010 I was assigned to Gas Operations as Vice President. In 2017, I was assigned to Gas Engineering as Vice President. In 2021, I was promoted to my current position as Senior Vice Present Gas Operations.

(Hassan) In 1993, I joined the Company's Corporate Intern Program and have since held various positions of increasing responsibility mainly in Gas Operations, with some assignments in Energy Management and Corporate Planning. In January 2013, I was promoted to General Manager Gas Operations, where I was responsible for the Construction and Distribution Services groups in regions of our service territory. In November 2019, I became the Chief Distribution Engineer, and in September 2021, I assumed my current position as Vice

President of Gas Engineering.

(Inga) In 1992, I joined the Company's Corporate Intern Program and have since held various positions of increasing responsibility in Gas Operations, Treasury, and Shared Services. In April 2008, I was promoted to General Manager of Stores Operations, where I was responsible for the Company's supply inventory and order fulfillment processes. In June 2011, I was appointed to the position of Director of the Gas Conversion Group. In January 2015, I was assigned to Manhattan Gas Operations as General Manager. In 2017, I assumed my current position as Vice President of Gas Operations.

(**Cummings**) In 2001, I joined the Company as a Management Associate following a previous career in global transportation, including roles in auditing and compliance, customer service, and corporate training. Since joining the Company, I have held various positions of increasing responsibility in Government Relations (Corporate Affairs) and the Gas Conversion Group. In January 2015, I was promoted to Director of the Gas Conversions Group. In 2018, I assumed my current position of General Manager of the Project Management and Customer Programs group.

(Massoni) In 1981, I joined the Company as a member of the union and have since held various positions of increasing responsibility in Central Operations, Shared Services and Gas Operations. In March 2011, I was promoted to General Manager of Astoria Operations, where I was responsible for several groups including the Logistics Operations Control Center responsible for supporting the Company operating groups during storm response and recovery. In January 2016, I was assigned to Bronx Gas Operations as the General Manger, and then in December 2017, moved to Manhattan as the General Manager of Gas Operations.

(Kimball) I joined Con Edison in 1987 as a Management Intern and held various positions of increasing responsibility until December 1998 when I was transferred to Consolidated Edison Energy, Inc. ("Con Edison Energy"). My responsibilities as Director of Asset Management included day-to-day scheduling, fuel procurement, electricity market sales and planning, and associated regulatory and accounting matters of generating facilities owned by Consolidated Edison Development, Inc. ("Con Edison Development") and other contracted generating facilities. In August 2008, I returned to Con Edison as Director of Electricity Supply. In that position I was responsible for day-to-day electricity supply operations, including the scheduling of generation and load bids with the New York Independent System Operator ("NYISO") and neighboring control areas;

developing the overall electric power procurement plans for full service customers; developing and implementing Con Edison's electric hedging program; strategically evaluating and participating in capacity and transmission congestion contract ("TCC") auctions; managing contractual rights with various non-utility generators; and processing monthly invoices for wholesale purchases and sales of capacity, energy, and TCCs for Con Edison and its affiliates, Orange and Rockland Utilities, Inc. ("ORU") and Rockland Electric Company ("RECO"). In July of 2012, I was promoted to my present position of Vice President of Energy Management.

(Trischitta) I joined Con Edison in 1993 as a Management Intern in Gas Operations and have held various positions of increasing responsibility in Con Edison's Gas Operations, Fuel Supply, Unregulated Retail Operations and Energy Trading and Energy Management organizations. In 1995, I joined Fuel Supply's newly formed off-system sales organization with responsibility for developing and implementing some of the Company's first strategies for gas asset optimization. In 1997, I transferred to the newly formed unregulated subsidiary Con Edison Solutions and was responsible for the implementation of the retail gas business. Immediately prior to assuming my current position in January 2016, I was Managing Director of the Energy

Trading organization within Con Edison Energy, another unregulated subsidiary of Con Edison, responsible for the oversight of electricity, gas, oil, and renewable energy credit trading.

Q. Please describe your current responsibilities.

A. **(Boden)** In my current position as Senior Vice President for Gas Operations, I am responsible for the overall Con Edison Gas Operations, Engineering, and Compliance and Quality Assessment groups.

(**Hassan)** In my current position as Vice President of Gas Engineering, I am responsible for the Technical Operations, Project Management & Customer Programs, Gas Distribution Engineering and Gas Transmission Engineering groups.

(Inga) In my current position as Vice President of Gas Operations I am responsible for leading and managing both Company employees and contractor personnel in the safe and effective execution of, primarily, the following work: leak response, leak repair, compliance inspections, main replacement, and service installations.

(**Cummings**) In my current position as General Manager of Project Management and Customer Programs Group, I am responsible for the overall management of the capital projects and programs and for leading and managing the

Company's program to connect customers. As such, I am responsible for the engineering, operations planning, and customer liaison activities related to customer connections and safety-related inspection programs in customers' premises.

(Massoni) In my current position as General Manager of Manhattan Gas Operations I am responsible for leading and managing both Company employees and contractor personnel in the safe and effective execution of leak response, leak repair, compliance inspections, main replacement, and service installations, in Manhattan.

(Kimball) I am responsible for providing the overall strategic planning and direction for forecasting service area demand, evaluating electric, natural gas, and steam resource options, and procuring electricity, natural gas, oil and renewable attributes. I perform these functions for the customers of Con Edison, ORU, and RECO.

(Trischitta) In my current position as Director of Commodity Operations, I lead three sections comprised of (i) commodity purchasing and scheduling; (ii) gas planning and transportation services; (iii) commodity hedging. I am responsible for the functions of gas transportation services, gas transportation planning financial hedging, physical procurement and associated scheduling of gas, fuel oil and renewable attributes. I oversee these areas for Con Edison and its corporate affiliate, ORU. I also oversee the procurement of gas and fuel oil for Con Edison-owned generation. Annual natural gas expenditures overseen by my areas are over $700 million dollars per year.

Q. Do you belong to any professional organizations?

A. (**Boden)** Yes, I am a member of the Board of Solar One, the Board of a start-up called I-GIT (Institute of Gas Innovation and Technology) with Stony Brook University, the Board of the Northeast Gas Association ("NGA") and the American Gas Association ("AGA") Leadership Council. I am engaged in a number of research and development ("R&D") initiatives, most notably the Electric Power Research Institute ("EPRI")-GTI Low Carbon Resources Initiative. I am the outgoing president and member of the Executive Committee of the Society of Gas Lighting.

(Hassan) Yes, I am a member of the Operations Management Committee ("OMC") of the NGA, AGA Executive Pipeline Safety Management System ("PSMS") Committee and the GTI Operations Technology Development ("OTD") Board.

(Inga) Yes, I am currently a member of the AGA Operations Managing Committee and former Chair of the AGA Field

Operations Committee. I am also a member of the Society of Gas Lighting, and a former member of various NGA technical committees, as well as the Gas Utilization Advisory Group.

(**Cummings**) Yes, I am currently a member of Women in Communications and Energy and a committee member of the AGA.

(Massoni) I am a member of the AGA Field Operations Committee and the Society of Gas Operators.

(**Kimball)** No.

(**Trischitta)** I am a member of Women in Communications and Energy and the Society of Gas Operators.

Q. Have any members of the Panel previously testified before the New York State Public Service Commission ("PSC" or "Commission")?

A. **(Boden)** Yes, I testified before the Commission in the 2004 Electric Rate Case on the Infrastructure Investment Panel when I was the Chief Electric Distribution Engineer (Case 04-E-0572) and in the previous gas rate case proceedings as part of the Gas Infrastructure and Operations Panel (Case 16-G-0061 and Case 19-G-0066).

(Hassan) No, I have not testified previously before the Commission.

(Inga) Yes, I testified before the Commission in previous gas rate case proceedings as part of the Gas Infrastructure and Operations Panel (Case 13-G-0031, Case 16-G-0061 and

Case 19-G-0066).

(Massoni) No, I have not testified previously before the Commission.

(Cummings) Yes, I testified before the Commission in previous gas rate case proceedings as part of the Gas Infrastructure and Operations Panel (Case 13-G-0031, Case 16-G-0061 and Case 19-G-0066).

(Kimball) Yes, I have testified before the Commission as the witness in previous electric and gas rate case proceedings (Cases 09-E-0428, 13-E-0030, 16-E-0060, 16-G-0061, 19-E-0065 and 19-G-0066).

(Trischitta) Yes, I have testified before the Commission as the Gas Supply witness in cases 18-G-0068, 19-G-0066 and 21-G-0073.

B. Purpose of Filing

Q. Please summarize and briefly explain the purpose of the Panel's testimony.

A. This is not a "business-as-usual" gas filing. Con Edison recognizes that use of its gas system must change over time in response to the State's policy to reduce greenhouse gas emissions and is moving in that direction. Our testimony describes our programs to reduce greenhouse gas emissions and to take steps to decarbonize the gas system by 2050. We will manage this transition and continue to provide safe, reliable and resilient service to our 1.1 million existing customers. We will explain how our main replacement program not only provides important safety benefits, but also is an important contributor to reducing methane emissions. We will also explain what we are doing to enhance the program to provide even more methane emission reductions without sacrificing safety. Additionally, to support electrification, we are the first utility in the State to propose removing many financial incentives for new gas customer connections. We are also recommending other changes to the gas tariff to align with the New York State Climate Leadership and Community Protection Act ("CLCPA") goals.

While we expect use of our gas system to decrease, we must make the investments necessary to continue to operate a safe gas system. Accordingly, this Panel will discuss the importance of, and overall need for, infrastructure, operations, and technology investments to enhance safety. We emphasize here that the overwhelming majority of our gas capital investments are devoted to making our gas system safer, and we understand this is our core responsibility. As identified in Exhibit ___ (GIOSP-1), programs focusing on safety make up approximately 85% of the overall capital investment request (excluding Municipal Infrastructure).

We will also continue to serve our customers reliably, including any new customers who choose gas notwithstanding our electrification education and incentive programs. Finally, the Panel recommends the continuation of most of our current performance measures, with some modifications to better align the performance measures with the work the Company plans to undertake.

Q. What period does this testimony cover?

A. The Panel will present the projects and programs planned for the 12-month period ending December 31, 2023 ("Rate Year" or "RY1"); the following 12-month period ending December 31, 2024 ("RY2"); and the following 12-month period ending December 31, 2025 ("RY3").

C. Key Themes

1. Core

Q. How does the Company plan to make investments that maintain a safe and reliable system?

A. We first want to emphasize that the overwhelming majority of our capital investments, and our increased operation and maintenance ("O&M") expense, are devoted to making our gas system safer. Our efforts to maintain a safe system are core to Gas Operations. Throughout the Company's Gas Operations projects, programs, and daily activities we strive to achieve high standards for planning, engineering, execution, and response which support effective Company operations. This focus on core service enables the Company to accomplish our most important goal, making the gas system safe for our customers, employees, and the public. Core also includes our programs for maintaining reliability for our existing customers and any new customers who choose gas notwithstanding our electrification education and incentive programs.

Q. What are some examples of the types of capital programs the Company plans to undertake to maintain a safe system?

A. The Company's main replacement program, federally-mandated transmission projects, natural gas detector program, and regulator station improvement projects, are the initiatives that will serve to reduce system risk and improve customer and system safety. On a smaller scale, our reliability upgrade and winter load relief projects will also maintain reliability. We will discuss these later in this testimony.

Q. Please describe the core strategies the Company uses to continuously enhance safety, reduce risk and improve operational performance.

A. The Company's gas safety and risk reduction efforts span a wide array of programs and processes. Our risk reduction strategy focuses on programs that enhance prevention, detection, and response to gas leaks. The American Petroleum Institute's Recommended Practice (API RP 1173) lays out the elements of an effective and holistic gas Pipeline Safety Management System ("PSMS") for pipeline operators. Through our PSMS, we follow a Plan-Do-Check-Act cycle for our daily activities, which promotes continuous improvement and feedback loops to our existing practices, procedures, and management systems. The application of this standard can be seen throughout our Distribution Integrity Management Program ("DIMP") and Transmission Integrity Management Program ("TIMP"). Our Integrity Management Programs support efforts to identify emerging areas of risk and allow the Company to take proactive steps to address them.

Q. How does the Company's Integrity Management Program reduce risk and enhance safety?

A. Both DIMP and TIMP use data analytics, root cause analysis, open communication, and standardization to examine risk and improve existing programs or create new ones. Additionally, the Company incorporates lessons learned from industry events and compliance directives to further advance our processes and business practices. DIMP analyzes the distribution system to target distribution mains and services for replacement, refurbishment, or abandonment. TIMP focuses on transmission risk reduction and compliance programs, including identifying specific transmission mains for replacement. We discuss these and associated integrity management programs and projects in more detail below.

Q. In addition to the Company's traditional leak response/repair programs and efforts to identify and prioritize leaks emitting the most gas, what advanced leak detection technology is the Company investing in?

A. The Company began installing remote Natural Gas Detectors ("NGDs") inside customers' homes or buildings near where the gas pipe enters the building in 2018. The Company is proposing to continue this program, with the installation of additional Advanced Metering Infrastructure ("AMI") enabled NGDs. This will allow for the Company to complete initial deployment of all NGDs to all buildings that opt-in by the end of a three-year rate plan, if adopted. The Company will install these detectors indoors. They are designed to detect natural gas and send an alarm to our Gas Emergency Response Center ("GERC"). The GERC then contacts the fire department and dispatches a Company emergency response crew. The use of these detectors will be for both indoor and outdoor meter configurations. Detection of gas leaks through state-of-the-art technology and public awareness is critical to our comprehensive approach to risk management and commitment to public safety. Through early/enhanced leak detection, we can respond and remediate quickly, thereby reducing risk, keeping the public safe, and protecting the environment by reducing methane emissions.

Another example of the Company's investment in advanced leak detection technology is the Piccaro Surveyor, which the Company currently proposes to use for a new high emissions leakage survey and will be discussed in more detail below.

Q. Have other safety regulators acknowledged the benefits of NGDs?

A. The installation of NGDs is considered a program with very high safety benefits. The National Transportation Safety Board ("NTSB") has listed the installation of methane-detection systems in residential occupancies as an item on their "Most Wanted List of Transportation Safety Improvements."[1]

2. Clean and Resilient

Q. Why is the Company focusing on reducing methane emissions?

A. Natural gas contains methane, a greenhouse gas that once

[1] See https://www.ntsb.gov/Advocacy/mwl/Pages/mwl-21-22/mwl-rph-01.aspx

emitted into the air is 86 times more potent than carbon dioxide, if modeled on a 20-year time frame used in the CLCPA. Methane is the largest component of natural gas, and it can be emitted during normal operating activities during transportation, or prior to combustion. Known as fugitive emissions, the Company is committed to reducing these emissions whenever possible.

Q. How do the Company's investments advance its clean and resilience goals?

A. To achieve the Company's Clean Energy Commitment as well as help the State comply with CLCPA requirements, we are implementing or proposing to implement a number of greenhouse gas emission reduction initiatives. The following clean investments are significant in limiting the amount of natural gas emissions into the environment:

- Main Replacement Program & Service Replacement
  - Abandons or replaces the most leak prone assets on the gas system, which reduces fugitive emissions; this program is responsible for reducing our emissions by 53% from 1990 to 2020 based on the methodology required by the EPA for companies to use to calculate their emissions. Given that the goal of the CLCPA is to reduce overall GHG emissions by 40% by 2030, we can

say that the contribution to that goal from our main replacement program is far outpacing the CLCPA goal. Additionally, the newly constructed replacement pipes will provide reliability for our existing customers and can accommodate blended or completely low-carbon fuels in the future.

- Use of non-pipeline alternatives instead of main replacement when possible removes potential future emissions by downsizing the system;

- Vacuum Purging Technology
  - Captures gas typically lost to the atmosphere during purging of gas lines and reintroduces it back into the gas system;
- Natural Gas Detectors and Leak Alarms
  - Installation of NGDs near where the gas pipe enters the building is another resource to allow us to find gas leaks more quickly, thereby reducing emissions and keeping customers safe;
- Local Renewable Natural Gas (“RNG”)
  - Natural gas supply from non-fossil sources (*e.g.*, food waste) that reduces the greenhouse gas impact; and
- Certified Natural Gas
  - Pilot the procurement of natural gas that is certified to have followed the best environmental practices,

including lower emissions, in production.

Q. In what other ways is the Company furthering its Clean Energy Commitment through its gas operations?

A. Besides the Company's capital projects, there are also tools, processes, and programs in place to help make our system safer that also support the reduction of natural gas emissions:

- Leak Detection
  - Monthly leakage surveys of our gas mains help find and address leaks in a rapid manner. The Company's program provides 11 more leak surveys per year than required under Commission regulations;
- Leak Response and Repair
  - Goals to repair 85% of leaks within 60 days, which includes leaks the Company is not obligated to repair under Commission regulations.
- High Emitter Survey
  - Development of a new high emitter surveillance program to find leaks, using advanced leak detection tools with the highest calculated standard cubic feet per hour ("SCFH"), and prioritize them for repair. Currently, the Picarro Surveyor technology is being utilized for this work;

- Internally coated pipe
    - o Prevents the loss of odor to newly installed steel mains. This significantly reduces the pickling process which would purge gas to the atmosphere, in order to odorize the main;
- Purge Burners
    - o Burn off planned natural gas releases (combusting natural gas that would have been released to the atmosphere reduces the greenhouse gases associated with these releases due to the higher global warming potential of methane); and
- Damage Prevention Plan
    - o Plan to reduce the number of damages, which in turn would reduce the number of unplanned natural gas releases.

Q. Is the Company also making investments to improve its resiliency to extreme weather events?

A. In addition to the greenhouse gas reductions, the Company recognizes that systems built today need to be resilient in the face of more frequent and severe weather than our service territory has experienced in the past. To account for these risks, the Company has expanded its flood zone criteria to identify and target additional gas assets with the greatest risk of flooding and water infiltration. These assets will be replaced as part of our main replacement program. Additionally, the Company's Climate Change Planning and Design Guideline is being used in conjunction with our specifications to design and plan projects to the projected future changes in climate. The Company is continually reviewing new data and information to determine if additional resiliency investments may be required.

The Company is also addressing environmental change and resiliency by incorporating higher flood elevation considerations into our design criteria, with the Company's Climate Change Planning and Design Guideline. Additionally, the Main Replacement Program will support climate resilience activities by replacing low pressure gas mains in flood-prone areas, using a FEMA+3 feet area. The Company will increase our targeted mileage of flood-prone gas main replacement per year.

3. Enhancing the Customer Experience

Q. How will the Company's planned investments enhance the customer experience?

A. The customer experience will be enhanced through new technology and tools designed to provide customers with the information they need to make effective decisions about their energy services. In order to align with the corporate, city and state's clean energy initiatives, all potential new gas customers will be offered information about clean alternatives to natural gas.

The Company is also proposing an investment in a new Gas Outage Management System. When implemented, this new system is expected to help identify outages quicker, track outages with advanced technology, improve efficiency in the restoration process, and provide timely and accurate information to customers when they need it most.

D. Gas System Description

Q. Please provide a high-level overview of the Company's natural gas transmission and distribution system.

A. A gas distributor since 1823, Con Edison currently provides natural gas service to more than 1.1 million customers in Manhattan, the Bronx, parts of Queens, and Westchester County. Con Edison manages a large, complex underground natural gas transmission and distribution system. This system contains approximately 4,400 total miles of gas main with approximately 375,000 service pipes that transport more than 330 million dekatherms of natural gas each year. The approximately 4,400 miles of gas mains consist of 97 miles of mains operating at pressures greater than 125 psig and 4,300 miles of distribution mains operating at pressures less than 100 psig. Approximately 300 miles are large-diameter distribution mains, greater than or equal to 16 inches that mostly connect the transmission mains to approximately 4,000 miles of smaller-diameter distribution mains.

Q. Please provide a general description of the parameters within which the Company designs its gas system.

A. We design our gas transmission and distribution system to meet state and federal gas safety requirements and the load requirements of all firm customers 365 days per year, 24 hours per day, based on the forecasted peak hourly load.

Q. What are the Company's gas infrastructure replacement objectives.

A. The Company's primary replacement objectives are to reduce risk, maintain safety, enhance reliability and resilience, and reduce fugitive methane emissions from the distribution system. By replacing leak prone pipe, we reduce the number of cracks and corrosion that could cause methane leaks. This provides an obvious safety advantage, reduces outages caused by flooding and, as discussed earlier, reduces emissions.

Additionally, certain projects, such as the Transmission replacement items, are required for regulatory compliance, in addition to risk mitigation.

Q. How does the Company implement these objectives?

A. One method of reducing risk is our distribution main replacement program (“MRP”), which proactively replaces 12-inch and smaller cast iron, wrought iron, and unprotected steel mains.

In addition to replacing the leak prone pipe, we have an aggressive leak management program whereby we routinely seek, find and fix leaks in a timely fashion, rather than waiting to prioritize lesser hazardous leaks (*i.e.*, Type 3’s) with future main replacement plans.

The Company seeks to combine as much of this work together with infrastructure replacement, in order to minimize costs to our ratepayers; however, with a multi-year MRP ending by 2040, and a need to safeguard our environment now, we cannot allow less hazardous leaks to go unchecked and unrepaired. There will be more discussion of our safety and environmental risk reduction efforts through inspections and leak management programs in subsequent sections of this testimony.

II. CAPITAL AND O&M SUMMARY INFORMATION

Q. What is the Company’s projected capital investment for the three rate years?

A. We are planning to invest $905.1 million in RY1, $924.2 million in RY2, and $890.2 million in RY3, excluding Municipal Infrastructure expenditures.

Q. What are the Company's projected O&M expenditures for the three rate years?

A. We are planning to spend $179.34 million in RY1, $182.12 million in RY2 and $184.65 million in RY3. Of these amounts, O&M program changes account for a $40.1 million increase in RY1, with decreases of $811,000 in RY2 and $1.1 million in RY3.

Q. Was the document entitled "CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. 2023-2025 GAS CAPITAL PROGRAMS" prepared under the Panel's direction and supervision?

A. Yes, it was. This is the document which has been identified as Exhibit ___ (GIOSP-1).

Q. Please describe this exhibit.

A. This exhibit summarizes Gas Operations' three-year capital expenditures for RY1, RY2, and RY3. These capital expenditures are organized into the functional areas shown on the exhibit. This exhibit also includes the "White Papers" associated with the three-year capital expenditures. The white papers provide the description of work, justification, alternatives, milestones, benefits and funding requirements for each capital program and project.

Q. How did you organize your testimony to address the programs and projects in Exhibits ___ (GIOSP-1)?

A. The testimony is broken down into the main areas set forth below:

- Distribution System Improvement Programs;
- Transmission Programs and Projects;
- Customer Connections;
- Technical Operations; and
- Gas Information Technology.

Q. Have you prepared an exhibit entitled "GAS OPERATIONS – O&M CHANGES BY CATEGORY"?

A. Yes, we have.

Q Was this exhibit prepared under your supervision and direction?

A. Yes, it was. This is the document which has been identified as Exhibit ___ (GIOSP-2).

Q. Please explain what is reflected in Exhibit ___ (GIOSP-2).

A. This exhibit shows the Company's incremental O&M expenditures, compared to the 12-month period ended September 30, 2021 ("Historic Year"), for RY1, RY2 and RY3.

Q. Do the Company's capital and O&M funding projections include funding for municipal infrastructure projects?

A. Yes, they do. However, these Public Improvement/Interference expenditures are not addressed in this testimony. These expenditures instead are addressed in separate testimony provided by the Company's Municipal Infrastructure Support Panel.

III. ANNUAL CAPITAL PROGRAMS

Q. Please summarize the gas capital request.

A. The Panel will identify major capital programs and projects to be conducted during the rate years. Each program and project is aligned with an exhibit or associated "white paper" that describes the scope of work, cost, schedule, and justification. As shown in Exhibit ___ (GIOSP-1), the Company projects overall capital expenditures are: $905.1 million in RY1, $924.2 million in RY2, and $890.2 million in RY3, excluding Municipal Infrastructure expenditures. This will provide for capital investments in:

- Programs/projects to reduce risk, enhance safety, and reduce methane emissions including main replacement efforts to eliminate 12-inch-and-under cast iron and unprotected steel gas main over the next 20 years;
- Programs/projects to improve system reliability, including Winter Load Relief and various system and regulator station upgrades;

- Transmission project and program investments to continue pipeline integrity management and meet regulatory requirements; and
- Information technology projects to reduce administrative and operational risk and achieve improved efficiencies and management of operations, programs and projects.

Q. Please describe the nature of the gas capital expenditures the Company is planning, why the work is necessary, and the major drivers of the projected increase in capital expenditures.

A. The Company recognizes that use of its gas system must change over time and describes herein the programs it is implementing as a result. At the same time, Con Edison must continue to keep its system safe. The overwhelming majority of the Company's gas system investments are to enhance the safety of its system. This entails programs to replace and/or upgrade its piping, equipment, and facilities. As shown in Exhibit ___ (GIOSP-1), the major drivers for the increase in gas capital expenditures in RY1 include the Leak Prone Main and Service Replacement Programs and Transmission Projects. These and other projects and programs are described below within the five program areas, *i.e.,* distribution, transmission, customer connections, technical operations and information technology.

A. DISTRIBUTION SYSTEM IMPROVEMENT PROGRAMS

1. Distribution Integrity

Q. Describe the Company's DIMP.

A. The purpose of DIMP is to enhance public and employee safety by identifying gas distribution pipeline integrity risks and implementing mitigating measures to address them. Some of these risks include distribution system leaks, excavation damages, and human error. The Company uses DIMP to enhance safety and create capital programs to improve safety.

Q. How does DIMP assess risk?

A. DIMP enhances safety by identifying and reducing distribution pipeline integrity risks through system analysis and by monitoring potential threats identified by internal subject matter experts ("SMEs"), regulators, gas associations and peers. Risk analysis is an ongoing process of understanding what factors affect the degree of risk posed by threats. To further enhance this process, starting in 2018, the Company moved from an evaluation process that considered risks separately under DIMP and the MRP Model, respectively, to a single consolidated risk model. The Company reviews top gas safety projects for changes and considers further actions such as reprioritizing our current replacement schedule and creating new programs for mitigating or eliminating emergent risks.

Q. How does DIMP drive capital investments?

A. By properly collecting, documenting, and analyzing information and data about our distribution system, DIMP informs the Company’s decisions on how to reduce risk through capital investments. One example is DIMP has identified leaks on small-diameter cast iron, wrought iron, and steel mains to be a threat, which is addressed through our Main Replacement Program, described further below.

Q. What is the Company’s strategy for the Main Replacement Program?

A. The Company uses a risk-based approach to prioritize elimination of its inventory of 12-inch and smaller cast iron, wrought iron, and unprotected steel mains. Work falls into two categories: Planned and Emergent.

1. Planned – The Company uses the DIMP risk model to assess risk and select main replacement projects. Planned projects mainly consist of highly ranked segments and flood prone pipe. The program will support decarbonization of the gas system by targeting simplification opportunities that will decrease the footprint of the distribution gas system, as well as focusing on the abandonment of cast iron

and wrought iron pipe.

2. Emergent – The Company identifies circumstances where leak-prone main replacement is required for reasons other than the risk model selection. These types of projects are outside of the Planned work, as described above, but support overall risk reduction efforts and can lead to cost savings. For example, the Company looks to proactively replace all 12-inch and smaller cast iron, wrought iron, and unprotected steel on a street prior to its scheduled paving date to reduce cost and prevent the need to excavate a newly paved street, should a leak occur. Some other examples of emergent conditions are leaks that cannot be repaired, cast iron encroachments, and public improvement projects.

Q. How does the Company try to achieve efficiencies in its main replacement program?

A. The Company proactively seeks opportunities to improve the reliability of our gas system and address other planned work streams in conjunction with this program. Such work includes winter load relief, customer connections, isolation valve installation, regulator station installations, and other pipework done in association with these projects. This allows us to integrate schedules so that all work streams can be efficiently planned and completed concurrently. This enhanced coordination reduces the impact to customers of repeated excavations and gas work.

Q. What are the proposed goals for each Rate Year?

A. We propose to replace 85 miles of main in each of the three rate years. For each rate year, we will replace 80 miles of planned work and five miles of conjunctional work, such as municipal infrastructure work that eliminates leak prone pipe. These goals are in line with our 20-year replacement strategy to be completed by 2040.

Q. Why has the Company reduced its annual main replacement target from the 90-mile annual target in effect for the last gas rate plan?

A. We believe this modest reduction improves safety while accounting for expected decreases in system use as electrification increases. We believe it is imperative to continue to replace high-risk pipe at a rigorous pace. At the same time, we recognize that we must prepare for electrification and look for opportunities to reduce risk by retiring rather than replacing pipe. Moreover, slightly modifying our targets in this filing mitigates overall customer costs without compromising our ability to complete the MRP by 2040. Specifically, our proposal reduces the requested gas revenue requirement by approximately $23.2 million per rate year.

Q. Is the Company adjusting its main replacement program strategy to focus more on emissions reductions?

A. Yes. We are adjusting our strategy to maintain our focus on safety while emphasizing reducing methane leaks. Going forward, the Company will preferentially select cast iron/wrought iron replacement, over bare steel, when risk factors are equivalent. This shift could result in the Company reducing more methane emissions because the emissions factor for cast iron is greater than that of bare steel.

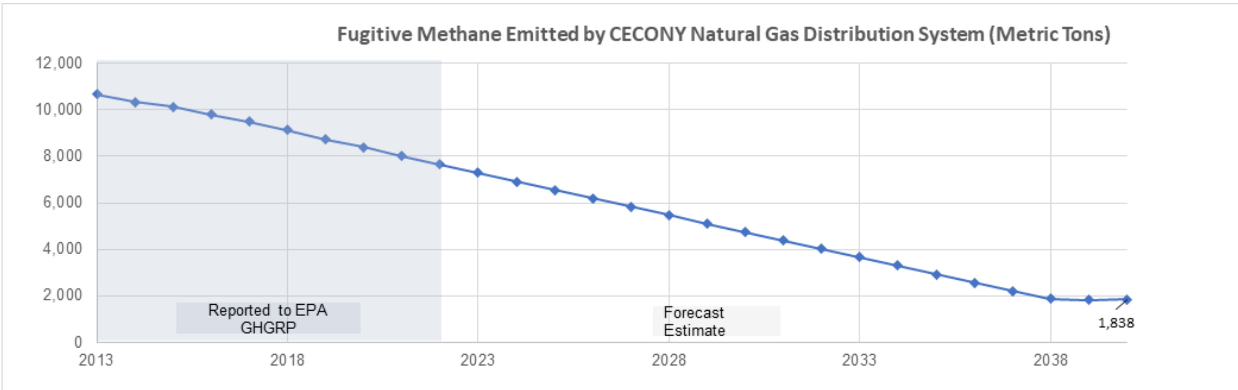
Q. Is the Company taking other steps to reduce emissions through its main replacement program?

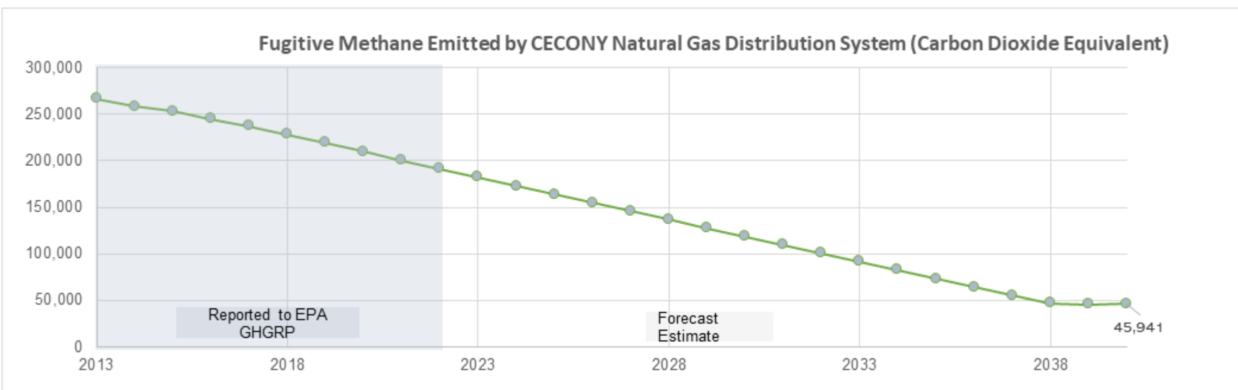
A. Yes. We are increasing our efforts to simplify the gas distribution system, which will serve to accelerate our methane emissions reduction. Simplification projects allow us to abandon leak-prone assets that will not be required in the long-term, given our expectations of lower system demand as a result of electrification to meet the State's CLCPA requirements.

Q. Can you quantify the emissions reductions from the MRP?

A. Yes. The reduction in emissions associated with these programs is quantifiable through the use of Title 40 – CFR 98. Subpart W. The projected annual reduction is shown in the charts below:

Table 1: Projected Fugitive Methane Emissions-CECONY





Q. What are the projected costs of the Main Replacement Program for each rate year?

A. The Company is projecting the following expenditures for this program: $404.8 million in RY1, $425.2 million in RY2, and $442.2 million in RY3, as set forth in Exhibit (GIOSP-1), which accounts for 45% in RY1, 46% in RY2 and 50% in RY3 of the total gas capital investment, excluding Municipal Infrastructure projects.

Q. Does the Company have any other proposals related to its

Main Replacement Program?

A. Yes, the Company proposes to capitalize all main installations, regardless of length. Currently, segments that are less than 25 feet are expensed as O&M.

Q. Has the Commission approved a similar proposal as part of any other NYS gas utility rate plan?

A. Yes, the Commission recently approved a similar proposal in National Grid's gas rate plan (Case 19-G-0309, *et. al*).

Q. Does the Company propose any additional investments that will reduce methane emissions?

A. Yes. The Company is introducing a new Methane Capture Technology program, which will procure and deploy Zero Emissions Vacuum ("ZEVAC") units to construction crews. Currently, certain construction activities release natural gas to the atmosphere. The ZEVAC unit can be used to mitigate methane emissions on larger volume pipe replacements for pipes operating at greater than or equal to medium pressure (15 psig MAOP). The ZEVAC units pump the gas out of the isolated pipe segment being replaced and into the portion of pipe remaining in service. The Company plans for full deployment by the end of 2026. The Company is projecting the following expenditure for this program: $1 million in each of RY1, RY2 and RY3.

Q. Is the Company proposing to continue the Safety and Reliability Surcharge Mechanism ("SRSM") to recover the carrying costs on incremental capital expenditures and O&M expenses associated with the replacement of main above the targets established for the Main Replacement Program?

A. Yes, the Company proposes to continue the SRSM for the Main Replacement Program.

Q. Are there additional costs not accounted for in this expenditure?

A. Yes. On January 12, 2022, the Company was informed that Urbint, the company that provides our current MRP modeling software, has made the strategic decision to no longer provide maintenance and support services for their Optimain products. Maintenance and support services will be discontinued on March 31, 2023. As a result of this announcement, the Company must seek an alternative software application to fill our MRP risk modelling needs. The cost of procuring an alternative software application is currently unknown and not accounted for in the costs presented for the Main Replacement Program. Therefore, the Company plans to determine the costs associated with this new project and present this information during the update phase of the proceeding.

2. System Reliability

Q. Are you planning any other programs that will address risk on the distribution system?

A. Yes. We plan to continue our gas system reliability improvement programs, which are described in the Company submitted White Papers. Some key programs include the Gas Reliability Improvement Program and Winter Load Relief. Currently our design criteria for regulator stations includes installation of components to prevent over pressurization of our gas distribution system. We also plan on initiating a program to install additional equipment to provide redundancy to the existing over pressure protection ("OPP") components, which is discussed later in this testimony. The benefits of the Company's proposed gas system reliability programs are described in more detail below.

Improve safety/reduce risk: The Gas Distribution System Over Pressure Protection improvement program will improve public safety and continue to reduce the risk of an over pressurization event by employing secondary OPP technology on our gas distribution system. Where regulator stations employ primary and monitor regulator design, this program will seek to eliminate common mode of failure by providing added protection, as outlined in the Protecting Our Infrastructure of Pipelines and Enhancing Safety ("PIPES")

Act, Section 206.[2] An over pressurization downstream of the regulator stations may create leaks on the system or, in the worst case, put life and property in imminent danger. This program increases public safety, and at the same time provides environmental benefits by minimizing methane emissions.

Operational excellence: Supply mains facilitate the delivery of natural gas to every customer on the Con Edison gas system. Improvements to these facilities are needed to enable the Company to continue to deliver reliable gas service to all our customers on the coldest winter days. This will be accomplished largely by planned capital programs, including the Winter Load Relief and the Gas Reliability Improvement Programs.

Customer experience: Programs such as Winter Load Relief and the Regulator Station Revamp Programs are designed for the natural gas system to be able to accommodate required gas pressures for existing customers as well as provide reliable service with minimal interruption, thus enhancing the customer experience.

Q. Please describe the planned work for each of the above-listed programs, the costs projected in RY1, RY2 and RY3,

[2] PIPES Act of 2020, S. 2299, 116th Cong. (2019)

as well as additional details regarding the benefits of this work.

A. 1. Winter Load Relief – To maintain system reliability, Con Edison needs to reinforce our systems to achieve the minimum pressures required to serve customers. We must also reinforce our system to maintain minimum inlet pressures to our low and medium-pressure regulator stations. Using our annual network analysis model validation process, we project anticipated system loads and system performance for the following winter season. Where marginal pressures are anticipated, areas are identified for additional reinforcement and can be addressed through specific recommended projects under the Winter Load Relief program. These projects typically consist of installing new mains to make ties or replacing smaller mains with larger diameter mains to eliminate area constraints. The Company is projecting the following expenditures for Winter Load Relief related projects: $13.4 million for RY1, $14.0 million for RY2 and $14.3 million for RY3, as set forth in Exhibit ___ (GIOSP-1).

2. Gas Reliability Improvement Program – Our priority is to avoid large-scale outages on our system during peak demand periods. To address this potentially devastating and costly risk, system reinforcements such as main ties,

or regulator station upsizing are needed, specifically targeting vulnerable segments, more described in the whitepaper. The Company is projecting the following expenditures for the Gas Reliability Improvement Program: $10.1 million for RY1, $10.7 million for RY2 and $10.7 million for RY3, as set forth in Exhibit ___ (GIOSP-1).

B. TRANSMISSION PROGRAMS AND PROJECTS

Q. Please describe Con Edison's gas facilities, which operate above 125 psig.

A. Con Edison has 97 miles of 6-inch to 36-inch diameter mains in Manhattan, Queens, the Bronx, and Westchester County, that operate above 125 psig. For purposes of this testimony, these pipelines will be referred to as transmission. These mains, most of which were installed between 1947 and 1973, have a maximum allowable operating pressure of either 245 psig or 350 psig. The transmission facilities are supplied by seven gate stations from four pipeline companies. In addition, most of these facilities are part of a larger regional network called the New York Facilities ("NYF") System, which is jointly owned and used by Con Edison and National Grid. Con Edison's system is connected to National Grid's system at two bi-directional metering stations, as well as five metered take-off locations in Queens.

Q. Please describe the capital investment that is planned for the gas transmission facilities.

A. As presented in Exhibit __(GIOSP-1), the following expenditures are related to transmission programs and projects: $115.3 million in RY1, $133.8 million in RY2 and $112.8 million in RY3. These investments are required to comply with the new state and federal Transmission MAOP Reconfirmation Rule (MAOP Rule, part 1).

1. Transmission Risk Reduction and Reliability

Q. Please describe each of the gas transmission capital programs and projects that are planned for the 2023-2025 period and how they address safety and reliability.

A. The gas transmission capital programs are as follows:

1. Installation of Remotely Operating Valves ("ROVs") - This program provides for rapid isolation of a compromised section of the transmission facilities; rapid isolation of transmission facilities at river and tunnel crossings and at the outlet of gate stations; and rapid separation of intersecting transmission mains at tee or branch locations. The ROV program consists of converting existing transmission valves or installing new ROVs to meet the future ROV design criteria, specifically targeting those transmission mains that are not slated for pipeline

replacement. Once the program is complete, the closure of any two consecutive ROVs will not negatively impact supply mains or the distribution system on an average winter day. Five total ROVs are required to meet System Design Criteria, as part of this program. All will be installed by the end of RY3. The Company projects the following expenditures for this program: $ 3.1 million in RY1; $3.3 million in RY2; and $3.3 million in RY3, as set forth in Exhibit ___ (GIOSP-1).

2. The Newtown Creek Metering Station - This is a capital project that addresses a facility constructed in 1951 that contains older piping configurations and obsolete metering equipment that is maintenance intensive. One of those pieces of new equipment is the addition of a new control valve that would allow Con Edison to control the flow rate to National Grid. Our ability to control flow to National Grid would allow us to regulate the Con Edison portion of the gas transmission system and protect the Con Edison portion of the gas transmission system from abnormal operating conditions and maintain flow to the maximums permitted under the New York Facilities agreement. The Company forecasts the following expenditures for this project: $15.6 million in RY2; and $14.5 million in RY3, as set forth in Exhibit ___ (GIOSP-1).

3. Transco Gate Station Over Pressure Protection – This project addresses the installation of Con Edison owned OPP at the following Transco facilities: Transco's Upper Manhattan Gate Station located in Manhattan and Transco's Central Manhattan gate station located in New Jersey. The Con Edison OPP will provide for the safe operation of the gas transmission system if Transco's OPP device at any of the two gate stations fails and the pipeline's operating pressure cannot be controlled. This project will also include installing new piping from the Transco-Con Edison demarcation point up to the outlet of the ROV with piping for the same MAOP as the Transco station inlet piping. The Company forecasts the following expenditures for these projects: $10 million in RY1; and $10.0 million in RY2, as set forth in Exhibit ___ (GIOSP-1).

4. Knollwood Overpressure Protection Project - This project addresses the installation of Con Edison owned OPP at the Tennessee Knollwood Gate Station. Upgrades at the Knollwood station are to be completed in 2022, after which, this OPP project can commence. The Con Edison OPP will provide for the safe operation of the gas transmission system in the event that the pipeline's OPP device fails and the pipeline's operating pressure cannot be controlled. This project will also include the installation of new

piping from the Tennessee-Con Edison demarcation point up to the outlet of the ROV, as set forth in Exhibit ___ (GIOSP-1).

5-9. MAOP Rule Replacement – The Company has five projects required for compliance with federal and state law. These projects will replace transmission infrastructure installed using legacy construction practices, for which traceable, verifiable and complete records related to the pipeline's MAOP show that the pipeline was not pressure tested to the new federal and state requirements.

Pursuant to federal and state regulations, "transmission lines" are defined as pipelines that operate at a hoop stress of 20 percent or more of Specified Minimum Yield Strength ("SMYS") (*see* 49 CFR 192.3). The Company plans to replace vintage federally defined transmission pipelines with new facilities that will improve safety and reliability by operating at less than 20 percent SMYS. Loss of supply from these facilities would otherwise cause widespread customer outages.

In addition to complying with federal and state law, these projects will improve safety through the retirement of certain high-risk assets, including: a compressor station, certain regulators and a super monitor.

The Company forecasts $99.8 million in RY1; $108.4 million in RY2; and $88.4 million in RY3 for these initiatives, as set forth in Exhibit ___ (GIOSP-1).

2. Gate Station Work

Q. Please describe the two broad categories of gate station work that the Company typically undertakes.

A. The first category is capital work at Company-owned gate station facilities. The second category is work on pipeline-owned facilities that primarily benefits the Company and its customers. Costs associated with this second category are usually recovered as a surcharge through the monthly rate adjustment ("MRA") for projects approved by the Commission, as set forth in the Company's Gas Tariff.

Q. Is the Company proposing any gate station projects during RY1-RY3 that fall under the first category (*i.e.*, work on Company-owned facilities)?

A. Yes, the Company plans to refurbish the Algonquin Cortlandt gate station. This work is scheduled to occur in 2022 and 2023. The cost associated with this project is $11 million in RY1, as set forth in Exhibit ___ (GIOSP-1). The need for this project is discussed in the whitepaper.

Q. Is the Company proposing any gate station projects during RY1-RY3 that fall under the second category (*i.e.*, work on pipeline-owned facilities that primarily benefit the Company and its customers)?

A. The Company is not proposing any new projects in this second category. But the Company is updating the cost estimate for the Tennessee White Plains gate station project, which was approved under the current Gas Rate Plan (Case 19-G-0066). The work at the gate station has been completed.

Q. What are the Company's final costs related to the White Plains gate station?

The final costs associated with the White Plains gate station work have not been provided to the Company as of the date of this rate filing. To the extent available, the Company will provide any additional information it obtains during the update phase of this proceeding. In the event that final cost information is not available by the update phase of this proceeding, the Company proposes to defer any costs in excess of the $11 million approved in Case 19-G-0066, for recovery in the Company's next base rate filing.

3. Renewable Natural Gas – Mount Vernon Interconnection

Q. Please describe the Mount Vernon RNG interconnection facility investment.

A. The Mount Vernon RNG interconnection facility is part of the Company's Smart Solutions initiatives. One of the

Smart Solutions for gas customers is to solicit the energy market for cost effective alternatives to pipeline capacity though non-pipeline alternatives (“NPAs”). In response to a request for proposals (“RFP”), a vendor has proposed a facility that will produce RNG from food waste within Con Edison’s service territory. Con Edison will install equipment to support the interconnection to this RNG facility, which will consist of metering, gas quality measurement, odorant measurement and remote shutdown. The Company forecasts the following expenditures for these projects: $1.5 million in RY1, as set forth in Exhibit ___ (GIOSP-1).

Q. How does this investment align with the Company’s clean energy commitments?

A. This RNG facility provides the ability for waste-related methane to be captured and used, in lieu of being released into the environment.

This interconnection is the first of its kind supplying the Con Edison system and opens the door for other similar interconnections in the future.

4. Pressure Control

Q. Please describe the functions performed by the Pressure Control Department.

A. The Pressure Control Department is primarily responsible for the maintenance and operation of the Company's gas pressure reduction equipment. This equipment ranges from major transmission gate station assets to the many components that make up the high and low-pressure district regulator stations located throughout the Company’s service territory. Most of this equipment is located within below-grade manhole structures underneath roadways and sidewalk areas. This equipment includes 337 regulator stations. The Pressure Control Department validates each station’s operating condition annually, as well as conducting monthly site inspections.

Q. Please summarize the capital expenditures projected for the Pressure Control Department during the 2023-2025 period.

A. The Pressure Control Department sponsors three capital programs that are planned for the rate years. The Company estimates capital expenditures of $20.3 million in RY1; $20.2 million in RY2; and $20.2 million in RY3, as set forth in Exhibit ___ (GIOSP-1). These investments are needed for safe and reliable service, because they keep essential pressure control equipment operational and give the Company new monitoring and control capabilities, which reduce the possibility of an overpressure event or loss of service continuity.

Q. Please describe the capital programs planned to be completed by the Pressure Control Department.

A. The capital programs planned to be completed by the Pressure Control Department are: Regulator Automation, Regulator Station Improvements, and Station Gas Detector & Fire Detection/Alarm Systems. All are described in more detail in the applicable White Papers.

The largest project of this category is Regulator Automation. The purpose of this program is to install automated control equipment at regulator stations throughout the gas system to enable remote operation while providing real time visibility. Also included is the installation of enhanced OPP equipment on the low-pressure gas system to provide additional levels of protection to prevent pressure exceedances. Where applicable, these installations will also include the replacement of regulator station piping that contains bypasses which connect different MAOP systems, the replacement of distribution mains that connect to pressure division valves, or the relocation of regulator station sensing, control, and overpressure protection monitoring lines within the boundaries of regulator stations to improve station operation and overpressure protection. The Company forecasts the following expenditures for this program: $19.1 million in each of RY1, RY2, and RY3, as set forth in

Exhibit ___ (GIOSP-1).

C. NATURAL GAS DETECTORS

Q. What is the purpose of NGDs?

A. NGDs are safety devices installed indoors near the gas point-of-entry ("POE") and head of service valve intended to provide continuous monitoring of atmospheres for a concentration of methane that result in an alarm. When a NGD alarms (10% lower explosion limit), this alarm information is transmitted through the AMI network to the Gas Emergency Response Center ("GERC"). The GERC will then notify the local fire department and dispatch a Gas Distribution Services ("GDS") mechanic to respond to the potential gas leak using normal leak response protocols.

Q. What benefits do NGDs provide to customers?

A. The accumulation of natural gas in a building can occur from a leak on the buried gas distribution infrastructure located outside of the building. Gas migrates through the soil or through a utility service POE and into the building. Buildings are typically constructed where the majority of utility POEs (water service, sewer pipe, buried electric service) are normally in close proximity to the gas POE. Locating the NGD on service line pipe near POE provides detection capability for this type of occurrence.

It will also detect leaks on nearby customer piping or equipment.

The development of methane sensor technology in combination with the Company's AMI communication network presents a first-of-a-kind and unique opportunity to pair remote methane detection with the AMI communication infrastructure that will enable a direct alarm to the Company's GERC that could prevent a gas incident in the future, improving public safety.

Using NGD technology will improve public and employee safety by identifying potential leaks much earlier than relying on odor calls, allowing GDS crews more time to identify potential gas leaks, make the location safe and evacuate the public if necessary.

Q. What investments are required to install and maintain NGDs?

A. Con Edison started mass deployment and monitoring of AMI enabled NGDs in 2020 after successful completion of the pilot phase of NGD deployment in 2019. To date, the Company has installed approximately 90,000 AMI NGDs and is estimated to install a total of 150,000 through the end of 2022. As of December 31, 2021, the Company has received and responded to over 900 NGD alarms.

NGD installations for rate case years 2023-2025 are estimated to be: 65,700 in RY1, 73,300 in RY2, and 67,800 in RY3. To reduce the cost of installations and decrease the number of visits to customers' homes and buildings, when possible, NGD installations will be completed with other work including service line/meter inspections.

In total, we currently anticipate the following capital expenditures to install and support NGD's during the upcoming 2023-2025 period: $33.3 million in RY1, $37.6 million in RY2, and $35.2 million in RY3 as shown in Exhibit ___ (GIOSP-1).

D. PROPOSALS TO INCREASE CUSTOMER INTEREST IN GAS ALTERNATIVES

Q. How does the Company propose to make alternative energy solution options more attractive for new customers and support non-fossil technology adoption?

A. In line with the Company's clean energy commitment, we are proposing to eliminate certain tariff provisions that facilitate natural gas use but exceed statutory requirements. The Company is also enhancing the information it provides to customers, with the goal of discouraging customers from using or expanding their use of natural gas.

Q. Please describe the Company's proposed tariff modifications.

A. First, the Company is proposing to eliminate language in its gas tariff that allows multiple customers seeking to connect to the Company's gas distribution system to pool their installations and avoid connection costs. Eliminating the "concurrent connections" tariff language will preclude sharing of benefits between customers who otherwise would exceed their individual allotment of main, but for the fact that other customers connected at the same time and did not use their full allotment. As an example, a customer who needed 120 feet of main while the next building only needed 80 feet could "use" the current tariff allowance and would not incur any additional cost. This language is a legacy of the gas expansion period in the Company's history and is no longer part of our forward-looking clean energy vision.

Second, customers who pay for the main extension currently benefit from connections made along that length of main by subsequent customers connecting within a five-year window. Going forward the Company proposes that reimbursement (in part or in full) for costs to customers who chose to pay for their main extension be eliminated. Third, the Company is proposing to eliminate the "revenue test" for all customers, thus requiring every foot beyond the 100-foot allotment under law be paid for by the customer in full prior to the commencement of the work. Customers can currently avoid such charges if they can demonstrate that their gas usage will generate revenues above a specified threshold.

Finally, the Company proposes that no customer will receive a service determination (also referred to as a "ruling") for natural gas service of any size or for any purpose without first acknowledging in written form that they have been provided information on non-fossil alternatives and that they are aware of climate protection laws and regulations.

Q. What is the "100-foot rule"?

A. The obligation to provide customers a total of 100-feet of main and/or service without cost is codified in Public Service Law § 31. Section 230.2 of the Commission's regulations goes beyond the Public Service Law, based on the type of customer requesting service and usage. Specifically, for a residential heating customer, Section 230.2 requires New York State local distribution companies ("LDCs") to provide 100 feet of main *and* 100 feet of service, while for Residential non-heating customers and nonresidential customers Section 230.2 requires a *total* of 100 feet of main and/or service, plus the length of service line necessary to reach the edge of the public right-of-way.

Q. What is the Company proposing with respect to the "100-foot rule"?

A. The Company is not proposing any deviation from the requirements of the Public Service Law. But we are requesting a waiver from the requirements of 16 NYCRR §230.2 that provides additional piping to residential heating customers. Instead, the Company is proposing to provide all customers (regardless of customer type or usage) with a combined total of 100 feet of main and/or service, plus the length of service line necessary to reach the edge of the public right-of-way.

Q. Why are you requesting a waiver?

A. Some of the tariff modifications described above are not consistent with current Commission regulations and therefore require a waiver for implementation. Specifically, a waiver is required for the Company's proposals: to eliminate the revenue test for all customers; to eliminate reimbursements to customers who chose to pay for their main extensions due to subsequent customer connections; and to combine the 100-foot allotment of main and service, irrespective of the customers' service classification or usage. The Company's waiver request will apply to new customer connections only. These proposed measures will bring greater price parity between natural gas service and alternatives for many customers, while still allowing customers to make connections to existing infrastructure in accordance with our statutory obligations. These changes, however, require a waiver of 16 NYCRR §§230.2 and 230.3.

Q. What is the Company's justification for such a waiver?

A. As explained throughout our testimony, the Company fully supports the State's clean energy policy and efforts to achieve CLCPA requirements. While we recognize that important work related to the CLCPA is ongoing and final decisions in many key areas are still pending, we view the requirements in 16 NYCRR §§230.2 and 230.3 as incongruent with the CLCPA and highly unlikely to continue in their current form. Therefore, we believe a waiver is justified in anticipation of expected changes to the Commission's regulations and to advance important, state-wide policy goals.

E. CUSTOMER CONNECTIONS

Q. How has the Company advanced its goals through Customer Connections?

A. As described in more detail below, the Company's Customer Connections investments have offered the opportunity to enhance both customer engagement and operational performance. The Company is obligated by the Public

Service Law to provide gas service to new customers (even if we have educated them on the alternatives and they decline) and requests to increase gas demand for existing customers. In accordance with this obligation, we will continue to provide safe, reliable service to our customers in a cost-effective manner. However, as stated above, we encourage all potential natural gas customers to consider alternative (*i.e.*, non-fossil) energy solution options. Additionally, as outlined above, the Company's proposed tariff changes should have an impact on Customer Connections, as those changes are put into effect. The Company is forecasting a reduction in the number of customer connections during RY1-RY3, with even more significant reductions anticipated in the future.

Q. Are the Company's proposed tariff changes reflected in the forecast for customer connections?

A. No, considering we have no experience regarding the impact these proposed changes would have, it would be premature to reflect them in the Company's forecast. However, the Company notes that, under the downward-only capital reconciliation it is proposing, any capital underspending would be returned to customers.

Q. What are the projected overall costs associated with the Customer Connections Program?

A. As presented in Exhibit ___ (GIOSP-1), the Company projects the following expenditures for this program: $73.1 million in RY1; $74.6 million in RY2; and $76.7 million in RY3. The overall costs are for the installation and replacement of gas services and main associated with facilitating customer connection requests.

Q. Does the Company's request reflect an overall lower growth rate, including the impact of this industry change?

A. Yes. The current request assumes a significant reduction from historical service installations and associated main installation.

Q. Do you expect the Westchester moratorium to continue during the potential 2023-25 rate plan period?

A. No. We anticipate being able to lift the moratorium at the end of in RY1, as further described below in the Gas Supply portion of this testimony.

Q. Have you considered the New York City legislation or other state CLCPA initiatives when planning the Customer Connections program?

A. Yes. As discussed above, the number of customer connections anticipated is decreasing, but this will have a limited impact in the RY1-RY3 period. We expect to see more dramatic reductions in future rate cases.

Q. Why is the Company anticipating a limited impact in the RY1-RY3 period?

A. The New York City legislation will only begin to go into effect during this rate case, with certain building sectors having until 2027 to comply.

Q. Beyond the construction cost to install gas services and gas main to support growth, are there additional associated expenses the Company will incur?

A. Yes. We have a dedicated program to purchase and install gas meters. As explained in Exhibit ___ (GIOSP-1), Meter Purchases and the Meter Installation programs support the mandated replacement of existing meters for new connections and conversions programs. The following Section F.3 discusses this topic further.

F. TECHNICAL OPERATIONS

Q. Please summarize and briefly explain the purpose of this Technical Operations testimony.

A. Consistent with core Company principles this Section will discuss the importance of, and overall need for, infrastructure, operations, and technology investments to reduce risk, enhance safety across the system, and enhance system operational performance, for specific Company assets. Included is the Liquified Natural Gas (“LNG”)

Plant, Tunnels, Meters, Natural Gas Detectors, and Gas Information Technology.

1. LNG Plant

Q. How does the Company's LNG facility benefit customers?

A. Con Edison uses its liquefied natural gas facility to maintain adequate supply during gas peak operations. The LNG Plant serves as a cost-effective alternative to more expensive firm peaking supplies and as a contingency resource, in the event of any incident impacting our external supply sources.

The LNG Plant is the only source of in-city natural gas supplying Con Edison's customers in the event of an interstate pipeline interruption or other emergency condition affecting external gas supply. The LNG Plant continues to serve as a supply and hourly balancing source during very cold days, as its capacity is needed during design peak day conditions to meet the needs of our firm customers. The LNG Plant also serves firm gas customers by potentially mitigating short term price volatility.

Q. Why are the LNG Plant's planned programs necessary?

A. The proposed capital programs and projects are important to continue safe plant operations and maintain plant reliability for the following plant systems: withdrawal (vaporizers), tank management, and injection (liquefaction) process plant. In addition, these projects are important measures to harden the LNG Plant.

Critical components of the plant are obsolete, with the original equipment manufacturer(s) unavailable to provide parts and services. Mechanical integrity of equipment is important for employee and public safety. The current liquefaction nitrogen refrigeration cycle is inefficient and does not fill the LNG tank in six months, consistent with its original design. To bring the plant up to standard, we plan to invest over $70.4 million in plant infrastructure over the next five years, starting in RY1. This will allow for the Company to continue to deliver affordable natural gas to our customers when they need it the most and continue to provide reliable services for gas peaking, unplanned upstream gas system contingency and to mitigate gas price volatility.

Q. What investments are required in the Company’s LNG facility?

A. As shown in Exhibit ___ (GIOSP-1), the investments are described in five areas:

1) Instrumentation upgrade program:

- Plant Controls Instrumentation Upgrade Program: $12 million in RY1 and $2 million in RY2.

2) Nitrogen Refrigeration Cycle Replacement:

- Nitrogen Refrigeration Cycle Replacement: $10 million in RY1 and $10 million in RY2.

3) Electrical equipment upgrades and relocation:

- Motor Control Center: $2.8 million in RY1 and $500,000 in RY2.
- Electrical Distribution System Upgrade: $1.9 million in RY1.

4) Equipment integrity projects:

- Plant Boil-Off Compressor Replacement: $2 million in RY1 and $400,000 in RY2.
- Security Upgrade Program: $2.87 million in RY1.

5) Reliability Remediation Program:

- Various reliability projects including relocation of the LNG Meter Station, and the Independent Flare Gas Supply: $7 million in RY1, $8.25 million in RY2 and $4.75 million in RY3.

These programs reflect a $68 million capital improvement investment at the LNG Plant during this coming rate period. This amount is broken down as follows: $38.6 million in RY1, $21.15 million in RY2, and $4.75 million in RY3, as set forth in Exhibit ___ (GIOSP-1), with some projects extending past this proposed rate period.

Q. Please explain further the work that is planned for the LNG facility.

A. The new Instrument Upgrades Program contains real-time monitoring, data acquisition and analysis tools. The new Nitrogen Refrigeration Cycle Replacement will replace the original obsolete equipment. The nitrogen refrigeration cycle will have a new, more efficient turbine that will produce less CO_2 air emissions per million cubic feet of LNG produced. With recent local supply constraints and the LNG plant having the ability to withdraw and provide 15% daily supply to the transmission system, the ability to quickly, efficiently, safely fill the tank with new modern reliable nitrogen refrigeration cycle allows the LNG Plant to be a reliable supply source for gas system resiliency.

The new Electrical equipment upgrades and relocation will provide both a new motor control center and a new high tension vault substation relocated away from the existing natural gas transmission main and both projects will improve employee safety and plant reliability. The new equipment will meet current arc flashing, newer national electric code requirements, and replace original (50-year old equipment upon replacing) and obsolete equipment. This upgrade and relocation will modernize, make electrical power more reliable, and increase the plant's safety. LNG projects consist of multiple system reliability requirements for safety, system reliability and to enable continued safe operation as shown in Exhibit ___ (GIOSP-1).

2. Tunnels

Q. Briefly describe the Company's tunnel facilities and their importance in delivering safe and reliable energy services to the Company's electric, gas and steam customers.

A. There are eight utility tunnels on the Company's system. These tunnels house critical electric, gas, and steam facilities, as well as a fuel oil line and telecommunications systems. They are critical pathways for service lines under bodies of water, except for one, which was needed for our steam transmission infrastructure after the retirement of the Waterside Steam Generating Plant and does not cross under a body of water. Tunnel infrastructure is significantly impacted by atmospheric corrosion, water infiltration and salt deposits. The original infrastructure (*e.g.*, cast steel liner, steel beams), feeder cables, lighting and electrical outlets, and gas main rollers are exposed to heavy salt and water infiltration. In addition, safety components such as the fire and gas monitoring systems have become obsolete. If this infrastructure is not replaced there is an increased risk of a catastrophic failure jeopardizing the reliability of the electric, gas and steam transmission and distribution systems.

Q. Why are the proposed projects necessary for the tunnels?

A. These projects are required for system reliability, employee safety, and to enable continued access to critical infrastructure. This includes the gas main rollers, feeder cables, elevators, cast steel liner, structural concrete, ladders and landings, electric and ancillary equipment such as sump pumps, lighting, and remote monitoring capability. All of these are subject to corrosion and deterioration due to ground water intrusion and exposure to extreme moisture, salt, humidity, and heat, especially in the tunnels that carry steam mains.

Q. What are the critical projects related to tunnel system safety, customer experience, operational excellence or clean energy?

A. As shown in Exhibit ___ (GIOSP-1), and described further in the associated white papers, the tunnels projects are:

- Fire and Gas Monitoring Replacement: $1.5 million in RY1 and $1.5 million in RY2.

- Ravenswood Gas Main Rollers: $1.7 million in RY1 and $1.8 million in RY2.
- Ravenswood Concrete Restoration: $225,000 in RY1.
- Conduit Bulkhead Replacement: $1.0 million in RY1.
- Astoria Cast Steel Liner Replacement: $1.0 million in RY1.
- Lighting Improvement Program: $1.0 million in RY1; $1.0 million in RY2; and $1.0 million in RY3.
- Carbon Fiber Wrap Program: $701,000 in RY1; $744,000 in RY2; and $765,000 in RY3.
- Replacement Feeder Rollers: $1.7 million in RY2.
- Steel Replacement Program: $877,000 in RY1; $930,000 in RY2; and $957,000 in RY3
- Astoria Elevator Modernization: $600,000 in RY1.
- Annual Sump Pump Program: $100,000 in RY1; $100,000 in RY2; and $100,000 in RY3.

In total, the capital expenditures to support these tunnel projects during the upcoming 2023-2025 period are $8.7 million in RY1; $7.8 million in RY2; and $2.8 million in RY3.

Q. Is the Company considering moving responsibility for the tunnels to another organization?

A. Yes. We are considering moving the Tunnel Maintenance organization from Gas Operations to Central Operations.

Q. Please explain why this move is under consideration?

A. There are several reasons. These are multi-commodity tunnels that carry electric transmission feeders, steam mains, as well as gas mains. However, Gas Operations has historically had the responsibility for the maintenance of the tunnels, and the capital expenditures associated with improvement projects have fallen under Gas Operations and therefore paid for by gas customers. Additionally, most O&M expense for maintenance of the tunnels is also paid by gas customers. As we consider future rate mitigation opportunities given the foreseeable drop in demand for gas, we are evaluating whether the tunnels would be more appropriately paid for by electric customers. As such, we are exploring a re-organization to place the Tunnel Maintenance group under Central Operations and thereby shift the capital and O&M expenditures to electric customers. An update of the Company’s analysis and plans will be provided in the update testimony.

3. Meters

Q. How will the Company’s proposed meter purchase and meter installation programs foster better customer engagement?

A. These programs allow the Company to provide safe and reliable gas service to our customers. In addition, these programs also support the Company’s mandated meter replacement programs. We discuss below the need for this program and how its related to the Company’s AMI program.

Q. What meter investments are required by Technical Operations?

A. Technical Operations purchases gas meters and related devices for all our customers. When possible, we refurbish meters and when necessary we replace them. Our investment in this area takes into account historic replacement and refurbishment. Currently, 34 percent of the meters purchased and installed are related to mandated meter replacement programs and required replacements, while 66 percent of the meters purchased and installed are associated with customer connections or replacements of existing customer meters who are increasing their existing gas demand. While customer connection projects have decreased, we have experienced an increased need to replace undersized meters, which have been identified as a result of new AMI information. For this reason, the estimates used below remain level with historical numbers, for the short-term forecasting related to this rate case.

Installations are estimated at approximately $17 million annually, while purchases are estimated at approximately $11 million annually. Annual costs for purchases and installations are based on historical and projected usage. These capital expenditures include funding for the purchase of meters and related devices (*e.g.*, interruptible customer monitors (Metscans), service regulators, and electronic correctors); outsourced meter-related services for mandated meter programs required by 16 NYCRR 226; and for repair/replacement of defective meters (*e.g.*, customer complaints, broken meters, tampering) in accordance with Commission regulations. As shown in Exhibit ___ (GIOSP-1), these programs are listed as:

- Meter Purchases - Customer Connections and Meter Replacement Programs ($12 million in RY1, $12 million in RY2, and $12 million in RY3); and
- Meter Installations – Customer Connections and Meter Replacement Programs ($19.4 million in RY1, $20.9 million in RY2, and $20.9 million in RY3).

Q. How do the meter investments discussed above take into account AMI deployment?

A. Metering costs and savings associated with AMI are independent of the meter investments discussed above because there will still be a need for meter installations and replacements independent of AMI deployment. Approximately 250,000 gas meters have been replaced with new meters equipped with AMI modules, that were required by the PSC to be remediated by 2021. The remaining 950,000 or so gas meters were retrofitted with AMI gas modules. Although there are many benefits to these AMI replacements, once in service, these meters will have the same operations and maintenance requirements as any other meter. Additionally, a large population of older meter classes will require remediation during this coming rate case.

G. GAS INFORMATION TECHNOLOGY

Q. What Information Technology ("IT") improvements are planned for Gas Operations?

A. Gas Operations is presenting IT investments in the following two categories: Gas Control Center and Outage Management. Further details for each can be found in the associated white papers, with a few of the larger capital investments highlighted below. There are also gas-related IT programs, including the Work Management Program, that are separately being addressed by the Company's IT Panel.

1. Gas Control Center Improvements

Q. What improvements are planned for the Gas Control Center?

A. Gas Control is presenting three items for this Rate Case. They are Operator Training System ("OTS") Simulator Project, End of Life ("EOL") Equipment Replacement Program, and Gas Control Center ("GCC") Improvements Projects. Further details for each item can be found in the associated white papers.

The GCC Improvements is the largest capital investment in this category and consists of three improvement projects for the GCC. The first is the relocation of the Alternate GCC from Manhattan to Westchester, the second is the Gas Operations Supervisory System ("GOSS") and Gas Day Operations ("GDO") Application Upgrades, and the final project is the furnishment for the relocation of the Primary GCC. The expenditures associated with this project are $2.7 million in RY1; $3.0 million in RY2; and $3.95 million in RY3, as shown in Exhibit ___ (GIOSP-1). This project also has an O&M component which is further detailed below.

Q. What are the benefits to Gas Operations that are anticipated from the GCC Improvements?

A. The proposed GCC Improvement projects will provide numerous safety and reliability benefits for our gas customers and the public. The relocation of the Alternate GCC from Manhattan to Westchester will significantly reduce response time under a forced relocation from the primary site, while developing the site using industry and international standards will help address Pandemic lessons-learned and the expansion of the Gas Control Department since the original facility's construction. The GOSS and GDO Application upgrade will maintain Gas Operations critical remote monitoring and control applications on supported software and mitigate potential cybersecurity threats to the Gas HVN. Finally, the new GCC will allow Gas Operations to leverage best-in-class Control Center strategies to provide Gas Control Operators the tools to rapidly address abnormal operating conditions while facilitating Gas Operations organizational response to significant events, all while remaining compliant with Control Room Management compliance requirements.

Q. Have plans for the new GCC changed since the last rate case filing?

A. Yes, due to lessons learned from the pandemic, business user requirements, and projected schedules for the original location's Re-Development Project, the location of the new GCC has changed to a location within an existing facility in Westchester.

Q. What changes were made?

A. Additional user requirements were incorporated, which was not possible at the original location. The schedule was also deferred to later years, due to the pandemic, which temporarily halted progress. Due to these challenges, the new GCC will now be completed within this rate case.

Q. What investments are being requested for this Rate Case, related to the new GCC?

A. As described above and further in the associated white paper, the furnishment portion of the GCC Improvements Projects, as presented by the GIOSP. Other additional funding included as part of the relocation and new location's re-development project is being put forth by Facilities, under the Shared Services panel.

2. Gas Outage Management System

Q. What is the Company proposing related to a gas outage management system ("OMS")?

A. The Company is proposing an investment in the development and deployment of a gas OMS. The Company does not currently have such a system, so initial IT software development will be required for this project. The projected expenditures associated with this project are $9 million in RY1 and $8.8 million in RY2, as shown in Exhibit ___ (GIOSP-1), with associated O&M costs to be seen in RY3 and discussed further below.

Q. What are the current challenges in managing gas outages?

A. Without an OMS, identifying gas outages is done through direct communications with customers and tracking outage impacts is done by manually researching several systems, then using field verification to confirm. This is an administrative burden that requires extensive resources from several departments.

Q. In what scenarios would the Company use the OMS?

A. Generally speaking, the Company would leverage an OMS during larger outages, of 50 or more services or when larger buildings with 200 or more customers are affected. However, we believe even the management of smaller scale outages can benefit from an OMS.

Q. Please provide an example of a situation when such a large outage might be expected to occur.

A. While the gas system is extremely reliable, when outages do occur, they can be extensive. The most common occurrence is a result of water intrusion or damage, such as an event like Hurricane Ida. Gas outages can take considerably longer to restore service than an electrical outage; therefore, the implementation of an OMS system could be very beneficial to the affected customers and facilitate a better response.

Q. What are the benefits of having an OMS?

A. Having an OMS would help identify outages quicker via instant detection when faced with extreme weather or system related issues that compromise supplying service to customers. Having the ability to track outages with advanced technology as opposed to a manual process will provide an administrative advantage. One such example is: through system integrations (with systems such as AMI), the OMS can receive the electric meter count data for master metered buildings, providing quick and accurate customer outage information. The OMS would also serve as a repository to record outages throughout our system.

Q. How would an OMS impact communication?

A. Field, control center, and administrative employees will be able to view status information for outages. Dashboards will be shared that include locations, resources, and real-time status information. This will enhance communication between the control center and the field. Dashboards that include outage progress and additional tracking information will also be available.

Q. How does the Company plan to use an OMS to improve outage restoration?

A. An OMS should provide quick visibility into the number of customers affected by an event. Large outage areas can then be divided into several outage status areas, to increase visibility on customers pending restoration and to focus resources accordingly. Additionally, when implemented, we expect this new system will provide timely and accurate information to customers when they need it most.

IV. OPERATION & MAINTENANCE PROGRAM CHANGES

Q. What O&M Program Changes are the Company putting forward?

A. The Company is requesting O&M Program changes for the following programs: Service Line Inspections, Bridge Inspections, High Emissions Surveillance, and various software needs related to capital projects, with the Service Line Inspections being the largest O&M change request. Similar to the Company's capital expenditures, the majority of projected O&M expenses are focused on safety-related programs. The following testimony describes these program changes in further detail:

A. Service Line Inspections

Q. Please explain how the definition of "service line" has changed in recent years.

A. On April 2, 2015 in Case No. 14-G-0357, the Commission revised the definition of "service line" in 16 NYCRR 255.3(a)(29) to align with federal law. As a result of the new definition, New York State gas utilities were required to perform leakage surveys and corrosion inspections on piping that was previously not considered to be a "service line" under the Commission's rules. Specifically, under the prior definition, a service line associated with a gas meter inside a building ended at the first fitting inside the building. Under the revised definition, a service line extends further into the building and ends at the meter's outlet.

Q. Please describe the Company's experience inspecting the piping that was newly designated as Commission-jurisdictional service lines.

A. In accordance with the Commission's order in Case 15-G-0244, the Company initiated "baseline" inspections in 2017 to evaluate the newly jurisdictional pipe for the first time. These inspections targeted more than 300,000 service lines and nearly 1 million inside gas meters, of which approximately 200,000 are inside building sets in apartments (room sets).

Pursuant to State executive orders to address COVID-19, Con Edison suspended the inspections in March 2020. The Company resumed inspections in July 2020, when New York City entered Phase III of the reopening plan. At that time, the Company had 150,000 services and 400,000 gas meters left to inspect. Con Edison and other local distribution companies petitioned the Commission for an extension to complete the inspections until August 1, 2020, and the Commission granted the request.

Q. What efforts had the Company taken to complete the inspections prior to July 2020?

A. The Company notified customers of the required inspections and their obligation to provide access to our equipment. The Company communicated with customers through emails, letters, social media, a dedicated webpage, drop cards, phone calls, meetings with building management associations, and a robust appointment-scheduling process employed by our contractor. The Company made at least two attempts per premises (as required) to gain access for the inspections.

Q. Did the Company complete the inspections by August 1, 2020?

A. No.

Q. What was the primary reason that the Company was not able to complete the inspections?

A. Inability to gain access to the inside of buildings to perform the inspections, despite several attempts, exacerbated by customer reluctance to provide access because of COVID-19.

Q. What are some of the actions the Company took to gain access?

A. In addition to the efforts we already described, after resuming inspections in July 2020, the Company initiated an email campaign for customers who have email addresses on file and modified its letters and drop cards to include enhancements to appointment scheduling and information about the Company's COVID-19 safety precautions. The Company also created a notice that is placed directly on customers' bills when a fee is assessed. On December 22, 2020, the New York State Department of Public Service Chief of Pipeline Safety and Reliability provided a letter ("DPS Letter") emphasizing the importance of these inspections and the need for customers to provide access to allow utilities to perform these inspections. The Company began sending the DPS Letter to No-Access customers shortly after it became available. Con Edison also used no access fees to encourage customers to provide access for inspections.

Q. Did the Company take any further actions to complete inspections at these no access locations?

A. Yes. The Company increased the number of dedicated technicians performing additional cold call attempts, which resulted in a significant number of scheduled appointments through these communication efforts. In addition, the Company increased efforts to perform additional service line inspections when it was able to access a building for other work reasons (*e.g.*, turn-ons, inside leaks, meter exchanges, NGD installations, second cycle business district re-inspections). Despite these efforts, these opportunistic inspections resulted in only modest reductions in the Company's remaining backlog.

Q. Did Staff direct the Company to further revise its procedures for complying with the new gas service line rules?

A. Yes. On December 31, 2020, to comply with Staff's directive, the Company filed a compliance plan in Case 15-G-0244 (Petition to Establish an Additional Compliance Method for Gas Service Line Leakage Surveys/Corrosion Inspections for Premises with Access Issues) ("Service Line Compliance Plan"). The Commission has not issued an order on the petition, but Staff has made it clear that the Company must comply with the revised plan that it filed.

Q. What has the Company done under the Service Line Compliance Plan and what have been the results?

A. As outlined in the Service Line Compliance Plan, the Company has continued to conduct baseline gas service line inspections and intensified its efforts to notify customers of the inspection requirements in writing, assess fines where appropriate, and place customers that continued to refuse access under the threat of termination. Since the inception of the program, the Company has sent out: 1.1 million letters, over 110,000 e-mails, over 170,000 fee warning letters (a net of over 60,000 accounts were assessed fees) over 110,000 turn off warning letters, and over 77,000 final and reoccurring termination warning letters.

Q. How is the Company handling the remaining “No-Access” customers?

A. After all efforts were exhausted, Con Edison placed these customers into a separate service termination process. As of December 31, 2021, there were approximately 26,000 services and approximately 52,000 gas meters remaining to be inspected. The Company continues to attempt to gain access to complete these inspections to avoid terminating the customers’ gas service. The remaining customers will continue to receive communications warning them about the possibility of service termination until the customer either grants the Company access to complete the inspection, the Company cuts and caps the existing gas service or, where appropriate and for buildings where the Company has been able to inspect some but not all meters, the Company replevins the relevant gas meter. We intend to resume potential service terminations after the heating season has concluded in March 2022.

Q. What are the inspection requirements after the baseline inspections?

A. The general periodic inspection requirement is once per year (not to exceed 15 months) for business district services and once every three years (not to exceed 39 months) for non-business districts. In Case 15-G-0244, the Commission authorized a pilot program for Con Edison designed to test whether extended inspection intervals for all service lines of once every five years (not to exceed 63 months), combined with conditions such as the installation of AMI-enabled methane detectors at each inspected meter, meets or exceeds existing safety standards.

Q. Have there been any other significant regulatory developments as they relate to inspection intervals for gas service lines?

A. Yes, on March 21, 2021, PHMSA modified 192.481 to extend onshore service line atmospheric corrosion control inspections to once every five calendar years, not to exceed 63 months. Then on October 25, 2021 in case 19-G-0736 the Commission proposed to modify 255.481 reflecting the PHMSA code modifications. Once the proposed 255.481 changes are adopted, all non-business district service line inspections can be extended to once every five-years, not to exceed 63 months.

Q. Based on the foregoing, what is the inspection interval that is assumed for purposes of the Company's forecast?

A. The Company's forecast assumes the extension of the inspection cycles for all services to a five-year cycle, not to exceed 63 months starting January 1, 2023.

Q. Please describe the Company's Service Line Program O&M request.

A. We propose a program change increase of $39.2 million in RY1, with reductions of $0.9 million in RY2 and $1.2 million in RY3. This proposed change reflects only a change in the cost recovery mechanism (from surcharge to base rates) and a significant reduction compared to the Company's recent costs for the service line inspection program.

Q. What were the Company's historic costs for this program during the current Gas Rate Plan?

A. The Company's actual costs under this program were $29.3 million in 2020 and $68.6 million in 2021 when it began following its revised compliance plan at Staff's direction.

Q. Why does the Company believe it can reduce the costs of this program so significantly in RY1?

A. We believe we can achieve these reductions through the anticipated completion of the baseline inspections and the expected corresponding decrease in repairs associated with baseline inspections. The Company also had high rates of access refusal due to customer concerns related to COVID-19.

Q. How does the Company recover the costs for this program under the current Gas Rate Plan?

A. The current Gas Rate Plan included a relatively small amount in base rates (approximately $7.0 million in 2020 and $700,000 in each of the subsequent two rate years) for this program. The Plan authorized an MRA surcharge mechanism, which was capped at approximately $99 million for the term of the three-year Gas Rate Plan.

Q. Has the Company gained sufficient experience with this program since its last rate filing to develop a projection of its future costs?

A. Yes. As we have explained, the Company has undertaken extensive and comprehensive measures to comply with the Commission's and Staff's additional directives relating to service line inspections and repairs.

Q. What is the basis for the Company's estimated expenditures for this program?

A. The Company has approximately 1 million inside building sets, of which an estimated 200,000 inside building sets are in apartments (room sets) or other remote locations that are less readily accessible. As described above, the Company made significant efforts and is continuing to complete the remaining baseline inspections pursuant to its revised compliance plan. Because of the new five-year inspection cycle, inspections will be spread out more evenly throughout the five-year period. We will also attempt to bundle this work with installation of AMI natural gas detectors where feasible. Projected expenditures include all costs associated with the emergency response when a leak is detected, the repair to Company piping from the point of entry to the outlet of the gas meter, labor to perform the inspections and support the customer communication and scheduling. The expenditures enable a minimum of two cold call field attempts, plus additional attempts that may result from customer letters warning of fines and subsequent termination of service.

Q. What is the breakdown of the program forecast?

A. The $39.7 million annual forecast for this safety program is divided into the following functions:

1. $18 million annually for field inspections;

2. $4.2 million annually for non-field support, which includes customer support, scheduling, training and equipment;

3. $6.9 million annually for corrosion repairs and all necessary follow-up surveillance and rechecks after repair inspections;

4. $2.7 million annually for emergency response associated with any leaks identified during the service line inspection; and

5. $7.9 million annually for operating and maintenance costs associated with cutting and capping and/or replevin when a customer fails to provide access after the required attempts, and notifications fail to result in a completed inspection.

Q. Is the Company proposing any tariff changes related to the Service Line Inspection program?

A. Yes. The Company is proposing to modify the fee structure for customers or access controllers who deny the Company access to the premise to perform the inspection. The proposed change will modify the fee from one-time billed, to a fee assessed in every billing period, until access is provided. The customer will also be responsible for all costs associated with meter seizure/forced access if refusals continue.

Additionally, when customers refuse an outdoor meter location while Con Edison is performing work on their service, it perpetuates the need for inside service line inspections. Therefore, the Company is also proposing that the meter relocation refusal fee be increased to cover inside inspection costs that would have otherwise been avoided.

Q. Are there any other costs not included in this request?

A. Yes. The costs for additional vehicles and associated maintenance are not included. These costs are approximately $600,000, which we may include as part of our update filing.

B. Bridge Inspections

Q. Please describe the Company's next O&M program change.

A. The Company is proposing a reallocation of funding for its Bridge Inspection program. Looking ahead to 2026, we see a much higher number of bridge inspections coming due in a single year than normal. Gas mains at bridges receive a visual inspection every three years and a more costly, detailed inspection (including preventative maintenance) every 21 years. The inspection workload varies, with inspections at 257 locations coming due on a cyclical basis. However, 137 inspections (about 62% above the normal amount) are due in 2026. Planning ahead, we expect that this increase in workload will challenge our ability in 2026 to complete these inspections. Therefore, the Company is proposing to preemptively move 30 detailed inspections, due in 2026, to the rate case years and spread them evenly across 2023, 2024, and 2025.

A total of $1,104,750 for the three years cumulatively needs to be reallocated to cover additional pipe inspection and preventative maintenance proposed for 2023, 2024, and 2025. The amount will be evenly distributed across the three years. Further details of this program change can be found in the associated white paper.

C. High Emissions Survey

Q. Please describe the next O&M change.

A. The Company has designed a program to identify and target the highest emitting natural gas leaks, which are currently defined as leaks emitting greater than 10 standard cubic feet per hour. To conduct the survey, we attach advanced leak detection technology to a passenger vehicle and drive multiple passes over the course of two to three nights down the same street, according to the manufacturer’s recommendation. Currently, the Company is utilizing the Picarro Surveyor device for this survey. Once all passes are completed, data is downloaded and analyzed. This survey complements our current leak survey programs by covering one-third of the of the distribution system that has not recently been covered by the walking compliance survey.

Q. Once identified, how will the Company eliminate fugitive emissions?

A. The Company has a performance metric to repair gas leaks within 60 days, 85% of the time. On average, all leak types are repaired within 30 days or less, far exceeding code requirements. Once a high emitter is identified, the Company will maintain these high standards by repairing the known leak and eliminating the emissions.

Q. What benefits does this program provide?

A. By targeting leaks with the highest emissions and running the program as a complement to other existing leak survey programs, we are able to focus on eliminating fugitive methane emissions efficiently. Due to its propriety algorithms, the advanced leak detection system can detect methane leaks farther from the source, and it is the only leak detection equipment able to quantify the emissions rating. This program also supports the future rulemakings PHMSA will implement as required by the PIPES Act. The PIPES Act calls for rules to be promulgated for the use of advanced leak detection technologies on new and existing gas distribution pipeline facilities. In a recent industry presentation, PHMSA announced that it anticipates a notice of proposed rulemaking on this subject in 2022.

Q. Please provide the projected expenditures, and how the Company developed its projection.

A. We currently anticipate the following O&M expenditures for this new program: $499,000 per year, in each of RY1, RY2 and RY3. This cost was estimated based on the mileage per year needed to be surveyed, number of required passes per manufacturer's recommendation, and experience utilizing the equipment to know how many miles could be covered each day. Labor rates were then used to determine staffing increases.

D. Capital Projects Software Changes

Q. What is the final O&M change being proposed?

A. The Company, as described in more detail throughout this testimony and in the associated White Papers, is making capital investments, which includes the development and/or implementation of software technology. Licensing fees associated with software usage have an O&M expense and are therefore presented here.

Q. Which capital investments include such O&M expenses?

A. The following investments include an O&M component:

- The Gas Outage Management System: As described further in the associated white paper, this brand-new software solution will require ongoing licensing fee O&M expenses of $140,000 per year, starting in RY3.

- The Gas Control Operator Training System Simulator: As described further in the associated white paper, this new software solution will require ongoing licensing fee O&M expenses of $60,000 per year, starting in RY2.

V. DEFERRAL ACCOUNTING/SURCHARGES

A. Pipeline Safety Act

Q. Please describe the Pipeline Safety Act of 2011 ("PSA") and its requirements.

A. The PSA was signed into law in January 2012. The PSA authorizes and directs the United States Department of Transportation ("DOT") to perform studies and adopt rules intended to enhance gas pipeline safety.

Q. Please explain the status of PSA implementation.

A. To date, PHMSA has completed 40 of the 42 mandates and a number of non-mandated actions, leaving certain significant issues still pending. These pending issues include rules on the use of automatic and remote-controlled shutoff valves and expansion of the transmission integrity management program requirements.

Q. Please identify the continuing uncertainties associated with PSA requirements.

A. Although PHMSA has published Notice of Proposed Rulemakings ("NPRM") on certain aspects of the PSA, those were met with a large amount of public comment. Additionally, the Gas Pipeline Advisory Committee ("GPAC") has also modified and voted on these proposed rules. As a result, there are a number of uncertainties regarding the pending PSA regulations that could have a significant impact on the Company's costs. These include the following related to transmission mains: expansion of the existing integrity management requirements; new material verification requirements; new risk modeling requirements; and the required use of automatic or remote-controlled shut-off valves. As such, the Company proposes to continue the reconciliation for any costs related to compliance through a surcharge. As further explained below, the costs to comply remain uncertain.

Q. Has PHMSA taken any action to complete the remaining mandates?

A. To date, TIMP requirements and MAOP verification have been proposed by PHMSA through the NPRM "Pipeline Safety: Safety of Gas Transmission and Gathering Lines", Docket PHMSA-2011-5 0023. The NPRM was released in 2016, and GPAC meeting concluded in 2017, yet all parts of the final rule(s) have yet to be published. To date, only part one has been released, leaving two parts outstanding. It remains uncertain whether PHMSA will address the industry/public comments that they received and how they will modify the rulemaking, based on the GPAC comments and voting.

Q. Why is it reasonable to reconcile costs related to compliance with the PSA through a surcharge?

A. As described above, there are a number of uncertainties associated with pending DOT regulations enacted in response to the mandates in the PSA. Some of the uncertainties are directly related to the requirements that DOT may include in these new regulations, which are unknown at this time. Other uncertainties (and their related costs) are dependent on the regulations the DOT ultimately adopts.

Q. Can the Company provide an estimate of the costs of these pending regulations?

A. No, the Company does not have a basis to include an estimate. The uncertainties of these pending regulations, including the timeframe of enactment, make it too difficult to develop a cost estimate for the Rate Years.

Q. Why is the Company proposing a surcharge?

A. The Company believes it makes more sense to use a surcharge to avoid a potential large deferral build-up prior to the next rate case filing. The surcharge mechanics are described in the Gas Rates Panel testimony.

B. PIPES Act

Q. Please describe the new regulations that may be enacted by the United States DOT in response to the PIPES Act of 2020?

A. The PIPES Act of 2020 authorizes and directs the DOT to perform studies and adopt rules intended to enhance gas pipeline safety, as well as ties environmental safety to pipeline and public safety.

Q. What, if any, uncertainty exists with respect to the regulations that may be promulgated under the PIPES Act and their impact on Company operations?

A. As this Act is relatively recent, PHMSA has yet to propose any rulemakings to implement its directives. Without seeing the proposed rulemakings, significant uncertainty exists as to whether such new or modified rulemakings will have an impact on the Company's operations or investments.

Q. What is the anticipated timing of the PHMSA rulemaking associated with the PIPES Act?

A. Although no notices of proposed rulemaking have been released, the PIPES Act provides timeframes for each directive to PHMSA. These timeframes vary based on the topic within the Act; however, it is reasonable to expect that some associated rulemakings will be enacted during the rate years. During a recent industry presentation, PHMSA forecasted that Notice of Proposed Rulemakings ("NPRMs") should be expected as follows:

- Leak Detection NPRM in 2022
- Safety of Gas Distribution NPRM in 2022
- Pipeline Operational Status NPRM in 2023

Q. Why is it reasonable to reconcile the costs related to compliance with the PIPES Act through a surcharge?

A. As described above, there currently is uncertainty associated with pending DOT regulations enacted in response to the mandates in the PIPES Act. Some of the uncertainties are directly related to the requirements that DOT may include in these new regulations, which are unknown at this time. Other uncertainties (and their related costs) are dependent on the regulations the DOT ultimately adopts.

Q. Can the Company provide an estimate of the costs of these pending regulations?

A. No, the Company does not have a basis to include an estimate. The uncertainties of these pending regulations, including the timeframe of enactment, make it too difficult to develop a cost estimate for the Rate Years.

Q. Why is the Company proposing a surcharge?

A. The Company believes it makes more sense to use a surcharge to avoid a potential large deferral build-up prior to the next rate case filing. The surcharge mechanics are described in the Gas Rates Panel testimony.

C. NY Operator Qualification Rulemaking

Q. Why does uncertainty exist with respect to new regulations that may be enacted by the Commission related to the Operator Qualification ("OQ") notice of proposed rulemaking?

A. On December 17, 2021, the Company and other utilities and industry groups provided comments on the proposed OQ rule. Many of Con Edison's comments sought clarity from the Commission on regulatory language, which may affect the new investments necessary to comply with a final rule. Until the final rule is adopted, the Company cannot anticipate what investments will be necessary to present for recovery.

Q. What sections of the proposed regulation has the Company identified as areas with potential cost implications for the Company's operations?

A. The following topics within the proposed rule may result in the need for further investment, depending on the final rule:

- Time restrictions prior to evaluations;
- Span of control records;

- Training records associated with qualification records;
- Automatic failure from abnormal operating condition questions; and
- Program effectiveness.

Q. What is the anticipated timing of the OQ final rule?

A. As comments have already been submitted, Con Edison anticipates a final rule to be released sometime in mid-2022; therefore, any associated investments may not able to be included in this case.

Q. Why is reconciliation through a surcharge reasonable for such costs?

A. As described above, there currently is uncertainty associated with the pending OQ rule. Some of the uncertainties are directly related to the requirements that the Commission may include in these new regulations, which are unknown at this time. Other uncertainties (and their related costs) are dependent on the regulations the Commission ultimately adopts.

Q. Can the Company provide an estimate of the costs of these pending regulations?

A. No, the Company does not have a basis to include an estimate. The uncertainties of these pending regulations, including the timeframe of enactment, make it too difficult to develop a cost estimate for the Rate Years, at this time.

Q Why is the Company proposing a surcharge?

A. The Company believes it makes more sense to use a surcharge to avoid a potential large deferral build-up prior to the next rate case filing. The surcharge mechanics are described in the Gas Rates Panel testimony.

VI. PERFORMANCE MEASURES

A. Gas Performance Measures

Q. Is the Company proposing any changes to the existing Gas Performance Measures, which are set forth in Appendix 17 of the Joint Proposal adopted by the Commission in its January 16, 2020 rate order?

A. The Company proposes to continue most of the major elements associated with current Gas Performance Measures. We are proposing modifications to some of the targets and negative revenue adjustments, as discussed in more detail below.

Q. Are any of the Company’s proposed changes similar to changes that have been approved in other Commission-approved utility rate plans or rate plans that are pending approval?

A. Yes, many of the changes the Company is proposing are consistent with recent trends of increased positive incentives in other utility rate plans that have been approved or are pending approval. However, the Company recognizes that each utility rate plan should be viewed in total and that individual elements of an overall settlement agreement should not be evaluated in isolation.

Q. How should NRAs be applied?

A. The Company proposes that any NRAs it incurs should be applied to fund incremental gas safety programs to be developed at the Company's direction, in consultation with Staff.

Q. Which specific Gas Performance Measures does the Company propose to modify?

A. The Company is proposing to modify the following performance measures, established under its current Gas Rate Plan: Gas Main Replacement, Leak Management, and Gas Regulations Performance Measure.

1. Gas Main Replacement

Q. Please describe the Company's proposed changes to the Gas Main Replacement Program Safety Performance Measure.

A. As discussed earlier under the Main Replacement Program, the Company is proposing a slight reduction from the prior rate case main replacement target of 90 miles to 85 miles per year for each rate year, for a total of 255 miles of leak prone pipe over the three-year period 2023 through 2025.

2. Leak Management

Q. What is the Company's proposed change to the Leak Management Performance Measure?

A. As set forth in the current Gas Rate Plan, the Company receives a positive revenue adjustment, up to an annual maximum of four basis points, for reducing the leak backlog below the associated annual targets. The Company would maintain the 2022 year-end total leak backlog target of 200, for each rate year. However, the Company is proposing an increase to the positive revenue adjustment basis points.

Q. What positive revenue adjustment changes are the Company proposing?

A. The positive revenue adjustment would be awarded as follows:

Total Leak Backlog:	Prior Rate Case Positive Basis Points:	Proposed Positive Basis Point:
76-100	1 BP	2 BP
26-75	2 BP	4 BP
<=25	4 BP	6 BP

Q. Why does the Company believe such positive revenue adjustment increases are appropriate?

A. In order to achieve such low total leak backlog targets, the Company must expend a significant level of resources. The cost of deploying such resources currently exceeds the value of the positive revenue adjustment ("PRA"). Therefore, the Company is proposing a PRA structure that is more in line with the costs associated with achieving such goals.

Q. Are there benefits to customers and other stakeholders associated with the gas main replacement and leak management positive incentives?

A. Yes. Eliminating 12-inch and smaller cast iron, wrought iron, and unprotected steel above the established targets will enhance safety and reduce emissions.

Q. Is the Company proposing any modifications to the current Joint Proposal language regarding the calculation of the final leak backlog count?

A. Yes. The Company believes additional clarity is needed regarding leaks being added back into the final leak backlog.

Q. Why is the Company proposing additional language around leaks being added back into the final leak backlog?

A. In 2021, there was a disagreement regarding the meaning of "successful elimination" of leaks and how type 3 leaks are successfully eliminated.

Q. What is Con Edison’s position on how a type 3 leak is successfully eliminated?

A. Type 3 leaks do not require follow up inspections by State code or Company specification and, therefore, the successful elimination of a type 3 leak is the action of repairing said leak and confirming (at the time of the repair) that there are no gas readings.

Q. What additional language is needed to clarify what is meant by “successful elimination?”

A. The language in any potential joint proposal or rate plan in this proceeding should be specific that successfully eliminated leaks are defined as both: 1.) leaks that have been repaired that do not require follow up by code or Company specification; and 2.) leaks that do require follow up by code and specification which have successfully passed the follow-up inspection.

Q. Is the Company proposing to continue the SRSM to recover incremental O&M expenses associated with lowering the Company’s leak backlog below the target established for the Leak Backlog performance measure?

A. Yes, the Company proposes to continue the SRSM for the Leak Backlog performance measure.

3. Emergency Response

Q. What modifications does the Company propose with respect to the Emergency Response Safety Performance Measure?

A. The Company is not proposing any changes to the Emergency Response Safety Performance Measure. The response time percentages set in the prior rate case (and associated negative and positive revenue adjustments) should remain, as is, for the next three years.

Q. Is the Company proposing any additional modifications to the Emergency Response Safety Performance Measure?

A. Yes, the Company proposes to clarify the exclusion under the Emergency Response Measure in the current Joint Proposal. The exclusion in the current Joint Proposal allows the Company to seek Staff's approval to exclude gas leak and odor calls resulting from circumstances that are beyond the Company's control, such as mass area odor complaints, major weather-related occurrences, and major equipment failure (unrelated to Company action/inaction or infrastructure).

Q. Why is the Company proposing to clarify this particular exclusion?

A. The rationale for including an exclusion for this performance measure is to address rare but expected situations when an inordinate number of odor calls are received for reasons beyond the Company's control. There is a general recognition that, under such circumstances, it would be unreasonable to expect the Company to meet the targets that apply under normal conditions. Put another way, the Company should not be punished for failing to meet targets that are unrealistic due to rare and extreme conditions that arise for reasons beyond the Company's control. This general understanding of the purpose of the exclusion should inform how it is implemented.

As a result of Hurricane Ida, the Company sought to invoke this exemption for odor calls and leaks that arose due to the hurricane and which were beyond the Company's control. The Company experienced an increase in odor call volumes of over 400%. There was a disagreement regarding whether this exclusion should apply only to leaks that could directly be attributable to the storm (an identification and attribution process which would be impossible to validate). The Company believes this exemption applies to all odor calls that occurred during the hurricane, since the entire weather-event was out of the Company's control.

Q. How is the Company proposing to modify the exclusion language?

A. The Company proposes the following:

"The Company may seek the following exclusion to operating performance under this measure: All odor calls associated with mass area odor complaints, major weather-related occurrences, and major equipment failure. Con Edison shall provide notification…"

4. Gas Regulations Performance Measure

Q. What modifications is the Company proposing to the Gas Regulations Performance Measure?

A. The Company is proposing the following modifications to this metric:

- Change in the NRA calculation;
- Establish audit protocols;
- Eliminate NRA for violations that were previously identified in a quality control/assessment process and rectified prior to an audit; and
- Eliminate NRA for violations that were self-reported and not subject to reporting requirements.

Q. Please describe the Company's first modification.

A. The Company is proposing to change the NRA calculation for violations identified in Records and Field Audits.

Q. How does the Company propose to calculate the NRAs for Records and Field Audit Violations?

A. Records Audit Operations

High Risk: 6-20 (1/2 BP); 21+ (1BP)

Other Risk: >15 (1/4 BP)

Records Audit Central

High Risk: 10-25 (1/2 BP); 26+ (1BP)

Other Risk: >15 (1/4 BP)

Field Audit

High Risk: 6-20 (1/2 BP); 21+ (1BP)

Other Risk: >15 (1/4 BP)

Q. What is the basis for separating the Central category and excluding that categories' first 10 audit high risk items and 15 other risk items in the records audit?

A. During the 2021 PSC Records Audit of 2020 Records, Staff changed the audit protocols for Central Records by sampling by borough, instead of the Central group as a whole, which resulted in quadruple the number of records and field inspections than had been historically sampled, in the Central categories. Con Edison has a Central Operations organization which singularly performs this work, and therefore, DPS Staff's historical practice of treating this group similar to an operational borough (*i.e.*, sampling protocols in place prior to 2021) was appropriate. Additionally, these changes were not negotiated for Rate Years 2020-2022 nor were they established in the current Gas Rate Plan. If this is the audit protocol going forward, the Company is requesting a separation of this category with the proposed dead band, in order to establish appropriate targets that reflect the audit protocol changes. Con Edison has shown a consistent downward trend in our Records and Field audit violations since this metric was put into place, and we will strive to continue this decline in violations.

Q. What is the basis for proposing a dead band for Field Audit findings?

A. Since the current rate case's negotiations, DPS Staff has greatly increased its field presence overall, and therefore, increased the number of field audits in the process.

Additionally, and as discussed above, in 2021 DPS Staff modified its sampling practices related to the Central group. This change occurred in the field audit as well, which resulted in quadruple the number of field inspections than had been historically sampled, in the Central categories. These changes were not negotiated for Rate Years 2020-2022 nor were they established in the Gas Rate Plan. Therefore, the Company is requesting a dead band of 5 high risk and 15 other risk Field Audit findings, in order to establish appropriate targets that reflect the audit protocol changes.

Q. Please describe the Company's next proposed modification to the Gas Regulations Performance Measure.

A. The next proposed modification would establish more consistency around audit sampling. In the context of annual field and record audits, where violations carry significant NRA implications and are reported in the annual Performance Measurement Report, it is imperative that consistent sampling and audit protocols be established. There is currently no documented methodology or protocols explaining how Staff develops samples and/or audits a LDC's records. As stated in the prior two answers, Staff has modified sampling protocols outside of rate case negotiations, which has greatly increased the number of audited items for both the Records and Field audit. To address this issue, the Company is requesting that the Commission direct Staff, in consultation with New York State LDCs, to establish a documented sampling and audit protocol to promote greater consistency.

Q. What is the Company's next proposed modification related to the Gas Regulations Performance Measure?

A. The Company is proposing the elimination of NRA for violations resulting from self-reported events not subject to reporting requirements, as long as the Company takes immediate corrective action to resolve said issue. To promote transparency and cooperation, the Company has self-reported issues or incidents to Staff, which do not meet current regulatory reporting requirements. These self-reported events should not be subject to NRA, because the Company should not be penalized for going above and beyond its reporting requirements.

Q. What is the Company's next proposed modification related to the Gas Regulations Performance Measure?

A. The Company is proposing the elimination of any NRA penalties associated with violations that were previously identified by internal quality control processes and rectified prior to identification in a PSC audit. The Company puts considerable effort into identifying and rectifying compliance or quality issues; therefore, it not reasonable for the rate plan to establish disincentive for a violation that has already been identified and rectified by the Company. Indeed, it is contrary to governmental policy regarding compliance, which is to encourage disclosure and correction.

VII. GAS SUPPLY

A. Capacity and Supply Portfolio

Q. Please describe the nature of the Companies' gas supply portfolio.

A. The Company manages a joint gas supply and capacity portfolio ("joint portfolio") with (Orange and Rockland Utilities, Inc. ("O&R") that allows for the joint utilization of both Companies' gas supply and interstate pipeline capacity contracts, including storage. The joint portfolio is operated for the benefit of the firm gas customers of both Con Edison and O&R (the "Companies"). The contracts that the Companies' have entered into are listed in Schedules 1, 2, 3, and 4 of Exhibit___(GIOSP-3).

Q. Please describe the objective of the Companies' long-term gas supply plan.

A. The Company evaluates supply and capacity requirements over a ten-year planning horizon and integrates and extends this over a 20-year planning horizon to determine the plan to meet the needs of its firm gas customers. While the Company plans only for its firm customers, it is cognizant of needs of its non-firm customers and of electric customers. The Companies have also adopted the objective of decreasing the emissions associated with the gas flowing through the system, through the purchase of certified gas and the interconnection of RNG facilities.

Q. Please describe the objective of the Companies' gas purchasing and hedging programs.

A. The Company's objective is to obtain reliable, diverse, lower emission, and reasonably-priced gas supply in order to: (i) meet the design winter requirements of its firm gas customers, (ii) minimize costs to its firm customers, (iii) reduce price volatility, (iv) react to changing weather conditions, (v) to the extent possible, maintain service during a contingency event affecting a major pipeline or supply basin and (vi) reduce the emissions associated with the gas it purchases.

Q. How do the Companies seek to maintain reliability of supply?

A. One of the cornerstones of a reliable gas portfolio is diversity. The Companies' joint gas supply and capacity portfolio includes contracted supplies from the Marcellus Shale in the Northeast, the Gulf Coast, and Canada, from suppliers on multiple pipelines, as set forth in Exhibit___(GIOSP-3), Schedule 1, Gas Supply Contracts. The Companies also have firm pipeline capacity contracts with various interstate pipeline transportation companies, as set forth in Exhibit___(GIOSP-3), Schedule 2, Pipeline Transportation Contracts, which provide access to diverse sources of supply. In addition, the Companies have a number of contracts for underground storage, which are listed in Exhibit___(GIOSP-3), Schedule 3, Storage Contracts, an LNG peaking facility, whose deliverability is set forth on Exhibit___(GIOSP-3), Schedule 4, baseload and peaking delivered service, as set forth in Exhibit (GIOSP-3), Schedule 2, and has contracted for CNG peaking deliveries, whose deliverability is set forth on Exhibit___(GIOSP-3), Schedule 4.

Q. What are design weather conditions?

A. The peak day demand represents the quantity of gas that firm customers would require in a twenty-four hour period of a gas day, which starts at 10:00 am, at a Temperature Variable of zero degrees Fahrenheit. The Temperature Variable is defined as the sum of 70 percent of the projected gas day average temperature plus 30 percent of the prior gas day average temperature, which provides the best correlation with firm customer demand. Exhibit___(GIOSP-3), Schedule 5, Forecasted Requirements – Peak Day, shows the forecast of Con Edison's and O&R's firm customers' peak day demand for each winter period (*i.e.*, November through March) beginning with the winter of 2019/2020 through winter 2021/2022. The Companies also calculate the gas requirements for meeting demand over the course of a winter under severe weather conditions (a "design winter") in order to establish storage and Delivered Services amounts needed to meet potential customer demand.

Q. Please explain how the Companies' contracts enable them to meet these design weather conditions.

A. The Companies meet peak day demand in four ways. First, the Companies rely on the delivery of firm supply through their firm interstate pipeline transportation and firm storage contracts, which are listed in Exhibit___(GIOSP-3), Schedules 2 and 3. Second, the Companies maintain contracts for Delivered Services. Historically, these have primarily been firm peaking supplies that give the option to purchase gas for a pre-determined number of days during the winter (typically 15, 30, or 60 days) and pay the daily citygate index price for the gas on those days. The Companies' also have base delivered supply contracts in addition to peaking supplies. Base delivered supplies are a commitment to procure gas at the citygate for a set winter term (typically December through February or November through March) and are priced at a NYMEX index price plus a fixed basis. These contracts for Delivered Services, which are listed in Exhibit___(GIOSP-3), Schedule 2, contribute to the Companies' ability to meet peak load. Third, Con Edison vaporizes gas from its LNG facility to meet peak day demand. Fourth, Con Edison can call upon its contracted CNG facility to meet peak day demand.

Q. What do you mean by "Delivered Services?"

A. Delivered Services are gas supplies procured at the citygate from third party suppliers that have primary firm capacity to the citygate.

Q. What risks does a high level of Delivered Services introduce to the Gas Supply portfolio?

A. The Company has identified three risks: re-contracting, availability, and price volatility.

Q. Please explain these risks.

A. Unlike the Company's contractual rights for pipeline capacity, there is no regulatory renewal right for Delivered Services and, therefore, no certainty that the Company can continue to rely on the same Delivered Service supply contract year-to-year, to reliably meet customer heating needs.

Second, with the pipeline capacity coming into the Con Edison service territory being fully contracted and new pipeline projects facing increased difficulty in securing necessary permits, the future availability of Delivered Services required to meet our forecasted peak demand is uncertain because shippers who hold this capacity can market it to persons outside of the service territory.

Third, the increased reliance on Delivered Services in the portfolio results in higher gas price volatility and potentially increased costs for our customers. Instead of buying gas at low price volatility production area receipt points and transporting it on pipeline capacity to our service territories, the Companies must purchase at New York area citygates where prices are subject to significant volatility during high demand periods.

Q. What actions have the Companies taken to reduce their reliance on Delivered Services?

A. The Companies actively seek to acquire firm transportation capacity to the New York area citygates as it becomes available from other shippers through permanent capacity release transactions or by contracting directly with pipelines once the capacity has been turned back by the existing shipper. The Companies have also acquired capacity released through Asset Management Agreements ("AMA") with third party capacity holders in addition to traditional capacity release agreements. The Companies will pay a fee in exchange for capacity with a supply component from the third party.

Q. Have there been changes to the Companies' supply and capacity portfolio over the last three years?

A. Yes. The Companies have recently entered into new agreements and elected not to renew certain agreements.

Q. Please describe the recent agreements the Companies have entered.

A. As discussed in further detail below, the Companies are diversifying their Delivered Services portfolio. The Companies have entered Delivered Services contracts with up to two or three-year durations to meet firm gas customers' current and future peak day requirements. These contracts give the Companies the right to call upon the supplier and purchase daily-priced gas for a maximum of 30 or 60 days during the winter season. As previously discussed, these Delivered Services contracts provide needed supply to our gas system to supplement pipeline capacity under contract by our suppliers.

The Companies have new contracts for additional deliverability to our citygates: four with Texas Eastern for 147,500 Dt/ of pipeline capacity which delivers to Lower Manhattan.

Beginning in 2020, the Companies have also subscribed to pipeline capacity through Asset Management Arrangements, specifically a total of 80,000 Dt/d delivery on Transco Pipeline to Manhattan and 15,500 (increases to 40,000 Dt/d in November 2023) on Tennessee pipeline to Westchester.

Q. How do the Companies evaluate whether to renew an expiring contract?

A. The Companies evaluate the capacity portfolio. If an expiring contract is still required to serve firm customers or manage system operations, the Companies assess the market to determine if there are more economic alternatives available that provide at least the same degree of reliability and flexibility. If not, the Companies will renew the contracts by exercising their rights pursuant to existing interstate pipeline tariff Right of First Refusal ("ROFR") provisions or other applicable contract provisions.

Q. Have the Companies elected not to renew certain expiring contracts?

A. Over the past three years, the Companies elected not to renew some of their firm transportation contracts with National Fuel.

Q. Why did the Company elect not to renew these contracts?

A. The increase in supply available from the Northeast Marcellus and Utica shale regions has affected how the Companies evaluate certain contracts. Historically, the Companies seek to access receipt points where gas can be purchased from multiple sellers, which are often referred to as a "liquid supply points." To accomplish this, the Company has historically entered contracts that formed paths accessing the Gulf, Canada, or a storage field. Some of these paths include multiple contracts such as one upstream pipeline with access to a liquid supply point, connected with one downstream pipeline with access to NYC.

With the increased gas available in the Northeast, liquid supply points that previously did not exist have formed on the downstream pipelines.

The firm transportation contracts with National Fuel were upstream transportation contracts that were needed to reach a liquid supply point. Since liquid supply points are now available on their downstream counterpart along the same path, the Companies no longer need to purchase firm transportation rights on this upstream pipeline.

Q. Do you anticipate any future changes to the capacity portfolio?

A. Yes. As described in our testimony in Case 19-G-0066, the Companies have subscribed to pipeline capacity on Mountain Valley Pipeline ("MVP") which is scheduled to be in service as early as 2022. The Companies have also subscribed to pipeline capacity on Iroquois pipeline for 62,500 Dt/d of capacity for deliveries from Waddington, NY to New York City, NY and on Tennessee pipeline for 115,000 Dt/d of capacity for deliveries from Pennsylvania to Westchester, NY. The estimated in-service date of the Iroquois pipeline is winter 2023 and while Tennessee pipeline has indicated an estimated in-service date of winter 2022, due to the high risk associated with that aggressive schedule, the Companies continue to plan for an in-service of winter

2023.

Q. What is the current/updated status of the anticipated future pipeline projects?

A. MVP was originally planned to be in service in 2018 and has now been delayed such that the earliest it will be in service is November 2022. In Case 19-G-0066, the Companies had also described a project, Penn East Pipeline, for 100,000 Dt/d. The pipeline company has permanently terminated that project.

The estimated in-service date of the project on Iroquois Pipeline has not changed since inception. The estimated in-service date of the project on Tennessee Pipeline has also not changed. The Tennessee project will allow Con Edison to lift its moratorium in Westchester, but we continue to plan for an in-service date of no earlier than winter 2023.

Q. Have there been any changes to the Companies' supply portfolio?

A. Yes. As illustrated in Exhibit__(GIOSP-3), certain of the Companies' gas supply contracts expire each year. Existing contracts may be renegotiated or replaced through competitive bidding or RFPs.

In the past, the gas supply contracts required to fill open firm transportation capacity typically had one, three, or five-year terms. The Companies' purchasing strategy has changed in recent years. Upstream supplies have generally been limited to one year or less, whereas for Delivered Services or peaking supplies, the Company will look to procure up to three years or more based on availability. The Companies have entered multi-year upstream supply purchase deals for a small portion of their supply in order to capture some of the current market differentials and will continue to do so when market conditions support it. The Companies re-evaluate their purchasing strategy and make changes as circumstances dictate. Exhibit___(GIOSP-3), Schedule 1, lists all gas supply contracts effective winter 2021/22.

B. Price Volatility Reduction

Q. What efforts have the Companies undertaken to reduce the volatility of delivered services?

A. To address the price volatility risk, the Companies have begun diversifying the type of Delivered Services procured by adding base delivered services to the portfolio. These products are priced at a fixed basis for the term plus the NYMEX settle for the month and are intended to reduce the impact of citygate commodity-priced peaking supplies on the total portfolio during periods of high volatility. On

October 22, 2018, the Commission approved the Company's request to include the costs of the new base delivered services as part of its DDS program (Case 18-G-0393).

Q. Please describe the procurement strategies the Companies employ in the wholesale market to minimize gas costs.

A. The Companies use many procurement strategies to minimize gas costs. For procurement of supply in liquid markets, such as production area receipt points, we use a competitive bidding process through Requests for Proposals ("RFPs") and by participating in on-line reverse auctions. In illiquid markets, such as Delivered Services procured at certain of our service area citygates, the Companies will at times engage in direct negotiation with the third parties capable of meeting the supply requirement.

Q. Please describe the Companies' gas hedging program.

A. The Companies' hedging program is designed to reduce gas price volatility. One of the hedging program's components is the Monthly Plan, which dictates the use of various financial instruments to hedge natural gas prices for part of the gas supply necessary to meet the monthly requirements of firm sales customers. The program provides for the Companies to hedge a predetermined quantity of their forecasted sales using financial price hedges for the winter period.

Q. Are there other efforts to reduce costs?

A. Yes. The dynamic nature of the wholesale gas market, since the advent of shale-based production, has created new opportunities for the Companies to purchase more economic natural gas at alternative receipt points along the path of its interstate pipeline capacity. As new production and upstream pipeline capacity go into service the Companies are frequently assessing and modifying their purchasing strategy for the resulting changes in pricing dynamics. In addition, the Companies seek to optimize their joint portfolio primarily through capacity releases, AMAs, and off-system bundled sales.

Q. Please provide an illustration of the historical benefits from the Companies' portfolio optimization efforts.

A. Exhibit___(GIOSP-3), Schedule 6, Non-Traditional Revenues, illustrates annual benefits received over the past five years from the Companies' portfolio optimization efforts to minimize overall costs to their firm gas customers.

Q. How are portfolio optimization benefits derived?

A. The expected benefits are derived when available capacity, not used to serve the Companies' customer requirements or balancing needs, is offered to the market through capacity releases, off-system sales, or AMAs that together are referred to as "discretionary capacity releases."

Q. What changes do you see for revenue from discretionary capacity releases?

A. We expect the revenue from discretionary capacity releases to decrease. First, because more existing capacity will be needed to serve firm customers more often, projected near term load growth, and therefore will be unavailable for release during times of higher market value. Second, the market value of some capacity has decreased because of recent pipeline buildouts from the Marcellus region (*e.g.*, Atlantic Sunrise, Rover) that have increased the capacity price in that region. This price increase decreases pricing differentials with other regions and decreases the value of released capacity.

C. Marginal Cost Study

Q. Please address the marginal cost study with respect to gas supply costs.

A. Supply-side marginal costs are the costs of procuring and transporting an additional unit of gas to the Companies' distribution systems. Fixed costs of existing resources are not considered because they do not vary with additional usage and because the Companies cannot avoid paying them. The marginal costs projected for the 2022-2025 period average $4.06/dt for the year, $6.95/dt for the winter period and $13.46/dt for a peak day.

Q. Please define the marginal commodity cost.

A. Marginal commodity cost is the cost of an incremental purchase of gas required to meet system demand that exceeds committed supply sources and planned supply additions.

Q. Please explain the development of the marginal commodity cost.

A. Exhibit___(GIOSP-3), Schedule 8, Summer Season Supply/Demand Balance and Schedule 9, Winter Season Supply/Demand Balance, compare the Companies' firm transportation and supply capability to serve gas demand for firm sales customers on a summer season and for a normal winter season. Exhibit___(GIOSP-3), Schedule 10, Peak Day Supply/Demand Balance compares the Companies' firm transportation and supply capability to serve all firm customers on a peak-day. The Companies' firm transportation and supply capability includes all firm transportation deliverability and accompanying purchased firm supplies. As shown by these Schedules, the highest cost of supply was assumed for purposes of the marginal cost study, combined with the projected firm demand, are less than the Supply Capability of the Companies except on a design day. The need to add capacity to serve firm customer requirements is driven by the Companies' requirements on a design day. As such the marginal cost for commodity on a design day reflects the purchase of gas through a peaking contract at a Con Edison citygate. The Companies often secure peaking supplies to supplement baseload, storage and other supplies to meet our peak demand on a design day.

Q. Please explain the calculation of the marginal commodity cost.

A. The marginal commodity cost is measured by using an optimization model to dispatch load profiles under normal and design weather and taking the resulting highest cost of supply.

Q. What is the forecast period used in your marginal cost study?

A. The forecast period for the marginal cost study is the three-year period from November 2022 through October 2025. Exhibit___(GIOSP-3), Schedule 11, Natural Gas Monthly Marginal Commodity Costs, displays the monthly forecasted marginal commodity costs for the three years of the study. Exhibit___(GIOSP-3), Schedule 12, Marginal Commodity Costs, summarizes these costs to show the impact of the incremental increase on an average annual, summer season, winter season, and design day basis.

D. Capital and O&M Investments

Q. Are there presently Gas Supply IT systems requiring capital enhancements?

A. Yes, there are presently two systems that require enhancements. The first is for the Transportation Customer Information System ("TCIS") with a capital cost of $1.08 million over the rate period; the white paper is called "Utilizing AMI Data for Interruptible Gas Marketer Forecasting and Retail Choice Information System ("RCIS") Migration." The second project is for the Gas Transaction System ("GTS") with a capital cost of $1.9 million in 2025 and is called "FIS GTS Enhancements and Upgrade." The white papers for these two projects are included in the exhibits of the Company's IT Panel.

Q. Starting with the first System Enhancement, Utilizing AMI Data for Firm and Interruptible Gas Marketer Forecasting and RCIS Migration, please describe the project's purpose.

A. TCIS is a software used by marketers to communicate gas operational information to Con Edison. TCIS has many functions, including the ability to communicate gas scheduling information, control access security, generate reports, post messages to the internet, store rates, create invoices and vouchers, and track enrollments/de-enrollments. In 2021, Con Edison enhanced TCIS to include the implementation of capacity release, implementation of rebill adjustments, and include a display of AMI meter reading data. The project proposed in this rate filing will expand TCIS' capability to leverage AMI data for forecasting as well as enable the Company to migrate current functionality from RCIS to TCIS. Currently, the system uses monthly data to create a linear forecasting equation that intakes forecasted temperature to determine the projected usage of firm transportation customers. AMI data will allow the Company to use daily information for daily forecasts, thus improving the accuracy of its forecasts. The movement of marketer related functionality from RCIS to TCIS will allow for the retirement of RCIS and combine all marketer related functionality into one system.

Q. Please describe the purpose of the second project, FIS GTS Enhancements and Upgrade.

A. GTS acts as the operational and accounting system of record, used by commodity operations to record and schedule deliveries of natural gas purchases to the Companies' service territory. In addition, it identifies, assembles, analyzes and reports the organization's transactions for accrual purposes, accounts for the related assets and liabilities and allocates the various costs of natural gas purchases to the various end uses. This purpose of this project is to upgrade the FIS GTS application to is latest version, modernize the system application to the cloud, and automate select processes, notifications, and business activities.

Q. Are there projected additional O&M expenses associated with these projects?

A. Yes, there are. The additional O&M expense is $690,000 over the rate period.

Q. What are the drivers for the projected increases in O&M?

A. The O&M expenses are associated with maintaining and supporting the TCIS system on a real-time basis. TCIS is a system used for daily operations, specifically to calculate the daily gas delivery requirements of the more than eighty gas marketers serving firm and interruptible customers in our service territory. TCIS also acts as the electronic bulletin board for accepting gas schedules from the gas marketers in accordance with both day ahead and intra-day scheduling deadlines. Those schedules are then sent through systems to Gas Control every fifteen minutes. These deliveries represent 50% of all nominations for firm gas customers on our system. This information is critical to Gas Control’s confirming of gas supplies at the various pipeline citygates in order to maintain system reliability. This system is currently being supported by the capital team working on the current TCIS upgrades. However, the complexity of this in-house developed product combined with a recent uptick in system performance issues are driving the need for more internal IT support to supplement those of the third-party vendor. Due to the operational nature of the system, system performance issues are urgent and need to be resolved quickly, which is why the Company uses the capital team to resolve these issues. The O&M request is to provide funding to internally support TCIS starting in late 2023, after the proposed capital project ends.

Q. Was the document titled "CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. – GIOSP Gas Distribution Peak Forecasting Model O&M" prepared under this Panel's direction and supervision?

A. Yes, it was. This is the document which has been identified as Exhibit ___ (GIOSP-4).

Q. Please describe this exhibit.

A. This exhibit outlines the O&M program change called Gas Distribution Peak Forecasting Model.

Q. Please briefly describe its benefits and justification.

A. Given the Company's commitment to a clean energy future and the interests of its stakeholders, optimization and accurate planning for the gas distribution system is necessary. The effectiveness of the Company's plans for its gas distribution system has a direct impact on its gas customers. If the gas distribution system is not planned for properly, there is the risk of shedding gas load in certain areas. Identifying distinct areas of load growth will assist with pinpointing non-pipe solutions instead of the need for system reinforcements. Current gas policy is moving towards less development of gas supply. As such, the margins on the system will become tighter thus prompting the need for a more granular and longer term forecasting model for the distribution system.

The Company is seeking to develop a firm gas distribution forecasting model that predicts firm gas peak day demand at design weather conditions. This new model will predict the peak-day and peak-hour firm gas demand for newly established districts within the gas distribution system in the Company's gas service territory out 20-years, which will be developed by an expert forecasting vendor and the Company's forecast development team. The Company's forecast development team will be comprised of subject matter experts from Gas & Steam Forecasting, Policy Integration Forecasting, Forecasting Services, Gas Engineering, and Gas Control – all working incrementally on this effort.

The total cost of this project is projected to be $2.05 million, which will result in:

- The development of an Excel based firm gas distribution peak day forecasting model.
- A proven methodology and algorithms for transposing the firm gas transmission system and regulator peak day forecasts to distribution level district forecasts.
- Mapping or the gas service territory to distribution districts.

Accordingly, the cost request here is for forecast vendor professional services and incremental Company labor costs. The nature of this work is considered O&M and three additional Full Time Equivalents(“FTE”) are required for Rate Year 1. In Rate Years 2 and 3, ongoing operations, maintenance, and calibration of the model/methodology/mapping will occur to sustain accuracy, totaling $190,000 per year for 1 FTE and associated overheads for the Gas & Steam Forecasting Section.
As such, projected incremental O&M costs total $1.67 million in Rate Year 1 (2023), $0.19 million in Rate Year 2 (2024) and $0.19 million in Rate Year 3 (2025). Please note that the total of these values is about $1 million less than what is included in the associated program change form and will be revised on update. The Company expects the

completion of the forecast tool to occur early in RY2.

E. Lost and Unaccounted for Gas

Q. Please explain the current methodology for calculating lost and unaccounted for ("LAUF") gas.

A. In accordance with the current Gas Rate Plan, the Company uses a throughput method that calculates unaccounted for gas by subtracting metered deliveries to customers from metered supplies to the system. An adjustment is made for Generators who contribute 0.5% of their metered deliveries to the unaccounted for gas as well as the Delivering Party to the Receiving Party among the New York Facilities companies. Beginning September 2020 and going forward, gas loss due to inactive accounts are no longer part of the net gas loss calculation. The remaining LAUF gas is compared against a rolling five-year average. The calculation of the current average is shown on Exhibit___(GIOSP-3), Schedule 13.

Q. Are you proposing any changes to Con Edison's LAUF calculations for the period commencing January 1, 2023?

A. No.

F. Renewable Natural Gas and Retail Access

Q. Is RNG currently included in the retail access program?

A. Yes. In the event the Company purchases RNG on behalf of customers, Retail Access customers would receive a portion through Tier 3.

Q. Are you proposing any changes to RNG and the Retail Access program?

A. Yes. The Company is looking to incorporate the option for Retail Access marketers to directly procure RNG injected directly into our distribution system themselves. This would not change any current allocations for baseload or any of the tiers. Deliveries from RNG would be included in the marketers' daily delivery requirement and those volumes would be subject to the same imbalance and cashout procedures as all other volumes delivered to Con Edison.

Q. Why are allocations for baseload or any of the tiers not being changed if a Retail Access marketer subscribes to RNG?

A. The Company is responsible for ensuring sufficient capacity for all firm customers. The Company will continue to procure sufficient capacity for all firm customers to ensure that in the event a marketer turns its customers back to the Company, there will be adequate capacity to account for their peak day usage. If the Company were to reduce the amount of capacity procured by the annual amount of RNG, it may be unable to provide service down to the peak day in the event that customers return to the utility from a marketer.

G. Certified Natural Gas

Q. Is the Company proposing any procurement of certified natural gas?

A. Yes. The Company is proposing a pilot program designed to allow for the procurement of certified gas, during the rate period, limited to an annual cost above traditional supplies of $800,000 per year.

Q. What is certified natural gas?

A. Certified natural gas is natural gas originating from producing sites that have undergone third-party certification to verify that the operator has met high environmental standards and best practices for methane emissions reduction in their operations.

Q. Does the procurement of certified gas align with the goals of CLCPA?

A. Yes, per CLCPA, the 1990 net emissions baseline includes not only all statewide sources of greenhouse gas emissions but also those associated with imported electricity and fossil fuels.

Q. Why is the Company proposing a pilot program only?

A. The Company is proposing a pilot program given the market for certified natural gas is still evolving and many certification processes exist, rather than an industry standard. The experience from the pilot coupled with the reporting requirements of the pilot will allow the program to be ramped up or down as appropriate.

Q. What reporting requirements is the Company proposing as part of the pilot?

A. The Company will file an annual report each May, describing progress of the pilot to date and meet with DPS Staff each June to review the report and recommend next steps, which could include filing with the Commission for modification of the program.

H. Gas Supply Constraints and Temporary Moratorium

Q. Are there any updates to the status of the moratorium?

A. Yes, existing gas supply constraints in this part of our service territory still limit our ability to meet customer demand there.

Q. Is there an expectation of when the temporary moratorium will be lifted?

A. The temporary moratorium is expected to be lifted when the Company's subscribed Tennessee compression-only project is in service. The Company contracted with Tennessee Gas Pipeline to increase firm transportation capacity to our Westchester citygates utilizing increases in compression only. Tennessee has applied for permits for this project and those requests are currently pending before the Federal Energy Regulatory Commission and various state agencies.

While Tennessee continues to work toward an in-service date of November 1, 2022, the Companies are planning for an estimated in-service date of November 1, 2023.

Q. Are there other considerations that would allow the temporary moratorium to be lifted?

A. Yes, if the demand in the area decreases to a level where gas supply constraints no longer exist, but our current forecast does not show demand decreasing to that degree.

Q. What changes has the Company undertaken to its supply portfolio while the moratorium remains in effect?

A. In order to meet the increase in demand associated with the acceleration of customer applications received in the sixty days between moratorium announcement and implementation, the Company entered into an agreement with a trucked CNG vendor. As a result, a trucked CNG facility capable of providing 25,000 dt per day of supply is now in-service in Westchester County. This facility is temporary and will be retired once the Tennessee Pipeline project enters service or demand is reduced such that the CNG facility is no longer necessary and the moratorium is lifted.

Q. Has the Company provided any assistance to customers during the moratorium?

A. Yes. The Company provides information on non-fossil alternatives and has worked with potential customers prior to the purchase or lease of a property to find alternative solutions that will meet their energy needs.

I. Regulatory Activities

Q. Do the Companies undertake any regulatory efforts to maintain the reasonableness of their gas costs and the reliability of their supply?

A. Yes. The Companies participate in FERC proceedings involving: (i) their interstate pipeline transportation and storage providers ("service providers") and (ii) generic issues that impact the cost and quality of the gas service received by the Companies from FERC-regulated entities. The Companies review all significant FERC filings made by the interstate pipelines and storage companies from which they receive service. Since January 2017, the Companies have participated in numerous FERC proceedings and, when circumstances dictate, have filed detailed comments or objections. Exhibit___(GIOSP-3), Schedule 7, lists the FERC dockets in which Con Edison has filed detailed comments since January 2017.

The Companies are also active participants in the AGA FERC Regulatory Committee, which takes an active role in a range of federal regulatory issues relating to gas. The Companies closely follow FERC proceedings that impact rates and terms and conditions of service of their interstate pipeline service providers and actively participate in litigation as well as settlement negotiations. In addition to the FERC proceedings listed in Exhibit___(GIOSP-3) Schedule 7, the Company is participating in several federal appellate court cases where we advocate in favor of reasonable prices and adequate supply for our customers. The Companies have also actively participated in the FERC’s inquiries into gas-electric coordination and, more recently, impacts to pipeline rates due to the Tax Cuts and Jobs Act. The Companies are also actively engaged on several pipeline rate cases, both ongoing and expected, to negotiate reasonable rates for our customers. When appropriate, the Companies also participate in collaborative discussions among pipelines and their customers, the North American Energy Standards Board (“NAESB”) and the Natural Gas Council (“NGC”), either directly or through their membership in the AGA.GSP-

Q. Please provide examples of the Companies’ active participation in the rate proceedings of their interstate pipeline suppliers.

A. As examples, the Companies participated and are actively participating in rate settlements with Texas Eastern (RP21-1001 and RP21-1188), Eastern Gas (RP21-144 and RP21-1187), National Fuel (RP19-1426) and Transcontinental Gas

Pipeline's ongoing market-based rate proceeding (RP21-1143). The Companies are actively participating in Texas Eastern's (RP21-1001 and RP21-1188), Eastern Gas' (RP21-1187), and Transcontinental Gas Pipeline's (RP21-1143) ongoing FERC proceedings with LDC customer groups and is leading the LDC customer groups in Texas Eastern's and Transcontinental Gas Pipeline's proceedings, the Texas Eastern Customer Group and the WSS Customer Group, respectively.

Other FERC proceedings the Companies are following relate to interstate pipeline cost allocation issues involving, for example, fuel retention and electric power compression charges. In a recent case, the Companies negotiated a favorable settlement agreement related to Algonquin's fuel rates (RP18-75), protecting a substantial one-time refund and preventing unreasonable cost shifting to our customers. In 2016 and 2017, the Companies were involved in settlement discussions regarding costs Texas Eastern had incurred and will incur as a result of its PCB Environmental Remediation Program. The Companies were participants in a shipper group that successfully negotiated a settlement agreement with Texas Eastern, and this agreement was ultimately approved by FERC in Docket Nos. 17-964 and 17-967.

The Companies also closely monitor proposed tariff changes by service providers that modify their terms and conditions of service, including matters related to rights of first refusal, gas quality, lost and unaccounted for gas, bidding rules, shipping priority, service provider credit policies, and tariff and negotiated agreement filings that could affect the quality of pipeline service to the Companies. The Companies also closely monitor new incremental services being offered by the Companies' current service providers so that the rates of those new incremental services are not subsidized by existing customers, such as the Companies. For example, in 2017, the Companies protested two National Fuel proceedings that would have resulted in the subsidization of fuel costs for the new Northern Access 2015 ("NA2015") expansion by system shippers, including the Companies. FERC ultimately sided with the Companies and required separate accounting for NA2015 fuel costs in Docket Nos. CP14-100 and RP17-407.

Q. What other regulatory efforts have the Companies taken to maintain the reliability of their supply?

A. The Companies have focused on preventing increasing electric system reliance on natural gas as a fuel from adversely affecting gas system reliability. In particular, the Companies advocated vigorously for the NYISO to prohibit electric generators from recovering penalties they incur as a result of violating Operational Flow Orders. Related rules changes were approved by the NYISO's stakeholder committees and FERC in 2016. In addition, the Companies continue to advocate for coordination of electric and gas system reliability and resilience through market rule changes, such as expanding dual-fuel requirements in New York State to outside of our service territory. The Companies are currently working closely with the NYISO on a Fuel Security Study, which, among other things, will identify possible system needs to be addressed.

Q. Are the Companies a member of any groups addressing gas reliability issues in New York State?

A. Yes. The Companies have been an active participant in the Natural Gas Reliability Advisory Group ("NGRAG") from its initiation. The NGRAG was formed to consider the evolving gas capacity markets and how they affect reliability, and to inform the Commission about issues that need to be addressed to protect reliability. The NGRAG has focused discussion on the NYISO gas/electric workgroup to address gas supply and transportation issues, updates of an ongoing LDC collaborative addressing Gas Marketer Transportation and Balancing Programs, and operational updates provided by gas industry LDCs, pipelines, marketers, customer groups, NYSERDA and NYMEX representatives.

Q. Please describe the Companies' efforts in connection with NAESB.

A. We have been a member of NAESB and its predecessor organization, the Gas Industry Standards Board ("GISB"), since the latter's inception in 1994. The Companies continue to monitor the development of new business standards and, as appropriate, participate in periodic revisions to the NAESB Base Contract, a form agreement frequently used in the industry for the purchase and sale of natural gas.

Q. Please describe the Companies' efforts in connection with the NGA.

A. The Companies participate on NGA's New York State Gas Utility Planning Committee ("NYPLAN"). NYPLAN is comprised of planning, supply, and regulatory personnel from New York's investor-owned natural gas utilities. Its mission is to provide a forum for New York State gas companies to address the broad spectrum of issues relating to the natural gas supply, transportation, storage, peak shaving, and demand planning process. This includes, but is not limited to, such responsibilities as responding to regulatory mandates, discussion/follow-up on key regulatory/ legislative issues, and working in collaboration with NYSEARCH, a collaborative Research, Development & Demonstration organization that serves its gas utility member companies, on R&D projects.

The Companies are members of the NGA Gas Supply Task Force ("Task Force"). The Task Force includes representation from all the interstate transmission companies serving the region, LNG importers and trucking companies, and the largest of the northeast region's LDCs. Recent members include several of the larger power generation owners who use natural gas as a major part of their fuel supply. The Task Force meets prior to the winter heating season to confirm communication protocols and to provide updates on the status of member company transmission and storage systems. The Task Force is convened during the winter to monitor supply and deliverability issues. The region's state regulators and the electric grid operators are notified of Task Force meetings and are provided meeting summaries.

Q. Does this conclude your direct testimony?

A. Yes, it does.