CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

DIRECT TESTIMONY – ACCOUNTING PANEL

TABLE OF CONTENTS

Page

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.

---

[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,

[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.

---

[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

DEMAND ANALYSIS AND COST OF SERVICE PANEL

Table of Contents

I. INTRODUCTION

Q. Would the members of the Demand Analysis and Cost of Service Panel (the "Panel") please state their names and business address?

A. William Atzl, Yan Flishenbaum, and Christine Kim, 4 Irving Place, New York, New York 10003.

Q. By whom are you employed, in what capacity, and what are your professional backgrounds and qualifications?

A. **(Atzl)** We are employees of Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company"). I am Director of the Rate Engineering Department. My background is as follows: 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 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 job was with 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. ("O&R") as a Commercial and Industrial Representative in the Commercial Operations Department. At O&R, 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. I have testified in numerous regulatory proceedings before the New York State Public Service Commission ("Commission"), New Jersey Board of Public Utilities and Pennsylvania Public Utility Commission.

(Flishenbaum) I am a Department Manager in the Rate Engineering Department. 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 was promoted to my current position in 2016. I previously testified before this Commission.

(Kim) I am the Section Manager of the Load Research section in the Rate Engineering Department. In that capacity, I am responsible for preparing demand analyses related to electric service. Additionally, I have a variety of duties related to load research sample design and data analysis. I began my employment with Con Edison in 2010 as a Senior Energy Analyst in Forecasting Services. In 2013 I moved into Load Research as a Senior Rate Analyst and in 2018 was promoted to Section Manager. I received a Bachelor of Arts degree in Economics from New York University in 2007, and a Master of Science degree in Quantitative Methods and Modeling from Baruch College in 2012. Prior to working for Con Edison, I worked as an analyst for MCEnergy Inc., an energy consulting company providing consulting services and brokering energy deals for various REITS (Real Estate Investment Trusts) throughout the country. I have been in my current position since November 2018 and have previously testified before this Commission.

II. PURPOSE OF TESTIMONY

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

A. Our testimony:

(1) presents the Company’s Class Demand Study;

(2) presents the Company’s Electric Embedded Cost-of-Service (“ECOS”) study;

(3) presents the Company’s Seasonal Rate Study;

(4) presents the Company’s NYPA Rate Classes ECOS study; and

(5) describes and requests capital funds for a computer system enhancement program associated with performing bill analyses on certain off-system data, including enhancements to reflect changes to billing and data requirements and data handling.

Our testimony also addresses marginal costs.

III. CLASS DEMAND STUDY

Q. Have you prepared an exhibit showing the Class Demand Study?

A. Yes. Exhibit ___ (DAC-1) is entitled "Consolidated Edison Company of New York, Inc., Class Demand Study – Electric Department, Year 2019." It includes four pages of descriptive text, a two-page index, and over 150 pages of tabular reports.

Q. Please describe the purpose of the Class Demand Study.

A. The Class Demand Study presents energy and demand cost responsibility measures for each Company service class and for NYPA delivery service customers. These cost responsibility measures, in turn, were used in the ECOS Study presented in this proceeding.

Q. Please describe the cost responsibility measures developed in the Class Demand Study.

A. There are two general types of cost responsibility measures used in the ECOS study - energy cost responsibility measures and demand cost responsibility measures. Energy cost responsibility measures reflect total kilowatt-hours that customers use over the entire year. Demand cost responsibility measures reflect customer demands during peak periods and are divided into two categories. The first is system peak responsibility, which reflects customer demands at the time of the Con Edison system peak. The second is class non-coincident peak responsibility, which reflects customer demands at the times of individual class peaks. The Class Demand Study develops a set of demand and energy cost responsibility measures for various delivery systems. We describe these delivery systems later in our testimony.

Q. What period does your study cover?

A. It covers calendar year 2019 and includes specific analyses of the summer and winter peak periods for that year.

Q. Please explain the general organization of Exhibit ___ (DAC-1), Schedule 1.

A. The title page is followed by four pages of explanatory notes and an index for the study's tabular data. Tabular Reports 2 through 4 show step-by-step development of demand and energy cost responsibility measures for each service class. Tabular Reports 5 through 8 summarize results of the detailed class-by-class analyses contained in Reports 2 through 4.

Q. Please summarize the demand and energy cost responsibility measures developed in the Class Demand Study and indicate where these data are found.

A. The following table shows this information:

Cost Responsibility Measure	Report Number
Energy Responsibility	5
Class Summer and Winter System Peak Demand Responsibility	6
Class Summer and Winter Non-Coin. Demand Resp. by Delivery System	8

Q. Please describe the explanatory notes that detail the method used in developing Exhibit ___ (DAC-1), Schedule 1.

A. The text briefly explains the procedures used to develop the class energy and demand responsibility estimates shown in the Exhibit. It includes a short discussion of Con Edison's customer load testing program, which is the starting point for many of the calculations in the Exhibit. Finally, it provides a brief description of each report in the Exhibit.

Q. Please explain the analyses shown in Reports 2 through 4.

A. These reports show the step-by-step development of demand cost responsibilities for each service class. Data are first organized by energy or demand strata. The strata data are then added to develop subclass data, and the subclass data are further aggregated into class data. Report 2 shows the starting data utilized in developing the class demand responsibilities and shows the results of our test customer sites by class and stratum. While this sample was formerly comprised of either load research test sample customers or profile data for time-of-day (TOD) customers, the sample is now sourced from the pool of new AMI interval meter installations approved in Case 15-E-0050.

Report 3 shows a summary of class population data by stratum for each service class.

Finally, Report 4 shows the resulting class demand responsibilities by stratum for each service class.

Reports 2, 3, and 4 are provided by class for both the summer and winter peak periods.

Q. Please continue with your explanation of the remaining reports in this Exhibit.

A. Report 5 shows electrical energy flows for the Con Edison System for the year 2019. This report forms the basis for energy cost responsibility measures, and develops the annual energy flow, in kilowatt-hours, through the various paths of the electrical T&D system, starting at the system input level and continuing to the customers' meters. It considers cable and equipment losses and unaccounted-for-energy. The report shows total kilowatt-hours registered at the customers' meters, total kilowatt-hours at the system input level, sales to other utilities, and kilowatt-hours delivered to the local distribution system.

Q. Please continue with your explanation of Report 5.

A. Report 5 also shows the kilowatt-hours distributed and sold, the distribution efficiency for each delivery system, and the resultant annual energy distribution efficiency for each customer class. This efficiency calculation reflects the various paths that energy takes from delivery system input to customers.

Q. Please explain what you mean by "delivery system."

A. Power generally flows from generation sources to customer loads through an electrical grid composed of high voltage transmission lines and substations, and lower voltage distribution lines and substations. For purposes of the Class Demand Study, the grid is subdivided into separate serially-connected systems, which are called delivery systems.

Q. Please continue with your explanation of the reports shown in Exhibit ___ (DAC-1), Schedule 1.

A. Report 6 provides a summary of the class demand responsibilities for each season, obtained from the individual pages of Report 4. Report 6A develops the low tension non-coincident billing kilowatts based on the low tension kilowatt-hours shown in Report 5.

Report 7 is similar to Report 5, except that it shows in greater detail the kilowatt-hour flow, by class, from the system input level through the various delivery systems, to the customers' meters.

Report 8 traces the class non-coincident summer and winter peak demands through the various levels of the delivery system, starting at the customers' meters and terminating at the system input level.

Q. As a typical example of the calculation procedure used for each class in this exhibit, please describe the method employed in developing the summer and winter class demand responsibility estimates for Service Classification (“SC“) 1, the Residential and Religious class.

A. Referring first to Report 2 (summer page 1, winter page 1), the data in Columns 3 through 9 were developed from load tests that the Company performed on sample residential and religious test customers. Column 2 lists the sample test strata. Columns 3 and 4 show the range of consumption or demand for the customers in each test stratum. Column 5 shows the number of customers in each stratum for which test results were obtained. Column 6 shows the calculated average consumption or demand per customer for each test stratum. Columns 7 and 8 show the load test results reduced to average kilowatts per customer for each test stratum. Column 7 lists the summer (average of July and August) and winter (average of January and February) maximum demands per customer. Column 8 lists the maximum coincident demand per customer for each test stratum, based on averages for five selected system peak days for the summer or five selected system peak days for the winter during the test period. Column 9, derived from

Columns 7 and 8, shows the calculated coincidence factor for each test stratum.

Q. Please describe the derivation of the coincidence factors.

A. The coincidence factors are derived from interval-metered data collected for the load test customers. For each stratum of test customers, the recorded half-hourly demand data obtained from each test location were averaged for the five seasonal system peak days. For this study, the coincidence factor is defined as the ratio of the per-customer maximum coincident half-hour demand of a stratum of test customers, averaged for five days, to the per-customer individual maximum non-coincident half-hour demands of the test customers in that stratum.

Q. Please continue your explanation of the SC 1 reports.

A. Turning to Report 3, the stratum definitions are shown in columns 3 and 4. The stratum level customer count and kilowatt-hours for the residential class shown in columns 5 and 6 were derived from billing records for the year 2019. Column 7 contains the average usage by stratum based on columns 5 and 6. The summer and winter coincident maximum half-hour demands for each stratum in the class population were then calculated using the respective sample test stratum load characteristics. These results appear in Column 11, and the computations are described in footnotes.

Q. Please continue.

A. Since each stratum's maximum half-hour demand (shown in Column 11) occurs at different times, complete daily profile curves were computed for each stratum in the class, again based on test results. The summation of all 24-hour stratum load curves at the customers' meters produced composite summer and winter load curves for the entire class. The summer and winter coincident half-hour demands for each stratum shown in Column 5 of Report 4 were obtained by examining the stratum load curves at the time of the class peak. The summer and winter class load curves were further examined to determine the average class demands for the highest continuous four-hour period. Those results are shown in Column 6 of Report 4.

The demands described so far have all been based on measurements and calculations at the customers' meters. To determine the system input level class responsibility shown in Column 8, the class demand at the customers' meters was divided by the annual distribution efficiency for the class. The class distribution efficiencies are shown on Report 5 of this exhibit. After applying class distribution efficiencies, the calculated grand total of all the class load curves, developed through the procedures described thus far, closely approximates but does not exactly match the known total system load curve at each half-hour. The total discrepancy during the high load periods of the day is generally found to be a few percent during any half-hour. For sampled classes, a percentage adjustment factor for every half-hour was applied to each of the class demands. For those classes with sampled test data that were borrowed, an adjustment factor equal to two times the above-mentioned adjustment factor was applied. Classes that are 100% profile-metered did not receive any adjustment. After adjusting the class data, the total of all class profiles exactly matched the total system load curve. The demand values in Columns 7, 9, and 10 of Report 4 are the adjusted class demands. These values are the average demands obtained from class load profiles for the four peak hours of the seasonal system peak load shape or the class peak load shape.

Q. Please continue with the explanation of the development of the demands for SC 1.

A. Report 6 (starting at Page 6-1), Columns 5, 6, 7, and 8, summarizes the class seasonal demand responsibilities developed in Report 4. Report 6A (starting at Page 6A-1), Column 7, develops the low tension non-coincident billing kilowatts, using the total non-coincident billing kilowatts in Report 3 and the relationship of low tension kilowatt-hours to total kilowatt-hours found in Report 5.

Report 7 (starting at page 7-1) provides a more detailed analysis of the kilowatt-hour flow for each class through each of the delivery systems listed in Column 3. Column 4, which comes directly from Report 5, Column 4, shows total kilowatt-hours (high tension plus low tension service) delivered to customers' meters. Column 5 of Report 7 shows only low tension kilowatt-hours delivered to the customers' meters. Column 6 shows kilowatt-hour input to the secondary (line) transformers, and Column 7 shows kilowatt-hours distributed at the system input level. Kilowatt-hours shown in Columns 6 and 7 are calculated using the electrical path efficiencies shown in Report 5.

Report 8 (starting at Page 8-1) traces the four-hour class non-coincident peak, obtained from Column 7 of Report 4, through each of the delivery systems shown in Columns 5 through 7. Report 8 utilizes the energy flows shown in Report 7 and assumes that the energy delivered through each component of the system has a load factor identical to that of the entire class.

Q. Do the computations and analyses, which you have just described for SC 1, apply to the other classes shown in this exhibit?

A. Yes. With a few exceptions, which we will describe, the analyses for the remaining classes are similar to those for SC 1.

Q. Please describe the exceptions to which you referred.

A. For street lighting and traffic signals load shape estimation, lamp wattages in service and lamp burning hours (with an allowance made for lamp outages) were used to arrive at the estimated class demand responsibilities.

IV. ECOS STUDY

Q. Did you prepare an exhibit showing the ECOS study and unbundled cost components analysis?

A. Yes, Exhibit ___ (DAC-2) is entitled "Consolidated Edison Company of New York, Inc. – Embedded Cost of Service – Electric Department - Year 2019 Rates in Effect January 1, 2022."

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

A. The ECOS study and unbundled cost components exhibit consists of three schedules. Schedule 1 shows the results of the study. Schedule 2 shows the Merchant Function Charge ("MFC") calculations. Schedule 3 shows the unbundled costs for printing and mailing a bill and receipts processing functions.

Q. Please continue.

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

Q. What cost categories are analyzed in this ECOS study?

A. The ECOS study analyzes costs and revenues associated with the Company's delivery system (i.e., transmission and distribution), and customer-related cost categories or functions, and also includes cost categories related to the electric merchant function, the receipts processing function and the printing and mailing a bill function. The major supply function costs, *i.e.*, purchased power and generation costs, are not included in the ECOS study. Also, revenues and expenses associated with the uncollectible component of the MFC and the System Benefits Charge ("SBC") have been excluded from the study.

Q. What time period does the ECOS study cover?

A. The study covers Con Edison's electric 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 the abnormal disruptions to customer behavior due to the COVID-19 pandemic that occurred. 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 subway service, and entertainment and sports venues. We note here that, as described in the testimony of the Electric

Forecasting Panel, the expectation is that New York City will have generally returned to its pre-pandemic normal in 2023.

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

A. Electric revenues reflect 2019 customer usage priced at delivery rates which went into effect January 1, 2022.

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

A. The study analyzes classes of customers corresponding to SCs contained in our electric rate schedules, including retail access customers and customers of NYPA served by Con Edison under the P.S.C. No. 12 - Electricity schedule.

Q. Did the Panel make any methodological changes to the ECOS Study since the Company’s last filing?

A. Yes. The Joint Proposal adopted by the Commission in Cases 19-E-0065 provided for the elimination of competitive metering charges consisting of meter data service provider, meter service provider and meter ownership charges. Corresponding functions have been eliminated from this ECOS study.

Q. Please continue with a description of the ECOS study and explain how the results of the ECOS study are expressed.

A. The results of the ECOS study are expressed as Total Company (“total system”) and 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 11.81% as shown on Table 1, Page 1, Column (1), Line 17 of the ECOS study. In addition, Table 1 shows rates of return for all classes analyzed in the ECOS study. For example, the SC 1 return is 11.39%, the SC 9-General Large-Non-Time-of-Day (“NTD”) return is 12.10% and the NYPA return is 10.06%.

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 11.81%, what are the ECOS study class surpluses and deficiencies?

A. The revenue surpluses are shown on Table 1, Line 26 and the revenue deficiencies are shown on Line 27. For example, the NYPA class has a revenue deficiency of $18,923,396 below the lower level of the tolerance band. The SC 9-General Large-TOD class has a revenue surplus of $23,890,981 above the upper level of the tolerance band.

Q. What is the significance, for example, of the NYPA class deficiency?

A. The deficiency is the amount of revenue increase, at current rates, required to bring NYPA's return to the lower 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 ___ (DAC-2) Schedule 1.

A. Due to the application of a 10% tolerance band around the system rate of return, the total of the ECOS surpluses and deficiencies in this study is a net system surplus. To ensure that ECOS study indications are revenue neutral to the Company, Table 1A adjusts classes with a rate of return below the system average based on their respective non-competitive delivery revenues used in the study to offset the net system surplus.

Q. Were any further adjustments made to Table 1A?

A. Yes, based on review of the ECOS study results, the Panel chose to exclude the SC 13 cost indications from the Table 1A analysis.

Q. Please explain the reasoning behind this decision.

A. SC 13 has only one account, a large residential housing complex that currently operates its own generator. Its use of the Con Edison system is erratic, changing not only from day to day, but from one cost study to another.

Q. Why would you choose to exclude the ECOS Study results for SC 13 from the Table 1A analysis and not do the same for other classes?

A. Recognizing the $1.2 million surplus, which is close to 50% of the SC 13 class revenues, could create tremendous rate instability. To change rates now, knowing that the cost indications could shift significantly in the next study, does not allow for proper cost assignment to a customer whose potential use of the Company's distribution system remains unchanged.

Q. Please continue with your explanation of Table 1A.

A. A check was made to make sure that classes affected by the adjustment described above remained within the tolerance band after reflecting the adjustments shown in Table 1A. The adjusted ECOS study indications are used in revenue allocation as described in the testimony of the Electric Rate Panel.

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 transmission, distribution, customer accounting and customer service with further division into sub-functions, such as distribution demand, distribution customer, and 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 employed in the ECOS study. This level of detail is required to differentiate, for example, demand-related costs from 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, energy-related or customer-related. Demand-related costs are fixed costs created by the loads placed on the various components of the electric system. Energy-related costs are variable costs resulting from the total kilowatt-hours delivered during the year. Customer-related costs are fixed costs that are caused by the presence of customers connected to the system, regardless of the amounts of their demand or energy usage.

Q. Please describe the allocation step in the study.

A. The allocation step allocates the functionalized and classified costs to the customer classes based on the appropriate demand, energy 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 ECOS study followed by seven tables of cost data.

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: merchant function, receipts processing, and printing and mailing a bill.

Q. What costs are included in the merchant function?

A. The merchant function contains costs associated with procuring electric commodity, including an allocation of customer care-related activities, customer service-related activities, and Information Technology.

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 outreach and education costs.

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

A. Pursuant to the Unbundling Policy Statement, customer care and customer service-related costs were allocated to the merchant function on the basis of total revenues (including SBC, MSC, MAC, T&D, NYPA, MFC and BPP revenues).

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

Q. Have you further unbundled the 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 (“C&C-related”) MFC components to recover the costs for these commodity-related competitive services from three categories of customers.

Q. How have you defined these costs?

A. The MFC is made up of two components. The first consists of the costs associated with procuring commodity and an allocation of IT and outreach and education associated with commodity (hereafter referred to as the competitive supply–related MFC component). The second consists of costs associated with credit and collection/theft (hereafter referred to as the competitive credit and collection related MFC component). Only full service customers will pay the competitive supply-related and competitive credit and collection-related MFC components.

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

A. One hundred percent of electric procurement activity costs and 25 percent of credit and collection/theft, IT, and outreach and education costs were allocated on a per kilowatt-hour basis. The remaining 75 percent of credit and collection/theft, IT, and outreach and education 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 electric procurement activity was allocated entirely on a volumetric (i.e., kWh 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, ("April 15 Order"), approving Con Edison's unbundled rates.

Q. Is the allocation of the MFC components to various groups of customers shown in Exhibit ___ (DAC-2)?

A. Yes. Schedule 2 of Exhibit ___ (DAC-2), pages 1 and 2, shows the allocation of the competitive supply-related MFC cost components and the competitive C&C-related MFC cost components to the residential and two non-residential/commercial categories of customers. The Exhibit presents these two components as percentages of total revenues, i.e., the sum of the T&D and competitive revenues (MFC, Metering, BPP and POR Discount Credit and Collection revenues) used in the ECOS study. Separate percentages are shown for the residential and the two non-residential/commercial groups of customers for use in the development of the MFC, as detailed in the testimony of the Electric Rate Panel.

Q. Is the allocation of unbundled costs for the printing and mailing a bill and receipts processing functions shown on Exhibit ___ (DAC-2), Schedule 3?

A. Yes. Schedule 3 of Exhibit ___ (DAC-2), pages 1 and 2, 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 48 cents per bill. The average unit cost for printing and mailing a bill is 73 cents per bill. The costs for these two functions combined yield $1.21 per bill in unbundled costs. The costs associated with billing and payment processing do not vary by service classification and, thus, the system-wide $1.21 per bill in unbundled costs is applicable to all service classifications. The Electric Rate Panel makes a recommendation about how to handle these costs.

V. SEASONAL RATE STUDY

Q. Have you prepared an exhibit showing the Seasonal Rate Study?

A. Yes. Exhibit ___ (DAC-3) is entitled the “Seasonal Rate Study”.

Q. Please provide some background on the Seasonal Rate Study.

A. The Joint Proposal adopted by the Commission in Cases 19-E-0065 and 19-G-0066 required the Company to study the cost basis for seasonal differentials in both the Con Edison and NYPA tariffs. Pursuant to the Joint Proposal, on January 19, 2021 the Company submitted its Seasonal Rate Study based on its 2017 Demand Analysis and ECOS study. On March 3, 2021 the Company held a meeting with interested parties to discuss the methodology used to develop the study and its results.

Q. Please continue.

A. The Seasonal Rate Study being submitted in this proceeding is an update of the Seasonal Rate Study described above. It uses the same methodology and is based on the 2019 Demand Analysis and ECOS study exhibits sponsored by the Panel in this testimony.

The Company’s proposed methodology to study seasonal rate differentials in its tariffs is based on a comparison of seasonal differentials in current rates to those exhibited in the Company’s ECOS study. The class-specific seasonal delivery revenue ratios shown in Exhibit___(DAC-3) reflect the ratio of monthly summer delivery revenue to monthly winter delivery revenue based on 2019 customer usage priced at delivery rates which went into effect January 1, 2022. This is consistent with revenues used to develop the ECOS study.

The class-specific seasonal cost ratios shown on Exhibit ___ (DAC-3) reflect the ratio of monthly summer costs to monthly winter costs based on the 2019 ECOS study and Demand Analysis. These ratios were developed based on classification of demand-related costs into load carrying facilities that were deemed to exhibit seasonal differences; and customer-related costs into non-load carrying facilities that do not exhibit seasonal differences and remain constant throughout the year.

Q. Is the Panel making any recommendations based on the Seasonal Rate Study filed in this case?

A. Yes. The results of the study clearly indicate two outlier service classes where summer/winter ratios currently embedded in rates greatly exceed cost-based summer/winter ratios. Therefore, the Panel recommends that seasonal rate differentials for SC8 TOD and SC9 TOD be adjusted to begin to gradually approach cost-based indications. The testimony of the Electric Rate Panel will describe these adjustments.

VI. NYPA RATE CLASSES ECOS STUDY

Q. Have you prepared an exhibit showing the NYPA Rate Classes ECOS study?

A. Yes. Exhibit ___ (DAC-4) is entitled the "NYPA Rate Classes ECOS study".

Q. Please provide some background on the NYPA Rate Classes ECOS study.

A. The Joint Proposal adopted by the Commission in Cases 19-E-0065 and 19-G-0066 required the Company to expand the 2017 electric ECOS study to provide results for three NYPA classes (Rate I Demand, Rate I Non-demand, and Rate II). Pursuant to the Joint Proposal, on January 19, 2021 the Company submitted the NYPA Rate Classes ECOS study. On March 3, 2021 the

Company held a meeting with interested parties to discuss the study’s results.

Q. Please continue.

A. The NYPA Rate Classes ECOS study being submitted in this proceeding is an update of the study described above, provided for illustrative purposes only. It is based on the 2019 Demand Analysis and ECOS study exhibits sponsored by the Panel in this testimony.

VII. RATE CASE ENHANCEMENTS PROJECT

Q. Please describe the Company's Rate Case Enhancement Project, starting with the Customer Usage System (“CUS”), that is reflected in Exhibit (IT-3) as presented in the testimony of the Information Technology Panel.

A. The purpose of CUS is to centralize and summarize data necessary for Rate Engineering to report on or develop various rate structures. CUS is integral to Rate Engineering’s overall strategic system replacement plan, which includes the replacement, enhancement, and integration of the functionality of four separate obsolete mainframe systems that we use. Over the last few years, as we have completed and tested new components, a need has arisen for additional functional enhancements to support electric and gas demand analysis, rate design, and rate impact activities and to expand functionality to improve efficiency and decrease the need for manual processes.

A number of items are being addressed within the scope of this Rate Case Enhancement project: (1) system requirements associated with anticipated billing changes not included in the original scope (e.g., capacity tag billing, net metering, campus billing, incentive rate designs including considerations regarding state-wide efforts to promote electric vehicles and REV proceeding outcomes); (2) technology and software enhancements including the need for additional fields, derivations, and data mining; (3) further automation related to the creation and storage of load shapes, e.g., Independent System Operator (ISO) market support activities, enhancements to the existing Load Shape Library,; and (4) additional server purchases and installation costs required to store larger volumes of customer billing and interval data. As Rate Engineering demands continue to evolve, it is critical that we have a flexible system to handle rate case analytic needs as they arise.

Q. Please describe the Rate Case Enhancements project.

A. The on-going Customer Usage System (CUS) project began because certain legacy systems were coded in software that is now obsolete. The goal is to replace and retire the existing legacy processes to achieve an integrated data warehouse and to automate production of snapshot billing determinant reports, which will eliminate the need to manually query multiple sources on multiple platforms. The CUS project will facilitate a more thorough and timely rate analyses, and CUS will function as a strategic data warehouse for Rate Engineering and other users across the Company. Moreover, without these enhancements, the Company will not be able to meet certain reporting requirements, such as reactive power data, when the legacy systems are retired.

Q. What specific enhancement projects are you proposing?

A. This enhancement project will serve to integrate and centralize billing determinants and reports used for rate and bill impact analyses, allow for the evaluation of alternative rate designs, and eliminate numerous manual processes currently performed in rate design, bill impact analysis, and demand analysis. In addition, the CUS system will be integrated into the new billing system and we will seek opportunities to further enhance its reporting capabilities.

Q. Please discuss the timeline and funding associated with this project.

A. This project is budgeted as multi-year capital projects with total expected expenditures of $6.3 million, and an estimated completion date of 12/31/2026.

Q. Is this system solely for electric-related data and analyses?

A. No. Please see the testimony of the Gas Rate Panel on this subject.

VIII. MARGINAL COST ANALYSIS

Q. Did you perform an analysis of the marginal cost to supply an additional kW of load on the T&D delivery system?

A. No. Given the current uncertainty around the technical aspects of distribution marginal cost estimation, as expressed in the Staff Whitepaper Regarding Future Value Stack Compensation, Including For Avoided Distribution Costs, filed December 12, 2018, in Case 15-E-0751 ("Staff Whitepaper") and the ongoing Marginal Cost of Service ("MCOS") Proceeding, Case 19-E-0283, the Company has not developed a new electric marginal cost study for this rate case.

Q. Please continue.

A. In Case 15-E-0751, the Commission's Order Regarding Value Stack Compensation issued and effective on April 18, 2019 tasks the MCOS Proceeding with examining MCOS methodologies employed by utilities in the state. The Order further directs that Value Stack compensation be based, in part, on the last MCOS studies accepted by the Commission until such time that the MCOS Proceeding is complete (page 16). Once the MCOS Proceeding is concluded, the Company will develop a new MCOS study in accordance with the terms of the resultant Commission Order in that case.

Q. Does this conclude your testimony?

A. Yes.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

DIRECT TESTIMONY - ELECTRIC RATE PANEL

TABLE OF CONTENTS

I. INTRODUCTION

Q. Would the members of the Electric Rate Panel (the “Panel”) please state their names and business address?

A. William Atzl, Ricky Joe, and Sherry Sung, 4 Irving Place, New York, New York 10003.

Q. By whom are you employed, in what capacity, and what are your professional backgrounds and qualifications?

A. **(Atzl)** We are employees of Consolidated Edison Company of New York, Inc. (“Con Edison” or the “Company”). I am Director of the Rate Engineering Department. My background is as follows: 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 job was with 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. ("O&R") as a Commercial and Industrial Representative in the Commercial Operations

Department. At O&R, 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. I have testified in numerous regulatory proceedings before the New York State Public Service Commission ("Commission"), New Jersey Board of Public Utilities ("NJBPU") and Pennsylvania Public Utility Commission ("PAPUC").

(Joe) I am a Department Manager in the Rate Engineering Department. In 1993, I graduated from Rutgers College with a Bachelor of Arts degree in Economics. In 2001, I graduated from the Rutgers Graduate School of Management, with a Master's degree in Business Administration in Finance. I joined Con Edison in 2004 as a Senior Analyst in the Rate Engineering Department and worked in positions of increasing responsibility through 2012. In those positions, I worked on rate-related matters for O&R, including its regulated utility subsidiaries, as well as for Con Edison. In 2012, I moved to a position working on Con Edison electric and steam rate matters and gained more responsibilities with the promotion to my current position. Prior to joining Con Edison, I was employed by the NJBPU from 1993 to 2000, PricewaterhouseCoopers from 2000 to 2003, and Amerada Hess Corporation from 2003 to 2004. I have testified before the Commission, the NJBPU and the PAPUC.

(Sung) I hold the position of Senior Rate Analyst in the Rate Engineering Department. In 2001, I graduated from Pace University with a Bachelor of Business Administration Degree in Management Science and minors in Mathematics and Finance. I joined Con Edison in 2017 and am responsible for revenue allocation and rate design for the Company’s electric customers. Prior to joining Con Edison, I was employed by National Grid. I joined National Grid (formerly KeySpan Energy) as an intern in 1999 in the Strategic Planning Department. Upon graduation, I moved to a position in the Gas Marketing Department and subsequently held positions of increasing responsibilities in the Regulatory and Pricing Department and the Gas Finance Department. I have testified before the Commission.

II. <u>SCOPE OF TESTIMONY</u>

Q. What is the scope of your direct testimony in this proceeding?

A. Our testimony:

(1) presents the Company's proposal for revenue allocation and rate design;

(2) discusses the relationship between high tension and low tension rates in certain demand billed service classifications ("SCs");

(3) summarizes the adjustment to seasonal rate differentials for certain classes;

(4) presents revenue and bill impacts showing the total bill effect of the proposed delivery rate changes on customers' bills and Company revenues, including three years of bill projections for selected customer usage levels in major classes that not only show the effects of the proposed delivery rate increase, but those of expected changes in certain other charges, such as changes in supply costs;

(5) proposes changes to the revenue decoupling mechanism ("RDM");

(6) proposes to extend the applicability of the Business Incentive Rate ("BIR") and establish a new program offering to provide temporary relief for small business customers impacted by the COVID-19 pandemic;

(7) describes proposed changes to the Company's Schedule for Electricity Service, P. S. C. No. 10 – Electricity ("Electric Tariff") and Schedule for PASNY Delivery Service P. S. C. No. 12 – Electricity ("PASNY Tariff") and other related tariff matters; and

(8) updates the system losses assessed on supply costs for full service customers.

Q. Is the Panel sponsoring any exhibits?

A. Yes, we are sponsoring two exhibits:

- Exhibit ___ (ERP-1) High Tension / Low Tension Rate Differentials, Schedules 1-5; and
- Exhibit ___ (ERP-2) – Rate Design, Schedules 1-9.

III. REVENUE ALLOCATION

Q. Did the Accounting Panel supply you with the increased delivery revenue requirement for the twelve-month period ending December 31, 2023 (the "Rate Year")?

A. Yes, the increased delivery revenue requirement for the Rate Year amounts to $1,198.8 million, including $37.1 million related to gross receipts taxes ("GRT"), which means the net increased delivery revenue requirement is $1,161.7 million. For purposes of this testimony, "delivery revenue" will mean amounts associated with total delivery, including competitive and non-competitive amounts, as well as certain items related to the Company's Monthly Adjustment Clause ("MAC"). References to transmission and distribution delivery revenue ("T&D delivery revenue") mean delivery amounts excluding the MAC items.

Q. Please describe the components of the $1,161.7 million net increased delivery revenue requirement.

A. The total net increased delivery revenue requirement of $1,161.7 million reflects: (1) a $1,109.3 million increase in T&D delivery revenues, (2) a $8.7 million increase in the retained generation component of the MAC,

(3) a $2.3 million increase in purchased power working capital, and (4) a $41.4 million increase associated with energy efficiency costs proposed by the Accounting Panel and Customer Energy Solutions ("CES") Panel and as discussed further below.

Q. Please explain the classes to which these components are allocable.

A. The T&D delivery revenue increase is allocated to customers taking service under the Electric Tariff ("Con Edison Customers") and to the New York Power Authority ("NYPA" or "PASNY"). The increase in the retained generation component of the MAC is allocated to Con Edison full service and retail access customers. The increase in purchased power working capital is allocated to Con Edison full service customers. The energy efficiency costs included in the revenue requirement are allocated to Con Edison full service and retail access customers.

Q. Did you make any adjustments to reflect the projected increase in low income program funding?

A. Yes. Prior to allocating the $1,109.3 million increase in T&D delivery revenues, we increased it by $49.1

million to offset the projected $49.1 million increase in credits to be issued under the Company’s Low-income Program as discussed by the Company’s Customer Operations Panel. This results in the adjusted increase in T&D delivery revenues of $1,158.4 million.

Q. Please provide an overview of how you allocated the Company’s T&D delivery revenue increase among Con Edison customers and NYPA.

A. We performed the following steps in allocating the T&D delivery revenue increase:

- o Based on the rates that became effective January 1, 2022(“Current Rates”), we established the revenue for the rate year (“Current Revenue Level”).
- o Con Edison and NYPA Rate Year T&D delivery revenues at the Current Revenue Level were realigned based on Table 1A of the Company’s 2019 Embedded Cost of Service (“ECOS”) study, which is Exhibit __ (DAC-2) - Schedule 1 in the Electric Demand Analysis and Cost of Service (“DAC”) Panel testimony. To mitigate bill impacts for deficient classes, we propose to realign revenues

in the Rate Year based on one third of the revenue adjustments shown on Table 1A. Our intent is to further realign revenues based on the remaining two thirds of the revenue adjustments shown on Table 1A in subsequent years.

- As discussed above, the $1,161.7 million net Rate Year delivery revenue increase includes certain components that are allocated in different ways. Therefore, the $1,161.7 million net Rate Year delivery revenue increase was adjusted, for revenue allocation purposes, to exclude the: (1) $8.7 million increase in the retained generation component of the MAC, (2) $2.3 million increase in purchased power working capital, and (3) $41.4 million increase associated with the energy efficiency costs. In addition, we increased the Rate Year T&D delivery revenue increase by $49.1 million to reflect the increase in low income program funding. This results in a net decrease adjustment of $3.3 million (i.e., $49.1 million, less the sum of $8.7 million, $2.3 million and

$41.4 million), which was then subtracted from the $1,161.7 million for an adjusted proposed T&D delivery revenue increase of $1,158.4 million, which was allocated to Con Edison customers and NYPA in proportion to their respective realigned Rate Year T&D delivery revenues. The $41.4 million in incremental energy efficiency costs was allocated to the Con Edison full service and retail access customer classes based on kWh sales in each class. We are proposing to continue the bill credit for Recharge New York ("RNY") customers to permit them to continue to receive an exemption from cost recovery associated with energy efficiency programs equivalent to the benefit of their exemption from energy efficiency costs that would have been recovered through the System Benefits Charge ("SBC"). The RNY credit is being increased to reflect incremental energy efficiency costs. An adjustment was made to increase the energy efficiency costs allocated to Con Edison customers by the projected amount of the RNY credit.

- The revenue adjustments we propose based on Table 1A of the 2019 ECOS study for the Con Edison classes and NYPA were added to the T&D delivery revenue increase and energy efficiency costs allocated to each class to determine the total T&D delivery revenue change applicable to each class.
- The total Rate Year T&D delivery revenue change for each class was allocated among non-competitive T&D delivery revenues, competitive service revenues, reactive power demand charge revenues and customer charge revenues.
- The portion of the T&D delivery revenue change assigned to competitive service revenues is determined by taking the difference between the competitive service revenues at the proposed rates, designed in accordance with the Commission's <u>Statement of Policy on Unbundling and Order Directing Tariff Filings</u>, issued August 25, 2004, in Case 00-M-0504 ("Unbundling Policy Statement"), and the competitive service revenues at Current Rates.

- The portion of the T&D delivery revenue change associated with the change in reactive power demand charge revenue is determined for demand-billed customers as described below.
- Customer charges for the following classes: SCs 1 (excluding Rates II and III), 2, and 6; the voluntary TOD classes for SCs 5, 8, 9, and 12; and the mandatory TOD classes for SCs 8, 9, 12, and 13 were increased to better reflect the Company's cost to provide service as further discussed in the Rate Design section of this testimony. The customer charges for SC 1 Rates II and III were set consistent with the SC 1 Rate I level. The total Rate Year T&D delivery revenue change for each class was adjusted to exclude the changes in competitive service revenues and reactive power demand charge revenues to determine the class-specific non-competitive T&D delivery revenue changes. The non-competitive T&D delivery revenue changes were then adjusted to exclude the changes in customer charge revenues to determine Adjusted Non-

competitive T&D Delivery Revenue changes for the Rate Year.

- o The Adjusted Non-competitive T&D Delivery Revenue changes for the Rate Year were restated as class-specific Adjusted Non-competitive T&D Delivery Revenue changes for the 12 months ended December 31, 2019 (“Historic Period”) for purposes of designing the proposed non-competitive T&D delivery rates, other than customer charges. The Historic Period is the period for which detailed billing data are available.

Q. Please describe how you developed the Adjusted Non-competitive T&D Delivery Revenue changes applicable to the Con Edison classes for the Historic Period.

A. Revenue ratios were developed for each class by dividing the Rate Year Adjusted Non-competitive T&D Delivery Revenues for each class by the Historic Period Adjusted Non-competitive T&D Delivery Revenues for each class at the Current Revenue Level. The revenue ratio for each class was applied to the Rate Year Adjusted Non-competitive T&D Delivery Revenue change for each class to determine each class's Adjusted Non-competitive T&D Delivery Revenue change for the Historic Period.

Q. Please explain the components of competitive service revenue and how you developed the change in competitive service revenue applicable to the Con Edison classes.

A. Competitive service revenues are comprised of revenues associated with: (a) the supply-related component of the Merchant Function Charge ("MFC"), including the purchased power working capital component; (b) the credit and collection ("C&C") related component of the MFC; and (c) the billing and payment processing ("BPP") charge. The changes in competitive service revenues by class were developed by computing the difference between the competitive service revenues at the proposed rates, as described in the Rate Design section below, and the competitive service revenues at Current Rates.

Q. Please describe how you determined the change in the reactive power demand charge revenues.

A. The revenues associated with the change in reactive power demand charges were determined based on the difference between the current reactive power demand charge, i.e., $2.14 per kVar of billable reactive power demand, and the proposed charge to reflect updated costs, i.e., $2.38 per kVar. The difference was applied to the Rate Year kVar usage amounts to determine the change in reactive power demand charge revenues.

Q. Please describe how you determined the changes in customer charge revenues.

A. The changes in customer charge revenues were determined by computing the differences in customer charge revenues between current and proposed customer charges. This was done for the following: SCs 1, 2, and 6; the voluntary TOD classes for SCs 5, 8, 9, and 12; and the mandatory TOD classes for SCs 8, 9, 12, and 13.

Q. Please describe NYPA's share of the T&D delivery revenue increase.

A. NYPA's share of the T&D delivery revenue increase, excluding GRT, was determined to be $130.0 million. This amount was increased by one third of the total ECOS study deficiency of $20.5 million from Table 1A of Exhibit ___ (DAC-2), to yield a total T&D delivery revenue increase to NYPA of $136.8 million for the Rate Year.

Q. Why did you address only one third of the NYPA deficiency of $20.5 million?

A. As we stated in our discussion regarding the Con Edison classes, we propose to realign revenues in the Rate Year for the Con Edison classes based on one third of the revenue adjustments to mitigate the customer impacts of this change. To be consistent in our treatment of all customer classes, including NYPA, we propose to apply one third of the revenue adjustment applicable to NYPA as well. Our intent is to adjust NYPA revenues based on the remaining two thirds of the NYPA deficiency in subsequent years.

Q. Please describe how you restated the Rate Year T&D delivery revenue change applicable to NYPA for the Historic Period.

A. Revenue ratios were developed by dividing the applicable Rate Year NYPA T&D delivery revenues by the Historic Period NYPA T&D delivery revenues at the Current Revenue Level. The revenue ratios were applied to the Rate Year NYPA total T&D delivery revenue change to derive the NYPA total T&D delivery revenue change for the Historic Period.

IV. RATE DESIGN

Q. Please explain how you designed the proposed T&D delivery rates for Con Edison SCs.

A. The rate design process for the Con Edison SCs consisted of the following steps:

1. Determine rates for competitive services in accordance with the Commission's Unbundling Policy Statement;
2. Eliminate incremental meter charges for SC 1 voluntary TOD (under Rates II and III) and SC 2 TOD rates (i.e., Rate II), as no incremental meter charge is appropriate under Advanced Metering Infrastructure (“AMI”); and
3. Revise customer charges for SCs 1, 2 and 6 including voluntary TOD rates, and TOD classes for SCs 5, 8, 9, 12, and 13, to better reflect the Company’s cost to provide service;
4. Design non-competitive delivery rates to recover the Adjusted Non-competitive T&D Delivery Revenue change assigned to each class.

Q. Please describe the first step of the rate design process.

A. The first step is to develop the rates for competitive services, i.e., the supply-related and C&C components of the MFC, and the BPP charge.

Q. Please describe the MFC.

A. The MFC consists of two components: a supply-related component, including a purchased power working capital component, and a C&C related component. Separate MFCs were calculated for (1) SC 1 customers, (2) SC 2 customers, and (3) all other customers.

Q. Please describe how you designed the MFC.

A. As shown in Exhibit __ (DAC-2) - Schedule 2, Page 1, the costs associated with the supply-related component are:
(1) 0.17512 percent of total Con Edison T&D delivery revenues at Current Rates for SC 1 customers,
(2) 0.02486 percent of total Con Edison T&D delivery revenues at Current Rates for SC 2 customers, and
(3) 0.05716 percent of total Con Edison T&D delivery revenues at Current Rates for all other Con Edison customers.

To determine the Rate Year revenue requirement associated with these costs for each SC group, the respective percentages were applied to the total Con Edison Rate

Year T&D delivery revenue requirement at the proposed rate level. The resulting Rate Year revenue requirement for the supply-related portion of the MFC for each SC group was then divided by the Rate Year sales of full service customers for SC 1, SC 2, and other Con Edison classes, respectively, to determine the $/kWh supply-related component of the MFC for each SC group.

Q. Have you recognized in the computation of the supply-related MFC rate component an allowance for working capital on purchased power?

A. Yes. In accordance with the Unbundling Policy Statement, we reflected in rates an allowance for working capital on purchased power. Specifically, the Accounting Panel provided us with a purchased power working capital allowance of $10.028 million, excluding GRT. The proposed rate associated with purchased power working capital has been computed by dividing the purchased power working capital amount of $10.028 million by Rate Year full service customers' sales to derive a 0.0450 cent per-kWh charge that was added to the applicable supply-related MFC component for each SC group.

Q. Please continue.

A. As shown on Exhibit __ (DAC-2) - Schedule 2, Page 2, the total costs associated with the C&C-related component of the MFC are 0.54418 percent of total Con Edison T&D delivery revenues at Current Rates. To determine the total Rate Year C&C-related revenue requirement, this percentage was applied to the total Con Edison Rate Year T&D delivery revenue requirement at the proposed level. The total Rate Year C&C-related revenue requirement was then split between full service and Purchase of Receivable ("POR") customers based on the respective split of full service and POR forecasted Rate Year kWh sales. 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 customers, (2) SC 2 customers, and (3) all other customers based on the breakdown of relative class percentages for full service customers' portion of C&C costs as shown on Exhibit __ (DAC-2) - Schedule 2, Page 2. The resulting Rate Year revenue requirements for the C&C-related portion of the MFC for each SC group were then divided by the respective Rate Year sales for full service customers to determine the

$/kWh 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. Do you propose to revise the BPP charge?

A. No. As noted in the DAC Panel testimony, the 2019 unbundled cost for electric billing and payment processing is $1.21 per bill, i.e., the sum of the $0.73 per bill cost for printing and mailing and the $0.48 per bill cost for payment processing. This 2019 cost was inflated to the current level by using the Gross Domestic Product Implicit Price Deflator index. The resulting adjusted billing and payment processing cost of $1.27 is extremely close to the current BPP charge, therefore, the Company proposes to keep the BPP at the current level.

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

A. The second step is the development of customer charges. Con Edison’s residential customer charges are currently lower than customer costs indicated in the ECOS study and among the lowest in New York State as shown in the table below (“TOD” means time of day rates).

Residential Customer Charges in NY

Company	Non-TOD	TOD
RG&E (effective 5/1/2022)	22.00	26.10
Central Hudson (eff.12/2021)	19.50	22.50
O&R (current)	19.50	32.00
O&R (pending)	20.50	32.00
National Grid (current)	17.00	30.00
National Grid (pending)	17.33	30.62
Con Edison (proposed)	**20.00**	**20.00**
Con Edison (current)	17.00	21.46
NYSEG (effective 5/1/2022)	17.00	19.60

Customer charges for SCs 1 (excluding Rates II and III), 2, 6, and the non-standby classes within SCs 5, 8, 9, 12 and 13 were increased to move customer charges closer to the customer costs indicated in the ECOS study. The customer charges applicable to voluntary TOD rates for SC 1 (Rates II and III) and SC 2 (Rate II) have been set equal to the proposed customer charges of Rate I for SCs 1 and 2, respectively. In the past, the customer charges applicable to voluntary TOD rates were greater than the customer charges for non-TOD rates due to an incremental metering charge to recover the incremental cost associated with a TOD meter. With AMI metering, which the Company will have essentially fully deployed by the end of the Rate Year, there is no difference in metering costs between TOD and non-TOD customers, and metering-related differentials in TOD and non-TOD customer charges are no longer necessary.

Lastly, the meter charge applicable to SC 1 Special Provision D (applicable to SC 1 customers taking service under a separate account billed under SC 1 Rate II for the sole purpose of heating water off peak and storing it) was eliminated since the incremental meter charge is not appropriate under AMI. The current Electric Rate Plan closed this Special Provision to new applicants, and the one remaining customer is grandfathered through December 31, 2023, after which this customer would be assessed standard SC 1 rates.

Q. Please describe the third step of the rate design process.

A. The third step is the design of the non-competitive charges for the Con Edison SCs to collect the Adjusted Non-competitive T&D Delivery Revenue change. We applied the following guidelines in designing the proposed rates:

- As explained in the Revenue Allocation section of this testimony, after accounting for the changes in the SC 1 Residential and Religious (Rate I), SC 2 General Small (Rate I) and SC 6 Public and Private Street Lighting customer charges, the per-kWh charges for these classes were designed to recover the balance of the residual revenue requirements assigned to each respective class.

- Consistent with past practice, VTOD rates for SCs 1 (Rates II, III and IV) and 2 (Rate II) were designed to recover each class's overall T&D delivery revenue requirement. The rates were designed to be revenue neutral, i.e., the rates were designed to yield the same level of class revenues that the Company would receive under the proposed conventional rates.
- For SC 12 customers billed for energy only, the minimum charge and the per-kWh charges were increased by the Adjusted Non-competitive T&D Delivery Revenue change applicable to the SC 12 (Rate I) customer class.
- As described in the section of this testimony on Tariff Changes and Other Related Tariff Matters, the Company is proposing Special Provision E in SC 12 to establish specific rules for customer transfers

between demand rates and energy-only rates in Rates I and III. This proposal creates a net revenue deficiency of approximately $144,700, which we propose to offset by increases in Rate I demand and energy-only rates in proportion to the annual revenues derived from those rates.

- For Rate I of SCs 5, 8, 9 and 12, prior to applying the revenue increase, 5 percent of the usage revenue (i.e., revenue from per-kWh charges) was shifted into demand revenue on a revenue neutral basis. Then, the Adjusted Non-competitive T&D Delivery Revenue changes were applied entirely to the demand charges, including minimum charges. Since the majority of transmission and distribution costs are fixed or demand-related, shifting a portion of usage revenue to demand revenue and applying the revenue increase to demand charges more closely aligns how costs are incurred and collected from customers. The usage charges for these classes will remain at their redesigned current levels (i.e., resulting from the shift of 5 percent of usage revenues to demand revenues on a revenue neutral basis). This results in a higher percentage of revenue for these classes being recovered through fixed and demand-related charges.

- For demand-billed classes, high tension/low tension differentials have been adjusted to assess the high tension/low tension unit cost relationships based on the ECOS study. These adjustments are explained in the Adjustments to High Tension and Low Tension Rate Differentials section of this testimony.
- As explained in the Adjustment to Seasonal Rate Differentials section of this testimony, adjustments have been applied to address differences between the ratios of the summer and winter revenue and the summer and winter costs. Adjustments were made to the TOD classes of SCs 8 and 9.
- The mandatory TOD rates for SCs 5, 8, 9, 12, and 13 and VTOD rates for SCs 8, 9, and 12 were designed to collect the increased T&D delivery revenue requirement applicable to these classes. The Adjusted Non-competitive T&D Delivery Revenue changes for these classes were applied entirely to demand rates to better reflect the nature of

transmission and distribution costs. In keeping with past practice, the per-kWh rates remain equal across these classes. Since we are applying the Adjusted Non-competitive T&D Delivery Revenue change entirely to demand charges, the per-kWh rates will remain at the current levels. VTOD rates were designed to recover the class revenue requirement of all customers not billed under mandatory TOD rates.

- As discussed in the Revenue Allocation section of this testimony, the reactive power demand charge, including the charge for induction-generation equipment, was increased to reflect updated costs.
- Rates for the Company's Innovative Pricing Pilot ("IPP") under Rider Z and Rider AA, applicable to SC 1 and SC 2 customers, respectively, were calculated using the methodology approved by the Commission in its <u>Order Approving Tariff Amendments with Modifications</u>, issued December 13, 2018, in Case 18-E-0397. However, where this methodology resulted in IPP percentage rate changes greater than 1.2 times the percentage rate changes for SC 1 Rate I or SC 2 Rate I, as applicable, we limited the increases to

1.2 times the percentage rate changes for SC 1 Rate I or SC 2 Rate I. Customer charges under Riders Z and AA were increased to the levels proposed for SC 1 and SC 2 Rate I customer charges, respectively.

- Rates for the Company's Smart Home Rate ("SHR") Demonstration Project under Rider AB Rate I, which is applicable to SC 1 customers, were calculated using the methodology approved by the Commission in its <u>Order Approving Tariff Amendments with Modifications</u>, issued February 7, 2019, in Case 18-E-0549. The customer charge under Rider AB Rate I was increased to the level proposed for SC 1 Rate I. The Company did not update Rider AB Rate II rates since the Company had proposed to eliminate this rate in its October 22, 2021 filing in Case 21-E-0534, to become effective on March 1, 2022. In the event the Commission rejects the Company's proposal, the Company will update Rider AB Rate II rates.
- Demand rates for the Company's Optional Demand-Based rate applicable to SC 1 Rate IV customers, were increased using the same methodology used for Rider Z rates. Similar to the IPP rate design, percentage

rate changes greater than 1.2 times the percentage rate changes for SC 1 Rate I were limited to 1.2 times the percentage rate changes for SC 1 Rate I. The customer charge under SC 1 Rate IV was set based on the embedded customer cost level excluding BPP in the 2019 ECOS Study.

- The customer charges and distribution contract demand charges in SC 11 - Buy-Back Service - were set equal to the customer charges and contract demand charges in Rate III and IV of SC 5, Rate IV and Rate V of SCs 8, 9, and 12, and Rate II of SC 13.

Q. How were standby rates developed?

A. Standby rates applicable under Rate III and Rate IV of SC 5, and Rate IV and Rate V of SCs 8, 9, and 12, were developed consistent with the Commission's Opinion No. 01-04, Opinion and Order Approving Guidelines for the Design of Standby Service Rates, issued and effective October 26, 2001 in Case 99-E-1470 ("Standby Rates Order"). The Commission stated "the standby rates for each service classification should produce the same revenues as the standard rates, using the class billing determinants (Standby Rates Order, Appendix A, p. 2). The Standby Rates Order (p. 7) says that revenue neutral means “the full service class (not any individual customer) would contribute the same revenues if the full class was priced under either the standard service class rates or the standby rates (given the historic usage patterns of the customers in that class).” Standby rates for SC 13 (Rate II) were developed by increasing the current rates by the non-competitive T&D delivery revenue percentage increase applicable to SC 13 Rate I.

Q. How were standby rates under Rider Q developed?

A. Standby as-used daily demand delivery charges for each SC under Option B of Rider Q – Standby Rate Pilot were developed to be revenue neutral to the class rates for the otherwise applicable Standby Service class. However, Rider Q Option B as-used daily demand delivery charges applicable to summer months were calculated to reduce Period 1 (i.e., weekdays 8 AM to 6 PM) hours to four-hour periods based on event call windows under the Company’s Commercial System Relief Program. Additionally, revenue was shifted from the as-used daily demand delivery charges applicable to the summer Period 2 (i.e., weekdays

8 AM to 10 PM) to the Period 1 as-used daily demand delivery charges. This is consistent with the methodology used to set current Rider Q Option B rates as approved by the Commission in its Order Approving Tariff Amendments with Modifications, issued January 19, 2018, in Case 16-E-0060.

Q. Did you propose any changes to standby rates related to the filing made by the Company on September 23, 2019, in compliance with the Commission's Order on Standby and Buyback Service Rate Design and Establishing Optional Demand-Based Rates, issued May 16, 2019, in Case No. 15-E-0751 ("May 2019 Standby Order")?

A. No. In that compliance filing, the Company proposed an allocated cost of service study and introduced Standby Service rate options for SC Nos. 1 and 2. Given that this filing is still pending with the Commission, the Company has used the existing methodology previously described to determine the proposed Standby Service rates and proposes no changes to the existing Standby Service rate structure and available rate options. Should the Commission approve the Company's filing or require changes to the proposed filing during this proceeding, the Company will revise its proposed Standby Service rates accordingly.

Q. Please discuss how you designed the proposed delivery rates for NYPA.

A. The facilities charge applicable to New York City street lights was increased to better reflect costs of facilities specifically associated with service to street lights. All other Rate I and Rate II charges under the PASNY Tariff were increased by the total T&D delivery revenue percentage increase applicable to NYPA. High tension/low tension differentials were reviewed to assess the high tension/low tension unit cost relationships based on the ECOS study. These adjustments are explained in the Adjustments to High Tension and Low Tension Rate Differentials section of this testimony. Consistent with the standby rate guidelines in the Standby Rates Order, Rate III and IV rates were developed for each class within the PASNY Tariff to be revenue neutral at the proposed revenue level, i.e., Rates III and IV were developed to produce the same delivery revenues as the equivalent non-standby rates.

Q. Have you updated the rate reductions for the Excelsior Jobs Program (“EJP”)(SC 9 Special Provision H)?

A. Not at this time. The EJP rate reductions are normally set based on marginal costs. However, as explained in the DAC Panel testimony, given the current uncertainty around the technical aspects of distribution marginal cost estimation, as expressed in the Staff Whitepaper Regarding Future Value Stack Compensation, Including For Avoided Distribution Costs, filed December 12, 2018, in Case 15-E-0751 (“Staff Whitepaper”) and the ongoing Marginal Cost of Service (“MCOS”) Proceeding, Case 19-E-0283, the Company has not developed a new electric marginal cost study for this rate case. Therefore, we propose to maintain EJP rate reductions at their current level.

Q. Have you verified that the proposed rates for the Con Edison classes and NYPA will produce the revenue increase proposed by the Accounting Panel when those rates are applied to projected Rate Year sales?

A. We have provided the Electric Forecasting Panel with the proposed rates, and they verified the amounts.

V. HIGH TENSION / LOW TENSION DIFFERENTIALS

Q. What is the high tension/low tension differential?

A. This differential refers to the difference between $/kW annualized high tension and low tension demand rates for demand-billed classes, including NYPA.

Q. Did you make any adjustments to the high tension/low tension differential for demand-billed classes?

A. Yes. The demand rates in Rates I and II of SC 5, and NYPA Rate I were adjusted to better reflect the relationship between unit costs for high tension and low tension services.

Q. How was this determination made?

A. The review of high tension and low tension differentials involves a three-step process.

The first step determines the relationships between high tension and low tension unit costs for each class based on the 2019 ECOS study.

The high tension unit cost was determined by dividing the sum of the required revenue for cost components applicable to both high tension and low tension customers by the total billed demands for high tension and low tension service.

The high tension/low tension unit cost differential was determined by dividing the sum of the required revenue for cost components applicable only to low tension customers by the total billed demands for low tension service.

The low tension unit cost was determined by adding the high tension unit cost and the high tension/low tension unit cost differential. Finally, we divided the high tension unit cost by the low tension unit cost to determine the high tension/low tension ratio, which allows us to compare high tension/low tension differentials among classes on a common basis.

The high tension unit costs, low tension unit costs, high tension/low tension $/kW unit cost differentials and high tension/low tension ratios are shown on Exhibit __ (ERP-1), Schedule 1.

Q. Please describe the second step in the process.

A. The second step in the process determines the high tension/low tension rate differentials and high tension/low tension ratios by class reflected in Current Rates. See Exhibit __ (ERP-1), Schedule 2.

The Current Rates are adjusted to reflect the shift of 5 percent of usage revenue to demand revenue on a revenue neutral basis that we described earlier for Rate I of SCs 5, 8, 9 and 12. The redesigned demand rates are shown in Exhibit __ (ERP-1), Schedule 3.

We determine annualized demand rates based on a weighted average of summer and winter rates. This calculation was performed for each rate block, and for the minimum charges that include a minimum number of kW, the rate was unitized to a per-kW rate by dividing it by the corresponding kW associated with the minimum charge. The high tension/low tension rate differential was determined by subtracting the annualized high tension rate from the annualized low tension rate. The high tension/low tension ratio was determined by dividing the annualized high tension rate by the annualized low tension rate. See Exhibit ___ (ERP-1), Schedule 4.

Q. Please describe the third step in the process.

A. The third step in the process compared, for each class, high tension/low tension ratios based on costs, derived in step one, to high tension/low tension ratios reflected in Current Rates, derived in step two. The differences between high tension/low tension ratios based on costs and high tension/low tension ratios reflected in Current Rates indicate that subsidies may exist and should be addressed to limit further subsidies. These ratios were compared by subtracting high tension/low tension ratios based on costs from the high tension/low tension ratios reflected in Current Rates. To the extent that the absolute value of the difference in ratios exceeded five percentage points for a particular rate class, that class would be selected for adjustment. This same approach was approved by the Commission in Case 19-E-0065. See Exhibit ___ (ERP-1), Schedule 5. Rates in selected classes would be adjusted by redistributing the revenues between the high and low tension services on a revenue neutral basis.

Q. How do you propose to adjust the demand rates for SC 5 and NYPA?

A. To limit the bill impacts of these adjustments, we are proposing to eliminate only one third of the difference between ratios.

VI. ADJUSTMENT TO SEASONAL RATE DIFFERENTIALS

Q. Are you proposing any adjustments to seasonal rate differentials?

A. Yes. We are proposing adjustments in certain service classes to summer - winter revenue differentials to adjust the seasonal delivery revenue ratio to begin to gradually approach the seasonal delivery cost ratio.

Q. How are the seasonal delivery revenue ratios and seasonal delivery cost ratios determined?

A. These ratios are explained in the testimony of the DAC Panel.

Q. Which service classes were selected for adjustment?

A. As recommended by the DAC Panel, SC 8 TOD and SC 9 TOD are the greatest outliers with respect to the differences between their seasonal delivery revenue ratios and seasonal cost ratios and were therefore selected for adjustment.

Q. Please describe the process for adjusting seasonal revenue differentials?

A. For each selected class, we followed a three-step process to establish a target seasonal delivery revenue ratio and adjust seasonal delivery revenue, on a revenue-neutral basis, to approach the new target ratio.

First, we adjusted the seasonal delivery revenue ratio by 10 percent of the difference between the current seasonal delivery revenue ratio and the seasonal cost ratio to establish a new target seasonal delivery revenue ratio.

Second, in order to approach the new target seasonal delivery revenue ratio, we applied a percentage adjustment to the winter revenue, and an offsetting adjustment to summer revenue to redesign rates at the current level on a revenue-neutral basis. The revenue adjustment was applied to the non-competitive delivery revenue.

Finally, the rates were redesigned based on the revised summer and winter revenues from step two.

Q. Please describe the results of this approach.

A. For the SC 8 TOD and SC 9 TOD classes, a portion of summer revenue was shifted to the winter revenue target. This adjustment resulted in summer to winter revenue ratios changing to make gradual progress (i.e., 10 percent of the difference) towards the summer to winter cost ratios.

VII. REVENUE 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 ___ (ERP-2), the first page of which is entitled "CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. ESTIMATED EFFECT ON ELECTRIC CUSTOMERS' BILLS AND COMPANY REVENUES RESULTING FROM PROPOSED ELECTRIC RATES BASED ON SALES AND REVENUES FOR THE 12 MONTHS ENDED DECEMBER 31, 2019."

Q. Please continue.

A. Exhibit __ (ERP-2) includes nine 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 __ (ERP-2) – Schedule 1, shows for the Electric Tariff, by SC, the number of monthly bills rendered, kilowatt hours delivered, and the revenues for the 12 months ended December 31, 2019, that would have been derived from Con Edison full service and retail access customers at the conventional and TOD rates at the Current Revenue Level. The annualized revenues reflect the effect of an estimated MAC and market supply charge ("MSC") for both full service and retail access customers.

Exhibit __ (ERP-2) – Schedule 2 shows, for the PASNY Tariff, the number of bills rendered on NYPA customer accounts, kilowatt hours delivered, and the annualized revenues for the 12 months ended December 31, 2019 that would have been derived at the Current Rates. The annualized revenues include an estimated supply cost for NYPA customers.

Exhibit __ (ERP-2) – Schedule 3 shows a comparison of Current Rates and proposed Rate Year Con Edison Rates and Charges. It consists of 49 tables, headed by an index sheet, which covers all of the existing SCs. Each table consists of two columns. The left hand column shows the rates and charges at the Current Revenue Level, and the right hand column shows the proposed rates and charges.

Exhibit __ (ERP-2) – Schedule 4 shows a comparison of the Current Rates and proposed Rate Year rates and charges under the PASNY Tariff. It consists of seven tables.

Each table consists of two columns. The left hand column shows the rates and charges at the Current Revenue Level, and the right hand column shows the proposed rates and charges.

Exhibit __ (ERP-2) – Schedule 5 shows bill comparisons for Con Edison customers at Current Rates and at the proposed rates. It consists of tables that show comparisons of monthly bills at various consumption levels under rates and charges at the Current Revenue Level and under the proposed rates and charges for the Con Edison SCs. These comparisons show bills covering a reasonable range of monthly use for the classes shown.

Exhibit __ (ERP-2) – Schedule 6 shows, for each TOD SC, the annual percentage change in customers’ bills under TOD rates at the Current Revenue Level and proposed TOD rates based upon consumption levels for the 12 months ended December 31, 2019.

Exhibit __ (ERP-2) – Schedule 7 shows, for each Con Edison SC, the estimated change in revenues under the proposed Rate Year conventional and TOD rates and charges, the overall percentage change by SC, and the estimated effect on customers' bills based on sales and revenues for the Historic Period.

Exhibit __ (ERP-2) - Schedule 8 shows for the Historic Period the estimated increase in PASNY delivery service revenues under the proposed Rate Year rates and charges.

The revenues and bill impacts shown in Exhibit ___ (ERP-2), Schedules 1, 2, 5, 6, 7 and 8 include the same MSC, SBC and Dynamic Load Management ("DLM") charges 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, including the increase in fixed generation costs to be included in the MAC, which is a component of the net Rate Year delivery revenue increase.

As discussed above, Current Rates and the Current Revenue Level are based on the rates that became effective January 1, 2022 since these are the Commission-authorized rates and revenue level that will be in effect prior to the changes proposed in this case.

Q. Have you prepared any analyses that show the change in total Con Edison customers' bills taking into account both the increase in proposed delivery rates and other expected changes, such as changes in supply costs?

A. Yes. We have prepared Exhibit __ (ERP-2) - Schedule 9 entitled “PROJECTED ELECTRIC BILLS.” In this schedule, we provide bill comparisons for the three 12-month periods commencing January 1, 2023, January 1, 2024, and January 1, 2025, at projected levels for the following customers: (1) an SC 1 residential customer using 280 kWh per month (median New York City customer); (2) an SC 1 residential customer using 425 kWh per month (median Westchester customer); (3) an SC 1 residential customer using 600 kWh per month; (4) an SC 2 customer using 600 kWh per month; and (5) an SC 9 Rate I customer with a maximum demand of 30 kW and load factor of 50 percent.

Q. Please explain Schedule 9.

A. Schedule 9 of Exhibit __ (ERP-2) shows average monthly bills for these selected customers at current rates and proposed rates for each 12-month period. In these comparisons, the supply and delivery-related portions of the bills are also shown. Supply charges assume projected MSC and GRT associated with the MSC based on the supply cost projections made by Company witness

Kimball - Electricity Supply. The delivery charges consist of projected non-competitive T&D delivery charges and projected competitive service 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 SBC and DLM, for each of the three Rate Years.

VIII. REVENUE DECOUPLING MECHANISM

Q. Are you proposing any changes to the RDM?

A. Yes. We are proposing to extend the applicability of the RDM to all Standby Service customers.

Q. Please describe the Standby Service customers that are currently included in the RDM.

A. Currently, the RDM is applicable to certain customers who opt into being billed under Standby Service rates pursuant to the May 2019 Standby Order. These customers have been designated as Rate Choice Customers and, in accordance with the May 2019 Standby Order, are included in the RDM. All other customers billed under Standby Service rates are excluded from the RDM.

Q. Why are you proposing to include the RDM to all customers billed under Standby Service rates?

A. By expanding the RDM to all customers that are billed under Standby Service rates, the level of standby revenues will be included in the RDM target revenue providing revenue assurances for the Company and stability for customers in the respective RDM groupings. Additionally, including standby customers in the RDM will provide consistency with all customers in the class paying or receiving credits as well as consistency statewide with other utilities. Examples of utilities with standby service in the RDM include Central Hudson Gas and Electric Corporation and Niagara Mohawk Power Corporation. Finally, in O&R’s recent Joint Proposal in Case 21-E-0074, parties agreed to include standby customers in the RDM. The Joint Proposal is pending approval by the Commission.

Q. When does the Company propose to include standby customers in the RDM?

A. Given the implementation of the Company’s new billing system in mid-2023, the Company proposes to include standby customers in the RDM commencing January 1, 2024.

Therefore, standby customers will be assessed the RDM Adjustment applicable to their SC effective August 1, 2024, which will reflect the reconciliation of January through June 2024.

Q. Are you proposing any other changes related to the RDM regarding Standby Service customers?

A. Yes. With the expansion of the RDM to include all Standby Service customers, the Company is proposing to combine SCs 8 and 13 into one revenue target effective January 1, 2024. SC 13 consists of a limited number of customers and an RDM category based solely on this class would not be appropriate.

IX. BUSINESS INCENTIVE RATE

Q. What is the Business Incentive Rate ("BIR")?

A. The BIR (Rider J of the Electric Tariff) provides a delivery rate reduction that has been typically used to promote economic development in the Company's service territory. Although it has several offerings, it is primarily available to businesses that open in new or formerly vacant buildings or receive a comprehensive package of economic incentives conferred by a governmental agency.

Q. Is the Company proposing to continue its BIR program?

A. Yes. Since the BIR supports the Company's continuing efforts to foster economic development in its service territory, the Company proposes to extend the BIR application period during the term of the new rate plan.

Q. Is the Company proposing a change to the BIR offerings?

A. Yes, it is.

Q. Please explain your proposed change.

A. The Company is proposing to add a new program offering to provide temporary relief for small business customers given the COVID-19 pandemic impact on that community.

Q. What are the eligibility criteria for the new program component?

A. To be eligible for the Company's proposed COVID-19 BIR, a small business customer must: (1) not be currently receiving BIR rate reductions; (2) provide proof that it has received assistance from city, county, state or federal government agencies directly related to COVID-19 such as a grant or loan; (3) receive service from the Company under either SC 2 or SC 9 Rate I with a monthly maximum demand less than 30 KW for the past 12 consecutive months, and (4) submit an application for COVID-19 BIR by December 31, 2023.

Q. Would there be any program limits?

A. Yes. We propose that COVID-19 BIR will have a maximum term of three years from the month the customer first receives the rate reduction and a total cumulative maximum benefit of $50,000 over the three years per customer. Additionally, the Company proposes that rate reductions are provided up to a maximum aggregated allocation of 30 MW, with 5 MW reserved for SC 9 customers and 25 MW reserved for SC 2 customers.

Q. What is the Company’s proposal on the source of the 30 MW allocation?

A. Currently, BIR has an aggregate limit of 452 MW to allocate among the various programs with the New and Vacant Program of BIR at a maximum of 125 MW. The Company proposes to use the 30 MW from unsubscribed allocations for the New and Vacant BIR program. In other words, we are preserving the full BIR allocation for all other BIR offerings.

Q. Would there be any requirement for an energy audit similar to other BIR program offerings?

A. No. Customers served under the COVID-19 BIR program would not be subject to energy audits as a condition for eligibility because this is a short-term temporary relief program and it enables applicants to enroll in the program sooner.

Q. What types of government grants or loans will be considered?

A. Due to the changing forms of government assistance available to COVID-impacted businesses, the Company is proposing to establish, at the onset of the program, a list of acceptable government programs on the Company’s website.

Q. What are the proposed COVID-19 BIR rate reduction percentages?

A. For COVID-19 BIR customers taking service under SC 9 Rate I, the rate reduction would be 39 percent, the same rate reduction percentage applicable to SC 9 Rate I customers under the other BIR offerings. For COVID-19 BIR customers taking service under SC 2, for which there is no current BIR rate reduction percentage, we propose a rate reduction percentage of 39 percent, equal to the SC 9 Rate I percentage, so all COVID-19 BIR customers are provided a common rate reduction percentage.

Q. How will the COVID-19 BIR rate reductions be funded?

A. In order to recover from all customers, including NYPA, the Company proposes to recover the rate reductions provided to customers under the COVID-19 BIR program through the MAC and Other Charges and Adjustments ("OTH") applicable to NYPA customers.

Q. Why is the Company proposing a different method of cost recovery for this BIR program?

A. The Company believes that there should be full cost recovery for all BIR programs, but the opposing view has been that the Company benefits from economic development programs to attract new customers in our service territory. But, even that view does not apply to this program because it is an assistance program for existing small businesses and not an economic development program designed to attract new customers.

Q. Are you proposing any other changes for the BIR Program?

A. Yes. The Company proposes that Special Provision C of SCs 2 and 9 does not apply to BIR customers. Special

Provision C provides certain criteria (i.e., demand thresholds over a period of time) for customer transfers between SC 2 and 9. Under this proposal, BIR customers would remain in the class under which they took service when commencing service under the BIR.

X. TARIFF CHANGES AND OTHER RELATED TARIFF MATTERS

Q. Are you proposing a change to the provisions of the Electric Tariff that requires the Company to provide compensation for losses related to service outages?

A. Yes. General Rule 21.1, Continuity of Supply (Leaf 171), currently provides compensation to (a) residential customers for actual losses of perishable prescription medicine and up to $540 for food spoilage, and (b) commercial customers for loss of perishable merchandise up to $10,700. Claimants must provide proof of loss, with the exception of residential claimants who are reimbursed without proof of loss for food spoilage up to $235 upon submission of an itemized list. We propose to increase the compensation limits for residential customers for food spoilage with and without proof of loss from $540 to $580 and from $235 to $250, respectively, and for commercial customers from $10,700 to $11,460.

Q. What is the basis for the proposed increases?

A. The proposed compensation limits were set following the methodology prescribed in the Commission's November 23, 2007 <u>Order Concerning Tariff Provisions Governing Reimbursement for Food Spoilage</u> in Case 06-E-0894 ("Reimbursement Order"). The methodology in the Reimbursement Order provides for updating the compensation limits based on applying the Gross Domestic Product Deflator ("GDPD") to current reimbursement limits. Based on the percentage change in the Implicit Price Deflators ("IPD") for GDPD for personal consumption expenditures, which the Bureau of Economic Analysis lists under Table 1.1.9, from the third quarter 2018 amount (108.452) to the third quarter 2021 amount (116.232), current tariff compensation limits were increased by 7.1 percent and rounded to the nearest multiple of $5 for residential customers and the nearest multiple of $100 for commercial customers. We used the third quarter 2018 IPD amount for comparison because that amount was the IPD at the time the current compensation limits became effective, on February 1, 2020.

Q. Are you proposing any tariff changes due to the Paulin/Comrie climate resiliency bill that was signed into law on December 22, 2021 that amends Section 66 of the Public Service Law?

A. Not at this time. The Company is assessing the newly enacted law and will address, if appropriate, in its Update filing.

Q. Are there changes required to the RDM Allowed Pure Base Revenue targets for the Con Edison service classes (Leaf 351) and PASNY tariff (Leaf 22)?

A. Yes. These targets will be revised at the end of this proceeding to set forth the annual revenue targets for Con Edison service classes and NYPA based on the final revenue requirement level approved by the Commission. In addition, as discussed in the RDM section above, the Panel will update the tariff to reflect the inclusion of customers served under all Standby Service rates and the combination of SC 13 with SC 8 in the RDM at least 30 days prior to January 1, 2024.

Q. Are there changes required for the Transition Adjustment mechanism?

A. Yes. We updated the competitive services revenue targets used in the determination of the Transition Adjustment in General Rule 28.2.

Q. Did the Company update the monthly bill credit applicable to RNY customers (Leaf 459.0.2)?

A. Yes. As discussed in the Revenue Allocation section above, since RNY customers are exempt from energy efficiency programs, the Panel has updated the monthly bill credit applicable to RNY customers to offset additional energy efficiency costs that will be recovered in base rates.

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 three sections of the Electric Tariff that reference UB factors: (1) POR discount on Leaf 146, which is currently based on the 12 months ending November; (2) reconciliation for the MSC and Adjustment Factors – MSC charges on Leaf 336, which is based on a level initially set at the onset of a rate plan; and (3) reconciliation for MAC and the MAC Reconciliation component of the Adjustment-Factor – MAC on Leaf 344, which is also based on the approved level at the onset of a rate plan.

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 MSC and MAC, a UB level set initially could change significantly up or down and allowing the UB factors to refresh annually would allow 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 allow for consistency of the changes to the MSC and MAC provisions. Since the UB factors for the MSC and MAC 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. Are you proposing any tariff changes for SC 1 Rate IV?

A. Yes. Rate IV currently requires that customers install geothermal heat pumps and includes a limitation on the number of other customers who may elect this rate. We propose to eliminate these eligibility requirements making SC 1 Rate IV an optional rate generally available to all SC 1 customers.

Q. Is the Company proposing any changes to the eligibility of SCs?

A. Yes. The Company is clarifying that SC 2 General - Small and SC 9 General – Large are SCs intended for which no other SC specifically apply, to avoid ambiguity. The other SCs are intended for the specific customers as specified while SCs 2 and 9 are designed for general non-residential customers that do not qualify for the other SCs. The only exceptions are certain religious organizations, community residences and veterans halls and accounts established for the sole purpose of plug-in electric vehicle charging that may select to be served under SC 1, or stay in SCs 2 or 9, which the Company also clarified.

Q. Is the Company proposing any tariff changes as a result of the implementation of AMI in its service territory?

A. Yes, the Company has made the following tariff changes as a result of the implementation of AMI in its service territory:

- Eliminated the provisions in the Electric Tariff and PASNY Tariff requiring Standby Service and Buy-back service customers to provide communications service for Output Meters. For new customers requiring Output Meters, AMI meters will be installed and communications for the AMI Output Meter will be included in the Company's AMI network. The Company will replace Output Meters with AMI meters for existing customers so that the Output Meters will be compatible with the Company's AMI system.
- Eliminated a provision in the Electric and PASNY Tariffs requiring Single and Multi-party Standby Offset customers to provide and maintain the communication services for non-AMI meters. The Company expects to replace all existing Single and

Multi-party Standby Offset customer meters with AMI meters by January 1, 2023. Going forward, new Standby Offset customers will have AMI meters. The Company will provide the communications service for AMI meters. Therefore, this provision is no longer needed.

- Modified the reference to interval data for Standby Offset customers in General Rule 20.4.6 from “each 15 minute interval” to “each metered interval,” because the Company is in the process of transitioning the meters for Standby Offset customers to AMI meters, which measure usage in five-minute intervals for commercial customers.
- Added an option for Rider R customers to close an account on the date of request for customers with communicating AMI meters, since the Company would be able to obtain an actual reading for such customers.
- Eliminated provisions in SC 2, SC 12, and the PASNY Tariff, requiring the installation of a demand meter if it is determined that the Customer might use more than 10 kW of maximum demand or if the Customer’s usage exceeds 6,000 kWhr for a 60-day period. The

Company has also eliminated in SCs 5, 8, 9, 11, and 13 language stating that it would install demand meters for those SCs. Since the Company has been installing AMI meters, which are capable of measuring demand, these provisions are no longer necessary.

- In SC 12, Multiple Dwelling Space Heating, we added Special Provision E to establish the demand thresholds for customers billed for both energy and demand, and customers billed for energy only under Rate I and Rate III. This is necessary for three reasons:(1) as noted above, we have eliminated provisions requiring installation of a demand meter under certain circumstances; (2) essentially every SC 12 Customer will have an AMI meter that is capable of measuring demand so rules are needed to clarify the conditions under which customers will be billed for both energy and demand versus energy only; and (3) to provide consistency with similar provisions under SCs 2 and 9. The proposed Special Provision E states that whenever a Customer's maximum demand under Rate I or Rate III of SC No. 12 exceeds 10 kilowatts in two consecutive months, the Customer's use thereafter will be billed under both energy and demand rates. And, whenever a Customer’s maximum demand under Rate I or Rate III of Service Classification No. 12 shall not have exceeded 5 kilowatts for a period of 12 consecutive months, the Customer’s use thereafter will be billed under energy only rates. Rates were adjusted to account for this change, as discussed in the Rate Design section above, and the revenue impact is minimal.

- Specified in General Rule 6.10 that Residential Customers who are required to have an Interval Meter cannot opt-out of AMI since the Company will no longer support non-AMI Interval Meters.

Q. Did the Company propose any tariff changes related to Standby Service and SC 11 – Buy-back Service?

A. Yes, the Company has made the following tariff changes related to Standby Service and SC 11 – Buy-back Service:

- Combined the interconnection and operation provisions under General Rule 20 – Standby Service and SC 11 – Buy-back Service under a new common General Rule 8.4 since they are duplicative. Any minor inconsistencies between the original Standby Service and Buy-back Service interconnection and operation provisions were made consistent. Furthermore, the option to pay the capital costs of interconnection in a lump sum rather than an annual surcharge that was only available to Standby Service customers has been extended to Buy-back Service customers.

- General Rules 20.2.1(B)(7), 20.2.1(B)(8), and 20.2.1(B)(9), were moved from General Rule 20.2 – Interconnection and Operation to a more appropriate section, General Rule 20.4 – Billing under Standby Service rates. References were updated throughout the tariff to reflect this change.
- Eliminated the requirement in General Rule 20.3.2 that customers with designated technologies make a one-time election to be billed under Standby Service rates 30 days before commencing operation of an onsite generating facility. This would allow flexibility for customers to make this one-time election at any time.
- Eliminated the option to sell to the NYISO under SC 11. Customers that seek to sell energy have two options. The customer may sell energy back to the Company under SC 11 or the customer may participate in the wholesale energy market by selling energy to the

NYISO under the Company's FERC–jurisdictional Open Access Transmission Electric Tariff.

- Eliminated the 20 MW upper limit for customers served under the new General Rules 20.4.5 and 20.4.6, because the Company has determined that distributed generators above 20 MW may be interconnected to the Company's distribution system subject to engineering review on a case-by-case basis. In addition, the Company has revised the reference to the Company's distributed generation guides from a reference to a specific guide to a general reference to the Company's multiple distributed generation guides.

Q. Is the Company proposing any housekeeping changes to the Electric Tariff and PASNY Tariff?

A. Yes, the Company proposes housekeeping changes as follows:

- Added the existing EV Make-Ready Surcharge section to the table of contents and to the list of delivery surcharges in General Rule 26.
- Clarified the definition for Pure Base Revenue on Leaf 17 so that it includes the comparable charges under the applicable Riders to the Customer's Service

Classification, such as comparable charges under Riders Z, AA and AB.

- Added an option for facilities to be installed underground to include when the Company elects to provide underground facilities on Leaf 45, to be consistent with the existing Elective Underground Installation provision on Leaf 47.
- Deleted specific language related to flood protection requirements for customers that are included in Company specifications on Leaf 56, since they may be updated from time to time. The Company also clarified that equipment associated with transformers should be protected in addition to the transformers themselves.
- Deleted a provision related to customer-owned meters on Leaf 129, which is obsolete.
- Made the following housekeeping changes to Rider T-Commercial Demand Response Program:
    - Deleted an obsolete provision that was applicable only in 2017 and 2018.
    - Deleted obsolete provisions that were applicable only during the 2020 capability period.

  - o Removed the “or” in the DRV and/or LSRV Rider R Value Stack Tariff restriction. As described under Rider R Value Stack Tariff, this restriction applies to both DRV and LSRV.
- Regarding the MAC, the Panel is proposing to remove or revise the following MAC components in General Rule 26.1.1:
  - o Revised component 9 regarding Customer’s share of the cost of the savings passed on to eligible Customers, rather than Madison Square Garden, in accordance with Section 3, Chapter 459, 1982 N.Y. Laws. A corresponding change was made in the PASNY Tariff. SC 9 Special Provision F was also revised to indicate that eligible Customers, rather than Madison Square Garden, will be subject to an adjustment pursuant to Section 3, Chapter 459, 1982 N.Y. Laws.
  - o Removed component 29 related to costs associated with non-Company owned generation facilities pursuant to a settlement agreement among the parties to Indeck v. Paterson, Index No. 5280-09, Supreme Court, Albany County.

- Revised component 33 to remove specific Energy Efficiency and Demand Response Program costs that have expired to be recovered in the MAC, with any remaining Energy Efficiency and Demand Response Programs to be recovered in the MAC, as approved by the Commission. A corresponding change was made in the PASNY Tariff.
- Removed component 34 related to the Smart Grid Project. General Rule 26.1.4 further describing the Smart Grid Project was also removed. A corresponding change was made in the PASNY Tariff.
- Removed component 35 related to payments made by NYSERDA pursuant to a settlement agreement among the parties to Indeck v. Paterson, Index No. 5280-09, Supreme Court, Albany County.
- Removed component 37 related to recovery of the 125 MW Energy Efficiency/Demand Reduction/Combined Heat and Power Program costs as this program has been completed.
- Removed component 47 related to consultant costs to develop a marginal cost study approach for a

climate change vulnerability study and implementation plan. A corresponding change was made in the PASNY Tariff.

- Added time periods to clarify the EV Make-Ready Surcharge applicable to Rate II of SC 5 and Rate II and Rate III of SCs 8, 9, and 12 on Leaf 359.1, to be consistent with the current practice and other similar surcharges.
- Deleted obsolete provisions in SCs 8, 9, and 12 that expired in 1997 that allowed 20 customers with thermal storage to be on Time-of-Day rates. The Company has since implemented voluntary Time-of-Day rates available to all customers in those service classes.
- Deleted SC 9 Special Provision D on Leaf 458, and all references to it, because the percentage reduction expired in 2018.
- Corrected the indentation in the last paragraph of the PASNY Tariff on Leaf 17.1.
- Clarified that Rate I PASNY customers transfer from non-demand billed service rates to demand billed service rates if their maximum demand exceeds 10 kilowatts in two consecutive months and transfers from

demand billed service rates to non-demand billed service rates if the PASNY Customer's maximum demand for a period of 12 consecutive months shall not have exceeded 5 kilowatts. This change is consistent with current practice and with similar provisions in SC 2 and SC 9 of the Electric Tariff. The Company is also updating the titles under Rate I of the PASNY Tariff from “non-demand metered service” to “non-demand billed service” and “demand meter service” to “demand billed service.”

- Deleted the obsolete Transition Adjustment for Metering Services in the PASNY Tariff.
- Deleted recovery for Earning Adjustment Mechanisms (“EAMs”) associated with the System Peak Reduction Program targets in the Contribution to EAMs and Other Revenue Adjustments section in the PASNY Tariff, since it is obsolete. The Company also clarified the energy efficiency programs for which costs are not allocated to PASNY customers.
- Added General Rule 5.2.5, Permits, which was erroneously deleted.

Q. Have you proposed tariff changes associated with proposals made by other Company witnesses?

A. Yes, the following tariff changes are described in other testimonies of the Company:

- As described in the testimony of the Accounting Panel, the Company has:
  - o Updated the corporate overheads and storage and handling fee in General Rule 17.3 of the Electric Tariff (Leaf 126), which lists the elements of costs charged for special services performed by the Company.
  - o Added MAC component 10 to recover carrying charges associated with interference costs causing an exceedance of the net electric plant target. A corresponding change was made in the PASNY Tariff to add a new section entitled "Reconciliation of Interference Costs" to the OTH section. The Municipal Infrastructure Support Panel also further describes this change.
  - o Added MAC component 11 to recover the amount by which annual storm costs exceed the annual rate allowance, when such excess amount exceeds $7

million each year, up to 2.5 percent of delivery revenue each year. A corresponding change was made in the PASNY Tariff to add a new section entitled "Reconciliation of Storm Costs" to the OTH section. The Storm Response and Resilience Panel also further describes this change.

- Added MAC component 20 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 collect/pass back any variance over a subsequent twelve-month period as authorized by the Commission. A corresponding change was made in the PASNY Tariff to the existing section "Unbilled Fees Adjustment" in the OTH section. In addition, the Panel has included in MAC component 20 recovery related to unbilled fees that were approved for recovery through the MAC pursuant to the Commission's <u>Order Authorizing Alternative Recovery Mechanism for Unbilled Fees</u>, issued and effective November 18, 2021, in Cases 19-E-0065 and 19-G-0066, for clarity. Furthermore, the Panel has deleted "of its current Rate Plan" in Case 19-E-0065 from the existing provision in the Unbilled Fees Adjustment component of the OTH section in the PASNY Tariff, since the Rate Plan in Case 19-E-0065 will no longer be considered to be the "current Rate Plan" if this Rate Plan were to be approved.

- Added MAC component 21 to 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. A corresponding change was made in the PASNY Tariff to add a new section entitled "Uncollectible Bill Expense Adjustment" to the OTH section.
- Added MAC component 23 to charge or credit customers the amount by which actual annual property taxes differ from Commission approved levels in base rates. A corresponding change was made in the PASNY

Tariff to add a new section entitled "Reconciliation of Property Taxes" to the OTH section.

- As described in the testimony of the Electric Infrastructure and Operations Panel, the Company has:
  - Updated its re-inspection charge in General Rule 16.3, Charges for Re-inspection (Leaf 121), charge for replacing a damaged AMI meter in General Rule 16.1 (Leaf 121), and charges for certain special services provided at stipulated rates (i.e., hi-pot, Megger, and dielectric fluid tests) in General Rule 17.1, Special Services at Stipulated Rates (Leaf 122).
  - Added a new provision to General Rule 7.1 – Customer Wiring and Equipment (Leaf 64) that for customers served under the Company's Selective Undergrounding Program, the Company will furnish and install the wiring and equipment, as necessary; provided that the Customer will maintain the wiring and equipment.
  - Added a new provision, General Rule 5.2.8 - Street or Sidewalk Services. Other conforming changes were made to address this new provision.

- With respect to the low-income program, which is also discussed by the Customer Operations Panel:
  - o General Rule 15.2, Reconnection Charge, of the Electric Tariff (Leaf 119) has been revised to continue the waiver of the reconnection charge for customers enrolled in the low-income program, up to an annual target amount of $1,188,186. The Company will notify parties in its most recent electric rate plan if it projects that the target cost will be reached during any Rate Year.
  - o The RDM sections in the Electric Tariff (Leaf 352) and the PASNY Tariff (Leaf 22) have been revised to reset the annual level of low-income program costs included in rates to $118.82 million for each rate year that the low-income program is in effect, and to indicate that the low-income program will continue beyond December 31, 2023, contingent on the continuation of full cost recovery through the RDM Adjustment or an equivalent mechanism.
- As described in the testimony of the Customer Energy Solutions Panel:

- The Company has eliminated Riders P, V, and W and references to those Riders throughout the Electric Tariff.
- The Company has added a new provision, General Rule 5.2.4.4, Distributed Energy Resources Make Ready Program for Disadvantaged Communities and Low-Income Customers.
- The Company will update the Electric Tariff to provide renewable bill credits to customers enrolled in the Company’s low-income program once the Company’s Low-Income Renewable Bill Credit program has been implemented, currently estimated to be in 2024.

XI. LINE LOSSES

Q. Does the Company account for system losses when billing customers for supply?

A. Yes, the Company’s existing factor of adjustment of 1.063 is included in the Company’s bill calculation methodology for the MSC components (i.e., energy, capacity, NTAC and Ancillary Services) for all customers who purchase supply from the Company, including customers billed under Rider

M – Day-ahead Hourly Pricing. This factor is reflected in the Factor of Adjustment for Losses applicable to the MSC.

Q. Describe the Company’s proposal with respect to the Factor of Adjustment for Losses.

A. The Company proposes to increase its Factor of Adjustment for Losses to 1.071 to reflect the loss percentage of 6.6 percent based on the five-year average ended 2020. The Company proposes to state the 1.071 Factor of Adjustment for Losses and the 6.6 percent loss percentage in the MSC section, General Rule 25.1.

Q. How is the loss percentage converted into a factor of adjustment that can be applied to total metered usage to account for losses?

A. The loss percentage, which is the result of dividing system losses by system sendout, is converted into the factor of adjustment by dividing 1 by a denominator that is 1 minus the loss percentage expressed as a decimal.

Q. Will the Factor of Adjustment for Losses be applied to all full service customers' supply costs, including Rider M customers?

A. Yes. The updated Factor of Adjustment for Losses will continue to be applied to supply costs for all full service customers, including Rider M customers.

Q. Does this conclude your testimony?

A. Yes.

TABLE OF CONTENTS

Q. Please state your name, title, employer, and business address.

A. My name is Ivan Kimball. I am Vice President, Energy Management for Consolidated Edison Company of New York, Inc. (“Con Edison” or the “Company”). My office is located at 4 Irving Place, New York, New York 10003.

Q. Please describe your responsibilities in that position.

A. 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 and natural gas, oil and renewable attributes. I perform these functions for the customers of Con Edison, Orange and Rockland Utilities, Inc. (“O&R”) and Rockland Electric Company (“RECO”).

Q. Please describe your professional background.

A. I have been in my current position since July 2012. From August 2008 to June 2012, I was Director, Electricity Supply for Con Edison. 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, Inc. (“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, O&R and RECO. From December 1998 to August 2008, I was employed by Consolidated Edison Energy, Inc. (“Con Edison Energy”) where I was most recently the Director of Asset Management. My responsibilities included management of the business aspects of the generating facilities owned by Consolidated Edison Development, Inc. (“Con Edison Development”) in New England and other generating facilities with whom Con Edison Energy had contracts. This included day-to-day scheduling, fuel procurement, electricity market sales and planning, and associated regulatory and accounting matters. From September 1987 to December 1998, I was employed by Con Edison in various positions of increasing responsibility.

Q. Briefly state your educational background.

A. I received a Bachelor of Science degree and a Master of Science degree in Nuclear Engineering from Rensselaer Polytechnic Institute in May 1986 and September 1987, respectively.

Q. Have you previously testified before the New York Public Service Commission ("Commission" or "PSC")?

A. Yes. I have testified before the Commission in Cases 09-E-0428, 13-E-0030, 16-E-0060, 16-G-0061, 19-E-0065, and 19-G-0066.

PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. I describe Con Edison's historical and projected wholesale electric supply purchases for the Company's full service customers. Historical supply purchases cover the period from January 2016 through December 2020 and projected supply purchases cover the period from January 2022 through December 2026, which includes the rate year. This section of the testimony also describes the Company's efforts to minimize supply costs to customers.

I also discuss seven capital projects and one operations and maintenance ("O&M") program the Company plans to implement to support Electricity Supply and Energy Management's forecasting and planning needs .

HISTORICAL SUPPLY COSTS

Q. What are the Company's objectives when purchasing electric supply for its full service customers?

A. The Company seeks the lowest reasonable electric purchase costs for its customers, subject to reliability and contractual constraints. As part of this objective, the Company also seeks to mitigate price volatility.

Q. In what ways does the Company accomplish these objectives?

A. The Company also pursues structural and tariff changes in the NYISO's wholesale electric markets that are beneficial to the Company's customers through active participation in the NYISO governance process and through filings with the Federal Energy Regulatory Commission (“FERC”). Where appropriate, the Company pursues certain matters before FERC through litigation, settlement and mediation conferences, and the filing of comments and petitions in an effort to obtain just and reasonable wholesale electric prices for its customers. I discuss these efforts later in my testimony.

Q. Please describe, in general terms, how Con Edison procures electric supply for its full service customers.

A. Electric energy and capacity are obtained from four main sources: Brooklyn Navy Yard (“BNY”); Con Edison’s own steam-electric generation; Con Edison’s Request for Proposal (“RFP”) Auctions for physical and financial products; and purchases made from the NYISO’s energy, capacity, and ancillary services markets. The Company also uses financial hedges to mitigate price volatility for its customers.

Q. I show you a one-page document entitled, “CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. - WHOLESALE ELECTRICITY SUPPLY COSTS – CALENDAR YEARS 2016 THROUGH

2020," and ask whether it was prepared under your supervision and direction?

A. Yes.

MARK FOR IDENTIFICATION AS EXHIBIT (ES-1)

Q. What does Exhibit (ES-1) show?

A. Exhibit (ES-1) illustrates the costs from January 1, 2016 through December 31, 2020 for energy, capacity, and other services acquired on behalf of the Company's full service customers. This exhibit shows a slight increase in the volume of the Company's total energy supplied, which is primarily due to customers migrating from retail access to full service.

Q. Please describe the Company's firm supply contracts.

A. As noted in Exhibit (ES-1), about 1,300 MW (approximately 17% of the Company's capacity supply) and almost 1.9 million MWh (approximately 9% of the Company's energy supply) were provided by the Company's firm contracts in 2020. The decrease in the Company's firm energy and capacity supply is due to the expiration of most of the long-term firm contracts over the past several years.

Q. Please describe the supplies from the Company's steam-electric generation.

A. As noted in Exhibit (ES-1), the Company's steam-electric generation facilities provided 679 MW (approximately 9% of the Company's capacity supply) and over 3.0 million MWh (approximately 14% of the Company's energy supply) in 2020.

Q. Please describe the Company's short-term purchases.

A. The Company's short-term energy purchases are made from the NYISO, primarily in its day-ahead market, but also from its real-time market. The NYISO prices energy in both of those markets at eleven different load zones. About 85% of Con Edison's customer consumption is in NYISO's Zone J, the New York City ("NYC") load zone. The remainder is located in NYISO Zones H (Millwood) and I (Dunwoodie).

The Company also makes short-term capacity purchases from the NYISO's capacity market auctions. The NYISO administers four capacity market areas: one for NYC, one for Long Island, one for Lower Hudson Valley ("LHV"), and one for rest-of-state ("ROS"). The majority of Con Edison's capacity obligations are in NYISO's NYC market; the remainder are in the NYISO's LHV and ROS markets. The NYISO conducts auctions that allow load serving entities ("LSEs"), like Con Edison, to purchase capacity for a one-month period or for periods of up to six months. The NYISO supplies any LSE with capacity obligations not met by the sum of contract purchases and purchases made in these "strip" or monthly auctions with the additional needed capacity from spot, or reconciliation, auctions that the NYISO conducts on a monthly basis. Prices in each of these spot auctions are set at the intersection of a demand curve, which the NYISO's governance processes administratively establishes and FERC approves, and the supply offer curve. One aspect of the spot auction is that it is a single clearing price auction, which means that all supply offers in NYISO's spot auction that are below the intersection of the administrative demand curve and the supply offer curve receive the spot market clearing price. The NYISO demand curve results in purchases in excess of reliability requirements, and it is typical for more capacity to be available for sale than is required to be purchased. Such excess capacity is purchased by NYISO on behalf of the LSEs, which are obligated by the NYISO tariff to pay their allocated share of such "excess capacity."

Q. Please describe the Company's financial hedging practices.

A. The Company uses financial hedge products to mitigate the volatility of its short-term purchases. Products include fixed-for-floating price swaps, also known as contracts for differences ("CFDs"), and options. CFDs are typically traded on a "5x16" basis, meaning their value is computed over the 16 peak hours (7 AM to 11 PM, prevailing time) on non-holiday weekdays. CFDs may also be traded on an "around the clock" basis, priced at the arithmetic average of all 24 hours in a day.

Options typically provide a financial benefit to the option holder when the contracted parameters, such as short-term price, temperature, or both, exceed prior agreed-upon thresholds. The premiums or purchase costs of such options are related to the volatility of the underlying product, the length of time prior to delivery, and the agreed-upon strike price and/or temperature threshold.

Q. What has been the impact of the Company's hedging program?

A. Exhibit (ES-1) identifies the net impact of the Company's financial hedging from 2016 through 2020, including the cost of those hedges. The exhibit shows that the Company's hedging practices stabilized wholesale supply prices for customers, which is the objective of the program. In accordance with the PSC's August 28, 2006 *Order Instituting Proceeding and Soliciting Comments* and its April 19, 2007 *Order Requiring Development of Utility Specific Guidelines for Electric Commodity Supply Portfolios and Instituting a Phase II to Address Longer-Term Issues* in Case 06-M-1017, the Company maintains a supply portfolio that is hedged, but not 100% hedged, for its residential and smaller commercial customers, and meets with Commission Staff at least once a year to review its hedging performance and plans.

PROJECTED SUPPLY COSTS

Q. Have you prepared a projection of generation capacity for the Company’s steam-electric plants?

A. Yes.

Q. I show you a one-page document entitled, “CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. - STEAM-ELECTRIC GENERATION CAPACITY (MW) PROJECTED FOR 2022 AND 2023,” and ask whether it was prepared under your supervision and direction?

A. Yes.

MARK FOR IDENTIFICATION AS EXHIBIT (ES-2)

Q. What does Exhibit (ES-2) show?

A. Exhibit (ES-2) shows the capacity from the Company’s retained generation located at its steam-electric plants (collectively referred to as “steam-electric generation”).

Q. Have you also prepared a projection of wholesale energy costs?

A. Yes.

Q. I show you a one-page document entitled “CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. - PROJECTION OF WHOLESALE ELECTRICITY SUPPLY COSTS – RATE YEARS ENDING

DECEMBER 2022 through DECEMBER 2026," and ask whether it was prepared under your supervision and direction?

A. Yes.

MARK FOR IDENTIFICATION AS EXHIBIT (ES-3)

Q. What does Exhibit (ES-3) show?

A. Exhibit (ES-3) sets forth my projections of electricity supply costs from January 2022 through December 2026, based upon the forecast of full service sendout provided to me by the Company's Electric Forecasting Panel.

Q. Please describe the methodology used to develop these projections.

A. As noted earlier, capacity and energy are supplied from four major categories: the BNY contract, steam-electric generation, the Company's RFP Auctions, and short-term purchases from NYISO.

Firm contract capacity and energy costs were projected based on existing contract terms. Natural gas price projections were based on September 2021 NYMEX Natural Gas forward prices.

Steam-electric generation costs were projected using the GE Maps cost optimization model. These projections reflect the decreased capacity provided by the Company’s steam-electric generation as a result of the planned retirement of various peaking units under the Company’s plan filed in compliance with the DEC NOx Rule.

Steam sendout projections and fuel price forecasts were input into GE Maps, which models the operating characteristics of the Company’s steam-electric units. The natural gas prices and “differentials” were based on the Wood-Mackenzie forecasts. The Wood-Mackenzie forecast information provided is proprietary and governed by confidentiality provisions under the contract provisions of the Company’s subscription. Wood-Mackenzie is a research and consulting firm that provides commercial analysis and strategic advice for the global energy, metals and mining industries. Natural gas “basis differentials,” reflecting the cost of interstate transportation from Henry Hub to Transco Zone 6 (NYC), were then applied to the natural gas prices. This delivered cost of natural gas was then increased to reflect the cost of taxes on generation fuel, yielding the natural gas price forecast. Wood-Mackenzie provided these forecasted natural gas basis differentials. The fuel oil forecasts – for the small amount of oil our plants burn for reliability reasons were based on a number of components that take into account historical prices and the relationship between different types of fuel oil (Platts) and NYMEX forward pricing (CME Group). This delivered cost of fuel oil was then increased to reflect the cost of taxes and shipping and handling, yielding the final, delivered fuel oil price forecast. Based on the modeled dispatch of the steam-electric units and a projected allocation of costs from Steam Operations for "processing charges," such as water, chemicals, and labor, the costs and volumes of energy available for electric supply were determined, as summarized on Exhibit (ES-3).

Q. Please continue with your description of Exhibit (ES-3).

A. Short-term capacity purchase costs are based on the NYISO's projection of capacity supply margins in the NYC, LHV, and ROS regions; the application of these margins to expected demand curve parameters to project prices; and then the application of these prices to the Company’s expected short-term capacity requirements in the NYC, LHV, and ROS regions. Excess capacity costs purchased by the NYISO and allocated to LSEs, as described earlier, are also included in these cost projections.

Short-term energy costs are based on market values as of September 30, 2021. These price projections are then applied to the forecast of full service volumetric requirements as provided to me by the Company’s Electric Forecasting Panel, after deducting energy projected to be supplied from firm contracts and steam–electric generation.

Q. Please continue with your description of costs in Exhibit (ES-3).

A. To mitigate the need for short-term purchases and the associated price volatility of short-term purchases, the Company has implemented multiple requests for proposals (“RFPs”) for physical and financial supply. Through multiple RFPs conducted in 2021, the Company purchased from counterparties up to 350 MW of around-the-clock NYISO Zone J (New York City) financial energy consisting of natural gas price-indexed products; through additional RFPs conducted in 2021, the Company purchased up to 800 MW of NYC and LHV unforced capacity ("UCAP") consisting of both financial and physical fixed priced capacity. The Company administered the RFPs through online auctions for energy products for each of the three calendar year terms from 2022 through 2024, and capacity products for one-year terms for each of the three capability years commencing May 2022, May 2023, and May 2024.

Q. Has the net impact of the RFPs been included in these projections?

A. Yes, the net impact is included in the costs of the firm contracts on the exhibit.

Q. How does the Company plan to use the RFP process going forward?

A. The Company plans to conduct additional RFPs for both energy and capacity up to three years forward into the future. The RFPs will complement the financial hedges in the Company's hedge plan. This will allow the

Company to further diversify its portfolio to mitigate wholesale supply price volatility to our customers.

Q. Has the net impact of financial hedges been included in these projections?

A. Hedges have been assumed to be “at the money,” thereby not affecting customers’ prices for the purposes of these cost projections. However, financial hedges command premiums for reducing buyers’ risks and so would be expected to increase costs marginally over the long term.

SUPPLY COST SAVING INITIATIVES

Q. What efforts does the Company undertake to minimize supply costs to customers?

A. The Company tries to minimize supply costs by working to reduce the administrative costs of running its RFPs, representing customer interests in regulatory proceedings, and advocating for proposals that would reduce supply costs.

Q. What efforts did the Company undertake to reduce the administrative costs of running its RFPs?

A. Since mid-2018, the Company has used a third-party RFP auction platform administered in-house at a significantly reduced cost over its prior vendor. Additionally, since 2020, the Company has conducted multiple RFP auctions for both energy and capacity supply throughout the year as opposed to a single energy auction and a single capacity auction. The multiple RFP auctions can help reduce supply costs to customers by taking advantage of dollar-cost averaging and generating more competitive offers by reducing the volume of each auction.

Q. What regulatory efforts has the Company undertaken to minimize supply costs to customers?

A. A primary objective of the Company is to actively promote customers' interests by advocating for the adoption of wholesale market rules that maintain reliability and resilience, align with State policy goals, and create fair and competitive market prices for all customers, including the Company's full service customers. The Company aggressively pursues NYISO market structure and tariff changes that are beneficial to its customers through active participation in the NYISO's governance processes and in FERC proceedings.

Q. Please give some examples of the Company's efforts in these NYISO governance processes and FERC proceedings.

A. Con Edison has been active in promoting rules that create fair and competitive wholesale markets. For example, the Company actively participates in the NYISO's Demand Curve Reset process. The Company's engagement in the 2021 Demand Curve Reset process culminated in FERC's approval of new capacity market reference prices in April 2021 that will lead to significant capacity supply cost reductions for our customers. The Company also supported a revised optimization methodology for determining Locational Capacity Requirements, which included a Transmission Security Screen to provide for reliability protection in the NYC load zone. FERC approved the methodology in 2018. In addition, the Company continues to advocate for the implementation and maintenance of supply-side market mitigation measures necessary to prevent the influence of market power on electric prices. Con Edison has also advocated for fair participation rules for new technologies in the NYISO markets. For example, the Company has been heavily engaged in projects relating to the integration of energy storage resources and distributed energy resources ("DER"). Working collaboratively with the Joint Utilities, the Company continues to meet with the NYISO and NYISO stakeholders to address operational issues across the bulk and distribution system to allow for the efficient integration of these technologies into the NYISO's markets. The new rules went into effect in May 2020 for energy storage and are scheduled to go into effect by the end of this year for DER wholesale market participation through an aggregator. Con Edison also participates actively in NYISO projects and proceedings and secures changes that benefit customers.

In addition, the Company has long advocated for the need to reform capacity market rules to accommodate state policy resources. Such reforms will remove barriers to the participation of generation resources receiving state subsidies, such as renewable energy and storage, in the NYISO capacity markets caused by the application of Buyer Side Mitigation (“BSM”) rules. The Company advocated for and supported a package of reforms that the NYISO filed at FERC in Docket No. ER22-772-000 on January 5, 2022. The reform package eliminates BSM applicability to state-sponsored resources, enabling those resources to receive capacity market revenues while also improving capacity accreditation rules. This will ensure that capacity payments received by resources are commensurate with their contributions to reliability. The reform package, once approved by FERC, will maintain appropriate market signals to incent needed clean generation while reducing customer costs.

Additionally, the Company advocated for a reasonable Operational Base Flow protocol to be used at the seam between NYISO and PJM Interconnection, L.L.C. (“PJM”) in absence of the historical 1,000 MW wheel. FERC ruled in favor of the Company and New York customers, preventing the allocation of transmission expansion costs from PJM to NYISO. These issues continue to be litigated, and the Company continues to actively work to protect customers from allocation of these costs.

The Company actively participates in the Budget and Project Prioritization process at the NYISO to influence the types of projects that the NYISO will work on from year to year.

Similarly, the Company actively reviews formula rate updates for previously approved bulk transmission projects to which its customers are allocated costs.

Finally, the Company assumes leadership roles within NYISO stakeholder groups and industry-wide organizations.

Q. What proposals does the Company advocate for that would reduce supply costs to customers?

A. As the Company has explained in comments to the Commission regarding new initiatives to help meet the State’s Renewable Portfolio Standards goals, Con Edison supports utility ownership of clean energy facilities over power purchase agreement (“PPA”) arrangements. Utility ownership will result in lower supply costs to our customers than PPAs would due to the ability to capture the continuing benefits of the clean energy facilities for our customers over the life of the facilities instead of ending at the expiration of the PPAs.

SYSTEM ENHANCEMENTS

Q. Please describe the Electricity Supply IT Systems.

A. Energy Management is responsible for forecasting electric peak demand, annual volumes, and annual revenues; electric resource analysis, performing daily scheduling, hedging requirements, and operations to serve the Company's customers; performing Metering Authority functions with the NYISO; and performing energy and capacity reconciliation with the NYISO. As such, the Company needs to upgrade or expand existing software systems and develop new applications to perform the foregoing forecasts, functions, and reporting to the NYISO.

Q. Do these systems require capital enhancements and related O&M support costs during the rate period?

A. Yes. There are seven IT system enhancements needed to support Electricity Supply and Energy Management's forecasting and planning needs. The Company estimates that it will incur total capital installation costs for these systems of $6.8 million in Rate Year 1 (calendar year 2023), $3.8 million in Rate Year 2 (calendar year 2024) and $4.6 million in Rate Year 3 (calendar year 2025).

Q. Are there incremental O&M costs associated with these seven capital projects after they are put in service?

A. Yes, ongoing maintenance and license fees are expected to increase to maintain these capital systems after they are in production. The total incremental O&M for these seven projects is: $0.22 million in Rate Year 1, $0.37 million in Rate Year 2, and $0.47 million in Rate Year 3. Please refer to Exhibits (IT-2), (IT-4), and (IT-5), which detail each of the seven projects.

Q. What are the drivers behind the need for these system enhancements?

A. There are three primary drivers for the system enhancements.

(1) Recent policies such as the Climate Leadership and Community Protection Act ("CLCPA") and Local Law 97 have significantly increased the

importance of the utility planning process and, therefore, have increased the need for accuracy of short-, medium- and long-term forecasting for the electric, gas, and steam systems. In support of the CLCPA goals and technology enhancement, the Energy Management organization must be prepared to leverage and factor into its planning the capabilities of clean energy technologies, including electric vehicles ("EVs"), heat pumps, battery storage, electric appliances (stovetops, hot water heaters, and clothes dryers), and solar photovoltaic ("PV") panels.

(2) The Company needs to be able to support changes in the makeup and operation of the electricity markets. These changes include support for DER, including electric storage and other intermittent assets that can be modeled and dispatched on a network level.

(3) The need for enhanced data analytics around advanced metering infrastructure ("AMI") can help reduce uncertainty and provide a higher level of confidence in the summer peak demand, winter peak

demand, and annual delivered volume forecasts for Con Edison electric.

Collectively, these projects will help enhance the variety of reporting, analytics, and forecasting that the Energy Management organization performs to support the forecasting and procurement of electricity.

Q. Please briefly describe the first capital project, AMI Business Analytics, and its benefits and justification.

A. The goal of this project is to design and deploy a suite of data analytics use cases to assess customer load profiles and patterns while leveraging the Company’s AMI data, as well as other internal and external data sources. This integrated application will allow the Company to gain predictive insight into specific customer trends, reconciliation of weather adjusted peaks of the gas and electric systems, and uptake of load modifiers. It also will help the system planning process, which is designed to identify current and future operating requirements, risks, and potential solutions to provide safe, reliable, and resilient systems. The use cases for this project include: Use Case 1: Electric Vehicle and Chargers Load Profiles; Use Case 2: Heat Pumps; Use Case 3: Battery Storage; Use Case 4: New Business Ramp Up; Use Case 5: New Business Load Density; and Use Case 6: Gas Load Distribution of Interruptible Customers. Please refer to Exhibit (IT-5) for the details of this project.

Q. Please briefly describe the second capital project, Con Edison REV/DER/EEDM Forecasting Tool,and its benefits and justification.

A. In 2020, the Energy Management organization hired a vendor to design, build, and deploy the Con Edison REV/DER forecasting application, containing forecasting modules for electric storage and for electrification of heat. In 2023, the Company is looking to continue its engagement with the vendor to enhance the analytics and tools used to forecast three more electric load modifiers that are undergoing significant changes in the coming years. The modules covered in this proposal are: EVs; Combined Heat and Power Distributed Generation installations (“DG/CHP”); and Solar PV installations. Additionally, the application will cover the 20-year electric forecasts for EVs, DG/CHP, and PV panels, and will be performed for Con Edison's electric service territory, specifying DER effects on: Electric System Annual Delivered Volume; Electric System Annual Billable Demand; and Peak load at Electric System Summer and Winter Peak Hours.

The evolving energy landscape has increased in its complexity. This application software will reduce this uncertainty and provide a higher level of confidence in the summer peak demand, winter peak demand, and annual delivered volume forecasts for Con Edison electric. This application will enhance the Company'sability to implement these modifiers in specific locations. Such forecasts are essential for reliability planning, capital planning, budget management and bill impact modeling, and rate design. Please refer to Exhibit (IT-4) for the details of this project.

Q. Please briefly describe the third capital project, Forecasting Services Compliance with Market Changes and MetrixIDR Upgrades, and its benefits and justification.

A. Metrix IDR is an application that produces the daily electric and steam hourly load forecasts. The Company’s System Operation department relies on these forecasts to plan daily operations and the Company’s Commodity Procurement and Scheduling department uses it to plan short-term electric purchasing and generation scheduling. The objectives of this project includes the following enhancements:

- Upgrade MetrixIDR to the latest version.
- Develop and implement new forecast models for CLCPA planning.
- Integration of additional meters for new networks and feeders as well as 5-minute forecasts for electric feeders and networks.
- Development of associated model performance reports and statistics.
- Integration of multiple weather vendors.
- Implementation of an interface with the Enterprise Data Analytics Platform to provide selected customer group forecasts.

- Integration of ConnectDER with MetrixIDR to collect actual and forecasted solar production data for regions.
- Integration of MetrixIDR with NYISO notifications for transmission line and generation outages, wind, and solar forecast to better forecast zonal pricing.

Please refer to Exhibit (IT-2) for the details of this project.

Q. Please briefly describe the fourth capital project, NYISO - PJM Energy and Capacity Daily Reconciliations - Transmission Owner Data Reporting System (“TODRS”), and its benefits and justification.

A. TODRS liaises between wholesale and retail markets, reconciling small retail meters with market settlements at the Independent System Operators (“ISOs”) (i.e., NYISO and PJM). Because the markets change continuously, these changes trigger modifications on the existing code, require building of new TODRS Structure Query Language code, and the addition of new interfaces with all billing and customer information systems around the Company and external ISOs. Because of these changes, it is challenging to anticipate the market’s next changes and how it will directly impact TODRS. In the last few years alone, the Company needed to make the following changes to TODRS: Value Stack or Value of Distributed Energy Resources (VDER) program, New York State Energy Research and Development Authority report requirements to calculate Zero-Emissions Credits (ZEC), Street Lighting software interface, and use of new AMI metering data.

This project addresses anticipated market changes, regulatory policies, and system requirements that will require enhancements to TODRS. This project will assist the Company in meeting market changes to improve market transparency and accuracy with Retail Access participants/Energy Service Companies and other market participants, and to continuously improve forecasting performance. Please refer to Exhibit (IT-2) for the details of this project.

Q. Please briefly describe the fifth capital project, Strategic Analytics - As Billed - Revenue Analytics (SARA), and its benefits and justifiscation.

A. Currently, the Energy Management organization uses multiple sources to obtain the information required to perform monthly variance analysis of volumes and revenues and to generate forecasts. Employees reach out to several departments and manually pull data from many different Company systems. These processes are time consuming and potentially prone to error. The proposed solution is to the develop a single and complete source of enterprise data used to support customer, sales, and revenue analytics that the Company will house in a user-friendly system that can automate the collection of critical data from across the Company's systems, automate the reconciliation process, and simplify and expedite the forecasting process. This project also will include exploring the potential use of AMI data to improve forecasting accuracy. Some of the expected key benefits of the project include:

- A more in-depth understanding of customer usage patterns and better impact analysis reporting for making decisions at the service class and customer level.

- Enhancing data flow and analytics transparency across the Company and developing new insights from improved analytic capabilities, as opposed to data gathering.
- Improving the tracking and reporting of bill components and the accuracy and timeliness of monthly, quarterly, and annual revenue reporting process.
- Reducing data error that will lead to greater forecast accuracy and have downstream positive benefits for finance, accounting, and operations. A more accurate forecast will lead to less under-purchasing or over-purchasing of commodities on same-day energy needs.
- Improving access to customer usage data across more dimensions will allow more granular analysis to determine potential impact of certain scenarios (e.g., COVID, network issues).

Please refer to Exhibit (IT-2) for the details of this project.

Q. Please briefly describe the sixth capital project, Replace nMarket to Avoid Lapses in ISO Transactions and Accommodate Electric Storage and Other REV-DER Resources, and its benefits and justifiscation.

A. Presently, Energy Management uses nMarket, which is an electricity nomination and scheduling system. It provides functionality to manage a participant's transactions, public settlements, and invoices with the ISO. These functions typically represent in excess of a billion dollars in transactions annually, but can be much higher depending on the market price of energy. The software the Company uses was once the industry leading software for ISO communications. However, after multiple corporate acquisitions and strategic decisions, the product is no longer adequate to address the Company's needs to adapt to a rapidly changing energy marketplace. At the same time, Energy Management's needs are growing, and the Company needs a product that can support the bidding of grid scale batteries and other DER in the near term for proper implementation of regulatory mandated programs. As such, the Company needs a product that can support the bidding of grid scale batteries and other DER in the near term for proper implementation of regulatory mandated programs. The current system is not able to meet these requirements. These developments will add complexity to Commodity Procurement and Scheduling's physical wholesale business requirements, creating the need to replace the existing nMarket System. This project will replace the nMarket System and utilize an alternative software solution to support Commodity Procurement and Scheduling's physical wholesale business requirements, which consist of the following:

- Electricity purchasing, scheduling and invoicing.
- Utilize and monetize electric storage assets in ISO energy, capacity and ancillary markets.
- Regulatory and SOX compliance.
- Interfacing with other internal systems.

Please refer to Exhibit (IT-4) for the details of this project.

Q. Please briefly describe the seventh capital project, ISOs Revenue Metering validation and reporting software phase 1 and phase 2, and its benefits and justification.

A. The objective of this project is to enhance and upgrade Metering Authority software, which will aid in the rehabilitation, consolidation, standardization, and streamlining of O&R’s and Con Edison's Metering Authority functions. The software will perform the daily and repetitive manual functions of collecting, validating, and reporting energy demand data to the NYISO and PJM from transmission revenue class meters located at transmission ties with neighbor utilities and local generating stations. The costs associated with this project are only for Con Edison’s portion of this project. The enhancement will allow the Company to adapt the reporting process to suit the needs of the market and provide reports of settled market data to various departments of the Company. This, in turn, will benefit market participants by improving the accuracy of financial settlements because transactions will be more transparent and will allow for Company personnel to readily troubleshoot and resolve metering issues reported by generating companies and neighboring utilities. The vendor software will provide an enterprise solution across both Con Edison and O&R that will allow for synergies across the companies and allow for business continuity. In addition, it will enable the analysts to focus on other issues that arise related to this function, for example: follow-up on repairs, investigate meter challenges, transmission loss estimations, and work on new interconnections. Please refer to Exhibit (IT-2) for the details of this project.

Q. Does this conclude your testimony?

A. Yes.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

ELECTRIC FORECASTING PANEL

TABLE OF CONTENTS

Page

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

ELECTRIC FORECASTING PANEL

I. INTRODUCTION

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

A. John Catuogno, Hock G. Ng, and Leanne M. Attanasio, 4 Irving Place, New York, New York 10003.

Q. By whom are you employed, in what capacity, and what are your professional backgrounds and qualifications, and current responsibilities?

A. **(Catuogno)** We are employed by Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company"). I am the Director of Energy Management's Commodity Forecasting Department. 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, Steam Operations, and Energy Management Organizations. 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; electric resource planning; and technical and analytical support for long range plans, strategies, and industry trends and issues that affect the Company.

(Ng) I am the Section Manager of Electric Forecasting in Energy Management. I graduated from the University of Western Australia with a Bachelor of Economics degree in 1983. I also received a PhD degree in Economics in 1992 from Stanford University. Prior to joining Con Edison, I taught and performed research in economics and econometrics at various universities. In 2005, I began my employment with Con Edison as a Senior Planning Analyst in Corporate Accounting. In April 2018, I was promoted to my current position in Energy Management. My responsibilities include overseeing the development of the electric delivery volume and revenue forecast. I have also co-authored two articles dealing with forecast modeling issues that have been published in the International Journal of Forecasting, and Systems Analysis Modeling Simulation.

(Attanasio) I am a Senior Planning Analyst in the Electric Forecasting Section in Energy Management. I received a Bachelor’s degree in Economics (Honors Program) from Ateneo de Manila University in 1998. I received a Master of Arts degree in Economics in 2008 and a Doctorate in Economics in 2010, both from Fordham University. I also hold the Chartered Financial Analyst® designation. Prior to joining Con Edison, I taught Economics and Statistics at Fordham and also managed the University’s Master of Arts Program in International Political Economy and Development. Other positions I have held in the past involved derivatives trading and macroeconomic forecasting. In 2013, I joined Con Edison in an Analyst position as an experienced economic modeler and forecaster. I have developed econometric time series models and forecasts for Con Edison and Orange and Rockland.

Q. Have you previously testified or submitted testimony in any proceedings before the New York State Public Service Commission?

A. **(Catuogno)** Yes, I have 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.

(Ng) I have testified in previous electric rate cases, including Cases 13-E-0030, 08-E-0539, and 07-E-0523, and submitted written testimony in Cases 21-E-0074, 19-E-0065, 16-E-0060, 15-E-0050, and 09-E-0428.

(Attanasio) I have submitted written testimony in Cases 19-E-0065 and 18-E-0067.

II. PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of the Forecasting Panel’s testimony?

A. The Panel presents the Company’s forecast of electric delivery volumes, revenues, and system sendout for October 1, 2021 through December 31, 2025, and discusses the methodologies used to develop these forecasts.

Q. What is the difference between delivery volume and sendout?

A. Sendout refers to the total amount of electric energy that was sent out by the Company. Delivery volume refers to the amount of electric energy delivered to the customer as recorded at the customer's meter. The latter differs from the former because of line loss in the system.

Q. What is the purpose of the delivery volume and sendout forecasts?

A. The delivery volume forecast is used to determine the revenue forecast. The delivery volume and revenue forecasts are then used by the Company's Rate Engineering department to determine rates per service class. The sendout forecast is used by Company Witness Kimball to develop the electricity supply cost forecast.

Q. What were the actual and normalized delivery volumes for the 12 months ended September 2021?

A. The actual CECONY service territory delivery volume for the 12 months ended September 2021 was 50,775 gigawatt hours ("GWh"). The normalized delivery volume for this period was 50,828 GWh. The normalization procedure is detailed in the Company's response to DPS-1-92.

Q. Would you please summarize, in aggregate form, your delivery volume forecast?

A. The delivery volume forecast for the three months ending December 2021 is 11,936 GWh. The delivery volume forecast for the 12 months ending December 2022 is 51,030 GWh. The delivery volume forecasts are 50,858 GWh for the 12 months ending December 2023 (“Rate Year” or “RY1”), 50,474 GWh for the 12 months ending December 2024 (which we will refer to as “RY2”), and 49,710 GWh for the 12 months ending December 2025 (which we will refer to as “RY3”).

Q. Would you please summarize, in aggregate form, your delivery revenue forecast?

A. The delivery revenue forecasts are $8,557.6 million for the 12 months ending December 2022, $8,464.0 million for RY1, $8,439.6 million for RY2, and $8,473.0 million for RY3.

Q. What is the actual and normalized sendout for the 12 months ended September 2021?

A. The actual franchise area sendout for the 12 months ended September 2021 was 55,526 GWh. The normalized sendout for the same period was 55,507 GWh.

Q. Please summarize your sendout forecasts.

A. The sendout forecast for the three months ended December 2021 is 12,627 GWh. The sendout forecast for the 12 months ending December 2022 is 55,245 GWh. The sendout forecasts are 55,269 GWh for RY1, 54,827 GWh for RY2, and 53,786 GWh for RY3.

Q. Do you have any exhibits that accompany this testimony?

A. Yes, we are presenting nine exhibits, Exhibit ___ (EFP-1) through Exhibit ___ (EFP-9).

Q. Were these nine exhibits prepared under the Panel’s direction and supervision?

A. Yes. We will describe each of these exhibits in the course of our testimony.

III. DELIVERY VOLUMES BY SERVICE CLASSIFICATION

Q. What forecasting methodologies are used to project the electric delivery volumes for each service classification (“SC”)?

A. The forecasts of delivery volumes for all SCs, except SC 5 (Electric Traction Systems), SC 6 (Public and Private Street Lighting), and SC 13 (Bulk Power – Housing Development) are based on econometric models. The forecasts of delivery volumes for SC 5 and SC 6 are performed on a deterministic basis, meaning we assume that delivery volumes remain at their current levels for these two SCs. The only customer in SC 13 is on Standby Service and the forecast for that customer is included as part of the forecast for Standby Service customers, which we discuss in Section III-I.

Q. Please explain why the Company uses a different methodology for SC 5 and SC 6.

A. SC 5 and SC 6 are small service classifications and their delivery volumes have not changed significantly over time.

Q. Are there any other delivery volume forecasts that are not based on econometric models?

A. Yes. For commercial customers receiving the Company's Business Incentive Rate ("BIR"), the Company forecasts delivery volumes by extending recent trends. For customers under the Recharge New York ("RNY") program, the Company forecasts the delivery volume ("below-the-allocation") that is exempt from the System Benefits Charge ("SBC") and Renewable Portfolio Standard ("RPS") charge on a deterministic basis. For customers under Standby Service programs (85 existing customers and 12 projected new customers), the Company performs an analysis of each individual customer's recent usage.

A. Econometric Models

Q. For which service classes did the Company use econometric models?

A. The Company used econometric models to forecast electric delivery volumes for SC 1 (Residential), SC 2 (Small Commercial), SC 8 (Master Metered Apartments), SC 9 (Large Commercial), and SC 12 (Multiple Dwelling Space Heating). The Company's modeling periods, independent variables, and model structure are described below.

B. Modeling Periods

The Company developed the SC 12 econometric model on a monthly basis, using data from October 1996 through September 2021. The Company developed all other econometric models on a quarterly basis, using data from the fourth quarter of 1996 through the third quarter of 2021. Due to data availability issues, SC 12 had to be modeled with monthly data in the past. We continue to use the same model for SC 12 because it has performed well.

C. Independent Variables

The Company employs four types of independent variables – weather, dummy, mobility, and economic. Weather variables, in terms of heating degree days ("HDD") and cooling degree days ("CDD"), are included in all models to account for delivery variations due to differences in weather conditions.

Dummy variables are included in the SC 12 model to account for structural breaks in the data. Each dummy variable can take the value of zero or one and is used to indicate the presence of sudden shifts in the level of the data. The inclusion of such a variable allows us to isolate the impact of sudden breaks in the trend of a data series. The mobility variables are ratio variables that proxy for the COVID impact on sales. These are based on the Google mobility data that indicate the proportional deviation of daily customer mobility in segments of the economy relative to a base week in February 2020. Mobility in the residential segment impacts SC 1, 8, and 12; mobility in the rest and recreation segment impacts SC 2; and mobility in the workplace segment impacts SC 9.

Economic variables are included in the various models as follows:

- The SC 2 and SC 9 models, which apply to small and large commercial customers, respectively, include the number of customers in the class, real electric price of the class, which refers to the price of electricity expressed in constant base-year dollars, and private non-manufacturing employment. The private non-manufacturing employment variable has not been seasonally adjusted.

- The SC 1 model, which applies to residential customers, includes the real electric price of the class and real disposable income.
- The SC 8 model includes the real electric price of the class.

D. Model Structure

Each econometric model consists of two parts: a regression model, which correlates the delivery volume with the set of independent variables selected into the model; and an autoregressive integrated moving average ("ARIMA") model, which is discussed below. The combined model is often referred to as an ARIMAX model in modeling literature, where the letter "X" stands for the set of independent variables included in the model. The ARIMA model can take many different forms, and each model has its own ARIMA structure, statistically determined according to the data pattern of each SC.

Q. What is the purpose of including ARIMA as part of the modeling?

A. In forecast modeling, the model includes only a few key economic variables, such as real electric price, number of customers, income and/or employment. Although other economic variables may have an effect on electric delivery, they cannot be included in the model because they are not quantifiable, or there are no data available on them. The ARIMA mechanism captures the collective effect of these other variables. In addition, ARIMA also smooths out autocorrelations in the data. Autocorrelation is the situation where the current value of a variable is significantly related to its own values in the recent past. It is frequently present in time series data. If left unaddressed, the presence of autocorrelation leads to high forecast errors.

Q. Have you prepared an Exhibit showing the models that you have just described?

A. Yes, we have prepared a six-page document entitled “VOLUME FORECASTING MODELS.” In the Exhibit, we provide the econometric models used for forecasting delivery volume for SCs 1, 2, 8, 9, and 12, as well as the sendout model.

MARK FOR IDENTIFICATION AS EXHIBIT ___ (EFP-1)

Q. What criteria are used to measure the accuracy of the econometric models?

A. The Company uses generally accepted criteria to measure the accuracy of each model. The Company tests many different model structures for each SC, with variations especially in the structure of the ARIMA part of the model. As was done in Cases 13-E-0030, 16-E-0060, and 19-E-0065, we use a Durbin-Watson value near two, a low standard error, and a high R^2 as criteria to select the full econometric model in each SC for forecasting.

Q. Have you prepared an Exhibit showing the measures of accuracy you have just described?

A. Yes, we have prepared a one-page document entitled "ELECTRIC FORECASTING MODEL STATISTICS." In this Exhibit, we present measures of model performance for SCs 1, 2, and 9. These three service classifications are featured in the Exhibit because they account for over 90 percent of total Con Edison delivery volumes.

MARK FOR IDENTIFICATION AS EXHIBIT ___ (EFP-2)

Q. Please explain this Exhibit.

A. The Exhibit lists the adjusted R^2, standard error, and Durbin-Watson statistic of the models for SCs 1, 2, and 9. All three statistics satisfy the criteria discussed above, indicating that the models fit the historical data very well.

E. Model Assumptions

Q. Did you consider the impact of climate change on your weather variables?

A. Yes. We incorporated the impact of climate change on HDD and CDD by adjusting the normal HDD and normal CDD in the forecast period. Thus, the delivery volume forecasts from the econometric models reflect the impact of climate change.

Q. Please describe the adjustments made to the normal CDD and normal HDD to reflect climate change.

A. The Company's Climate Change and Vulnerability Study (2019) indicates that "normal" weather is going to be warmer in upcoming years. As such, we adjusted the normal weather in each year of our forecasts using the implied annual rates of change in CDD and HDD from the study. CDD were increased, and HDD were reduced, year to year, by the respective implied annual growth rates. The CDD and HDD were allocated to the months according to the allocations in 2020.

Q. You listed the key economic variables used in the forecasting models as private non-manufacturing employment, real electric price, real disposable income, the number of customers in each SC, and mobility. Please explain how the data for private non-manufacturing employment are developed.

A. For the historical period, the Company uses the Bureau of Labor Statistics Current Employment Survey ("CES") data for New York City (through September 2021). Because CES employment data for individual counties has been discontinued, data for Westchester is not directly available. The Company uses the methodology proposed by Department of Public Service Staff in pages 13 through 15 of its testimony in Case No. 18-E-0067 to construct the employment data for Westchester. Thus, the historical data for Westchester is constructed based on CES data through September 2021 and Quarterly Census of Employment and Wages (QCEW) data through March 2021.

Q. How is the forecast for private non-manufacturing employment developed?

A. The private non-manufacturing employment forecast is developed using the forecast from Moody's. The Moody's forecast is also used by the New York Independent System Operator and other New York State utilities. The Moody's forecast is developed for New York State as a whole and for individual regions and counties within the State. The Company developed its forecast for New York City by applying the annual growth rates available in the Moody's database in September 2021 (the most current available at the time the forecast was developed) to the CES actuals. The Company developed its forecast for Westchester County by applying the annual growth rates available in Moody's database in September 2021 to the constructed historical data for Westchester.

Q. What is Moody's projection based on data through September 2021 for private non-manufacturing employment?

A. For the Company's service territory, private non-manufacturing employment is projected to increase by 1.6% in 2021 and by 3.0% in 2022. It is then projected to decline by 0.9% in 2023, by 0.2% in 2024, and by 1.3% in 2025.

Q. How does the Company develop the forecast for real disposable income?

A. We use the forecast for real disposable income provided by Moody's.

Q. What is Moody's projection for real personal disposable income?

A. For the Company’s service territory, Moody’s projects that real personal disposable income will decline by 2.1% in 2021 and by 0.2% in 2022. It is then projected to increase by 0.8% in 2023, 2.0% in 2024, and 0.9% in 2025.

Q. How is the data for real electric price developed?

A. For the historical period, we calculated the nominal electric price for each SC by dividing the total delivery revenue of full service customers in the SC by their delivery volume. We then divided the nominal electric price by a price deflator to obtain the real electric price.

Q. What assumption does the model use for the real electric price variable in the forecast period?

A. As was done in Cases 16-E-0060 and 19-E-0065, we assume that the real electric price in the forecast period remains at the level it was during the most recent 12-month period, which in this case is the 12 months ended September 2021.

Q. Did you account for COVID?

A. Yes, through the mobility variable.

Q. What is the mobility variable?

A. Google has been collecting data to track movement trends by region and across different categories of space (e.g.

Residential, Rest and Recreation, Workplace, etc.) via mobile phone location. Each mobility variable shows how visitors to (or time spent in) categorized places change, relative to Google's baseline days (the baseline day is the median value from the 5-week period Jan 3 – Feb 6, 2020).

Q. Why is the mobility variable a reasonable way to account for COVID?

A. Because the mobility variables track the variance between mobile phone users' movement pre-COVID and post-COVID, these variables inform the Company on changes in electric usage , by customer group, caused by the pandemic.

Q. How is the data for the mobility variable developed?

A. Daily Google mobility for each segment (Residential, Rest and Recreation, and Workplace) are available for each of the New York City boroughs and Westchester (Google LLC *"Google COVID-19 Community Mobility Reports"*. https://www.google.com/covid19/mobility/). We created a single variable for each segment using the number of customers from each borough and Westchester. Billing-day-weighted quarterly and monthly mobility variables are then created for use in the models as appropriate.

Q. What assumption does the Company use for the mobility variables in the forecast period?

A. Based on Moody’s Analytics’ assumption that the economy will go back to full employment in 2023, we assume that workplace mobility will gradually increase until 2023. However, it will settle at 0.2 lower than the base period from 2023 onwards due to permanent work-from-home (full- or part- time) arrangements for some employees. Similarly, because a certain proportion of the workforce will continue to work from home, residential mobility will remain about 0.05 higher than the base period. Finally, we assume that rest and recreation will return to normal, thus the rest and recreation mobility variable will go down to zero (back to pre-pandemic levels) from 2023 onwards.

Q. Are the foregoing projections of employment, real disposable income, real electric price, and mobility used as inputs in the forecasting models to generate the Con Edison delivery volume forecasts?

A. Yes.

Q. Please explain how you developed the customer forecasts for the various service classifications.

A. The forecasted number of customers for SCs 1, 2, 8, and 9 are based on quarterly ARIMA models, using data from the fourth quarter of 1996 through the third quarter of 2021. The forecasted number of SC 12 customers is based on a monthly ARIMA model, using data from October 1996 through September 2021.

The forecasted number of customers for SC 5 and SC 6 are done on a deterministic basis.

Q. How does the Company use the customer forecasts?

A. The forecasted number of customers in each service class is used to forecast the number of bills, which in turn is used in calculating the competitive delivery revenues, which we will explain later in our testimony.

Q. Have you prepared an exhibit showing the ARIMA models used for forecasting the number of customers?

A. Yes, we have prepared a five-page document entitled "CUSTOMERS FORECASTING MODELS." In the Exhibit, we provide the ARIMA models used to forecast the number of customers for SCs 1, 2, 8, 9 and 12.

MARK FOR IDENTIFICATION AS EXHIBIT ___ (EFP-3)

Q. Based upon the foregoing methodologies, what are the projections for customers for SC 1, SC 2, and SC 9?

A. We project the number of customers for SC 1, SC 2 and SC 9 to grow by the percentages in the table below. These three service classes account for over 99% of the total number of customers.

	2021	2022	2023	2024	2025
SC 1	-0.12%	0.90%	0.36%	0.58%	0.40%
SC 2	3.55%	1.69%	2.38%	1.53%	1.85%
SC 9	-0.74%	0.12%	0.30%	0.33%	0.44%

Q. Are the foregoing customer projections used as inputs in the forecasting models to generate the Con Edison delivery volume forecasts?

A. For SCs 2 and 9, these customer forecasts are used as inputs in their respective forecasting models. In addition, customer forecasts for all Con Edison service classes are used to project the number of bills to determine competitive charge revenues, as explained later in our testimony.

Q. Have you prepared an exhibit showing the economic assumptions you have described?

A. Yes, we have prepared a one-page document entitled “ECONOMIC ASSUMPTIONS.” In this Exhibit, we provide projected values of the economic variables during the forecast period.

MARK FOR IDENTIFICATION AS EXHIBIT ___ (EFP-4)

F. New York Power Authority Volumes

Q. Are there other delivery volumes that are included in the forecast?

A. Yes. We also include New York Power Authority ("NYPA") volumes.

Q. Please describe the methodology for forecasting NYPA volumes.

A. We developed the NYPA volumes using a combination of methodologies – some items were developed on a deterministic basis and others based on econometric models.

For SC 66 (Westchester Street Lighting) and SC 80 (New York City Street Lighting), we forecast delivery volume on a deterministic basis based on recent billing data. We forecast the delivery volume for the development of Hudson Yards based on data provided by Con Edison's Energy Services Department.

We used econometric models to forecast the power supplied by Kennedy International Airport Cogeneration ("KIAC") to

JFK Airport and to forecast delivery volumes for all other NYPA service classes.

Q. Please describe the econometric models used for NYPA.

A. The Company developed monthly econometric models for the NYPA service classes and for KIAC. The modeling period is from October 1996 through September 2021. Like CECONY, NYPA models include four types of independent variables – weather, dummy, mobility, and economic. Dummy variables are included in the SC 91 and SC 62 models to account for structural breaks in the data. The other variables impact the NYPA SCs as follows:

- The SC 91 model, which applies to majority of NYPA customers, includes weather and the mobility variable for the rest and recreation segment.
- The SC 62 model, which applies to small commercial customers, includes total non manufacturing employment (not seasonally adjusted) for the service territory. Historical data for this variable is constructed similarly as the employment variable used in the CECONY models. Forecasts are also based on Moody's Analytics projections.

- The KIAC model includes weather and the passenger variable. The passenger variable is a ratio variable, similar to the mobility variables described above, that proxy for the COVID impact on KIAC sales. This variable is based on the paying passenger data, known as revenue passenger data, obtained from the Port Authority of NY/NJ that indicates the proportional deviation of the number of revenue passengers in a given month relative to the same month of the base year. The base year is from March 2019 through February 2020. These months were selected as the base months as they were the 12 months immediately preceding the COVID pandemic. The variable is expected to increase at the beginning of the forecast period, but settle at 0.10 below the base year levels from 2023 onwards due to an expected decrease in business travel going forward.

Q. Have you prepared an exhibit showing the models that you have just described?

A. Yes, we have prepared a three-page document entitled "NYPA VOLUME FORECASTING MODELS." In this Exhibit, we provide the econometric models used for forecasting NYPA delivery volume.

MARK FOR IDENTIFICATION AS EXHIBIT ___ (EFP-5)

G. Recharge New York Volumes

Q. What is Recharge New York?

A. Recharge New York is a statewide economic development program administered by NYPA to provide low cost electric power to non-profits and small businesses.

Q. Please describe how you develop the RNY delivery volume forecast.

A. We develop the delivery volume forecast for RNY by using historical data for the 12 month period that ended September 2021 of the customers who have accepted a RNY allocation offered by NYPA.

Q. How are the total delivery volumes for the franchise area derived?

A. The total delivery volumes are equal to the sum of Con Edison, NYPA, and RNY volumes.

H. Demand Side Management Programs

Q. Does your forecast of delivery volumes reflect the impact of demand side management ("DSM") programs?

A. A. Yes. The forecasts are net of the impacts of Con Edison's New Efficiency: New York (NE:NY) and Clean Heat programs, and the Company's current Non-Wires Solutions ("NWS") portfolio, including the Brooklyn Queens Demand Management Program ("BQDM") and other NWS programs. The forecast also includes projected reductions attributable to other energy reduction programs, such as approved NYSERDA Clean Energy Fund ("CEF") programs, as well as NYPA's planned efficiency projects in the Company's service territory.

Q. What sources are used for energy efficiency program forecasts?

A. The energy efficiency program forecasts are based on the energy efficiency programs described in the Customer Energy Solutions Panel testimony (including NYPA projects) and additional Company modeling of the energy efficiency savings required to achieve CLCPA goals.

Q. What sources are used in other program forecasts?

A. The Company included projected energy savings from its BQDM Program based on Case 14-E-0302 and other NWS programs.

Q. Is NYSERDA's CEF included in this forecast?

A. Yes, savings related to the NYSERDA CEF are included in this forecast. We based forecasted energy savings on the estimated market development benefits found in the Clean

Energy Investment Plan: Budget Accounting and Benefits Chapter submitted by NYSERDA in Matter 16-00681, *In the Matter of the Clean Energy Fund Investment Plan*, and adjusted for expected future energy reductions in the CECONY service territory.

I. Other Volume Adjustments

Q. Are there any other adjustments to the delivery forecast?

A. Yes. The delivery volume forecast for CECONY customers includes the following additional adjustments:

1. Solar generation – to account for the projected reduction in delivery volumes associated with the installation of solar panels by customers who will then generate a portion or all of their energy requirements.
2. Standby service (DG/CHP) - to reflect the projected delivery volumes from customers who plan to convert a portion, or all, of their existing load to on-site generation and will pay standby rates.
3. Conservation Voltage Optimization - to account for the projected reduction in delivery volumes associated with voltage optimization that is made possible when advanced metering infrastructure

(“AMI”) is installed (which the Company expects to be completed in 2023).

4. Hudson Yards – to capture the projected delivery volumes from the development of the Hudson Yards, excluding the accounts that are eligible for NYPA rates. This adjustment is based on data provided by Con Edison’s Energy Services Department.

5. Steam air-conditioning conversions – to capture the projected delivery volumes to customers who currently operate steam air-conditioning chillers and plan to convert to electric chillers.

6. Electric Vehicles – to capture the projected delivery volumes to customers who will be operating electric vehicles.

7. Electrification of Heating – to capture the delivery volume to customers who we have forecasted to install electric heating systems.[1]

8. Electrification of Cooking, Hot Water, and Dryers - to capture the delivery volume to customers who might switch gas appliances to electric.

[1]The Company does not expect the recent NYC electrification law to impact the Company’s forecasts for RY1, RY2 or RY3, but will further evaluate this issue for the Update filing.

9. Battery Storage - to capture the delivery volume to customers who might install battery storage.

Q. Are you making any adjustments to the NYPA delivery volumes?

A. Yes. We adjusted the NYPA delivery volume forecast to reflect the impacts of DSM; solar generation; electrification of heating; electrification of cooking, hot water, & dryers; electric vehicles; and battery storage. We also adjusted the NYPA delivery volume forecast to reflect the projected reduction in delivery volumes from NYPA customers who plan to convert all or a portion of their existing load to on-site generation and the Hudson Yards accounts that are supplied by NYPA.

Q. Have you prepared an exhibit showing the adjustments you have made to the delivery volume forecast?

A. Yes, we have prepared a five-page document entitled "DELIVERY AND SENDOUT ADJUSTMENTS." In this Exhibit, we provide the impacts on delivery volume due to items noted above. The impacts are listed, by service class, for each rate year.

MARK FOR IDENTIFICATION AS EXHIBIT ___ (EFP-6)

Q. For what periods are delivery volumes forecasted?

A. Quarterly. However, the quarterly delivery volumes need to be disaggregated into monthly amounts.

Q. Why do you need to disaggregate the quarterly delivery volumes into monthly forecasts?

A. Monthly delivery volumes are required to calculate revenues.

Q. How are the quarterly delivery volumes disaggregated into monthly delivery volumes?

A. Quarterly delivery volumes are divided into monthly delivery volumes by replicating the patterns of historical weather-normalized monthly delivery volumes. Monthly delivery volumes are also adjusted to reflect the differences in forecasted billing cycle days.

IV. REVENUE FORECAST

Q. Please explain the method of estimating Con Edison's delivery revenues.

A. The delivery revenue forecast consists of both the non-competitive delivery revenues and the competitive delivery revenues. The non-competitive delivery revenues include revenues from customer charges, and the energy and demand delivery rates while the competitive delivery revenues are comprised of the Merchant Function Charge

("MFC"), Billing and Payment Processing Charge ("BPP"), and Metering Charge Revenues.

A. Non-Competitive Revenues

Q. Please explain the method of forecasting Con Edison's non-competitive transmission and distribution delivery ("T&D") revenues for the forecast periods.

A. The T&D revenues from the forecasted delivery volumes to Con Edison's customers are estimated by month and by service classification. For each of the energy-only classes (SCs 1 and 2), the Company develops a pricing equation by correlating the monthly average T&D revenue of the class to the monthly volume of the class, the number of billing days, and summer/winter rate differentials, if applicable, using 12 month pricing data.[1]

For each of the commercial classes (SCs 5, 8, 9, and 12), where energy and demand charges apply, the Company also develops a demand pricing equation by correlating

[1]The Company's 12 month pricing data is based on the period February 2015 through January 2017, which is the last period where the Company had 13 months or more without a rate change. Twelve months of billing data at the same rates are required to run the regressions on the pricing equations. Because of the billing cycles, we need to have 13 months at the same rates to get the 12 months of bills at the same rates.

monthly average T&D revenue of the class to monthly billed demand of the class, the number of billing-days, and summer/winter rate differentials, if applicable, using its 12 month pricing data. The T&D energy revenues for commercial classes are based upon pricing equations similar to those developed for the energy only classes. The delivery volume, billed demand, and revenues of customers receiving BIR under Rider J and RNY customers are excluded from the data used in these commercial pricing equations. These pricing equations are then applied to the delivery and demand forecast of the respective service classes to obtain revenue at rates that went into effect on January 1, 2015. The revenue from the pricing models is then adjusted to reflect the rate changes that went into effect on January 1, 2017, January 1, 2018, January 1, 2019, January 1, 2020, January 1, 2021, and January 1, 2022.

Q. How do you forecast the revenues for customers not included in the pricing equations?

A. The forecast of T&D energy and demand revenues for BIR customers are based on the trend of actual BIR revenues over the 36 months ended December 2020, adjusted to reflect current rates.

The forecast of T&D revenues for the allocated portion of RNY customers are based on historical billing data for the period October 2020 to September 2021 to develop the delivery volume forecast.

The T&D revenues for SC 6 and customers in SCs 8, 9, 12, and 13 that are taking service under standby service were estimated by applying the appropriate tariff rates.

B. Competitive Revenues

Q. Please explain the method of estimating Con Edison’s competitive delivery revenues for the forecast periods.

A. The MFC revenues represent the supply and credit and collection related charges. The service class delivery volumes for full service customers only were multiplied by the current MFC rate as determined in Case 19-E-0065.

The BPP revenues are determined by applying the BPP charge per bill to the forecasted number of bills. This charge is at the level set in Case 19-E-0065 and depends on the customer’s choice of billing option and choice of service.

Q. Please explain the development of the forecasts of the number of bills for the various service classifications.

A. We determine the forecasted monthly number of bills by service class by adding the monthly year over year change in the number of customers to the monthly number of bills for the twelve months ended December 31, 2013 (i.e., the historical period for which detailed billing data is available), as was provided to us by the Electric Rate Panel. For January 2014 through September 2021, this change in the number of customers is based on actual customer counts. For the forecast period, the change in the number of bills is based on the number of customers forecast.

Q. Please explain the projection of billable demand for Con Edison’s commercial customers.

A. The billable demand forecast is the ratio of the forecasts for energy volume and the average hours use.

Q. How is the average hours use forecasted?

A. For each SC, the Company performs a detailed analysis of the relationship between historical delivery volumes and billable demand to determine the average number of hours of usage in each month. We then project these historical monthly averages as the forecasted hours use.

C. NYPA Revenues

Q. Please explain the method of estimating NYPA delivery service revenues for the forecast periods.

A. We forecast NYPA delivery service revenues by applying monthly average demand rates to the estimated billable demand. The estimated monthly demand rates are based upon the average actual demand rates for the 12 months ended September 2021, adjusted to reflect the rate changes that went into effect on January 1, 2020, January 1, 2021, and January 1, 2022. For NYPA standby service, the energy only classes, KIAC, and Hudson Yards, the delivery revenues are estimated by applying the appropriate tariff rates to our forecast.

Q. Please explain the method of arriving at the estimated NYPA demand.

A. For NYPA SC91, consistent with the methodology for CECONY, the billable demand forecast is the ratio of the forecasts for energy volume and the average hours use. For SC80, we based the monthly billable demand projections on an analysis of historical growth patterns and a full year average billable demand. Billable demand is not applicable to small general services and non-New York City street lighting that only have an energy charge component.

Q. Please explain the method of arriving at KIAC billable demand.

A. KIAC billable demand forecast is also calculated by taking the ratio of the energy volume forecast and the average hours use.

Q. How are the average hours use for NYPA and KIAC forecasted?

A. We project average hours use by using the relationship between NYPA and KIAC’s historical delivery volumes and billable demand.

Q. Please explain the method of estimating Hudson Yards billable demand.

A. We develop the Hudson Yards billable demand forecast based on a deterministic method using the estimated load levels provided by the Company’s Energy Services Department.

D. Other Revenues

Q. The revenue forecast also includes Market Supply Charge (“MSC”) and Monthly Adjustment Clause (“MAC”) revenues. Please explain how these components are forecast.

A. Rates for the MSC and MAC charges for each service class are supplied by the Electric Rate Panel. These rates are then multiplied into the delivery volume forecast for the respective service classes to determine, by service class, the MSC and MAC charges.

V. SENDOUT FORECAST

Q. How is the franchise area sendout forecast developed?

A. We use an econometric model to forecast the franchise area sendout on a quarterly basis.

Q. What variables are used in the sendout model?

A. We use weather variables in terms of heating and cooling degree days to account for variations due to differences in weather conditions. Like the delivery volume forecast, the key economic variables included in the sendout model are real electric price, total employment, real disposable income, the number of customers, and a mobility variable to represent the impact of the COVID-19 pandemic. As with the private non-manufacturing employment series used in the delivery volume forecasting models, the total employment series used in the sendout model is not seasonally adjusted.

Q. Please explain how the forecast variables are derived.

A. The bases for the real electric price and real disposable income are the same as for the delivery volume forecast. Total employment is the sum of private employment and governmental employment. The employment projection is based on Moody’s Analytics’ forecast of total employment in our service territory. Total employment is projected to increase by 1.2% in 2021, 5.4% in 2022, 2.3% in 2023, 1.1% in 2024, and 0.4% in 2025. The number of customers is represented by a sales-weighted index of the number of customers in SCs 1, 2, 8, and 9.

Q. Does your forecast of system sendout reflect the impact of DSM programs?

A. Yes. Like the delivery volume forecast, the sendout forecast is net of the impact of the DSM programs.

Q. Are there any other adjustments made to the sendout forecast?

A. Yes. The sendout forecast is also adjusted for projected changes in each of the factors affecting delivery volumes as discussed in Section III above.

Q. How do you determine the sendout forecasts for the different categories of delivery volumes, such as NYPA, RNY, and retail access delivery volumes?

A. The NYPA and RNY sendout forecasts are derived from their respective delivery volume forecasts. We apply the historical averages of distribution efficiency factors to the delivery volume forecast to account for the line loss in the system. Forecasts for retail access customers are done using a proportional allocation.

Q. How was the sendout for Con Edison full service customers derived?

A. It is derived by subtracting the sendout forecasts for NYPA, RNY, and retail access customers from the franchise area sendout.

Q. Do you need to disaggregate the quarterly sendout forecasts into monthly forecasts?

A. Yes. Company Witness Kimball, Electricity Supply, requires the monthly full service sendout for forecasting fuel costs.

Q. How are the quarterly sendout forecasts disaggregated into monthly sendouts?

A. Quarterly sendouts are divided into monthly sendouts by reflecting the patterns of historical weather-normalized monthly sendout figures.

VI. FORECAST SUMMARY

Q. I show the Panel a one-page document entitled "ELECTRIC SENDOUT, DELIVERY VOLUMES, AND REVENUES FROM DELIVERY VOLUMES – FORECASTED THREE MONTHS ENDING DECEMBER 31, 2021, AND YEARS ENDING DECEMBER 31, 2022, DECEMBER 31, 20223, DECEMBER 31, 2024, AND DECEMBER 31, 2025" and ask if it was prepared under the Panel's supervision and direction?

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT ___ (EFP-7)

Q. Will you please describe what is shown on this Exhibit?

A. Yes. This Exhibit shows the forecast of electric system sendout, delivery volumes, and revenues from delivery volumes for the three months ended December 31, 2021 and the twelve months ending December 31, 2022, December 31, 2023 – RY1, December 31, 2024 – RY2, and December 31, 2025 – RY3. Lines 1 through 4 show sendout categories within the Con Edison franchise area, and the total sendout for each period. Lines 5 through 8 show electric system delivery volumes for the same categories. Lines 9 through 23 show revenues for each of the periods. For RY1, as shown in column 3, lines 24 through 29 show the proposed revenue increases from delivery volumes to Con Edison and NYPA customers, decreased revenues from discounts to low income customers, as well as the associated revenue taxes, and line 30 shows total revenue at the proposed rates.

Q. I show the Panel a document consisting of five pages, entitled “ELECTRIC DELIVERY VOLUMES AND REVENUES FROM DELIVERY VOLUMES BY SERVICE CLASSIFICATION” and ask if this Exhibit was prepared under the Panel's supervision and direction?

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT ___ (EFP-8)

Q. Does this Exhibit set forth the results of the forecasts?

A. Yes. This Exhibit sets forth in greater detail, by service classification, the data that were shown in summary form on Exhibit ___ (EFP-7). Page 1 of this Exhibit shows the forecasted electric delivery volumes and revenues by service classification for the three months ended December 31, 2021. GWh delivery volumes are shown in Column 1, the sum of the monthly billable demand for Con Edison and NYPA in Column 2, non-competitive transmission and distribution delivery revenues at the current rates in Column 3, competitive service revenues at the current rates in Column 4, Reactive Power revenues at the current rates in Column 5, System Benefit Charge/Renewable Portfolio Standard revenues in Column 6, MSC, MAC, and DLM revenues in Column 7, revenue taxes in Column 8, and total revenues at current rates in Column 9. Pages 2 through 5 are similar in format to page 1; page 2 covers the forecast for 12 months ending December 31 2022, page 3 covers the forecast for RY1, page 4 covers the forecast for RY2, and page 5 covers the forecast for RY3. For the rate years, the low income discounts are shown as a separate item on line 9 at the level proposed by the Customer Operations Panel. For RY1, as shown on page 3, the effect of the proposed changes in revenues, annualized for the Rate Year, are shown in Columns 10 through 13, with the associated increase in revenue taxes shown in Column 14. The proposed change in revenues from the purchase of receivables, as supplied by the Electric Rate Panel, is shown on line 10. Column 15 shows the total revenues at proposed rates. The total proposed revenue increase to be collected from Con Edison’s customers of $1,028,583,000, exclusive of Gross Receipts Tax (“GRT”), consists of the non-competitive T&D related delivery revenue increase of $885,153,000, the customer charge increase of $138,405,000, the competitive service revenue decrease of $4,154,000, reactive power revenue increase of $455,000, and a MAC increase of $8,724,000. The proposed rates also result in increases, exclusive of GRT, in NYPA delivery revenue of $136,704,000. The resultant proposed overall increase for RY1, inclusive of the increase in rates and charges of $37,288,000 for revenue taxes, amounts to $1,202,575,000.

Q. Should this revenue forecast be used as the basis for setting the target revenues in the revenue decoupling mechanism ("RDM")?

A. Yes, the non-competitive delivery revenue forecast shown in Columns 3, 5, 10, and 12 on Page 3 of Exhibit ___ (EFP-8) should be the basis for setting the target revenue for each relevant service classification.

Q. Please explain the current RDM methodology.

A. The current RDM is based on a total class revenue approach. That is, at the end of each rate year, the Company will reconcile, by service class, the actual delivery revenues including reactive power revenue to the allowed delivery revenues, which include reactive power revenue. The Company refunds to customers if the actual delivery revenues are more than the allowed delivery revenues and surcharges customers if the actual delivery revenues are less than the allowed delivery revenues. The RDM is applicable to SCs 1, 2/6, 8, 9/5, 12, and NYPA. BIR, RNY, and Standby Service customers, which includes SC 13, are currently excluded from the RDM.

Q. Is the Company proposing any changes to the RDM?

A. Yes, we are proposing to extend the applicability of the RDM to all Standby Service customers, and combine SC 8 and SC 13 into one target on January 1, 2024. Details of the proposal are provided in the Electric Rate Panel's testimony.

Q. Assuming that retail access customers' supply costs were equivalent to the supply cost projected by the Company to its full service customers, and assuming that NYPA customers' supply costs were $0.075620/kWh, as specified in the testimony of the Electric Rate Panel, what is the percentage increase in total overall revenues?

A. The percentage increase for RY1 is approximately 14.2 percent.

Q. Has the Electric Forecasting Panel prepared an exhibit that shows the future average prices of delivery and supply by service class, taking into account both the increase in proposed delivery rates and other expected changes, such as changes in the MSC and MAC?

A. Yes, we have prepared a one-page document entitled "FUTURE AVERAGE DELIVERY AND SUPPLY PRICES BY SERVICE CLASSIFICATION." In this Exhibit, we provide the forecast of the average price of T&D Delivery and Supply for each service classification for the three rate years.

The supply charges reflect the effect of projected MSC and MAC charges based on the electric supply cost projections made by Company Witness Kimball. The delivery charges consist of projected non-competitive T&D charges and projected competitive service charges based on three years of proposed delivery revenue increases as provided to us by the Electric Rate Panel.

MARK FOR IDENTIFICATION AS EXHIBIT ___ (EFP-9)

Q. Does this conclude the Panel’s direct testimony?

A. Yes, it does.