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PROPERTY TAX PANEL – ELECTRIC AND GAS

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I. INTRODUCTION

Q. Would each member of the Property Tax Panel ("Panel") state your name and business address.

A. Stephen Ianello and Stephanie J. Merritt. Our business address is 4 Irving Place, New York, New York.

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

A. We are employed by Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company") and our responsibilities include the property tax functions for the Company and its affiliate, Orange and Rockland Utilities, Inc. ("O&R").

Q. Please explain your educational background, work experience and current general responsibilities.

A. **(IANELLO)** I have a Bachelor's Degree in English from the College of the Holy Cross, a Juris Doctorate (cum laude) from Suffolk University Law School, and an LLM in Taxation from New York University Law School. I have been with Con Edison for over 28 years specializing in tax law. I started my career at Con Edison in 1990 in the Tax Department as an attorney, moved to the Law Department and was promoted to

Assistant General Counsel and then returned to the Tax Department as Tax Director. I handle federal, state and local tax issues facing the Company including compliance, audits, and controversies, and monitor evolving tax developments. In addition, my work involves executive compensation matters, payroll issues, property tax matters, as well as evaluating and drafting tax legislation that affects the Company and energy industry. I am admitted to practice law in the State of New York and the Commonwealth of Massachusetts. Prior to joining Con Edison, I spent approximately four years as a trial attorney with the IRS Office of Chief Counsel, Manhattan District. Before that, I practiced law in a small general practice firm in New York concentrating in real estate, litigation and trusts and estates.

(MERRITT) I graduated from Le Moyne College in 2004 with the degree of Bachelor of Science in Accounting as well as a Bachelor of Arts in Economics. Currently, I am pursuing a Master of Business Administration Degree in Accounting and Finance from Syracuse University. I have been employed by Con

Edison since 2005 and have held various positions of increasing responsibility within the Finance area. After approximately two years in Corporate Accounting, I transferred to the Tax Department where I was promoted to Staff Accountant in the Financial Accounting and Regulatory Depreciation Group. In that position, my major responsibilities included the preparation and interpretation of the Company’s depreciation studies in connection with rate proceedings. I have assisted in over ten rate proceedings for Con Edison; O&R; Rockland Electric Company (O&R’s New Jersey utility subsidiary); and Pike County Light & Power Company (O&R’s former Pennsylvania utility subsidiary). In 2010, I began working in the Property Tax Group. I started as the Accounting Supervisor and rose to the position of Senior Tax Accountant in 2014. In September 2015, I was promoted to Section Manger – Local Taxes. I have held my current position of Department Manager – General Tax since June 2017. My responsibilities include oversight of the sections and personnel responsible for taxes other than income taxes, including all local, excise, sales and use taxes.

Q. Have either of you previously testified before any regulatory commission regarding property taxes?

A. **(Ianello)** I have testified before the Public Service Commission (“Commission”) regarding property taxes in O&R’s most recent base rate cases (Cases 18-E-0067 and 18-G-0068).

(Merritt) I have testified before the Commission regarding property taxes in the following Con Edison base rate cases: Cases 13-E-0030, 13-G-0031, 13-S-0032, 16-E-0060 and 16-G-0061. I have also testified before the Commission regarding property taxes in O&R’s most recent base rate cases (Cases 18-E-0067 and 18-G-0068).

II. PURPOSE OF TESTIMONY

Q. What is the purpose of the Panel’s direct testimony in these proceedings?

A. Our direct testimony:

- Presents general background information on property taxes;

- Describes the level of electric and gas property taxes recently paid by the Company;
- Presents our electric and gas property tax forecast and explains the methodology and certain assumptions used in that forecast;
- Explains the limitations on the Company's ability to control, and consequently, the difficulty in estimating, the level of its property tax obligations and describes the corresponding need for and our support of a full and symmetrical property tax reconciliation, as proposed in the direct testimony of the Company's Accounting Panel;
- Discusses the Company's efforts to pay no more than its fair share of property taxes; and
- Discusses the Company's proposal to retain 14% of estimated future tax savings, regardless of whether such savings are in the form of either a refund or future property tax reductions.

Q. Please explain the general basis upon which property taxes levied upon the Company have historically been determined.

A. Historically, the property taxes Con Edison has paid were based on the “value” of taxable property and include taxes on land and the structures and/or equipment erected or affixed to the land. These property taxes are known as real estate taxes. In New York State, utilities also pay property taxes on utility equipment located on or under the public streets and highways. These property taxes are known as special franchise taxes. In New York State, public utility property is valued under a method known as the “cost approach.” The New York State Office of Real Property Tax Services (“ORPTS”) and many of the local assessors in the Company’s service territory determine value by using a Reproduction Cost New Less Depreciation (“RCNLD”) methodology for utility structures and/or equipment. RCNLD calculates what it would cost to reproduce the utility structures and/or equipment at current construction costs based on a trending index, subtracts an allowance for depreciation and obsolescence, if any, and adds the value of land to arrive at a “value” for the entire property. The RCNLD methodology is used to value only certain of the Company’s structures and all of its equipment. The value of real property and commercial buildings, such as the Company’s 4 Irving Place Headquarters or the Learning Center, are determined by comparable sales or rental data rather than the RCNLD methodology.

III. SUMMARY OF RECENT AND PROJECTED PROPERTY TAXES

Q. Please provide some background on the amount of property taxes paid by the Company.

A. The Company pays property taxes to New York City and other municipalities. The other municipalities are principally located in Westchester County, but also in Orange, Rockland, Dutchess and Putnam Counties, where Con Edison owns transmission facilities. In addition, the Company pays property taxes on gas storage facilities (pursuant to a service agreement) located in West Virginia and Mississippi. We will refer to those other municipalities as “Westchester & Other.” For the historic test year (*i.e.*, October 1, 2017 through September 30, 2018), property taxes for electric expense were $1,443.3 million, and for gas expense were $266.7 million. Of those amounts, $1,519.6 million was applicable to New York City and $190.3 million to Westchester & Other.

Q. Have you forecasted property taxes for calendar year 2020 for this proceeding?

A. Yes. For calendar year 2020 (“Rate Year”), we have forecasted property taxes for electric expense to be $1,628.5 million and for gas expense to be $351.3 million. Of those amounts, $1,770.1 million is applicable to New York City ($1,480.5 million for electric and $289.6 million for gas) and $209.7 million is applicable to Westchester & Other ($148.0 million for electric and $61.7 million for gas).

Q. Have you forecasted property taxes for calendar years 2021 and 2022?

A. Yes. We forecasted property taxes for the two annual periods beyond the Rate Year to provide a basis for settlement discussions regarding a multi-year rate plan.

Q. What are the main drivers of the Company’s property tax increases during the 2020 through 2023 period?

A. Property taxes increase because either the tax rate increases and/or there is an increase in assessed value. However, both of those items are influenced by many factors, making it difficult to estimate future property taxes. For example, it is not possible for us to determine the needs of each individual town government and school district each year. In all cases, the Company’s property taxes are subject to the vagaries of municipal management, economic circumstances and political influences. In addition, the Company has no control over tax rates, leaving assessment challenges, when warranted, as the only recourse to mitigate the Company’s property tax liability. Regarding assessments, the growth of the value of the Company’s property and equipment, either through new infrastructure investment, application of the Handy-Whitman construction index, or discontinuation of depreciation, is the primary driver of assessment increases.

Q. Will the Company provide updates related to property taxes during these proceedings?

A. Yes. The Company intends to update property taxes as part of its formal update at the update stage of these proceedings and will also provide updated property tax information throughout these proceedings if new information becomes available that is, in the Company's judgment, significant. It is the Company's recommendation to base the revenue requirement in these proceedings on the latest available information on property taxes, subject to full reconciliation as discussed later in our testimony and in the direct testimony of the Company's Accounting Panel.

Also, the Company is in the process of purchasing the Cricket Valley transmission facilities for a nominal amount. The Company is in the process of developing forecasts of the property tax impacts of this transaction and anticipates including the property taxes in the preliminary update.

IV. NEW YORK CITY TAX FORECAST

Q. Please explain how you forecasted New York City property taxes.

A. We used the Company's 2018/2019 final real estate and special franchise assessed values as a starting point, and applied current tax rates to those values to compute taxes for fiscal year 2018/2019. We then computed estimated changes to assessed values for subsequent periods based on net plant changes forecasted by the Company's Accounting Panel.

Q. For the purpose of estimating property tax rates in New York City, did you compute a five-year average percentage change in the tax rates?

A. Yes, we did, and it indicates that both the rates relevant to the Company (Class 3 and 4 rates as discussed below) have increased.

Q. What was the five-year average percentage change in the tax rate resulting from your calculations?

A. The five-year average change in the tax rates was an increase of 0.32% and 0.37% for Classes 3 and 4, respectively.

Q. Did you use the five-year average for the escalation rate?

A. Yes. Our forecast reflects the approximate five-year average. As discussed below, we have concluded that it is best to use this escalation percentage for all years being forecasted.

V. WESTCHESTER & OTHER TAX FORECAST

Q. Please describe how you arrived at the forecasted property tax amounts for Westchester & Other.

A. For Westchester & Other, we used the Company's most recent property taxes paid as a starting point. Then, because it is not practicable to specifically forecast property taxes for each of the many different municipalities, school districts and other special districts to which the Company pays property taxes, we calculated an overall escalation percentage to develop the forecasted amounts. We developed the escalation percentage based on recent historical tax payment information from calendar years 2013 through 2018.

Q. What escalation percentage did you use?

A. We used a five-year average escalation percentage of 5.00%.

Q. Are you sponsoring an exhibit containing the computation of the five-year average escalation rate?

A. Yes, we are sponsoring Exhibit __ (PTP-1) entitled "CONSOLIDATED EDISON COMPANY OF NEW YORK, INC., FIVE-

YEAR AVERAGE OF PROPERTY TAXES PAID, WESTCHESTER & OTHER" for that purpose. This exhibit summarizes the tax payments made for the last six calendar years and computes the five-year average for Westchester & Other.

Q. Was Exhibit __ (PTP-1) prepared by you or under your direction and supervision?

A. Yes.

Q. Is that because you expect taxes in each of the next several years to increase by 5.00%?

A. Yes, we believe it is a reasonable basis for estimate. The five-year average in Westchester & Other has been fairly stable and at this time we believe that a 5.00% escalation rate will be representative of the escalation rate applicable during the Rate Year.

Q. Is there a difference in methodology between the escalation rate you used for Westchester & Other and the escalation rate you used for New York City?

A. Yes. The five-year average for Westchester & Other is an average based on actual taxes paid by the Company that we believe should be relied upon to set the level of property taxes in this proceeding. In contrast, as noted above, for New York City we used the current fiscal period tax rates.

Q. How did you reflect the 2% cap law under the New York State real property tax law (*i.e.*, N. Y. General Municipal Law Section 3-C) with respect to property taxes in your analyses?

A. We made no effort to specifically reflect the 2% cap law in our analyses.

Q. Why not?

A. The impact of the 2% cap on the Company’s property taxes is necessarily limited by the fact that it does not apply to New York City. As to areas outside New York City (*e.g.*, Westchester), the legislation limits are not dispositive as they may be overridden by a 60% vote of the governing body of the local government or a 60% vote of school district voters. In addition, there are exclusions that limit the reach of the cap. For instance, there are exclusions for court orders or judgments against the governing body or school district. There are also exclusions for contributions to employee retirement funds beyond specified limits.

Other exclusions require computations to determine what the legislation refers to as a “quantity change factor,” which may allow the tax levy to increase above the cap due to development. There are also exclusions that will allow school districts to increase the tax levy for certain expenditures associated with facilities, capital equipment, debt service, lease expenditures, and transportation debt service, subject to the approval of the qualified voters where required.

VI. UNCERTAINTY ASSOCIATED WITH FORECASTING PROPERTY TAXES

Q. Why do you believe that a reasonable forecast of the Company’s property taxes is not practicable?

A. In New York State the main revenue source to balance local municipal budgets is property taxes. Local budgets are strongly influenced by general economic conditions. Moreover, as discussed above, the majority of the Company’s property taxes are New York City property taxes. In New York City, the classification system adds complexity and uncertainty.

Q. Please provide an overview of the tax rate process in New York City.

A. Each year, the Mayor submits to the City Council the executive budget for the upcoming fiscal year (*i.e.*, July 1 to June 30). After the City Council adopts a budget, it must fix the annual real property tax rates and authorize the levy of real property taxes for the fiscal year.

Q. What mechanism does New York City use to fix property tax rates?

A. The City Council must pass a resolution, known as the Tax Fixing Resolution, which authorizes the tax rates to be used for each class and authorizes the levy of real property taxes for the fiscal year. The City Council adopted the most recent Tax Fixing Resolution in June 2018, which authorized the use of the tax rates that became effective for fiscal year 2018/2019.

Q. Please describe New York City’s tax fixing process.

A. The City Council determines the amount of the real property tax levy in the following manner. First, the City Council acknowledges the amount of the fiscal year budget and the estimate of the probable amount of all non-property tax revenues. Both amounts are set forth in a communication from the Mayor. The City Council then determines the net amount to be raised by taxes on real property by subtracting the amount of the fiscal revenue amount from the fiscal budget amount. The property tax is unique in that it is the only tax over which New York City has the discretion to determine the rate without new legislation from the State and, therefore, property taxes may be used to balance the budget. New York City also makes allowances for such items as uncollectible property taxes, refunds and collections of levies from prior years, collectively known as the “property tax reserve.” The tax levy is equal to the property tax revenue plus the property tax reserve.

Q. What happens next?

A. After having determined the amount of the real property tax levy, the Council authorizes and fixes the real property tax rates. Three factors determine the amount of tax imposed on a property in New York City: the market valuation for the property itself; the fraction of the market value on which taxes are to be paid; and the tax rate for the property class. There are four classes of property in New York City and, therefore, four different tax rates.

- Classes 1 and 2 pertain to various forms of residential property.
- Class 3 contains most utility property. Special franchise property is included within this class.
- Class 4 contains all commercial and industrial properties, such as office, retail, factory buildings and all other properties not included in Classes 1, 2 or 3.

With minor exceptions covering certain vacant land that is classified within Classes 1 and 2, the vast majority of the Company’s property is included in Class 3, with the remainder included in Class 4. Each class is responsible for a specific share of the property tax levy, known as the “class share.”

Q. How are the class shares determined?

A. The class shares are determined each year according to a complex statutory formula that takes into account changes in the market value of taxable real property, physical changes resulting from new construction or demolitions, changes in taxable status, and transfers of real property among the four classes. The “base percentage” is the percentage of total market value that each class constituted on the 1989 base tax roll. This is the roll that was used in setting the tax levy for fiscal year 1990. The “local base proportions” are the class tax shares that were used to fix the tax rates for fiscal year 1991 and comprise the thresholds currently used. Each year the City Council certifies “current percentages” and “current base proportions” to the State Board of Real Property Services (“SBRPS”). The current percentage is similar to the base percentage but applies to the most recent year for which the SBRPS has established class equalization rates (typically the preceding fiscal year). The current base proportions are the local base proportions modified to take into account the market value changes indicated by the latest class equalization rates. The Council next certifies the “adjusted base proportions” to SBRPS. The adjusted base proportions are the current base proportions adjusted to reflect physical and quantity changes indicated on the current assessment roll. These adjusted base proportions constitute the class shares applicable to the tax levy on the current tax roll. Fundamentally, the process was designed so that each of the four classes would bear roughly the same class share of the overall tax levy as it did in 1990, subject to physical and market value changes.

Q. Is there a limitation on the levy and/or the class shares?

A. There are two limitations. One is a State constitutional operating limit provision and the second is a five percent cap.

Q. Please describe the operating limit provision.

A. The operating limit provision generally provides that New York City is not allowed to levy taxes on real property in any fiscal year in excess of an amount equal to a combined total of 2.5 percent of the average full valuation of taxable real property for the current year and the prior four years.

Q. Please describe the second limitation.

A. The second limitation is a five percent cap. The statute provides that the current base proportion (*i.e.*, the current year's class share) of any class cannot exceed the adjusted base proportion or adjusted proportion of the prior year by more than 5%. Where a class's share change exceeds the 5% limit, the excess is spread among the other classes. In most years, the New York State Legislature has passed annual laws lowering the 5% overall cap for Class 1. The effect of these laws has been to cause the other classes to bear more of the overall tax burden than would have been the case under the 5% limit.

Q. Did the New York State Legislature pass an annual law lowering the 5% cap for Class 1 for fiscal year 2018/2019?

A. Yes, and there was similar legislation passed for fiscal year 2017/2018. We believe that is the primary reason for the increase in the Class 3 tax rate from 11.891% in fiscal year 2017/2018 to 12.093% in fiscal year 2018/2019. However, we also see the potential for cap legislation as one of the factors that make forecasting property taxes in New York City so difficult.

Q. Does New York City’s tax fixing process facilitate projecting the Company’s future property tax liabilities?

A. No, it does not. The process can produce very different results from one year to the next. Exhibit __ (PTP-2) entitled “CONSOLIDATED EDISON COMPANY OF NEW YORK, INC., SUMMARY OF HISTORIC NEW YORK CITY PROPERTY TAX RATES,” which was prepared under our direction and supervision, illustrates the volatility of Class 3 and 4 rates over time.

Q. Please provide a recent example of this tax rate volatility.

A. In fiscal year 2017/2018, in conjunction with imposing the 5% cap on other Classes, New York City raised the property tax rate for Class 3 property from 10.934% to 11.891%. This resulted in, more than a 9% increase in the property tax rate from the prior year, while decreasing the property tax rate for Class 4 for, 10.574% to 10.514%, a decrease of 1%.

Q. Can you provide an example of the effect of a tax rate change for New York City?

A. Yes. Absent any other changes in the forecast, a 5.0% increase (*e.g.*, an increase from 12.093% to 12.698% for Class 3 and an increase from 10.514% to 11.040% for Class 4) in New York City’s tax rates above the rates we have used in our forecast would increase Rate Year taxes by $91.3 million for electric properties and $17.9 million for gas.

Q. What property tax rates do you propose to use for purposes of these proceedings?

A. We selected tax rate changes that approximate the five-year average percent changes. Our projected property taxes reflect escalations of the tax rates of 1% for both Classes 3 and 4.

Q. Is that because you expect the rate changes in each of the next several years to be equal to approximately 1% based on the five-year average?

A. No. NYC property tax forecasts are subject to much uncertainty and actual tax rate changes can be quite volatile. For example, the NYC’s tax rates have increased as much as 18.5% from one year to the next. We will address that subject later in our testimony, but we note that it is that degree of possible variability that results in an inability to reasonably forecast property taxes for the Rate Year, even based on recent experience. It is also for these reasons that a full property tax reconciliation is justified and appropriate.

Q. Will you update the New York City Rates during the course of these proceedings?

A. We will update our forecast for tax rate changes if available, during the course of these proceedings.

Q. Does the Company have a proposal regarding reconciliation of property taxes for the Rate Year?

A. Yes. Given the variability and uncertainty we have explained, and the very limited ability to mitigate this variability and uncertainty, the Company believes that an accounting and ratemaking mechanism that fully insulates customers and the Company from property tax forecast variations is reasonable and appropriate. The Accounting Panel describes this mechanism in its direct testimony.

Q. Do you believe that full and symmetrical property tax reconciliation reduces the Company’s incentive to mitigate its property tax liability?

A. No, not at all. As we explain in greater detail later in our testimony, and as the Company has explained in numerous rate proceedings, meetings with the Staff of the Department of Public Service (“Staff”), and annual reports to the Commission of the Company’s activities regarding property taxes, the Company has a long history of actively fighting to reduce the Company’s property tax burden. Challenges to unfair assessments, litigation, lobbying efforts to seek favorable legislation, and aggressively pursuing available property tax benefits are a normal course of business for the Company.

Q. Has the Commission previously approved the full reconciliation of property taxes for a single-year rate plan?

A. Yes, in Case 08-E-0539, a rate case in which the Commission established electric rates for Con Edison on a litigated rather than settled basis and for a single rate year (*i.e.*, outside of the context of a multi-year rate plan on settled terms).

Q. In Case 08-E-0539, did the Commission address concerns that a full reconciliation would reduce the Company's incentive to minimize property taxes?

A. Yes. The Commission concluded that would not be the case. In its *Order Setting Electric Rates*, issued April 24, 2009 in Case 08-E-0539 (pp. 106-107), the Commission concluded:

> We share DPS Staff's concern about removing an incentive for the Company to minimize its property tax expenses. However, the record in these cases shows that the Company has aggressively sought to minimize its property tax assessments. Indeed, there is no assertion to the contrary. Moreover, our long standing policy is that a utility will be allowed to retain a share of property tax refunds, frequently in the 10-15% range, to the extent it can be established conclusively that the utility's efforts contributed to that outcome. Taking these two factors into account, we conclude that the Company already has and will retain an incentive to minimize its property tax assessments.

Accordingly, given the variability and uncertainty we have discussed above, a full and symmetrical property tax reconciliation mechanism that serves to protect both customers and the Company from forecast variations is both reasonable and appropriate.

VII. EFFORTS TO MINIMIZE PROPERTY TAXES

Q. Please summarize the Company's efforts to minimize property taxes.

A. The Company has aggressively challenged its property tax assessments in an effort to pay no more than its fair share of property taxes. The Company has been and remains very concerned with the level of property taxes in its service territory and the impact of these taxes on customers.

Q. Please discuss the Company's efforts to reduce property taxes.

A. As discussed earlier in our testimony, property tax amounts are a function of a tax rate multiplied by an assessed value. The Company has no influence on the tax rates that municipalities set; therefore, the Company focuses on the fairness of assessed values set by the municipalities.

Q. How do you determine which assessments should be challenged?

A. Each year we review our property assessments to determine if they fall within a range of reasonableness under an RCNLD valuation. This approach to valuation begins with the original cost of property, which is then trended to the current time period using Handy Whitman indices to arrive at an estimated cost to reproduce the property today. That valuation is then reduced by depreciation. The RCNLD methodology develops what is considered the current value of utility property and the method is used for valuation purposes by the ORPTS and the New York City assessors. If the actual assessments vary substantially from our RCNLD calculations, we file complaints with the applicable taxing authorities. We first attempt to settle these complaints through negotiation as we believe that a settlement is a more cost-effective way of reducing our tax burden than costly prolonged litigation, which requires independent appraisals and has uncertain outcomes. We do, however, pursue litigation when our efforts fail to result in what we believe to be a fair compromise.

Q. Please describe the tax controversy process.

A. As indicated, we monitor the assessed values of the Company’s properties and take action for each property that we believe is not fairly assessed. Each municipality’s assessing authority publishes a tentative assessment roll on an annual basis. The roll includes the annual tentative assessed values for each property located in the jurisdiction. If a taxpayer disagrees with the tentative assessment for their property, they may file an administrative complaint during a designated grievance period. During that period, in order to determine if any assessments should be challenged, the Company undertakes a review of its assessments to determine whether they fall within a range of reasonableness when calculated under RCNLD. If the actual assessments are 25% higher than the RCNLD calculations and the property tax dollar amounts involved are significant, the Company files complaints with the applicable taxing authorities. The municipality must respond to the administrative complaint and it has been the Company’s experience that complaints are denied. Accordingly, after the tentative assessment roll becomes final, the Company files tax certiorari petitions with the applicable court to formally contest the final assessments. The Company makes every effort to settle these challenges by meeting with the assessors and with town or city officials. However, when efforts to reach a fair compromise fail, the Company pursues litigation.

Q. Please discuss the Company's efforts to reduce property taxes in New York City.

A. We have continued negotiations with the New York City Law Department concerning the settlement of proceedings challenging the assessments on certain of Con Edison's locally-assessed properties for the fiscal years 1994/1995 through 2018/2019.

In October 2018, Con Edison again filed real property tax petitions with the New York City Tax Commission that seek reductions of Con Edison's 2018/2019 final tax assessments on real property. The filings were based on the real property tax assessment roll finalized in May 2018. Each year such applications are filed for a great number of Con Edison's properties that the Company views as over-assessed.

Con Edison now has filings on a large percentage of its New York City properties dating back to fiscal year 1994/1995.

Q. Has the Company had any recent successes?

A. Yes. During 2013, Con Edison obtained a significant property tax refund from New York City. After extended negotiations with the New York City Law Department, we reached a settlement covering the production plant assets at the Hudson Avenue Station for the years 1994/1995 through 2011/2012 and at the Ravenswood and Astoria Stations, formerly owned by Con Edison, for the years 1994/1995 through 1998/1999. As a result of this settlement, the Company received a lump-sum tax refund of $140 million. In its February 21, 2014 order adopting rate plans in Con Edison Cases 13-E-0030, et. al., the Commission approved the distribution of the refund in the manner provided for by Con Edison’s then applicable rate plans. This distribution resulted in electric customers being credited with approximately $85.0 million, and steam customers with approximately $34.9 million.

Q. Has the Company had any other recent successes?

A. Yes. Beginning in the 1994/95 tax year and continuing through the 2013/14 tax year (together the “Tax Assessment Years”), Con Edison commenced lawsuits against New York City in Supreme Court, New York County, in order to challenge New York City's assessments of the structures, machinery and equipment located at the 74th Street generating station and its substation (“74th Street”) and the 59th Street Steam generating station (“59th Street) (collectively “the Properties”) for the Tax Assessment Years.

Q. Please continue.

A. Appraisals were exchanged on the valuations of the Properties and a trial regarding 74th Street was scheduled for February 16, 17, and 18, 2016. Trial of 59th Street was to occur at a later date following the 74th Street trial. At the urging of the court, the parties engaged in extensive settlement negotiations and eventually agreed to a reasonable compromise on 74th Street for the Tax Assessment Years. A consent judgment was signed by the Judge on March 6, 2017 and New York City paid the Company a cash refund on July

24, 2017 in the amount of $30,789,354.97. The Commission approved the distribution of the refund in the manner provided for by the Company's previous and current rate plans. This distribution resulted in electric customers being credited with approximately $9.7 million, and steam customers with approximately $16.5 million.

Q. Please continue.

A. Once New York City and the Company agreed to settle 74th Street, New York City was willing to entertain settlement discussions for 59th Street. After months of extensive negotiations, on December 13, 2017, the Supreme Court New York County approved a Stipulation of Settlement for 59th Street for the Tax Assessment Years. In 2018, New York City paid the Company a total cash refund of $19,782,824.38. The Commission approved the distribution of the refund in the manner provided for by the Company's current rate plans. This distribution resulted in electric customers being credited with approximately $3.1 million, and steam customers with approximately $13.8 million.

Q. Please explain the Company’s additional efforts to reduce property taxes.

A. Aside from litigation, Con Edison has for several years secured the tax benefits provided under the state law Industrial and Commercial Incentive Program (“ICIP”) in New York City. The ICIP was enacted to encourage the development, expansion and preservation of commercial and industrial real estate. The ICIP grants a property tax exemption for the additional real property taxes that would otherwise be payable as a result of eligible industrial and commercial construction work. Con Edison has filed ICIP applications for projects involving the construction of new facilities and substations, substation renovations, and substation upgrades. The Company filed for and received the exemption for 20 projects, some of which involved multiple filings. Assuming current tax rates, these exemptions will generate more than $1 billion in tax savings over the course of their benefit periods, which range from 12 to 25 years. Despite efforts by Con Edison to extend the ICIP program, the program expired as of June 30, 2008.

Con Edison continues, however, to receive benefits for the projects that were eligible under ICIP. During the 2018/2019 fiscal year, Con Edison estimates that the tax savings related to ICIP will amount to $44 million.

Q. Does the Company challenge its special franchise taxes?

A. Yes, the Company has open challenges on its special franchise taxes in New York City. The Company commenced proceedings in Supreme Court, Albany County challenging the ORPTS special franchise full values for New York City’s 2009/2010 through 2017/2018 assessment rolls. The court has consolidated the proceedings for trial and discovery has been largely completed.

The special franchise complaints allege that the ORPTS’s application of the RCNLD methodology produces anomalous results that significantly overstate the value of special franchise property. The complaints are based on the ORPTS not properly taking into account the effects of:

- Changes in the cost of materials;

- Depreciation due to use of an artificial property age ceiling in relation to the property's average service life; and
- The proper level of Economic Obsolescence ("EO") and Functional Obsolescence ("FO").

Q. Does the Company receive EO and FO benefits?

A. Yes. Although we have challenged the amount of obsolescence allowances in our special franchise tax legal actions, Con Edison continues to apply for and receive EO and FO benefits. A request for an EO benefit is filed on electric and gas services and the FO benefit is filed on the Company's gas low pressure distribution mains. For 2018, we were approved for a reduction for EO of 10% on our gas plant, which will be applied to the 2018 New York City special franchise full values. We also requested a reduction for functional obsolescence for excess capacity in the gas distribution low pressure system from ORPTS. The ORPTS will apply reductions for FO on the gas distribution mains as follows:

City of Yonkers	10%
Borough of Bronx	4%

Borough of Manhattan	4%
Borough of Queens	3%

Q. Please discuss the Company’s other efforts to reduce property taxes in Westchester & Other.

A. The Company aggressively challenges property tax assessments outside of New York City. As detailed in our annual Property Tax Reduction Reports filed with the Commission, the Company has reached property tax settlements with many of the cities, towns, and villages in Westchester and Upstate. These settlements cover a significant amount of the Company’s property outside of New York City and we continue to monitor assessments in all of these areas to determine if additional challenges are warranted.

Q. Has the Company commenced any recent proceedings to challenge property taxes outside of New York City?

A. Yes. In 2017, the Company commenced proceedings against the following Westchester communities: City of New Rochelle, City of Yonkers, City of White Plains, Village of Buchanan, Village of Elmsford, and the Town of Greenburgh. Settlement negotiations between the Company and these municipalities are on-going.

Q. Does the Company also pursue legislative avenues to mitigate its property tax liabilities?

A. Yes. Representatives of the Company have met with representatives from the New York State Department of Taxation and Finance to discuss a proposal to centralize property tax assessments. Centralized assessment of the Company’s non-special franchise property would lead to cost efficiencies, promote uniform assessment practices and result in a lower likelihood of litigation challenging the method of determining assessments.

Q. How would the Company benefit under central assessment?

A. The Company has long supported and pursued central assessment legislation. Con Edison believes that the ORPTS staff is in the best position to value utility properties given their expertise and independence. Central assessment by the ORPTS would provide for a uniform method of assessment state-wide, which would reduce the number of separate tax grievances that Con Edison files. In addition, the ORPTS property assessments are generally more current and transparent, as Con Edison is required to report all of its property additions to the ORPTS. Overall, the ORPTS property assessments may result in tax reductions on some of Con Edison's properties. The main goal of the proposal, however, is to establish assessment uniformity, predictability and transparency. In fact, central assessment could also provide some financial relief to local governments who must secure outside expertise to value certain complex utility properties and are frequently required to defend these assessments in court, resulting in appraisal and legal fees and property tax refunds resulting from successful legal challenges brought by utility companies.

Q. What is the legislative status of central assessment?

A. In December 2017, Chapter 510 of the Laws of 2017 was enacted, establishing a five-year pilot program wherein all of Con Edison's Westchester properties that are valued locally were valued by the ORPTS commencing January 1, 2018. The Governor's approval message on the legislation states that an amendment to this chapter will be forthcoming and will require that a study be conducted by the New York State Department of Tax and Finance, in consultation with the Commission, to assess the viability of implementing central assessment for utility properties state-wide, with recommendations due May 1, 2018. The study was published in November 2018 and both the NYS Department of Taxation and Finance and the Commission recommended Central Assessment for all utility companies.

Q.   Does the Company keep the Commission and Staff apprised of the Company's efforts to reduce its property tax obligations?

A.   Yes. The Company prepares an annual report to the Commission of its efforts to reduce its property tax obligations. The report is filed with the Commission each March. The Company also meets with Staff to update them on property tax issues. Legislative efforts and accounting and assessment issues have regularly been part of that agenda.

Q.   Have you considered the effects of the Commission's ongoing Reforming the Energy Vision ("REV") proceeding (Case 14-M-0101) in your property tax forecasts?

A. No, we have not included anything in our forecasts to reflect the impact of REV, but we believe REV increases uncertainty related to property taxes, which further demonstrates the need for full and symmetrical property tax reconciliation. For example, these rate filings support the development of battery storage, but we do not know how battery storage located on customer premises and owned by the utility will be taxed.

Q. Despite the Company’s efforts to mitigate property taxes, do the Company’s property taxes continue to increase?

A. Yes. The funds raised via the property tax levy are often the major revenue source used to finance county and local governments and public schools. The Company bears an inordinate share of the levied tax obligations determined by the taxing authorities seeking to raise the funds they determine are needed. Those needs, in concert with the Company’s activities resulting in increased capital investment, have historically resulted in higher tax bills for the

Company despite successful Company challenges to assessed valuations of its property.

VIII. DISPOSITION OF PROPERTY TAX BENEFITS ON FUTURE PROPERTY TAX REDUCTIONS

Q. Please discuss the Company's proposal regarding the disposition of property tax benefits from property tax settlements.

A. The Company's current electric and gas rate plans provide that the Company shall retain an amount equal to 14% of the property tax refunds and/or credits allocated to electric/gas operations against future tax payments. Consistent with the Commission's long-standing policy of allowing utilities to retain a percentage of tax refunds to encourage them to challenge taxes, the Company proposes to continue these provisions with one modification.

Q. What modification is the Company proposing?

A. The Company proposes to modify the current mechanisms to account for the most common outcome of tax challenges: settlements involving future assessment reductions that will result in future savings.

Q. Why is a modification needed to account for such settlements?

A. Although our efforts to seek tax refunds occasionally produce actual refunds or credits, these are extremely difficult to obtain from governmental entities. A future assessment reduction is often the solution to this problem because the Company obtains a property tax reduction and the governmental entity avoids both the current cash outlay of a refund and the administrative and political burden of obtaining internal approvals for a refund or credit.

Municipalities also prefer settlements for future assessment reductions because they facilitate the municipalities' financial planning. There are also overarching benefits to settlements in general, as they avoid costly litigation for the Company and municipalities, as well as help maintain a cooperative working relationship between the parties.

As settlements are the preferable outcome for governmental entities and the Company alike, the Company should be entitled to retain 14% of tax savings resulting from property tax settlements, for the same reasons that the Company is entitled to retain 14% of property tax refunds and credits, net the cost to achieve. This builds on the current sound regulatory policy to provide the Company with a meaningful incentive for its property tax reduction efforts.

Q. Does the proposed modification have other benefits?

A. Yes. The modification also gives the Company flexibility in settling property tax reduction claims in the most efficient way possible. Absent the modification, the Company is dis-incentivized from accepting settlements for future reductions in assessments in lieu of cash refunds because it is denied retention of the equitable share the Company earned through its efforts.

Q. Is the Company's proposal to share the savings resulting from future assessment reductions appropriate if a rate plan provides for property tax reconciliation?

A. Yes. Regardless of whether property taxes are reconciled, customers receive a direct benefit from future assessment reductions, especially when such reductions apply over a multi-year period. Consistent with longstanding Commission policy, utilities should share in these benefits in order to incentivize them to aggressively challenge municipal over-assessments. Such sharing is particularly appropriate in those instances when property taxes are not fully reconciled (*e.g.*, the 90/10 sharing arrangement under the Company's current electric and gas rate plans). In these circumstances, the Company would be at risk for property tax variations.

Q. How does the Company propose to collect its share of future tax savings?

A. As with refunds and credits obtained through litigation, the Company will file a petition explaining the terms of any settlement agreement and requesting authorization to share in the tax savings. Once the initial petition is approved by the Commission, the Company will make annual compliance filings with a savings calculation to demonstrate the savings that resulted from the settlement. For example, where the Company's settlement agreements for future tax savings are the result of a change in assessment methodology, the Company will calculate annual savings by taking the difference in assessments between the pre-settlement and settlement methodologies and multiplying that difference by the prevailing equalization and property tax rate. Forty-five days after the compliance filing, if Staff has not raised any issues with the Company regarding the calculation, the Company will defer 86 percent of the calculated savings for customer benefit and retain 14 percent of the calculated savings.

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

A. Yes, it does.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
DIRECT TESTIMONY OF
YUKARI SAEGUSA

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CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
DIRECT TESTIMONY OF
YUKARI SAEGUSA

Q. Please state your name and business address.

A. My name is Yukari Saegusa. I am Vice President and Treasurer of Consolidated Edison Company of New York, Inc. (“Con Edison” of the “Company”). My business address is 4 Irving Place, New York, New York.

Q. Briefly describe your educational background.

A. I graduated from the University of Pennsylvania, Wharton School in 1989 and received a B.S. degree in Economics. I received an MBA from the MIT Sloan School of Management in 1995.

Q. Please summarize your professional background.

A. I joined Con Edison in March 2013. Prior to joining Con Edison, from 2004 to 2013 I was employed by Barclays as a Managing Director in Debt Capital Markets covering the United States utility and energy sectors. I was employed from 1995 to 2004 by Citigroup, also in Debt Capital Markets covering the United States utility sector. In my roles at Barclays and Citigroup, I was broadly responsible for advising utility clients on the design and execution of debt capital-raising and liability management strategies.

Q. Have you previously sponsored testimony before the New York State Public Service Commission ("Commission")?

A. Yes. I submitted testimony on behalf of Orange and Rockland Utilities, Inc. in Cases 14-E-0493, 14-G-0494, 18-E-0067 and 18-G-0068.

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

A. My direct testimony discusses (1) the current financial market environment, (2) the Company's historic and projected capital structure and cost of capital, and (3) the Company's financial challenges and the need to maintain access to financial markets at reasonable cost.

I. CURRENT FINANCIAL MARKET ENVIRONMENT

Q. Please describe the current state of the financial markets.

A. The U.S. is currently in its ninth year of economic expansion. U.S gross domestic product grew at an annual rate of 3.4% in the third quarter of 2018, the second fastest in the last three years. The unemployment rate has dropped from a high of 10.0% in October of 2009 to 3.9% in December 2018. Despite the recent market pullback in late 2018, the U.S. equity market is trading near all time highs and valuations remain above historical averages. The S&P 500 stock index, a proxy for the U.S. equity market, is trading at approximately 15.1x forward twelve month earnings compared with a 10-year average of 14.6x based on data compiled by Factset as of December 14, 2018 (see Exhibit__(YS-1)).

Valuations in the utilities sector are also above the historical long-term averages. The S&P 500 Utilities Index traded at 18.2x forward twelve month earnings compared with a 10-year average of 15.2x as of December 14, 2018. Utility stocks, often viewed by investors as bond surrogates, are trading at a premium to historical valuation measures as investor search for yield in the current interest rate environment.

On the fixed income side, the U.S. fixed income market is now in its third decade of a bull market run. Investors have been willing to invest money at record low yields as they look to put funds to work in an artificially low interest rate environment. The yield on Moody's Baa Corporate Bond Index recently stood at 5.14% (December 14, 2018) compared to a long-term average of 7.38% since January 2, 1986. Record low yields have been driven in large part by unprecedented actions taken by the U.S. Federal Reserve and central banks around the world in response to the 2008 financial crisis. The Federal

Reserve and other central banks have injected a substantial amount of liquidity into their respective economies through multiple rounds of quantitative easing. Quantitative easing is the practice of using money, newly created by the central banks, to buy mortgage-backed and government securities. The practice increases liquidity by injecting money supply into the economy and suppressing interest rates by driving the prices of the mortgage-backed and government securities up and yields on those securities down.

Q. Has the Federal Reserve taken action to scale back the unprecedented actions it took after the 2008 financial crisis?

A. Yes. Starting in January 2014, the Federal Reserve gradually began to reduce the amount of its bond purchases, ending these purchases completely in October 2014, and signaled an end to its ultra-loose monetary policy. In the December 2015 meeting of the Federal Open Markets Committee("FOMC"), the Federal Reserve raised the Federal Funds rate by 25 basis points ("bps") further signaling the end of an easing cycle and the beginning of a hiking cycle. Subsequent to the December 2015 Federal funds rate increase, the FOMC has hiked rates by 25 bps eight times (at the December 2016, March 2017, June 2017, December 2017, March 2018, June 2018, September 2018 and December 2018 meetings). The Federal Funds rate target range currently stands at 2.25%-2.50%. The Federal Funds rate is the overnight interest rate at which a depository institution lends funds maintained at the Federal Reserve to another depository institution. The Federal Funds rate is generally only applicable to the most creditworthy institutions when they borrow and lend overnight funds to each other. The Federal Funds rate is one of the most influential interest rates in the U.S. economy, because it affects monetary and financial conditions, which in turn have a bearing on key aspects of the broad economy including employment, growth and inflation.

Q. Has the Federal Reserve provided any guidance on the Federal Funds rate beyond 2018?

A. Yes. The Federal Reserve publishes a forecast of the Federal Funds rate for 2019, 2020, 2021 and longer run. The projections are based on the individual assessments of the Federal Reserve Board members and Federal Reserve Bank presidents. In the lastest forecast (December 2018), the median of the FOMC participants’ assessments of appropriate monetary policy puts the Federal Funds rate at 2.9%, 3.1% and 3.1% for 2019, 2020 and 2021, respectively. The forecast implies a 52.5 bps increase in the Federal Funds rate in 2019 from year end 2018 levels or approximately two 25 bps rate hikes. The Federal Reserve has signaled a willingness to continue to raise the Federal Funds rate despite signs of slowing global economic expansion, tightening of financial conditions and increased financial market volatility.

Q. Has the Federal Reserve announced any additional policy changes with respect to its bond buying program that will likely put upward pressure on interest rates?

A. In September 2017, the Federal Reserve announced that it has embarked on an effort to reduce its $4.5 trillion balance sheet. At its September 2017 meeting, the FOMC stated:

> The Committee intends to gradually reduce the Federal Reserve's holdings of Treasury securities and agency securities--agency debt and agency mortgage-backed securities (MBS)--by decreasing the reinvestment of the principal payments it receives from securities holdings.

The Federal Reserve began reducing its balance sheet in October 2017. As of October 2018, the Federal Reserve had reduced its balance sheet by $288 billion to $4.2 trillion (see Exhibit__(YS-2)). At the December 2018 FOMC meeting, Jerome Powell, the Chair of the Federal Reserve, signaled that the reduction of the Federal Reserve's balance sheet would continue by saying:

> I think that the runoff of the balance sheet has been smooth and has served its purpose. And I don't see us changing that.

Q. What are the challenges faced by the Company in today's financial markets?

A. Taking the aforementioned factors into account, one of the main challenges faced by the Company is its ability to earn a fair rate of return. A confluence of factors including Staff of the Department of Public Service's ("Staff") approach to setting cost rates for debt and equity, a rising and volatile interest rate environment, and elevated utility equity market valuations expose the Company to the risk that it will not be able to earn its cost of capital.

Q. Please describe the shortcomings with Staff's approach to setting cost rates for debt in the current financial market environment.

A. Staff’s approach to setting cost rates for debt based on current interest rates ignores the risks of rising rates as the Federal Reserve continues to hike interest rates and reduce its balance sheet. As an example, the 10-year Treasury yield is up 17.3% and the 30-year Treasury yield is up 11.8% year to date through December 14, 2018. In addition to the upward trajectory of interest rates, rates have also exhibited volatility. At their highest levels, 10-year Treasury yields had increased 31.2% and 30-year Treasury yields had increased 22.8% year to date. We expect interest rate volatility to continue. Short-term interest rates may rise both earlier and more quickly in anticipation of further actions by the Federal Reserve given the fact that the markets are forward-looking. As evidence of this, the mere hint of the Federal Reserve’s decision to start tapering its monetary easing policy in May 2013 sent ten-year Treasury bill rates higher by 46 bps for the month. A 46 bps move in one month (or an increase of 25% on a relative basis) has few precedents since 1990. To put this into perspective, on an absolute basis, this movement ranked in the top 95th percentile of changes in monthly ten-year Treasury bill rates since 1990 (see Exhibit___(YS-3)), which was prepared under my supervision and direction). And on a relative basis, a 25% move ranked in the top 99.5 percentile of changes in monthly ten-year Treasury bill rates since 1990. Sustained high volatility will likely lead investors to require a higher rate of return to compensate them for the additional risks that they will have to bear given this increased volatility. Therefore, Staff should rely on forecasted rates to set cost rates for debt.

Q. Please describe the shortcomings with Staff’s approach to setting cost rates for equity in the current financial market environment.

A. The current low interest rate environment has pushed utility equity market valuations above historical levels. These conditions are exacerbating the flaws of Staff’s reliance on a formulaic approach to determining a fair return on equity. Staff’s discounted cash flow (“DCF”) model, in particular, is producing results that are well below historical levels. Company witness Villadsen further discusses the weaknesses in Staff’s formulaic approach. She also provides an example of how the Federal Energy Regulatory Commission has responded to concerns about the reliability of the DCF methodology in the current low interest rate environment.

Q. What additional challenges are faced by the Company in the current environment?

A. Volatility in the financial markets has been and will continue to be one of the Company's most significant challenges as the Company continually needs to access the capital markets. Geopolitical events have the potential to further increase volatility in the capital markets. World events like those from the past few years(*e.g.*, trade tensions between the United States and China, BREXIT, the potential of a global economic slowdown, and the ongoing shutdown of the Federal government) can produce shocks that could affect the Company's ability to access capital markets efficiently.

II. <u>CAPITALIZATION AND COST OF CAPITAL</u>

Q. What capital structure do you believe should be used in the context of these rate case proceedings?

A. A capital structure with a 50.00% equity ratio, 1.11% customer deposits ratio and a 48.89% debt ratio should be used.

Q. Please describe why this proposed capital structure is appropriate.

A. The proposed capital structure with a 50.00% equity ratio (as compared with the 48.00% equity ratio in the Company’s current electric and gas rate plans) is appropriate and necessary to address the Company’s weaker cash flow profile. The Company’s weaker cash flow profile is a direct result of the successive low return on equity and equity ratios in its recent rate plans. The weak cash flow profile has been exacerbated further by the passage of the Tax Cut and Jobs Act of 2017 (“TCJA”). The two provisions of the TCJA that most negatively impact the Company’s ability to generate cash flows have been the reduction of the maximum corporate tax rate from 35% to 21% and the curtailment of bonus depreciation. These two developments will reduce the amount of future cash flow contribution from deferred taxes. In addition, as discussed in the direct testimony of the Company’s Income Tax Panel, the reduction of the corporate tax rate means that the Company will need to return a portion of the difference between taxes that have been collected from customers at the 35% tax rate and the new 21% tax rate.

Q. How did the rating agencies respond to the passage of TCJA?

A. On January 19, 2018, Moody’s lowered the rating outlooks of 24 regulated utilities and utility holding companies from “stable” to “negative.” The rating outlooks for CEI, Con Edison and Orange and Rockland were lowered from “stable” to “negative”.

Q. What reasons did Moody’s provide to support the rating outlook changes?

A. In the report, included as Exhibit__(YS-4), Moody’s wrote:

> The change in outlook to negative from stable for the 24 companies affected in this rating action primarily reflects the incremental cash flow shortfall caused by tax reform on projected financial metrics that were already weak, or were expected to become weak, given the existing rating for those companies. The negative outlook also considers the uncertainty over the timing of any regulatory actions or other changes to corporate finance policies made to offset the financial impact.

Q. What are the implications of a negative outlook?

A. A Moody’s rating outlook is an opinion regarding the likely rating direction of a company over the medium term. A negative outlook indicates a higher likelihood of a negative ratings change.

Q. What factors did Moody’s state it would consider in deciding whether a ratings downgrade would be warranted?

A. Moody’s stated that it would continue to monitor the financial impact of the TCJA on each company over the next 12 to 18 months. Moody’s stated a focus on:

> …regulatory approach to rate treatment and any changes to corporate finance strategies. This will include balance sheet changes dues to the reclassification of excess deferred tax liabilities as a regulatory liability and the magnitude of any amounts to be refunded to customers.

Q. Did Moody’s provide their views on potential regulatory offsets to the negative cash flow impact of the TCJA?

A. Yes. Moody’s was of the view that potential regulatory offsets could include accelerated cost recovery of certain regulatory assets or future investment; changes to the equity layer or allowed ROEs in rates, and other actions.

Q. Did Moody's provide any comments supporting their change in outlook for the Company specifically?

A. In a report published January 31, 2018, Moody's commented that (see Exhibit__(YS-5)):

> CECONY's negative outlook is driven by the negative impact from Federal tax reform, signed into law in December 2017. The resulting deterioration in cash flow, due to the early termination of bonus depreciation among other cash negative provisions, will pressure already weaker financial metrics compared to peers.

but

> CECONY's outlook could return to stable if the company is able to mitigate the negative cash flow impact from tax reform through regulatory developments to offset cash flow leakage with some other cash generative measures.

Q. Has there been any changes made by Moody's to the Company's ratings since their January 31, 2018 report lowering the Company's rating outlook?

A. Yes. On October 30, 2018, Moody's downgraded the Company's senior unsecured rating from "A2" to "A3" and the commercial paper rating from "P-1" to "P-2". Moody's cited the Company’s weak financial profile as the cause of the downgrade. Moody’s commented that the Company’s credit challenges are:

- Stagnant cash flow generation expected due to tax reform;
- High capex requirements and high dividend payout drive higher debt levels;
- State’s move toward more renewable energy creates new operating demands; and
- Moderate carbon transition risk as a T&D utility with no generation ownership.

Moody’s expects the Company’s ratio of cash flow from operations before changes in working capital (“CFO pre-WC”) to debt to fall to 16%-17% from over 20% historically and warned that the two main factors that could lead to an additional downgrade are (1) CFO pre-WC to debt declining consistently below 17% and (2) a less predictable regulatory environment or reduced cost recovery provisions.

Q. Are the credit challenges of stagnant cash flows and higher capital requirements cited by Moody’s unique to the Company?

A. No. In a November 8, 2018 regulated utility sector report titled, "2019 outlook negative amid growing debt and stagnant cash flow" (see Exhibit__(YS-6)), Moody's maintained the utility sector outlook at "negative" citing:

> …increasing debt to fund capital spending and dividends, as well as stalled cash flow growth as utilities continue to sort out the implementation of tax reform with state regulators.

Q. Did this Moody's report provide an update on how various regulatory jurisdictions around the country have responded to the deteriorating credit profile of the sector?

A. Yes. Moody's highlighted the divergence in how various regulatory jurisdictions have responded to declining credit profiles. In summary, Moody's highlighted the contrast between regulatory jurisdictions that have been proactive in addressing the risks from deteriorating credit quality as compared with other jurisdictions that have offered little to no support. Moody's writes:

> Some regulatory decisions in 2018 will allow for incremental cash flow generation, such as increased equity capitalization allowed in Alabama, Georgia

> and Texas, while several others have allowed utilities to offset liabilities due to required customer rebates against assets to be collected in the future. These regulatory decisions should lend some stability to utility cash flows and the financial metrics of affected companies.

but

> On the other hand, some regulatory decisions offer no new cash flow offsets, or not enough to support utility financial metrics at historical levels. For example, a more straightforward application of the new tax law has resulted in the nullification of entire rate increases for Consolidated Edison Company of New York (A3 stable) and Oklahoma Gas & Electric Company (OG&E A3 negative)...

Q. Can any conclusions be drawn from how supportiveness of regulatory jurisdictions impact the creditworthiness of regulated utilities in the current environment?

A. Moody’s has shown that the supportiveness of the regulator has a direct and meaningful impact on a regulated utility’s creditworthiness. Going back to Moody’s January action of changing the rating outlooks to “negative” from “stable” for 24 regulated utilities and utility holding companies, six of those companies have had their rating outlooks changed back to “stable,” while five companies have had their ratings downgraded as of November 2018. Of the six companies that have had their rating outlooks change back to “stable,” four are in states that Moody’s has deemed to have implemented policies that provide cash flow support to lessen the negative impact of the TCJA. Conversely, four of the five companies that have been downgraded since Moody’s January outlook action are in states that Moody’s has deemed to have offered little to no offset to the negative cash flow impacts of the TCJA.

Q. Did Moody’s highlight any specific credit positive policies that provide incremental cash flow as an offset to the cash lost due to the TCJA?

A. Yes. In a June 18, 2018 report (see Exhibit__(YS-7)), Moody’s highlighted Georgia and Alabama as two jurisdictions that have increased the authorized equity ratios. Georgia approved a tax reform settlement agreement allowing Georgia Power Company to increase its authorized retail equity ratio from approximately 51% to as high as 55%. The Alabama Public Service Commission approved Alabama Power Company’s request to increase gradually its equity ratio to 55% by 2025. Moody's commented that (see Exhibit__(YS-8)):

> Georgia Power's settlement agreement and the increased authorized equity ratio also signal the continued credit supportive regulatory environment in Georgia and the constructive relationship the utility has with the Georgia Public Service Commission.

Moody's commented on Alabama's settlement (see Exhibit__(YS-9)):

> On 1 May 2018, in response to changes to US tax legislation, the Alabama Public Service Commission approved modifications to the Rate Stabilization and Equalization (plan) and made other commitments designed to support the credit quality of Alabama Power. As part of the Rate RSE modifications in May 2018, the APSC also approved an increase in Alabama Power's equity ratio to 55% by 2025, a credit positive.

Q. Besides Moody's November 8, 2018 utility sector report, has there been any other independent analysis that has evaluated the supportiveness of regulatory jurisdictions around the country?

A. Yes. On November 29, 2018, UBS' utility equity analyst published a sector report (see, Exhibit__(YS-10)) titled "North America Power & Utilities: Roll On". In this report, UBS ranks the various North American regulatory jurisdications based on five criteria: (1) whether commissioners are appointed or elected; (2) allowed return spread history; (3) mechanisms that reduce regulatory lag; (4) rates and customer levels compared to region; (5) tendency to settle versus litigate rate cases; and (6) a subjective investor friendliness factor.

Q. How did New York rank in UBS' evaluation?

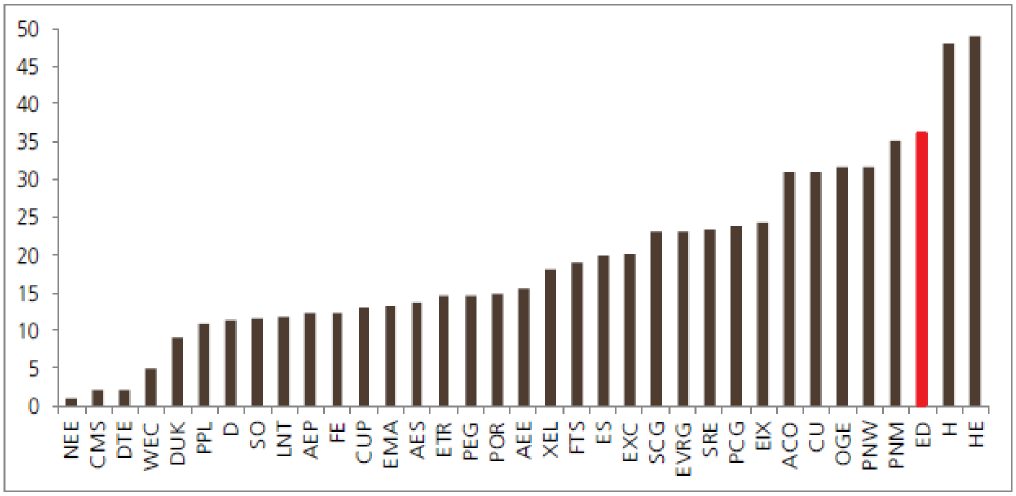
A. New York's regulatory jurisdiction ranked in the 4th tier, with the 1st tier being the most favorable and 5th tier being the least favorable. This represented a downgrade for New York from when UBS last published their rankings in February 2018. As noted in the chart below, New York was ranked in the 3rd tier before this downgrade. New York has been surpassed by states such as Connecticut and Delaware as those states have implemented supportive regulatory mechanisms, including the reduction of regulatory lag.

TIER 1	TIER 2	TIER 3	TIER 4	TIER 5
		Nova Scotia		
		North Dakota		
FERC		Iowa		
		Kentucky		
		Washington		
		Tennessee		
		Texas		
		Missouri		
		Massachusetts		
		South Carolina		
	Pennsylvania	Wyoming	Prince Edward Island	
	Illinois	Kansas	Nevada	
	Arkansas	Rhode Island	New Hampshire	
	Ohio	California	New York	
Florida	Louisiana	Alberta	Oklahoma	New Mexico
Michigan	Georgia	Newfoundland & Labrador	Alaska	Maine
Utah	Idaho	Delaware	West Virginia	Maryland
Wisconsin	British Columbia	Minnesota	South Dakota	Montana
Alabama	Indiana	Connecticut	Nebraska	Hawaii
Colorado	Virginia	New Jersey	Mississippi	Vermont
North Carolina	Oregon	Arizona	Ontario	District of Columbia

Source: UBS

Q. Did UBS rank Con Edison against its regulated utility peers?

A. Yes. As noted in the chart below, UBS ranked Con Edison 33rd out of the 35 companies evaluated by UBS based on UBS' proprietary ranking of regulatory jurisdictions. In addition, UBS applied a negative 5 percent discount to the Company's equity valuation to account for the New York regulatory environment.



Source: UBS

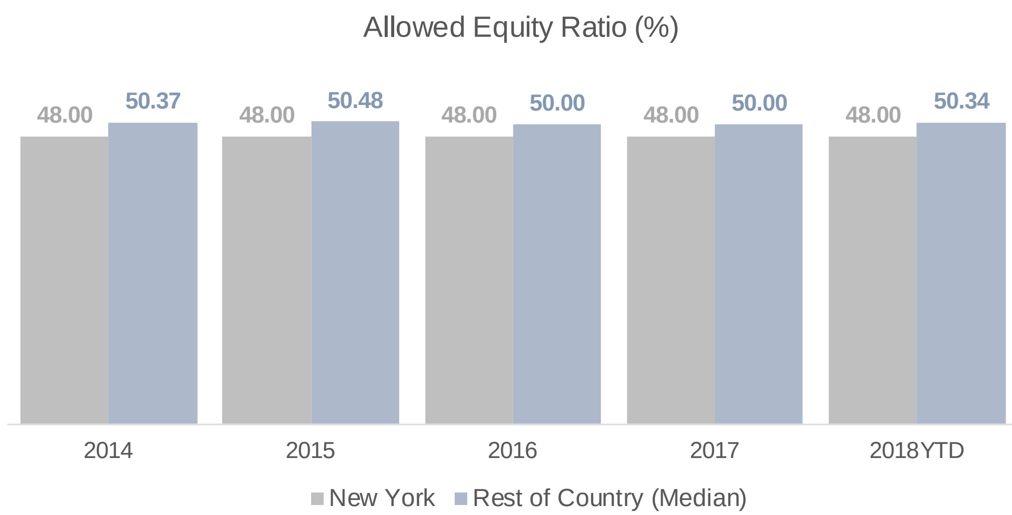
Q. What is the significance of the recent downgrades of both the Company and New York regulatory jurisdiction by both fixed income and equity analysts?

A. The recent downgrades are an independent confirmation of the deterioration of the New York regulatory environment relative to the rest of the country. A less supportive regulatory environment imposes additional costs for both customers and shareholders. The downgrade of the Company by Moody’s has already increased the rates at which the Company can borrow debt. The Company’s commercial paper rates have increased by approximately 3-5 bps and the credit spreads at which the Company borrows longer debt have widened by approximately 3-5 bps since the recent Moody’s downgrade of the Company’s credit rating. In addition, any discount applied by investors to the Company’s equity valuation to account for the less supportive regulatory environment in New York will increase the Company’s cost of equity.

The Company will be required to access both the debt and equity markets in the coming years due to weaker cash flows resulting from the TCJA paired with sustained capital spending in order to maintain the Company’s infrastructure. The ability to access the capital markets in an efficient and cost effective manner will benefit customers and shareholders.

Q. Why is a capital structure with a 50.00% equity ratio reasonable?

A. An equity ratio of 50.00% would bring New York up to the national average. The chart below shows the median equity ratio for the rest of the country over the last five years, as compared with a median equity ratio of 48.00% in New York.



Source: SNL Financial

In addition, as previously noted, some jurisdictions are further increasing equity ratios to offset the negative cash flow impact of the TCJA. A slightly higher equity ratio will also provide the capital markets with a clear signal that New York will act proactively to preserve the credit strength of its utilities.

Q. How would a 50.00% equity ratio potentially impact the Company’s credit profile?

A. As discussed above, a 50.00% equity ratio would be an important signal of the credit supportiveness of the New York regulatory jurisdiction to the credit rating agencies. The rating agencies’ assessment of regulatory framework is an important component of their rating methodology. For example, Moody's applies a 25% weighting to regulatory framework in its rating methodology. In addition, a higher equity ratio will result in stronger credit metrics for the Company. As an example, Moody's is most focused on the Company's CFO pre-WC to total debt ratio. In Moody's most recent write-up on its downgrade of Con Edison (Exhibit__(YS-11)), the agency listed "CFO pre-WC to debt declining consistently below 17%" as one factor that could lead to an additional downgrade of the Company's credit rating. In the same report Moody's calculated the Company's most recent CFO pre-WC to debt ratio (as of September 30, 2018) at 16.4%, which is below Moody's threshold for an additional downgrade. The chart below estimates the potential improvement to the Company's CFO pre-WC to debt ratio (as of September 30, 2018) based on Moody's methodology, assuming a 50.00% equity ratio instead of 48.00%.

	Last 12 Months Ending 9/30/18	Adjustment for 50% Equity Ratio	LTM 2018 with 50% Equity Ratio
CECONY Electric Ratebase	$19,588		$19,588
CECONY Gas Ratebase	5,342		5,342
Total Electric & Gas Ratebase	$24,930		$24,930
Allowed Return on Equity	9.00%		9.00%
Allowed Equity Ratio	48.00%	50.00%	50.00%
Moody's Credit Ratio			
Cash Flows from Operations (pre-working capital)	$2,711	$45	$2,756
Total Debt	16,554	(499)	16,055
CFO pre-WC / Debt	**16.4%**		**17.2%**

Increasing the Company current 48.00% equity ratio by 2.00% to 50.00% is estimated to improve the Company's CFO pre-WC to debt ratio by approximately 80 bps and put the ratio above Moody's downgrade threshold. Given the Company's already weak credit metrics, an 80 bps improvement can mean the difference between the Company maintaining its current rating as compared to a further downgrade.

Q. Has the Company prepared a required rate of return exhibit?

A. Yes. The document entitled "CONSOLIDATED EDISON COMPANY OF NEW YORK -- RATE OF RETURN REQUIRED FOR THE RATE YEAR -- THIRTEEN MONTH AVERAGE ENDING DECEMBER 31, 2020," is set forth as Exhibit__(AP-5), Schedule 2.

Q. Please describe any projected changes in Con Edison's long-term debt and how such changes have been incorporated into the required rate of return for the Rate Year (*i.e.*, January 1, 2020 through December 31, 2020).

A. The Company has issued and expects to issue the following debentures:

- During the linking period (*i.e.*, October 1, 2018 through December 31, 2019): $1,100 million of Debentures, Series D 2018, 4.600% to be issued November 2018, due November 2048, $600 million of Debentures, Series A 2019, 5.000% to be issued March 2019, due March 2049 and $600 million of Debentures, Series B 2019, 5.000% to be issued September 2019, due September 2049.
- During the Rate Year: $750 million of Debentures, Series A 2020, 5.450% to be issued March 2020, due March 2050 and $650 million of Debentures, Series B 2020, 5.450% to be issued September 2020, due September 2050.

Q. Please describe how you developed the cost of long-term debt.

A. Exhibit__(AP-5), Schedules 5 and 6, present the detailed calculation of the cost of the long-term debt at September 30, 2018 and for the thirteen-month average ending December 31, 2020, respectively. These schedules detail each issue of long-term debt outstanding and calculate an effective annual cost for each issue, taking into consideration the original net proceeds to the Company and annual interest costs. The sum of the effective annual cost for all issues is divided by the gross amount of debt outstanding to derive the weighted average cost of long-term debt.

Q. Did you provide the interest rate forecasts used as a basis for the cost of debt in this exhibit?

A. Yes.

Q. What method have you used to develop the interest rate forecasts?

A. The Company has used forecasts of Treasury bond rates from the publication *Blue Chip Financial Forecasts*, plus a spread to Treasury bond rates based on indicative quotes from financial institutions. The *Blue Chip Financial Forecasts* consist of the consensus forecast of approximately 45 economists. This approach provides more reasonable forecast results than simply using the most current Treasury bond rates. At the update stage of this proceeding, the Company will revise Exhibit__ (AP-5), Schedule 6, to reflect the most recent data available, as well as any new or refinanced debt that the Company may have issued by that time.

Q. Do you believe that current Treasury rates provide the best estimate of future long-term interest rates?

A. No. The position of Staff in recent base rate proceeedings that current rates are the best estimate of future long-term interest rates relies on a single academic paper that the Company believes is not relevant.

Q. Can you explain the flaw in Staff's position?

A. Yes. In the direct testimony of the Staff Capital Stucture Panel (pp. 55-56) submitted in recent Orange and Rockland Utilities, Inc. electric and gas base rate cases (*i.e.*, Case 18-E-0067 & 18-G-0068), Staff states that:

> …relatively short-term movements in long-term interest rates are difficult to forecast. Such forecasts are not only poor predictors of the magnitude of the expected change in interest rates, they are not even reliable with respect to the direction of the change. Instead, the best estimate of future long-term interest rates is no-change; in

other words, the current rates of these debt instruments.

Q. Does Staff offer any evidence to support their position?

A. Yes. Staff references a study titled, "On Forecasting Long-Term Interest Rates: Is the Success of the No-Change Prediction Surprising?", by Dr. James E. Pesando in the Journal of Finance, September 1980. This study relies upon research entitled *Econometric Models and Current Interest Rates: How Well do They Predict Future Rates,* from J. Walter Elliott and Jerome R. Baier published in 1979. The Company believes that both papers are not relevant to the discussion of forecasted interest rates in this rate case. Pesando and Elliot/Baier argue that short-term movements in long-term interest rates are not "forecastable." Their analyses determined that current long-term interest rates (*i.e.*, a no-change prediction) outperformed "unconditional predictions" in forecasting long-term interest rates one month forward. But Pesando cautioned that when a longer forecasting timeframe was used, the outperformance of the no-change prediction no longer held. When Pesando looked over a one-year forward period, the results were very different. In his research, Pesando notes the following when comparing the results from the one-month study to the one-year study:

> These figures highlight the fact that it is short-run movements in long-term rates which are not likely to be “forecastable” under the joint hypothesis of market efficiency and a time-invariant term premium.

The Company is setting the cost of debt rates anywhere from three months to three years forward and therefore this timeframe is not consistent with the Pesando and Elliot/Baier research.

Q. What is a better method than using current rates to forecast rates?

A. A forward looking measure of rates is a better forecasting method. Examples of forward looking measures are the forward rate curve or a consensus of economists’ estimates contained in the *Blue Chip Financial Forecasts*. The forward rate is the rate you can lock in today to borrow in the future and can be interpreted as the market’s consensus forecast of interest rates. A consensus forecast of Treasury rates, such as that produced by Blue Chip Financial, provides a more reasonable estimate rather than simply relying on current rates. Adopting a forward looking measure is essential in the current rising interest rate environment.

Q. Do you have a recommendation for the treatment of the Company’s variable rate debt?

A. Yes. I recommend the continuation of the true-up of interest costs for the Company’s variable rate debt, that the Commission authorized in the Company’s last electric and gas base rate cases (Cases 16-E-0060 and 16-G-0061).

Q. What would be included in the true-up?

A. The true-up would include the difference between the rates actually prevailing during the Rate Year and the interest costs set for the variable rate debt in this case. The true-up would also be applied to credit support costs such as letters of credit associated with such debt. In addition, existing long-term debt has associated unamortized issuance costs (representing underwriting fees and other costs from the time of issuance) which should also be included in the true-up. Furthermore, if the Company decides to refinance any variable rate debt, the actual cost of the replacement debt issues (including issuance costs and any credit support) and the new interest rate would be trued-up as well.

Q. What stand-alone capital structure for the Company results from the calculations that you described?

A. Exhibit__ (AP-5), Schedule 2, shows the forecasted capital structure for the thirteen months ending December 31, 2020 of 50.34% long-term debt, 1.14% of customer deposits, and 48.53% common stock equity. The Company has no preferred stock outstanding.

Q. Does Exhibit__ (AP-5) also show the forecasted capital structure, based on a thirteen-month average, for the twelve months ending December 31, 2021 and December 31, 2022, respectively?

A. Yes. Schedules 3 and 4 of Exhibit__ (AP-5) show the capital structure for those periods. These schedules show that the debt ratio would decrease slightly to 50.29% of the Company’s capital structure in 2021 and then increase slightly to 50.33% in 2022. These schedules also show that the customer deposit ratio would decrease modestly to 1.08% in 2021 and 1.04% in 2022. The equity ratio would increase to 48.63% and remain unchanged at 48.63% for the twelve-month periods ending December 2021 and 2022, respectively.

Q. What return on equity is the Company proposing be used for purposes of developing a revenue requirement in these filings?

A. For the reasons discussed in the direct testimony of the Company's Accounting Panel, the Company proposes a 9.75% return on equity ("ROE") be used. The Company is proposing a ROE that is slightly lower than what Company witness Villadsen is recommending in order to minimize the controversial issues in this proceeding and facilitate reaching a multi-year rate plan through settlement.

Q. What overall rate of return is the Company proposing in these proceedings?

A. Using the Company's proposed capital structure, cost of long-term debt and return on equity, the overall rate of return is 7.29% as shown on Exhibit__ (AP-5), Schedule 2.

III. CAPITAL NEEDS AND INVESTOR CONCERNS

Q. Please describe the financial challenges facing the Company during the Rate Year and beyond.

A. The Company faces the following interrelated financial challenges: (A) the capital intensive nature of its business, (B) flat to declining demand growth for electricity, (C) its unusually weak cash flows, (D) the restrictions that regulation places on its ability to respond to unfavorable developments in its environment, and (E) its dependence on the market to fund its capital needs.

Q. Please discuss the capital intensive nature of the Company’s business.

A. The Company’s business requires significant capital investment every year, its assets are long-lived and the underlying technology, facilities and customer base are mature.

Capital intensity is high for utilities. According to a June 2, 2011, IHS Cambridge Energy Research Associates presentation titled *Post Fukushima: If not nuclear, what energy mix?*, the electric utility industry is the most capital intensive industry as measured by the ratio of total assets to total revenues. As shown on Exhibit___ (YS-12), which was prepared under my supervision and direction, the Company’s capital intensity can be demonstrated by the fact that its ratio of net fixed assets per dollar of revenues is 3.2, as compared with 0.9 for the average S&P 500 company and 0.2 for the median company. Capital intensity amplifies risk for investors because capital intensive businesses have to recover much larger fixed costs (interest and depreciation) before achieving a return on their investment. The Company's assets also have extraordinarily long lives. Long-lived assets, in the context of rate regulation, present two financial challenges for the Company that are also risks for potential investors in the Company's debt issuances and equity shares. First, their investment horizons for capital recovery must be much longer. For debt investors, utility debt has much longer average maturities than other companies. Equity investors must also wait longer for repayment on their investment. Second, there is a regulatory risk in long-lived assets because United States rate regulation limits returns to a fraction of historic tangible book value rather than replacement or current market value. The Company's depreciation recoveries, which reflect historic tangible net book values, are small relative to its current capital costs, returning only 40% of its capital expenditures in the form of depreciation for the twelve months ended December 31, 2017.

Due to the long depreciation lives established in rates, this dynamic is likely to continue for many years. As shown on Exhibit___ (YS-13), which was prepared under my supervision and direction, by way of comparison, the average S&P 500 company recovered 152% of its capital expenditures through depreciation and amortization. This would have placed Con Edison near the bottom 10% of companies in the S&P 500 that had meaningful recovery rates. CEI (which had a 36% capital expenditure recovery rate) had the six-lowest recovery rate among the 27 utilities in the S&P 500 with reported results as shown on Exhibit___ (YS-14), which was prepared under my supervision and direction. This would have placed Con Edison in the bottom half among the 27 utilities in the S&P 500 with reported results. The average recovery rate for the utility companies in the S&P 500 was 48%.

The Company's large installed base of mature equipment requires a continuous investment in replacement assets. In other industries, a much larger portion of investment can be dedicated to new business (generating offsetting revenues) or new technology (lowering costs).

Mature assets raise operating costs and increase operating risks, particularly in an environment that requires the highest level of reliability and imposes regulatory penalties for failing to achieve it. The technology of the business is also mature, affording little opportunity to significantly reduce invested capital in the business through technological innovation. The need for continuous investment to maintain and improve the system with slight opportunities for demand growth and limited depreciation cash flow means that the Company must seek rate increases and raise new capital frequently to maintain its operations. Replacement capital needs alone substantially exceed the cash generated through depreciation recoveries for the Company.

Q. Please describe how flat to declining demand growth for electricity presents a financial challenge.

A. The Company's total retail electric sales volume has decreased by an average annual rate of 0.64% over the last five years (2013-2017). Flat to declining demand growth for electricity, coupled with the capital intensive nature of the business, puts upward pressure on the unit cost of electricity as the recovery of capital is spread over a smaller base.

Q. Please describe how the Company's weak cash flows present a financial challenge.

A. Because the Company will continue to be challenged by its weak operating cash flows and lack of positive free cash flows, Con Edison will continue to be more dependent on external funding.

Q. Have you prepared an exhibit to show this?

A. Yes, please refer to Exhibit___ (YS-15), which was prepared under my supervision and direction.

Q. Have any of credit rating agencies commented on the Company’s weak cash flows?

A. Yes. In addition to Moody’s commentary discussed above, S&P commented on the Company’s weak cash flows in a October 19, 2018 report (see Exhibit__ (YS-16)):

> …we expect FFO [“funds from operations”] to debt to average about 16% through 2020, down from about 19% in 2017. The company's weaker financial measures primarily reflect its elevated capital spending program, and the effects of U.S. tax reform.

Fitch, in a October 24, 2018 report (Exhibit__ (YS-17)), also mentioned the Company’s FFO leverage metrics provide little headroom at current rating levels.

Q. Please describe how restrictions on the Company’s business imposed by the Commission present a financial challenge.

A. The Company is subject to various regulatory restrictions that limit its ability to react to unfavorable circumstances. For example, the Company must provide service as requested, even if doing so entails significant investment upon unfavorable terms. It also is limited in its ability to reach beyond its franchise area to serve attractive new customers. The Company's assets are immovable; unlike those of most companies they cannot be used in a different location or business, their usefulness and profitability are tied to providing utility service in its New York service territory. Unlike non-utility companies, Con Edison has a limited ability to retain the advantages of its efforts to improve its efficiency and thus lower its costs of doing business for the benefit of its equity investors. The Commission routinely requires earnings sharing mechanisms, which serve to limit earnings opportunities, as a component of base rate case settlements. Moreover, any additional efficiencies achieved by management are fully allocated to customers each time rates are reset, given the capital recovery and cash flow parameters of historic cost-of-service rate making.

Q. Please describe how the fact that the Company must continually raise capital increases risk for existing and prospective investors.

A. As mentioned earlier in my direct testimony, the Company must approach the markets for additional new debt capital on a frequent and recurring basis. Con Edison is forecasted to raise $1,200 million in 2019, $1,400 million in 2020, $1,790 million in 2021 and $1,200 million in 2022. The Company will need the assurances of positive cash flows and favorable regulatory support to continue to market this debt at reasonable rates.

Each time Con Edison markets its debt securities, investors will assess the risks they would bear if they invested in the Company in light of the challenges identified above. Their assessment of these risks is, and will be, priced into the cost of debt each time the Company seeks new capital in the years ahead. To the extent that analysis of risk leads the market to reduce stock prices or raise interest rates, the existing investors are disadvantaged and other potential investors are made more wary. Through this cycle of investors assessing and pricing risks that the Company faces, customers are negatively impacted through increases in the cost of financing the Company’s capital investment needs. To raise this capital at a reasonable cost, the Company must remain an attractive investment to both debt and equity investors. To remain attractive to these investors, Con Edison must receive fair and reasonable treatment from its regulators.

Q. How much and what type of debt does the Company have outstanding?

A. As of September 30, 2018 Con Edison had $13,662 million of long-term debt. The Company also had letters of credit outstanding in an amount of $178 million. Letters of credit represent an additional capital need which must be met, requiring the Company to compete for scarce funds in a highly regulated bank market.

Q. Who owns the Company’s debt?

A. Investment managers, insurance companies, pension plans, hedge funds, banks, trust companies and individuals.

Q. How do bond investors evaluate Con Edison?

A. For most investors, the credit ratings assigned by the nationally recognized statistical rating organizations (*i.e.*, Moody’s, S&P and Fitch) are the threshold basis for evaluating individual corporate credits such as those offered by the Company.

Q. What are the current ratings on Company debt?

A. The long-term, senior unsecured debt ratings are A3, A-, and A- by Moody’s, S&P, and Fitch, respectively. The short-term debt is rated P-2, A-2, and F2, respectively.

All ratings have a stable outlook.

Q. Are bond ratings the correct indicator of the risks to shareholders?

A. No. The priority of bondholders' claim on the Company means that shareholders are subject to a higher level of risk. Shareholders, unlike bondholders, only have a residual claim to the resources and income of the Company, and thus face risks even in well-rated companies. If returns are inadequate, the bondholder may suffer a loss from a credit downgrade. The stockholder will suffer the loss directly through a drop in the share price and/or through a lower dividend.

Q. Why do companies such as Con Edison need to maintain a particularly strong financial condition?

A. Capital intensive companies with a duty to serve have to borrow in spite of the state of the market and need continuous access to capital. In addition, utilities may have to access the capital market in response to a natural catastrophe (*e.g.*, Superstorm Sandy). When utilities are forced to pay high rates, these rates will remain with the companies and their customers for as long as 30 years. On the short-end of the maturity spectrum, access to commercial paper and bank borrowing markets is key to allowing the Company to pay for energy that must be delivered, no matter the price. Only A-1/P-1 borrowers can maintain that status in all markets, a status that has become more tenuous for Con Edison due to its current A-2/P-2 (S&P’s/ Moody’s) rating for commercial paper. At the height of the financial crisis of 2008-2009, non-A-1/P-1 borrowers, if they had access to commercial paper market, paid significantly higher rates.

The seizing up of the commercial paper market at that time was relieved only by the Federal government’s extraordinary decision to provide an effective backstop for the highest-rated (A-1/P-1) commercial paper issuers, a solution that may not always be available, and may not extend to lower quality issuers such as Con Edison.

If the Company were to lose access to the commercial paper market, borrowing costs would increase as the Company would have to rely more upon long-term debt, which is more expensive. In addition, the Company could be forced to issue debt with less attractive terms because it lacked the flexibility to wait for better market conditions. The recent past has demonstrated the importance of maintaining a strong credit rating and investor confidence in our credit.

Q. Please explain why maintaining its current debt ratings is important for Con Edison.

A. The Company has a significant continuing construction program that must be funded in large part by debt financing. Access to credit markets will be restrictive for lower quality creditors. In addition, a part of the Company's financing program is comprised of short-term borrowing through its commercial paper program. Such borrowing is highly sensitive to credit quality and credit market conditions.

Q. Who owns the Company?

A. Con Edison has one shareholder, Consolidated Edison, Inc. ("CEI"). CEI, in turn, is owned by approximately 43,000 registered shareholders. Registered shareholders are the individuals or businesses whose names are listed on the shareholder register of CEI.

Q. What are the characteristics of the registered shareholders?

A. CEI's registered shareholders consist of individuals and institutional investors. Institutional investors often own shares for the benefit of others. These investors purchase CEI shares for the benefit of their investors who, in turn, may be pension funds or other individual investors. Since pension funds exist for the benefit of the individual participants in their plans, it makes sense to think of the ultimate beneficiaries of share ownership in CEI, and derivatively in the Company, of being millions of individuals who may own shares directly, invest in U.S. stock mutual funds, or receive or expect benefits from pension plans or life insurance policies.

Q. What do the people who own CEI shares, either directly or indirectly, provide to the Company?

A. They provide the capital that the Company needs above and beyond what debt investors provide. Their capital allows the Company to provide safe, reliable energy utility service to the Company’s customers. Without these shareholders, the Company’s customers would have to pay currently for all of the costs of the services they receive. For example, without these shareholders, customers would have to pay for a new substation as it is constructed rather thanover the subsequent decades during which they benefit from its operation.

Q. What do these equity investors expect in return?

A. They expect compensation either in the form of a periodic dividend payment or an increase in the value of the business, or both.

Q. How do equity investors in regulated utilities set their expectations for compensation?

A. The return expectations of equity investors in rate-regulated energy utilities are grounded in “the regulatory compact.” The regulatory compact’s essence is that equity investors forgo the monopoly earnings they would otherwise enjoy in return for the institutionalization of their monopoly in a defined geographic area and a fair and equitable return on the capital they have invested.

Q. What standards exist to help equity investors and regulators determine whether a rate-regulated utility offers a fair and equitable return?

A. The general standards for a fair and equitable return for investors in utility shares are well-established in the United States. The underlying requirement for fair treatment for equity investors has been recognized for years. As discussed in the direct testimony of Company witness Villadsen, it dates back to the *Hope* and *Bluefield* cases. The

United States Supreme Court in those cases established that in determining the fairness or reasonableness of a utility's allowed ROE, one needed to look at the consistency of a utility's allowed ROE with the returns on equity investments in other businesses having similar or comparable risks.

Q. How would a potential equity investor evaluate the return limitations on New York utilities as to their magnitude, timing and probability?

A. There are four significant factors in an equity investor's assessment of New York utility regulation: (1) headline rate of return on equity, (2) the likelihood of earning that return, (3) the symmetry of potential earned equity returns, and (4) the restrictions the regulator places on the scope of the business. To make this assessment, a potential equity investor will start with the basic parameters of the Commission's rate orders.

Q. How do the Commission's rate orders influence investors' evaluation of the first identified return consideration?

A. The first factor, the headline rate of return on equity, is important for an equity investor because it provides the most visible indication in the rate order of the regulator’s willingness to balance the needs of investors and customers.

Q. How have the Commission’s authorized returns compared to those in other jurisdictions?

A. As we demonstrate in this case and have demonstrated in previous rate cases, the rates of allowed return granted in New York are well below those in other states. I have provided a comparison of allowed returns in New York as compared with other states (based on data from Regulatory Research Associates (“RRA”)) to demonstrate the consistency of this practice (Exhibit___ (YS-18), which was prepared under my supervision and direction).

In past cases, Staff has argued that each of the rate cases in the RRA database is unique and, therefore, no meaningful conclusion can be drawn. While I would agree that each rate case is unique, it is equally obvious that the differences in the authorizations cannot always be such that New York companies should consistently be among the lowest returns in the country.

Q. Staff has pointed to the various regulatory recovery mechanisms authorized by the Commission as a justification for the low authorized ROEs granted to New York State utilities. Do you agree with Staff’s position?

A. No, I do not. The regulatory recovery mechanisms that New York State provides are not distinctive among the U.S. regulatory jurisdictions. As set forth in Exhibit___ (YS-19), which was prepared under my supervision and direction, many of the mechanisms put in place by the Commission are currently in use in other jurisdictions. Accordingly, the Company does not believe that these mechanisms compensate for the low ROEs consistently granted by the Commission.

Q. Can investors readily measure the degree to which a regulatory regime fairly rewards shareholders?

A. In New York, yes. The Commission has a clear and long-standing policy of setting returns relative to the historic tangible book value of the investors' shares. Information about returns on share book values for publicly-traded United States companies is readily available to investors from public sources as a basis for comparison.

Q. How does Con Edison compare to this universe of alternative investments?

A. Con Edison does not fare well in the comparison. When looking at the five-year historical average return on book equity, the Company had a return that would have placed it near the bottom fifth of S&P companies with meaningful available data. The median return on equity for the S&P 500 index was 15.8%. The comparable return on book equity for Con Edison was 9.2%.

Q. Have you prepared an exhibit to show this?

A. Yes, please refer to Exhibit___ (YS-20), which was prepared under my supervision and direction.

Q. Are companies typically valued by investors at their book value?

A. No, they are valued by investors based on their future business prospects. Exhibit___ (YS-21), which was prepared under my supervision and direction, shows the five-year average market to book ratios for those S&P companies with positive book equity. CEI’s market to book ratio is in the bottom 12% of this universe for this important measure of investor perceptions and expectations, even after the financial crisis which severely affected the financial sector and other industries.

Q. How would an investor assess the second factor: the likelihood of a utility actually earning the headline equity return?

A. The investor would analyze the adjustments made to actual costs that are allowed to be recovered, imputed productivity that may or may not be achieved, and any other revenue or expense adjustments. To the extent that such adjustments are made to real costs, the headline rate of return is unlikely to be achieved.

Q. How would an investor assess the third factor: the symmetry of potential returns?

A. There is ample opportunity through a system where potential negative revenue adjustments are far larger than potential positive incentives, as well one-way true-ups of costs--burdens which have been imposed in New York rate decisions--to realize significantly lower returns than the headline authorized return. All of these aspects of New York rate orders produce asymmetry in expected returns, which a rational potential equity investor would judge as ultimately reducing his or her expected return. Little evidence exists that these burdens are common in other jurisdictions in the country, where the peers that are the basis for the Commission’s DCF and CAPM results operate.

Q. How would an investor assess the fourth factor: the restrictions the regulator places on the scope of the business?

A. The adverse impact of the last factor is less quantifiable because it consists of opportunities foreclosed to the Company and thus to the investor. Restrictions on investments in generation in New York, and the punitive indirect restrictions on affiliate company capitalization, reduce the value of the Company to its owners, but in ways that are difficult to quantify explicity.

Q. Have the shortcomings in the treatment of the Company been reflected in equity analysts' views of the CEI?

A. Yes. As of January 14, 2019, CEI ranked as 499th of the 505 companies in the S&P 500 in terms of analyst buy/sell rankings (see Exhibit___ (YS-22), which was prepared under my superivision and direction).

IV. **CONCLUSION**

Q. Please summarize your testimony regarding the financial challenges facing the Company.

A. My testimony concerns the financial challenges and the need to maintain access to financial markets at reasonable cost. Both equity and debt investors perceive that the New York regulatory environment is a difficult one in which to operate. Such a perception, if it continues, will make the financing of needed expenditures more expensive in normal times and less certain in times of financial crises.

To avoid such an outcome, and to re-establish debt and equity investors' trust in the fairness of New York regulation, a fair and equitable rate of return, competitive with those available elsewhere in the market, and a reasonable chance to actually earn that return, are needed. And to achieve such, the Commission should grant the rate of return and capital structure requested by the Company.

Q. Does that conclude your direct testimony?

A. Yes, it does.

BEFORE THE
STATE OF NEW YORK PUBLIC SERVICE COMMISSION

CASE 19-E-[xxxx]	)	Proceeding on Motion of the Commission as
	)	to the Rates, Charges, Rules and Regulations
	)	of Consolidated Edison Company of New
	)	York, Inc. for Electric Service.
	)	
CASE 19-G-[xxxx]	)	
	)	Proceeding on Motion of the Commission as
	)	to the Rates, Charges, Rules and Regulations
	)	of Consolidated Edison Company of New
	)	York, Inc. for Gas Service.

DIRECT TESTIMONY OF BENTE VILLADSEN

January 25, 2019

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DIRECT TESTIMONY OF BENTE VILLADSEN

I. INTRODUCTION AND PURPOSE

Q1. Please state your name, occupation and business address.

A1. My name is Bente Villadsen and I am a Principal of The Brattle Group, whose business address is One Beacon Street, Suite 2600, Boston, Massachusetts, 02108.

Q2. Please summarize your professional qualifications.

A2. I have 20 years of experience working with regulated utilities on cost of capital and related matters. My practice focuses on cost of capital, regulatory finance, and accounting issues. I have testified or filed expert reports on cost of capital in Alaska, Arizona, California, Illinois, New Mexico, Oregon, and Washington, as well as before the Bonneville Power Administration, the Surface Transportation Board, the Alberta Utilities Commission, and the Ontario Energy Board. I have provided white papers on cost of capital to the British Columbia Utilities Commission, the Canadian Transportation Agency as well as to European and Australian regulators on cost of capital. I have testified or filed testimony on regulatory accounting issues before the Federal Energy Regulatory Commission ("FERC"), the Regulatory Commission of Alaska, the Michigan Public Service Commission, the Texas Public Utility Commission as well as in international and U.S. arbitrations and regularly provide advice to utilities on regulatory matters as well as risk management. I hold a Ph.D. from Yale University and a BS/MS from University of Aarhus, Denmark. Exhibit__(BV-1) contains more information on my professional qualifications as well as a list of my prior testimonies.

Q3. What is the purpose of your testimony in this proceeding?

A3. I have been asked by Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company") to estimate the cost of equity that the State of New York Public Service Commission ("NY PSC" or the "Commission") should allow the Company an opportunity to earn on the equity financed portion of its regulated (gas and electric) utility rate base. Specifically, I perform cost of equity analysis and provide return on equity ("ROE") estimates derived from market data for a proxy group of regulated electric utility companies, and provide additional estimates based on an analysis of allowed utility risk premiums. I also evaluate the business risk characteristics of Con Edison and consider the Company's requested regulatory capital structure to be applied for ratemaking purposes.

II. SUMMARY OF CONCLUSIONS

Q4. Please summarize your findings and recommendation.

A4. I recommend that Con Edison be allowed to earn a 10.00 percent rate of return on the equity portion of its regulated rate base. This recommendation is based on my implementations of standard cost of capital estimation models including two versions each of the Discounted Cash Flow ("DCF") model and Capital Asset Pricing Model ("CAPM"), as well as an implied risk premium analysis, along with an analysis of Con Edison's risks. Figure 1 and Figure 2 below summarize the model results and the corresponding reasonable ranges that are presented and discussed in Section V below. Based on my consideration of the model results in the context of Con Edison's specific business risk characteristics and financial circumstances and of current capital market conditions, I believe it is appropriate to place Con Edison's allowed return at 10.00

percent, which is in the upper half of the overall 9.25 - 10.25 percent range of reasonable cost of equity estimates suggested by my analysis.

Figure 1
Summary of Results

Model		Estimate
CAPM	[a]	8.9% - 9.3%
ECAPM (α = 1.5%)	[b]	9.4% - 10.0%
Single-Stage DCF	[c]	10.4%
Multi-Stage DCF	[d]	8.8%
Implied Risk Premium	[e]	9.8% - 10.4%

Notes:
Estimates as of 11/30/2018.
[a], [b]: Long-term risk free rate of 4.1%, Long-term market risk premium of 7.07%.
[d]: Long-run nominal GDP growth estimate of 4.1%.
[e]: Estimated using rate case data from SNL and treasury data from Bloomberg.

Figure 2
Summary of Reasonable Ranges of Estimates

Model		Estimate
CAPM/ECAPM	[a]	9.25% - 10%
DCF Models	[b]	9.25% - 10.25%
Implied Risk Premium	[c]	9.75% - 10.5%

Q5. How is the remainder of your testimony organized?

A5. Section III formally defines the cost of capital and explains the techniques for estimating it in the context of utility rate regulation. Section IV discusses conditions and trends in capital markets and their impact on the cost of capital. Section V explains my analyses and presents the results. Finally, Section VI discusses Con Edison’s business risk characteristics and other company specific circumstances relevant to my recommended allowed ROE for the Company within the reasonable ranges of cost of equity estimates.

III. COST OF CAPITAL PRINCIPLES AND APPROACH

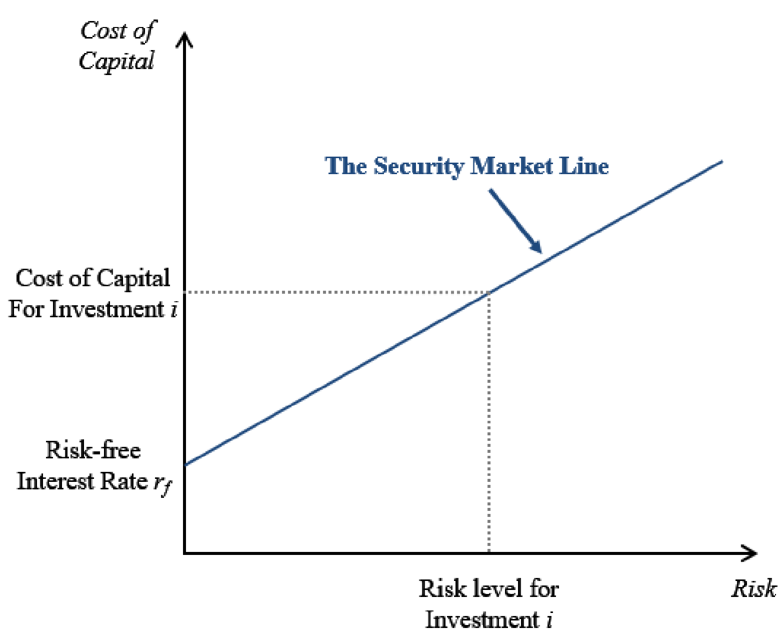
A. Risk and the Cost of Capital

Q6. How is the "Cost of Capital" defined?

A6. The cost of capital is defined as the expected rate of return in capital markets on alternative investments of equivalent risk. In other words, it is the rate of return investors require based on the risk-return alternatives available in competitive capital markets. The cost of capital is a type of opportunity cost: it represents the rate of return that investors could expect to earn elsewhere without bearing more risk. "Expected" is used in the statistical sense: the mean of the distribution of possible outcomes. The terms "expect" and "expected," as in the definition of the cost of capital itself, refer to the probability-weighted average over all possible outcomes.

The definition of the cost of capital recognizes a tradeoff between risk and return that can be represented by the "security market risk-return line" or "Security Market Line" for short. This line is depicted in Figure 3 below. The higher the risk, the higher the cost of capital required.

Figure 3
The Security Market Line



Q7. What factors contribute to systematic risk for an equity investment?

A7. When estimating the cost of equity for a given asset or business venture, two categories of risk are important. The first is business risk, which is the degree to which the cash flows generated by the business (and its assets) vary in response to moves in the broader market. In context of the CAPM, business risk can be quantified in terms of an "assets beta" or "unlevered beta." For a company with an assets beta of 1, the value of its enterprise will increase (decrease) by 1% for a 1% increase (decline) in the market index.

The second category of risk relevant for an equity investment depends on how the business enterprise is financed and is called financial risk. Section III.B below explains how financial risk affects the systematic risk of equity.

Q8. What are the guiding standards that define a just and reasonable allowed rate of return on rate-regulated utility investments?

A8. The seminal guidance on this topic was provided by the U.S. Supreme Court in the *Hope* and *Bluefield* cases,[1] which found that:

- The return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks;[2]
- The return should be reasonably sufficient to assure confidence in the financial soundness of the utility; and
- The return should be adequate, under efficient and economical management for the utility to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[3]

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1 Bluefield Water Works & Improvement Co. v. Public Service Com'n of West Virginia, 262 U.S. 679 (1923) ("Bluefield"), and Federal Power Com'n v. Hope Natural Gas Co., 320 U.S. 591 (1944) ("Hope").

2 Hope, 320 U.S. at 603.

3 Bluefield, 262 U.S. at 680.

Q9. How does the standard for just and reasonable rate of return relate to the cost of capital?

A9. The first component of the *Hope* and *Bluefield* standard, as articulated above, is directly aligned with the financial concept of the opportunity cost of capital.[4] The cost of capital is the rate of return investors can expect to earn in capital markets on alternative investments of equivalent risk.[5]

By investing in a regulated utility asset, investors are tying up some capital in that investment, thereby foregoing alternative investment opportunities. Hence, the investors are incurring an "opportunity cost" equal to the returns available on those alternative investments. If the allowed return on the utility investment is not at least as high as the expected return offered by alternative investments of equivalent risk, investors will choose these alternatives instead, and the utility's ability to raise capital and adequately fund its operations will be adversely impacted or even prevented. This is a fundamental concept in cost of capital proceedings for regulated utilities such as Con Edison.

Q10. Please summarize how you considered risk when estimating the cost of capital.

A10. To evaluate comparable business risk, I looked to a proxy group of regulated electric utilities. Further, (as explained in Section III.B below) I analyzed and adjusted for differences in financial risk due to different levels of financial leverage among the proxy companies and between the capital structures of the proxy companies and the regulatory capital structure that will be applied to Con Edison for ratemaking purposes. To determine where in the estimated range Con Edison's ROE reasonably falls, I compared the business risk of Con Edison to that of the proxy group companies, and also considered recent capital markets developments.

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4 A formal link between the opportunity cost of capital as defined by financial economics and the proper expected rate of return for utilities is set forth by Stewart C. Myers, "Application of Finance Theory to Public Utility Rate Cases," Bell Journal of Economics & Management Science 3:58-97 (1972).

5 The opportunity cost of capital is also referred to as simply the "cost of capital," and can be equivalently described in terms of the "required return" needed to attract investment in a particular security or other asset (i.e., the level of expected return at which investors will find that asset at least as attractive as an alternative investment).

B. FINANCIAL RISK AND THE COST OF EQUITY

Q11. How does capital structure affect the cost of equity?

A11. Debt holders in a company have a fixed claim on the assets of the company and are paid prior to the company's owners (equity holders) who hold the inherently variable residual claim on the company's operating cash flows. Because equity holders only receive the profit that is left over after the fixed debt payments are made, higher degrees of debt in the capital structure amplify the variability in the expected rate of return earned by equity-holders. This phenomenon of debt resulting in financial leverage for equity holders means that, all else equal, a greater proportion of debt in the capital structure increases risk for equity holders, causing them to require a higher rate of return on their equity investment, even for an equivalent level of underlying business risk.

Q12. How do differences in financial leverage affect the estimation of the cost of equity?

A12. The CAPM and DCF model rely on market data to estimate the cost of equity for the proxy companies, so the results reflect the value of the capital that investors hold during the estimation period (market values).

The allowed ROE is applied to Con Edison's rate base, which will be financed with a different portion of debt than the proxy companies. I consider the impact of any difference between the financial risk inherent in those cost of equity estimates and the capital structure used to determine Con Edison's required return on equity.

Differences in financial risk due to the different degree of financial leverage in Con Edison's regulatory capital structure compared to the capital structures of the proxy companies mean that the equity betas measured for the proxy companies must be adjusted before they can be applied to determining Con Edison's CAPM return on equity. Similarly, the cost of equity measured by applying the DCF models to the proxy companies' market data requires adjustment if it is to serve as an estimate of the appropriate allowed ROE for Con Edison at its different regulatory capital structure.

Importantly, taking differences in financial leverage into account does not change the value of the rate base. Rather, it acknowledges the fact that a higher degree of financial leverage in the regulatory capital structure imposes a higher degree of financial risk for an equity investment in Con Edison's rate base than is experienced by equity investors in the market-traded stock of the less leveraged proxy companies.

Q13. How specifically do you take financial risk into account in your analysis of the cost of equity using market data for the proxy group companies?

A13. There are several manners in which the impact of financial risk can be taken into account in an analysis of cost of equity using market-based models such as the DCF and CAPM. One way is to determine the after-tax weighted-average cost of capital for the proxy group using the equity and debt percentages as the weight assigned to the cost of equity and debt. If this figure is constant between the estimate obtained for the proxy group and the entity to which it is applied—in this case the capital structure used in the rate of return calculation—then the ROE that is required for the regulated entity can be determined. This approach assumes that the after-tax weighted average cost of capital is constant for a range that spans the capital structures used to estimate the cost of equity and the regulatory capital structure.

A second approach was developed by Professor Hamada, who estimated the cost of equity using the CAPM and made comparisons between companies with different capital structure using beta. Specifically, in the Hamada approach, I use the estimated beta to calculate what beta would be associated with a 100 percent equity financed firm to obtain a so called all-equity or assets beta and then re-lever the beta to determine the beta associated with the regulatory capital structure. This requires an estimate of the systematic risk associated with debt (*i.e.*, the debt beta), which is usually quite small. In Exhibit___(BV-2) I set forth additional technical details related to methods to account for financial risk when estimating the cost of capital.

Q14. Can you provide a numerical illustration of how the cost of equity changes, all else equal, when the degree of financial leverage changes?

A14. Yes. I constructed a simple example below, where only the financial leverage of a company varies. I assumed the return on equity is 11.00 percent at a 50 percent equity capital structure and determine the return on equity that would result in the same overall return if the percentage of equity in the capital structure were reduced to 45 percent.

Figure 4
Illustration of Impact of Financial Risk on ROE

		Company A (50% Equity)	Company B (45% Equity)
Rate Base	[a]	$1,000	$1,000
Equity	[b]	$500	$450
Debt	[c]	$500	$550
Total Cost of Capital (8%)	[d] = [a] × 8%	$80.0	$80.0
Cost of Debt (5%)	[e] = [c] × 5%	$25.0	$27.5
Equity Return	[f] = [d] - [e]	$55.0	$52.5
Rate of Return on Equity (ROE)	**[g] = [f] / [b]**	**11.00%**	**11.67%**

Figure 4, above, illustrates how financial risk affects returns and the ROE. The overall return remains the same for Company A and B at $80. But Company B with the lower equity share and higher financial leverage must earn a higher percentage ROE in order to maintain the same overall return. This higher percentage allowed ROE represents the increased risk to equity investors caused by the higher degree of financial leverage.

The principle illustrated in Figure 4 is exemplary of the adjustments I performed to account for differences in financial risk when conducting estimates of the cost of equity applicable to Con Edison.

C. Approach to Estimating the Cost of Equity

Q15. Please describe your approach for determining the cost of equity for Con Edison.

A15. As stated above, the standard for establishing a fair rate of return on equity requires that a regulated utility be allowed to earn a return equivalent to what an investor could expect to earn on an alternative investment of equivalent risk. Therefore, my approach to estimating the cost of equity for Con Edison focuses on measuring the expected returns required by investors to invest in companies that face business and financial risks comparable to those faced by Con Edison. Because certain of the models require market data, my consideration of comparable companies is restricted to those that have publicly traded stock. To this end, I have selected a proxy group consisting of publicly traded companies. The proxy group consists of companies providing primarily regulated electricity services.[6] With this proxy group, I derive estimates of the representative cost of equity according to standard financial models including two versions of the CAPM—the traditional version and an empirically-adjusted version—and single- and multi-stage versions of the DCF.

I also perform an analysis of historical allowed ROEs for electric utilities in relation to prevailing risk-free interest rates at the time, and use the implied allowed risk-premium relationship to estimate a utility cost of equity consistent with current economic conditions. The results of this implied risk premium analysis (sometimes referred to herein as the "Risk Premium" model) are an additional consideration that informs my recommendation and serves as a check on the reasonableness of my market-based results.

Q16. How do your approach and the models you employ compare to those traditionally employed by the Staff of the New York Department of Public Service ("Staff")?

A16. As exemplified in the Commission's most recent order regarding the Company's ROE[7] and in the testimony of Staff witnesses,[8] the Commission's Generic Finance Methodology is broadly similar to, but also has important differences from, my approach.

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6 Consistent with past precedent in Con Edison's rate cases, I use a proxy group of electric utilities to calculate the recommend ROE for both Con Edison's electric and gas regulated operations.

7 Order Approving Electric and Gas Rate Plans (Case 16-E-0060, 16-G-0061, and 16-E-0196), January 25, 2017 ("2017 Order"), p. 28.

8 Direct Testimony of Staff Finance Panel in Cases 16-E-0060 and 16-G-0061, p. 63.

The market-based DCF and CAPM estimation techniques I rely on align with the Commission's historical reliance on both DCF and CAPM results to inform its allowed ROE determinations. Of note, Staff has consistently implemented a "zero-beta" version of the CAPM,[9] which is conceptually and methodologically aligned with the version of the empirical CAPM (*i.e*., ECAPM) that I implement.

While Staff and I both derive estimates from the DCF and CAPM, there are differences in how we select inputs to implement the models. For example, Staff's approach to the DCF attempts to infer a "sustainable growth" rate based on Value Line forecasts of return on book equity and retention ratio, whereas I implement both single- and multi-stage DCF models based directly on forecasts (including by Value Line) of growth in earnings available for distribution to investors. As discussed further below, I believe considering the results of both single and multi-stage models is appropriate in light of current market conditions and their impact on dividend yields.

Similarly, for the CAPM, Staff typically relies on current Treasury yields for the risk-free rate, whereas I look at forecasts of the Treasury yield in an attempt to capture investor expectations for the risk-free rate of return during the period rates set in this proceeding will be in effect. While currently prevailing yields are somewhat lower than the forecasted yield I use, the reverse is true of the market risk premium ("MRP") estimates traditionally relied on by Staff, which are significantly higher than the estimate I employ, which (as discussed below) is supported by both historical and forward-looking evidence.

Importantly, as discussed in Section III.B, my CAPM and DCF analyses employ standard finance techniques to adjust explicitly for differences in financial leverage between the proxy group companies and the Company's requested regulatory capital structure. The fact that Staff's typical approach does not take financial risk into account by using the standard adjustment techniques means that Staff's analysis misses an important step in

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[9] Id., p. 87; see also Prepared Testimony of Staff Panel in Cases 18-E-0067 & 18-G-0068, p. 92.

estimating the opportunity cost of capital commensurate with an investment of equivalent risk.[10]

Finally, in contrast to Staff's practice, I do not believe it is appropriate to place fixed primary emphasis on one model in deriving a recommended allowed ROE. Whereas the Commission has traditionally placed 2/3 weight on the DCF and 1/3 on the CAPM, I consider the ranges of results produced by the models I employ: two versions of the CAPM, two versions of the DCF, and the implied Risk Premium method. The reason I believe it is important to consider the range is that I prefer to focus on the tendency of the data rather than a weighted average of results for two models – either of which may be affected by idiosyncratic market conditions (model risk) at any given point in time.

Q17. Why do you believe your approach to considering ranges of estimates derived from multiple versions of both the DCF and CAPM, and also relying on an implied Risk Premium analysis, is justified?

A17. There is no one perfect model for estimating the cost of equity, and the various models and estimation approaches I employ each have different strengths and sensitivities. For example, the CAPM relies on an explicit measurement of systematic risk (beta) for which the cost of equity capital must compensate investors, but this parameter must be measured using historical data,[11] and thus changes more slowly in response to changes in industry risk characteristics. Conversely, the DCF models incorporate current market prices and the most recent dividends, enabling them to capture shifts over time. However, this also makes the DCF sensitive to short-term market phenomena that may or may not be representative of the capital market conditions and required investor returns that will prevail during the time Con Edison's electric and gas rates are in effect. In contrast to both the CAPM and DCF models, the implied risk premium analysis focuses directly on

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[10] I am not aware of any textbooks that do not discuss methods to account for financial risk.

[11] I note that Value Line applies an empirical adjustment (the Blume adjustment) that converts the beta derived from historical return data into a better indicator of forward-looking systematic risk (i.e., a better predictor of beta going forward).

the relationship of allowed returns for regulated utility companies to observable rates of return (*i.e.*, bond yields) reflective of contemporaneous capital market conditions.

Q18. Have other important utility regulatory bodies acknowledged the importance of relying on multiple models?

A18. Yes. Notably FERC, which regulates electric transmission operations, recently issued an order proposing to rely explicitly on four models in its determination of just and reasonable ROEs for transmission owners.[12] The FERC ROE Order represents a substantial change of FERC's historical practice of relying on only a single model—the DCF—to set allowed ROEs. In it, FERC explicitly recognizes that different models offer complementary views of investor requirements and market expectations and that it is necessary to evaluate and consider all such evidence.

Q19. What reasons did FERC give for revising its approach to consider multiple models rather than only the DCF?

A19. In the FERC ROE Order, FERC stated its concern that compared to when it originally adopted the DCF model as its only focus of consideration for determining utility ROEs, "the DCF methodology may no longer singularly reflect how investors make their decisions," since "investors have increasingly used a diverse set of data sources and models to inform their investment decisions."[13] The FERC ROE Order also lays out other "difficulties with sole reliance on the DCF methodology," including that the single model's results appear at times to diverge from its underlying principles and the real world experience of capital market participants, and that the results sometimes move differently from the results of other models on which those market participants may rely to inform their investment decisions.[14] Ultimately, FERC views its proposal to rely on

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[12] See Coakley v. Bangor Hydro-Electric Co., 165 FERC ¶ 61,030 (October 2018) (referred to herein as the "FERC ROE Order"). The ROE estimation methodologies in the FERC ROE Order include versions of the DCF and CAPM, as well as the implied Risk Premium method and an Expected Earnings analysis.

[13] FERC ROE Order, paragraph 40.

[14] *Id*., paragraphs 40-45.

multiple models as a way to avoid this "model risk" and summarizes its rationale as follows.

> In relying on a broader range of record evidence to estimate [New England Transmission Owners'] cost of equity, we ensure that our chosen ROE is based on substantial evidence and bring our methodology into closer alignment with how investors inform their investment decisions.[15]

FERC's assessment and reasoning in this regard is very much in line with the principles that guide my own decision to inform my analysis based on the results of multiple complementary analyses.

Q20. Are there any potential concerns about how current capital market conditions may influence the DCF model results that may caution against giving it disproportionate weight in setting Con Edison's ROE?

A20. Yes. To the extent utility stocks are currently acting as a *relatively* less risky investment vehicle for risk-averse investors seeking returns in a time of increased volatility and still-low government bond yields, this may contribute to their price-to-earnings ratios ("PE ratios") being unrepresentatively high—and their dividend yields unrepresentatively low—compared to what investors might expect in a more normal (or normalizing) interest rate environment. If this is the case, implementing the DCF model using current market data may produce results that understate what investors' required returns will be when interest rates move higher as expected in the near future (including during the time period Con Edison's rates set during these proceedings will be in effect).

FERC addressed a similar issue in the FERC ROE Order, expressing its concern about the reliability of DCF model results in the current market environment as follows.

> Under [the premise of the DCF methodology], increases in a company's actual earnings or projected growth in earnings would ordinarily be required to justify an increase in the company's stock price. Moreover, there is no evidence that investments in the utility sector have become less risky during these periods. However, it appears that during the periods at issue in these complaint proceedings, average utility stock prices have increased by more than would be justified by any increase

[15] Id., p. 15.

> in actual utility earnings or projected growth in earnings. From October 1, 2012 through December 1, 2017, the Dow Jones Utility Average increased from about 450 to 762.59, an increase of almost 70 percent. However, utility earnings did not increase by nearly the same amount, as demonstrated in Figure 3 below, which shows the substantial increase in utilities' price to earnings (PE) ratio during the same period. Moreover, average IBES three to five year growth projections appear not to have increased during that period. Thus, there has not been an increase in either current or projected utility earnings that would justify the substantial increase in utility stock prices.[16]

FERC concluded from this discussion that recent investor behavior with respect to utility stocks appears to have diverged from the DCF model's predictions, a factor that informs FERC's decision (discussed in Section III.C) to reconsider its primary reliance on the DCF in favor of giving equal weight to four different and complementary models. Similarly, this concern informs the way I consider the results of the DCF models as well as the CAPM and Risk Premium models in selecting my recommendation.

IV. CAPITAL MARKET CONDITIONS AND THE COST OF CAPITAL

Q21. Why do you discuss capital market conditions in testimony aimed at determining Con Edison's ROE?

A21. This section discusses important market conditions that affect the inputs to the cost of equity models. Because the risk-free rate is an input to the CAPM, recent and expected developments in risk-free government interest rates are important to assess the validity of any measure of the risk-free rate. Similarly, the MRP is an input to the CAPM, so factors that affect the MRP (*e.g.*, volatility and changes in investors risk perception) are vital for an accurate determination of the ROE.

As to DCF model inputs, developments in the economy in general affect growth rates and utility stock prices. Consequently, the capital market developments impact the growth rates, dividend yield, and general assessment of the estimates' reasonableness.

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[16] FERC ROE Order, paragraph 45 (citations omitted).

Finally, the Tax Cuts and Jobs Act of 2017 ("TCJA") affected utilities differently than other companies in that tax reductions generally flow to customers and, consequently, impacts the utility's credit metrics and earnings volatility. As a result, it is necessary that the allowed ROE and appropriate equity capital structure ratio for Con Edison fulfill the requirements set forth by *Hope* and *Bluefield* once the implications of the TCJA are considered.

Q22. Please summarize how your analysis of capital market conditions affects your conclusions?

A22. First, I conclude that interest rates are on an increasing trajectory, with practitioner forecasts and bond yield spread evidence suggesting further increases in long-term government bond yields. This supports my reliance on forecasts of long-term U.S. Treasury yields for the risk-free rate.

Second, because forward-looking estimates of the MRP have recently been at or slightly above the long-term historical average level and market volatility indicators have recently been higher, I conclude my reliance on the historical average U.S. MRP of 7.07% is reasonable and conservative as an input to my CAPM and ECAPM analysis.

Finally, I conclude that because (all else equal) the TCJA results in reduced cash flows and increased volatility of cash flows for Con Edison, it may be appropriate to increase the Company's allowed ROE, its equity capital structure, or both. While I do not make any explicit adjustment for TCJA's impact in my implementation of the models, I do consider it in placing my recommendation within the range of reasonable cost of equity results from the DCF, CAPM, and Risk Premium analyses.

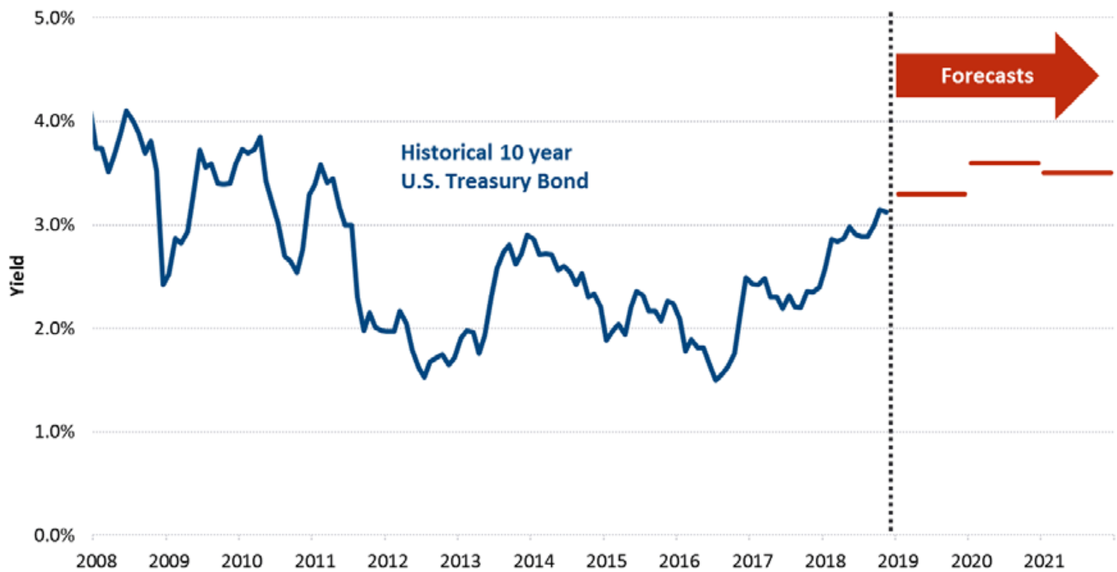
A. Interest Rate Developments

Q23. What are the relevant developments regarding interest rates?

A23. Interest rates, including the long-term government bond yields that are typically used to represent the risk-free rate in the context of regulated utility ratemaking, have remained extremely low in the years since the global financial crisis of 2008. However, yields have increased substantially over the past year and are forecasted to continue on their upward trajectory in coming years. For example, since hitting an all-time low in July 2016, the yield on ten-year U.S. Treasury bonds has more than doubled to over 3 percent at the time of my analysis.[17]

Furthermore, the consensus forecast from Blue Chip Economic Indicators—which surveys more than 50 institutional market analysts and participants, including major banks, academic finance departments, credit rating agencies, institutional investors, and Fortune 500 companies—is that the yield on ten-year Treasury bonds will increase to 3.6 percent by 2020. Figure 5 below plots these expected increases in the ten-year Treasury bond yield.

Figure 5
Historical and Projected Ten-Year Treasury Bond Yields



Source: Historical data from Bloomberg. Forecasts from Blue Chip Economic Indicators Oct. 2018 issue.

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17 Bloomberg as of 11/30/2018. The November 2018 average ten-year U.S. Treasury yield was 3.12%. On July 5, 2016, the ten-year U.S. treasury yield closed at 1.37%.

Q24. What forces contributed to the sustained period of very low interest rates over the decade following the financial crisis?

A24. The monetary policy actions of the Federal Reserve (the "Fed") in response to the financial crisis were a key driver of the low interest rates. The Fed's Federal Open Market Committee ("FOMC") undertakes market actions to influence interest rates—especially the so-called "federal funds rate"[18]—subject to its statutory mandate to maximize employment and keep inflation under control. In response to the financial crisis, the FOMC drastically reduced its target federal funds rate from 5.25 percent in August 2007 to 0.00 – 0.25 percent starting in December 2008.[19] The Fed's zero interest rate policy remained in effect for the next seven years, ending in December 2015 when the FOMC finally raised its federal funds target to 0.25 - 0.50 percent.[20]

Concurrent with its sustained monetary policy actions related to the short-term federal funds rate, the Fed also implemented several unprecedented policy interventions with the explicit goal of reducing interest rates on long-term borrowing instruments. This "quantitative easing" program of long-term government bonds served to keep Treasury yields at very low levels for an extended period of time. And importantly, even after the FOMC ceased buying securities, it maintained trillions of dollars' worth of Treasuries and government-backed mortgage backed securities on its balance sheet, continuing to reinvest the principal when the assets matured.[21]

Global economic conditions also contributed to the unprecedented low rates on U.S. government debt. For example, at the height of the European sovereign debt crisis in 2011-2012, flight from European bonds and yield-lowering actions by the European

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[18] The federal funds rate is the rate at which large banks lend and borrow funds in the short-term. It is therefore influential in determining market interest rates throughout the economy.

[19] See FOMC Statements issued August 7, 2007 and December 16, 2008 accessed at https://www.federalreserve.gov/monetarypolicy/fomc_historical.htm

[20] See FOMC Statement, December 16, 2015 accessed at https://www.federalreserve.gov/monetarypolicy/fomccalendars htm

[21] As of October 4, 2018, the Fed's long-term Treasury and Agency securities balance was at $4.0 trillion. See Board of Governors of the Federal Reserve System, Credit and Liquidity Programs and the Balance Sheet, accessed at https://www.federalreserve.gov/releases/h41/20181004/.

Central Bank ("ECB") spurred increased demand for U.S. Treasury bonds—thus driving up prices and bringing yields down. This pattern repeated in 2016 in the period leading up to, and especially following, the "Brexit" vote. Indeed, on July 10, 2016, shortly after Great Britain officially voted to leave the European Union, the ten-year U.S. Treasury Yield reached its all-time low of 1.37%.[22]

Q25. What forces have contributed to the current rising trend in interest rates?

A25. As shown in Figure 5, U.S. Treasury bond yields have been on an increasing trend since their low point in mid-2016. This is consistent with the Fed's recognition that the economy has strengthened, employment conditions remain strong, and inflation—while still below its 2.0 percent target—has begun to increase. The FOMC has responded by increasing the target federal funds rate eight times since ending the zero interest rate policy in December 2015, consistently over each subsequent quarterly meeting. After the most recent hike announced at the FOMC's December 19, 2018 meeting, the federal funds target rate stands at 2.25 – 2.50 percent.[23] In addition, the Fed signaled its intention to continue the consistent rate increases going forward.

Importantly, the Fed has also recently enacted "Policy Normalization" procedures, whereby it is gradually decreasing its holdings of long-term bonds by not reinvesting principal from expiring securities. These procedures took effect starting in October 2017 and have continued at an accelerating pace ever since.[24]

In summary, central bank monetary policy action is aligned with and supportive of a continued gradual steady increase in interest rates, including yields on risk-free long-term government bonds. This is consistent with the economic forecasts of continued increases in the risk-free rate continuing through the period at issue in this proceeding.

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[22] Yield from Bloomberg. See also "U.S. 10-Year Treasury Yield Closes at Record Low" (July 5, 2016) The Wall Street Journal, accessed at https://www.wsj.com/articles/government-bond-yields-in-u-s-europe-hit-historic-lows-1467731411.

[23] See FOMC Statement, September 19, 2018, accessed at https://www.federalreserve.gov/newsevents/pressreleases/monetary20181219a.htm

[24] See FOMC Communications related to Policy Normalization, April 16, 2018, accessed at https://www.federalreserve.gov/monetarypolicy/policy-normalization.htm

B. RISK PREMIUMS AND YIELD SPREADS

Q26. What is the Market Risk Premium?

A26. In general, a risk premium is the amount of "excess" return—above the risk-free rate of return—that investors require to compensate them for taking on risk. As illustrated above in Figure 3, the riskier the investment, the larger the risk premium investors will require.

The MRP is the risk premium associated with investing in the market as a whole. Since the so-called "market portfolio" embodies the maximum possible degree of diversification for investors,[25] the MRP is a highly relevant benchmark indicating the level of risk compensation demanded by capital market participants. It is also a direct input necessary to estimating the cost of equity using the CAPM and other risk-positioning models.

Q27. Do you have any data on how estimates of the MRP have evolved over the time leading up to and since the 2008 financial crisis?

A27. Yes. Bloomberg publishes a forward-looking estimate of the MRP based on market prices and expected dividends for U.S. stocks.[26] Figure 6 displays the development of Bloomberg's forecasted MRP since 2006.

The Bloomberg MRP increased substantially with the onset of the financial crisis and has remained elevated relative to pre-crisis levels. Though the November 2018 average forward-looking MRP reported by Bloomberg is in line with the long-term historical

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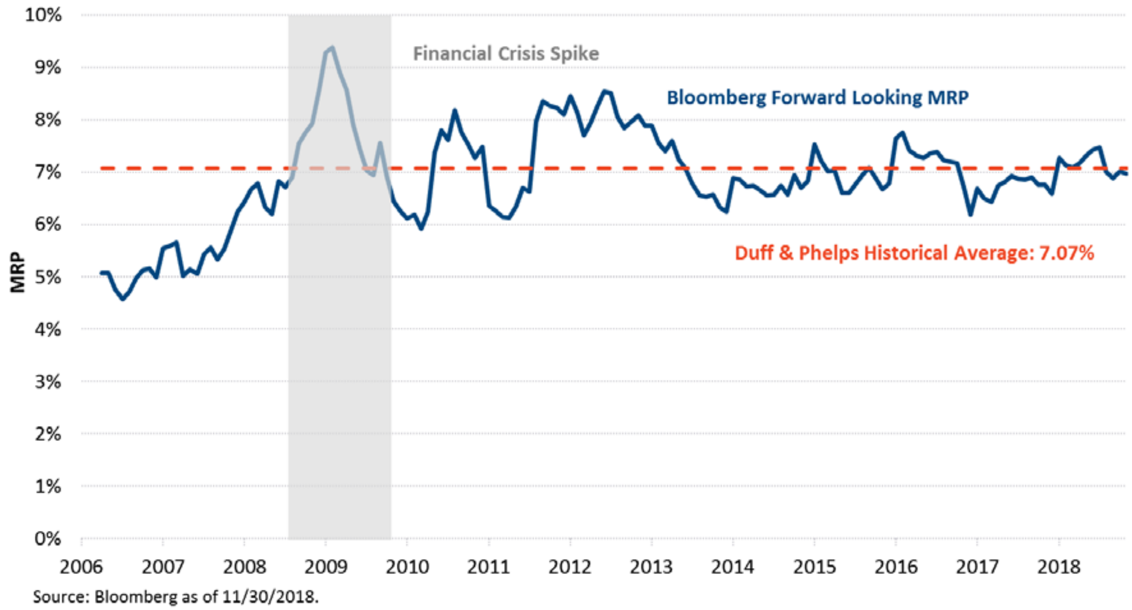
[25] In finance theory, the "market portfolio" describes a value-weighted combination of all risky investment assets (e.g., stocks, bonds, real estate) that can be purchased in markets. In practice, academics and financial analysts nearly always use a broad-based stock market index, such as the S&P 500, to represent the overall market.

[26] Bloomberg's calculation of the expected market return is based on an implementation of a multi-stage DCF model (see Section V.D.1 below) applied to all dividend paying stocks in the S&P 500 index; Bloomberg calculates the MRP by subtracting the current ten-year Treasury bond yield from the estimated expected market return, however, it is also possible to calculate the MRP measured relative to a 20-year Treasury bond yield, which is the calculation I perform for ease of comparison to historical average risk premiums calculated by comparing the Ibbotson data on stock market returns in excess income returns on long-term U.S. Treasury yields with an approximate average maturity of 20 years.

average MRP,[27] the average since the 2008 financial crisis was 7.2 percent,[28] indicating the investors have displayed increased risk aversion and demanded higher compensation for taking on risk in the time since the financial crisis.

Figure 6
Bloomberg Forward looking MRP (2006-2018)



Q28. Is there any other market evidence concerning risk premiums?

A28. Yes. One observable risk premium is the spread between yields on risk-free Treasury bonds and the yields on corporate bonds of the same maturity. Unlike U.S. government bonds, debt instruments issued by corporate entities come with some probability of default and have some associated level of systematic risk. To compensate for this risk, corporate bonds—including utility bonds—offer higher expected returns (as measured by the market yield) than do government bonds.

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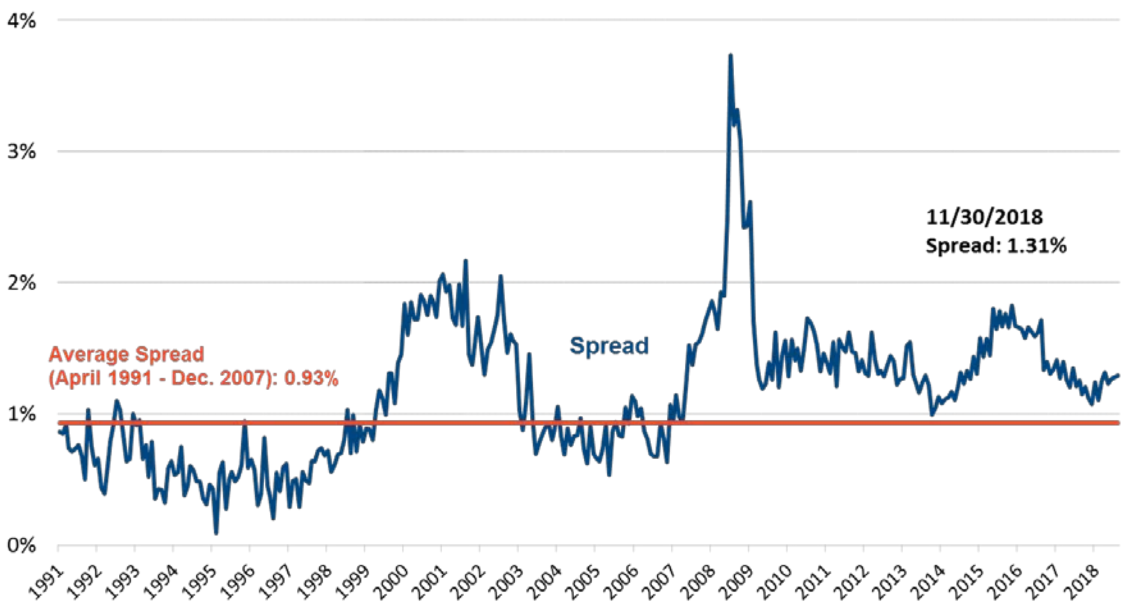
[27] As noted below, the historical average MRP calculated using the long-established Ibbotson stock and bond market data currently published by Duff & Phelps is 7.07 percent.

[28] Average of Bloomberg forecasted MRP (relative to 20-year Treasury Bonds) for the U.S. from January 2009 - November 2018. Bloomberg as of 11/30/2018.

Figure 7 plots the yield spread for A-rated utility bonds compared to Treasury bonds for the longest period of available data. As the figure shows, utility yield spreads spiked dramatically with the onset of the financial crisis and have remained elevated to their pre-crisis average level.

Figure 7
Spread between 20-year A-rated Utility Bond and 20-year Treasury Bond Yields



Source: Bloomberg as of 11/30/2018.

Q29. What are the implications of elevated yield spreads to the cost of equity?

A29. The yield spread is simply one form of risk premium, albeit for assets (corporate bonds) that are relatively lower risk compared to equity securities (*i.e.*, stock). Consequently, one explanation for the elevated yield spread is that investors are requiring a higher premium to take on market risk than they did on average prior to the financial crisis.[29] This would indicate an elevated MRP compared to the historical average.

An alternative explanation for the elevated yield spread is that the yield on Treasury bills remains artificially low due to the lingering after-effects of Fed's unprecedented

[29] See "Explaining the Rate Spread on Corporate Bonds," Edwin J. Elton, Martin J. Gruber, Deepak Agarwal, and Christopher Mann, The Journal of Finance, February 2001, pp. 247-277.

monetary policy. Under this explanation, the yield spread would be expected to return to its historical average level as the risk-free rate returns to more normal levels.

Regardless of which interpretation is correct, the consequence is that if the cost of equity is estimated using the current risk-free rate and a historical average MRP, the estimate will be downward biased. Hence, it is necessary to "normalize" the risk-free rate in CAPM model inputs, which I have done by using a forecast for what government bond yields will be throughout the period at issue in this case.

C. Market Volatility

Q30. How does the stock market's volatility relate to the cost of capital?

A30. Academic research has found that investors expect higher risk premiums during more volatile periods,[30] indicating that the MRP may increase when market volatility is high, even when investors' level of risk aversion remains unchanged. This is relevant to estimating the Company's cost of equity because increased volatility suggests higher risk premiums and therefore higher market-required ROE.

A measure of the market's expectations for volatility is the VIX index, which measures the 30-day implied volatility of the S&P 500 index.[31] These indices are also referenced as the "market's fear gauge."[32] While the VIX had recently been trading substantially below its long term historical average of approximately 19.40, it spiked substantially

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[30] See, e.g., K. French, W. Schwert and R. Stambaugh (1987), "Expected Stock Returns and Volatility," Journal of Financial Economics, Vol. 19, p. 3:

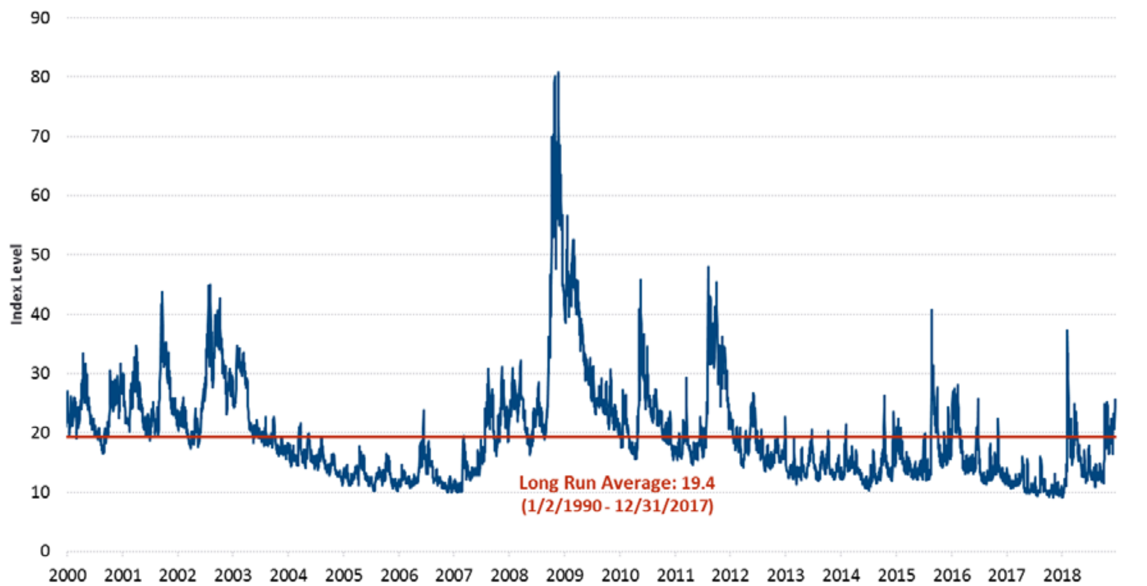
> We find evidence that the expected market risk premium (the expected return on a stock portfolio minus the Treasury bill yield) is positively related to the predictable volatility of stock returns. There is also evidence that unexpected stock returns are negatively related to the unexpected change in the volatility of stock returns. This negative relation provides indirect evidence of a positive relation between expected risk premiums and volatility.

[31] *See*, *e.g.*, Chicago Board Option Exchange at http://www.cboe.com/micro/VIX/vixintro.aspx

[32] CNBC, "VIX, the Market's Fear Gauge Plunges in Historic One-Week Move," July 5, 2016.

above that level in early October and again in December 2018, each time concurrent with a significant drop in the stock market.[33]

Figure 8
VIX Index



Source: Bloomberg as of 12/19/2018

Q31. Do you look at any other indexes regarding market volatility?

A31. Yes. The SKEW index, which measures the market's willingness to pay for protection against negative "black swan" stock market events (*i.e.*, sudden substantial downturns), offers a reason to be cautious of interpreting recent low VIX levels as an indicator of improved capital market certainty over the long term. A SKEW value of 100 indicates outlier returns are unlikely, but as the SKEW increases, the probability of outlier returns become more significant. Figure 9 shows that the SKEW currently stands at almost 132, while the index has averaged 119 over the last 15 years. This indicates that investors are willing to pay for protection against downside risk and thus are exhibiting signs of elevated risk aversion concerns of downside tail risk.

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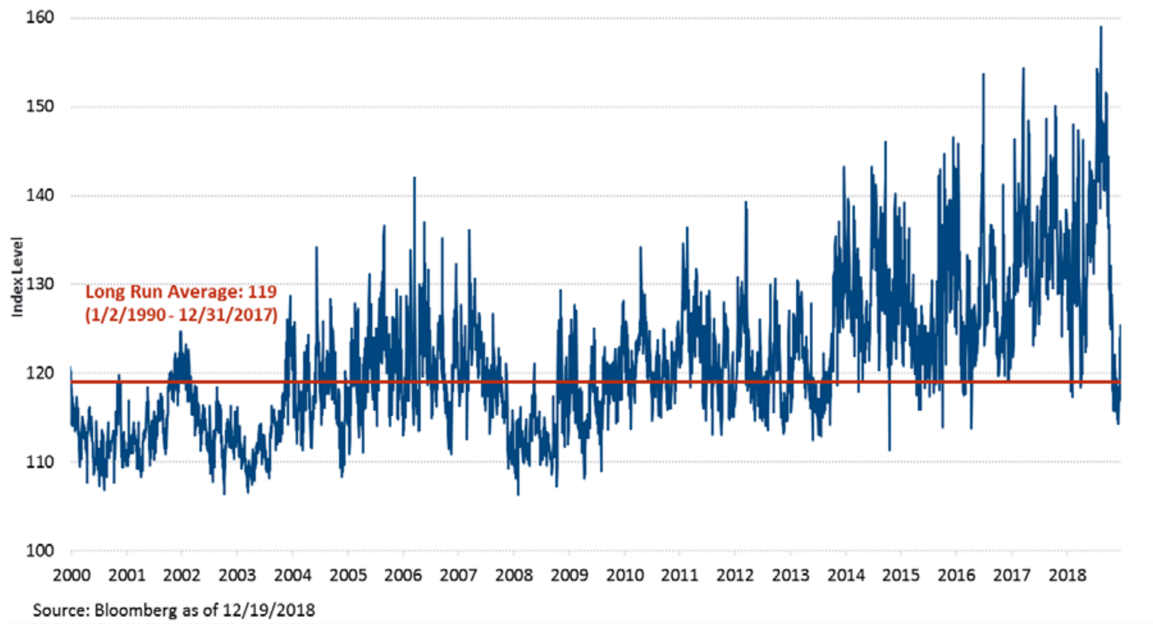
[33] As an illustration of the market volatility, the S&P 500 dropped more than 350 points (12%) during the first three weeks of December.

The SKEW has briefly dropped below its long-run average in November and December 2018, but generally has been on an upward trend since at least 2015.

Figure 9
SKEW Index



Q32. Are there reasons why capital markets may exhibit high volatility going forward?

A32. Yes. A few contributing reasons to capital market volatility recently include notably the shut-down of the federal government, which has been going on since December 23, 2018 and where no resolution are in sight. This may impact economic growth and regulatory policy implementation, and will likely contribute to uncertainty among capital market participants.

Additionally, the ongoing exchange of trade tariffs between the United States and China, challenging negotiations occurring in the European Union regarding finalization of the exit of Great Britain, which could lead to a no-deal Brexit, and the new agreement seeking to replace the North American Free Trade Agreement ("NAFTA").

Throughout 2018, the U.S. and China engaged in an exchange of new trade tariffs, as exemplified by China's September 18, 2018 response to a September 17, 2018 U.S.

declaration of tariffs on $200 billion of Chinese exports.[34] As these trade tensions have unfolded and escalated, uncertainty in the markets has increased significantly because investors do not know when or if tariffs will be implemented on products affecting companies in which they hold equity. On any given day, a tariff could be announced, significantly affecting the value of a company or companies. Thus, the current market landscape embodies significant uncertainty.

To further the instability facing U.S. markets resulting from the trade dispute with China, the removal of NAFTA and the implementation of the United States-Mexico-Canada Agreement ("USMCA") has been an ongoing source of insecurity for all investors and those doing business throughout North America. Though the USMCA was formally signed in November 2018, the negotiation process was far from transparent and led to significant concerns of the fallout for investors holding equity in any business needing to trade across the applicable borders. Before the USMCA, which still requires approval from the U.S. Congress, is finally approved and implemented, certain tariffs and trade rules will change, likely leading investors to be unsure of the direction of certain businesses.

D. IMPLICATIONS OF THE TAX CUTS AND JOBS ACT OF 2017 ("TCJA")

Q33. How does implementation of the TCJA affect regulated utilities?

A33. The TCJA reduced the federal corporate marginal tax rate from 35% to 21%. Although the TCJA is likely to be a net positive for investors in unregulated companies, for the Company, the vast majority (if not all) of the benefits will flow to customers. This is because the savings in income taxes will flow through to customers in the form of lower rates. At the same time, the implementation of the TCJA (including its treatment by utility regulators in a ratemaking context) will likely increase the risks facing regulated companies because they will experience (i) a near-term decrease in cash flows and (ii) an increase in the variability of after-tax earnings (and cash flows).

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[34] The U.S. announced a 10% tariff on these goods for the remainder of 2018, which will escalate to a 25% tariff afterward. The Chinese retaliation included $60 billion of U.S. goods. See "The Trade War is on: How We Got Here and What's Next, Bloomberg," 9/18/2018.

Q34. How does the lower corporate tax rate under the TCJA affect the expected volatility of cash flows for regulated companies?

A34. For regulated companies, as for unregulated corporate taxpayers, the change in the income tax allowance will result in greater volatility of net income (and cash flow) because the income tax provides a "buffer" against the impact of variations in expected costs and expected revenue on net income. Consider for example the effect on net income of a 10% increase in sales revenue. All else equal, net income would increase by about 6.5% for a 35% income tax rate, (*i.e.* 0.10 times (1 – 0.35)), but would increase by 7.9% for a 21% income tax rate. The change would be similar and symmetrical for a decrease in revenue.

Further, the amplified variability in net income due to the lower corporate tax rate is likely to amplify systematic risk, because variations in revenue are generally related to variations in the broader economy that affect the value of all risky assets, not just tax-paying corporations. Since systematic risk is the type of risk that affects the cost of capital, it is reasonable to expect that the TCJA will, all else equal, contribute to higher required returns for corporate equity holders, including those in regulated utilities.

Importantly, while this increase in variability of income applies to all corporate tax-paying entities, unlike unregulated corporations, regulated utilities do not benefit from after-tax higher profits under the new lower tax rate, because the revenue requirement is adjusted to pass the tax savings on to customers.[35]

Q35. How will the TCJA affect a regulated company's credit metrics?

A35. Credit metrics are negatively affected by regulatory ratemaking treatment of the TCJA, because such treatment causes a near-term reduction in the regulated utilities' cash flow and related cash flow metrics that are closely observed by debt ratings agencies. As discussed further in Section V.B below, the expected refunds of excess deferred taxes and lower tax deferrals associated with new investment due to the lower tax rate and loss

[35] This discussion assumes that the revenue requirement has been adjusted to account for the lower corporate income tax rate.

of bonus depreciation under the TCJA will reduce cash flow. Yet the tax reform has no impact on the amount of assets needed for reliability and to serve customers, a portion of which will be debt-financed. Decreases in key cash flow metrics, such as the cash flow to debt ratios that inform the credit rating agencies credit opinions, have negatively affected the credit profile of many regulated utilities, and will continue to do so.[36] Indeed, as discussed below, Con Edison is among the group of regulated utility companies that have had their credit ratings downgraded by one or more rating agencies due to the effects of the TCJA.

Q36. What are the implications of the reduced cash flows and increased volatility of cash flows in the context of these proceedings?

A36. These effects suggest that it could be appropriate to increase either the allowed ROE or the amount of equity in the capital structure (or possibly both) to help compensate for the increased financial risk imposed on regulated utilities by the TCJA.

While the uncertainty surrounding the passage of the TCJA has been removed, it is unlikely that impacts on the cost of capital will immediately appear in the estimation models. The TCJA has not yet been in place for one complete fiscal year, and the regulatory treatments in various jurisdictions have been in effect for an even shorter period. A longer period of market data may be needed before the cost of capital estimation models can be expected to reflect impacts of the TCJA on investors' required returns.

Notwithstanding that decreases in cash flow metrics and increased volatility of earnings both increase financial risk in ways that may not be reflected in the cost of capital model

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[36] See Moody's Investor Service, Global Credit Research, "Moody's changes outlooks on 25 US regulated utilities primarily impacted by tax reform," January 19, 2018; Sector Comment, "Tax reform is credit negative for sector, but impact varies by company," January 24, 2018; Regulated Utilities - U.S., "2019 outlook shifts to negative due to weaker cash flows, continued high leverage," June 18, 2018; and Regulated Utilities - U.S., "2019 outlook negative amid growing debt and stagnant cash flow," November 8, 2018. See also S&P Global Ratings, Rating Direct, "U.S. Tax Reform: For Utilities' Credit Quality, Challenges Abound," January 24, 2018 and Fitch Ratings, Special Report, "Tax Reform Impact on the U.S. Utilities, Power & Gas Sector: Tax Reform Creates Near-Term Credit Pressure for Regulated Utilities and Holding Companies," January 24, 2018.

results, I do not make an explicit upward adjustment to my estimate of the cost of equity or my recommended allowed ROE to account for the impact of the TCJA. However, in Section V.B below, I address the question of how increasing the proportion of equity in Con Edison's regulatory capital structure could help to mitigate some of the TCJA's negative effects on credit quality.

V. ESTIMATING THE COST OF EQUITY

A. PROXY GROUP SELECTION

Q37. How do you identify proxy companies of comparable business risk to Con Edison?

A37. Con Edison is primarily engaged in the regulated distribution of electricity and natural gas. The business risk associated with these endeavors depends on many factors, including the specific characteristics of the service territory and regulatory environment in which the provider of these services operates. Consequently, it is not possible to identify publicly traded proxy companies that replicate every aspect of Con Edison's risk profile. However, selecting companies with business operations concentrated in similar lines of business and/or business environments is an appropriate starting point for selecting a proxy group of comparable risk to Con Edison.

To this end I have selected a proxy group composed of companies focused on the provision of electricity to end users, which also includes some companies that—like Con Edison—engage in the regulated distribution of both electricity and natural gas ("Electric Proxy Group").

Q38. Please summarize how you selected the members of the Electric Proxy Group.

A38. To identify companies suitable for inclusion in the Electric Proxy Group, I started with the universe of publicly traded companies in the electricity utility industry as identified by *Value Line Investment Analyzer* ("*Value Line*"). Next, I reviewed business descriptions and financial reports of these companies and eliminated those which had less than 50 percent of their assets dedicated to regulated electric utility activities.[37]

With this group of companies, I applied further screening criteria to eliminate companies which have had recent significant events that could affect the market data necessary to perform cost of capital estimation. Specifically, I identify companies that have cut their dividends or engaged in substantial merger and acquisition ("M&A") activities over the relevant estimation window.[38] I eliminate companies with such dividend cuts because the announcement of a cut may produce disturbances in the stock prices and growth rate expectations in addition to potentially being a signal of financial distress. I generally eliminate companies with significant M&A activities because such events typically affect a company's stock price in ways that are not representative of how investors perceive its business and financial risk characteristics. For example, a utility's stock price will commonly jump upon the announcement of an acquisition to match the acquirer's bid.

Further, I require companies have an investment grade credit rating[39] and more than $300 million in annual revenues for liquidity purposes. A final, and fundamental, requirement is that the proxy companies have the necessary data available for estimation.

Q39. What are the characteristics of the Electric Proxy Group?

A39. The Electric Proxy Group is comprised of electric utilities whose primary source of revenues and majority of assets are subject to regulation. The final proxy group consists of the 26 electric utilities listed in Figure 10 below. These companies own regulated electric utility subsidiaries and are classified by EEI as either "regulated"—having at

37 I rely on Edison Electric Institute (EEI), Stock Performance – 2017 Q4 Financial Update. This report gives industry financial information as well as a percentage of regulated assets for each of the companies.

38 As described in Sections V.C, the CAPM requires five years of historical data, while the DCF relies on current market data.

39 In some cases, a proxy company does not have a credit rating from any of the major rating agencies. However, if they were to be rated, they would receive an investment grade rating. In these instances, I assign the company the average credit rating of the rest of the Electric Proxy Group.

least 80% of their assets dedicated to regulated utility operations) or "mostly regulated"—having at least 50% regulated assets.[40] (These EEI categories are designated with an "R" or "M" in the table below). Therefore, the Electric Utility Proxy Group is broadly representative of the regulated electric industry from a business risk perspective.

Figure 10 reports the proxy companies' annual revenues for the most recent four quarters as of Q3, 2018 and also reports the market capitalization, credit rating, beta and growth rate. The annual revenue as well as the market cap was obtained from Bloomberg. The credit rating is reported by S&P Research Insight. The growth rate estimate is a weighted average between estimates from Thomson Reuters and *Value Line*. Betas were obtained from *Value Line*.

[40] Edison Electric Institute (EEI), Stock Performance – 2017 Q4 Financial Update.

Figure 10
Electric Proxy Group

Company	Annual Revenues (USD million)	Regulated Assets	Market Cap. 2018 Q3 (USD million)	Beta	S&P Credit Rating (2018)	Long Term Growth Est.
	[1]	[2]	[3]	[4]	[5]	[6]
ALLETE	$1,388	M	$3,878	0.65	BBB+	5.7%
Alliant Energy	$3,517	R	$10,181	0.60	A-	6.2%
Amer. Elec. Power	$16,205	R	$35,280	0.55	A-	5.8%
Ameren Corp.	$6,274	R	$15,714	0.55	BBB+	6.8%
CMS Energy Corp.	$6,822	R	$14,027	0.55	BBB+	6.9%
DTE Energy	$13,733	M	$20,096	0.55	BBB+	5.6%
Entergy Corp.	$11,121	R	$14,961	0.60	BBB+	1.7%
MGE Energy	$560	M	$2,260	0.60	AA-	8.3%
OGE Energy	$2,260	R	$7,331	0.85	BBB+	1.1%
Otter Tail Corp.	$902	R	$1,907	0.75	BBB	6.1%
AVANGRID Inc.	$6,346	M	$15,110	0.30	BBB+	9.7%
Consol. Edison	$12,349	R	$24,364	0.40	A-	3.2%
Duke Energy	$24,205	R	$57,441	0.50	A-	4.9%
Eversource Energy	$8,309	R	$19,745	0.60	A+	5.7%
NextEra Energy	$16,360	M	$81,411	0.55	A-	8.3%
PPL Corp.	$7,772	R	$21,335	0.70	A-	3.4%
Public Serv. Enterprise	$9,324	M	$26,428	0.60	BBB+	6.7%
Southern Co.	$23,787	R	$43,762	0.50	A-	2.2%
Unitil Corp.	$434	R	$763	0.55	BBB+	4.0%
Edison Int'l	$12,868	R	$22,051	0.55	BBB+	4.2%
El Paso Electric	$909	R	$2,418	0.65	BBB	4.4%
IDACORP Inc.	$1,364	R	$5,003	0.55	BBB	2.4%
Pinnacle West Capital	$3,695	R	$8,907	0.55	A-	4.5%
PNM Resources	$1,425	R	$3,135	0.65	BBB+	5.7%
Portland General	$1,984	R	$4,113	0.60	BBB+	4.9%
Xcel Energy Inc.	$11,453	R	$24,475	0.50	A-	6.1%
Average	$7,899		$18,696	0.58		5.2%

Sources and Notes:
[1]: Bloomberg as of 9/30/2018.
[2]: Company 10-Ks. See Table No. BV-2.
[3]: See Table No. BV-3 Panels A through Z.
[4]: See Supporting Schedule # 1 to Table No. BV-10.
[5]: S&P Credit Ratings from Research Insight as of 2018 Q3.
[6]: See Table No. BV-5.

Q40. How does the Electric Proxy Group compare to Con Edison in terms of financial metrics?

A40. Con Edison's electric distribution operations generated an annual revenue figure of $7.1 billion in 2017, which is smaller than the average member of the Electric Proxy Group by approximately $0.8 billion. The approximate equity rate base of Con Edison's electric distribution operations is $8.4 billion, less than half the market capitalization of the average member of the Electric Proxy Group.[41] Con Edison's issuer credit rating of A- is above the median credit rating of BBB+ for the Electric Proxy Group.[42]

B. CAPITAL STRUCTURE

Q41. What regulatory capital structure for Con Edison did you employ in your analysis?

A41. As recommended by Con Edison company witness Saegusa, I use a capital structure consisting of 50.00 percent equity, 48.89 percent debt, and 1.11 percent customer deposits. I understand this request reflects a greater equity ratio than the capital structure in Con Edison's most recent approved rate order,[43] and I believe an increase in equity financing of rate base is appropriate at this time for reasons discussed below. I also note that Con Edison's requested 50% equity ratio is in line with regulatory capital structures determined in recent U.S. utility rate cases,[44] but is also substantially lower than the market value equity ratios for the Electric Proxy Group that affect the cost of equity estimates measured for those companies using market data.[45]

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41 This estimate falls between the median ($8 billion) and average ($10.4 billion) book value of equity of the Electric Proxy Group.

42 Con Edison data as reported by S&P Global Market Intelligence, accessed 10/11/2018.

43 2017 Order, p. 28. See also Joint Proposal in Case 16-E-0060, 16-G-0061, and 16-E-0196, Appendix 1, page 6 of 11.

44 The average allowed equity ratio from 2013 to 2018 for Electric cases was 49%. Calculated using data from SNL Financial as of 12/7/2018.

45 Exhibit___(BV-3), Table No. BV-4

Q42. Are there any reasons why it might be appropriate to consider including a higher equity ratio in Con Edison's regulatory capital structure used for ratemaking purposes compared to what has been applied in past rate cases?

A42. Yes. The impact of the TCJA, coupled with Con Edison's significant ongoing capital expenditures, has placed downward pressure on the Company's cash flows and associated credit metrics. As a result, Moody's recently downgraded Con Edison's long term debt issuer rating (from A2 to A3), along with that of its corporate parent CEI (from A3 to Baa1), stating that regulatory treatment of the new tax law would lead to "a series of revenue and cash flow reductions" for Con Edison "that will offset some of the expected general rate increases that the utility would otherwise have."[46] Moody's explained that offsetting rate increases and cash flow reductions will lead Con Edison's "cash flow to remain steady, at the same time that the utility's capital spending – and debt – is expected to increase for infrastructure resiliency, energy efficiency, and other New York policy priorities," resulting in "cash flow to debt ratios around 16-17% through 2020, … down from over 20% in recent years."[47]

Q43. How does regulatory treatment of the TCJA lead to lower cash flows and deteriorating credit metrics for regulated utilities such as Con Edison?

A43. The TCJA can reduce cash flows for regulated companies in several ways. First, when the benefits of decreased tax costs are passed through to utility customers, this manifests in a lower "gross up" for taxes (*i.e.*, the income tax allowance) in the revenue requirement. Reduced revenues in turn lead to decreased pre-tax cash flows and associated credit metrics.[48]

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[46] "Rating Action: Moody's downgrades ConEd to Baa1, CECONY to A3 and O&R to Baa1; outlooks stable," Moody's Investor Service, October 30, 2018.

[47] *Ibid*.

[48] EBIT (earnings before interest and taxes) and EBITDA (earnings before interest, taxes, depreciation and amortization) are common measures of pre-tax cash flow that are considered by credit rating agencies as part of credit metrics such as EBIT and EBITDA interest coverage ratios or the debt-to-EBITDA ratio. As discussed below, cash flow mesures such as Funds from Operations (FFO) and associated credit metrics (such as FFO-to-debt and FFO interst coverage) for regulated utilities are also negatively affected by the TCJA.

Second, on an after-tax basis, the benefit of accelerated tax depreciation is reduced in proportion to tax rate, leading to a reduction in after-tax cash flows. Third, the TCJA eliminated bonus depreciation for utility assets, drastically reducing the amount of tax deductions that can be taken immediately for new capital investment.

Fourth, regulated utilities will be required to amortize back to customers the balances of Excess Deferred Income Taxes ("EDIT") that arise from the reduced corporate tax rate. EDIT relates to Accumulated Deferred Income Tax ("ADIT"), which represents the accumulated effect of timing difference in depreciation for income tax and regulatory purposes. Because tax depreciation deductions are accelerated relative to regulatory depreciation expense included in rates, utilities collect and accumulate positive deferred taxes in the early years of a regulated asset; these balances are drawn down in later years when the tax deductions are reduced below the levels of book depreciation (or entirely exhausted). The assumption is that the ADIT balance will return to zero for any asset at the end of its regulatory life. However, with a reduction in the corporate tax rate, some of the taxes deferred in the early years (at the higher tax rate) will never become due to the IRS in later years (at the new lower rate). This excess ADIT represents a temporary windfall to the utility until it is amortized back to customers via adjustments to the revenue requirement. As the EDIT is amortized, the portion of rate base that must be financed by investors increases, since EDIT (like ADIT) is a source of zero cost financing for the utility. However, despite this partially offsetting increase in required return on rate base, the net effect of returning EDIT to customers is to decrease the utility's cash flows, both before and after taxes, until the EDIT has been exhausted. In addition, because amortizing EDIT increases the proportion of rate base that must be financed with external capital, this may place additional downward pressure on cash flow-to-debt metrics (to the extent the additional capital required is in the form of debt).

Q44. Please illustrate how implementation of the TCJA reduces utility cash flows and credit metrics.

A44. Figure 11 below illustrates the impact of TCJA on incremental after-tax cash flows generated by a new investment in utility rate base. It compares the pre-TCJA status quo (*i.e.*, a 35% corporate tax rate and 40% year-1 bonus depreciation that was scheduled to be permitted for new utility investment in 2019 under the prior tax code) with the new situation, namely 21% tax rate and only the standard year-1 Modified Accelerated Capital Recovery System ("MACRS") tax depreciation deduction.[49] As shown, the funds from operations ("FFO")[50] measure of cash flow is dramatically lower under the new tax regime compared to what utilities would have forecasted for new rate base investments prior to the TCJA taking effect. In turn, the incremental impact of new capital expenditures on utilities' cash flow to debt ratios is diminished by the new law,[51] contributing to the kind of deterioration in the aggregate levels of these metrics that Moody's discussed in justifying its downgrade of Con Edison's credit rating.

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49 For illustrative purposes, the figure posits a hypothetical $1 million investment in new utility assets with a 30-year economic life for depreciation purposes and qualifying for accelerated tax depreciation according to the 20-year MACRS schedule. The investment in rate base is assumed to be financed with 50.00% debt / 50.00% equity and receive a 10.00% allowed ROE.

50 For purposes of this example, FFO is defined as the result of adding back depreciation expense and deferred taxes (which are non-cash expenses) to net income. All credit rating agencies consider an after-tax cash flow measure of this type for purposes of calculating cash flow to debt ratios.

51 Under standard depreciated original cost ratemaking and absent the effects of accelerated tax depreciation, the incremental impact of a given rate base asset to the FFO-to-debt metric is lowest when the asset is new and improves as the asset depreciates; accelerated tax depreciation, and especially bonus depreciation, mitigates or even reverses this trend by providing more cash flow in early years.

Figure 11
TCJA Impact on Year-1 Incremental Cash Flow and Credit Metrics
Illustrated for $1,000 of New Utility Plant Investment
Financed with 50% Equity / 50% Debt

		No TCJA - 35% tax rate with bonus depreciation	**TCJA - 21% tax rate without bonus depreciation**	**Difference**
		[1]	[2]	[3] = [2] - [1]
Net Income	[a] = 500 * 10%	$50.0	$50.0	-
Depreciation	[b] = 1,000 / 30	$33.3	$33.3	-
Deferred income Taxes				
Tax Depreciation	[c]	$422.5	$37.5	($385.0)
Book Depreciation	[d] = [b]	$33.3	$33.3	-
Temporary Difference	[e] = [c] - [d]	$389.2	$4.2	($385.0)
Deferred Income Taxes	[f] = [e] * tax rate	$136.2	$0.9	($135.3)
Funds From Operations	[g] = [a] + [b] + [f]	$219.5	$84.2	($135.3)
FFO-to-Debt (%)	[h] = [g] / 500	43.9%	16.8%	-27.1%

Notes:
[1] [c] = 1,000 * 42.25%; Represents year-1 deduction from 20-year MACRS schedule with 40% bonus depreciation.
[2] [c] = 1,000 * 3.75%; Represents year-1 deduction from 20-year MACRS schedule.

I note that while Figure 11 focuses on the impact of TCJA for new investment, the combined effect of differences in on-going tax deferrals and EDIT amortization is to reduce cash flow and cash flow-to-debt metrics associated with many pre-existing rate base assets also. Indeed, Moody's has evaluated all components of the TCJA as a drag on credit quality across the regulated utility industry, estimating that the average reduction in the ratio of cash flow to debt for utilities due to implementing the new tax law is 150-250 bps.[52]

[52] Moody's Investor Service, "Moody's Changes Outlook on 25 US Regulated Utilities Primarily Impacted by Tax Reform," January 19, 2018. The average reflects bonus depreciation and the impact on cash flow and financing of both new and pre-existing assets. See also Moody's Investor Service, Regulated Utilities - U.S., "2019 outlook shifts to negative due to weaker cash flows, continued high leverage," June 18, 2018 and "2019 outlook negative amid growing debt and stagnant cash flow," November 8, 2018.

Q45. Has the Commission recognized that its proposed ratemaking treatment of the TCJA will decrease cash flows and credit quality for Con Edison and other regulated utilities?

A45. Yes. In its August 9, 2018 Order Determining Rate Treatment of Tax Changes, the Commission acknowledged the findings of Staff and the submissions of the utilities with respect to the negative cash flow implications of TCJA described above,[53] and stated that "the prospective cash flow reductions that utilities will experience because of the Tax Act warrant a careful consideration of the methodology for passing back the Tax Act savings to customers."[54] Further, the Commission described credit quality concerns as an important factor for consideration in recent and future rate proceedings.[55]

Q46. Can using a greater percentage of equity in the regulatory capital structure mitigate some of the detrimental impacts of the new tax law on utility credit quality?

A46. Yes, as discussed by Company witness Saegusa, by financing a greater portion of rate base assets with equity, regulated utilities can both improve cash flow (due to earning an after-tax return) and reduce their debt obligations, both of which serve to improve credit metrics and overall credit quality as evaluated by rating agencies. Figure 12 below illustrates this point using a simple example of a utility with aggregate accelerated tax depreciation deductions approximately 1.5 times the composite depreciation expense included in rates.[56] This example demonstrates that, holding all other factors constant, increasing the percentage of equity vs. debt financing included in the regulatory capital structure can lead to meaningful improvements in after-tax cash flow-to-debt metrics.

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[53] Case 17-M-0815, Order Determining Rate Treatment of Tax Changes, issued August 9, 2018 ("2018 Tax Order"), pp. 61-62.

[54] *Id.*, p. 61.

[55] *Id.*, p. 62.

[56] Specifically, the example assumes ratemaking depreciation at 3.33% and accelerated tax depreciation deductions at 5.00% of aggregate rate base value.

Figure 12
Effect of Capital Structure on Cash Flow to Debt Credit Metrics
Illustrated per $1,000 of Rate Base

		48% Equity / 52% Debt	50% Equity / 50% Debt	52% Equity / 48% Debt
		[1]	[2]	[3]
Equity Portion of Rate Base	[a]	$480.0	$500.0	$520.0
Debt Portion of Rate Base	[b] = 1,000 - [a]	$520.0	$500.0	$480.0
Net Income	[c] = [a] * 10%	$48.0	$50.0	$52.0
Depreciation	[d] = 1,000 / 30	$33.3	$33.3	$33.3
Deferred income Taxes				
Tax Depreciation	[e] = 1,000 * 5.00%	$50.0	$50.0	$50.0
Book Depreciation	[f] = [d]	$33.3	$33.3	$33.3
Temporary Difference	[g] = [e] - [f]	$16.7	$16.7	$16.7
Deferred Income Taxes	[h] = [g] * 21%	$3.5	$3.5	$3.5
Funds From Operations	[i] = [c] + [d] + [h]	$84.8	$86.8	$88.8
FFO-to-Debt (%)	[j] = [i] / [b]	16.3%	17.4%	18.5%

Q47. Have utilities and regulators recognized that increasing the equity ratio in the regulatory capital structure is a viable and effective mechanism for mitigating the negative credit impacts associated with regulatory implementation of the TCJA?

A47. Yes. The Georgia Public Utilities Commission increased Atlanta Gas Light Co's common equity ratio from 51.00 to 55.00 percent and also increased the equity thickness for Georgia Power.[57] Similarly, the Kentucky Public Service Commission allowed Atmos Kentucky to increase its equity percentage from 52.30 to 58.20 percent,[58] and the Alabama Public Service Commission has approved a plan to allow Alabama Power Company to gradually increase its regulatory equity ratio from 47.00 to 55.00 percent by 2025 or sooner.[59] In addition the New Jersey Board of Public Utilities has authorized PSE&G to increase its regulatory equity ratio to 54.00 percent.[60]

57 GA PUC, Docket D-40828 and Southern Company, "Investor Presentation," Nov. 7, 2018.

58 KY PSC, Docket C-2018-00281.

59 *See* Moody's Investor Service, Regulated Utilities - U.S., "2019 outlook shifts to negative due to weaker cash flows, continued high leverage," June 18, 2018.

60 *See* BPU Docket Nos. ER18010029 and GR18010030, NJ BPU Decision, pp. 7, 14. PSE&E has been steadily increasing its regulatory equity ratio since 2013, a year in which its year end regulatory equity

At the same time, utilities have been issuing a larger volume of equity than at any time since the financial crisis according to Thompson Reuter's data.[61] According to Moody's, approximately $24 billion in new equity issuances by regulated U.S. utilities were announced in 2018 (though November).[62]

Both utility managers and utility regulators recognize that "deleveraging" through use of more equity financing—especially as accompanied by recognition of this greater reliance on equity financing for ratemaking purposes—is an effective and appropriate option for supporting utility credit ratings in the face of the cash flow reductions and increased investor financing requirements imposed by regulatory implementation of the TCJA.

C. THE CAPM BASED COST OF EQUITY ESTIMATES

Q48. Please briefly explain the CAPM.

A48. In the CAPM the collective investment decisions of investors in capital markets will result in equilibrium prices for all risky assets such that the returns investors expect to receive on their investments are commensurate with the risk of those assets relative to the market as a whole. The CAPM posits a risk-return relationship known as the Security Market Line (*see* Figure 3 in Section III), in which the required expected return on an asset is proportional to that asset's relative risk as measured by that asset's beta.

More precisely, the CAPM states that the cost of capital for an investment, S (*e.g.*, a particular common stock), is determined by the risk-free rate plus the stock's systematic risk multiplied by the market risk premium. Mathematically, the relationship is given by the following equation:

$$\boldsymbol{r_s = r_f + \beta_s \times MRP} \qquad (1)$$

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ratio was 51%. See BPU Docket Nos. ER18010029 and GR18010030, Direct Testimony of Scott Jennings, 12+0 Update, August 8, 2018, p. 55.

61 Reuters Business News, "US tax reform reenergizes equity markets for utility companies," June 12, 2018.

62 Moody's Investor Service, Regulated Utilities - U.S., "2019 outlook negative amid growing debt and stagnant cash flow," November 8, 2018.

- r_S is the cost of capital for investment S;
- r_f is the risk-free interest rate;
- β_S is the beta risk measure for the investment S; and
- MRP is the market equity risk premium.

The CAPM is a "risk-positioning model," which operates on the principle (corroborated by empirical data) that investors price risky securities to offer a higher expected rate of return than safe securities. It says that an investment whose returns do not vary relative to market returns should receive the risk-free interest rate (that is the return on a zero-risk security, the y-axis intercept in Figure 3), whereas investments of the same risk the overall market (*i.e.*, those that by definition have average systematic market risk) are priced so as to expect to return the risk-free rate plus the MRP. Further, it says that the risk premium of a security over the risk-free rate equals the product of the beta of that security and the MRP.

1. Inputs to the CAPM

Q49. What inputs does your implementation of the CAPM require?

A49. As demonstrated by equation (1), estimating the cost of equity for a given company requires a measure of the risk-free rate of interest and the MRP, as well as a measurement of the stock's beta. There are many methodological choices and sources of data that inform the selection of these inputs. I discuss these issues below. (Additional technical detail, along with a discussion of the finance theory underlying the CAPM is provided in Exhibit___(BV-2).)

Q50. What value did you use for the risk-free rate of interest?

A50. I used the yield on a 20-year U.S. Treasury bond as the risk-free asset for purposes of my analysis. Recognizing the fact that the cost of capital set in this proceeding may be in place over the next several years, I rely on a forecast of what Treasury bond yields will be in 2020. Specifically, *Blue Chip Economic Indicators* projects that the yield on a ten-year Government Bond will be 3.6 percent by 2020.[63] I adjust this value upward by 50 bps, which is my estimate of the representative historical maturity premium for the 20-year over the ten-year Government Bond. This gives me 4.1 percent as an estimate of the risk-free rate.

Q51. What value did you use for the MRP?

A51. Like the cost of capital itself, the MRP is a forward-looking concept. It is by definition the premium above the risk-free interest rate that investors can *expect* to earn by investing in a value-weighted portfolio of all risky investments in the market. The premium is not directly observable. Rather, it must be inferred or forecasted based on known market information. One commonly used method for estimating the MRP is to measure the historical average premium of market returns over the income returns on government bonds over some long historical period. The average market risk premium from 1926 to the present (2017) is 7.07 percent.[64] I use this value of the MRP in my CAPM analyses.

I also note that Bloomberg's forward-looking market-implied MRP is currently estimated at approximately 7.0 percent (when expressed relative to 20-year bond yields) and was above the 7.07 percent long-term historical average value in most months of 2018. The fact that recent forward-looking estimates of the MRP exceeded the historical average level is consistent with the broader body of evidence that risk premiums have remained elevated relative to their pre-financial crisis levels. (See Section IV above.)

Therefore, and considering the recent increase in measures of market volatility, I believe the 7.07 percent long-term historical average MRP value I rely on is a reasonable and conservatively low estimate of what the market risk premium will be during the period at issue in this proceeding.

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[63] Blue Chip Economic Indicators, October 2018, p. 14.

[64] Duff & Phelps, Ibbotson SBBI 2018 Valuation Yearbook 10-21.

Q52. What betas did you use for the companies in the Electric Proxy Group?

A52. I used *Value Line* betas, which are estimated using the most recent five years of weekly historical returns data.[65] The *Value Line* levered equity betas measured for the Electric Proxy Group are reported in Figure 10 and above. Importantly, as explained in Section III.B above, these betas—which are measured (by *Value Line*) using the market stock return data of the proxy companies—reflect the level of financial risk inherent in the proxy companies' market value leverage ratios over the estimation period. Because Con Edison's regulatory capital structure includes a substantially higher proportion of debt financing compared to the proxy companies,[66] the financial risk associated with an equity investment in Con Edison's rate base is correspondingly greater than the financial risk borne by investors in the proxy companies' publicly traded stock.[67]

Consequently, when standard textbook techniques are applied to unlever the *Value Line* betas reported in Figure 10 and relever the resulting asset betas at Con Edison's regulatory capital structure, the resulting proxy group averages are 0.68 – 0.70 for the Electric Proxy Group.[68]

2. The Empirical CAPM

Q53. What other equity risk premium model do you use?

A53. Empirical research has long shown that the CAPM tends to overstate the actual sensitivity of the cost of capital to beta: low-beta stocks tend to have higher risk premiums than

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65 See Value Line Glossary, accessible at http://www.valueline.com/Glossary/Glossary.aspx

66 Con Edison's proposed regulatory capital structure debt ratio of 48.89% (with 1.11% customer deposits) is above the maximum of five-year average debt ratios measured for the Electric Proxy Group. The average debt percentage of the Electric Proxy Group is 40%.

67 A further detailed discussion is contained in Exhibit___(BV-2), Section III.

68 See Exhibit___(BV-3), Table Nos. BV-13 – BV-15. The Technical Appendix (Exhibit___(BV-2)) to this testimony provides a detailed description of the standard textbook formulas used to implement the "Hamada" technique for unlevering measured equity betas based on the proxy companies' capital structures to calculate "asset betas" that measure the proxy companies' business risk independent of the financial risk impact of differing capital structures. The proxy group average asset betas are then relevered at the target capital structure (i.e., Con Edison's regulatory capital structure), with the precise relevered beta depending on the specific version of the unlevering/relevering formula employed.

predicted by the CAPM and high-beta stocks tend to have lower risk premiums than predicted.[69] A number of variations on the original CAPM theory have been proposed to explain this finding, but the observation itself can also be used to estimate the cost of capital directly, using beta to measure relative risk by making a direct empirical adjustment to the CAPM.

The second variation on the CAPM that I employ makes use of these empirical findings. It estimates the cost of capital with the equation,

$$\boldsymbol{r_S = r_f + \alpha + \beta_S} \times (\boldsymbol{MRP - \alpha}) \qquad (2)$$

where $\boldsymbol{\alpha}$ is the "alpha" adjustment of the risk-return line, a constant, and the other symbols are defined as for the CAPM (see equation (2) above).

I label this model the Empirical Capital Asset Pricing Model, or "ECAPM." The alpha adjustment has the effect of increasing the intercept but reducing the slope of the Security Market Line in Figure 3, which results in a Security Market Line that more closely matches the results of empirical tests. This adjustment is portrayed in Figure 13 below. In other words, the ECAPM produces more accurate predictions of eventual realized risk premiums than does the CAPM.

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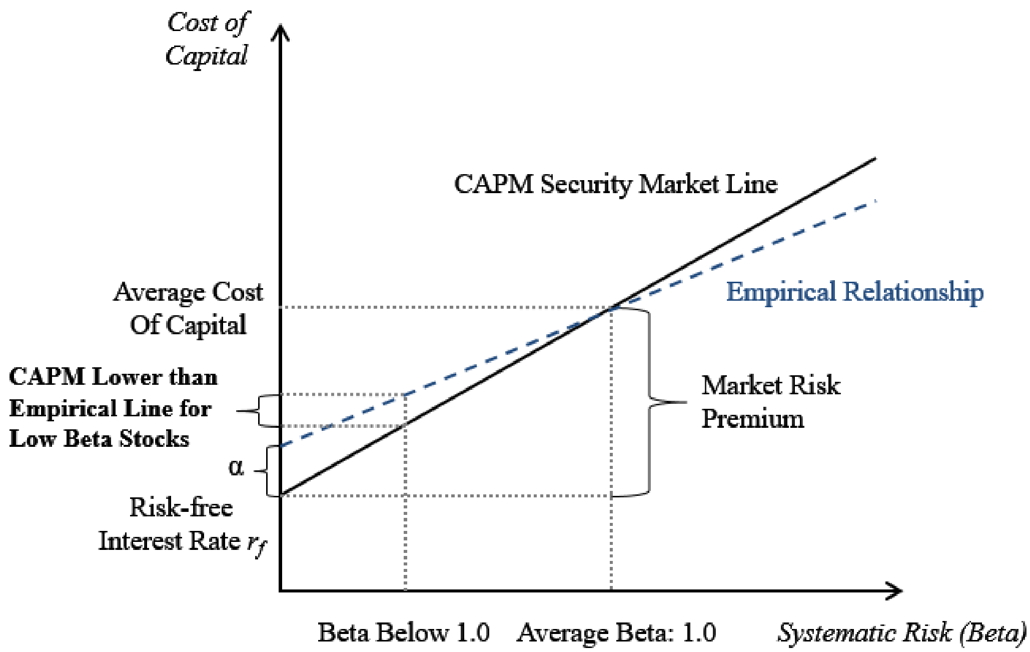
69 *See* Figure A-2 in Exhibit___(BV-2) for references to relevant academic articles.

Figure 13
The Empirical Security Market Line



Q54. Why do you use the ECAPM?

A54. Academic research finds that the CAPM has not generally performed well as an empirical model. One of its short-comings is directly addressed by the ECAPM, which recognizes the consistent empirical observation that the CAPM underestimates the cost of capital for low beta stocks. In other words, the ECAPM is based on recognizing that the actual observed risk-return line is flatter and has a higher intercept than that predicted by the CAPM. The alpha parameter (α) in the ECAPM adjusts for this fact, which has been established by repeated empirical tests of the CAPM. Exhibit___(BV-2), Section II.C discusses the empirical findings that have tested the CAPM and also provides documentation for the magnitude of the adjustment, α.

Q55. How does your implementation of the ECAPM compare to the "Zero Beta" CAPM that has recently been employed by Staff?

A55. The two models are conceptually linked. In recent base rate proceedings involving Con Edison (as well as CEI's other regulated subsidiary Orange and Rockland Utilities, Inc.), Staff testified that "a considerable body of research has shown that the Traditional CAPM may underestimate required returns when betas are below 1.0."[70] This is the same reason I employ the ECAPM. In addition, while the specific formula employed by Staff differs from Equation 2 above, the mathematical impact of the two adjustments is similar, with Staff's formula adjusting the slope of the risk-return relationship somewhat more (and thus increasing the estimated cost of equity for low beta companies somewhat more) than my ECAPM formula.[71]

3. Results from the CAPM Based Models

Q56. Please summarize the parameters of the scenarios and variations you considered in your CAPM and ECAPM analyses.

A56. The parameters are displayed in Figure 14 below. As discussed above, the risk-free interest rate represents Blue Chip Economic Indicators projection for the ten-year Treasury Yield to prevail in 2020, adjusted to a 20-year horizon. The MRP is the long-term historical arithmetic average of annual realized premiums of U.S. stock market returns over long-term (approximately 20-year maturity) Treasury bond income returns from 1926 to 2017 as reported by Duff and Phelps.

Figure 14
Parameters in Risk Positioning Analyses

Risk-Free Interest Rate	4.10%
Market Risk Premium	7.07%

[70] Direct Testimony of Staff Finance Panel in Cases 16-E-0060 and 16-G-0061, pp. 87-88; Direct Testimony of Staff Finance Panel in Cases 18-E-0067 and 18-G-0068, pp. 92-93.

[71] Staff uses the formula $\boldsymbol{r_S} = \boldsymbol{r_f} + 0.25 \times \boldsymbol{MRP} + \boldsymbol{\beta_S} \times (0.75 \times \boldsymbol{MRP})$. If this formula were applied with an MRP of approximately 7.0%, it would be equivalent to applying an alpha of $\alpha = 1.75\%$ in my ECAPM formula, rather than the $\alpha = 1.5\%$ I actually use.

Q57. Please summarize the results of the CAPM-based models.

A57. The results of CAPM and ECAPM estimation for the Electric Proxy Group are presented in Figure 15 below. The ranges of results for each model (CAPM and ECAPM) reflect the application of different specific versions of the textbook formulas used to account for the impact of different financial leverage on financial risk.

Figure 15
CAPM Summary: Electric Proxy Group

	CAPM	ECAPM (α = 1.5%)
Overall Cost of Capital	9.3%	10.0%
Hamada Adjustment Method (with taxes)	8.9%	9.4%
Hamada Adjustment Method (without taxes)	9.1%	9.5%

Note: Long-Term Risk Free Rate of 4.10%, Long-Term Market Risk Premium of 7.07%.

Q58. How do you interpret the results of your CAPM and ECAPM Analyses?

A58. In my opinion, the estimates reported above support a reasonable cost of equity range of 9.25 - 10.00 percent based on the Electric Proxy Group.[72] As discussed above, the established academic evidence indicates that the traditional CAPM tends to understate the cost of equity for lower-than-average risk companies such as those in the Electric Proxy Group, I therefore give somewhat greater weight to the ECAPM results to inform my recommendation and consider the lowest estimate from the CAPM to be too low.

D. DCF BASED ESTIMATES

1. Single and Multi-Stage DCF Models

Q59. Can you describe the DCF model's approach to estimating the cost of equity?

A59. The DCF model attempts to estimate the cost of capital for a given company directly, rather than based on its risk relative to the market as the CAPM does. The DCF method assumes that the market price of a stock is equal to the present value of the dividends that

[72] I consider the lowest of the CAPM estimates unreasonable and round the results to the nearest 0.25 percent to assess the reasonable range.

its owners expect to receive. The method also assumes that this present value can be calculated by the standard formula for the present value of a cash flow—literally a stream of expected "cash flows" discounted at a risk-appropriate discount rate. When the cash flows are dividends, that discount rate is the cost of equity capital:

$$\boldsymbol{P_0 = \frac{D_1}{1+r} + \frac{D_2}{(1+r)^2} + \frac{D_3}{(1+r)^3} + \cdots + \frac{D_T}{(1+r)^T}} \quad (3)$$

Where,

$\boldsymbol{P_0}$ is the current market price of the stock;

$\boldsymbol{D_t}$ is the dividend cash flow expected at the end of period $\boldsymbol{t}$;

$\boldsymbol{T}$ is the last period in which a dividend cash flow is to be received; and

$\boldsymbol{r}$ is the cost of equity capital.

Importantly, this formula implies that if the current market price and the pattern of expected dividends are known, it is possible to "solve for" the discount rate r that makes the equation true. In this sense, a DCF analysis can be used to estimate the cost of equity capital implied by the market price of a stock and market expectations for its future dividends.

Many DCF applications assume that the growth rate lasts into perpetuity, so the formula can be rearranged algebraically to directly estimate the cost of capital. Specifically, the implied DCF cost of equity can then be calculated using the well-known "DCF formula" for the cost of capital:

$$\boldsymbol{r = \frac{D_1}{P_0} + g = \frac{D_0}{P_0} \times (1 + g) + g} \quad (4)$$

where $\boldsymbol{D_0}$ is the current dividend, which investors expect to increase at rate $\boldsymbol{g}$ by the end of the next period, and over all subsequent periods into perpetuity.

Equation (4) says that if equation (3) holds, the cost of capital equals the expected dividend yield plus the (perpetual) expected future growth rate of dividends. I refer to this as the single-stage DCF model; it is also known as the Gordon Growth model, in honor of its originator Professor Myron J Gordon of the University of Toronto.

Q60. Are there other versions of the DCF model?

A60. Yes. There are many alternative versions, notably (i) multi-stage models, (ii) models that use cash flow rather than dividends, or versions that combine aspects of (i) and (ii).[73] One such alternative expands the Gordon Growth model to three stages. In the multistage model, earnings and dividends can grow at different rates, but must grow at the same rate in the final, constant growth rate period. [74]

In my implementation of the multi-stage DCF, I assume that companies grow their dividend for five years at the forecasted company-specific rate of earnings growth, with that growth then tapering over the next five years toward the growth rate of the overall economy (*i.e.*, the long-term GDP growth rate forecasted to be in effect ten years or more into the future).

2. DCF Inputs and Results

Q61. What growth rate information do you use?

A61. The first step in my DCF analysis (either constant growth or multi-stage formulations) is to examine a sample of investment analysts' forecasted earnings growth rates for companies in my proxy group. For the single-stage DCF and for the first stage of the multi-stage DCF, I use investment analyst forecasts of company-specific growth rates sourced from *Value Line* and Thomson Reuters IBES.

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73 The Surface Transportation Board uses a cash flow based model with three stages. See, for example, Surface Transportation Board Decision, "STB Ex Parte No. 664 (Sub-No. 1)," Decided January 23, 2009.

74 See Exhibit___(BV-2), Section I for further discussion of the various versions of the DCF model, as well as the details of the specific versions I implement in this proceeding.

For the long-term growth rate for the final, constant-growth stage of the multistage DCF estimates, I use the long-term U.S. GDP growth forecast of 4.1 from Blue Chip Economic Indicators.[75] Thus, the long-run (or terminal) growth rate in the multi-stage model is nominal GDP growth.

Q62. What are the pros and cons of the input data?

A62. Both the Gordon Growth and single-stage DCF models require forecast growth rates that reflect investor expectations about the pattern of dividend growth for the companies over a sufficiently long horizon, but estimates are typically only available for three - five years. In the multi-stage version, I taper these growth rates toward a stable growth rate corresponding to a forecast of long-term GDP growth for all companies.

One issue with the data is that it includes solely dividend payments as cash distributions to shareholders, while some companies also use share repurchases to distribute cash to shareholders.

Q63. Please summarize the DCF based cost of equity estimates for the Electric Proxy Group.

A63. The results of the DCF based estimation for the Electric Proxy Group are displayed below in Figure 16.

Figure 16
DCF Model Results: Electric Proxy Group

Single-Stage	10.4%
Multi-Stage	8.8%

Q64. How do you interpret the results of your DCF analyses?

A64. As discussed above, the DCF models are currently estimated based on dividend yields that may be expected to increase as interest rates continue to rise in the coming months

[75] See Blue Chip Economic Indicators, October 2018, p. 14.

and years. As a consequence, the multi-stage DCF model's assumption that *current* prices reflect investor's expectations that dividend growth will converge with the rate of GDP growth in the long term may underestimate how that pattern of expected dividends will be valued in the market throughout the period for which the rates decided in this proceeding will be in effect (*i.e.*, 2019 onward).[76] Thus, while I acknowledge that the single-stage DCF model makes the strong assumption that current three-to-five year Earnings Per Share growth expectations will persist into perpetuity, I conclude that a reasonable estimate of the cost of equity falls somewhere between what is estimated by the two versions of the model. In considering the results from the Electric Proxy Group, I believe the DCF model supports a reasonable range of 9.25 to 10.25 percent for Con Edison's cost of equity.

E. RISK PREMIUM MODEL ESTIMATES

Q65. Did you estimate the cost of equity that results from an analysis of risk premiums implied by allowed ROEs in past utility rate cases?

A65. Yes. In this type of analysis, sometimes called the "risk premium model," the cost of equity capital for utilities is estimated based on the historical relationship between allowed ROEs in utility rate cases and the risk-free rate of interest at the time the ROEs were granted. These estimates add a "risk premium" implied by this relationship to the relevant (prevailing or forecast) risk-free interest rate:

$$Cost\ of\ Equity = r_f + Risk\ Premium$$

Q66. What are the merits of this approach?

A66. First, it estimates the cost of equity from regulated entities as opposed to holding companies, so that the relied upon figure is directly applicable to a rate base. Second, the allowed returns are readily observable to market participants, who will use this one

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[76] Blue Chip's forecasted GDP growth was 4.10% at the time of estimation, while the realized nominal GDP growth for Q2 and Q3, 2018 was 7.60 percent and 4.90 percent, respectively.

Source: https://www.bea.gov/news/glance

data input to making investment decisions, so that the information is at the very least a good check on whether the return is comparable to that of other investments. Third, I analyze the spread between the allowed ROE at a given time and the then prevailing interest rate to ensure that I properly consider the interest rate regime at the time the ROE was awarded. This implementation ensures that I can compare allowed ROE granted at different times and under different interest rate regimes.

Q67. How did you use rate case data to estimate the risk premiums for your analysis?

A67. The rate case data from 1990-2018 is derived from Regulatory Research Associates.[77] Using this data I compared (statistically) the average allowed rate of return on equity granted by U.S. state regulatory agencies in electric utility and electric distribution rate cases to the average 20-year Treasury bond yield that prevailed in each quarter.[78] I calculated the allowed utility "risk premium" in each quarter as the difference between allowed returns and the Treasury bond yield, since this represents the compensation for risk allowed by regulators. Then I used the statistical technique of ordinary least squares ("OLS") regression to estimate the parameters of the linear equation:

$$Risk\ Premium\ =\ A_0\ +\ A_1\ \times\ (Treausury\ Bond\ Yield) \qquad (8)$$

I derived my estimates of A_0 and A_1 using standard statistical methods (OLS regression) and find that the regression has a high degree of explanatory power in a statistical sense. I report my results for the respective classifications of rate cases below in Figure 17.[79]

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77 SNL Financial as of December 2018.

78 I rely on the 20-year government bond to be consistent with the analysis using the CAPM to avoid confusion about the risk-free rate. While it is important to use a long-term risk-free rate to match the long-lived nature of the assets, the exact maturity is a matter of choice.

79 My workpapers for the implied risk premium analysis are contained in Exhibit___(BV-4).

Figure 17
Implied Risk Premium Model Estimates

		R Squared	Estimate of A_0	Estimate of A_1	Implied Cost of Equity
Electric Utility	[a]	0.829	8.48%	-0.542	10.4%
Electric Distribution	[b]	0.877	8.87%	-0.762	9.8%

Sources and notes: [a], [b]: Estimated using SNL Past Rate Case data as of 12/7/2018 and Bloomberg Treasury yield data as of 11/30/2018.

The negative slope coefficient reflects the empirical fact that regulators grant smaller risk premiums when risk-free interest rates (as measured by Treasury bond yields) are higher. This is consistent with past observations that the premium investors require to hold equity over government bonds increases as government bond yields decline. In the regression described above the risk premium declined by less than the increase in Treasury bond yields. Therefore, the allowed ROE on average declined by less than 100 bps when the government bond yield declined by 100 bps. Based on this analysis, I find that the current market conditions are consistent with an ROE of 10.4 percent for the average electric utility and 9.8 percent for the average electric distribution utility.

Q68. What conclusions did you draw from you risk premium analysis?

A68. The results in Figure 17 indicate a range of approximately 9.75 - 10.5 percent as a reasonable allowed ROE for Con Edison based on the risk premium model, which overlaps with the upper half of the estimates from the reasonable range from the DCF and CAPM models. While the risk premium model based on historical allowed returns are not underpinned by fundamental finance principles in the manner of the CAPM or DCF models, I believe that this analysis, when properly designed and executed and placed in the proper context, is a valid and useful approach to estimating utility ROE. Because the risk premium analysis as implemented takes into account the interest rate prevailing during the quarter the decision was issued, it provides a useful benchmark for the cost of equity in any interest environment. Because it relies on the returns for regulated utilities, I believe this method provides a good way to directly assess whether the ROE is commensurate with that available to alternative investments of similar risk.

VI. CON EDISON SPECIFIC CIRCUMSTANCES AND ROE RECOMMENDATION

A. BUSINESS RISK CHARACTERISTICS

Q69. Are there any differences in the regulatory environment in which the comparable companies and Con Edison operates?

A69. Yes. There are several. First, the state of New York has undertaken a package of energy and utility policy reforms known as New York's Reforming the Energy Vision (REV) programs. The stated goal of these programs is

> promoting more efficient use of energy, deeper penetration of renewable energy resources such as wind and solar, wider deployment of "distributed" energy resources, such as micro grids, roof-top solar and other on-site power supplies, and storage …[80]

From an electric utility perspective, energy efficiency and distributed energy resources reduces the amount of power the utility distributes and most of the comparable companies operate in states without such comprehensive plans.[81] In addition, the New York REV programs reflect a new regulatory environment, so that its ultimate impact on the utilities is unknown and therefore results in higher business risk.

Second, the Company's most recent electric and gas rate orders each included an earnings sharing mechanism, where earnings are shared between customers and the Company above the allowed ROE plus 50 bps. There is no similar sharing mechanism when earnings are below the allowed ROE minus 50 bps.[82] An asymmetric sharing mechanism inherently makes it more difficult for the Companies to earn their allowed ROE on average as illustrated in the example below.

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80 *See*, http://www3.dps.ny.gov/W/PSCWeb.nsf/All/CC4F2EFA3A23551585257DEA007DCFE2?OpenDocument

81 New York does have a decoupling mechanism in place. Source: SNL, "Adjustment Clauses: A State-by State Overview," September 28. 2018.

82 2017 Order, pp. 26-29.

Figure 18
Example of Asymmetric Risk Associated with Sharing Mechanism

		8% Earned ROE	9% Earned ROE	10% Earned ROE
Rate Base	[a]	$1,000	$1,000	$1,000
Equity (%)	[b]	48%	48%	48%
Allowed Return on Equity	[c] = [a] × [b] × (9%)	$43.20	$43.20	$43.20
Earned Return	[d] = [a] × [b] × Earned ROE	$38.40	$43.20	$48.00
Earned Return - reimbursed to Customers	[e]	$0.00	$0.00	$1.20
Net Earned Return	[f] =[d] - [e]	$38.40	$43.20	$46.80
Deviation from Allowed Return	**[g] = [f] - [c]**	**-$4.80**	**$0.00**	**$3.60**

Notes:
[e]: For earned return on equity from 9.5% - 10%, Con Edison must reimburse customers 50% of value.
Thus, $1.20 = (10% - 9.5%) × [a] × [b] × .5 must be reimbursed to customers if Con Edison were to realize a 10% return on equity.

As is shown in the figure, the negative deviation from under-earning by 1% is *greater* than the positive deviation associated with over-earning by 1%. As a result, on an expected value basis, Con Edison is more likely to under-earn than they are to over-earn and consequently they will be challenged in earning the allowed ROE.[83]

Third, Con Edison's electric operations have the opportunity to earn incentive for Non-Wires Alternatives based on the net benefits of such programs. Based on periodic filings with the Commission, the Company can earn up to 30% (with customers earning 70%) of the net benefits associated with pursuing non-wires alternative projects.[84] As these incentives are granted for replacing wires with alternatives, there is no distinct impact on the cost of capital or the estimation hereof.

Fourth, I understand Con Edison is implementing an aggressive cost mitigation program - the Business Cost Optimization ("BCO") Program - and has reflected projected savings from the BCO Program in its revenue requirements in these cases. I also understand Con

[83] Statistically speaking, the expected value is the average across all possible outcomes weighted by their likelihood. In this simple example, this points to the average of $-4.80 and $3.60 being less than zero, despite the percentage deviation from the allowed return being +/- 1%. A circumstance without asymmetric risk would retain an expected value of zero for the identical percentage deviation in expected return. This example assumes that Con Edison is equally likely to over earn by 1% as Con Edison is to under earn by 1%.

[84] 2017 Order pp. 29-32 and "Order Approving Shareholder Incentives," Case 15-E-0229, pp. 9-13; Joint Proposal in Case 16-E-0060, pp. 29-31.

Edison has not proposed a reconciliation mechanism if the savings actually realized are less than the projected amounts. As a result, Con Edison bears additional business risk associated with not achieving the BCO Program related costs savings that it provides to customers. This business risk increases the difficulty the Company will face earning its allowed ROE going forward.

Q70. How do these regulatory mechanisms compare to those of the comparable companies?

A70. As noted above, REV-like programs are not common. Looking next to adjustment clauses, a study published by Regulatory Research Associates has found that New York State is neither at the top nor at the bottom regarding the use of adjustment mechanisms for new investments.[85] However, New York is among the few states that operate with a multi-year rate plan for both electric and gas utilities.[86] I also note that Con Edison has a decoupling mechanism, as do more than half of the proxy companies, although the specifics of each plan differ.[87] Because a decoupling mechanism is common, any impact on the ROE or the ability to earn the allowed ROE would be included in the proxy group data, so there is no impact on what Con Edison should be allowed. In addition, research has shown that statistically the presence of a decoupling mechanism has no impact on the cost of capital for electric or gas utilities.[88]

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[85] Regulatory Research Associates, "Adjustment Clauses: A state-by-state overview," September 28, 2018.

[86] Mark A. Lowry, "Multi-year Rate Plans," NRRI, May 9, 2017.

[87] Regulatory Research Associates, "Adjustment Clauses: A state-by-state overview," September 28, 2018.

[88] *See*, for example, Joe Wharton and Michael J. Vilbert, "Decoupling and the Cost of Capital," The Electricity Journal vol. 28, 2015, pp. 19-28.

B. Equity Flotation Costs

Q71. Are there any other Con Edison-specific considerations relevant to the determination of its allowed ROE?

A71. Yes. It is my understanding that the Company (through its parent company CEI) has incurred flotation costs associated with equity issuances that have not been recovered in rates. These costs take the form of underwriting fees and discounts to the offer price. For example, if flotation costs represent approximately 2.5% of the proceeds raised by the issuances, only $97.50 out of every $100 raised in equity issuances would actually be available to finance Con Edison's assets and operations. To the extent these costs were / are not recovered as expenses at the time of the issuances, they should appropriately be recovered via an adjustment to the return on equity going forward.

Q72. How can Con Edison's ROE be adjusted to allow recover of equity issuance costs?

A72. A standard approach to adjusting the allowed ROE to provide recovery of all past equity issuance costs can be implemented via a straightforward adjustment to the single-stage DCF model. In place of the standard single-stage DCF formula (equation 7), the following formula is used.

$$r = \frac{D_1}{P_0(1-f)} + g$$

where f is the percentage of proceeds lost to underwriting fees or other flotation costs. This formula recognizes that if shares trade at (for example) $100, but 2.5% of the proceeds of the initial issuance of those shares was consumed by flotation costs, only $\$100 \times (1 - 0.025) = \$97.5$ represents value invested in cash-flow generating assets. Therefore, it is relative to this "adjusted" price, not the nominal market price, that investors' required return should be measured.

Comparing the flotation cost-adjusted formula to the standard DCF formula for values of the dividend yield, growth rate, and financial leverage that are representative of the Electric Proxy Group (see Figure 19 below), I find that ten bps is an appropriate ROE adjustment to allow recovery of costs amounting to 2.5% of equity issuance proceeds.

Figure 19
Representative Flotation Cost Adjustment Calculation

		Without Adjustment [1]	With Adjustment [2]
Flotation Cost Share of Issuance Proceeds	[a]	n/a	2.5%
Sample Average Dividend Yield	[b]	3.4%	3.5%
Growth Rate Estimate	[c]	5.4%	5.4%
Single Stage DCF Cost of Equity	[d]	8.8%	8.9%
Sample Average Equity Market Value Ratio (%)	[e]	60.9%	60.9%
Sample Average Debt Market Value Ratio (%)	[f]	39.1%	39.1%
Sample Average Cost of Debt Estimate	[g]	4.8%	4.8%
Tax Rate	[h]	26.1%	26.1%
Single Stage DCF Overall Cost of Capital	[i]	6.8%	6.8%
ConEd Regulatory Equity Ratio (%)	[j]	50%	50%
ConEd Regulatory Debt Ratio (%)	[k]	50%	50%
ConEd Cost of Debt Estimate	[l]	4.5%	4.5%
Implied Cost of Equity	**[m]**	**10.2%**	**10.3%**

Sources and Notes:
[a]: Villadsen Direct Testimony.
[b], [c]: Table No. BV-6 - Panel A.
[d] = [b] + [c]
[e]: Table No. BV-4
[f] = 1 - [e]. For simplification, I include preferred equity in debt.
[g]: Table No. BV-7.
[h]: Composite State and Federal Tax Rate.
[i] = ([d] x [e]) + ([g] x [f] x (1 - [h]))
[j], [k]: ConEd Regulatory Capital Structure.
[l]: Representative Cost of Debt for A rated Utilities.
[m] = ([i] - [k] x [l] x (1 - [h])) / [j]

C. COST OF CAPITAL RECOMMENDATION

Q73. What do you recommend for Con Edison's cost of equity in this proceeding?

A73. I recommend that Con Edison be allowed to earn a 10.00 percent rate of return on the equity portion of its regulated rate base. This estimate is situated in the upper half of the reasonable range of 9.25 - 10.25 percent I obtained from the DCF and CAPM estimation. It is also consistent with the range of 9.75 to 10.25 percent that I obtained from the implied risk premium model. The fact that 10.00 percent is within what is observed for all three models, DCF-based, CAPM-based, and Risk Premium, suggests that it is a central tendency of the data.

In my opinion, placing Con Edison's allowed rate of return in the upper half of the reasonable range of DCF cost of equity estimates, at the high end of the CAPM/ECAPM range, and in a range consistent with the implied Risk Premium model results is reasonable. As noted above, (i) Con Edison faces somewhat elevated uncertainty and business risk related to substantial changes in regulatory policy, and (ii) the TCJA has resulted in greater volatility of equity cash flows and negative credit quality impacts for the Company, which will only be partially offset by a higher equity ratio (*i.e.*, 50 percent).[89] Finally, although the illustrative ten bps flotation costs adjustment derived in Section VI.B above is not explicitly included in my model results or reasonable ranges, I believe my recommendation is sufficient to allow Con Edison to earn compensation for past (and potential future) equity flotation costs as a component of its ROE.

Q74. Does this conclude your direct testimony?

A74. Yes, it does.

[89] The impact of the TCJA on the Company is discussed in greater detail in the Direct Testimony of Yukari Saegusa.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

GAS FORECASTING PANEL

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CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

GAS FORECASTING PANEL

I. INTRODUCTION

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

A. John Catuogno, Patrick F. Hourihane and Robert Downes, 4 Irving Place, New York, New York 10003.

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

A. (**Catuogno**) We are employed by Consolidated Edison Company of New York, Inc. (“Con Edison” or the “Company”). I am Director of Resource Planning and Forecast in Energy Management. I graduated from Polytechnic University with a Bachelor of Science degree in Mechanical Engineering in 1991 and with a Master of Science degree in Management in 2002. I am a registered Professional Engineer in the State of New York. I am an Adjunct Assistant Professor in the Mechanical Engineering Department of Manhattan College, where I perform graduate lectures on energy. I joined Con Edison in 1991 and have held various positions of increasing responsibility in the Fossil Power, Nuclear Power Engineering, Energy Management, and Steam Operations Departments. Since December 2013, I have been the Director of Energy Management’s Resource Planning & 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.

(**Hourihane)** I am Section Manager of Gas and Steam Forecasting in Energy Management. My background is as follows: I received a Bachelor of Arts Degree in History from Saint Meinrad in 1974 and a Master’s Degree in Energy Management from New York Institute of Technology in 2000. In 1975, I joined Con Edison in the Customer Service Department. Between 1978 and 2005, I worked in positions of increasing responsibility in the Customer Service and Energy Management Departments working on such projects as the electric governmental forecast and gas sales forecast. In 2005, I transferred to the Rate Engineering Department. In December 2006, I was promoted to Section Manager of Electric Volume and Revenue Forecasting. In July 2017, I assumed my present position. My responsibilities include overseeing the development of the gas delivery volume and revenue forecast.

(Downes) I am a Senior Analyst of Gas and Steam Forecasting in Energy Management. My background is as follows: I received a Bachelor's degree in Economics from East Carolina University in 2009. I also received a Master of Science in Economics degree from East Carolina University in 2010. Prior to joining Con Edison, I worked at Seattle City Light where I worked on the electric volume and electric peak forecast. In 2016, I joined Con Edison gas forecasting where I work on developing econometric time series models and gas forecasts for Con Edison.

Q. Have you previously submitted testimony to the New York State Public Service Commission ("Commission")?

A. **(Catuogno)** I submitted testimony in Case Nos. 13-S-0032, 09-S-0794, 09-S-0029, and 07-S-1315.

(Hourihane) I testified in Case Nos. 13-E-0030, 10-E-0362, 08-E-0539, and 07-E-0523 and submitted testimony in Case Nos. 18-G-0068, 16-E-0060, 15-E-0050, 11-E-0408, 09-E-0428, and 07-E-0949.

(Downes) No.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of the Gas Forecasting Panel's testimony in this proceeding?

A. The Gas Forecasting Panel’s testimony presents the Company’s forecast of gas delivery volumes(both full service and transportation combined)and revenues for the 12 months ending December 31, 2020(“Rate Year”) also known as (“RY1”), and two additional twelve month periods ending December 31, 2021 and December 31, 2022, (which we refer to as “RY2” and “RY3” respectively). The testimony explains the development of these forecasts starting from the 12 months ending September 30, 2018 (“Historic Year” or “Base Period”), and the key factors expected to impact future delivery volumes through the end of RY3.

Q. What was the adjusted actual and weather normalized firm delivery volume for the twelve (12) months ended September 2018?

A. The adjusted actual firm delivery volume for the 12 months ended September 2018 was 168,484 MDt. The weather and water normalized firm delivery volume for this same period was 168,819 MDt.

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

A. The firm delivery volume forecast for the three months ending December 2018 is 40,944 MDt. The firm delivery volume forecast for the 12 months ending December 2019 is 172,889 MDt. The firm delivery volume forecast are

175,778 MDt for 12 months ending December 2020 (“Rate Year” of “RY1”), 176,332 MDt for the 12 months ending 2021 (which we will refer to as “RY2”), and 177,995 MDt for the 12 months ending 2022 (which we will refer to as “RY3”). The drivers of the changes in the forecasted volumes are discussed further in Section IV.

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

A. The firm delivery volume forecast is used to determine the revenue forecast. The sendout forecast is used by Company witness Kathleen Trischitta to develop a gas supply cost forecast.

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

A. Yes, we are presenting four exhibits, Exhibit ___(GFP-1) through Exhibit ___ (GFP-4).

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

A. Yes. We describe each of these exhibits below in our testimony.

III. DELIVERY VOLUMES BY SERVICE CLASSIFICATION

Q. Which customers are included in the delivery volume forecast?

A. Both firm and non-firm customers are included in the delivery volume forecast. Firm customer classes include:

- SC-1 – Residential and religious customers;
- SC-2 – Rate 1 (General commercial and industrial customers);
- SC-2 – Rate 1 Rider H (General commercial and industrial customers);
- SC-2 – Rate 2 (General commercial and industrial customers);
- SC-3 – Residential (1 to 4 family dwelling units);
- SC-3 – Residential Rider J (1 to 4 family dwelling units);
- SC-3 – Residential (>4 family dwelling units);
- SC-13 – Seasonal off-peak water heating;
- SC-14 – Natural gas vehicles; and
- Special Contract Customers.

Non-firm (Interruptible) customer classes include:

- SC-9 – Transportation service customers who would otherwise take SC-12 service;
- SC-12 Rate 1 – Non-firm (interruptible) customers; and
- SC-12 Rate 2 – Off-peak firm customers.

IV. FIRM VOLUME FORECAST

Q. What are the key factors expected to impact future gas delivery volume?

A. The key factors expected to impact future gas delivery volume in the various service classifications are:

- Historic Year volume;
- The assumption of normal weather conditions;
- The assumption of normal water temperature;
- The number of annual billing days;
- New Business;
- Energy Efficiency, including Smart Solutions Programs; and the
- Temporary Westchester Gas Moratorium.

Q. Were any adjustments made to the Historic Year volume?

A. Yes. The Historic Year volume was adjusted for:

- Normalizing the impact of actual weather conditions to a 30-year average condition measured in Heating Degree Days ("HDDs");
- Normalizing the impact of actual water temperature to a historical average of water temperature condition measured as an average cycle water temperatures;
- Transferring of customers between non-firm service and firm service;
- Theft of Service;
- Adjustment of A/C volumes;
- Manual Adjustments of Large Volumes to correct months;

and

- Billing days.

Q. Please explain why each of these adjustments is made.

A. The weather normalization adjustment is performed to adjust the Base Period volume to the 30 years ended 2017 normal level of HDDs. The Company used a 30-year normal of HDDs in line with the Commission's requirement in the *Order Approving Electric, Gas and Steam Rate Plans in Accord with Joint Proposal*, in Cases 16-G-0061 et al. We calculated the monthly impact on firm delivery volume by service classification by multiplying the variation between normal and actual HDDs, measured on a billing cycle basis, by a "use per heating degree-day per bill factor" times the actual number of bills by applicable service classification.

Q. How is annual average weather normalized use per bill calculated?

A. Con Edison calculates the annual average weather normalized use per bill by dividing volume for the Historic Year by the number of bills during the Historic Year.

Q. What did you do next with the HDD calculation?

A. We used a regression analysis of the adjusted actual monthly-billed volumes per customer per billing day versus actual monthly billing cycle heating degree days per billing day to determine the factors by service classification.

- We preform the water normalization adjustment to the Base Period volume for deviations from normal average water temperatures to the actual average water temperatures to adjust for the impact on water heating requirements. The Adjustment for SC-1 and SC-2 R1 is for all 12 months. The water adjustments for SC-2 R2 and SC-3 cover the three summer months July – September that are outside the weather normalization discussed above for these two service classes. We determine the usage per degree of average water temperature factors for the average customer of each class by regression analysis, which demonstrated a correlation between sales and water temperature. We applied these factors in a similar manner as the space heating factors were applied in the weather normalization adjustment to derive the water normalization adjustment.
- We made adjustments to account for customers transferring from non-firm to firm service during the Base Period. We preformed this adjustment to annualize the transfers occurring in the historic period. These customers moved either electively or because their gas usage did not meet

interruptible tariff terms.

- We performed adjustments to remove theft of service volumes from the Historic Year. Theft of service primarily covers billing periods in the Historic Year of October 2017 through September 2018.
- We preformed adjustments for air conditioning volumes where billing is outside the cooling season.
- We preformed billing adjustments for large volume customers that smooth out billing cancellations and re-billings to reflect what the actual bills would have been on a monthly basis.

Q. Please discuss the adjustment to billing days.

A. We preformed the adjustment for the number of billing days to account for the difference between the number of days billed in the Historic Year versus the number of expected billing days in the Rate Year.

Q. Have you prepared an exhibit showing the RY1 firm gas volumes?

A. Yes, we prepared a three page Exhibit ___ (GFP-1), the first page of which is titled “CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. - DEVELOPMENT OF 12 MONTHS ENDING DECEMBER 31, 2020 - FORECASTED FIRM GAS VOLUMES (MDt)” with this information.

MARK FOR IDENTIFICATION AS EXHIBIT ___ (GFP-1)

Q. Please describe page 1, line 1 of Exhibit ___ (GFP-1).

A. Page 1, line 1 of Exhibit ___ (GFP-1) shows the adjusted actual firm gas volumes recorded during the Historic Year on a service classification basis.

Q. Please describe page 1, line 2 of Exhibit ___ (GFP-1).

A. Page 1, line 2 of Exhibit ___ (GFP-1) shows the adjusted volumes associated from the weather normalization.

Q. Please describe page 1, line 3 of Exhibit ___ (GFP-1).

A. Page 1, line 3 of Exhibit ___ (GFP-1) shows the adjusted volumes associated from the water normalization. Water temperatures during the Historic Year were warmer than normal. As a result, the Historic Year delivery volumes were lower than they otherwise would have been under normal conditions. This resulted in an upward adjustment to firm volumes of 54 MDt.

Q. Please explain the annualization adjustment labeled "Transfers From Interruptible Service" on line 5.

A. The 292 MDt of delivery volumes on line 5 reflects the net of delivery volumes of customer movement between firm and interruptible service. The volume on line 5 represents the annualized usage of the customers that have switched during the Historic Year.

Q. Please explain line 6 "Billing Schedule Adjustment".

A. The Billing Schedule Adjustment represents the variations in the meter reading schedule from Historic Year to the rate years.

Q. What does line 7, “Base Estimate” represent?

A. The Base Estimate represents the Historic Year volume with the adjustments described previously in this section. The Base Estimate is the starting point for the Rate Year’s firm delivery volume forecast. We then apply the adjustments described below to develop the firm delivery volume forecast.

Q. Please explain the “4 & 6 Oil Conversions” forecast shown on line 8.

A. The 4 & 6 Oil to Gas Conversions forecast are forecasted volumes for anticipated new business from customers converting to natural gas from number 4 and number 6 heating oils.

Q. What is the New Business forecast on line 9?

A. The forecast on line 9:

1) annualizes the volumes associated with customers added or lost during the Historic Year that were not fully realized in the Historic Year and customers that have left gas service and are not forecasted to return, and

2) estimates the expected volume to be realized in the Rate Year associated with new construction and

conversions.

Q. Please explain how the New Business forecast was developed.

A. The New Business volume forecast begins with a forecast of the number of customers for SC-1, SC-2 rate 1, SC-2 rate 2, and SC-3 split between 1 to 4 dwelling units and greater than 4 dwelling units.

We also utilized the weather-normalized average use per customer during the Base Period. We multiplied the weather-normalized average use by the forecast of the number of customers resulting in the New Business forecast.

Q. In developing the New Business volume forecast, how was the forecast of customers developed?

A. We developed the forecast of customers based on time-series regression models using customer count history. Regression models were used to forecast customers for service classifications SC-1 – Residential and religious customers, SC-2 – Rate 1 (General commercial and industrial customers), SC-2 – Rate 2 (General commercial and industrial customers), SC-3 – Residential (1 to 4 family dwelling units), and SC-3 – Residential (>4 family dwelling units). These regressions by service classification used historical customer data as dependent variables. We adjusted the historical customer counts for historical oil-to-gas conversions in service classifications SC-2 – Rate 2 (General commercial and industrial customers), SC-3 – Residential (1 to 4 family dwelling units), and SC-3 – Residential (>4 family dwelling units) to account for the Company's programs that provide incentives to customers who convert from #4 and #6 heating oils. In addition, we used service class regression equations to account for the reclassification of customers between service classifications SC-2 – Rate 1 (General commercial and industrial customers) and SC-2 – Rate 2 (General commercial and industrial customers), as agreed in the prior rate Case 16-E-0061 as well as to account for inactive accounts in service classification SC-2 – Rate 1 (General commercial and industrial customers).

Q. Explain how you developed the 30-day bills forecast.

A. We created the 30-day bills forecast in this filing by converting the customer forecast mentioned previously in the description of the New Business Forecast in this section. Afterwards, we developed an analysis of the historical relationship between customers and 30-day bills. We then used this analysis to create the 30-day bills forecast.

Q. What is the “Energy Efficiency-Smart Solution” forecast shown on line 10?

A. The Company’s Energy Efficiency Department develops the Energy Efficiency forecast. This forecast reflects the expected impact of energy efficiency plans and programs developed by the Company.

Q. Please explain the basis of the “Energy Efficiency–Smart Solution” forecast shown on line 10.

A. The Company develops the forecast based on programs and plans that include: the Con Edison Gas Energy Efficiency Transition Implementation Plan (“ETIP”), the Smart Solutions Energy Efficiency Implementation Plan (“SSEIP”), and Gas Non-Pipes Solutions (“NPS”) programs. For the NPS programs, the Commission has not approved these programs yet. Nevertheless, we included 50% of proposed savings from the NPS programs in the forecast. We will update the savings at the time of the preliminary update if the Commission rules on the Company’s petition. In addition, we have included in the forecast the expected savings from the New York State Energy Research and Development Agency (“NYSERDA”) and New York Power Authority (“NYPA”) energy efficiency programs.

The ETIP and NYSERDA programs provide resources and incentives to the residential (1 to 4 dwelling units), multi-family and commercial customer segments to promote energy efficiency.

Goals for both Con Edison and NYSERDA have been adjusted, in part, as a result of the July 12, 2018 order in Case 17-G-0606 that authorized the Smart Solutions program. This order reauthorized most of the energy efficiency programs covered under ETIP through 2020 and revised targets and budgets where it was deemed appropriate. The energy efficiency usage reductions (in MMBtu) reflected in the forecast were based on the Commission-ordered goals and budgets, available information on past performance, and the program administrators' expectations of energy savings from these programs.

Q. Were there any adjustments made to Energy Efficiency and Smart Solutions forecast shown on line 10?

A. Yes, the Gas Forecasting Panel increased the reductions shown on line 10 to include Natural or "Organic" efficiency. Natural or "Organic" efficiency is the normal turnover of boilers and hot water heaters on the gas system as well as other normal improvements made to customers' energy systems and buildings during renovations. The Energy Efficiency Department's forecast only reflects savings from the marketed programs and does not reflect the total reduction realized from this natural or organic efficiency.

Q. Please explain the basis of the "Temporary Westchester Moratorium" forecast shown on line 11.

A. The Temporary Westchester Moratorium on line 11 projects the Company's forecasted reduction in gas delivery volume from the temporary moratorium in Westchester County. As discussed in the Gas Infrastructure Operations and Supply testimony, the Company announced a temporary moratorium for this region of our service territory on January 17th. The impact of this Temporary Westchetser Moratorium is approximately a 1% decrease in gas service territory peak demand and delivered volume by the end of 2022.

Q What do pages two and three of Exhibit (GFP-1) show?

A. These pages quantify the impacts that the forecast drivers previously discussed in this section are expected to have on RY2 and RY3, respectively.

Q. Based on page one of Exhibit __ (GFP-1), what are the projected firm delivery volumes for the Rate Year?

A. Line 12 on page one of Exhibit __ (GFP-1) summarizes the firm delivery volume forecast for the Rate Year. Firm delivery volume is estimated to total 175,778 MDt. This represents an increase of 2,889 MDt over the Historic Year's volume adjusted to normal weather, which equates to an average annual growth rate of approximately 1.7%.

Q. Are the volumes shown by service classification and in total on page one of Exhibit __ (GFP-1) the volumes the Panel is recommending to be used for rate setting forecasting?

A. Yes. These are the service class delivery volumes for this rate filing.

V. NON-FIRM (INTERRUPTIBLE) VOLUME FORECAST

Q. How was the volume projected for SC-12 Rate 1 Non-Firm (Interruptible) and SC-12 Rate 2 Off-Peak Firm developed?

A. We developed the forecast of the future volume for SC 12 Rate 1 Non-Firm (Interruptible) and SC-12 Rate 2 Off-Peak Firm by making adjustments to the Historic Year volumes. These adjustments include:

(1) a weather adjustment that was computed in a manner similar to the weather normalization adjustments for the weather sensitive firm rate classifications;

(2) an adjustment for the service interruptions that occurred within the Historic Year for the interruptible service classes; and

(3) an adjustment for the transfer of customers between interruptible and firm service discussed earlier.

Q. Based on Exhibit __ (GFP-3), described later, what are the projected non-firm sendout volumes for the Rate Year?

A. Line 13 of Exhibit __ (GFP-3 page 1) summarizes the non-firm sendout volume forecast for the Rate Year. We forecast that Non-Firm sendout volume will be 23,766 MDt.

VI. REVENUE FORECAST

Q. Was Exhibit ___ (GFP-2) and (GFP-3), which is entitled "CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. – FORECSATED GAS VOLUMES AND REVENUES," PREPARED UNDER THE Gas Forecasting Panes supervision and direction?

A. Yes. They were.

MARK FOR IDENTIFICATION AS EXHIBIT ___ (GFP-2) and (GFP-3)

Q. Please explain what page 1 of Exhibit ___ (GFP-2)shows?

A. Page 1 shows forecasted volumes and revenues for the three months ended December 31, 2018 at January 1, 2018 rates.

Q. What does column 1 "Gas Delivery Volumes (MDt)" of this exhibit show?

A. Column 1 shows by service classification grouping the gas volumes forecasted for the three months ending December 31, 2018.

The firm gas service classifications are: SC-1 - Residential and Religious; SC-2R1 – General Commercial and Industrial; SC-2R1 – Rider H - General Commercial and Industrial (customer using gas service for on site Distributed Generation); SC-2R1 – Contract General Commercial and Industrial (non-heating); SC-2R2 – General Commercial and Industrial (heating); SC-3 - Residential and Religious (heating); SC-3 – Rider J - Residential and Religious (customer using gas service for on site generation); SC-13 – Seasonal Off Peak Water Heating; and SC-14 – Natural Gas Vehicles. Column 1 also shows projected SC-12 Rate 1 - Non-Firm and SC-12 Rate 2 - Off-Peak Firm volumes for the three months ending December 31, 2018.

Q. Please explain how the Base Revenues, shown in column 2 on page 1, for firm related volumes were determined.

A. For SC-1, SC-2 Rate 1, SC-2 Rate 2, SC-3, and SC-13, we computed the forecasted Base Revenues by month on a billing determinant basis. The forecast is the product of three steps: 1) the estimated number of 30-day bills associated with the forecasted usage is multiplied by the minimum charge rate to obtain minimum charge revenues; 2) the forecast usage is broken down into usage by rate block and multiplied by the associated rates as they appear in the Company’s gas rate leaves for each rate block; and 3) the minimum charge revenues and block charge revenues are summed to obtain total Base Revenues. The air conditioning volumes of certain customers within these service classifications are charged lower rates for associated incremental volumes and were priced separately. Volumes to distributed generation customers and contract customers were priced according to their appropriate rate/contract terms. The volumes related to SC-14 were priced at the rate in effect at the time the forecast was developed.

Q. Please explain how the Base Revenues related to the projected volumes for SC-12 Rate 1 Non-Firm were determined.

A. SC-12 Rate 1 Non-Firm Base Revenue was provided by Accounting reflecting the base period’s actual revenue’s.

Q. Please explain how the Base Revenues, shown in column 2, related to the projected volumes for SC-12 Rate 2 Off-Peak Firm, were determined.

A. Customers taking service are charged a fixed tariff delivery charge that is based on the term of service elected by the customer. The forecast of Base Revenues reflects a weighted average delivery charge.

Q. Please describe the revenues shown in columns 3,4,5,6, and 7 on page 1.

A. Column 3 on page 1 shows Competitive Charges, which are the associated Merchant Function charges for Supply, Credit and Collections, plus Billing and Payment Processing revenues. Columns 4 through 7 on page 1 are revenues supplied by Financial Forecasting for this Exhibit. “Other Charges” on column 4 include various components of the Monthly Rate Adjustment, Uncollectible Bills, and Purchase of Receivables. Column 5 is System Benefit Charges. Column 6 is the Gas Cost revenues. Column 7 is the revenue taxes associated with columns 2 through 6, and column 8 shows the total revenues of column 2 through column 7.

Q. Please explain what page 2 of Exhibit ___ (GFP-2) shows?

A. Page 2 in the same format shows forecasted volumes and revenues for the 12 months that lead up to the “Rate Year”, 12 months ending December 31, 2019 at January 1, 2019 rates.

Q. Please explain Exhibit ___ (GFP-3)?

A. (GFP-3) is similar to Exhibit ___ (GFP-2) as it shows the Gas Delivery Volume and Revenues for the “Rate Year” and “RY2” and “RY3” at current rates. The Rate Year shown on page 1 of Exhibit ___ (GFP-3) has four additional columns, columns 8, 9, 10, and 11, to include the Proposed Rate Increase and additional Revenue tax. Column 8 is the proposed change in Base Revenues. Column 9 is the proposed change in non-competitive revenues. Column 10 is the additional taxes, and Column 11 is the grand total of the proposed rate increase and associated taxes added to the Total Revenues at current rates shown in Column 8.

Q. What is the rate increase proposed in the Company's rate filing?

A. The total proposed rate increase inclusive of revenue tax is $210.131 million.

Q. You stated above that you developed the Rate Year base revenue forecast by using billing determinants. Did you develop exhibits summarizing the details of the billing determinant forecast?

A. Yes. This data is shown for the three rate years on a three-page exhibit, the first page of which is entitled "CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. – FORECASTED GAS VOLUMES AND BASE REVENUES - 12 MONTHS ENDING DECEMBER 31, 2020 AT CURRENT RATES BY BILLING DETERMINANTS".

MARK FOR IDENTIFICATION AS EXHIBIT ___ (GFP-4)

Q. Please describe what this exhibit shows.

A. This exhibit shows, where applicable, the firm volumes shown in Exhibit ___ (GFP-4) by billing determinant. The volumes by billing determinant were developed using actual billing determinant volumes for the Historic Year, modified to reflect the impact of the variables previously discussed. The allocation of the impact of each of those variables on billing determinant volumes was assessed on an individual basis. For example, the impact of large volume new business and customers transferred from interruptible to firm service has a relatively greater impact on total penultimate and terminal billing determinant usage than that of smaller size new business customers.

We based the forecast of firm delivery revenues from tariff customers (other than SC-14) based on billing determinants. Firm delivery revenues from contract customers were based on their current contract terms. We developed the firm delivery revenues SC-14 revenues by using prices in effect at the mid-point of the Historic Year.

Q. Does this conclude the Gas Forecasting Panel’s testimony?

A. Yes. It does.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC

GAS INFRASTRUCTURE, OPERATIONS AND SUPPLY PANEL - GAS

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I. INTRODUCTION

A. Introduction and Qualifications of Panel Members

Q. Would the members of the Gas Infrastructure, Operations and Supply Panel ("GIOSP" or "Panel") please state your names and business addresses?

A. Our names are Marc Huestis, Katherine Boden, Nicholas Inga, Christine Cummings, Ivan Kimball and Kathleen Trischitta. Our business addresses are 4 Irving Place, New York, New York 10003 for Huestis, Boden, Inga, Cummings, Kimball and Trischitta.

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

A. We are all employed by Consolidated Edison Company of New York, Inc. ("Con Edison" or "Company").

(Huestis) I am the Senior Vice President of Gas Operations.

(Boden) I am the Vice President of Gas Engineering.

(Inga) I am the Vice President of Gas Operations.

(Cummings) I am the General Manager of Project Management and Customer Programs.

(Kimball) I am the Vice President of Energy Management.

(Trischitta) I am the Director of Gas Supply.

Q. Please state your educational background.

A. **(Huestis)** I hold a bachelor's degree in Mechanical Engineering from Stevens Institute of Technology and a master’s degree in Mechanical Engineering from Manhattan College. I have also completed Power Technology Institute’s (“PTI”) Power Technology Transmission Course.

(Boden) I hold a bachelor’s degree in Electrical Engineering from Polytechnic University, and a Master of Business Administration in Management from Hofstra University. I have also completed PTI’s Power Technology Course, PTI’s Electric Distribution System Engineering Course, and Gas Technology Institute’s (“GTI”) Registered Gas Distribution Professional Course.

(Inga) I hold a Bachelor of Science Degree in Mechanical Engineering from Polytechnic University, and a Master of Business Administration Degree in Corporate Finance from Fordham University. I have also completed PTI’s Power Technology Transmission and Distribution Systems programs, and a Project Management certificate course through the Company’s program with Stony Brook University.

(**Cummings**) I hold a Bachelor of Science degree in Economics from Queens College. I have also completed GTI’s Registered Gas Distribution Professional Course.

(**Kimball)** I hold a Bachelor of Science degree and a Master of Science degree in Nuclear Engineering from Rensselaer Polytechnic Institute.

(**Trischitta)** I hold a bachelor's degree in Electrical Engineering from the State University of New York at Stony Brook.

Q. Please describe your work experience.

A. **(Huestis)** I joined Con Edison in 1982 as a Management Intern. I have held various positions of increasing responsibility in Nuclear Power Generation, Steam Operations, Substation Operations, Construction, Electric Operations, and Gas Operations. I was promoted to Vice President of Construction in October 2008, a position I held through December 2013. In January 2014, I was assigned to Manhattan Electric Operations as Vice President. In January 2015, I was promoted to Sr. Vice President of Gas Operations, assuming responsibility for all aspects of Gas Operations on February 1, 2015.

(**Boden)** I joined Consolidated Edison in 1990 as a Management Intern. I have held various positions of increasing responsibility in Construction, Operations, and Engineering in Electric Operations. In 2005, I was promoted to Vice President Manhattan Electric Operations a position that I held through 2010. In 2010 I was assigned to Gas Operations as Vice President. In 2017, I assumed my present role as Vice President of Gas Engineering.

(Inga) I have been with Con Edison for 26 years. In 1992, I joined the Company's Corporate Intern Program and have since held various positions of increasing responsibility in Gas Operations, Treasury, and Shared Services. In April 2008, I was promoted to General Manager of Stores Operations, where I was responsible for the Company's supply inventory and order fulfillment processes. In June 2011, I was appointed to the position of Director of the Gas Conversion Group. In January 2015, I was assigned to Manhattan Gas Operations as General Manager. In 2017, I assumed my current position as Vice President of Gas Operations.

(**Cummings**) I have been with Con Edison for 17 years. In 2001, I joined the Company as a Management Associate following a previous career in global transportation, including roles in auditing and compliance, customer service, and corporate training, and have since held various positions of increasing responsibility in Government Relations (Corporate Affairs) and the Gas Conversion Group. In January 2015, I was promoted to Director of the Gas Conversions Group. In 2018, I assumed my current position of General Manager of the Project Management and Customer Programs group.

(Kimball) I joined Con Edison in 1987 as a Management Intern and held various positions of increasing responsibility until December 1998 when I was transferred to Consolidated Edison Energy, Inc. (“Con Edison Energy”). My responsibilities as Director of Asset Management included day-to-day scheduling, fuel procurement, electricity market sales and planning, and associated regulatory and accounting matters of generating facilities owned by Consolidated Edison Development, Inc. (“Con Edison Development”) and other contracted generating facilities. In August 2008, I returned to Con Edison as Director of Electricity Supply. In that position I was responsible for day-to-day electricity supply operations, including the scheduling of generation and load bids with the New York Independent System Operator (“NYISO”) and neighboring control areas; developing the overall electric power procurement plans for full service customers; developing and implementing Con Edison’s electric hedging program; strategically evaluating and participating in capacity and transmission congestion contract (“TCC”) auctions; managing contractual rights with various non-utility generators; and processing monthly invoices for wholesale purchases and sales of capacity, energy, and TCCs for Con Edison and its affiliates, Orange and Rockland Utilities, Inc. ("O&R") and Rockland Electric Company ("RECO"). In July of 2012, I was promoted to my present position of Vice President of Energy Management.

(Trischitta) I joined Con Edison in 1993 as a Management Intern in Gas Operations and have held various positions of increasing responsibility in Con Edison's Gas Operations, Fuel Supply, Unregulated Retail Operations and Energy Trading and Energy Management organizations. In 1995, I joined Fuel Supply's newly formed off-system sales organization with responsibility for developing and implementing some of the Company's first strategies for gas asset optimization. In 1997, I transferred to the newly formed unregulated subsidiary Con Edison Solutions and was responsible for the implementation of the retail gas business. Immediately prior to assuming my current position in January 2016, I was Managing Director of the Energy Trading organization within Con Edison Energy, another unregulated subsidiary of Con Edison, responsible for the oversight of electricity, gas, oil and renewable energy credit trading.

Q. Please describe your current responsibilities.

A. **(Huestis)** In my current position as Senior Vice President for Gas Operations, I am responsible for the overall Con Edison Gas Operations, Engineering, and Compliance and Quality Assurance groups.

(Boden) In my current position as Vice President of Gas Engineering, I am responsible for the Gas Technology, Technical Operations, Project Management & Customer Programs, Gas Distribution Engineering and Gas Transmission Engineering groups.

(Inga) In my current position as Vice President of Gas Operations I am responsible for leading and managing both Company employees and contractor personnel in the safe and effective execution of, primarily, the following work: leak response, leak repair, compliance inspections, main replacement and service installations.

(**Cummings**) In my current position as General Manager of Project Management and Customer Programs Group, I am responsible for the overall management of the capital projects and programs and for leading and managing the Company’s program to connect customers with new and additional loads. As such, I am responsible for the engineering, operations planning, and customer liaison activities related to customer connections as well as managing the incentive program established in the current rate agreement.

(**Kimball)** I am responsible for providing the overall strategic planning and direction for forecasting service area demand, evaluating electric, natural gas, and steam resource options, and procuring electricity and natural gas. I perform these functions for the customers of Con Edison, O&R, and RECO.

(**Trischitta)** In my current position as Director of Gas Supply, I lead three sections comprised of (i) gas purchasing and scheduling; (ii) gas transportation services and planning; (iii) project management and analysis and contract administration. I am responsible for the functions of gas transportation services, gas transportation planning, procurement of gas and fuel oil, scheduling of delivery of gas and fuel oil and the coordination of all software applications used in the Energy Management organization. I oversee these areas for Con Edison and its corporate affiliate, O&R. I also oversee the procurement of gas and fuel oil for Con Edison-owned generation. Annual natural gas expenditures overseen by my areas are over $700 million dollars per year. In addition, I contribute to the development of the Gas Hedging Program.

Q. Do you belong to any professional organizations?

A. **(Huestis)** Yes, I am a member of the Board of Directors of the Northeast Gas Association (“NGA”),and served as Chairman in 2018, and a member of the Leadership Council of the American Gas Association (“AGA”). I am also a member of the GTI, and the Operations Technology Development (“OTD”). I am a member of the Board of Directors of Westchester Community College, and a member of the Executive Advisory Board of NYC First (For Inspiration & Recognition of Science & Technology) as well.

(Boden) Yes, I am the Chair of the Operations Management Committee (“OMC”) of the NGA and a member of Operations Managing Committee of the AGA. I am a member of the GTI OTD Board. I am also Vice Chair of the Executive Committee of the Society of Gas Lighting.

(Inga) Yes, I am currently 1st Vice Chair of the American Gas Association Field Operations Committee and a member of the Northeast Gas Association’s Operations Managing Committee. I am also a member of the Society of Gas Lighting, and a former member of various NGA technical committees, as well as the Gas Utilization Advisory Group.

(**Cummings**) Yes, I am currently a member of Women in Communications and Energy and a committee member of the AGA.

(**Kimball)** Yes, I am currently a member of AGA and serving on the Steering Committee of the Electrification Impact Assessment Study. I am also a member of the Society of Gas Lighting.

(**Trischitta)** I am a member of Women in Communications and Energy, Society of Gas Operators and a committee member of the AGA.

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

A. **(Huestis)** Yes, I testified before the Commission in the 2008 rate case proceeding as part of the Electric Infrastructure Investment Panel (Case 08-E-0539) and in the previous gas rate case proceeding as part of the Gas Infrastructure and Operations Panel and the Gas Policy Panel (Case 16-G-0061).

(Boden) Yes, I testified before the Commission in the 2004 Electric Rate Case on the Infrastructure Investment Panel when I was the Chief Electric Distribution Engineer (Case 04-E-0572) and in the previous gas rate case proceeding as part of the Gas Infrastructure and Operations Panel (Case 16-G-0061).

(Inga) Yes, I testified before the Commission in previous gas rate case proceedings as part of the Gas Infrastructure and Operations Panel (Case 13-G-0031 and Case 16-G-0061).

(Cummings) Yes, I testified before the Commission in previous gas rate case proceedings as part of the Gas Infrastructure and Operations Panel (Case 13-G-0031 and Case 16-G-0061).

(Kimball) Yes, I have testified before the Commission as the witness in previous electric and gas rate case proceedings (Cases 09-E-0428, 13-E-0030, 16-E-0060 and 16-G-0061).

(Trischitta) Yes. I have testified before the Commission as the Gas Supply witness in case 18-G-0068.

B. Purpose of Filing

Q. Please summarize and briefly explain the purpose of the Panel’s testimony.

A. Consistent with Con Edison’s mission, which includes providing energy services to our customers safely, reliably, efficiently, and in an environmentally sound manner, this Panel will discuss the importance of, and overall need for, infrastructure, operations, and technology investments to reduce risk and enhance safety across the system, continue meeting customer needs, and enhance system operational performance. At the same time, we will keep our focus on the impact to the environment. Furthermore, the Panel will discuss changes in the gas supply and transportation markets and how these changes are affecting the Company's gas purchasing, hedging programs, and capacity plans, including the temporary moratorium recently implemented for most of Westchester County. Investments are primarily comprised of the Company's request in this case for capital programs and increased operation and maintenance ("O&M") requirements. The Panel also proposes to continue deferral accounting/reconciliation for projects/programs whose cost impacts could be significant, but are currently unknown. The Panel also discusses our implementation of the Company's business cost optimization initiative to reduce costs. The Panel also recommends the continuation of most of our current performance measures, with some modest modifications to better align the performance measures with the work the Company plans to undertake. As an enhancement to the existing performance measures, the Company also proposes additional positive incentives that allow the Company to earn added revenue for superior performance.

Q. What period does this testimony cover?

A. The Panel will present the projects and programs planned for the 12 month period ending December 31, 2020 (“Rate Year” or “RY1”). While as discussed by the Company’s Accounting Panel, the Company is not proposing a multi-year rate plan in this rate case, the Company would be willing to pursue, through settlement discussions with Staff and interested parties, a multi-year rate plan. To facilitate settlement discussions, we also address capital plant additions and other programs and initiatives for the two years following the Rate Year. For convenience, we will refer to the 12 month periods ending December 31, 2021 and December 31, 2022 as “RY2” and “RY3”, respectively.

C. Key Themes

1. Safety and Risk Reduction

Q. Please describe the strategies the Company uses to continuously enhance safety, reduce risk and improve operational efficiency.

A. The Company’s gas safety and risk reduction efforts span a wide array of programs and processes. Our risk reduction strategy focuses on programs that enhance prevention, detection and response to gas leaks. The American Petroleum Institute’s Recommended Practice (API RP 1173) lays out the elements of an effective and holistic gas Pipeline Safety Management System (“PSMS”) for pipeline operators. Through our PSMS, we follow a Plan-Do-Check-Act cycle for our daily activities which promotes continuous improvement and feedback loops to our existing practices, procedures and management systems. This standard is then cascaded into our Distribution Integrity Management Program (“DIMP”) and Transmission Integrity Management Program (“TIMP”). Our Integrity Management Programs will support efforts to identify emerging areas of risk and will allow the Company to take proactive steps to address them.

Q. How will our Integrity Management Program reduce risk and enhance safety?

A. Integrity Management examines risks on our system through data analytics, root cause analysis, open communication and standardization, which in turn will lead to the improvement of existing programs or the creation of new programs to reduce these risks and as a result enhance safety. Additionally, the Company incorporates lessons learned from industry events to further advance our processes and business practices.

Q. Please list the gas programs designed to address safety, risk reduction, reliability and operational efficiency that largely come out of the DIMP and TIMP programs.

A. Some programs that come out of DIMP include:

- Main Replacement Program
- Distribution Integrity Main Enhancement Program
- Large Diameter Program
- Service Replacement Program
- AMI-enabled Natural Gas Detectors (“NGDs”)

Some programs that come out of TIMP include:

- Remote Operated Valve Program
- Gate Station Over Pressure Protection Program
- Replacing Aging Infrastructure Program
- Bronx River Tunnel and Easement
- Bronx River Tunnel to Bronx-Westchester Border
- Bronx-Westchester Border to White Plains

All programs and descriptions can be found in Section IV.

Q. What new leak detection technology is the Company investing in?

A. The Company is investing in the installation of approximately 375,000 Advanced Metering Infrastructure (“AMI”) enabled natural gas detectors. These detectors will be installed indoors and are designed to detect natural gas and send an alarm to our Gas Emergency Response Center ("GERC"). The GERC will then contact the fire department and dispatch a Company emergency response crew. The use of these detectors will be for both indoor and outdoor meter configurations. Detection of gas leaks through state-of-the-art technology and public awareness is critical to our comprehensive approach to risk management and commitment to public safety. Through enhanced leak detection, we can respond and remediate quickly, thereby reducing risk, keeping the public safe, and protecting the environment by reducing emissions of un-combusted methane.

2. Operational Excellence

Q. How do the Company's investments advance its goals of achieving operational excellence?

A. Efforts to achieve operational excellence are weaved into all aspects of Gas Operations. Throughout all of the Company's Gas Operations projects, programs, and daily activities, we strive to achieve high standards for planning, engineering, execution, and response which support efficient and effective Company operations. This focus on operational excellence enables the Company to accomplish several important goals, including:

- addressing incoming odor calls on a timely basis;
- continuing to improve leak detection methods;
- substantially reducing the duration of an outside leak;
- continuing to maintain gas system reliability; and
- maintaining a robust system capable of withstanding changing weather and climate conditions.

In addition, Gas Central, the Company’s work and asset management system, will aggregate multiple databases and enable more efficient overall management of programs by aligning gas work across the Company’s service territory. Gas Central will help reduce both administrative and operational risk while creating better efficiencies across our work processes and across our portfolio of commodities.

3. Enhancing Customer Experience

Q. How does the Company plan to enhance the customer experience through its investments?

A. Con Edison is mindful of the impact on our customers and the communities we serve when performing system improvements and reinforcements. By coordinating between various Company capital programs, work is performed in a more efficient and timely manner. The average turnaround time for customer connections has improved, which demonstrates the Company’s commitment to customer satisfaction. To reduce customer disruptions and future costs, Con Edison judiciously assesses customer requests and demands when planning and conducting repairs or replacements across programs and projects. Additional efforts to reduce costs further for customers include using repair sleeves newly developed by a collaborative effort between our R&D Department and NYSEARCH. These repair sleeves avoid the need to perform a main replacement and subsequent customer interruptions to make connections to the new main.

Q. Please describe the technologies and tools the Company uses to enhance the customer experience.

A. Technologies and tools, such as AMI meters, are designed to provide customers with the information they need to make effective decisions about their energy services. In addition, Con Edison has developed and will continue to develop an array of programs for customers under the Smart Solutions for Natural Gas Customers proceeding (Case 17-G-0606). Most of the Smart Solutions programs are designed to give customers more options to monitor gas usage and enhance energy efficiency and are described in more detail by the Customer Energy Solutions Panel.

Q. How has the Company demonstrated its commitment to enhancing Environmental Performance?

A. Since 2005, the Company has reduced its carbon footprint by 49 percent. This is equivalent to taking approximately 500,000 cars off the road each year. This reduction in greenhouse gas (“GHG”) emissions includes reductions in SF_6 emissions from the electrical distribution system, reductions in CH_4 emissions from the gas distribution system, and reductions in CO_2 emissions from the generating stations. The Company has converted more than 7,600 large buildings from oil to cleaner natural gas, which has helped New York City achieve its cleanest air in 50 years.[1] Fine particulate matter reduction has been a focus of the Company since 2011, when we created and staffed a team to support the City of New York’s “Clean Heat” regulations. We have reduced 534 tons of fine particulate matter (2.5 microns) from the air – the equivalent of taking 1.7 million cars off the road. We have also been a member of the Environmental Protection Agency’s (“EPA”) Natural Gas STAR Program since its inception in 1993. The Natural Gas STAR Program is a flexible, voluntary partnership that

[1] http://www1.nyc.gov/office-of-the-mayor/news/311-13/mayor-bloomberg-new-york-city-s-air-quality-has-reached-cleanest-levels-more-than#/0

encourages natural gas companies to adopt proven, cost-effective technologies and practices to improve operational efficiency and reduce methane emissions. The Company also participates in industry clean energy reporting and benchmarking efforts.

Q. How do the Company's planned investments reduce methane emissions?

A. Con Edison is committed to improving the environmental impact associated with our gas system infrastructure. The Main Replacement Program that we are undertaking will not only improve safety by reducing the risk associated with gas leaks, but will also reduce fugitive methane emissions. We will continue working with new natural gas detection technologies to better identify and quantify gas leaks so that leak repairs can be prioritized to effectively reduce methane emissions. The Company is currently exploring alternative supply side solutions such as renewable natural gas ("RNG"), which also have the potential to reduce methane emissions. We are also participating in collaborative climate change studies that will help us identify, anticipate and plan for environmental trends that may impact our system.

D. Gas System Description

Q. Please provide a high-level overview of the Company’s natural gas transmission and distribution system.

A. A gas distributor since 1823, Con Edison currently provides natural gas service to more than 1.1 million customers in Manhattan, the Bronx, parts of Queens, and Westchester County. Con Edison manages a large, complex underground natural gas transmission and distribution system. This system contains approximately 4,400 total miles of gas main with approximately 375,000 service pipes that transport more than 330 million dekatherms of natural gas each year. The approximately 4,400 miles of gas mains consist of 94 miles of transmission mains operating at pressures greater than 125 psig and 4,300 miles of distribution mains operating at pressures less than 100 psig. Approximately 300 miles are large-diameter distribution mains, greater than or equal to 16” that mostly connect the transmission mains to approximately 4,000 miles of smaller-diameter distribution mains.

Q. Please provide a general description of the parameters within which the Company designs its gas system.

A. We design our gas transmission and distribution system to meet the requirements of 16 NYCRR Part 255, 49 CFR 192 and the load requirements of all firm customers 365 days per year, 24 hours per day, based on the forecasted peak hourly load.

Q. Please describe the Company's gas infrastructure replacement objectives.

A. The Company's replacement objectives seek to reduce risk and maintain safety and reliability. One method of reducing risk, is the Company's proactive replacement of 12-inch and smaller cast iron, wrought iron, and unprotected steel. The Company's gas system is predominantly a "zero contingency" system, meaning that a single point of failure could result in the disruption of service to some customers. In order to minimize potential disruptions, the Company has developed written specifications identifying the Company's gas infrastructure replacement objectives, which are as follows:

- To maintain the reliability of the gas transmission and distribution system
- To avoid significant outages on distribution supply mains in the event of an outage to a gate station or critical regulating station
- To reduce the potential of incoming gas leaks

- To maintain the system at optimal operating pressures while satisfying applicable design basis conditions

We adhere to these objectives in designing our system and in making infrastructure replacement decisions. As such, these objectives are a central feature of our daily decisions and the Company's long-term strategy for Gas Operations.

II. GAS SUPPLY CONSTRAINTS AND TEMPORARY MORATORIUM

Q. Have there been changes in market conditions over the last few years that affect the Company's gas supply program?

A. Yes. The outlook for development of new or expansion of existing interstate pipelines has turned increasingly uncertain.

At the same time, customer conversions from oil to natural gas, driven by NYC's Clean Energy Program, have led to significant load growth in the Con Edison service territory. Since 2011, the peak demand for firm natural gas customers has increased by over 40%.

Q. How have these changes affected Company operations?

A. The significant peak demand growth, coupled with the uncertainty associated with new pipeline capacity, has led to supply constraints and the Company's pursuit of alternative solutions for meeting peak gas demand.

Q. What have the Companies done to try to address the supply constraints?

A. In September 2017, Con Edison filed a petition with the Commission to approve its Smart Solutions for Natural Gas Customers Program. The program proposes a multi-faceted strategy to decrease gas peak demand, procure alternative supply resources and continue pursuit of new or expanded interstate pipeline infrastructure. The status of the non-pipeline initiatives is discussed by the Customer Energy Solutions Panel.

Q. What other steps has the Company taken to address the uncertainty in being able to maintain a supply portfolio capable of meeting its forecasted peak demand?

A. On January 17, 2019, the Company filed notice with the Commission stating that it was implementing a temporary moratorium on the addition of new firm gas customers in most of Westchester County, to commence on March 15, 2019. Starting on that day, the Company will no longer accept applications for gas service in the area of Westchester County subject to the moratorium. Up to that day, the Company expects that it will be able to provide gas service to any customer who applies for gas service, or already has applied for gas service.

Q. Please describe the temporary moratorium in more detail

A. As stated in our January 17, 2019 notice to the Commission, this temporary moratorium is necessary because there are gas supply constraints in this part of our service territory that limit our ability to meet customer demand on the coldest winter days. The moratorium will apply to any new firm gas customers that will increase winter peak demand, including heating, hot water, laundry, and cooking loads. During the temporary moratorium, the Company will continue to accept applications from new customers that do not contribute to gas peak day demands, such as applications for interruptible service or gas service for emergency generators.

Q. Is the Company helping its customers pursue clean alternatives to natural gas?

A. Yes. Con Edison is working with its customers to help them find clean energy alternatives. As stated above, the Company is developing and implementing programs through its Smart Solutions programs it has filed for approval with the Commission, including geothermal heating and air source heat pump programs and renewable gas supplies and local gas storage. The Company is also working with the New York State Energy Research and Development Authority and will assist customers to access additional clean energy programs that may be available. We also note that while existing natural gas customers are not affected by the temporary moratorium, they may choose to participate in our gas energy efficiency and demand response programs to manage energy costs and reduce usage. And these programs will result in existing customers reducing their contribution to peak demand.

Q. What other ongoing outreach initiatives are in place to educate potential natural gas customers about the temporary moratorium?

A. We are advising customers that the Project Management and Customer Programs group can be reached at 1-800-643-1289, and that information can be obtained at www.conEd.com. The Gas Yellow Book, which contains technical information and specifications, is also available on the Company's website.

Q. Does the Company's filing reflect the implementation of the temporary moratorium?

A. Yes. As will be seen in this testimony, the Company's filing reflects a reduced forecast and reduced spending in certain areas that reflect the implementation of the temporary moratorium. We assumed that the moratorium would be in effect through 2022 for the purposes of developing the illustrative Rate Years 2 and 3.

III. CAPITAL AND O&M SUMMARY INFORMATION

Q. What is the Company’s projected gas infrastructure and operations capital investment for the three rate years?

A. We are planning to invest $943.8 million in RY1, $959.4 million in RY2 and $967.6 million in RY3, including Municipal Infrastructure Support expenditures. This is exclusive of the Company’s projected Gas Supply capital investment in certain information technology initiatives, which is discussed at the end of this testimony.

Q. What is the Company’s projected gas infrastructure and operations O&M expenditures for the three rate years?

A. We are planning to spend $187.9 million in RY1, $188.2 million in RY2 and $188.7 million in RY3.

Q. Was the document entitled “CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. 2020-2022 GAS CAPITAL PROGRAMS,” prepared under the Gas Infrastructure, Operations and Supply Panel’s direction and supervision?

A. Yes, it was. This is the document which has been identified as Exhibit ___ (GIOSP-1).

Q. Please describe this exhibit.

A. The first schedule in this exhibit summarizes Gas Operations' projected capital expenditures for RY1, RY2, and RY3. This capital expenditure is organized into the functional areas shown on the exhibit. This exhibit also includes the "white papers" associated with the three-year capital expenditures. The white papers provide the description of work, justification, alternatives, milestones, benefits and funding requirements for each capital program and project. We note that we do not discuss each capital project in the testimony because each project is described in detail in the white papers.

Q. How did you organize your testimony to address the programs and projects in Exhibit ___ (GIOSP-1)?

A. The testimony is broken down into the main areas set forth below:

- Distribution System Improvement Programs;
- Transmission Programs and Projects;
- Customer Connections;
- Work Execution Strategy;
- Technical Operations;
- Gas Information Technology; and
- Security Improvements

Q. Have you prepared an exhibit entitled “GAS OPERATIONS – O&M INCREASES BY CATEGORY?”

A. Yes, we have.

Q. Was this exhibit prepared under your supervision and direction?

A. Yes, it was. This is the document which has been identified as Exhibit ___ (GIOSP-2).

Q. Please explain what is reflected in Exhibit ___ (GIOSP-2).

A. This exhibit shows the Company’s projected incremental O&M expenditure for the 12-month period ended September 30, 2018 (“Historic Year”) for RY1, RY2, and RY3. It also includes the white papers for the programs associated with the incremental O&M expenditures for RY1, RY2, and RY3.

Q. Do the Company’s capital and O&M funding projections include funding for municipal infrastructure projects?

A. Yes, they do. However, these Public Improvement/Interference expenditures are not addressed in this testimony. These expenditures instead are addressed in separate testimony provided by the Company’s Municipal Infrastructure Support Panel.

IV. ANNUAL CAPITAL PROGRAMS

Q. Please summarize the gas capital request.

A. The Panel will identify major capital programs and projects that are planned during the rate years. Each program and project is aligned with an exhibit or associated white paper that describes the scope of work, cost, schedule, and justification. As shown in Exhibit ___ (GIOSP-1), the Company projects overall capital expenditures of: $842.8 million in RY1, $850.4 million in RY2, and $850.6 million in RY3, excluding Municipal Infrastructure expenditures. This will provide for capital investments in:

- Programs/projects to reduce risk and enhance safety on our Distribution System, which are primarily identified through our DIMP and includes but is not limited to our main replacement efforts
- Programs/projects to improve system reliability for existing customers, including the Gas Reliability Improvement Program
- Programs/projects to continue TIMP and meet regulatory requirements
- Programs/projects to support customer requests/ connections
- Programs/projects to enhance safety and ensure contingency in the event of any incident that may

impact our external supply sources by upgrading our Liquefied Natural Gas plant

- Information technology projects to reduce administrative and operational risk and achieve improved efficiencies and management of operations, programs and projects

Q. Please describe the nature of the gas capital expenditures the Company is planning, why the work is necessary, and the major drivers of the projected increase in capital expenditures.

A. Con Edison’s gas distribution and transmission systems must be continually maintained and upgraded in order for the Company to provide its customers with safe, reliable, cost-effective, and clean-burning natural gas service on an ongoing basis. This entails programs to replace and/or upgrade its piping, equipment, and facilities. In particular, the Company’s residential and commercial customers rely on the gas delivery system to provide the necessary fuel for their space heating, water heating, cooking, air conditioning, and other needs. These gas customers, including hospitals, all play a critical role in serving the needs of the public throughout New York City and Westchester County. Moreover, as the primary alternative to fuel oil in New York City, the Company's natural gas delivery infrastructure offers residents throughout its service territory significant environmental benefits by providing an alternative to the harmful emissions that result from burning oil. As shown in Exhibit ___ (GIOSP-1), the major drivers for the increase in gas capital expenditures in RY1 include the Main Replacement Program ($342.3 million), Service Replacements ($119.1 million), Transmission Programs and Projects ($117.8 million), Customer Connections ($91.8 million), Technical Operations ($59.1 million), System Reliability Programs and Projects ($42.7 million), and the Gas Information Technology projects ($20.1 million). These and other projects and programs are described below within the six program areas, *i.e.*, distribution, transmission, customer connections, technical operations, information technology, and security improvements.

A. DISTRIBUTION SYSTEM IMPROVEMENT PROGRAMS

Q. Provide a breakdown of the Company's Gas Distribution System.

A. **Table 1 – Inventory of Gas Distribution Mains and Services**

Material	12" and Smaller Main	Percent of Total	16" and Larger Main	Percent of Total	Number of Services	Percent of Total
Cast Iron	814	19%	137	3%	-	-
Wrought Iron	53	1%			-	-
Unprotected Steel	876	20%	46	1%	60,629	16%
Protected Steel	188	5%	77*	2%	25,313	7%
Plastic	2,123	49%	4	0%	274,620	73%
Copper/Undetermined	-	-			15,336	4%
Total	**4,054**	**94%**	**264**	**6%**	**375,898**	**100%**

*Does not include transmission mains operating at less than 20% specified minimum yield strength ("SMYS")

Q. Describe the Company's Distribution System Improvement Programs.

A. The Distribution System Improvement Programs include two major categories: Distribution Integrity and System Reliability. The Distribution Integrity Programs are designed to prioritize and address specific risks on the distribution system. The System Reliability Programs improve the reliability of the gas system by reducing the possibility of poor pressure problems and mitigating a large scale loss of customer gas service in the event of a system contingency.

As shown in Exhibit ___ (GIOSP-1), the projected cost for the Distribution System Improvement Programs is: $534.8 million in RY1; $541.9 million in RY2; and $555.8 million in RY3. These Distribution System Improvement Programs are described in more detail below.

1. Distribution Integrity

Q. Describe the Company's DIMP.

A. The purpose of DIMP is to enhance public and employee safety by identifying gas distribution pipeline integrity risks and implementing mitigating measures to address them. Some of these risks include distribution system leaks, excavation damages, and human error. By properly collecting, documenting, and analyzing information and data about our distribution system, DIMP enhances or creates capital programs and improves existing processes and procedures.

Q. How does DIMP assess risk?

A. DIMP enhances safety by identifying and reducing distribution pipeline integrity risks through system analysis and by monitoring potential threats identified by internal subject matter experts ("SMEs"), regulators, gas associations and peers. Risk analysis is an ongoing process of understanding what factors affect the degree of risk posed by threats. To further enhance this process, starting in 2018, the Company moved from the two risk evaluation process, a Con Edison DIMP plan and Main

Replacement Prioritization Model, to a single consolidated risk model. This process considers all threat categories and all distribution facilities, regardless of material and diameter, at the segment level. The risk model enables the Company to focus efforts on specific asset groups and threats posing the greatest risk. After each data upload, projects are either created or recalculated using the latest information. The top projects across the Company are reviewed for changes and further actions are considered such as reprioritizing our current replacement schedule, creating new programs for mitigating or eliminating emergent risks, or potentially increasing leak survey intervals.

The DIMP risk model calculates the risk for each project. The total project risk score is the sum of the main risk project score plus the service risk project score. The DIMP risk calculates a separate risk profile score for each failure type and uses the expected value ("EV") of the number of failures of that type to calculate a separate risk score for each failure type. The total main or service risk score for the project is the sum of the main or service risk scores for each failure type. Some failure types include: Breaks, Corrosion on Pipe, Equipment, Incorrect Operations, Joint (Not Corrosion), Natural Forces, Outside Forces, and Strike.

The DIMP risk model also calculates a separate risk profile score for various consequence factors. These factors include: Building Class, Building Proximity, Critical Gas Facility, Depth Maximum, Enclosed Space Type, Foundation Type, Leak Grade, Leak Source, Meter Location, Population Density, Service Class, Vaulted Service, Volume Pressure Factor, and Wall to Wall Cover.

Q. How does DIMP drive capital investments?

A. By properly collecting, documenting and analyzing information and data about our distribution system, DIMP informs the Company’s decisions on how to reduce risk through capital investments. One method DIMP uses is generating quarterly reports on distribution system data for each operating area. The DIMP team uses these reports to monitor existing threats and identify potential new ones. Discussions with SMEs are also initiated to identify threats that may not be apparent through analytics and risk modeling. The Gas Engineering department reviews this information and determines if revisions to the existing programs or development of new programs is needed. One example is DIMP has identified leaks on small-diameter cast iron, wrought iron, and steel mains to be a threat, which is addressed through our Main Replacement Program, described further below.

Q. What is the strategy for the Main Replacement Program?

A. The Company uses a systematic risk based approach in order to eliminate its inventory of 12-inch and smaller cast iron, wrought iron, and unprotected steel by 2036. However, emergent conditions may take priority as they occur.

1. Planned – The Company uses the DIMP risk model to assess gas main and service risk in order to select main replacement projects. These projects consist of geographic area replacement, highly ranked segments, and flood prone pipe. The selected geographic areas will be identified annually in all four operating regions – Manhattan, the Bronx, Queens, and Westchester – to maximize risk reduction across the distribution system. The size of each geographic area will be designed to allow for greater efficiencies that will minimize community disruptions. This enhanced coordination will reduce the impact to customers of repeated excavations and gas work. The Company proactively seeks opportunities to improve the reliability of our gas system and address other planned

work streams in conjunction with this program. Such work includes service inspections, winter load relief, customer connections, isolation valve installation, and regulator station installations. This will allow us to integrate schedules so that all work streams can be efficiently planned and completed concurrently.

2. Emergent – Engineering identifies circumstances where emergent main replacement is required. These types of projects are outside of the planned scope of work but support overall risk reduction efforts and can lead to cost savings. For example, the Company looks to proactively replace all 12-inch and smaller cast iron, wrought iron, and unprotected steel on a street prior to its scheduled paving date in order to reduce cost and prevent the need to excavate a newly paved street should a leak occur. Some other examples of emergent conditions are leaks that cannot be repaired, cast iron encroachments, and emerging public improvement projects.

Q. What categories of pipe does the Main Replacement Program target?

A. Based on the consolidated risk model described above, the Company’s Main Replacement Program targets the replacement of 12-inch-and-under cast iron, wrought iron, and unprotected steel pipe.

Q. What is the year-end goal of this program for the current calendar year and what are the proposed goals for each Rate Year?

A. In accordance with the current Gas Rate Plan, the Company plans to replace at least 90 miles of pipe in 2019. The Company proposes to maintain this level of replacement for RY1, RY2, and RY3. During the three years, the Company plans to replace 85 miles in RY1, 85 miles in RY2, and 86 miles in RY3 by using a risk-based approach. The remaining 5 miles in RY1, 5 miles in RY2, and 4 miles in RY3 will be achieved through "other" programs such as public improvement and customer connections. These goals are in line with our 20-year replacement strategy to be completed by 2036.

Q. Why has the Company reduced its annual main replacement target from the 95-100 mile annual target after 2019 (proposed in Case 16-G-0061)?

A. Some of the primary drivers for maintaining our annual target at 90 miles is competition for resources across a changing portfolio based on consistent analysis, emergence of new risk reduction strategies and the need to balance improvements with the bottom line in mind. Pipeline Safety Management Systems (“PSMS”), DIMP, and approaches have us in a continuous analysis, feedback and improvement loop that lead to a necessary review of the effectiveness of all of our programs and a competition between them to provide the best outcome in system safety and cost for our customers. While the Company continues to increase levels of work, so have neighboring utilities. There is a limited resource pool in the Northeast and some neighboring utilities benefit from less constraining field conditions that make it more favorable for contracted resources to predict costs – including less bedrock, greatly reduced traffic patterns and interference. Additionally, the Company has proposed other programs, new or enhanced, throughout this testimony that will use the same resource pool required for main replacement. Maintaining the 90 mile target will help the Company strike a balance between safety, reliability, resource constraints, and customer costs. Achieving 90 miles is significant and keeps the Company at a continued level of main replacement above historical levels.

Q. Please summarize any additional changes to this program the Company has planned in the Rate Year and beyond.

A. The Company plans to consolidate the Replacement of Cast Iron and Replacement of Unprotected Steel into a single category along with Encroachments. Replacement of Cast Iron and the Replacement of Unprotected Steel were previously two separate programs and budgets. Encroachments were previously budgeted under Public Improvement, in the Municipal Infrastructure Support Panel, and were captured under the “other” category. While budgeted under Public Improvement, the majority of encroachments are not driven by Public Improvement projects but by third-party contractors. The replacement of encroached cast iron gas mains is necessary as it mitigates the risk of cast iron breaks, which are a threat to public safety. As a result, these costs will be added to Gas Operations’ Main Replacement Program, and the Municipal Infrastructure Panel will reduce their forecasted costs accordingly.

Q. What are the projected costs of the Main Replacement Program for each rate year?

A. The Company is projecting the following expenditures for this program: $342.3 million in RY1, $349.2 million in RY2, $360.3 million in RY3, as set forth in Exhibit ___ (GIOSP-1).

Q. Briefly describe any additional major capital programs that DIMP identified and provide the projected costs of those programs for each rate year.

A. The four additional major programs identified by DIMP are as follows:

1. Distribution Integrity Main Enhancement Program – This program targets the replacement of plastic and protected steel mains of all diameters. This program is an expansion of the Replacement of Existing Plastic and Emergent Water Intrusion Program in the current Gas Rate Plan. This new program gives the Company the ability to replace sub-standard and undersized mains on both a proactive and emergent basis. Sub-standard gas mains will be identified by DIMP through routine risk analysis of the Distribution System. The Company is projecting the following expenditures for this program: $13.1 million in RY1; $13.4 million in RY2; and $13.6 million in RY3, as set forth in Exhibit ___ (GIOSP-1).

2. Large Diameter Gas Main Program – Under this program the Company will replace or rehabilitate large diameter gas mains throughout the distribution system. Since these mains act as primary supplies, the loss of service along these mains could lead to customer outages during the

winter heating season. Emergent conditions and DIMP risk model results contribute to the prioritization of these projects. As shown in Exhibit ___ (GIOSP-1), Con Edison uses five methods to address these mains: Cast Iron Sealing Robot ("CISBOT"), Liner, Encapsulation, Cathodic Protection, and Replacement. This new program consolidates the Large Diameter Rehabilitation, Emerging Supply Mains Reliability, and Cathodic Protection programs under the current Gas Rate Plan. The Company is projecting the following expenditures for this program: $11.4 million in RY1; $12.0 million in RY2; and $12.6 million in RY3, as set forth in Exhibit ___ (GIOSP-1).

3. Service Replacement Program - There are three categories of work that are performed under this new program. The first category, previously known as the Services Associated with Main Work Program, addresses unprotected steel services that exist on 12-inch and smaller cast iron, wrought iron, and unprotected steel gas mains being replaced. These services will be replaced concurrently with the main. The second category addresses all unprotected steel services that exist on plastic and protected steel gas mains. These proactive measures reduce the risk of a leak on gas services and provide a less

disruptive option to the customer, resulting from the ability to schedule and coordinate replacement work. The third category, previously known as the Leaking Services Program, replaces actively leaking gas services when found in connection with Con Edison’s leak survey program or in response to incoming leak calls. The Company estimates replacing approximately 5,800 services per year under this new program. The estimated cost is $119.1 million in RY1, $120.6 million in RY2, $123.2 million in RY3, as set forth in Exhibit ___ (GIOSP-1).

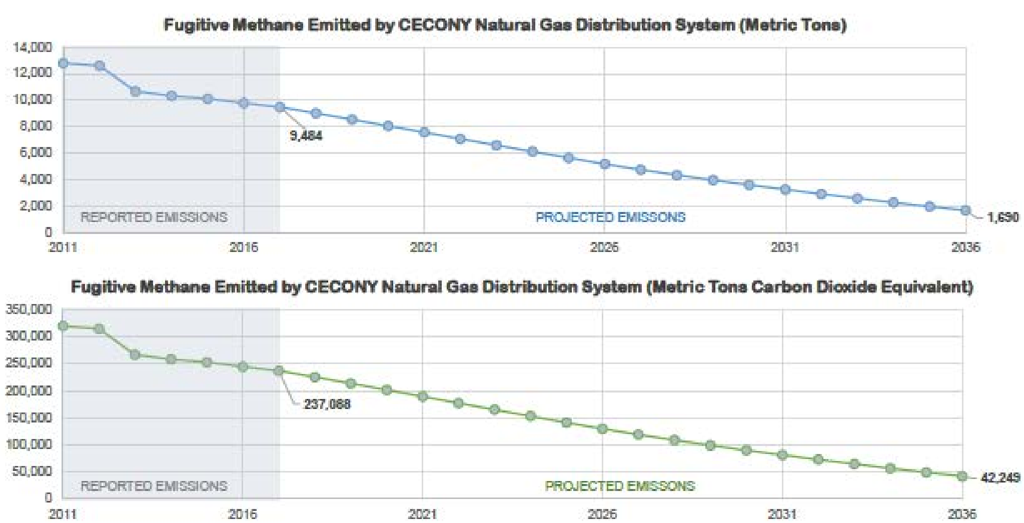
4. Isolation Valve Program – The Company implemented a five-year Isolation Valve Program in 2017 to install isolation valves in the event of an imminent uncontrolled release of natural gas. Gas customers addressed through this program are based on the Company’s New York City (“NYC”) and Westchester County Critical Facilities List. This list includes, but is not limited to, customers such as hospitals, ambulatory facilities, nursing homes, developmental disabilities institutions, schools, museums, and libraries. Over 500 customers were initially identified, primarily on our Low Pressure system, requiring approximately 1,200 valves for area isolation. The program is currently on track to address these customers by 2021.

Starting in 2022 the Company plans to address major NYC landmark structures through this program. As set forth in the Isolation Valves white paper in Exhibit ___ (GIOSP-1), the Company is projecting the following expenditures for the Isolation Valve Program: $5.1 million for RY1, $5.0 million for RY2 and $5.0 million for RY3.

Q. Will any of these programs also provide environmental benefits?

A. Yes. The Main Replacement and Service Replacement Programs will significantly reduce GHG emissions. The reduction in emissions associated with these programs is quantifiable through the use of Title 40 – CFR 98.Subpart W. The projected annual reduction is shown in the charts below:

Table 2: Projected Fugitive Methane Emissions-CECONY



2. System Reliability

Q. Are you planning other programs that will address risk on the distribution system?

A. Yes. We plan to continue gas system reliability improvement programs, which include the Gas Reliability Improvement Program (previously called the Gas System Vulnerability Elimination Program), Winter Load Relief, and the Regulator Station Revamp Program. The programs are intended to accomplish one or more of the following goals: improve safety and reduce risk; maintain or enhance operational excellence; and improve system reliability.

Q. Can you generally describe the benefits of these programs?

A. Yes. The benefits of these programs are as follows:

Improve safety/reduce risk: The Gas Reliability Improvement Program, Winter Load Relief, and the Regulator Revamp Program will mitigate the loss of gas to customers by reinforcing the existing gas system to ensure that adequate pressures are met. Gas is a major fuel used by customers for heating in the winter time and typically, system pressure issues manifest during periods of cold temperatures. These programs will provide the reinforcement needed to prevent loss of gas service to customers, which provides essential heating in the winter.

Operational Excellence: Supply mains facilitate the delivery of natural gas to every customer on the Con Edison gas system. Improvements to these facilities are needed to enable the Company to continue to deliver reliable gas service to all our customers on the coldest winter days. This will be largely accomplished through planned capital programs that include Winter Load Relief and the Gas Reliability Improvement Program.

Customer Experience: Natural gas remains economical for customers and is the heating fuel of choice for many of our customers. With over 1.1 million gas customers that currently rely on natural gas, additional capability and reliability improvements will be required throughout the gas distribution system, even with a temporary moratorium in place in most of Westchester. Eliminating constraints and facilitating the movement of gas across our existing system will become even more important for our customers with a temporary moratorium in place in most of Westchester County. Programs such as Winter Load Relief and the Regulator Station Revamp Programs are designed for the natural gas system to be able to accommodate the supply of gas to the customers as well as provide reliable service with minimal interruption thus enhancing the customer experience.

Q. Please describe each of the above-listed programs, the work that is projected in RY1, RY2 and RY3, as well as additional details regarding the benefits of this work.

A. 1. Winter Load Relief – To improve system reliability, Con Edison needs to reinforce the low, medium and high-pressure systems in order to maintain the minimum pressures required to serve our customers. We must also reinforce our system to maintain minimum inlet pressures to our low and medium-pressure regulator stations. As a result of our annual network analysis model validation process, we project anticipated system loads and project system performance for the following winter season. Where marginal pressures are anticipated, areas are identified for additional reinforcement and can be addressed through specific recommended projects under the Winter Load Relief program. These projects typically consist of installation of new mains or the replacement of smaller mains with larger diameter mains, to increase capacity. The Company is projecting the following expenditures for Winter Load Relief related projects: $17.7 million for RY1, $17.5

million for RY2 and $17.5 million for RY3, as set forth in Exhibit ___ (GIOSP-1).

Q. Does this proposed program include the impact of the temporary moratorium in most of Westchester?

A. Yes, the Winter Load Relief Program includes the impact of the temporary moratorium in most of Westchester. This program also accounts for additional improvements to the entire gas distribution system both outside and inside of the areas in Westchester impacted by the temporary moratorium. The reliability reinforcement under the Winter Load Relief Program will further improve the pressures on the gas systems which in turn will prevent service disruption to our gas customers. Additionally, improved system capacity will allow the system to be operated at a lower pressure and therefore reduce leak rates.

2. Gas Reliability Improvement Program – Our priority is to avoid large-scale outages on our system during our peak demand periods. To address this risk, various system reinforcements, such as main upsizing, main ties, or regulator station upsizing are needed. The Company is projecting the following expenditures for the Gas Reliability Improvement Program: $9.2 million for RY1,

$11.5 million for RY2 and $11.5 million for RY3, as set forth in Exhibit ___ (GIOSP-1).

Q. Does this proposed program include the impact of the temporary moratorium in most of Westchester?

A. Yes, the temporary moratorium was taken into consideration. However, the Gas Reliability Improvement Program is independent of the moratorium, as it addresses existing system conditions. The moratorium in Westchester will neither reduce nor add gas usage demand to the current system load profile and therefore will not have any impact to this program.

3. Regulator Station Revamp Program – This program is for the rehabilitation of existing regulator stations to improve system reliability. This program will rebuild regulator stations to replace unserviceable equipment and verify the regulators are adequately sized to provide the capacity to meet existing and added load in the event of the loss of other system components. Regulator stations are taken out of service for various reasons, including inspections, compliance work, contractor damages and environmental issues. Having surrounding regulators that can compensate and pick up the load for such circumstances is needed to minimize the impact to our customers. This

program will also improve the safety of our gas customers because it will prevent the loss of gas service that is essential for heating in the winter and for maintaining potential life sustaining equipment year-round. The Company is projecting the following expenditures for the Regulator Station Revamp Program: $5.0 million for RY1, $5.0 million for RY2 and $5.0 million for RY3, as set forth in Exhibit ___ (GIOP-1).

Q. Please describe any additional System Reliability projects that the Company is planning.

A. In addition to the distribution system reliability programs explained above, we have several additional projects involving replacement or extension of distribution gas mains. These projects address individual areas in our system where reinforcement is needed to support system conditions. To execute this work, the Company plans to invest $10.9 million in RY1, $7.0 million in RY2, and $7.0 million in RY3. Details on each of these projects can be found in their respective white papers, found in Exhibit ___ (GIOSP-1).

Q. What are the total costs associated with all the Distribution System Reliability Programs?

A. As presented in Exhibit ___ (GIOSP-1), we currently anticipate the following capital expenditures to support these projects during the 2020-2022 period: $42.7 million in RY1; $41.0 million in RY2; $41.0 million in RY3.

B. TRANSMISSION PROGRAMS AND PROJECTS

Q. Please describe Con Edison's gas transmission facilities.

A. Con Edison's gas transmission facilities are comprised of 94 miles of 6 inch to 36 inch diameter mains in Manhattan, Queens, the Bronx, and Westchester County. These mains, most of which were installed between 1947 and 1973, have a maximum allowable operating pressure of either 245 psig or 350 psig. The transmission facilities are supplied by seven gate stations from four pipeline companies. In addition, most of these facilities are part of a larger regional network called the New York Facilities ("NYF") System, which is jointly owned and used by Con Edison and National Grid. Con Edison's system is connected to National Grid's system at two bi-directional metering stations, as well as four metered take-off locations in the 2nd Ward of Queens.

Q. Please describe the capital investment that is planned for the gas transmission facilities.

A. As presented in Exhibit ___ (GIOSP-1), the Company projects the following expenditures related to transmission programs and projects: $117.8 million in RY1, $130.4 million in RY2 and $109.9 million in RY3. These investments are designed to enable the Company to continue to provide safe, reliable operation of the transmission facilities by reducing risk and enhancing operational performance. The projects that relate to these investments are described below and do not take into account new rules that may result from the Pipeline Safety Act, discussed further in Section VI.

1. Transmission Risk Reduction and Reliability

Q. How many transmission projects and programs will be undertaken in Rate Year 1 and beyond?

A. The Company proposes to undertake eight projects and programs to promote safety and reliability of the gas transmission system, as well as the gate stations supplying these facilities.

Q. How will the Company's proposed transmission projects and programs address public safety and reduce risk?

A. The Company has a number of initiatives that address the replacement of high risk transmission infrastructure. According to federal regulations, "transmission lines" are defined as pipelines that operate at a hoop stress of 20 percent or more of SMYS (*see* 49 CFR 192.3). The Company plans to install new larger diameter transmission facilities that will improve safety and reliability by operating at less than 20 percent SMYS. In addition, the enhanced gas transmission facilities will reinforce the transmission system to withstand the loss of one of the six gate stations that supply non-radial sections of the gas system. Loss of supply from these facilities would otherwise cause widespread customer outages.

Q. Please describe each of the eight gas transmission capital programs and projects that are planned for the 2020-2022 period that address safety and reliability.

A. The eight gas transmission capital programs are as follows:

<u>1. Installation of Remotely Operating Valves (“ROVs”)</u> - This program provides for: rapid isolation of a compromised section of the transmission facilities; rapid isolation of transmission facilities at river and tunnel crossings and at the outlet of gate stations; and rapid separation of intersecting transmission mains at tee or branch locations. The ROV program consists of converting existing transmission valves or installing new ROVs, to meet the future ROV design criteria. Once the program is complete, the closure of any two consecutive ROVs will not negatively

impact supply mains or the distribution system on an average winter day. The Company projects the following expenditures for this program: $3.5 million in RY1; $3.5 million in RY2; and $3.5 million in RY3, as set forth in Exhibit ___ (GIOSP-1).

<u>2. Transmission Main Leaks</u> - This program allows for the immediate replacement of sections of transmission main containing leaks or defects that cannot be made safe using a maintenance repair technique. All transmission gas leaks are treated as Type 1 leaks, and are addressed immediately. On most occasions, we can address the leak using an O&M maintenance repair. However, sections of transmission main containing leaks or defects that require replacement instead of maintenance repair will be funded through this capital program and include pipe or equipment replacement. The Company projects the following expenditures for this program: $5.2 million in RY1, $7.9 million in RY2, and $7.9 million in RY3, as set forth in Exhibit ___ (GIOSP-1).

<u>3. The Newtown Creek Metering Station</u> - This is a capital project that addresses a facility constructed in 1951 that contains older piping configurations and outdated metering equipment that is obsolete and maintenance intensive. The level of maintenance required at the facility has reached a

point where the most cost effective course of action is to install new equipment. One of those pieces of new equipment is the addition of a new control valve that would allow Con Edison to control the flow rate to National Grid. Our ability to control flow to National Grid would allow us to regulate the Con Edison portion of the gas transmission system and protect the Con Edison portion of the gas transmission system from abnormal operating conditions. The Company forecasts the following expenditures for this project: $6.3 million in RY1 and $4.8 million in RY2, as set forth in Exhibit ___ (GIOSP-1).

<u>4-5. Gate Station Over Pressure Protection</u> – These projects address the installation of Con Edison owned over pressure protection at the following Transco and Tennessee facilities: Transco's Upper Manhattan Gate Station located in Manhattan, Transco's Central Manhattan gate station located in New Jersey and Tennessee's Rye gate station located in Westchester. The Con Edison OPP will provide for the safe operation of the gas transmission system in the event that the pipeline's OPP device at any of the three gate stations fails and the MAOP of the pipeline cannot be controlled. The Company forecasts the following expenditures for these projects: $1.0 million in RY1; $8.0

million in RY2; and $8.0 million in RY3, as set forth in Exhibit ___ (GIOSP-1).

6-8. Replacing Aging Infrastructure - The Company has three projects focused on improving the gas transmission infrastructure by replacing aging infrastructure installed using legacy construction practices. The pipe material and the construction practices are not as robust as current day materials and construction practices. These projects will replace existing gas mains with larger diameter and lower SMYS mains. As a result, these projects will reduce risk and provide contingency for the loss of White Plains Gate Station. This gate station supplies approximately 125,000 firm customers on a design day.

The three projects include:

- Westchester Bronx Border to White Plains
- The Bronx River Tunnel to Bronx Westchester Border
- The Bronx River Tunnel and Easement

These three initiatives, when complete, would provide a continuous, 350 psig MAOP main from Hunts Point, through the Bronx and Westchester, to the White Plains Gate station. The Company forecasts $101.7 million in RY1, $106.2 million in RY2, and $90.5 million in RY3 for this initiative, as set forth in Exhibit ___ (GIOSP-1).

2. Gate Station Work

Q. Does the Company's current Gas Rate Plan include projects that involve work on pipeline owned facilities at gate stations that benefit the Company?

A. Yes, the current Gas Rate Plan includes such projects at the Peekskill Algonquin Gate Station and the Tennessee Rye Gate Station.

Q. Please describe the work performed as part of the Peekskill Algonquin Gate Station project.

A. Enbridge (formerly Spectra Energy), as part of the Algonquin Incremental Market ("AIM") Expansion, replaced the 26 inch pipeline that currently feeds the Company's transmission facilities at the Peekskill gate station. The AIM expansion project also increased the Enbridge pipeline pressure from the current 750 psig MAOP to 850 psig MAOP. This increase in the MAOP prompted Enbridge to modify the Peekskill gate station. As a part of this modification, Con Edison requested that Enbridge upgrade the station to enable the supply of 1,300 dt/h.

The upgrade of the Peekskill gate station involved increasing the piping size in the station, as well as increasing the equipment size, to allow for capacity that can supply the 1,300 dt/h flow that Con Edison requested.

The existing Enbridge meter and regulator building, the Remote Terminal Unit building, and the heater were rebuilt to accommodate the new piping and equipment.

Q. Please describe the work performed at the Rye Gate Station.

A. The Rye Gate Station was constructed in 1961. The current maximum capacity of the station is 2,500 dt/h. Upgrades to this station will extend the maximum capacity of the station to 5,000 dt/hr. Some of the upgrades that are required for station improvement are:

- Replacement and upsizing of regulators
- Upgrade to the metering
- Replacement of the heater with a high capacity heater
- Replacement of existing station outlet piping with larger diameter pipe
- A replacement station monitor valve on the increased diameter station outlet piping
- A new Remote Terminal Unit
- New communication, MPLS and Secure Wireless
- New instrumentation to support metering
- Overpressure protection

Q. How is the Company recovering the payments made to the pipelines to upgrade and/or modify their interstate pipeline facilities at the Peekskill and Rye gate stations?

A. The current Gas Rate Plan (Case 16-G-0061) provides for the Company to recover through a surcharge up to $9 million of payments made to Algonquin for work at the Peekskill gate station and up to $9 million of payments to Tennessee for work at the Rye gate station. Any costs incurred above $9 million at either or both of these gate stations were to be deferred and addressed in the Company’s next base rate filing.

Q. Is the Peekskill project complete?

A. Yes, the Peekskill gate station upgrade is in service.

Q. What were the actual costs associated with the Peekskill project?

A. The Peekskill gate station upgrade cost $11.1 million, subject to reconciliation.

Q. What caused the actual costs to exceed the initial estimate?

A. We implemented a number of changes to the initial design because of changes necessary after further engineering work was performed to update the design to a fully developed final design. The odorant injection point was changed to an odorant monitor, a tee tap was made in lieu of a hot tap, and a filter separator back-up generator, and security system were added.

Q. Is the Rye gate station project complete?

A. No, the Rye gate station is still under construction.

Q. When is this project scheduled for completion?

A. This project was originally scheduled for completion in October 2018. There have been a number of delays due to change of design scope, complications relating to electrical requirements, and requirements for redundancy. This project is now estimated to be complete by the fourth quarter of 2019.

Q. Are there any updates to the estimated cost of the project?

A. Yes. The project’s actual costs to date are $3.9 million and total costs are currently projected to be $12.1 million.

Q. What has caused the current cost estimates to exceed the initial estimate?

A. The installation of the temporary gate station took more time than initially anticipated. Negotiations between Tennessee and Con Edison to reach agreement on the final design scope also took longer than expected. Additionally, contractor bids came in higher than estimated.

Q. How does the Company propose to recover the amounts over the initial estimate for both Peekskill and the Rye Gate stations?

A. The Company proposes to recover the amounts over the initial estimates through the Monthly Rate Adjustment (“MRA”), in the same manner that the initial estimate amounts are treated under the current Gas Rate Plan.

Q. Is the Company planning on doing work on additional gate station facilities owned by interstate pipelines?

A. Yes, the Company plans to request that Tennessee pipeline upgrade and/or modify its White Plains gate station.

Q. Why is this work necessary?

A. The work is needed to replace aging regulating and metering equipment and to provide contingency to our medium and high pressure systems. The work will also meet the peak demand for natural gas in Westchester County. Natural gas peak demand will continue to grow in Westchester until the temporary moratorium takes complete effect because the temporary moratorium will not affect new customers who are already “in the queue” for natural gas connections.

Q. When is this work scheduled to take place?

A. This work is currently scheduled for 2021.

Q. How does the Company propose to recover the costs associated with this project?

A. The Company proposes to recover the cost of the White Plains gate station project through the MRA surcharge since the gate station is owned by Tennessee pipeline.

Q. What are the anticipated costs of this project?

A. The preliminary estimate of the White Plains meter upgrade is $11 million.

Q. Please describe the Transco heaters project.

A. The Transco Heater and odorization project addresses concerns associated with two gate station delivery points in Manhattan. In order to enhance the Company's system reliability and comply with applicable State requirements and Company specifications, Con Edison asked Transco to upgrade its heating and odorizing equipment. More specifically, Con Edison requested that Transco replace three existing heaters and install supplemental gas odorization equipment.

The Company is obligated by Commission regulations to odorize the natural gas in its system. It is also compelled by safety and system reliability considerations to require that the natural gas entering its system meets certain minimum-temperature standards. The odorization and heating equipment that was previously used for gas delivered by Transco needed to be upgraded and expanded. As a result, the arrangement involved the construction and operation of three new heaters, modified piping, and odorization equipment. Because of facility configurations and space limitations, the optimal arrangement was for Transco to own and operate the equipment as part of Transco's interstate pipeline system.

Q. What was the actual cost to complete this project?

A. The actual cost is currently at $40.4 million and is projected to be $40.6 million when completed. The initial estimate for the project was $32.1 million.

Q. Please explain why the actual costs exceeded the initial estimate.

A. The actual costs have exceeded the initial estimate due mostly to increased costs of construction and also in cost of materials.

Q. How does the Company propose to recover the amounts over the initial estimate for the Transco Heaters?

A. Consistent with the current Gas Rate Plan, the Company proposes to defer these costs as a regulatory asset and recover the costs over the remaining 15 year period.

3. Pressure Control

Q. Please describe the functions performed by the Pressure Control Department.

A. The Pressure Control Department is primarily responsible for the maintenance and operation of the Company's gas pressure reduction equipment. This equipment ranges from major transmission gate station assets to the many components that make up the high and low-pressure district regulator stations located throughout the Company's service territory. Most of this equipment is located within below-grade manhole structures underneath roadways and sidewalk areas. This equipment includes more than 333 regulator stations. The department validates each station's operating condition annually, as well as conducting monthly site inspections. Currently our design criteria for regulator stations include the installation of components to prevent over pressurization of our gas distribution system. We also plan on installing additional equipment to provide redundancy to the existing OPP components, which is discussed later in this testimony.

Q. Please summarize the capital expenditures projected for the Pressure Control department during the 2020-2022 period.

A. The Pressure Control Department sponsors fourteen capital programs that are planned for 2020-2022. The Company estimates capital expenditures of $18.2 million in RY1, $14.6 million in RY2, and $14.2 million in RY3, as set forth in Exhibit ___ (GIOSP-1). These investments support efforts to provide gas service safely and reliably by sustaining the various mechanical and electrical components that are associated with each pressure reduction site and select gate stations.

Q. Please describe the capital programs/projects planned to be completed by the Pressure Control Department.

A. The capital programs/projects planned to be completed by the Pressure Control Department range from mechanical equipment replacement and piping refurbishment to remote electronics monitoring and control system replacements and upgrades. Some of the major programs are:

<u>1. Unserviceable Equipment</u> – addresses complete replacement of equipment where corrosion is excessive and the component requires replacement, designs are obsolete, or equipment upsizing is required.

<u>2. Pressure Monitoring / Telemetrics</u> - relocates various regulator station control lines to the optimum locations within the distribution system.

3. Regulator Automation – installs automated control equipment to include conduits, power and communication at a total of 231 gas system regulator stations. The rate of implementation will be approximately 50 locations per year (approximately 150 locations for the rate period). This will improve system pressure regulation and visibility. This program also includes the installation of Over Pressure Protection ("OPP") equipment on the gas system or rehabilitates the existing system to prevent pressure exceedances over MAOP. The Gas Distribution System Over-Pressure Protection Program will improve public safety and continue to reduce the risk of an over pressurization event on our gas distribution system, such as occurred in Massachusetts. An over pressurization downstream of the regulator stations may create leaks on the system or, in the worst case, put life and property in imminent danger. This program increases public safety and at the same time provides environmental benefits by minimizing methane emissions. This program will improve the existing protection against over pressurization downstream, thus greatly enhancing system safety and reducing risks. These OPP projects may involve:

- the installation of additional regulator station sensing lines and equipment inside of the manhole vaults;
- the installation of relief valves at or near regulator stations;
- the installation of slam-shut devices to prevent pressure exceedances; and
- the replacement of regulator station piping that contains bypasses which connects different MAOP systems the replacement of distribution mains that connects to pressure division valves.

4. Gridboss / Automated Adaptive Controls - electronic control devices for regulator stations will be upgraded with modern automated controls which use system data to adjust regulator station pressures and output.

5. Replace Network and Control System at Iroquois - The purpose of this project is to replace and upgrade the obsolete Iroquois gate station control and power management system.

The remaining nine Pressure Control projects consist of multiple system reliability and structure upgrades that are required for safe operation. Details of the remaining projects are included in the white papers in Exhibit ___ (GIOSP-1).

C. CUSTOMER CONNECTIONS

Q. How has the Company advanced its goals through customer connections?

A. As described in more detail below, the Company's customer connections have offered the opportunity to advance Company goals for both customer engagement and operational excellence. We provide safe, reliable service to our customers in a cost-effective manner while meeting high customer expectations for service quality. Historically, the Company divided its gas growth efforts under several separate programs including: Traditional New Business, #4/#6 OTG conversions, #2 OTG conversions in NYC, Westchester gas conversions, and Westchester Area Growth. Going forward, the Company has consolidated these programs into one program called the "Customer Connections Program." In addition, this consolidated capital program includes requests for gas service for Distributed Generation, Compressed Natural Gas ("CNG"), and steam and electric production customers. As discussed in more detail in the Customer Energy Solutions Panel, the Company also promotes alternatives for new construction customers, especially in

Westchester where it has implemented a temporary moratorium.

Q. What are the projected costs associated with the Customer Connections Program?

A. As presented in Exhibit ___ (GIOSP-1), the Company projects the following expenditures related to the growth related program: $84.6 million in RY1, $75.1 million in RY2 and $72.9 million in RY3. The overall costs are for the installation and replacement of gas services and main associated with facilitating connections. This forecast includes the impact of the temporary moratorium implemented in Westchester.

Q. Please summarize pending changes in the Company's growth program.

A. In addition to consolidating the numerous growth programs, the Company will complete the NYC Area Growth program by the end of 2019. The Company's NYC Area Growth plan established a framework for addressing NYC mandated conversions from #6 fuel oil by 2016 and from #4 oil by 2030. In accordance with the current Gas Rate Plan, the Company has filed quarterly reports with the Commission describing the results of our efforts and the Company's Area Growth zones were published through 2019 on the

Company website (https://www.coned.com/en/save-money/convert-to-natural-gas/growth-plan). The Area Growth program allowed potential customers to view our future growth plans and plan their individual conversion activity accordingly.

Q. Why does the Company plan to end the NYC Area Growth program in 2019?

A. As indicated in prior rate plans, the Company would offer every New York City oil-burning customer the opportunity to participate in an Area Growth Zone, and the Company has met this obligation. By the end of 2019, the Company anticipates that it will have converted over 65% of roughly 7,000 buildings in Con Edison's service territory impacted by the current Clean Heat regulations. Since the inception of these regulations in 2011, over 63% or 4,400 buildings have successfully converted to gas heat. While the Company focused on heavy heating oil customers, there remains a large population of oil-burning buildings within the City of New York - approximately 10,000 buildings that burn the cleaner oils that are supposed to be phased out later.

Q. Are there any additional changes to the growth related program?

A. Yes. We discontinued the Westchester Area Growth program. We initiated this program in 2017 and targeted White Plains in 2017 and Port Chester in 2018, specific areas where there was a high concentration of non-gas heating multi-family and commercial customers potentially interested in conversion. The Company received minimal interest for conversions within these areas. Due to the lack of interest for conversions driven by price parity with oil, coupled with gas supply constraints, Con Edison terminated this program in 2018.

Q. Has there been an overall decrease in new customer connections in Con Edison's service territory?

A. No. While there has been a decrease in oil to gas conversion requests, we have not seen a decrease in all other customer connection requests, which include new construction and existing customers requesting additional gas demand.

Q. Are there any aspects of the Company's gas tariff that it is proposing to modify as a result of the temporary moratorium?

A. Yes. In addition to the end of the Area Growth Program, the Company will allow customers to connect gas service for emergency generators while the temporary moratorium remains in effect. We are allowing these connections because emergency generators are not coincidental to winter peak demand. We will allow customers who wish to install an emergency generator for emergency electric generation and who were not previously approved by the Company to use natural gas for heating, under certain conditions.

Q. What are the changes you are proposing?

A. We are proposing new tariff language that a customer may not opt out of either an AMI electric or gas meter, or must agree to the installation of an electric and gas AMI meter and penalizing customers who use gas for purposes other than emergency electric generation.

Q. When a customer installs an emergency electric generator powered by natural gas in supply-constrained areas, why does the customer meter need to be an AMI meter?

A. The Company needs the ability to monitor emergency generator gas usage to ensure the appropriate utilization of this service consistent with a temporary moratorium process. We will continue to allow the connection of electric emergency generators even in supply-constrained areas as long as the customer agrees to the proposed requirement. In other words, while the Company is currently requiring AMI meters for new emergency generator customers in areas affected by the temporary moratorium, the Company is proposing this tariff change so that AMI meter requirement will apply to all new customers that seek to install emergency generators and will not be allowed to opt out of an AMI meter unless they are already a gas heating customer.

Q. Is the Company proposing any other changes?

A. Yes. The Company proposes to change the tariff leaf related to emergency generators powered by natural gas to remove section (1) of this section of the tariff, which seems to limit the sizing of the generators to a customer’s minimum needs and to add a penalty for customers using the generator’s service line for uses that have not been approved by the Company.

Q. Why is the Company proposing these changes?

A. The Company does not believe it should determine what a customer’s minimum electric needs are for safety and health. Additionally, a per day penalty of $500 is appropriate for customers that use a gas service line installed solely to power an emergency electric generator during electric outages for a purpose that has not been approved by the Company. Such a penalty will be a sufficient deterrent to circumventing any temporary moratoriums or distribution constraints that may be in effect.

Q. Now that both NYC Area Growth and Westchester Area Growth programs will be ending or have ended, are there other ways to address oil to gas conversion requests?

A. While Area Growth helped aggregate oil to gas conversions in a geographic area and allowed the Company to reinforce the system effectively to support the new gas demand, there are customer requests to convert that are not part of the Area Growth timelines and boundaries. With the Customer Connections program, Con Edison will continue to connect new construction and conversion customers seeking gas service, in locations where there are no moratoriums in effect. Even though customer conversions will continue, the Company is forecasting a reduction from historical service and main installation levels.

Q. Do you have any other programs that support new connections?

A. Yes. Regulator stations are a key component for connecting new customers and minimizing construction activity. Con Edison will site these district regulator stations to best support growth in new customer connections and maintain adequate pressure for both new business and existing customers. We plan to install regulator stations as shown in Exhibit ___ (GIOSP-1) under New Business – Regulator Stations.

Q. In light of the challenges resulting from constrained gas supply, and the temporary moratorium in part of its franchise area, is the Company terminating its oil-to-gas conversion incentive program ("Conversion Incentive Program")?

A. Yes. The Company is not proposing to continue the Conversion Incentive Program (*i.e.*, up to $1.465 million annually). Con Edison, however, will continue to proactively work with customers to manage their energy needs and costs. This includes working with the State to develop, offer, and continually refine our suite of energy efficiency programs that drive efficient end-use behavior and technologies that permanently reduce per-unit energy use.

Q. Is the Company proposing a positive incentive mechanism to encourage the Company to sign more new customers up for gas service?

A. No. Based on the constrained gas supply, and the imposition of the temporary moratorium, the Company is not proposing an annual incentive to further encourage new customer conversions and, as described in the testimony of the Company Gas Rate Panel, the Company is proposing to end the revenue per customer incentive that is part of the current gas revenue decoupling mechanism.

D. WORK EXECUTION STRATEGY

Q. What are the primary drivers for the increased costs associated with your Capital Programs?

A. One of the drivers for increased costs is new roadway restoration requirements imposed in NYC and various municipalities in Westchester. There are instances where we are required to pave the entire street from curb to curb where historically we would have restored exclusively what was disturbed. Another driver is higher material costs as we are installing higher quantities of larger diameter plastic and steel to improve reliability of our system. Lastly, federal regulation and policy changes based on recent incidents have driven up cost as the Company must fund new programs to remain in compliance.

Q. What actions does the Company plan to take to mitigate these escalating costs?

A. In order to mitigate costly restoration and paving, the Company requests paving schedules from NYC and Westchester municipalities and meets regularly to coordinate and construct projects prior to paving. Additionally, Gas Operations is actively identifying opportunities to bundle capital program work together and create contractor efficiencies. Bundling work allows us to address multiple work streams simultaneously. There may also be an opportunity to obtain better traffic stipulations through early communication with NYC Department of Transportation ("NYCDOT") and municipalities in Westchester County which will minimize lost hours of work. However, the NYCDOT and municipalities will determine final permits and stipulations.

Q. What measures does the Company plan to take to improve the customer experience?

A. We continue to coordinate work in an attempt to limit the number of times we return to and excavate a particular area. The various organizations within Gas work together as a team to geographically address our capital programs and improve work management planning processes. The Company is looking to continue this practice and further enhance coordination with other commodities such as Electric and Steam as well as outside agencies to further minimize customer impact. Community outreach is another critical component when improving the customer experience so the Company proactively presents upcoming projects and tentative schedules to community boards. We are looking to extend this communication to public officials and city agencies well in advance of our pending work. Lastly, we have implemented training for our employees and our contractors and employ quality assurance, and quality control practices to facilitate new construction being performed at the highest standard of quality. This will help ensure long term system and component reliability, reducing the potential need for future repairs, thereby enhancing public and employee safety.

E. TECHNICAL OPERATIONS

1. Liquefied Natural Gas

Q. How does the Company’s Liquefied Natural Gas (“LNG”) facility benefit customers?

A. LNG serves as a cost-effective alternative to more expensive peaking supplies, and provides a reliability/contingency resource in the event of incidents impacting our external supply sources. The LNG Plant is the only source of in-city natural gas that Con Edison’s customers can be supplied from in the event of an interstate pipeline interruption or other emergency condition affecting its external gas supply. The LNG Plant continues to serve as a supply and hourly balancing source during very cold days, as its capacity is needed during design peak day conditions to meet the needs of our firm customers. The Plant also serves firm gas customers to potentially mitigate short-term price volatility.

Q. Please summarize the proposed LNG projects.

A. The Company’s proposed LNG projects include but are not limited to the following:

- Install Vaporizer 1
- Plant Controls Instrumentation Upgrade Program
- Nitrogen Refrigeration Cycle Replacement
- Electrical Distribution System Upgrade Project

Q. Why are these planned programs necessary?

A. These capital programs are important to continue safe plant operations and maintain plant reliability for the following plant systems: withdrawal (vaporizers), tank management, and injection (liquefaction) process plant. The plant provides gas peaking service and may be used as a cost mitigation tool for the benefit of customers during high gas cost periods. Critical components of the plant are obsolete, the original equipment manufacturers are unavailable to provide parts and services and mechanical integrity of equipment is important for employee and public safety. The liquefaction nitrogen refrigeration cycle is inefficient and does not fill the LNG tank in six months as per its original design. In order to renew the plant for more efficient use for decades to come and to bring it up to today's standards of operation; we plan to invest over $100 million in plant infrastructure over the next five years, starting in 2019. This investment will help us continue to deliver reasonably priced natural gas to our customers when they need it the most. It will also improve the Company's ability for its New York City customers to continue providing reliable services for gas peaking and to address unplanned upstream gas system contingencies. The use of the LNG facility to reduce volatility of gas prices is discussed further in the "Price Volatility and Cost Reduction of Gas Supply" section below.

Q. Please explain in more detail some of the work that is planned for the LNG facility.

A. 1. Install Vaporizer 1 – There are five vaporizers at the plant. The remaining original vaporizer is Vaporizer 1, which is near the end of its useful service life and needs to be replaced to increase reliability and mechanical integrity. Vaporizer 1 is scheduled for installation in 2020 which completes all vaporization projects. The Company is projecting the following expenditures for this project: $1 million in RY1; as set forth in Exhibit ___ (GIOSP-1).

2. Plant Controls Instrumentation Upgrade Program - will provide a system with real-time monitoring, data acquisition and analysis tools, and control center alarm response, which will provide reliable operation by expediting troubleshooting operator awareness of plant conditions thereby reducing risk. The Company is projecting the following expenditures for this program: $1.2 million in RY1; $4.1 million in RY2; and $4.1 million in RY3, as set forth in Exhibit ___ (GIOSP-1).

3. Nitrogen Refrigeration Cycle Replacement - will provide a new nitrogen refrigeration closed loop system for the liquefier that will replace the original obsolete equipment with a new modern nitrogen refrigeration closed loop cycle that will be able to provide the required cryogenic chilling to liquefy clean natural gas and fill the LNG tank in six months. The current refrigeration cycle is inefficient and at times only allows the plant liquefier to fill the tank at half the rate, *i.e.*, filling can take as long as 12 months. The nitrogen refrigeration cycle will have a new efficient turbine that will produce less air emissions per million cubic feet of LNG produced. The

Company is projecting the following expenditures for this program: $3.4 million in RY1; $9.0 million in RY2; and $14.0 million in RY3, as set forth in Exhibit ___ (GIOSP-1).

4. Electrical Distribution System Upgrade Project - will provide both a new motor control center and a new high tension vault substation relocated away from the existing natural gas transmission main, which will improve employee safety and plant reliability. The new equipment will meet current arc flashing and newer national electric code requirements. The Company is projecting the following expenditures for this program: $2.0 million in RY2; and $4.0 million in RY3, as set forth in Exhibit ___ (GIOSP-1).

The remaining LNG projects consist of multiple system reliability and security and structural upgrades that are required for safe operation and risk reduction.

Details of the remaining LNG projects are included in the white papers in Exhibit ___ (GIOSP-1).

Q. Please describe the combined effect of these projects.

A. In addition to improving the safety of the facility, the Company will be able to increase the design capability of this facility for serving New York City on a peak day or for operational needs when all of these projects are complete.

Q. How much capital investment is required for all of the Company’s LNG Plant Renewal programs/projects during the rate plan?

A. The LNG programs/projects reflect a total $64.7 million capital improvement investment during the period 2020 through 2022. This amount is broken down as follows: $11.5 million in RY1, $20.7 million in RY2 and $32.4 million in RY3, as set forth in Exhibit ___ (GIOSP-1).

2. Tunnels

Q. Briefly describe the Company’s tunnel facilities and their importance in delivering reliable energy services to the Company’s electric, gas and steam customers.

A. There are eight utility tunnels on the Company’s system. These tunnels house critical electric, gas, and steam facilities, as well as fuel oil lines and telecommunications systems. They are critical pathways for service lines under bodies of water, with the exception of the 1st Avenue tunnel, which was needed for our steam transmission infrastructure after the retirement of the Waterside Steam Generating Plant. These eight utility tunnels range in age from seven years (Harlem River) to over 120 years old (Ravenswood). The depth of the tunnels ranges from approximately 60 feet to 260 feet below grade and span between 540 feet to 4,662 feet. The diameter and number of utilities vary within each tunnel. Access to the tunnels is gained from an elevator and/or ladders and landings. The aforementioned characteristics make working in the tunnels challenging.

Q. Why are the proposed projects needed?

A. These projects are required for system reliability, employee safety, and to enable continued access to critical infrastructure. Structures and components in the tunnels require continuous maintenance, refurbishment, replacement or upgrade. This includes the elevators, structural concrete, ladders and landings, ventilation fans, electric and communication systems, and ancillary equipment such as sump pumps, oil/water separators, lighting and remote monitoring capability. All of these are subject to corrosion and deterioration due to ground water intrusion and exposure to extreme moisture, salt, humidity, and heat especially in the tunnels that carry steam mains. The original carbon steel supports, feeder racks and gas main rollers are exposed to heavy salt and water infiltration. If this steel is not replaced there is an increased risk of a catastrophic failure jeopardizing the facilities contained within.

Q. Please describe the tunnel system projects.

A. 1. Ravenswood Tunnel Projects - In this tunnel, there are multiple projects required for continued safe and reliable operations and to enable maintenance teams' safe access as detailed in Exhibit ___ (GIOSP-1). These capital projects include replacing corroded steel support beams and rollers supporting high-voltage electrical transmission feeders and replacing all of the rollers assemblies supporting the transmission gas main, all of which will continue to provide for the safe delivery of gas, electric and steam to our customers. The Company is projecting the following expenditures for these projects: $4.0 million in RY1; $4.0 million in RY2; and $4.0 million in RY3, as set forth in Exhibit ___ (GIOSP-1).

2. 11th Street and Astoria Elevator Modernization – These two tunnels require new elevators as the existing equipment is due for replacement and there are code compliance requirements to meet. These projects will install new code compliant elevators in the Brooklyn shaft of the 11th Street Conduit and Queens shaft of the Astoria tunnel. The tunnels are deep and climbing ladders and landings for

access puts employees at risk of injury. Replacing the elevators will provide safe access to the equipment. The Company is projecting the following expenditures for these projects: $3 million in RY1 and $3 million in RY2, as set forth in Exhibit ___ (GIOSP-1).

3. Lighting Improvement Program - The existing lighting systems in the tunnels are obsolete, inefficient and need to be replaced. Poor lighting is also a safety concern and puts employees at risk for injury. This program will replace all of the lighting fixtures in six tunnels over six years. The new lights will be replaced with high efficient light emitting diode (“LED”) fixtures, which use significantly less power with a longer life span. The Company is projecting the following expenditures for this program: $0.6 million in RY1; $0.6 million in RY2; and $0.6 million in RY3, as set forth in Exhibit ___ (GIOSP-1).

4. Carbon Fiber Wrap - Increasing the lifespan of the facilities within the tunnels is critical to enhancing system reliability. The area where the high-voltage electrical transmission feeders transition from the shaft into the horizontal portion of the tunnel are more susceptible to corrosion. Carbon fiber is wrapped over the existing wax tape to prevent corrosion of the steel feeder

pipes and also creates a new pressure boundary. Wrapping the transition zone in carbon fiber will greatly reduce the likelihood of future dielectric fluid leaks, create a new pressure boundary for the feeder extending its useful life and reduce the impact to operation and maintenance. The Company is projecting the following expenditures for these projects: $0.8 million in RY1; $0.8 million in RY2; and $0.8 million in RY3, as set forth in Exhibit ___ (GIOSP-1).

5. The Steel Replacement Program - is the continuation of an existing program to replace deteriorated structural steel members with corrosion resistant steel throughout the tunnels. This steel supports critical infrastructure including transmission gas mains, high-voltage electric transmission feeders and steam mains. This program reduces risk and promotes reliability of critical infrastructure. The Company is projecting the following expenditures for this program: $1.0 million in RY1; $1.0 million in RY2; and $1.0 million in RY3, as set forth in Exhibit ___ (GIOSP-1).

Details of the remaining Tunnels projects are included in the white papers in Exhibit ___ (GIOSP-1).

Q. How much capital expenditure is required for all of the Company’s tunnel projects?

A. Exhibit ___ (GIOSP-1) describes all of the projected capital expenditures for the Company's major tunnel projects. We currently anticipate the following capital expenditures to support these tunnel projects during the upcoming 2020-2022 period: $10.3 million in RY1, $9.4 million in RY2, and $6.4 million in RY3.

3. Meters

Q. How will the Company's proposed meter purchase and meter installation programs foster better customer engagement?

A. These programs allow the Company to determine gas usage in order to accurately bill our new and existing customers. In addition, these programs also support the Company's mandated meter replacement programs.

Q. What meter investments are required?

A. Con Edison purchases meters and related devices for all our customers. Thirty-eight percent of the meters purchased and installed are related to mandated meter replacement programs and required replacements, while 62 percent of the meters purchased and installed are associated with new customers or replacements of existing customer meters who are increasing their existing gas demand. Installations are estimated at approximately $19 million annually, while meter purchases are estimated at approximately $11 million annually. These capital expenditures include funding for the purchase of meters and related devices (*e.g.*, interruptible customer monitors, service regulators, and electronic correctors); outsourced meter-related services for mandated meter programs required by 16 NYCRR 226; and for repair/replacement of defective meters (*e.g.*, customer complaints, broken meters, tampering) in accordance with Commission regulations. In total, we currently anticipate the following capital expenditures to support these meter projects during the upcoming 2020-2022 period: $29.1 million in RY1, $29.7 million in RY2, and $30.6 million in RY3. As shown in Exhibit ___ (GIOSP-1), these programs are listed as:

- Meter Purchases – New Business and Program Replacements ($10.4 million in RY1, $11.1 million in RY2, and $11.6 million in RY3); and
- Meter Installations – New Business and Program Replacements ($18.7 million in RY1, $18.6 million in RY2, and $19.0 million in RY3).

Q. What are the Company's plans with respect to deploying AMI?

A. The Company will continue to deploy AMI across its service territory through 2022. This effort will allow the Company to better engage customers and provide them with the information and tools necessary to become active energy consumers through the introduction of new processes, applications and technology infrastructure. The Customer Energy Solutions Panel discusses the AMI program in detail, including its anticipated benefits and the costs associated with this program. The Customer Energy Solutions Panel will also discuss how AMI costs will be allocated between the gas and electric services.

Q. How do the meter investments discussed above take into account the planned AMI investments?

A. The meter investments discussed above are independent of the planned AMI investment programs. Meter investment programs are for meter purchases and installations that are driven by, but not limited to, customer connections for new and additional gas loads, unplanned meter maintenance, meter sampling and planned meter replacement programs, the costs of which are not included in the AMI program. All new meters funded through the meter investment programs are equipped with AMI modules. The AMI investment programs include retrofitting 950,000 existing gas meters with AMI gas modules and the replacement of a total of 240,000 gas meters, of which 170,000 are gas meters that cannot be retrofitted with the AMI module and approximately 70,000

Rockwell and Sprague Class 250 gas meters that the PSC required to be remediated by 2021. The AMI investment programs are discussed in more detail in the Customer Energy Solutions testimony.

4. Natural Gas Detectors

Q. What is the purpose of AMI-enabled Natural Gas Detectors (“NGDs”)?

A. AMI NGDs are safety devices that the Company will install near the service point of entry. The NGDs are designed to provide continuous monitoring of methane. When an AMI-enabled NGD alarms (10% of the Lower Explosive Limit (“LEL”)), this alarm information is transmitted through the AMI network to the GERC. The GERC will then dispatch a Gas Distribution Services (“GDS”) mechanic to respond to the potential gas leak using normal leak response protocols. The GERC will also notify the applicable Fire Department. These detectors will help reduce risk and prevent natural gas incidents. In addition to enhancing safety, these devices will also help to reduce fugitive emissions of methane.

Q. Where is the optimum location for NGDs?

A. The accumulation of natural gas in a building can occur from a leak on the buried gas distribution infrastructure located outside of the building. Gas can then migrate through the soil or through a utility service point of entry (“POE”) and into the building. Buildings are typically constructed where the majority of utility POEs (water service, sewer pipe, buried electric service) are in close proximity to the gas POE. Locating the NGD on service line pipe near the POE provides detection capability for this type of occurrence. The Company’s proposed use of this technology presents a first-of-a-kind and unique opportunity to pair remote methane detection with the AMI communication infrastructure, which could prevent potential gas incidents in the future.

Q. What benefits do NGDs provide to customers and our employees?

A. Con Edison Gas Operations/R&D has been actively pursuing products for methane detection. Using NGD technology will improve public and employee safety by identifying potential leaks much earlier than current methods, allowing GDS crews more time to identify potential gas leaks, make the location safe and evacuate the public if necessary.

Q. Are the NGDs being classified as capital assets?

A. The initial program cost to install the NGDs will be capitalized under a new retirement unit for detectors and we plan to capitalize the replacement cost of the devices as well.

Q. What investments are required by Technical Operations to install and maintain NGDs?

A. In the fourth quarter of 2018, Con Edison started a pilot to deploy and monitor 9,000 AMI enabled NGDs and plans to complete the installation phase of the NGD pilot by the second quarter of 2019. Dependent on the outcome of the pilot, we plan future phases to commence for a total of 375,000 installations. If the pilot is successful, NGD installations are estimated to be approximately: 30,000 in RY1, 60,000 in RY2, and 60,000 in RY3. In order to reduce the cost of installations, when possible, NGD installations will be completed with other planned work, including AMI installations and service line/meter inspections. In total, we currently anticipate the following capital expenditures to install and support NGDs during the upcoming 2020-2022 period: $8.2 million in RY1, $16.5 million in RY2, and $16.5 million in RY3 as shown in Exhibit ___ (GIOSP-1). Additionally, we currently anticipate the following incremental O&M expenses to maintain NGDs during the upcoming 2020-2022 period: $0.5

million in RY1, $0.9 million in RY2, and $1.3 million in RY3.

F. GAS INFORMATION TECHNOLOGY

1. Gas Central

Q. Please describe the upcoming work planned under the Gas Central System.

A. Gas Central System is our gas work and asset management system. It is a single repository for work and asset related data that will be established to facilitate improved regulatory compliance, operational efficiencies, and financial insights. We plan to manage assets in an integrated platform to more effectively coordinate all construction, operation, and maintenance activities. A mobility solution, discussed further in the IT Panel Testimony, will be the interface that allows field personnel to receive, acknowledge and perform action on incoming work requests from the work and asset management system. Further, the platform will match the user experience expectations of our field employees and other stakeholders. The adoption of a comprehensive mobile solution will facilitate improved cost tracking, work scheduling, data management, status reporting and productivity analysis.

Q. What is the deployment plan for the Gas Central System?

A. The project commenced in 2017 and has an approximate implementation timeframe of four years. Activities in 2019 include testing and deployment of the system for inspection based work and emergent work such as leak response. In 2020 (RY1), activities include development and comprehensive testing in preparation for a deployment for construction. For the Gas Central System, the Company projects expenditures of $19.5 million in RY1.

Q. What are the anticipated benefits of this program?

A. Some of the anticipated benefits from this program include:

- An integrated view of financial and operational data for better trending and analysis;
- More effective risk mitigation strategies and movement to a more proactive approach to integrity management; and
- Increased transparency and visibility into materials management, job costing, resource availability, operational productivity, operational efficiencies, and enhanced customer experience through improved efficiencies coupled with more accurate and timely information around work flow and job status.

2. Geographic Information System

Q. Are there any other technology improvements planned?

A. Yes. The Company is investing in an enterprise Geographic Information System ("GIS") that will capture, store, and analyze geospatial data, such as the physical location and other characteristics of facilities and assets. The GIS investment is part of the Grid Innovation plan and is primarily discussed by the Electric Infrastructure and Operations panel.

Q. What are the benefits to Gas Operations that are anticipated from the enterprise GIS system?

A. As discussed in the Business plan attached as an Exhibit to the Electric Infrastructure and Operations testimony (EIOP-3), the Company proposed GIS project will provide numerous safety and efficiency benefits for our Gas customers and the public. With the GIS system, Gas Operations should realize benefits related to risk reduction in lowering the number of excavation related incidents and by reducing operating errors. Real-time collaboration with municipal agencies when responding to gas/public safety incidents as well as when implementing planned work will be enhanced by the geospatial visualization offered by a new GIS. Our performance in widespread outage management and restoration would become more efficiently monitored on both the Gas Transmission and Distribution Systems. This will benefit our customers by improving the Company's incident response through the outage mapping and damage assessments. Gas Operations could also have potential integration opportunities with AMI to monitor system performance at the service level. Additionally, Gas would have the ability to improve gas flow modelling and simulations for planned and emergency work. This GIS enterprise solution would also provide a gas system inventory that will give us the ability to trend data and analytics required to identify threats for our Distribution/Transmission Integrity Management Programs, as well as ad-hoc reporting.

3. Leak Detection Equipment

Q. Please describe the Picarro leak detection technology.

A. The Picarro Surveyor system is a state of the art mobile methane leak detection technology. The detection equipment uses Cavity Ring Down Spectroscopy ("CRDS"). Due to its sensitivity and the use of propriety algorithms, the system detects methane leaks much farther from the source when compared to traditional leak survey equipment.

Q. What progress has been made with the Picarro leak detection technology since the Company’s rate case filing in terms of purchasing and testing this leak detection technology?

A. Con Edison purchased a single Picarro Surveyor for continued use and field testing at the end of 2017. In 2018 we continued to gain familiarity with the operation and capability of the unit and have developed use cases for future applications.

Q. Please describe the planned work for the Picarro project.

A. Con Edison plans to continue using the Picarro technology for various applications such as pre-paving surveys and quality control prior to and after main replacement work. In the future, Con Edison may utilize this technology for data acquisition use cases for the DIMP.

Q. Did Con Edison look at alternative suppliers for more cost effective options that use a similar CRDS technology for leak detection?

A. Yes. Other suppliers offer similar CRDS technology and Con Edison is currently renting a CRDS from a different supplier to assess its performance through field trials to determine if it warrants purchase after the rental period.

Q. Please provide a breakdown of projected capital expenditures required for the leak detection equipment the Company has acquired or plans to acquire.

A. We currently anticipate the following capital expenditures in the upcoming 2020-2022 period: $0.56 million in RY1, $0.26 million in RY2, and $0.02 million in RY3. In RY1 and RY2 we have a yearly installment payment of $0.26 million for the existing Picarro leak detection equipment. In RY1 we also plan to purchase new leak detection equipment from an alternative supplier of CRDS technology for $0.30 million.

G. SECURITY IMPROVEMENTS

Q. How will customers and Company employees benefit from the Company’s proposed security improvements?

A. Secure facilities will contribute to enhanced reliability for customers and a safer work environment for Company employees. Details of the security improvement projects are included in the white papers in Exhibit ___ (GIOSP-1).

Q. What are the expected capital expenditures for Security Improvement Projects?

A. We currently anticipate the capital expenditures of $1.0 million in RY1, $3.0 million in RY2, and $3.0 million in RY3, as set forth in Exhibit ___ (GIOSP-1).

V. OPERATION AND MAINTENANCE (O&M) EXPENDITURES

Q. In addition to the capital programs/projects the Company has planned for the 2020-2022 period, what are the O&M expenses that the Company is projecting?

A. As described in more detail below, the O&M expenses that the Company is projecting are $187.9 million, $188.2 million, and $188.7 million in RY1, RY2 and RY3, respectively, as set forth in Exhibit ___ (GIOSP-2).

Q. What were the Company's Gas O&M expenditures for the Historic Year?

A. The Company had $150.8 million in O&M expenditures in the Historic Year.

Q. How does the Company's projected O&M expenditures for RY1, RY2 and RY3 compare to the level of O&M for the Historic Year?

A. The amount of O&M expenditures projected by the Company reflect increases of $37.1 million in RY1, $37.5 million in RY2, and $37.9 million in RY3 over the Historic Year.

Q. What is the main driver for the projected increases in O&M expenditures over the Historic Year?

A. The main driver is the change in the service line definition. We are projecting an increase in O&M due to the change in the service line definition to be $36.6

million, which is discussed in more detail below. Under the current gas rate plan, the Company is deferring all incremental inspection and repair costs associated with the new service line definition. Therefore, these costs were not reflected in O&M expenditures in the test year. As we are not complete with the first cycle of inspections, we are projecting the total cost based on an estimate that will be discussed later in this testimony.

A. O&M Program Changes

Q. Please summarize the drivers for the Company’s RY1, RY2, and RY3 projected O&M increase over the Historic Year.

A. The main drivers for the increase in O&M over the Historic Year fall into two general categories: (1) changes in the service line definition and (2) maintenance of natural gas detectors.

The Company’s O&M budget otherwise maintains historical levels of spending on existing programs while projecting increased expenses to support the aforementioned programs. Each of these two drivers is discussed in more detail below.

1. Service Line Definition

Q. Please describe the projected $36.6 million increase in O&M expenses associated with the change in the Service Line Definition.

A. On April 2, 2015, in Case No. 14-G-0357, the Commission adopted an amendment to its Gas Safety Regulations that revised the Commission's service line definition. The change alters long-standing practice by extending the Commission's jurisdiction over gas piping inside buildings up to the outlet of the meter. Under the revised definition, PSC jurisdiction for inside meter gas service lines that had previously ended at a building's foundation wall now extend to the outlet of the meter, including in apartments. The primary effect of this change requires the gas utility to perform leak surveys and corrosion inspections to cover the additional piping that is now covered by the revised definition of "service line."

Q. Please explain how the Company developed its projected O&M expenses for this item.

A. While the regulation was amended, the Commission initiated a separate proceeding (Case No. 15-G-0244) to develop a State implementation framework that considers the practical application of, primarily, leakage survey and corrosion inspection requirements. On April 20, 2017 the Commission issued an Order in Case 15-G-0244 that immediately implemented the expanded leak survey and corrosion inspection requirements. In accordance with the April 20, 2017 Order, Con Edison was required to complete baseline natural gas leakage surveys in 2018 and atmospheric corrosion inspections within three years for all newly defined gas service lines in business districts. Con Edison is also required to complete both baseline leak surveys and corrosion inspections for all newly defined gas service lines in non-business districts within three years. In addition, Con Edison must complete leak surveys in business districts annually not to exceed 15 months once the business district baseline surveys are complete. Upon completion of the baseline inspection Con Edison may request to increase the intervals for performing these required periodic inspections. Con Edison currently estimates expenses of $36.6 million in each of RY1, RY2, and RY3 to perform leak survey and atmospheric corrosion inspections for inside pipe as well as to complete any necessary repairs.

Q. What is the basis for the Company’s estimated expenditures for this program change?

A. The Company has approximately 1.1 million inside meter sets, with approximately 200,000 of these meter sets in apartments (“room sets”) or other remote locations. The expenditure level assumes an inside leak survey and corrosion inspection program for the inside piping associated with all inside meter sets, as well as any necessary repairs. We estimated the cost based on the assumption that we will be able to complete a portion of these inspections during the normal course of business, such as responding to leaks and performing other inspections. However, we will be required to complete the majority of these inspections during dedicated visits. Furthermore, some locations will require multiple attempts due to inability to access the building. In order to reduce the percentage of no access we also included programmatic funding to raise awareness of these inspections.

Q. Has the Company included its forecast of $36.6 million per rate year in the gas revenue requirement?

A. Yes. The April 2017 Order directed LDCs to perform follow-up (*i.e.*, post-baseline) surveys and inspections using the same intervals described above. However, the April 2017 Order also indicates that longer intervals for follow-up surveys and inspections would be considered on an individual LDC basis. According to the April 2017 Order, any request for an extension on follow-up survey/inspection intervals should be based on: (1) the results of the baseline inspections; (2) the results of a GTI study; and (3) a company-specific engineering analysis and risk assessment. Therefore, the forecasted impact of this new requirement may change when Con Edison files a petition to alter the interval and the Commission approves the request.

Q. Are there other issues to consider that could affect the Company’s forecast of the impact of the new service line definition?

A. Yes, NYC is in the process of enacting Local Law 152 regulations regarding gas safety of interior building piping requiring inspections of all visibly accessible interior gas piping from the POE through the tenant space. NYC LDCs have worked collaboratively with the NYCDOB and Licensed Master Plumbers (“LMP”) to provide enhanced training programs focused on conducting atmospheric corrosion inspections and leak surveys as well as recognizing and reacting to interior piping abnormal operating conditions. Further, LDCs and NGA worked closely with the Plumbing Foundation of New York and the Master

Plumbers Council to develop an Operator Qualification Program for the Plumbing Trades in NYC. Therefore, once LMPs begin conducting leak surveys and corrosion inspections NYC LDCs may be able to use these inspections to fulfill their obligation for the leak survey and corrosion inspections required by Part 255.

Q. Did the Company include the potential reduction in costs of inspections and corrosion inspections associated with Local Law 152 when it developed its forecast for the impact of the new service line definition?

A. No, not at this time. We expect that the New York City Department of Buildings will adopt Local Law 152 implementing regulations in the first quarter of 2019. These proposed regulations provide that building owners will have five years to conduct their first inspection. We worked with National Grid, the Plumbing Foundation, the Master Plumber’s Council and the Northeast Gas Association to file synergistic comments regarding inspection cycles, and other items, in the proposed DOB regulation to try to gain the most efficient and cost effective safety inspections of gas service lines inside buildings consistent with local (NYC), state and federal laws with the least disruption to the building owners all with a goal of maximizing customer and public safety benefits.

Q. How does the Company propose to address the uncertainty related to these costs?

A. The Company proposes to reconcile actual expenditures above and below the projected $36.6 million, for future recovery from or credit to customers. The bi-lateral reconciliation for these costs is described further in the Deferral Accounting/Reconciliations section of this testimony. We may also revise our cost estimate in our update dependent upon the final regulations that the DOB adopts.

2. Methane Detectors Maintenance

Q. Please describe the second program driving the Company's projected O&M increase.

A. The deployment of 375,000 AMI enabled natural gas detectors will put the Company at the forefront of detecting leaks and improving employee and public safety. The installation will be capital and subsequent maintenance related work will be covered under O&M. The O&M expense constitutes:

- troubleshooting the detector if it fails;
- fixing the detector;
- replacing the detector if it cannot be fixed; and

- removing the detector if the customer no longer wants it.

The projected O&M expenses associated with this program change are $0.5 million in RY1, $0.9 million in RY2 and $1.3 million in RY3, as set forth in Exhibit ___ (GIOSP-2). As deployment of devices progresses, annual O&M expenses to increase to fixed annual cost upon completion of deployment.

B. Business Cost Optimization

Q. What approach did Gas Operations use to identify potential savings?

A. Gas Operations focused on identifying areas of O&M savings that could be implemented while maintaining the quality of services and continuing to comply with all safety mandates. Gas Operations will be implementing various BCO initiatives in RY1-RY3. The cost savings associated with the Company’s various BCO initiatives are presented in Exhibit ___ (AP-3), Schedule 16.

Q. Please describe Gas Operations first BCO initiative.

A. The Gas Central initiative will focus on a review of legacy information systems used by the organization with a focus on developing a single mobile solution thereby streamlining processes, reducing handoffs between organizations and reducing the level of clerical work required to manage the overall function. The estimated benefits were developed by leveraging time-study information gathered during the Phase 0 assessment to derive financial benefits from anticipated productivity gains achieved through the implementation. Additionally, benefits related to the retirement of legacy IT systems were included into the calculation.

Q. Please describe the Organizational Alignment BCO initiative.

A. In this initiative, Gas Operations looked at areas of the Company where there was a decline in work load and at areas where employees were needed due to an increase in the work load. We then aligned these two areas by either merging groups or by assigning employees to new roles. As employees assumed new roles or as the Company lost employees through attrition, some positions were eliminated. One example of a successful implementation is the merging of the Oil to Gas Conversion group with the Project Management group with a realignment of positions within the new group, Project Management and Customer Programs.

Q. What is Gas Operations’ next BCO initiative?

A. While still in the design phase, the Company plans to reduce the use of per diem work force, which is the Company’s most expensive form of labor. This initiative should be fully implemented by 2023.

Q. Is the Company reviewing the manner it completes current compliance activities as part of the BCO initiative?

A. Yes. Con Edison plans to review the process by which compliance activities are completed. As part of the review, the Company will examine and ensure that the reduction of tasks will not lead to a decrease in the quality and compliance of the work output. Costs savings are based on an estimate of the time to complete additional tasks that will no longer be necessary.

Q. Please describe the Work Execution BCO initiative.

A. This initiative will focus on streamlining existing business processes within Gas Operations with a focus on making the processes more efficient. The cost savings for this program are based on benchmarking with others business groups that have redesigned their business processes. The effort, which is still in the design phase, is projected to produce savings starting in 2021.

Q. In addition to the direct BCO savings discussed above, are there other savings that may be realized within the Gas Operations function?

A. Yes. We have identified “influenced savings.” “Influenced savings” refer to savings driven by initiatives implemented by Utility Shared Services, but that are allocated to another organization. For more detail on such savings, please see the direct testimony of the Shared Services Panel.

Q. What are the challenges to realizing the savings associated with these initiatives?

A. The timing of the realized savings is difficult to predict because there could be unanticipated changes in implementation. For instance, we relied on benchmarking in developing certain cost savings. In implementing an initiative tailored to Con Edison, we may discover the need to adjust the implementation timeline. Similarly, our cost savings depend heavily on employee redeployment. This is contingent on an anticipated change in business needs (*i.e.,* impact of the temporary moratorium in parts of Westchester County). To the extent the business need changes slower or faster than predicted, the Company cost savings will be impacted.

Moreover, we expect to implement cost savings initiatives prior to RY1. Future gains in productivity may be more difficult for initiatives that have already achieved greater efficiencies.

VI. DEFERRAL ACCOUNTING/RECONCILIATION

A. Gas Service Line Definition

Q. Does the Company's current rate plan provide for deferral of the costs associated with its implementation of a change to the service line definition?

A. Yes, in the Company's current Gas Rate Plan, the Commission allowed the Company to defer the recovery cost associated with Service Line Definition inspections.

Q. Is the Company proposing to modify this deferral mechanism?

A. Yes. Although the Company has proposed that an estimated amount for this work be included in the revenue requirement, for the reasons explained earlier in our testimony, the costs to implement this change are still very uncertain and cannot be reasonably forecasted. Accordingly, as explained by the Accounting Panel, the Company is proposing that the deferral mechanisms be modified to permit the Company to fully reconcile actual expenses above or below the estimated amounts.

Q. Why is the Company's proposed reconciliation mechanism necessary and reasonable?

A. As described above, there are a number of uncertainties associated with survey and inspection requirements (*i.e.*, the frequency of the post baseline leak surveys and corrosion inspections and the impact of Local Law 152 is not yet known). Other uncertainties (and their related costs) are not dependent on the issues discussed above. For example, the level of "no access" meters the Company encounters, could significantly impact the Company's costs regardless of the frequency of the post baseline inspections. Some of these costs include but are not limited to multiple attempts, turn-offs, turn-ons, and raising public awareness of these surveys and inspections. Additionally, the level of repairs required post baseline inspection cannot be forecasted reliably.

Q. Has the Commission authorized reconciliation of other uncertain expenses to implement gas safety regulations in the past?

A. Yes. In the Company's 2006 gas rate case, the Commission adopted a provision that permitted the Company to defer for recovery costs incurred as a result of new regulatory requirements for distribution integrity and/or gas inspections promulgated by either federal or state regulatory agencies during the term of that rate plan. This deferral mechanism was in addition to a traditional new laws provision included in that rate plan for new legal and regulatory obligations that were not foreseeable, unlike the distribution integrity costs.

Q. How does the Company propose to reconcile any actual O&M costs that arise out of the Company's implementation of changes to the Gas Service Line Definition as compared to the amount included in rates?

A. The Company Accounting Panel discusses in its testimony a proposed deferral/reconciliation mechanism (both upward and downward) that would offer protection to both the Company and customers for actual costs related to this program that are higher or lower than estimated.

B. Pipeline Safety Act

Q. Does the Company's current rate plan provide for reconciliation of the costs of complying with the federal Pipeline Safety Act?

A. Yes. The current rate plan provides with respect to that Act that to "the extent that over the term of the Gas Rate Plan, the Company incurs any incremental costs to comply with the new regulations, the Company will defer these costs on its books of account for future recovery from customers." Section E. 19. In addition, the rate plan further provides that this reconciliation will continue unless modified by the Commission. Section E.23. While this provision would remain in effect unless modified, we provide an update here to show that the uncertainty concerning the federal regulations continues.

Q. Why does the uncertainty continue with respect to new regulations that may be enacted by the United States Department of Transportation ("DOT") in response to the Pipeline Safety Act of 2011 ("PSA")?

A. The DOT has not yet adopted all of the PSA therefore many requirements remain unknown. As such, the reconciliation for compliance should continue. As further explained below, the costs to comply remain uncertain.

Q. Please describe the PSA and its requirements.

A. The PSA was signed into law in January 2012. The PSA authorizes and directs the DOT to perform studies and adopt rules intended to enhance gas pipeline safety.

Q. Please explain the PSA's status.

A. To date, PHMSA has completed 34 of the 42 mandates and two of the six non-mandated actions, leaving the most significant issues still pending. These issues include rules on the use of automatic and remote-controlled shutoff valves, expansion of the integrity management program (“IMP”) requirements, and MAOP verification.

Q. Please identify the continuing uncertainties associated with the PSA requirements.

A. Although PHMSA has published Notice of Proposed Rulemakings (“NPRM”) on certain aspects of the PSA, those were met with a large amount of public comment. Additionally the Gas Pipeline Advisory Committee (“GPAC”) has also modified and voted on these proposed rules. As a result, there are a number of uncertainties regarding the pending PSA regulations that could have a significant impact on the Company’s costs. These include: applicability to our transmission mains required to reconfirm MAOP; expansion of the existing integrity management requirements; new material verification requirements; new risk modeling requirements; DOT may extend its testing/pipe replacement requirements to include all transmission pipe (*i.e.*, greater than 20 percent SMYS instead of limiting the testing/pipe replacement requirement to transmission pipelines operating above 30 percent SMYS); and DOT’s compliance schedule may remain more aggressive than the industry has identified (via NPRM comments) as reasonable.

Q. Has PHMSA taken any action to complete the remaining mandates?

A. To date, TIMP requirements and MAOP verification have been proposed by PHMSA via the NPRM “Pipeline Safety: Safety of Gas Transmission and Gathering Lines”, Docket PHMSA-2011-0023. The NPRM was released in 2016, and GPAC meeting concluded in 2017, yet a final rule(s) has yet to be published. Uncertainly lies around whether PHMSA will address the industry/public comments in which they received and how they will modify the rulemaking, based on the GPAC comments and voting.

Q. When will PHMSA-2011-0023 be in effect?

A. As described above, although steps forward have been taken on this rulemaking, no final rule or associated effective dates have been published. Through PHMSA’s prior comments, we anticipate the first part of this rulemaking may be coming out in the 1st or 2nd quarter of 2019, and a second rulemaking sometime at the end of 2019/beginning of 2020. However, these anticipated release dates are not official.

Q. Why is reconciliation continuation reasonable?

A. As described above, there are a number of uncertainties associated with pending DOT regulations enacted in response to the mandates in the PSA. Some of the uncertainties are directly related to the requirements that DOT may include in these new regulations, which are unknown at this time. Other uncertainties (and their related costs) are dependent on the regulations the DOT ultimately adopts. For example, although the PSA focused on pipelines operating above 30% SMYS, PHMSA has indicated an interest to expand the proposed regulatory changes to all transmission pipelines (*i.e.*, pipelines operating above 20% SMYS).

Q. Can the Company provide an estimate of the costs of these pending regulations?

A. No, unlike the service line definition estimated costs discussed above, the Company does not have a basis to include an estimate. The uncertainties of these pending regulations, including the timeframe of enactment, make it too difficult to develop a cost estimate for the Rate Years.

VII. PERFORMANCE MEASURES

A. Gas Performance Measures

Q. Is the Company proposing any changes to the currently-effective Gas Performance Measures, which are set forth in Appendix 16 of the Joint Proposal adopted by the Commission in its January 25, 2017 rate order?

A. The Company proposes to continue most of the major elements associated with current Gas Performance Measures. We propose modifications to some of the 2019 targets and negative revenue adjustments, as discussed in more detail below. The Company is also proposing additional positive incentives to supplement existing positive incentives to reward superior performance that we achieve in a cost-effective manner.

Q. Are any of the Company’s proposed changes similar to changes that have been approved in other utility rate plans or that are pending approval?

A. Yes, many of the changes the Company is proposing are consistent with recent trends of increased positive incentives in other utility rate plans that have been approved or are pending approval. The Company recognizes that each utility rate plan should be viewed as a total package and that individual elements of an overall settlement agreement should not be evaluated in isolation. For the reasons described below, the Company’s proposed changes are justified by the Company’s overall proposal.

Q. Which specific Gas Performance Measures does the Company propose to modify?

A. The Company is proposing to modify the following performance measures, established under its current Gas Rate Plan: Gas Main Replacement, Leak Management, Emergency Response, Damage Prevention, and Gas Regulations Performance Measure.

1. Gas Main Replacement

Q. Please describe the Company's proposed changes to the Gas Main Replacement Program Safety Performance Measure.

A. As discussed earlier under the Main Replacement Program, the Company is proposing to maintain the 2019 main replacement target of 90 miles per year for RY1. The Company is, however, proposing to eliminate the cumulative three-year target and associated NRA.

Q. Why does the Company believe it is reasonable to eliminate the three-year target?

A. The cumulative three-year target under the current Gas Rate Plan was established in the context of a joint proposal for a three-year rate plan. Moreover, the current Gas Rate Plan has no cumulative target for the post-2019 period. Accordingly, the three-year target has no applicability in the context of the Company's proposal for a one-year rate plan.

Q. Is the Company proposing any changes to the positive incentives associated with this performance measure under the current Gas Rate Plan?

A. No. As set forth in the current Gas Rate Plan, if the Company exceeds the target established in the applicable rate year, the Company would receive a positive revenue adjustment of two basis points per additional whole mile in excess of the target for that year, capped at a maximum of 10 basis points (five miles) per calendar year.

Q. Is the Company proposing to continue the Safety and Reliability Surcharge Mechanism ("SRSM") to recover the carrying costs on incremental capital expenditures and O&M expenses associated with the replacement of main above the targets established for the Main Replacement Program?

A. Yes, the Company proposes to continue the SRSM for the Main Replacement Program.

2. Leak Management

Q. What is the Company's proposed change to the Leak Management Performance Measure?

A. As set forth in the current Gas Rate Plan, the Company receives a positive revenue adjustment, up to an annual maximum of five basis points, for eliminating the highest volume Type 3 leaks. The Company would maintain the 2019 year-end total leak backlog target of 500 for 2020 and increase the annual maximum positive incentive to six basis points. If 28 of the top 30 highest volume Type 3 leaks (highest to lowest) are eliminated from the year-end backlog (after adding back in failed rechecks), the Company would earn 2 basis points; if 56 of the top 60 leaks are eliminated, the Company would earn 3 basis points; if 84 of the top 90 leaks are eliminated, 4 basis points; if 112 of the top 120 leaks are eliminated, Company would earn 5 basis points; and if 140 of the list of 150 leaks are eliminated, the Company would earn 6 basis points.

Q. Why would it be reasonable to increase this positive incentive from five basis points to six basis points?

A. Increasing the maximum positive incentive to six would provide additional inducement to address the highest volume leaks. More specifically, the Company is proposing to increase the incentive for achieving the first target (*i.e.*, eliminating 28 of the top 30 highest volume Type 3 leaks) from one basis point to two basis points. The incentives associated with the remaining targets would continue to increase at one basis point increments, up to the six basis point maximum. We believe that the combination of maintaining the year-end backlog target at 500 (which is a threshold requirement for earning the incentive) and eliminating 28 of the top 30 highest volume Type 3 leaks merits two basis points as an incentive.

Q. Are there any benefits to customers and other stakeholders associated with the gas main replacement and leak management positive incentives?

A. Yes. Eliminating 12-inch and smaller cast iron, wrought iron, and unprotected steel above the established targets will enhance safety. There is also an environmental benefit associated with the gas main replacement and leak management incentives, as Company efforts to earn these incentives will further reduce GHG emissions.

Q. Is the Company proposing to continue the SRSM to recover incremental O&M expenses associated with lowering the Company's leak backlog below the target established for the Leak Backlog performance measure?

A. Yes, the Company proposes to continue the SRSM for the Leak Backlog performance measure.

3. Emergency Response

Q. What modifications does the Company propose with respect to the Emergency Response Safety Performance Measure?

A. The Company proposes a positive revenue adjustment for exceeding the Safety Performance Measures related to

Emergency Response. For its 30 minute response rate, the Company proposes the positive revenue adjustments below:

Table 3 – Proposed Emergency Response Revenue Adjustments

30 Minute Response Time	Revenue Adjustment
86% - < 88%	2 BP PRA
≥ 88% - < 90%	4 BP PRA
≥ 90%	6 BP PRA

Q. Why are such positive incentives appropriate?

A. Allowing the Company to earn a positive incentive for achieving superior performance benefits both customers and public safety. For example, faster response means that we improve safety and reduce emissions from leaks.

Q. In order to achieve these positive incentives will the Company require additional resources?

A. While we anticipate achieving these targets may require us to train additional employees in leak response so we can strategically position additional employees and resource for leak response, the Company is not proposing an increase related to achieving these targets.

Q. Is the Company proposing any additional modifications to the Emergency Response Safety Performance Measure?

A. Yes, the Company proposes to modify the exclusion to operating performance under the Emergency Response Measure in the current Joint Proposal approved by the Commission in the Company's last gas rate proceeding.

Q. How is the Company proposing to modify the exclusion?

A. Currently the exclusion allows the Company to seek Staff's approval to exclude gas leak and odor calls resulting from mass odor complaints (unrelated to Company action/inaction or infrastructure) where the Company receives 10 odor complaints or more within any one hour period for the duration of the mass area odor. The Company is proposing to also allow the Company to seek Staff's approval for the exclusion for circumstances that are beyond the Company's control, such as natural disaster and third party damages that result in mass odor complaints.

4. Damage Prevention

Q. Does the Company propose any modifications with respect to the Damage Prevention Safety Performance Measure?

A. We propose modifying the Damage Prevention Safety Performance Measure to eliminate the following two components:

- Damages to Gas Facilities Resulting from Mismarks
- Damages by Company Employees and Company Contractors

We propose elimination because the Total Damages Measure is inclusive of the two components listed above and provides a comprehensive indication of our overall damage prevention performance.

Q. Are there any other changes that you are proposing?

A. Yes. The Company also proposes to modify the method for the calculation of the Total Damage Prevention Safety Performance Measure. The current method for the Company provides that the measure is derived by the total number of damages incurred per every thousand one-call tickets ("OCTs") received excluding refreshes (aka relocates). However, while the downstate call center (New York 811) has the ability to provide the total number of refreshes that are received, the upstate call center (Dig Safely New York) does not. Dig Safely New York can only segregate one call ticket refreshes that are less than ten days old, commonly known as "revision tickets". Thus, the Company's reported measure is calculated using two different methods for NYC and Westchester based on the capabilities of each call center.

Q. Do other NYS peer LDCs have a similar issue with the two different methods?

A. No. We have confirmed that upstate LDCs use OCT data from Dig Safely New York that only excludes "revision tickets" (*i.e.*, only refresh one call tickets that are less than ten days old) from their damage prevention performance calculations. The other downstate LDCs that use New York 811 are also using OCT data that does not exclude the refresh tickets. So while all the other NYS LDCs are using the same or very similar methods for their calculations (they all include the vast majority of refresh tickets), the method the Company is currently following in our NYC territory, where the vast majority of our OCTs are, is a fundamentally different standard because it does not include refresh tickets and makes it impossible to compare the Company’s damage prevention performance to our NYS peers. Changing the method to include OCT refreshes greater than ten days old in the Company’s calculation for Total Damages will measure the Company on the same basis as other NYS LDCs for reporting damage prevention performance data, and on a consistent basis for NYC and Westchester.

Q. What method of calculation does O&R and Central Hudson use for calculation of their Total Damage Prevention Safety Performance Measure?

A. Similarly to what we are proposing, O&R and Central Hudson both include OCT refreshes greater than ten days old in their calculation but do not include revision tickets.

Q. How has the Company performed compared to both methods over the current rate case?

A. The Company had rates of 2.24 and 2.13 for 2017 and 2018 and did not meet the respective targets of 1.94 and 1.92 for total damages per 1,000 one-call tickets excluding refreshes in NYC. This places us in the lower quartile of LDC performance within NYS. If refreshes for NYC are included in 2017 and 2018, the rates would be 1.21 and 1.15. These rates would place the Company in the upper quartile of LDC performance within NYS. They also indicate a decrease in rates and improvement in total damage prevention from the previous 5 year period from 2012-2016.

Q. What target is the Company proposing for this new measure?

A. The Company proposes a Total Damage Prevention Safety measure of 1.20 damages per 1,000 one-call tickets for RY1, RY2, and RY3. The Company proposes the following targets and revenue adjustments:

Table 4 – Proposed Damage Prevention Revenue Adjustments

Total Damages per 1000 OCTs	Revenue Adjustment
>1.40	6 BP NRA
>1.30 - ≤1.40	4 BP NRA
>1.20 - ≤1.30	2 BP NRA
1.20	0 No NRA or PRA
≥1.10 - <1.20	2 BP PRA
≥1.00 – <1.10	4 BP PRA
<1.00	6 BP PRA

Q. Please explain why the modified Company’s Damage Prevention Safety Performance Measure is reasonable.

A. The Company believes that a measure of 1.20 damages per 1,000 one-call tickets is reasonable. This number is based on the three year average (2016-2018) of total damages per 1,000 one-call tickets including refreshes. Refreshes are critical aspect of our damage prevention program and constantly communicated to excavators as a means for providing awareness of underground facilities. The complexity of utilities in NYC and traffic conditions often extend the durations and intended scope of projects and require OCTs to be called in again. The method would be consistent with the process used by other NYS utilities that recently settled their rate cases. In addition, the Company is striving to meet ambitious safety related goals for miles of main replaced as well as focusing on replacing main with a higher service density, which inherently increases the risk of potential excavation related damages compared to historical experience. This is due to the increased volume of service work associated with a given one call ticket location. Therefore, the adoption of the 1.20 target would still provide the Company with an incentive to improve performance from prior years.

Q. Is there Positive Revenue Adjustments for any of the Damage Prevention Safety Performance Measures under the current Gas Rate Plan?

A. No. We currently only have negative revenue adjustments associated with the Damage Prevention Safety Performance Measures.

Q. Why is the Company proposing Positive Revenue Adjustments?

A. The Company is proposing Positive Revenue Adjustments to provide an incentive to achieve superior performance and further improve damage prevention efforts.

Q. Why are the Company’s proposed graduated targets reasonable?

A. The Company is fully committed to public safety, and we do not take damages lightly. However, we are undertaking an unprecedented amount of work within our service territory and the targets are a stretch goal.

Q. What additional actions does the Company plan to take to meet the proposed Damage Prevention Safety Performance Measure target?

A. The Company has initiated several efforts to reduce damages. These include: reviewing and providing education for safe excavating practices with contractors and local labor trades, expanding the Damage Prevention Vehicle program in the areas that exhibit high volumes of 3rd party damages, performing additional quality checks on mark-outs, exploring and implementing risk assessment software for OCTs, and increasing the educational outreach to NYC Agencies and Westchester municipalities. We will also continue to promote 811 through customer communication channels.

Q. Does the Company have any proposals with respect to the use of negative revenue adjustments for the Damage Prevention metric it has incurred under the current Gas Rate Plan?

A. Yes. We are proposing to fund expansion of our current damage prevention portfolio as described above (including the expansion of the Damage Prevention Vehicle) and fund new damage prevention efforts through the use of these dollars. Specifically, the Company plans to explore efforts such as damage data analysis so that we can better anticipate where damages may occur. This would allow us to be more precise with our efforts and proactive. We would also expand our educational efforts, including expansion of educational advertising in local markets, such as nurseries and home improvement stores) and seasonal reminders in local media.

5. Gas Regulations Performance Measure

Q. What modifications is the Company proposing to the Gas Regulations Performance Measure?

A. The Company is proposing the following modifications to this metric:

- Change in the NRA calculation;
- Lower the total NRA cap for Gas Regulations Performance Measure;
- Eliminate NRA for violations of work procedures;
- Establish audit protocols;
- Clarify information to be provided at compliance meetings;
- Provide ten days to cure document deficiencies;
- Clarify violations to be included within scope of Field/Record Audits;

- Establish two-year timeframe for issuing final NRA Letters; and
- Examine how "High Risk" and "Other Risk" violations are defined.

Q. Please describe the Company's first two modifications.

A. The Company is proposing to change the NRA calculation for violations identified in Field and Record Audits and to reduce the overall NRA cap for violations associated with Field and Record Audits.

Q. How does the Company propose to calculate the NRAs for Records and Field Audit Violations?

A. The Company proposes the following targets and associated NRAs for each category violations:

High Risk:

Threshold: 0-5 (0 BP) for RY1, RY2, RY3

RY1 – 6-20 (1/4 BP); 21-40 (1/2 BP); 41+ (1 BP)

RY2 – 6-17 (1/4 BP); 18-33 (1/2 BP); 34+ (1 BP)

RY3 – 6-13 (1/4 BP); 14-27 (1/2 BP); 28+ (1 BP)

Other Risk:

Threshold: 0-15 (0 BP) for RY1, RY2, RY3

RY1 – 16-45(1/9 BP); 46+ (1/3 BP)

RY2 – 16-38 (1/9 BP); 39+ (1/3 BP)

RY3 – 16-32 (1/9 BP); 33+ (1/3 BP)

Q. What is the basis for excluding the first five “High Risk” violations and the first 15 “Other Risk” violations from being subject to a NRA?

A. The Company believes that the expectation of perfection in all aspects of our audited work is not reasonable, and should not be the standard for evaluating the Company’s performance. Con Edison has shown a consistent downward trend in our Records and Field audit violations since this metric was put into place, and we will strive to continue this decline in violations. We believe a goal of no higher than five High Risk and 15 Other Risk violations would be a more reasonable standard for measuring Company performance.

Q. Under the Company’s current Gas Rate Plan, is there a total NRA cap for the Gas Regulations Performance Measure?

A. Yes. The current total NRA cap for this performance measure is 100 basis points.

Q. Is the Company proposing to modify this cap?

A. Yes, the Company proposes to reduce the total cap to 75 basis points.

Q. Is the Company’s proposed change consistent with the changes made for other LDCs?

A. Not entirely. While Central Hudson (Commission-approved rate plan) and O&R (pending Commission consideration) reduced the cap for this metric from 100 to 75 basis points, they agreed to re-allocate the NRAs associated with the Gas Regulations Performance Measure to other performance measures. Con Edison is not proposing that these NRA basis points be allocated to other metrics, which thereby reduces its total NRA exposure for all gas performance measures from 150 basis points to 125 basis points.

Q. Why would such a reduction to the total cap be reasonable for Con Edison?

A. It is neither appropriate nor necessary to re-allocate basis point NRAs to other performance measures unless it can be demonstrated that the basis point NRAs associated with the other metrics are inadequate, which we do not believe is the case for Con Edison. The proposed reduction to the total basis point cap from 100 to 75 basis points would still result in significant exposure for failing to meet performance targets under this metric. Consequently, such a reduction would have no adverse impact on the Company’s ongoing commitment to safety.

Q. What is the Company’s next proposed modification to the Gas Safety Regulations Performance Measure?

A. The next modification is the elimination of a NRA for a work procedure violation, *i.e.,* 16 NYCRR Section 255.603. There are two situations in which this violation is applied. First, when the same Company action or inaction triggers a violation of an underlying regulation that falls in the Other Risk category, as well as a work procedure violation. The second is when a Company work procedure exceeds the requirements of the Commission's regulations.

Q. In terms of the first situation described above, how are alleged violations handled under the current Rate Plan?

A. In instances where there are Other Risk violations alleged, as well as an alleged violation of 255.603, the first violation is treated as a violation of 255.603, (*i.e.*, a High Risk violation) and any subsequent violations as violations of the underlying section of code (*i.e.*, an Other Risk violation).

Q. Why is this approach unreasonable?

A. This approach is unreasonable because it treats the same Company action/inaction as both High Risk and Other Risk, even when the underlying regulation is categorized as Other Risk.

It is neither appropriate, nor does it serve a useful purpose, to penalize the Company for an infraction of a

High Risk violation when the underlying violation is identified as an Other Risk violation. Therefore, the Company is proposing that only the underlying code section in which a violation occurs should count towards the NRA.

Q. Please explain in more detail the second situation discussed above.

A. The Company's procedures frequently have requirements that are not contained in New York State Gas Safety regulations. Many of the Company's procedures are more stringent and/or go above and beyond the requirements contained within the regulations. It is neither appropriate nor does it serve a useful purpose to penalize the Company for having more stringent internal work procedures. Therefore, the Company is proposing that violations of the Company's procedures, which are not required by code (*i.e.*, exceed the requirements of the Commission's regulations), not be counted for the NRA.

Q. Does the Company believe it is important for its employees to adhere to internal work procedures?

A. The Company adamantly believes compliance with internal work procedures is vital and is an integral component of operational excellence and we emphasize this continually with our employees. Identifying these circumstances in audit reports and directing the Company to address them with an action plan (without applying a NRA) would be an effective method and would not result in the Company being automatically punished for having procedures that exceed regulatory requirements. We note that the Commission would continue to have the discretion to pursue gas safety issues under its penalty authority, where warranted.

Q. Please describe the Company’s next proposed modification to the Gas Regulations Performance Measure.

A. The next proposed modification would establish more consistency around audit sampling and redefining risk categories. In the context of annual field and record audits, where violations carry significant NRA implications and are reported in the annual Performance Measurement Report, it is imperative that consistent sampling and audit protocols be established. There is currently no documented methodology or protocols explaining how Staff develops samples and/or audits a LDC’s records. This could potentially result in inconsistent methodologies being applied across the State. To address the potential issue, the Company is requesting that the Commission direct Staff, in consultation with New York State LDCs, to establish appropriate sampling and audit protocols to promote greater consistency prospectively.

Q. What is the Company’s next proposed modification related to the Gas Regulations Performance Measure?

A. The Company’s current rate plan states “At the conclusion of each audit, Staff and the Company will have a compliance meeting at which Staff will present its findings to the Company, <u>including which violation(s), if any, that Staff recommends be subject to this metric</u>.” (emphasis added) The Company is proposing to clarify this provision by stating that Staff will present its recommendations as to violations subject to this metric either (i) at the initial compliance meeting, or (ii) at a separate and subsequent compliance meeting specific to the topic of NRA violations that would be conducted prior to the receipt of an audit letter that identifies a violation that subjects the Company to a NRA. This would allow the Company a fair opportunity to be presented with, and discuss with the appropriate Staff, audit violations that are subject to a NRA.

Q. What is the Company’s next proposed modification related to the Gas Regulations Performance Measure?

A. The Company is proposing that the Company be allowed ten business days to “cure any identified document deficiency.” Under the current rate plan, the Company is allowed five business days from the date of the compliance meeting. In previous audits, the Company has identified reasons to re-evaluate and/or opportunities to “cure” violations in drafted audit violations and provided documentation and/or an explanation to Staff, and the violation has been removed from the final audit letter. Addressing such potential violations and collecting the necessary documentation can be difficult in five business days. Con Edison records are maintained in various systems, some of these systems require specialized report generation and queries, adding to the amount of time it take to retrieve them.

Q. Is the Company aware of other LDCs having ten business days to cure identified document deficiency related to audits?

A. Yes. KEDNY’s most recent rate plan (Case No. 16-G-0059) provides KEDNY ten business days from the date of the audit findings presentation to cure any identified document deficiency.

Q. What is the Company’s next proposed modification related to the Gas Regulations Performance Measure?

A. The Company is proposing to clarify the existing language in the current Gas Rate Plan that violations identified outside the scope of the Records and/or Field Audits should not be included for the purposes of applying a NRA. Staff has included self-reported incidents and/or gas damages in Records or Field audit letters, and applicable DPS Staff's NRA for Violations Performance Measure letters. These violations are identified outside the scope of an audit and, therefore, are not appropriate to include for the purposes of this performance measure. In other words, we believe the Company should encourage self-reporting, as occurs with virtually all other governmental enforcement agencies, and it is unreasonable to automatically penalize the Company for self-reports.

Q. What is the Company's next proposal related to the Gas Regulations Performance Measure?

A. The Company is proposing a maximum of two years for Staff to issue a Gas Regulations Performance Measure NRA letter, calculated based on the close of the calendar year. The two years would be based on the year in which the NRA is identified.

Q. Why is the Company proposing this timeframe?

A. The reason for this proposal is related to proper accounting and accruals. The Company accrues a liability when a potential NRA is identified. It is not reasonable that the Company be required to accrue funds for greater than two years.

Q. What is the Company’s final proposed modification related to the Gas Regulations Performance Measure?

A. The Company proposes that the Commission re-examine how it defines safety violations as either “High Risk” or “Other Risk.” The Company believes that the risk classification of a violation depends more on the specifics of the infraction, than on its predetermined section within the Code. Therefore, the Company is proposing that Staff, in consultation with the New York State LDCs, reexamine the existing general categorization of “High/Other Risk” violations to determine if it is practicable to establish objective criteria to measure the degree to which the safety of an employee or the public was compromised, when determining the severity of safety violations.

Q. How should NRAs associated with Gas Regulations Performance Measures be applied?

A. The Company proposes that any NRAs it incurs associated with Gas Regulations Performance Measures should be applied to fund future incremental gas safety programs to be developed at the Company's direction, in consultation with Staff.

Q. What modifications is the Company proposing relating to the annual reporting of Performance Metrics?

A. The Company is proposing that the Gas Safety Performance Metric be removed from the annual report due to the time between when NRA letters and Record and Field Audit letters are received and when the annual report is issued. The intention of the annual report is to report on each LDC's performance related to year-end gas safety metrics. However, the Staff report on the Gas Regulations Performance Metric is typically issued by Staff in March of the following year, and the LDCs frequently have not been provided a final determination of which audit violations will or will not be counted towards the NRA. This leads to the annual report including all identified violations found within that year's Record and Field audits. This has resulted in an over reporting of violations and an inaccurate accounting of the particular performance metric. The following examples are provided:

- The 2015 annual report identified violations from the 2014 calendar year audit and showed the Company incurred 83 High Risk and 54 Other Risk violations. However, the 2014 NRA letter the Company received identified 52 High Risk violations and 34 Other Risk violations.

- The 2016 annual report identified violations from the 2015 calendar year audits and showed the Company incurred 50 High Risk violations and 20 Other Risk violations. However, the 2015 NRA letter the Company received identified 34 High Risk violations and 1 Other Risk violation.

Due to the scheduling of audits and the time between the completion of audits and the issuance of NRA letters, it is likely similar inaccuracies will continue to occur. The Company does not believe it is fair or accurate to continue to include this metric in the annual report going forward.

6. AMI-enabled Natural Gas Detectors

Q. Is the Company proposing any new Gas Safety Performance Measures?

A. Yes. The Company is proposing to add a Performance Measure for the installation of AMI-enabled natural gas detectors. For every 1,000 units installed above the Rate Year Target, the Company is proposing the opportunity to earn one basis point, up to five basis points.

Q. Why is this appropriate?

A. The Company believes that based on initial pilot data that this effort will have a significant positive impact on customer safety and reduces reliance on a human being notifying the Company of a gas odor. Leaks that are identified faster will also reduce the length of time of a leak, which has a positive environmental benefit. We believe that a positive incentive for deploying these devices faster is appropriate.

B. Performance Measures Incentive Summary

Q. Is the total amount of positive incentives the Company proposes for Safety Performance Measures reasonable?

A. The maximum annual level of positive incentives the Company is able to achieve will be 33 basis points which is much less than the potential negative revenue adjustments of 125 basis points. Consequently, the Company's proposals for positive incentives are not only reasonable, but modest in comparison to the Company's significantly higher exposure to negative revenue adjustments.

Q. Please explain why it is reasonable to base positive incentives on basis points?

A. The Commission has used return on equity ("ROE") basis points to determine incentives. We support using ROE basis points and are accordingly using them to calculate our incentives. ROE basis points should be used for calculating incentives because they provide a useful yardstick for the Commission to provide comparable incentives to utilities and for evaluating whether the incentive itself is meaningful enough to provide a positive signal to achieve a policy goal.

VIII. GAS SUPPLY

A. Capacity and Supply Portfolio Changes

Q. Please describe the nature of the Company's gas portfolio.

A. The Company manages a joint gas supply and capacity portfolio with O&R ("joint portfolio") that allows for the joint utilization of both Companies' gas supply and interstate pipeline capacity contracts, including storage. The joint portfolio is operated for the benefit of the firm gas customers of the Companies. The contracts that the Companies' have entered into are listed in Schedules 1, 2, 3, and 4 of Exhibit___(GIOSP 3).

Q. Please describe the objective of the Companies' long-term gas supply plan.

A. The Companies evaluate supply and capacity requirements over a ten-year planning horizon and integrates and extends this over a 20-year planning horizon in order to determine the plan to meet the needs of firm gas customers.

Q. Please describe the objective of the Companies' gas purchasing and hedging programs.

A. The Companies' objective is to obtain reliable, diverse, and reasonably-priced gas supply in order to: (i) meet the design winter requirements of firm gas customers, (ii) minimize costs to firm customers, (iii) reduce price volatility, (iv) react to changing weather conditions, and (v) to the extent possible, maintain service during a contingency event affecting a major pipeline or supply basin.

Q. How do the Companies seek to maintain a reliable supply?

A. One of the cornerstones of a reliable gas portfolio is diversity. The Companies' joint gas supply and capacity portfolio includes contracted supplies from the Marcellus Shale in the Northeast and the Gulf Coast, from suppliers on nine pipelines, as set forth in Exhibit___(GIOSP 3), Schedule 1, Gas Supply Contracts. The Companies also have firm pipeline capacity contracts with thirteen different interstate pipeline transportation companies, as set forth in Exhibit___(GIOSP 3), Schedule 2, Pipeline Transportation Contracts, which provide access to diverse sources of supply. In addition, the Companies have a number of contracts for underground storage, which are listed in Exhibit___(GIOSP 3), Schedule 3, Storage Contracts, and an LNG peaking facility, whose deliverability is set forth on Exhibit___(GIOSP 3), Schedule 4.

Q. What are design weather conditions?

A. The peak day demand represents the quantity of gas that firm customers would require in a twenty-four hour period of a gas day, which starts at 10 am, at a Temperature Variable of zero degrees Fahrenheit. The Temperature Variable is defined as the sum of 70 percent of the projected gas day average temperature plus 30 percent of the prior gas day average temperature, which provides the best correlation with firm customer demand. Exhibit___(GIOSP-3), Schedule 5, Forecasted Requirements – Peak Day, shows the forecast of Con Edison’s and O&R’s firm customers’ peak day demand for each winter period (*i.e.*, November through March) beginning with the winter of 2019/2020 through winter 2021/2022. The Companies also calculate the gas requirements for meeting demand over the course of a winter under severe weather conditions (a “design winter”) in order to establish storage and

Delivered Services amounts needed to meet potential customer demand.

Q. Please explain how the Companies' contracts enable them to meet these design weather conditions/demands.

A. The Companies meet peak day demand in three ways. First, the Companies rely on the delivery of firm supply through their firm interstate pipeline transportation and firm storage contracts, which are listed in Exhibit___(GIOSP 3), Schedules 2 and 3. Second, the Companies maintain contracts for Delivered Services. Historically, these have primarily been firm peaking supplies that give the option to purchase gas for a pre-determined number of days during the winter (typically 15, 30, or 60 days) and pay the daily citygate index price for the gas on those days. Recently, the Companies' have begun adding base delivered supply contracts in addition to peaking supplies. Base delivered supplies are a commitment to procure gas at the citygate for a set winter term (typically Dec through Feb or Nov through Mar) and are priced at a NYMEX index price plus a fixed basis. These contracts for Delivered Services, which are listed in Exhibit___(GIOSP 3), Schedule 2, contribute to the Companies' ability to meet peak load. Third, Con Edison vaporizes gas from its LNG facility to meet peak day demand. The Company has proposed a capital project that would increase the reliability and operational efficiency of the facility.

Q. What do you mean by “Delivered Services?”

A. Delivered Services are gas supplies procured at the citygate from third party suppliers that have primary firm capacity to the citygate.

Q. Please describe the gas portfolio’s increased dependence on Delivered Services.

A. Both Con Edison and O&R (the “Companies”) have increased their dependence on Delivered Services from about five percent of their total peak demand needs in Winter 2014/2015 to about 20 percent of their total needs in Winter 2018/2019. The Companies’ current forecast of reliance on Delivered services increases to 22 percent by 2023/2024.

Q. What risks does the increase in Delivered Services introduce to the Gas Supply portfolio?

A. The Company has identified three risks: re-contracting, availability, and price volatility.

Q. Please explain these risks.

A. Unlike the Company’s contractual rights for pipeline capacity, there is no regulatory renewal right for

Delivered Services and, therefore, no certainty that the Company can continue to rely on the same Delivered Service supply contract year to year, to reliably meet customer heating needs.

Second, with the pipeline capacity coming into the Con Edison service territory being fully contracted and new pipeline projects facing increased difficulty in securing necessary permits, the future availability of Delivered Services required to meet our forecasted peak demand is questionable because shippers who hold this capacity can market it to persons outside of the service territory.

Third, the increased reliance on Delivered Services in the portfolio results in higher gas price volatility and potentially increased costs for our customers. Instead of buying gas at low price volatility production area receipt points and transporting it on pipeline capacity to our service territories, the Companies must purchase at New York area citygates where prices are subject to significant volatility during high demand periods.

Q. What other actions have the Companies taken to address the re-contracting risk associated with Delivered Services?

A. In order to address the re-contracting risk, the Companies actively seek to acquire firm transportation capacity to the New York area citygates as it becomes available from other shippers through permanent capacity release transactions or by contracting directly with pipelines once the capacity has been turned back by the existing shipper. Currently, the Companies are seeking to acquire capacity released through Asset Management Agreements (“AMA”) with third party capacity holders in addition to traditional capacity release agreements. The Companies will pay a fee in exchange for capacity with a supply component from the third party.

Q. How does Con Edison propose to recover its share of the costs of these AMAs?

A. The Company proposes to recover these AMA costs, including fees, through the Gas Cost Factor (“GCF”) and the appropriate tier of the Daily Delivery Service (“DDS”) program as pipeline capacity costs.

Q. Please describe the Company’s efforts during the past several years to procure additional pipeline capacity.

A. In 2014, the Company forecasted a need for additional pipeline capacity and began reviewing several proposed pipeline projects that could provide new pipeline capacity to the service area with a planned in-service date by the 2019/2020 heating season. As a result of this review, in early 2016, the Company was working toward agreements with pipeline developers to move forward on two to three projects.

As this work was ongoing, the landscape for pipeline projects in the Northeast was changing. Proposed pipelines were having issues with procuring the necessary permits, resulting in project delays and cancellations. It became increasingly unclear whether the projects selected by the Company would be able to successfully complete the permitting process as these projects had aspects similar to some of the projects facing challenges. Accordingly, in late 2016, the Company modified its plan for procuring additional pipeline capacity based on the on-going events.

Q. Have there been changes to the Companies’ supply and capacity portfolio over the last three years?

A. Yes. The Companies have recently entered into new agreements and elected not to renew certain agreements.

Q. Please describe the recent agreements the Companies have entered into.

A. As discussed in further detail below, the Companies are diversifying their Delivered Services portfolio. The Companies have entered into Delivered Services contracts with up to two or three-year durations to meet firm gas customers' current and future peak day requirements. These contracts give the Companies the right to call upon the supplier and purchase daily priced gas for a maximum of 30 or 60 days during the winter season. As previously discussed, these Delivered Services contracts provide needed supply to our gas system to supplement pipeline capacity under contract by our suppliers.

The Companies increased their volumes on one of their existing contracts with Iroquois pipeline, which provides increased deliverability to our citygate, from 100,000 Dt/d to 110,000 Dt/d, and increases our takeaway from Algonquin pipeline. This enables the Companies to redirect supplies from Northern Westchester to New York City where there is greater demand. The Companies entered into two new contracts for additional deliverability to our citygates; one with Iroquois pipeline for 20,000 Dt/d, which enables the Companies to deliver gas from an interconnect with Algonquin pipeline in Connecticut to New York City, and a second with Tennessee pipeline for 30,625 Dt/d of pipeline capacity, which enables the Companies to deliver gas from an interconnect with Iroquois pipeline in Connecticut to Westchester.

The Companies also restructured their contracts with Crestwood Gas Marketing, LLC, in which the Company's affiliate, Con Edison Transmission, has an interest. The Companies had two contracts for Stagecoach storage and associated pipeline capacity on the North/South lateral, which connects the fields to Millennium and Tennessee pipelines. The restructuring of the contracts resulted in an additional 1 Bcf of storage capacity and 37,500 Dt/d of new pipeline capacity, which allows the Companies to deliver gas to a third pipeline, Transco, increasing operational flexibility.

Q. How do the Companies evaluate whether to renew an expiring contract?

A. The Companies continuously evaluate the capacity portfolio. If an expiring contract is still required to serve firm customers or manage system operations, the Companies assess the market to determine if more economic alternatives that provide at least the same degree of reliability and flexibility are available. If not, the Companies will renew the contracts by exercising their rights pursuant to existing interstate pipeline tariff Right of First Refusal ("ROFR") provisions or other applicable contract provisions.

Q. Have the Companies elected not to renew certain expiring contracts?

A. Over the past three years, the Companies elected not to renew some of their firm transportation contracts with Tennessee and Columbia Gulf.

Q. Why did the Company elect not to renew these contracts?

A. The increase in supply available from the Northeast Marcellus and Utica shale regions has had an effect on how the Companies evaluate certain contracts. Historically, the Companies seek to access receipt points where gas can be purchased from multiple sellers, which are often referred to as a "liquid supply points." In order to accomplish this, the Company has historically entered into contracts that formed paths accessing the Gulf, Canada, or a storage field. Some of these paths include multiple contracts such as one upstream pipeline with access to a liquid supply point, connected with one downstream pipeline with access to NYC. With the increased gas available in the Northeast, liquid supply points that previously did not exist have formed on the downstream pipelines.

The firm transportation contracts with Tennessee and Columbia Gulf were upstream transportation contracts that were needed to reach a liquid supply point. Since liquid supply points are now available on their downstream counterparts along the same path, the Companies no longer need to purchase firm transportation rights on these upstream pipelines.

Q. Do you anticipate any future changes to the capacity portfolio?

A. Yes. The Companies have subscribed to 100,000 Dt/d of pipeline capacity on the PennEast pipeline and 250,000 Dt/d of pipeline capacity on Mountain Valley Pipeline (“MVP”), in which the Companies’ affiliate, Con Edison Transmission, has an investment interest, and Equitrans Pipeline to access low cost and growing Marcellus supplies. The PennEast Pipeline would connect to our existing Texas Eastern Pipeline contracts that deliver to our citygate and the MVP would connect to our existing Transcontinental Gas Pipe Line and Columbia Gas Pipeline contracts that connect to our citygates. These existing citygate contracts are currently supplied by natural gas from higher cost areas, such as New Jersey and the Gulf Coast, respectively. These new contracts will allow the Companies to deliver gas from Marcellus and Utica shale into our existing citygate contracts. Penn East pipeline is scheduled to begin service as early as November 2020 and MVP/Equitrans is scheduled to begin service as early as November 2019. The Companies have also subscribed to 15,500 Dt/d of pipeline capacity on Millennium Pipeline’s Eastern System Upgrade, which will provide increased citygate deliverability to Orange and Rockland. This project is projected to be in-service starting first quarter 2019.

Q. Is there any additional pipeline capacity that the Companies are currently considering?

A. Yes. The Companies have been considering several proposed pipeline projects designed to increase the deliverability of supply into Westchester and New York City to meet growing firm customer demand and to reduce the dependence on Delivered Services in the portfolio. The Companies are currently considering two separate projects that would increase capacity by adding compression. Both projects strive to limit permitting risk during the design phase. This approach minimizes the environmental impact and therefore the need for new permits.

Q. Have there been changes to the Companies’ supply portfolio?

A. Yes. As illustrated in Exhibit__(GIOSP 3), Schedule 1, certain of the Companies’ gas supply contracts expire each year. Existing domestic contracts may be renegotiated or replaced through competitive bidding or RFPs, and Canadian supplies may be added/replaced through Northeast Gas Markets LLC and Alberta Northeast Gas Limited, which acts as the agent for a group of utilities, including the Companies.

In the past, the gas supply contracts required to fill open firm transportation capacity typically had one, three, or five-year terms. The Companies' purchasing strategy has changed in recent years. Upstream supplies have been limited to one year or less, whereas for Delivered Services or peaking supplies, the Company will look to procure up to three years or more based on availability. The Companies have entered into multi-year upstream supply purchase deals for a small portion of their supply in order to capture some of the current market differentials and will continue to do so when market conditions support it. The Companies re-evaluate their purchasing strategy and make changes as circumstances dictate. Exhibit___(GIOSP 3), Schedule 1, lists all gas supply contracts effective winter 2018/2019.

B. Price Volatility and Cost Reduction for Gas Supply

Q. What have the Companies done to address the price volatility risk of Delivered Services?

A. In order to address the price volatility risk, the Companies have begun diversifying the type of Delivered Services procured by adding base delivered services to the portfolio. These products are priced at a fixed basis for the term plus the NYMEX settle for the month and are intended to reduce the impact of citygate commodity- priced peaking supplies on the total portfolio during periods of high volatility. On October 22, 2018, the Commission approved the Company's request to include the costs of the new base delivered services as part of its DDS program (Case 18-G-0393).

Q. Please describe the procurement strategies the Companies employ in the wholesale market to minimize gas costs.

A. The Companies use many procurement strategies to minimize gas costs. For procurement of supply in liquid markets, such as production area receipt points, we use a competitive bidding process through Requests for Proposals ("RFPs") and by participating in on-line reverse auctions. The Companies will be able to further reduce transaction costs by conducting reverse auctions using software that brings the auction process in-house. This software can be used across commodities and is explained in detail in the Electricity Supply Panel testimony filed in the Company's electric rate proceeding. In illiquid markets, such as Delivered Services procured at certain of our service area citygates, the Companies will at times engage in direct negotiation with the third parties capable of meeting the supply requirement.

Q. Will the use of auction software require a tariff change?

A. Yes. We are proposing that the variable cost of gas include all costs associated with using an on-line auction platform. This is inclusive of licensing fees, maintenance fees, customization fees and other related costs as proposed by the Electric Supply Panel.

Q. Why is there a need to change the tariff to capture these costs?

A. As discussed in the Electric Supply Panel testimony, these costs were previously incorporated into the bidders' prices. The tariff needs to be amended to allow for recovery of these costs because with the implementation of the on-line auction platform, they will no longer be incorporated into any bidder's offer.

Q. What other efforts have the Companies undertaken to reduce the volatility of gas prices to their firm gas customers?

A. Through active management of the joint gas supply and transportation portfolio, the Companies seek to reduce the volatility of gas prices delivered to their firm gas customers. Specifically, the Companies take advantage of: (i) pricing mechanisms in their gas supply contracts, (ii) storage utilization, (iii) firm transportation agreements on numerous interstate pipelines, (iv) the LNG facility and (v) a gas hedging program.

Q. Please explain.

A. The Companies' gas supply contracts generally provide the option to trigger a NYMEX price, use first-of-the month index prices and daily index prices, or negotiate a monthly commodity price months before commencement of the delivery period. If the future commodity price is agreed upon in advance, the cost of gas for these quantities is no longer subject to market volatility. Storage also plays a significant role in reducing the volatility of total gas costs. Gas is purchased and injected into storage during the summer months, when the price of gas has traditionally been lower than in the winter months, and stored for use by firm customers during colder winter days.

Long-haul firm transportation agreements, in addition to satisfying the need for reliability of gas deliveries, enable the Companies to avoid basis volatility (*i.e.*, the value of transporting gas from a supply point to a delivery point).

Q. Please describe the Companies’ gas hedging program.

A. The Companies’ hedging program is designed to reduce gas price volatility. One of the hedging program’s components is the Monthly Plan, which dictates the use of physical price locks and/or various financial instruments to hedge natural gas prices for part of the gas supply necessary to meet the monthly requirements of firm sales customers. The program provides for the Companies to hedge a minimum quantity of its forecasted sales using physical and/or financial price hedges for the winter period.

Q. Are there other efforts to reduce costs?

A. Yes. The dynamic nature of the wholesale gas market, since the advent of shale based production, has created new opportunities for the Companies to purchase more economic natural gas at alternative receipt points along the path of its interstate pipeline capacity. As new production and upstream pipeline capacity go into service the Companies are continually modifying their purchasing strategy for the resulting changes in pricing dynamics. In addition, the Companies seek to optimize their joint portfolio primarily through capacity releases, AMAs, and off-system bundled sales.

Q. Please provide an illustration of the historical benefits from the Companies' portfolio optimization efforts.

A. Exhibit___(GIOSP 3), Schedule 6, Non-Traditional Revenues, illustrates annual benefits received over the past five years from the Companies' portfolio optimization efforts to minimize overall costs to their firm gas customers.

Q. How are portfolio optimization benefits derived?

A. The expected benefits are derived when available capacity, not used to serve the Companies' customer requirements or balancing needs, is offered to the market through capacity releases, off-system sales, or AMAs that together are referred to as "discretionary capacity releases."

Q. What changes do you see for revenue from discretionary capacity releases?

A. We expect the revenue from discretionary capacity releases to decrease. First, because of projected load growth, more existing capacity will be needed to serve firm customers more often, and therefore will be unavailable for release during times of higher market value. Second, the market value of some capacity has decreased because of recent pipeline buildouts from the Marcellus region (*e.g.*, Atlantic Sunrise, Rover) that have increased the capacity price in that region. This price increase decreases pricing differentials with other regions and decreases the value of released capacity.

C. Regulatory Activities

Q. Do the Companies undertake regulatory efforts to maintain the reasonableness of their gas costs and the reliability of their supply?

A. Yes. The Companies participate in FERC proceedings involving: (i) their interstate pipeline transportation and storage providers (“service providers”) and (ii) generic issues that impact the cost and quality of the gas service received by the Companies from FERC-regulated entities. The Companies review all significant FERC filings made by the interstate pipelines and storage companies from which they receive service. Since January 2016, the Companies have participated in numerous FERC proceedings and, when circumstances dictate, have filed detailed comments or objections. Exhibit___(GIOSP 3), Schedule 7, lists the FERC dockets in which Con Edison has filed detailed comments since January 2016.

The Companies are also active participants in the AGA FERC Regulatory Committee, which takes an active role in a range of federal regulatory issues relating to gas. The Companies closely follow FERC proceedings that impact rates and terms and conditions of service of their interstate pipeline service providers and actively participate in litigation as well as settlement negotiations. In addition to the FERC proceedings listed in Exhibit___(GIOSP 3) Schedule 7, the Company is participating in several federal appellate court cases where we advocate in favor of reasonable prices and adequate supply for our customers. The Companies have also actively participated in the FERC's inquiries into gas-electric coordination and, more recently, impacts to pipeline rates due to the Tax Cuts and Jobs Act. The Companies are closely tracking the FERC Form 501-G filings being submitted by the pipelines under Order 849 and accounting changes being proposed by the pipelines under various AC dockets which could ultimately impact their rates. As a result of monitoring the pipelines' tax filings, the Companies have worked with other similarly-situated shippers to file comments or protests in the various FERC dockets dealing with the reduction in the corporate tax rate. The Companies are also actively engaged on several pipeline rate cases, both ongoing and expected, to negotiate reasonable rates for our customers.

When appropriate, the Companies also participate in collaborative discussions among pipelines and their customers, the North American Energy Standards Board (“NAESB”) and the Natural Gas Council (“NGC”), either directly or through their membership in the AGA.

Q. Please provide examples of the Companies’ active participation in the rate proceedings of their interstate pipeline suppliers.

A. As examples, the Companies participated in Iroquois Gas Pipeline’s rate settlement (RP16-301) and Transcontinental Gas Pipeline’s ongoing 2018 rate case proceeding (RP18-1126). The Companies are also prepared to participate, individually and with an LDC customer group, in the anticipated Texas Eastern Transmission rate case to be initiated before year-end.

In Iroquois Gas Pipeline’s unopposed rate settlement, the Companies achieved favorable results, leading the LDC customer group throughout negotiations. Iroquois agreed to phased-in rate reductions over the 4.5 year settlement term and a rate moratorium until April 1, 2021.

The Companies are engaged in settlement negotiations, individually and as a member of the Transco Cost of Service

Customer group, as Transco seeks rate increase of 30% in their 2018 rate case.

Other FERC proceedings the Companies are following relate to interstate pipeline cost allocation issues involving, for example, fuel retention and electric power compression charges. In a recent case, the Companies negotiated a favorable settlement agreement related to Algonquin's fuel rates (RP18-75), protecting a substantial one-time refund and preventing unreasonable cost shifting to our customers.

In 2016 and 2017, the Companies were involved in settlement discussions regarding costs Texas Eastern had incurred and will incur as a result of its PCB Environmental Remediation Program. The Companies were participants in a shipper group that successfully negotiated a settlement agreement with Texas Eastern, and this agreement was ultimately approved by FERC in Docket Nos. 17-964 and 17-967.

The Companies also closely monitor proposed tariff changes by service providers that modify their terms and conditions of service, including matters related to rights of first refusal, gas quality, lost and unaccounted for gas, bidding rules, shipping priority, service provider credit policies, and tariff and negotiated agreement filings that could affect the quality of pipeline service to the Companies.

The Companies also closely monitor new incremental services being offered by the Companies' current service providers so that the rates of those new incremental services are not subsidized by existing customers, such as the Companies. For example, in 2017, the Companies protested two National Fuel proceedings that would have resulted in the subsidization of fuel costs for the new Northern Access 2015 ("NA2015") expansion by system shippers, including the Companies. FERC ultimately sided with the Companies and required separate accounting for NA2015 fuel costs in Docket Nos. CP14-100 and RP17-407.

Q. What other regulatory efforts have the Companies taken to maintain the reliability of their supply?

A. The Companies have focused on preventing increasing electric system reliance on natural gas as a fuel from adversely affecting gas system reliability. In particular, the Companies advocated vigorously for the NYISO to prohibit electric generators from recovering penalties they incur as a result of violating Operational Flow Orders. Related rules changes were approved by the NYISO's stakeholder committees and FERC in 2016. In addition, the Companies continue to advocate for coordination of electric and gas system reliability and resilience through market rule changes, such as expanding dual-fuel requirements in New York State to outside of our service territory. The Companies are currently working closely with the NYISO on a Fuel Security Study, which, among other things, will identify possible system needs to be addressed.

Q. Are the Companies a member of any groups addressing gas reliability issues in New York State?

A. Yes. The Companies have been an active participant in the Natural Gas Reliability Advisory Group ("NGRAG") from its initiation. The NGRAG was formed to consider the evolving gas capacity markets and how they affect reliability, and to inform the Commission about issues that need to be addressed to protect reliability. The NGRAG has focused discussion on the NYISO gas/electric workgroup to address gas supply and transportation issues, updates of an ongoing LDC collaborative addressing Gas Marketer Transportation and Balancing Programs, and operational updates provided by gas industry LDCs, pipelines, marketers, customer groups, NYSERDA and NYMEX representatives.

Q. Please describe the Companies' efforts in connection with NAESB.

A. We have been a member of NAESB and its predecessor organization, the Gas Industry Standards Board ("GISB"), since the latter’s inception in 1994. The Companies continue to monitor the development of new business standards and, as appropriate, participate in periodic revisions to the NAESB Base Contract, a form agreement frequently used in the industry for the purchase and sale of natural gas.

Q. Please describe the Companies’ efforts in connection with the NGA.

A. The Companies participate on NGA’s New York State Gas Utility Planning Committee (“NYPLAN”). NYPLAN is comprised of planning, supply, and regulatory personnel from New York’s investor-owned natural gas utilities. Its mission is to provide a forum for New York State gas companies to address the broad spectrum of issues relating to the natural gas supply, transportation, storage, peak shaving, and demand planning process. This includes, but is not limited to, such responsibilities as responding to regulatory mandates, discussion/follow-up on key regulatory/ legislative issues, and working in collaboration with NYSEARCH, a collaborative Research, Development & Demonstration organization that serves its gas utility member companies, on R&D projects.

The Companies are members of the NGA Gas Supply Task Force ("Task Force"). The Task Force includes representation from all the interstate transmission companies serving the region, LNG importers and trucking companies, and the largest of the northeast region's LDCs. Recent members include several of the larger power generation owners who use natural gas as a major part of their fuel supply. The Task Force meets prior to the winter heating season to confirm communication protocols and to provide updates on the status of member company transmission and storage systems. The Task Force is convened during the winter to monitor supply and deliverability issues. The region's state regulators and the electric grid operators are notified of Task Force meetings and are provided meeting summaries.

D. Marginal Cost Study

Q. Please describe Con Edison's marginal cost study with respect to gas supply costs.

A. Supply-side marginal costs are the costs of procuring and transporting an additional unit of gas to the Company's distribution systems. Fixed costs that are associated with existing resources are not considered because they do not vary with additional usage and because Con Edison cannot avoid paying them. The marginal costs projected for the Rate Years average $4.05/Dt for the year, $6.33/Dt for the winter period and $17.79/Dt for a peak day.

Q. Please define the marginal commodity cost.

A. Marginal commodity cost is the cost of an incremental purchase of gas required to meet system demand that exceeds committed supply sources and planned supply additions.

Q. Please explain the development of the marginal commodity cost.

A. Exhibit___(GIOSP 3), Schedule 8, Summer Season Supply/Demand Balance and Schedule 9, Winter Season Supply/Demand Balance, compare the Companies' firm transportation and supply capability to serve gas demand for firm sales customers on a summer season and for a normal winter season. Exhibit___(GIOSP 3), Schedule 10, Peak Day Supply/Demand Balance compares the Companies' firm transportation and supply capability to serve all firm customers on a peak-day. The Companies' firm transportation and supply capability includes all firm transportation deliverability and accompanying purchased firm supplies. As shown by these Schedules, the highest cost of supply was assumed for purposes of the marginal cost study, combined with the projected firm demand, are less than the Supply Capability of the Companies except on a design day. The need to add capacity to serve firm customer requirements is driven by the Companies' requirements on a design day. As such the marginal cost for commodity on a design day reflects the purchase of gas through a peaking contract at a Con Edison citygate. The Companies often secure peaking supplies to supplement baseload, storage and other supplies to meet our peak demand on a design day.

Q. Please explain the calculation of the marginal commodity cost.

A. The marginal commodity cost is measured by using an optimization model to dispatch load profiles under normal and design weather and taking the resulting highest cost of supply.

Q. What is the forecast period used in your marginal cost study?

A. The forecast period for the marginal cost study is the three-year period from November 2019 through October 2022. Exhibit___(GIOSP 3), Schedule 11, Natural Gas Monthly Marginal Commodity Costs, displays the monthly forecasted marginal commodity costs for the three years of the study. Exhibit___(GIOSP 3), Schedule 12, Marginal Commodity Costs, summarizes these costs to show the impact of the incremental increase on an average annual, summer season, winter season, and design day basis.

E. New York Facilities Payments and Receipts

Q. Please explain how net payments and receipts among the parties to the New York Facilities Agreement are currently reflected in the Company's base rates.

A. Currently, an estimate of the Company's net payments and receipts under the New York Facilities Agreement is included as other operating revenues in the Company's base rates. In accordance with the rate plan adopted in Case 16-G-0061, the Company trues up the estimate to its actual net payments and receipts year through the New York Facilities Adjustment of the MRA and/or the Company's calculation of its lost and unaccounted for gas.

Q. How does the Company propose to recover/refund net payments and receipts under the New York Facilities Agreement beginning with this rate plan?

A. The Company proposes that its actual net payments and receipts under the New York Facilities Agreement be recovered or refunded, respectively, through the MRA's New York Facilities Adjustment (or as lost and unaccounted for gas, as discussed in the next section of our testimony) and that base rates no longer reflect an estimate of such payments and receipts.

Q. What are the reasons for the proposed change?

A. Using the MRA as proposed would eliminate the uncertainty associated with forecasting the net payments and receipts among the New York Facilities parties and the need to reconcile the estimated amounts to the actual amounts. Using the MRA for these costs and revenues would also be consistent with the Company's recovery or refund of its other upstream gas payments and receipts.

The Gas Rate Panel discusses the tariff change associated with the change in recovery method.

The Accounting Panel discussed the proposed termination of the existing New York Facilities Agreement reconciliation mechanism, which is also associated with the change in recovery method.

F. Lost and Unaccounted for Gas

Q. Please explain the current methodology for calculating lost and unaccounted for ("LAUF") gas.

A. In accordance with the current Gas Rate Plan, the Company uses a throughput method that calculates unaccounted for gas by subtracting metered deliveries to customers from metered supplies to the system. An adjustment is made for

Generators who contribute 0.5% of their metered deliveries to the unaccounted for gas. The remaining LAUF gas is compared against a rolling five year average.

Q. Have there been any changes to the calculation during the current Gas Rate Plan?

A. Yes, as specified in the Joint Proposal adopted in Case 16-G-0061, an agreement among the New York Facilities companies was completed and requires a contribution of 0.5% of net deliveries by the Delivering Party to the Receiving Party. The Commission approved this change by its Order Regarding New York Facilities System Agreement issued and effective October 18, 2018, in Case 18-G-0318.

The calculation of the current average is shown on Exhibit___(GIOSP 3), Schedule 13.

The Gas Rate Panel discusses the tariff change to the Factor of Adjustment in the Company’s Gas Cost Factor to reflect this New York Facilities component of the LAUF.

Q. Are you proposing any other changes to Con Edison’s LAUF calculations for the period commencing January 1, 2020?

A. No.

G. Interruptible Service Program

Q. Is the Company proposing changes to the balancing provisions applicable to interruptible gas service?

A. Yes. The Company is proposing to add a maximum delivery charge for "over-deliveries" above 110% of the Daily Transportation Quantity to the Monthly Balancing Program for interruptible marketers. Currently, there is a minimum delivery charge for a Daily Transportation Quantity that is less than the minimum delivery quantity ("under-deliveries") but no charge for "over-deliveries."

Q. Why is the Company proposing this change?

A. Currently marketers elect either a 70%, 80%, or 90% minimum delivery quantity. An over-delivery of 110% would result in swings of 20-40% depending on the customer class. Since both under- and over- deliveries to our gas system adversely impact operations (e.g., pressure), we believe the same charge to under-deliveries above 10-30% should be applied to over-deliveries above 10%. With increased demand on our system, the Company has less room to handle these types of daily swings.

Q. Is the Company proposing any other changes to the interruptible program?

A. Not at this time.

Q. Please explain why.

A. The Company is currently engaged in a collaborative with Staff and other stakeholders interested in the Company's interruptible service. The collaborative was established in the Joint Proposal approved by the Commission in the Company's last gas rate proceeding. A technical conference related to interruptible service was held on November 27th in Albany. The scope of the collaborative discussions was thereafter expanded to include issues raised by the Commission's December 14, 2018 order in Case 18-G-0565. As a result, the interruptible collaborative did not conclude, as anticipated, by December 31, 2018. The Company anticipates additional collaborative discussions over the next couple of months and the Company will be filing a Gas Interruptible Collaborative Report on or before April 1, 2019.

Based on these continuing discussions and the extended date for filing the collaborative report, the Company may make additional proposals for its interruptible service in the preliminary update and/or at a later stage of this proceeding, as appropriate.

H. Capital and O&M Investments

Q. What is the Company's projected gas supply capital investment for the three rate years?

A. We are planning to invest $3.9 million in RY1, $2.2 million in RY 2 and $0.0 million in RY3 on Information Technology System ("ITS") solutions.

Q. Please explain Gas Supply's ITS strategy.

A. During the current rate plan, several ITS projects were initiated to replace the Integrated Gas Supply ("IGS") system and update the Transportation Customer Information System ("TCIS"). These projects were undertaken to update the technology, streamline processes, accommodate new functional requirements required to support changing market conditions, accommodate new retail access program initiatives and adhere to the Companies' corporate strategy to consolidate applications.

Q. What is the status of these projects?

A. The projects are in progress and expected to be completed during the rate year (TCIS) and in RY2 (Gas Transaction System replacement). The whitepapers for these projects are found in Exhibit___(GIOSP 4) pages 2-7.

Q. Are there projected additional O&M expenses associated with these projects?

A. Yes, there are. The additional O&M expenses are estimated at $0.5 million in RY1, $0.8 million in RY2 and $0.6 million in RY3.

Q. What are the drivers for the projected increases in O&M?

A. The Gas Transaction System replacement will be a vendor supported system. The annual maintenance on this system is expected to be approximately $0.3 million per year plus additional IT support for the infrastructure and interfaces to other systems needed. The TCIS upgrade will transfer Company employees working on the software and business requirements to O&M to support the new functionality of the system. Please see Exhibit ___ (GIOSP-4) pages 8-10 “Energy Management Gas Program Changes.”

Q. Does this conclude your direct testimony?

A. Yes, it does.

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INTRODUCTION

Q. Would the members of the Customer Energy Solutions ("CES") Panel please state their names and business addresses?

A. Janette Espino, Margarett Jolly, Matt Ketschke, Vicki Kuo, Tom Magee, and Damian Sciano. Our business address is 4 Irving Place, New York, NY 10003.

Q. In what capacity are the panel members employed and what are their professional backgrounds and qualifications?

A. (**Espino**) I am Janette Espino, General Manager of Customer Information Systems. In my current position, I am responsible for replacing Consolidated Edison Company of New York, Inc.'s ("CECONY" or the "Company") and Orange and Rockland Utilities, Inc.'s ("O&R") Customer Service Systems ("CSS") with one new platform. I have held this position since October 2017. I joined Con Edison in 1988 and have held positions of increasing responsibility. Positions held prior to my current position include General Manager of Specialized Activities, Customer Operations; System Manager, Information Technology; Section Manager, Executive Action Group; Testing Lead, Human Resource PeopleSoft Implementation; Section Manager, Purchasing Services Technology and Strategic Initiatives; and Director, Procurement Operations – Supply Chain. I have a Bachelor of Science-Computer

Science from Manhattan College and a Master of Computer Science from Pace University.

(**Jolly**) I am Margarett Jolly, Director, Reforming the Energy Vision ("REV") Demonstration Projects. In my current position, I am responsible for the development and execution of the Company's REV Demonstration Projects and related projects. I have held this position since 2017. I have over 20 years of utility experience in a variety of positions of increasing responsibility, including power plant and control room engineer, Steam Business Unit; Policy Specialist, Energy Markets and Policy Group, Con Edison's Distributed Generation ("DG") Ombudsperson, and Director, Research & Development ("R&D"). I serve on the Board of the New York Battery and Energy Storage Technology consortium. I am a Registered Professional Engineer in New York State and hold a Bachelor of Science degree in Mechanical Engineering from Cooper Union.

(**Ketschke**) I am Matt Ketschke, Senior Vice President of CES. I am responsible for efforts to evolve the Company towards a customer-centric Distributed Energy Resource ("DER") enabled future through work in the following CES departments: Energy Efficiency ("EE") and Demand Management ("DM"), Advanced Metering Infrastructure ("AMI") Implementation Team, CSS Implementation Team, Distribution Planning, Utility of the Future, REV Demonstration Projects and Rate Engineering ("RE"). I have been in my current position since 2017. I have been employed by Con Edison for 23 years. I have held senior level positions in Electric Operations, Electric Construction, Electric Engineering, and Human Resources, including Vice President Manhattan Electric Operations, Human Resources Director, and General Manager of Electric Operations. I earned a Bachelor of Engineering degree in Mechanical Engineering and a Master of Science degree in Management Technology from Stevens Institute of Technology. Additionally, I earned a Master of Business Administration from Columbia University.

(**Kuo**) I am Vicki Kuo, Director, EE and DM ("EEDM"). I am responsible for the Company's EE, demand response ("DR"), DM, non-wires solutions ("NWS") and non-pipeline solutions ("NPS") programs. I have been in my current position since 2016. I have been employed by Con Edison for 20 years in a variety of positions within Electric Operations, Strategic Planning, IT, and with Con Edison Development. I also have 10 years of experience building new products and developing new markets outside of the utility industry in both North America and Europe. I hold a Bachelor of Science degree in Electrical

Engineering and a Master's degree in Management from NYU-Polytechnic School of Engineering.

(**Magee**) I am Tom Magee, General Manager of the AMI Implementation Team. I am the business lead for the Company's AMI Project. The AMI Project scope includes a full-scale rollout of AMI smart meters and supporting infrastructure for the Company's electric and gas customers. I have been in this position since 2015. I have been employed by Con Edison for 33 years. I have held various positions including watch supervisor, Ravenswood Generating Station; associate engineer, Electrical Engineering; and engineer, Fossil Power Engineering. I have also served as Project Manager, Energy Management Plant Divestiture; Section Manager, Steam Distribution Engineering; Section Manager, East River Repowering Project, Technical Manager, East River Generating Station, and General Manager, Smart Grid Implementation Group. I hold a Bachelor of Science degree in Marine Engineering from the U.S. Merchant Marine Academy.

(**Sciano**) I am Damian Sciano, Director, Distribution Planning. I am responsible for the evolving integration of the Company's Distributed System Implementation Plan ("DSIP") and Distributed System Platform ("DSP") designed to integrate DER, such as solar energy, into the traditional electric distribution system. I have been in my current position since 2015. I have nearly 30 years of utility experience working as a developer of cogeneration projects for Trigen Energy as well as working in power generation, strategic planning, electrical engineering, and, most recently, as Senior System Operator at Con Edison's Energy Control Center. I am a Registered Professional Engineer in New York State and hold a Doctorate degree in Electrical Engineering from NYU-Polytechnic School of Engineering and a Master of Business Administration in Finance from Baruch College as well as a Bachelor of Science degree in Mechanical Engineering from Cooper Union, and a Masters degree in Electrical Engineering from Manhattan College.

Q. Have panel members previously submitted testimony or testified before the New York State Public Service Commission ("Commission")?

A. Ms. Espino, Ms. Jolly, Mr. Ketschke, and Mr. Magee have submitted testimony or testified before the Commission in prior proceedings. Ms. Kuo and Mr. Sciano have not previously submitted testimony or testified before the Commission.

Purpose and Summary

Overview of CES Group

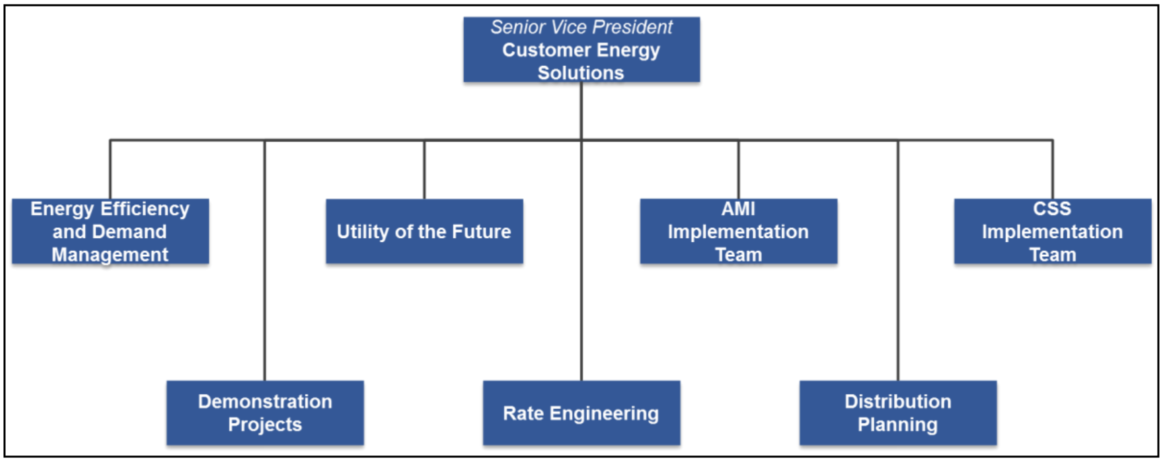
Q. Please explain the initiation, organization and responsibilities of the Company's CES group.

A. Con Edison recognizes that having an organization capable of quickly adapting to policy and technology advances and customer preferences is critical to facilitating the transition to a customer-oriented clean energy economy. Con Edison formed the CES organization in fall 2017. Initially, the Company formed this group to enable focused development and innovation across the functions directly affecting customers' clean energy experience. Since then, the group has evolved and is now responsible for the Company's EE, DM, REV, electric vehicles ("EV"), AMI, CSS, distribution planning, RE, and other projects. CES guides the Company's overall clean and distributed energy strategy, pursuant to which the Company has taken on a leadership role in providing a clean energy future for New Yorkers.

Q. Can you please explain how CES is organized?

A. Yes. CES's organization chart is:

Figure 1 – CES Organizational Chart



Organized in this manner, CES is leading the Company to evolve its energy business to become cleaner, adapt its business model to be more innovative, and transform the customer experience to provide best-in-class service. (Please note that although RE is part of this transition, it provides separate testimony to cover demand analyses, cost of service studies, revenue allocation, rate design, tariff changes and other RE items.)

The CES organization currently has 230 employees. Many of the departments that comprise CES were transferred into CES, moving their employees as well.

Q. Have there been any major changes in regulatory policy that, among other changes, CES was established to address?

A. Yes. Since late 2014, the Commission has been conducting a proceeding, REV, intended to transform the electric utility industry in New York. CES was formed to better respond to advancing policy goals, customer preferences, and technology developments. For example, REV's objectives include reducing greenhouse gas ("GHG") emissions, growing the clean energy economy, creating a robust market for DER, and expanding customer choice. In addition, with the encouragement of the Commission, Con Edison recently commenced its Smart Solutions proceeding to explore demand side and renewable gas alternatives to delivered services and contracting for new gas pipeline capacity.

Through REV and its related proceedings, the Commission and the State have set emission reduction and EE goals. These include generating 50 percent of New York's electricity from renewable energy sources and reducing GHG emissions State-wide by 40 percent by 2030,[1] and increasing EE savings to a level equivalent to three percent of utility sales by 2025.[2] Additionally, the Commission has set goals for emerging technology, like energy storage and EVs. For storage, a recent Commission Order targets 1.5 GW of State-wide storage to be

[1] Case 15-E-0302, Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard, *Order Adopting a Clean Energy Standard*, issued August 1, 2016.
[2] Case 18-M-0084, In the Matter of a Comprehensive Energy Efficiency Initiative, New Efficiency New York ("NE:NY"), filed April 26, 2018.

installed by 2025 and 3.0 GW by 2030.[3] For EVs, the State has adopted Zero Emission Vehicle ("ZEV") regulations and is a signatory to the Multi-State ZEV Memorandum of Understanding which sets a New York goal of approximately 800,000 EVs by 2025.[4]

The investments requested in this testimony are aligned with the latest policy requirements in this dynamic regulatory environment.

Purpose

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

A. This Panel's testimony presents an overview of Con Edison's investments and initiatives for both the electric and gas systems to promote a cleaner, more sustainable energy future, enhance the customer experience, and build the capabilities necessary for integrating DER. These efforts include working towards a transformative and scalable DSP which enables the bi-directional flow of energy. Implementing these projects and programs will position the Company to meet customer expectations as well as make progress towards meeting the

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[3] Case 18-E-0130, In the Matter of Energy Storage Deployment Program, *Order Establishing Energy Storage Goal and Deployment Policy*, issued December 13, 2018.

[4] Zero Emission Vehicle Program, Memorandum of Understanding (executed on Oct. 24, 2013), *available at* http://www.nescaum.org/documents/zev-mou-9-governors-signed-20180503.pdf/

State's clean energy policy goals. Each program and project for which the Company seeks funding is described in an accompanying exhibit that includes scope of work, cost, schedule, and justification, including discussion of alternatives, presented here as Exhibits __ (CES-1 through CES-9).

Q. What investments and programs are covered in the CES testimony?

A. The proposed investments and activities related to CES described in this testimony are listed below:

- EEDM – Increase the Company's Electric and Gas EEDM initiatives for Commercial and Residential Customers.
- EVs – Expand access to public EV charging through an EV make-ready program and continue incentivizing off peak EV charging under SmartCharge New York.
- Energy Storage – Develop six energy storage facilities on Company locations and one turn-key make-ready site for third-party storage developers.
- DSP Implementation – Invest to further develop the DSP services related to DER integration, information sharing with customers and third parties, and market mechanisms.
- Targeted Initiatives to Defer Electric Infrastructure – Implement two NWS solutions to eliminate or defer

traditional infrastructure projects to meet forecasted electric demand.

- New CSS Implementation – Replace the existing CSS with a Commercial-off-the-Shelf ("COTS") system.
- AMI – Complete deployment of the AMI smart meters and gas modules, communications network, and back office IT systems.
- Innovation Initiative – Implement a corporate-wide innovation center of excellence and its activities.
- Demonstration Projects – Develop and test new business models that will help pave the way for a customer-centric, DER-enabled future.
- Earnings Adjustment Mechanisms ("EAMs") – Propose electric, gas, and AMI awareness EAMs.

We describe these programs and their status in the testimony that follows.

Q. Why is the Company undertaking these investments during the upcoming rate period?

A. The energy industry, including Con Edison, is undergoing a rapid transformation on several fronts. Technology advances and regulatory changes are accelerating the development and deployment of DER requiring new grid functionality, such as bi-directional power flows and the ability to host additional DER. At the same time, customer expectations are changing as instantaneous information and customization of available customer information becomes more widespread. Customers expect to better understand and manage their energy usage. Further, the utility business is evolving to facilitate State policies seeking to meet Commission and State goals for emissions reduction and EE. We chose the proposed investments to meet the near-term needs of our customers and our system while also positioning the Company to advance a customer-centric, DER-enabled, clean energy future.

Q. What period does your testimony cover?

A. This Panel presents the projects, programs, and initiatives planned for the 12-month period ending December 31, 2020 ("Rate Year" or "RY1"). Because the Company has stated that it is willing to enter into settlement discussions for a three-year rate plan, the Panel also addresses the capital additions and other programs and initiatives planned for the two years following the Rate Year. For the sake of convenience, we refer to the 12-month periods ending December 31, 2021, and December 31, 2022 as ("RY2") and ("RY3"), respectively.

Q. What are the capital costs associated with the initiatives described in this testimony?

A. Aggregate project capital requested for the investments described in this testimony is $1.365 billion over the three-year rate plan period, with $408 million in RY1.

Q. What is the Company's CES Operations and Maintenance ("O&M") expenditure for the historic test year (the period October 1, 2017 through September 30, 2018)?

A. The Company's total CES O&M expenditure for the Historic test year is $29.1 million.

Q. What are the Company's O&M program cost changes for CES in RY1, RY2, and RY3?

A. The Company is planning an increase of $55.5 million in RY1, a decrease of $5.0 million between RY1 and RY2, and an increase of $0.3 million between RY2 and RY3.

Q. Are there any previously approved expenditures?

A. Yes. The Commission previously approved forecasted AMI expenditures of $573 million in capital for the three-year rate period.

Q. Please provide an overview of the capital and O&M spending by activity.

A. A summary of the capital and O&M requirements for each activity is provided in the table below:

Table 1 - Total Capital and Regulatory Asset Requests ($000):

Investment	**2020**	**2021**	**2022**	**Total**
EEDM	$215,900	$257,800	$300,300	**$774,000**
EV Initiatives	$12,859	$14,478	$17,743	**$45,080**
Energy Storage	$14,000	$16,501	$60,000	**$90,501**
DSP	$35,200	$35,200	$35,200	**$105,600**
CSS	$129,619	$100,388	$119,100	**$349,107**
Total	**$407,578**	**$424,367**	**$532,343**	**$1,365,288**

Note that: (i) funds related to AMI, NWS, NPS, and Demonstration Projects are not included in this chart as they have been previously authorized by the Commission or pending before the Commission in a separate proceeding; and (ii) the Energy Efficiency Transition Implementation Plan[5] ("ETIP") portion of EE is included in base rates as a regulatory asset and reflected in the EEDM investment.

Q. What is a regulatory asset?

A. A regulatory asset is an accounting treatment arising in instances where a utility incurs a cost that is typically not treated as a capital expenditure. However, because treating such costs similar to capital investments advances policy objectives or provides customer benefits, for example, moderation of customer bill impacts through amortization of costs, regulatory Commissions, including

[5] Case 15-M-0252, In the Matter of Utility Energy Efficiency Programs, *Order Authorizing Utility-Administered Energy Efficiency Portfolio Budgets and Targets for 2019-2020*, issued March 15, 2018.

this Commission, have permitted treatment that allows for cost recovery over time. The regulatory asset appears on the utility's balance sheet and represents the costs that have been incurred by the utility but have not yet been recovered from customers.

Q. Which of the forecasted expenses listed in the "Total Capital and Regulatory Asset Requests" table above are considered as regulatory assets?

A. All EEDM costs and the SmartCharge portion of the EV initiatives. The SmartCharge portion is the total EV initiatives' cost minus $10 million (for the make ready program) each year in the rate period.

Q. Why are these investments treated as regulatory assets?

A. Regulatory asset treatment permits amortization of costs over time, moderating customer bill impacts. Such moderation allows the Company to make necessary investments towards clean energy resources and other initiatives to advance integration of DERs. Consequently, and as explained further below in this testimony, the Company is proposing continued regulatory asset treatment for these investments.

Q. What incremental O&M is requested by this Panel?

A. The chart below shows the O&M request.

Table 2 - Incremental Year over Year

Program Change O&M Requests ($000)

Investment	**2020**	**2021**	**2022**	**Total**
EEDM	$3,444	$1,370	$774	**$5,588**
Energy Storage	$12,868	$(11,689)	$233	**$1,412**
DSP	$2,090	$461	$339	**$2,890**
CSS	$7,283	$(1,348)	$3,563	**$9,498**
AMI	$27,597	$6,010	$(5,661)	**$27,946**
Innovation Initiative	$2,251	$225	$1,068	**$3,544**
Total	**$55,533**	**$(4,971)**	**$316**	**$50,878**

Note that funds related to incremental labor for Targeted DM is included in the EEDM line and exhibit, but discussed in the NWS section of this testimony.

Q. Does the Panel propose any incentives, regulatory asset treatments, or rate mechanisms?

A. Yes. The Company is making several proposals – continued treatment of EE as a regulatory asset, regulatory asset treatment of the SmartCharge portion of the EV initiatives, continuation of the existing regulatory framework for recovery of NWS projects not included in base rates, and continuing many of the existing EAMs. First, Con Edison proposes to continue to recover EE costs as a regulatory asset. The Commission should continue regulatory asset treatment because it:

- mitigates immediate bill impacts by smoothing expenses over time when benefits are realized,
- matches costs to the benefit period, i.e., customers will receive the benefits during the period they are receiving service, and
- aligns EE investments with other utility business investments by treating such investments in a similar manner to traditional investments.

Second, the Company proposes all EV programs costs related to the SmartCharge program be treated as a regulatory asset.

Third, although the Company has not included costs for any new NWS projects in these filings, we anticipate proposing cost recovery for certain NWS projects in base rates in its preliminary update filing. To the extent the Company implements additional NWS projects during the term of the rate plan, the Company proposes to continue the existing cost recovery mechanism for NWS projects not already included in base rates.

Fourth, the Company proposes:

- electric EAMs for the three-year rate period building on the currently effective EAMs that positively incent the Company to deliver energy and peak demand savings, increase the amount of DERs that interconnect to the

Company's delivery system in order to reduce reliance on the grid, and increase the amount of DERs, particularly beneficial electrification technologies, in order to reduce GHG emissions,

- gas EAMs that positively incent the Company to deliver energy and peak demand savings and reduce GHG emissions,
- continuation of AMI Customer Engagement EAM, and
- discontinuation of the Energy Intensity and Interconnection EAMs.

The proposed EAM earnings opportunities are at 100 basis points each rate year for electric and 70 basis points each rate year for gas. The Company developed this proposed set of EAMs in advance of the December 2018 Commission orders in the New Efficiency: New York ("NE:NY") proceeding and the proceeding on energy storage goals and deployment. The Company may propose in its preliminary update additional EAMs to align with the NE:NY and Storage Orders.

Q. How is this testimony structured?

A. This testimony addresses the main categories of the CES Panel's responsibility. Programs and projects are discussed in testimony generally, and more fully in the corresponding exhibits for the projects. The testimony addresses recent Commission orders that affect the activities of this Panel. In addition, we have included white papers that provide more detailed information on each of the programs/projects in this testimony as exhibits.

Objectives

Q. What are the CES organization’s overarching objectives with the investments and programs described in this testimony?

A. The investments proposed by this Panel support the following Company objectives:

- Integrating clean and distributed energy resources into the Con Edison system while empowering our customers to manage their energy usage,
- Optimizing our systems and business to provide excellence in the integration of DER, and
- Enhancing our customers’ experience.

While the investments and programs described in this testimony and accompanying exhibits are primarily intended to meet one objective, many provide benefits across most of the objectives.

These objectives also align with and support our overall corporate objectives of enhancing the customer experience and further engaging our customers, advancing clean energy and operational excellence, and seeking benefits for our customers. The Electric and Gas Policy Panels further discuss these corporate objectives.

Integrating Clean and Distributed Energy Resources while Empowering Our Customers to Manage Their Energy Usage

Q. Describe how the Company is integrating clean and distributed energy resources and empowering customers to manage their energy usage.

A. Driven by State policy objectives and increasing customer interest, the Company is integrating a variety of clean and distributed energy resources into the grid, while reducing environmental impacts. These resources include the expansion of EE, EVs, and energy storage.

Q. Please discuss some successes to date in the expansion of EE, EVs, and energy storage.

A. The Company has increased program achievements and exceeded the maximum rate case EE targets in 2017 and expects to have done so again in 2018. In 2017, Company efforts saved 300 GWh and achieved over 60 MW of peak reduction as compared to the maximum stretch targets of 198 GWh and 59 MW. EE innovations included significant improvements to delivery of EE savings, through (i) accelerated implementation of projects and compression of lead times, *i.e.*, the time between identification of a prospective project and the beginning of project implementation, in commercial EE achievements, (ii) targeting upstream portions of the supply chain to align incentives across vertical supply chain market actors in promoting EE, and (iii) enhanced customer targeting and marketing.

For EVs, the Company has implemented a multi-faceted approach to promoting and preparing for increased EV adoption, including off-peak charging incentives and rate design, facilitating charging infrastructure deployment, and fleet initiatives.

Con Edison has also furthered the goal of integrating energy storage by procuring and installing a battery energy storage system rated at 2 MW and 12 MWh in the Brooklyn-Queens Demand Management ("BQDM") area and by initiating Demonstration Projects to better understand energy storage capabilities while testing new business and operational models.

Optimizing Our Systems and Business to Provide Excellence in the Integration of DER

Q. Is the Company working to integrate DER while continuing to prioritize grid reliability and safety?

A. Yes. The Company's efforts to build DSP capabilities will continue during this upcoming rate period by the development of systems, processes, and technologies to further integrate DER in alignment with the policy objectives noted above. Increasing monitoring and smart control capabilities and expanding distribution automation will make the distribution system more capable of managing bi-directional energy flow reliably, further enabling DER integration and providing operational flexibility. The Company's NWS and NPS focus on procuring DER to mitigate the need for traditional investments, while maintaining system reliability and enabling DER market development.

Enhancing Our Customers' Experience

Q. Describe the Company's approach to enhancing the customer experience.

A. In this evolving environment, customers expect access to data to manage their energy usage and alternatives to meet their energy needs. The Company's efforts to better serve our customers are discussed in this testimony as well as in other testimonies, including Electric Infrastructure and Operations Panel ("EIOP"), Gas Infrastructure, Operations and Supply Panel ("GIOSP") and Customer Operations Panel. As Con Edison's electric and gas infrastructure evolves, and more DERs and EE alternatives become available, the new CSS will enable the underlying transactions and more complex rate designs so that customers can take advantage of these new products and services.

Through Con Edison's continued AMI implementation, AMI-enabled customers are already accessing their own usage data, enabling them to make energy-related decisions, through tools such as customized-energy-usage reports and high-bill alerts. Together, the new CSS and AMI will provide the infrastructure and data to enable greater customer choice. Further, customers will be able to more easily adopt DER and market actors will be able to provide them with useful products and services enabled through the Company's investments in maintaining and building new DSP capabilities.

CES INVESTMENTS

Energy Efficiency and Demand Management

Q. Did the Company formulate a proposal for electric and gas EE initiatives as part of its development of these electric and gas rate filings?

A. Yes. The Company developed an electric and gas EE program that recognizes the State's clean energy goals, and specifically the goals to increase EE achievement State-wide. As part of this development, we considered the NE:NY white paper ("White Paper") jointly issued by Staff and the New York State Energy Research and Development Authority ("NYSERDA") in Case 18-M-0084.

Q. Did the Commission act on the White Paper?

A. Yes. On December 13, 2018, the Commission issued its *Order Adopting Accelerated Energy Efficiency Targets* ("EE Order"). The EE Order adopts Con Edison-specific budgets and targets for calendar year 2020 (i.e., RY1 for these proceedings), and procedures for the development of utility EE programs for the period 2021 through 2025, which five-year period includes RY2 and RY3 in these rate filings.

Q. Does the Company's rate filing reflect the EE Order's Con Edison-specific budgets and targets?

A. No.

Q. Please explain why.

A. The Commission issued the EE Order while the Company was finalizing its proposed program and associated revenue requirement for its electric and gas rate filings. The Company did not have adequate time to complete its review and evaluation of its EE program in light of the timing of the EE Order prior to finalizing its revenue requirements.

Q. Does the rate filing reflect EE budgets and targets equal to or greater than the Con Edison-specific budgets and targets adopted in the EE Order?

A. Yes. The EE Order's Con Edison-specific budgets and targets, however, are premised on certain assumptions that differ materially from assumptions the Company used to develop its EE budgets. Accordingly, the Company may adjust its EE programs at the preliminary update stage of these proceedings. The Commission routinely accepts updates, if appropriate or necessary, when associated with developments outside of the utility's control that are close in time to the filing date.

Q. Is the Company also considering modifications to RY2 and/or RY3?

A. In light of the processes that the Commission has ordered be undertaken in 2019 for the five-year period (2021-2025), which includes these two years, the Company may update its proposal as discussed above. The Company may present additional information in its preliminary update in this regard.

Q. Does the Panel have an exhibit that discusses the costs associated with EEDM programs?

A. Yes. The Company has an exhibit entitled, "Energy Efficiency," which was prepared under the Panel's supervision and direction.

MARK FOR IDENTIFICATION AS EXHIBIT __ (CES-1)

Q. What are the EE costs reflected in the Company's proposed revenue requirements for electric and gas?

A. We developed the electric and gas revenue requirements assuming aggregate forecasted EE program expenditures (electric and gas), including beneficial electrification technologies, such as efficient electric heating, of $215.9 million in RY1, $257.8 million in RY2 and $300.3 million in RY3.

The electric and gas revenue requirements reflect recovery of these expenditures in base rates as regulatory assets amortized over a ten-year period (e.g., $178.5 million and $37.4 million in RY1 for electric and gas, respectively).

The electric and gas revenue requirements also reflect recovery of incremental labor costs of approximately $3.4 million, $1.4 million, and $0.8 million in base rates as O&M expenses in RY1, RY2 and RY3, respectively. This is the result of the Company's plans to add 34 full-time employees to implement various functions in the EEDM Department.

Q. Why does this panel discuss the EE costs in aggregate for electric and gas?

A. The Company proposes to manage its electric and gas EE programs as a single combined portfolio for the benefit of electric and gas customers. For purposes of setting rates, the costs are allocated between electric and gas based on the costs of the proposed electric and gas programs in the proposed portfolio. The Company seeks flexibility to move actual expenditures between the electric and gas programs and proposes that full reconciliation of EE costs be continued, as discussed below.

Q. Are the goals and objectives of the State's energy policies reflected in these rate filings?

A. Yes. The Company's EE portfolio is designed to:

- Advance the State's clean energy goals and help meet policy objectives through a reduction in emissions,
- Deliver meaningful benefits cost-effectively and with moderate bill impacts to our customers, and
- Integrate EE as a core part of the utility's business.

The Company intends to achieve expansion of its EE portfolio through expanding existing, as well as adding new, programs and delivery channels, innovating to deliver additional savings more cost-effectively, using data analytics to target outreach and increase marketing effectiveness, and further developing data governance processes. These are discussed in greater detail in Exhibit __ (CES-1).

We will also discuss the EE regulatory framework needed to moderate customer bill impacts. This framework is particularly important as the State seeks to ramp up EE achievements and looks to utilities to make other investments that advance clean and distributed energy. The regulatory framework will also provide customers with a better opportunity to participate in programs and more meaningfully reduce their energy use and net bill impacts.

The Commission has recognized that EE is the most cost-effective means for achieving State environmental policy goals and that the utilities will have a key implementation role in helping achieve those goals. The Company will continue to optimize costs and improve the efficiency and effectiveness of program delivery. Importantly, the proposed approach is helpful to low-to moderate-income ("LMI") customers specifically and allows more opportunity for their participation to offset program costs as well.

Q. What factors impact the unit cost of EE that the Company intends to pursue?

A. Despite efforts to optimize costs and the Company's success at driving down costs by more than 20 percent over two years, the Company notes that there will be countervailing upward pressure on costs as:

- the Company seeks to diversify beyond lighting (the predominant EE measure today) requiring the Company to work with customers to achieve greater savings from measures such as heating, ventilation, and air-conditioning ("HVAC") and building envelope,

- reported energy savings change due to baseline increases driven by building and manufacturing code improvements, decreasing reported savings for the same set of measures, even when the real savings realized through projects are actually higher, and
- lower-cost measures and programs reach saturation and the Company will need to implement EE at harder-to-reach customer locations with more expensive measures.

Q. How does the EE portfolio support the Company's overarching clean energy objectives as set forth in this testimony?

A. Con Edison's approach to meet EE growth targets supports the integration of clean energy. Our approach will also enable our customers to manage their energy usage while enhancing our customers' experience. The Company's proposed EE portfolio, with increasing targeted amounts of achievements over the three-year period, is designed to produce customer benefits, including environmental benefits.

Q. Please describe the Company's proposed portfolio of EE Programs.

A. The Company's portfolio is forward-looking but reflects and builds upon more than a decade of experience running cost-effective EE programs that deliver reduced energy usage and emissions. The Company's programs will enable customers to better manage their energy use, enhance their use of beneficial electrification technologies improve their comfort and well-being, and save on their utility bills.

At the broad level, the efficiency portfolio is divided into electric and gas offerings across customer segments. We reach our customers through a focus on four primary customer segments - commercial and industrial ("C&I"), small business, multifamily, and residential - designed to meet each customer group's needs.

The Company plans to grow the portfolio from current levels by:

- optimizing delivery for current offerings in order to generate more energy savings and demand reductions from current offerings, for example, by further streamlining the customer experience from the application stage to the point of full implementation of the EE measure using transparent information and simplifying and standardizing processes, and
- employing new strategies to reach deeper savings, expanding beyond lighting offers, exploring upstream interventions in the supply chain to fundamentally transform markets towards greater EE, and engaging harder to reach customers such as residential customers, including LMI customers.

In building the portfolio reflected in this rate filing, the Company envisioned growth across all customer segments. To achieve the expanded portfolio targets proposed in this testimony, including a trajectory for savings achievement to 1.5 percent of sales by 2022, the Company envisioned a GWh savings growth in C&I of over 180 percent, in small business of over 115 percent, in residential over 40 percent, and in multi-family of over 125 percent. The Company intends for the portfolio to evolve as it adjusts to the market response. Efficiency offerings and delivery channels are not static, nor are they uniform within a segment. Accordingly, the Company intends to manage and revise offerings and delivery channels applying continuous improvement and innovation as key priorities. While the portfolio is designed to provide solutions for all customers, in all customer segments, the Company will allocate 20 percent of incremental funding to LMI customers. In the Company's territory, LMI customers generally live in public housing or are tenants in multi-family buildings and present uniquely difficult challenges to reach and serve.

In addition to the delivery channels described above, the Company will employ a host of strategies and operational improvements to better serve customers in a more innovative and market-oriented manner that is transparent and transformational for our customers, partners and other stakeholders in the EE marketplace. This includes giving our customers multiple options and opportunities to reduce their energy use based on their unique needs and continuing or expanding programs targeted to upstream portions of the supply chain that align interests in promoting more widespread installations of energy efficient equipment at our customer locations. Examples for residential customers include accessing rebates and incentives through market partners, shopping directly through the Company's Online Marketplace, managing energy and demand through smart thermostats and Wi-Fi-enabled air conditioners, and benefiting at the retail level from market-based partnerships between Con Edison and mid- and up-stream retailers and manufacturers.

The Con Edison Online Marketplace will transition in late 2019 from a REV Demonstration Project to a full integration within the EE portfolio. As this transition occurs, the Marketplace is expected to evolve to meet customers' needs through engagement channels of their preference.

Q. Please describe other programs that will be offered through the EE portfolio.

A. Other examples of programs that explore innovative delivery models and promote transformative offerings include (i) Instant Lighting, an upstream program that provides instant incentives to customers on eligible ENERGY STAR®-certified and Design Lights Consortium-listed lamps at the distributor point of sale; (ii) Smart Kids, that provides fifth-grade students in the service territory with classroom education on EE as well as a take-home kit of electric and gas efficiency measures; (iii) strategic energy partnerships, through which the Company is focused on identifying and engaging customers that are heavy-energy users (working to secure longer-term partnerships with customers in segment verticals such as hospitals, schools, and the banking sector are some of the areas where Con Edison may see significant potential for savings); (iv) Retail Lighting that provides instant rebates to customers at their point of purchase in big-box retailers, as well as other retailers, such as drug stores and dollar stores, providing accessibility to customers, including LMI; (v) Residential Upstream HVAC that focuses on incenting distributors or other entities in the supply chain upstream of the customer; and (vi) ENERGY STAR™ Retail Products Platform that leverages the purchasing power of multiple nation-wide utilities to work with retailers nationally to incent them to stock and sell efficient appliances.

The Company is also proposing a three-year beneficial electrification program, focused on increasing adoption of beneficial electrification technologies such as air-source and ground-source heat pumps that (i) provide customers with alternative options for heating, especially considering customers impacted by gas moratoriums, (ii) reduce environmental emissions that advance State, New York City, and other local or municipal decarbonization goals, including an 80 percent reduction in GHG emissions by 2050, and (iii) generally decrease peak energy usage and increase off-peak energy usage. The Company seeks to also expand electrification to customers that currently use a non-jurisdictional fuel, such as oil, gasoline, kerosene, or propane, to incentivize them to convert to an electrification technology. The Company may, however, update its beneficial electrification proposal after further evaluation of the EE Order and Commission decision on the proposed NPS portfolio.

NPS is a part of the Smart Solutions filing, Case 17-G-0606, Petition of Consolidated Edison Company of New York, Inc. for Approval of the Smart Solutions for Natural Gas Customer Program, filed on September 29, 2017. The Company proposed four non-traditional initiatives to alleviate forecasted increases in customer demand for natural gas. These initiatives are a doubling of the Company's natural gas EE programs; developing a new natural gas DR pilot program; issuing a competitive market solicitation (the "Non-Pipeline RFP") to acquire resources as part of NPS that would seek to offset the Company's needs for pipeline capacity; and the Gas Innovation Program. In developing and implementing the beneficial electrification program, the Company plans to work with key stakeholders such as NYSERDA, New York City, and Westchester County, so Company efforts are complementary to other efforts related to beneficial electrification in its territory.

Q. What other demand-side programs does the Company offer to its customers?

A. In addition to the EE portfolio for both electric and gas customers described above, the Company offers or plans to offer customers and third parties (i) NWS opportunities that seek to aggregate customer-side solutions to enable deferral of or elimination of the need for traditional electric infrastructure described later in this testimony, (ii) DR opportunities through tariff-based programs that seek aggregation of commitments to reduce load during periods of high demand or periods of reliability needs, (iii) NPS opportunities that the Company has proposed to develop and implement upon

Commission approval to seek to aggregate customer-side and supply-side resources that are capable of providing peak-day gas consumption relief to reduce reliance on Delivered Services and potentially defer the need for incremental pipeline capacity when possible; and (iv) specific EV-related programs and investments described later in this testimony.

Q. Is the Company seeking to continue the EE Partnership Pilots with NYSERDA as authorized by the Commission in the ETIP proceeding?

A. Yes, the Company intends to continue collaboration with NYSERDA so more of the Company programs and offerings to customers account for and are generally complementary to those offered by NYSERDA. Such partnerships, which are limited to five percent of the total portfolio per partnership, allow for positive and enhanced cooperation by leveraging each organization’s strengths and resources to ultimately increase our customers’ EE adoption.

Q. Has there been material progress in program delivery and performance in the current rate period (2017-2019)?

A. Yes, the Company has made significant progress and achieved above the stretch goals established for 2017, and expects that the 2018 results will show the same.

Q. To what does the Company attribute this improvement?

A. The Company attributes these achievements to its enterprise focus on EE, which drove optimization of program performance and costs. This focus was driven at least in part by the regulatory framework that aligned customer and stakeholder interests with policy objectives. This framework is based on EAMs and amortization of new investments. Amortization of new investments has the additional important benefit of moderating bill impacts by allowing customers costs to be smoothed over a 10-year period, aligning costs with realized benefits.

Managing Electric and Gas Energy Efficiency as a Single Budget Portfolio

Q. How does the Company propose to manage the implementation and reconciliation of the budget for the portfolio of programs?

A. While the Company's program includes separate, annual electric and gas energy savings targets, the Company proposes to manage the portfolio of electric and gas EE programs as a single budget over the three-year period. The Company believes that managing its EE portfolio on a combined basis will benefit customers, for example, by providing flexibility:

- within the budget, which allows for the portfolio to respond to market conditions and customer needs, creating opportunities for focus to be shifted across programs to more cost-effective efforts that are driving results, and

- between the electric and gas programs, which allows the Company to align with the State's fuel-neutral approach to programs to be delivered by utilities.

The Company has previously discussed coordinating the electric and gas EE in prior electric rate cases.

Q. How does the Company propose to allocate the combined EE program costs between electric and gas customers?

A. The Company proposes to use the current allocation methodologies for EE costs, i.e., electric customers, excluding New York Power Authority ("NYPA")-supplied customers, are allocated the costs of the electric portion of the EE portfolio and firm gas customers are allocated the costs of the gas portion of the EE portfolio. These allocation methodologies were used to develop the revenue requirements.

Q. What is the relationship between the annual targets to the three-year program period?

A. The Company proposes to manage to the annual budgets and targets that form the basis of its final EE portfolio targets. The Company's annual budgets and targets that it developed prior to issuance of the EE Order are set forth later in this testimony.

To enable the Company the opportunity to maximize benefits to customers, the Company proposes that unspent funds in RY1 and/or RY2 be available to spend for customer benefit in RY2 and/or RY3.

That said, RY2 and RY3 are presented for illustrative purposes to facilitate settlement discussions. If there is no three-year rate plan established by Commission approval of a joint proposal, only the RY1 proposal would apply.

Q. Does the Company propose that the EE costs reflected in rates be fully reconciled to actual expenditures?

A. Yes we do, in accordance with historic practice and the Commission's confirmation in the EE Order (p. 67) that "[t]he governing principle for cost recovery will continue to be full recovery of prudently incurred costs."

In addition, consistent with our proposal to manage these expenditures over a three-year period, the Company proposes that reconciliation of amounts reflected in electric and gas rates be performed at the end of the three-year period, rather than annually, and be based upon comparing the total actual expenditures to the aggregate of three annual budgets.

Reconciliation would be subject to a total cap equal to the sum of the budgets for RY1, RY2 and RY3, where the amount by which actual expenditures are less than the cap are deferred for customer benefit. The Company is proposing such a unitary arrangement to provide the necessary flexibility to use authorized funds to manage the energy savings that the Commission expects the Company to achieve and that the Company expects will be reflected in the final targets established in this rate proceeding.

Regulatory Asset Framework ("RAF")

Q. How does the Company propose to recover costs for the portfolio of EE programs?

A. The Company proposes to continue the ratemaking framework established in the Company's current electric rate plan,[6] which provides for the recovery of EE costs over ten years using the overall pre-tax rate of return, with the extension to gas and reconciliation across the commodities over a three-year period, as discussed by the Accounting Panel.

Q. Why is the Company proposing continuation of this RAF?

A. Over the last rate period, the RAF has successfully assisted the Company in delivering on its EE targets and

[6] Case 16-E-0060, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, *Order Approving Electric and Gas Rate Plans*, Appendix A – Joint Proposal ("current rate plan"), January 25, 2017.

providing benefits to our customers. Given the continued growth of the portfolio, the current RAF is in the best interests of our customers to mitigate the bill impact while achieving significant program and achievement expansion. The Commission stated in the EE Order that "amortization of EE program costs may be permitted where the overall context of the rate plan establishes a benefit to doing so, such as moderation of overall customer bill impacts." (p. 67)

Amortization in this rate case would moderate bill impacts for electric and gas customers, allowing more opportunity to address policy priorities, as described in this case, and incent important technologies that support REV initiatives to integrate DER and improve the customer experience. For example, if the Company's EE program collects $103 million from customers in RY1 when expensed, the RY1 revenue requirements with amortization would only require recovery of approximately $13 million, reducing the annual customer bill impact. Moreover, while many customers stay in their premises for many years, others change location within and outside the service area; allocating the costs over time means that the right customers are paying for the benefits over the period the benefits, on average, are being realized.

Q. Is this adding costs to the overall program?

A. We have reviewed this on a net present value basis of the revenue requirement over the period, considering EE investments amortized over 10 years. When we use the Company's regulated rate of return, which is the same discount rate used for the Commission-approved Benefit Cost Analyses ("BCAs"), the result is slightly lower than if the revenue requirements of the EE investments were expensed in the first year. For example, the same EE investment described in the previous question would result in revenue requirements with a $102 million net present value when amortized instead of $103 million of net present value if expensed. In essence, the same cost.

Q. Are there other benefits that should be considered?

A. Yes. The Company's proposal includes the treatment of dollars approved under ETIP in the RAF rather than as a surcharge.

As noted already, matching costs to the benefits provided by EE programs is appropriate so customers bearing the costs of the EE program receive the benefits contemporaneously, rather than concentrating costs on customers at the time of expenditure. The life of the measures deployed in our EE portfolio, on average, is approximately 10-12 years and thus an amortization of 10 years appropriately matches costs to benefits. Further, when the costs and benefits established under the Commission-authorized BCA framework are considered, a 10-year amortization results in benefits exceeding costs every year. For example, an investment in a rate year that results in $103 million in EE related revenue requirement when expensed that same year, would result in a revenue requirement of approximately $13 million in the first year, increasing to and peaking at approximately $16 million in the second year, well below the average annual $37 million benefit the EE investment provides customers over the 10-year amortization period, when amortized over ten years.

Q. Please continue.

A. Further, American Council for an Energy Efficient Economy ("ACEEE") in its policy brief released on December 11, 2018 (https://aceee.org/topic-brief/pims-121118) states, "ROE mechanisms allow utilities that are rapidly ramping up EE investment to spread those costs over the entire period that customers benefit from the investment, often making it more equitable."

The policy brief also states that "another notable development is the recent adoption of incentive mechanisms that allow utilities to earn a rate-of-return on EE expenditures and to amortize EE expenses for cost recovery." The brief notes that Illinois, Maryland, New

Jersey, and Utah are examples of states pursuing such policies and states that the rationale for that type of approach is that it both moderates bill impacts when there are large changes in efficiency spending as well as makes EE investments, and the level of focus given to EE by the utility and its executives, more comparable to traditional rate-of-return treatment for supply-side investments.

In short, the cost recovery mechanism that is the most just and reasonable for customers is amortization over the average life of the EE investment.

Q. Are there unspent funds available from the Energy Efficiency Portfolio Standard ("EEPS") program?

A. Yes, there are and the Company recognizes that the EE Order provides for Con Edison to use some of these unspent amounts to fund its NE:NY Incremental Electric Budgets in 2020.

The revenue requirements in these filings were developed by the Company in advance of the EE Order. The Company will consider the Order in its preliminary update filing.

Q. What benefits does this regulatory framework provide in addition to mitigating customer bill impacts?

A. As discussed above, the Company believes that a regulatory framework that fosters long-term robust utility engagement in achieving EE goals is critical to advancing the State's clean energy objectives, including NE:NY EE goals, while also managing customer impacts. The White Paper estimates that the State must achieve energy savings equivalent to both three percent of investor-owned utility sales by 2025 and an average of two percent savings level or greater between 2019 and 2025. As a result, the Company must more than double its EE efforts and investments from current levels, which are currently under one percent of sales. Recovering these expenditures as regulatory assets through base rates, amortized using our overall pre-tax rate of return over a period of ten years, will not only moderate bill impacts but also establish parity with other utility capital investments and aligns interests of customers, policymakers, third party providers and utility investors.

Further, establishing the RAF framework for EE investments supplemented by appropriate EAMs supports the State's long-term commitment to EE, including the development of the business and human resource infrastructure and spurring private sector clean energy jobs critical to the success of clean energy policy objectives.

Q. Are there any other differences in cost from the proposed budget if the Company does not amortize the EE costs?

A. Yes, there is a 3% gross up on costs that are expensed.

EE Portfolio Budgets and Targets and Other Demand Reduction Initiatives

Q. What are the EE program funding levels associated with the EE programs reflected in the revenue requirements?

A. As noted above, the electric and gas revenue requirements reflect an aggregate of $215.9 million, $257.8 million, and $300.3 million in RY1, RY2 and RY3, respectively. Of these aggregate amounts, the electric revenue requirements reflect allocated shares equal to $178 million, $216 million and $254 million, and the gas revenue requirements reflect allocated shares equal to $37.2 million, $39.2 million and $41.8 million, for RY1, RY2 and RY3, respectively. As noted earlier in our testimony, the Company is also proposing beneficial electrification budgets that the Company may update after further evaluation of the EE Order and Commission decision on the proposed NPS portfolio. The respective proposed beneficial electrification budgets for RY1, RY2 and RY3 are $0.7 million, $2.6 million, and $4.5 million, respectively.

Q. Do these budgets capture expenditures made pursuant to the Company's Smart Solutions programs (Case 17-G-0606), in which the Company has proposed a number of non-traditional alternatives to meeting firm gas customer demand?

A. They do, in part.

Q. Please explain.

A. The aggregate electric and gas budget for RY1 includes the $20.2 million funding level for the Enhanced Natural Gas Efficiency Program approved by the Commission for 2020 in the Smart Solutions proceeding.

However, while these budgets include growth of gas EE savings above levels authorized in the Enhanced Gas Energy Efficiency program, they do not include the additional gas EE expenditures that may be approved by the Commission as part of the Company's portfolio of non-pipeline solutions ("NPS Portfolio"). The Company petitioned the Commission for approval of this program in September 2018, which is currently pending Commission action.

Q. How does the Company propose to recover NPS Portfolio and other Smart Solutions program costs?

A. Recovery of NPS Portfolio expenditures authorized by the Commission would be governed by the order issued in the Smart Solutions proceeding.

In addition, the Company is continuing to recover through the Monthly Rate Adjustment ("MRA") expenditures for customer incentives, metering, and administration of the gas DR pilot approved by the Commission in August 2018. Finally, the Company requested that the Commission approve a $10 million Gas Innovation Program proposal, which costs are not part of the EE budgets reflected in the revenue requirements. This program is focused on testing new business models leveraging clean heating technologies.

The Company may reflect changes to its current proposal in this filing, to the extent appropriate, in its update filing in response to a Commission order on Smart Solutions.

Q. What are the energy savings targets for the EE programs reflected in the revenue requirements?

A. The Company designed the electric program to achieve savings of 482 GWh, 562 GWh, and 640 GWh in RY1, RY2 and RY3, respectively, including beneficial electrification goals of 115 MWh, 340 MWh, and 550 MWh over those same years. The Company designed the gas program to achieve savings of 620,000 Dekatherm (“Dth”), 640,000 Dth, and 670,000 Dth in RY1, RY2 and RY3, respectively. Ramping electric EE savings from a level that is equivalent to approximately 1 percent of sales in 2019, the Company would reach an equivalence of 1.5 percent of sales in 2022 if the program met the targets.

Q. On what unit costs are the program budgets based?

A. The program budgets are based on the Company achieving an average unit cost of $0.37-$0.40 for each kWh saved through further optimization of program delivery and internal operations. This unit cost is lower than the Commission-approved levels of $0.43/kWh for ETIP and around the range of the blended ETIP and EE Order unit costs of $0.36/kWh-$0.37/kWh reflected in the Con Edison-specific budget and targets for achievements without and with LMI. It represents significant improvement in cost efficiency, particularly considering countervailing upward cost pressures discussed below. The Company projects $62.4/Dth gas EE unit cost efficiency.

Q. Are there other efforts that may impact gas EE growth?

A. Yes, the non-pipeline RFPs will advance gas EE and may reduce the direct EE program potential. The Company's unit costs for gas EE is higher than the currently authorized unit cost because of the need to develop new efficiency offerings to achieve significant growth in gas efficiency. The Company will continue to monitor this developing market.

Table 3 - EE Portfolio:

		2020		2021		2022	
Electric		**GWh**	**$M**	**GWh**	**$M**	**GWh**	**$M**
	Total	482	$178	562	$216	640	$254
	Unit Cost ($/kWh)	$0.37		$0.38		$0.40	
	% of Sales	1.1%		1.3%		1.5%	
Electri-fication		**MWh**	**$M**	**MWh**	**$M**	**MWh**	**$M**
	Total	115	$0.7	340	$2.6	550	$4.5
Gas		**Dth**	**$M**	**Dth**	**$M**	**Dth**	**$M**
	Total	620,000	$37.2	640,000	$39.2	670,000	$41.8
	Unit Cost ($/Dth)	$60.0		$61.3		$62.4	
	% of Savings	0.36%		0.37%		0.39%	

Q. Please explain how the Company determined the estimates for EE savings?

A. The Company made some key assumptions when determining the EE energy savings estimates. The Company, combining its EE program experience and market research with its most recent potential study,[7] evaluated the ramp up needed to align achievement with the State's ambitious policy goals, while minimizing customer bill impacts. In development of the estimated EE savings, the Company (i) looked at historic program achievement and ramp up; (ii) benchmarked current ramp up against other utilities around the country, looking at cost structure and

[7] Case 15-M-0252, 2017 Distributed Energy Resources (DER) Potential Study, December 18, 2017; and Case 15-M-0252, Con Edison DER Potential Study Supplemental Report: Natural Gas Add-on Analysis, November 22, 2017.

achievement for illustrative benefit even though the Company's territory represents a more complex, uncertain and expensive urban environment; and (iii) estimated the results of the above against the economic and annual achievable potential results in the potential study. The Company made other assumptions such as the calculation of savings in accordance with the 2018 Technical Resource Manual ("TRM").

Q. Please explain how the Company determined the budget for EE spending.

A. The Company established an overall budget for its EE portfolio using indicative unit costs, i.e., cost per unit of energy (kWh or Dth) saved or cost per unit of beneficial electricity consumed, that it can reasonably forecast. During implementation, EE unit costs will depend on a number of external variables that could have significant impact on program costs such as: (i) the Company seeking to diversify beyond lighting, the predominant EE driver today, requiring the Company to work with customers to achieve greater and deeper levels of savings from more complex measures such as HVAC and building envelope that have longer payback periods for customers and longer lead times to implement; (ii) amount of reported energy savings decline for the same set of measures, as baselines increase driven by code improvements such as the anticipated 2007 Energy Independence and Security Act federal efficiency standards for manufacturers lighting baseline shift in 2020; (iii) lower-cost measures and programs reaching saturation, for example, as anticipated for residential lighting measures, which would result in the Company implementing more expensive measures with harder-to-reach customers; (iv) additional desired outcomes, such as implementing longer-lived EE measures, for example, through maintenance of existing portfolio average levels of effective useful life; (v) overall level of flexibility provided to achieve reductions; and (vi) targets established and the target levels relative to the remaining potential of various measures in the Company’s territory. Consequently, while recognizing Commission determinations in the EE Order, the Company believes that unit costs, as currently calculated, will increase as the proposed EE and beneficial electrification program portfolios evolve and ramp up.

Q. Please explain why the Company’s proposed unit cost increases over the three-year rate period.

A. As the Company grows the portfolio at an accelerated pace to achieve unprecedented levels of EE, there will be upward pressure on unit costs. The Company anticipates unit costs to escalate over the three-year rate period even as the unit costs proposed represent significant cost efficiencies as discussed above. The Company forecasts that this will result from the uncertainties discussed above, i.e., the need to include program offers beyond lighting to HVAC, building shell, and other new technologies while reported savings decline due to the increase in baselines.

Q. Does the Company plan to make capital investments to advanced software applications to facilitate delivery of the EEDM portfolio?

A. Yes, the Company will continue to implement and expand advanced software applications to enhance EE and DM programs including the Demand Response Management System ("DRMS"), Demand Management Analytics Platform ("DMAP"), Demand Management Tracking System ("DMTS"), and for benchmarking of building energy performance. These investments are discussed further in the DSP section of this testimony. Similar to the EE portfolio, the Company plans to update the budgets for these programs as part of its preliminary update, as the Company identifies the scope of the applications and support needed to meet the analytical requirements directed through the EE Order.

Q. Does the Company propose to add any personnel to manage its expanded programs?

A. Yes, in order for the Company to achieve its proposed EE portfolio by 2022, an increase in labor resources across a number of functions will be critical. In total, we forecast that we will need to add thirty-four (34) incremental full-time employees, as described by job function below, 16 incremental Full Time Equivalents ("FTE") to be added in 2020 or earlier, 11 incremental FTEs to be added in 2021, and 7 incremental FTEs to be added in 2022.

As discussed in more detail in the attached white paper, we proposed the following 34 incremental employees:

i. 14 incremental employees to expand and grow successful current programs that have potential for expansion and design, build and execute on newer and more innovative programs including through new delivery channels across customer segments, and engineering to provide technical support and advice to customers

ii. 6 incremental employees to manage program data and analytics

iii. 7 incremental employees to focus on managing the different budgets, compliance, and manage process optimization and controls

iv. 6 incremental employees to develop additional capabilities in Evaluation, Measurement and Verification

v. 1 incremental employee to focus on marketing communication and develop the portfolio's marketing communication strategy

Q. Has the Company compared its department to other utility departments in terms of number of employees?

A. Yes. We benchmarked our program with peer utilities that are achieving similar levels of EE achievement as a percentage of utilities sales.

Q. Are certain employees in the EEDM Department compensated differently than other Con Edison employees?

A. Yes, with respect to the variable portion of their compensation for the eight employees on the sales team.

Q. Please explain.

A. We recently started compensating some EEDM Department employees engaged in sales and business development on a commission-based variable pay structure. These employees are excluded from the Management Variable Pay ("MVP") Program applicable to all other Con Edison management employees.

Q. Why are these employees subject to a different variable pay program?

A. Given the public policy goals to significantly increase EE, the Company is working to build a performance and results driven EEDM sales organization that will create a robust sales pipeline. In analysis for this compensation shift, the Company reviewed the sales representatives pay levels and selling activities, investigated sales team compensation structures in energy services companies and general industry, and are proposing a sales incentive plan that aligns with the Company’s strategic and financial objectives, the responsibilities of the sales representatives role, and addresses the sales representatives’ earning opportunity with a strong pay-for-performance orientation. Under the commission-based variable pay structure, sales people will be compensated based on performance and the variable compensation can range from zero to twice the MVP level that they would otherwise be eligible for.

Q. Is the Company recovering these payments in rates?

A. No. As stated above, these employees are not part of the MVP and this compensation is not being recovered in rates. This means that the cost of this compensation is excluded from the MVP reconciliation under the current rate plan.

Q. Does the Company’s proposed revenue requirement reflect this commission-based variable pay?

A. No, it does not. As testified by the Compensation/Benefits Panel, these employees were excluded from the Company’s calculation of MVP for the Rate Year and no separate amount was included for projected commissions payable to these employees because the Company believes that this program is too new to reasonably forecast the amount of commissions that may be earned.

Q. How does the Company propose to recover commissions paid to these employees during the rate plan established in this proceeding?

A. The Company proposes to treat these commissions as EE program expenses recoverable through the Monthly Adjustment Clause for electric and through the MRA for gas. The Electric and Gas Rate panels have included information about the recovery mechanism of the new variable compensation.

Q. Does the Company propose any other changes to the Company's Schedule for Electricity Service, P.S.C. No. 10 – Electricity ("Electric Tariff") and Schedule for Gas Service, P.S.C. No. 9 – Gas ("Gas Tariff")?

A. Yes, the Commission's Order Adopting Whole Building Energy Data Aggregation Standard,[8] Electric Tariff Leaf 128 and Gas Tariff Leaf 118.1, are updated to reflect the new standard established in the Order, subject to

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[8] Case 16-M-0411, In the Matter of Distributed System Implementation Plans and Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vison, *Order Adopting Whole Building Energy Data Aggregation Standard*, issued April 20, 2018.

additional Terms and Conditions on the Company's website. The Company also proposes to update Electric Tariff leaf 355 related to the proposed conclusion of surcharge-funded EE programs as they are moved to base rates as ordered in the 2018 ETIP Order.[9] Finally, the Company proposes to eliminate Rider O – Curtailable Electric Service, which was added to the Electric Tariff in April 2003 as shown in Case 03-E-0112. No Customers have ever enrolled for service under Rider O and the Company has since implemented other DR programs such as Rider L - Direct Load Control Program and Rider T - Commercial Demand Response Programs with many participants in each of these programs.

Electric Vehicles

Q. Does Con Edison support State and local policy goals related to EVs?

A. Yes. The Company seeks to expand efforts related to EVs to facilitate expansion of the EV market in New York State consistent with State and local policy objectives for EVs, enabling progress towards the State's 2050 GHG goal. The State's EV policy goals are to enhance EV adoption through rebates, education, and incentives,

[9] Case 15-M-0252, In the Matter of Utility Energy Efficiency Programs, *Order Authorizing Utility-Administrated Energy Efficiency Portfolio Budgets and Targets for 2019 – 2020*, issued March 15, 2018.

expand accessible charging stations to 10,000 by 2021, assist in meeting ZEV vehicle targets, and expand interstate and urban fast charging stations.

Q. Why is Con Edison proposing investments that increase options for customers seeking to adopt EVs?

A. The Company believes that transition from a fossil-fuel based transportation system to electrified transportation is an alternative approach that can meet customers' needs for transportation options. Increased EV options will support public policy goals by providing important environmental benefits. Transportation electrification will provide a meaningful pathway to reducing GHG emissions with the additional potential to provide customers with reduced fuel costs. Additionally, more EV options can enable more efficient use of the electric system if the times of charging, and discharging when applicable, are optimized.

Q. What has the Company already done to advance EVs?

A. The Company has taken several steps to increase EVs. The Company has implemented: (i) a SmartCharge NY program to incent off peak EV charging; and (ii) an EV category under its Business Incentive Rate ("BIR") to promote Direct Current Fast Charging ("DCFC"). The Company has also received approval for a REV Demonstration project for EV school bus charging. Finally, along with the other New York State utilities and several State agencies, including the NYPA, the Company is proposing an incentive to assist DCFC.

Q. Does the Company have a proposal to further advance EV?

A. Yes. The Company is proposing in this rate filing to (i) expand access to public EV charging through implementation of an EV make-ready program; and (ii) continuing the SmartCharge New York program to charge EVs during off-peak hours.

Q. Does the Panel have an exhibit that discusses these two EV programs?

A. Yes. The Company has an exhibit entitled, "Electric Vehicle Charging," which was prepared under the Panel's supervision and direction.

MARK FOR IDENTIFICATION AS EXHIBIT __ (CES-2)

Q. What is make-ready infrastructure?

A. Make-ready infrastructure refers to the equipment associated with providing an electric service connection from Con Edison from the point of interconnection to the property line. Generally, customers with an existing electric service connection are responsible for costs to extend a new electric service to a new charging station. Such extensions can be costly, requiring extensive trenching and construction.

Q. Please explain the Company's proposal for make-ready infrastructure.

A. The Company is proposing a three-year program, at a cost of $10 million each year for a total of $30 million, to pay for interconnections and service line extensions costs for DCFC EV supply equipment that is installed on private property for public charging. The Company's efforts will result in development of delivery infrastructure enabling third parties to develop publicly accessible EV charging facilities on non-utility private properties that are not located in the public right-of-way.

Q. How would this program work?

A. Customers would file an application to qualify and demonstrate their intention to move forward with projects to build publicly-accessible charging stations (i.e., by installing their "property line box") and by meeting the terms of the BIR, which requires the EV-charging facilities be accessible to the public. The Company would process qualifying applications in a queue on a first-come, first-served basis. The Company would absorb the cost for the installation of the service facilities up to $10 million annually.

Q. How many stations would receive incentives under a $10 million per year program?

A. The median cost of a connection for an EV station with six 150 kW DCFC plugs in Con Edison's service territory is $900,000. We expect to connect approximately 11 stations annually, adding approximately 10 MW of DCFC capacity.

Q. Why is this make-ready program necessary?

A. For publicly accessible EV charging stations, the Company's analysis of the business case for third-party developers building DCFC stations indicates that the economic viability of such stations is closely tied to station utilization levels. The stations only become economically viable at utilization rates above approximately 25-30 percent. At this early stage of EV adoption in New York, vehicle counts, and consequently, demand for charging stations are relatively low. This results in a lower likelihood of charging stations reaching over 25 percent utilization, which discourages investment. However, without the buildout of adequate charging infrastructure, EV owners face the barrier of lack of adequate charging stations, which results in lower EV penetration rates. Accordingly, there needs to be sufficient publicly accessible charging infrastructure in place to enable increased adoption of EVs. The Company's proposal lowers the capital costs associated with charging station development and facilitates an accelerated buildout of third-party-developed charging stations, while leveraging Company strengths.

Q. Does the program require the Company to modify its Electric Tariff?

A. Yes. The tariff rules related to the extension of electric facilities must be modified to reflect this program and the electric service connections at no cost. Please see the Electric Rate Panel testimony for a description of this tariff change.

Q. Turning to the other program, please explain the SmartCharge NY program.

A. As explained in Exhibit __ (CES-2), Con Edison's SmartCharge NY program currently offers incentives to eligible EV drivers for charging in Con Edison's service territory at off-peak times and provides a one-time financial incentive for installing and activating a free connected car device from FleetCarma that allows users (and the Company) to know where, when, and how much energy an EV consumes during charge events. Participants receive additional fixed monthly incentives for keeping the device plugged in and charging within the Con Edison service territory.

Q. Please explain how the SmartCharge NY program helps Con Edison develop EV offerings for its customers?

A. The SmartCharge NY program helps Con Edison understand charging behavior and EV driver and fleet operator response to incentives.

Q. Does the Company plan to continue SmartCharge NY?

A. At this time, yes. We will continue offering this program to customers. However, we will continue to review the results and determine if other off-peak charging incentives are available or provide greater customer response. For example, for buses, the FleetCarma device is not necessary as buses will have communication capabilities.

Q. What is the current enrollment level for SmartCharge NY?

A. There are currently over 1,500 EVs enrolled in the program, comprised of privately-owned and fleet vehicles.

Q. Has the Company made any changes to the SmartCharge NY program?

A. On September 12, 2018, the Commission approved the Company's expansion of the eligibility criteria for the SmartCharge NY program to include medium- and heavy-duty vehicles, including buses.[10] The charge rates for medium- and heavy-duty vehicles are also typically higher, with

[10] Case 16-E-0060, Proceeding as to the Motion as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service ("2016 Con Edison Electric Rate Proceeding"), *Order Expanding Electric Vehicle Charging Program Eligibility*, issued September 12, 2018.

some buses charging at 500 kW. The Company believes it is important to understand and manage these loads through incenting customers to shift as much charging as possible away from system peak times. Based on the projected increase of new vehicles in this category, the Company anticipates requiring additional funds to continue implementation of an EV program focused on influencing and understanding customers' EV charging patterns.

Q. Has the Company seen any enrollment associated with medium and heavy duty vehicles?

A. The Company is working with State agencies and private fleets to enroll the first medium- and heavy-duty vehicles into the program. We expect about twenty vehicles to enroll in 2019, and that enrollment could increase to almost 250 by 2022 as electric transit buses are placed into service by the Metropolitan Transit Authority ("MTA"). Consequently, the Company anticipates that the EV program will constitute a greater proportion of medium and heavy duty vehicles in the future.

Q. What is the Company proposing to do in this rate case for SmartCharge NY?

A. The Company is seeking increased funding for the program over the prior three-year funding level. We are looking to increase funding for the program by $9 million over the amount authorized in the current rate period to a total of $15 million over the upcoming three year period.

Q. How does the Company propose to recover these costs?

A. The Company proposes all EV programs costs related to the SmartCharge program be treated as a regulatory asset, which provides for the recovery of the EV regulatory asset over ten (10) years using the overall pre-tax rate of return. The Company's Accounting Panel discusses the cost recovery framework.

Energy Storage

Q. What is Energy Storage?

A. Section 74 of the New York State Public Service Law defines storage as "commercially available technology that is capable of absorbing energy, storing it for a period of time, and thereafter dispatching the energy using mechanical, chemical, or thermal processes to store energy that was generated at one time for use at a later time."

Q. Has the Commission addressed energy storage recently?

A. Yes. The Commission recently issued its *Order Establishing Energy Storage Goal and Deployment Policy*[11] ("Storage Order") that discussed storage. The Commission concluded that storage can provide benefits to customers,

[11] Case 18-E-0130, In the Matter of Energy Storage Deployment Program, *Order Establishing Energy Storage Goal and Deployment Policy*, issued December 13, 2018.

including reductions in GHG emissions and other air pollutants and improvements to the efficiency and resiliency of the grid.

Q. Did the Commission establish an energy storage goal in its recent order?

A. Yes. The Commission set two storage goals. First, the Commission established a goal of the installation of 3,000 MW of storage in New York by 2030, with the deployment of 1,500 MW by 2025. Second, the Commission required the Company to issue a Request for Proposal in 2019 to procure the dispatch rights to 300 MW of bulk system connected storage to be sited in the Con Edison territory.

Q. What is the status of the energy storage market in New York State?

A. Although energy storage has the potential to play an important role in New York's clean energy future, the energy storage market is in the early stages of development. This market remains uncertain related to several issues -- technology maturity, wholesale market rules, permitting requirements, and economics. Additionally, the costs of batteries and other storage technologies are forecast to remain high relative to the system benefits and potential revenues they provide. These uncertainties are discussed in detail in DPS

Staff's New York Energy Storage Roadmap, filed in Case 18-E-0130.

Q. Is the Company pursuing storage in this case? If so, why?

A. Yes. Energy storage is a transformational technology that can provide numerous benefits to the electric system, and ultimately, to electric customers. Con Edison envisions a future state where storage provides support to the distribution system, enables the operation of intermittent renewable resources, and reduces GHG emissions and other local emissions.

Furthermore, as storage costs decline and use cases evolve, broader proliferation of storage will help customers and communities manage their usage to align with system capabilities, participate in DR, support integration of new applications, like EV charging, and respond to more cost-reflective rate designs, such as hourly pricing and demand-based rate structures.

Finally, the proposed investments will support the Commission's goals for energy storage deployment in part by supporting the development of the storage market in New York.

Q. Does the Company have any experience with installing energy storage systems?

A. Yes. While the energy storage market in Con Edison remains nascent, the Company has successfully procured and installed a battery rated at 2 MW and 12 MWh, the largest in our territory, on utility-owned land to support our BQDM effort.[12]

Q. Please describe the Company's proposed energy storage investments in this filing?

A. The Company is proposing a two-part strategy for energy storage. First, the Company intends to develop six energy storage facilities on Company locations. Second, the Company will develop one turn-key make-ready site for third-party storage developers.

Q. How much storage capacity will these two programs provide?

A. Together, the two project approaches will provide approximately 41.5 MW of load relief and up to 160 MWh of energy for discharge. In total, our six facilities will provide 31.5 MW and 120 MWh. The third-party-owned system will provide up to 10 MW and 40 MWh.

Q. Does this proposal support the State's energy storage deployment goals?

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[12] Case 14-E-0302, Petition of Consolidated Edison Company of New York, Inc. for Approval of Brooklyn/Queens Demand Management Program, issued January 22, 2015.

A. Yes. The Company’s proposed projects will advance the deployment of storage in New York by building and testing scalable market capabilities, while also providing key learnings about the grid benefits. The proposed utility-sited projects provide a near-term path to developing a more robust storage market, testing storage for potential grid applications, and continuing to address permitting issues. The use of utility land can accelerate project development timeframes and reduce or eliminate some implementation costs – including soft costs like customer acquisition, siting, permitting, and interconnection. We note that the proposed projects will provide storage manufacturers and service providers with actual, shovel-ready opportunities.

Q. Has the Company prepared an exhibit that discusses its energy storage plan?

A. Yes. There is a white paper entitled ”Utility Energy Storage.”

MARK FOR IDENTIFICATION AS EXHIBIT __ (CES-3)

Q. Was this exhibit prepared under the Panel’s direction and supervision?

A. Yes.

Q. Why is the Company proposing two different types of energy storage ownership models?

A. Con Edison expects that ultimately the New York energy storage marketplace will include a combination of utility-owned, customer-owned, and third-party owned energy storage, both in front of the meter ("FTM") and behind the meter ("BTM"). As a result, it is important to test different ownership models.

Q. Why is the utility proposing distribution system connected investments?

A. As the New York State Energy Storage Roadmap indicates, energy storage can provide unique values at different locations in our energy system. Smaller storage assets procured under existing and future NWS and Demonstration Projects will be installed at customer properties at lower voltages. On the other hand, the larger assets installed under the forthcoming bulk storage procurement will likely be interconnected at higher voltages. Even with these procurements, there is a gap for utility-scale systems on the distribution system at intermediate voltages. The investments proposed here address that gap so that a diverse portfolio of storage procurements is established along with the associated learnings around procurement, development, and operation of these assets, including for distribution level use cases at intermediate voltage classes.

Q. Why does Con Edison propose to own the six storage systems?

A. The REV Track One Order[13] permits utility ownership for storage integrated into the distribution system because the Commission recognized the usefulness of energy storage as a distribution system asset meeting key system needs. Utilities are best positioned to identify, develop, and procure solutions to distribution system needs. Storage can and should serve as an important option in the utility "toolbox."

Additionally, the six proposed sites are substation properties that house critical electrical infrastructure. Allowing third parties access to operations at the site will introduce potential personal safety and security concerns and risks.

While these six proposed storage facilities will be utility-owned, the Company will issue competitive solicitations allowing battery developers to submit proposals to design, implement, and commission the battery systems, similar to the process followed for the battery rated at 2 MW and 12 MWh in the BQDM area.

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[13] Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, *Order Adopting Regulatory Policy Framework and Implementation Plan*, issued February 26, 2015.

Further, there exist opportunities for customer- and developer-owned assets through NWS, the forthcoming bulk storage procurement, and the Nevins Street make-ready site. Put in context, the proposed Company-owned storage systems with capacity and energy ratings of 31.5 MW and 120 MWh are roughly 10 percent of the 300 MW and 1,200 MWh of the forthcoming bulk storage procurement alone and just over 2 percent of the 2025 State-wide storage goal.

Q. Turning to the first storage program, please describe the six proposed energy storage facilities.

A. These locations, which are dispersed across three operating regions to address a diverse set of use cases, discussed below, will enable the Company to broaden its expertise for future deployments. The proposed locations and projected performance are listed below and not ranked in any specific order of deployment.

Table 4 – Proposed Storage Locations

Region	**Location**	**Facility Type**	**Power (MW) / Energy (MWh)**	**Estimated Capital Cost ($M)**	**Estimated Start date for Remediation/ Construction**
Brooklyn/ Queens	Richmond Hill	Unit Substation	6 / 12	10.4	2020
	Long Island City	Area Substation	3 / 12	9.9	2021
Staten I0sland	Fresh Kills	Area Substation	9 / 36	25.7	2021
	Fox Hills	Future Use	7.5 / 30	21.7	2020
Bronx/ Westchester	New Rochelle	Area Substation	2.4 / 12	8.6	2021
	Millwood	Substation	3. 6 / 18	14.1	2020
TOTAL			31.5 / 120	90.5*	

Note: Capital costs do not sum due to rounding

Q. How does the Company propose to deploy these assets?

A. In 2020, we will start the procurement process for a system at the Richmond Hill site in Queens. Con Edison has already received Board of Standards and Appeals approval for a battery installation at this site because this site was considered as an alternative for the BQDM 2 MW and 12 MWh battery system. We also began work on the permitting process with the Fire Department of New York and Department of Buildings at this location. Given the process that is underway, starting deployment at the Richmond Hill site is an efficient way to jumpstart the Company's storage deployment.

In parallel, starting in 2020, we will begin the preparation of the other five sites, including any necessary remediation activities, with a goal of beginning construction on a second site in 2021 and the remaining sites in 2022. A more detailed deployment schedule cannot be provided at this time due to uncertainties in the remediation activities required and the local permitting process and requirements across the different city and municipal agencies, both of which can significantly impact project schedules.

Q. What are the in-service dates for these energy storage systems?

A. The energy storage devices at the six utility-owned sites are estimated to be in service by 2025 or earlier. The make-ready site is estimated to be in service by 2021.

Q. What is the proposed O&M expenditure during the rate period?

A. The O&M expenditure projected over the three rate years will total $15.5 million, including $11.5 million for remediation at the six sites and $4.0 million for operating and maintaining the systems.

Q. Does the Company have a proposed recovery method for the six energy storage locations?

A. Yes. The Company is seeking to recover all development and implementation costs of this grid support asset as a Company-owned asset.

Q. How were the six sites selected from a list of eligible sites?

A. The sites were selected with the goal of identifying available land in diverse geographical regions with an array of energy storage use cases where the systems may also provide system benefits. Larger-size sites were prioritized since they likely allow for lower unit cost of the overall storage installation through economies of scale, provide greater operational flexibility through various discharge modes (which can extend the life of the storage systems), and improve the cost effectiveness of battery installations to the benefit of our customers. Additionally, we selected locations that are within networks and load areas experiencing load growth and other current or potential needs storage may address, but which have not yet triggered an NWS solicitation. The Company will continue to adjust the criteria for installing energy storage based on its experience as it develops these proposed sites.

Q. Please explain the need to have diverse locations and use cases.

A. The diversity in location and use cases will allow for key learnings around factors affecting energy storage deployment and operations, such as construction considerations, managing relationships with the local communities, permitting requirements, and operations at different voltage classes and in regions with different load profiles.

Q. Please describe the diverse use cases the six storage systems will address.

A. The batteries will follow a variety of operational profiles depending on the local needs at the point of interconnection to address peak shifting, load ramping, and contingency response use cases. Battery systems in areas where local capacity is more limited will follow a peak shifting profile where the batteries charge overnight when prices and GHG emissions are relatively low, and then discharge during the day or evening during the local network peak. The systems installed in areas with growing solar penetration, such as those in Staten Island and Westchester, will address voltage management challenges associated with a duck-curve type load profile developing in these regions. This load profile contains a relatively steep evening ramp as solar generation wanes and local loads increase, creating the potential for voltage issues. Finally, in regions where a system contingency can cause voltage issues within a load area, the storage assets can be discharged to maintain reliability in lieu of the current operational measure in which diesel generators are deployed.

Q. Is there potential for modifications to the list of six deployment sites?

A. Yes. The Company will conduct a more detailed construction review before final site selection. The Company seeks the approval to pursue the proposed opportunities at the selected locations or at an alternate location if the Company, as it begins project implementation, determines an alternate location to be more suitable.

Q. If the Company receives any revenues for operations at these six storage facilities how will Con Edison manage them?

A. Any potential revenues received by the Company, such as wholesale market revenues, will be deferred to the next rate case, subject to any applicable Company incentives.

Q. Please explain the second proposed storage investment.

A. The Company proposes to build a turnkey energy storage docking facility at the Nevins Street property for third-party-owned energy storage. The Company will prepare the land, including any remediation and grading, extend distribution system feeders onto the land, and install interconnection hardware to accommodate up to 10 MW and 40 MWh of energy storage. The Nevins Street make ready investment is described Exhibit __ (EIOP-4).

Third-party storage developers will submit bids for access to the docking facility and interconnection, and winning developers will install, own, and operate their storage assets. This arrangement will provide a unique opportunity for the Company to collect revenues to offset docking station project costs while also allowing third-party developers the flexibility to leverage the storage systems for grid services, New York Independent System Operator ("NYISO") market services, or other applications. Additionally, DCFC EV chargers will be co-located on the site, allowing the Company to gain a better understanding of how energy storage can help mitigate the impact of EV charging on the grid. These EV chargers will be deployed and funded by a Demonstration Project and no funds for these chargers are requested here.

Q. How does the Company plan to recover the costs for this project?

A. The Company is seeking to recover all development and implementation costs of the turnkey energy storage project as a Company-owned asset. The EV charger costs will be recovered through the Demonstration Project as noted above. Before entering into a lease agreement with the third-party storage developers for access to the make-ready facility, we plan to file a petition under Section 70[14] which will include, among other items, a proposal to address revenues collected under the lease agreement.

Q. Why is the Company proposing FTM projects?

A. Investment and policy action to support FTM distribution system and bulk system deployment use cases will produce significantly higher overall benefits for all customers than untargeted BTM customer sited deployments. Both the distribution system and bulk system FTM use cases allow for the development of larger and more economic storage installations (on a per MW and per MWh basis, as recognized in the New York State Energy Storage Roadmap) that can be targeted to meet electrical system needs while also preparing our system for greater levels of intermittent renewable integration. Although customer-sited applications can provide grid benefits, particularly, when located in constrained areas and operated during grid need times, installations that are

[14] Public Service Law Section 70 requires a company to obtain Commission approval before disposing of its property; the granting of a lease is considered a disposition requiring Section 70 review and approval.

primarily operated to mitigate customer bills (for example, demand charges) offer fewer benefits to the system.

Q. Is the Company considering any customer sited BTM models?

A. Con Edison will continue to consider BTM storage through NWS and Demonstration Projects as well as support BTM storage interconnection requests. Additionally, the Company will continue to evaluate new storage opportunities, including BTM applications that can provide broad grid and customer benefits.

Distributed System Platform Implementation

Q. What is the DSP and what services does it provide?

A. New York's REV initiative is moving the electric industry forward to a sustainable energy future. This transformation includes increased market penetration for DER to focus on customer choice and participation and facilitates advances in technology, DER integration, and enables customer choice. The Company filed its second DSIP on July 31, 2018 in Case 16-M-0411 as a comprehensive roadmap to achieving its vision for the DSP. The Company's development of the DSP will allow it to offer the platform services necessary to evolve the distribution system. These services will enable the bi-directional flow of energy resulting from the growth of

DER and facilitate transactions to support market opportunities for DER.

Con Edison is building the DSP through investments in the people, processes, and systems that allow Con Edison to provide three core, interrelated platform services described below:

- **DER integration services** are the planning and operational enhancements that promote streamlined interconnection and efficient integration of DER, while maintaining safety and reliability.
- **Information sharing services** are information and communications systems that collect, manage, and share granular customer and system data, enabling customer choice and expanding third-party vendors' and aggregators' participation in markets for DER.
- **Market services** are utility programs, procurement, wholesale market coordination, and tariffs that create value for DER customers through market mechanisms.

Q. Please continue.

A. The projects included in this rate filing as DSP investments are incremental elements required to support the functionalities that will enable Con Edison to serve as the DSP Provider. Several of these investments (Modernizing protective relays, Volt VAR Optimization

("VVO"), and DER Management System ("DERMS")) are aligned with and enabled by Con Edison's Grid Innovation Roadmap, which is further described in the EIOP testimony.

Q. Do you have a document that explains the projects being proposed for the DSP?

A. Yes. We have developed a white paper entitled "Distributed System Platform."

MARK FOR IDENTIFICATION AS EXHIBIT __ (CES-4)

Q. Was this document prepared under the Panel's direction and supervision?

A. Yes, it was.

Q. Please describe steps the Company has already taken to develop its DSP and enable greater DER penetration.

A. Company investments have already supported significant progress in implementing the DSP. The full list of DSP achievements is included in Exhibit __ (CES-4), and an excerpt of notable accomplishments is included below:

- Installed advanced network protector relays that allow reverse power flow on network systems, increasing the amount of DER that can be hosted on a circuit.
- Installed VVO controllers and communicating modems at 150 4kV unit substations necessary for executing VVO capabilities in the 4kV grid.

- Implemented the Interconnection Online Application Portal ("IOAP") and developed hosting capacity maps to provide developers valuable information and streamline the interconnection process.

Q. Has market participation increased?

A. Yes. The Company's investments have resulted in greater integration of DER into the Company's planning and operations processes, such as forecasting, engineering, and area station planning to include NWS, and determining hosting capacity. These processes have enabled greater market penetration of DER than would have otherwise occurred. Since January 1, 2016:

- The amount of installed solar capacity connected to Con Edison's distribution system has doubled to approximately 190 MW Alternating Current.
- There are now over 20,000 rooftop solar installations in Con Edison's service territory, approximately double the amount in 2016.
- Customers can share their usage data with authorized DER developers through the Green Button Connect My Data, which will be enhanced as AMI is fully deployed.

Q. Please continue.

A. These achievements demonstrate Company progress from its Initial DSIP[15] and provide a solid foundation for continued development.

The net effect of all these efforts is DER totaling over 500 MW in capacity in the Company's service territory. This amount will help offset peak demand growth increases driven by population growth, economic development, and new technologies, such as EVs.

Q. Is the Company proposing changes to the Electric Tariff to promote DER and DER interconnection?

A. The Company is proposing a number of tariff changes to facilitate DER interconnection, as described below.

- General Rule ("GR") 8.2, Emergency Generating Facilities Used for Self Supply, has been amended to allow electric energy storage used as an emergency generating facility to be connected to the grid as long as it is not exporting. As this rule is currently written, an emergency generator cannot operate in parallel with the grid. With the increased use of energy storage as an emergency generator, this would preclude the charging of electric energy storage

[15] Case 16-M-0411, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Initial DSIP Con Edison, (filed June 30, 2016).

used as an emergency generator. Importantly, this change maintains the ability of customers with electric energy storage to apply for parallel service under GR 20 and/or Rider R service.

- GR 8.3, Generating Facilities Used under Special Circumstances for Export, currently states that a customer may not deliver to the Company's distribution system while the customer receives electric energy delivered by the Company. This section has been amended to specify that a customer may not deliver to the Company's distribution system while it is receiving electric energy delivered by the Company at the same point. This change allows customers with multiple service points to export from their DER at one of their service points while still importing energy at another.
- The Company proposes a number of changes to Form G[16] to clarify the application language and streamline the application process. Specifically, the Company created a separate section in the Targeted Exemption and Rider Q forms for applicants to certify their eligibility. The Company is requesting additional

[16] Changes are proposed to Leaf Nos. 382.1, 383, 384, 384.1, 385, 385.0.1, 385.1, 386, 386.0.1

information regarding Contract Demand under GR 20 to track any revenue differences from Contract Demand under Rider Q Option A.

The Electric Rate Panel further discusses these tariff changes.

Q. What is the Company's proposed DSP investment in this rate filing?

A. The Company proposes to invest $35.2 million in capital in each of the three rate years. In addition to this capital request, the Company proposes an O&M investment of $7.5 million in total across a three year rate period. The O&M costs per year are $2.1 million in RY1, $2.6 million in RY2 and $2.9 million in RY3.

Q. What investments is the Company proposing in the filing and in this case?

A. The investments proposed for DSP development are intended to build upon and continue the Company's work in this area. The DSP investments are grouped and discussed using a framework in three categories, with several components under each overall category:

- DER Integration
- Market Services
- Information Sharing

Q. What are the proposed programs and expenditures?

A. The proposed DSP investments are shown in the table below:

Table 5 - DSP Capital Requests ($000)

Component	**Investment**	**2020**	**2021**	**2022**	**Total**
DER Integration	VVO	$14,300	$14,300	$14,300	**$42,900**
	Modernize Protective Relays	$12,600	$12,600	$12,600	**$37,800**
	IOAP	$1,300	$1,300	$1,300	**$3,900**
Market Services	DERMS	$2,800	$2,800	$2,800	**$8,400**
	DMTS	$1,600	$1,600	$1,600	**$4,800**
	DRMS	$1,300	$1,300	$1,300	**$3,900**
	DMAP	$1,300	$1,300	$1,300	**$3,900**
Information Sharing	Web Service Interface	$0	$0	$0	**$0**
	Total	**$35,200**	**$35,200**	**$35,200**	**$105,600**

Q. Are there any O&M costs associated with these capital investments?

A. Yes. Three of the programs require O&M expenditures:

- DMTS ($1.7 million in RY1, $2.0 million in RY2, $2.3 million in RY3)
- DMAP ($0.2 million in RY1, $0.3 million in RY2, $0.3 million in RY3)
- Web Service Interface ($0.2 million in each rate year)

Q. Before discussing the projects, please explain the relationship between the Company's DSP investments and its Grid Innovation investments described in the EIOP testimony.

A. The Company's DSP investments are part of a holistic and comprehensive plan to modernize the grid. The Company's Grid Innovation Roadmap complements and enables DSP investments to develop capabilities and deliver benefits to customers in both the short term and the long term. Through the Grid Innovation initiative, the Company is building capabilities to facilitate a more dynamic integrated grid. Grid Innovation investments serve to develop a number of capabilities, beginning with foundational investments that both provide immediate benefits while also enabling future capabilities. Some Grid Innovation investments are foundational for capabilities developed through DSP initiatives, for instance, a Geographic Information System ("GIS"), described by EIOP, is necessary to implement a DERMS.

DER Integration

Q. Please elaborate on the DER Integration category.

A. DER integration refers to planning and operational enhancements that promote integration of additional DER. There are two key elements for DSP DER integration services - interconnection and operations. For interconnection, the goal is to safely, securely, and timely interconnect DG and energy storage to the distribution system.

Operationally, the goal is for safe and reliable operation of the distribution system as more DER, energy storage, EVs, and electric heating loads connect to the system.

Q. Please discuss the projects in the DER Integration category.

A. We discuss VVO and Modernizing Network Protector Relays in this testimony. IOAP/Hosting Capacity is explained in Exhibit __ (CES-4).

Q. Please describe the VVO project.

A. VVO is a set of voltage management capabilities, which includes both Conservation Voltage Optimization ("CVO") and reactive power management. The primary purpose of VVO is to maintain the proper voltage levels along distribution feeders under different loading conditions. Currently, there may be a higher level of voltage at the beginning of a feeder closest to the substation, and a lower level of voltage towards the end of the feeder. AMI data will provide voltage level visibility at the customer meter. This information will advise the Company where equipment, hardware, and communication upgrades will be required to optimally manage voltage under various loading conditions and greater DER penetration.

Q. Please continue.

A. Optimally managing system voltage levels increases system efficiency by regulating the voltage to adequately serve the points at the grid edge, while not oversupplying the points closer to the substations. VVO enhances control of voltage along distribution feeders, which, in turn, provides GHG reductions, customer energy usage savings, and allows for greater penetration of DER on the system, particularly in non-network areas where solar potential is greater and improved voltage control may increase hosting capacity.

Q. Does VVO assist with other technologies?

A. Yes. VVO functionality supports the penetration of solar photovoltaic ("PV") systems with smart inverters. The smart inverters are able to control the output of the PV system's active and reactive power. This can help balance active and reactive power, which protects customer and utility equipment, and improves grid efficiency by reducing line losses.

Q. How is VVO enabled?

A. This investment uses granular AMI data along with IT systems interfacing with the AMI platform. It also is enabled by system electrical equipment, hardware, and communications upgrades. Using this information helps determine if additional equipment is necessary to improve voltage levels.

Q. Please continue.

A. The full execution of VVO involves an evolution of capabilities in several phases that extend beyond the rate period. The first phase, and the focus of this rate period, comes from receiving the AMI data from the grid edge to set baselines across various load areas, and this will be done in parallel with equipment upgrades described below. Later phases involve more dynamic and distributed voltage control, and require additional voltage control equipment, real-time data analysis, and system integration.

Q. What VVO work has been completed to date?

A. Hardware and communication upgrades at 4kV Unit Substations have begun and all 224 of these substations will be completed by December 2019.

Q. What VVO work will take place during the rate period?

A. Work enabling VVO during the rate period involves:

- Installing additional VVO equipment at targeted area substations,
- Integrating this equipment to the back-end systems as more VVO-driven Supervisory Control and Data Acquisition ("SCADA") endpoints are created for operators to consume and visualize the VVO data, and

- Monitoring area substation meters for voltage and current levels at the area substation bus provides visibility to system operators so they can adjust voltage as required, keeping it within specifications.

Q. Why is visibility important?

A. Visibility is important because an understanding of the voltage at the grid edge is one of many inputs for optimizing voltage using VVO on the distribution system. In addition, as DER penetration increases, the Company will require dynamic capabilities to maintain optimal voltage and reactive power under various load conditions. To provide more granular voltage measurements necessary to enable VVO, the Company will target metering and SCADA equipment replacements at older (pre-1980) substations. This work is also required to verify the energy savings achieved through AMI-enabled VVO capabilities.

Q. What are the benefits of implementing VVO?

A. VVO benefits are closely related to the CVO benefits that will be achieved through the AMI implementation, as outlined in the AMI business plan.[17] The CVO benefits in AMI target a 1.5 percent aggregate energy savings,

[17] Case 15-E-0050, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, Con Edison Advanced Metering Infrastructure Business Plan, filed November 16, 2015.

however, in local pockets taking action on AMI data is not possible without the SCADA monitoring and metering equipment installed under this initiative.

Q. Please describe the Modernize Network Protector Relays project.

A. The Modernize Network Protective Relays project continues and scales up the installation of these relays, which started in 2017, to complete approximately 400 installations per year in 2018 and 2019. Simply put, and as more fully explained in Exhibit __ (CES-4), upgrading the network protector relays allows DER to safely backfeed into, *i.e.*, export, to the grid, and provides communications capability that is not available on existing network protector relays. Network protector relays on network transformers were originally designed for one purpose: to interrupt (commonly referred to as "clear") "backfeed," or stop the flow of power, from the associated low voltage network back onto the faulted portion of the grid. In a traditional electric distribution system, this uni-directional power flow design was a check so that backfeed from fault conditions would be cleared or stopped so as to avoid system or safety issues. However, when DER are providing power to the grid, they too can backfeed and open the network protector relay, *i.e.*, disconnect the DER from the grid.

To avoid these DER-related network protector relay operations, the DERs’ size was previously constrained so they could not export to the grid. The modernized, communicating network protector relays enable bi-directional power flow, afford the Company greater operational flexibility, and expand DER hosting capacity. As DER penetration increases, this capability becomes more important.

This project represents an opportunity to further use the AMI network in transformer vaults, which house the network protectors. The Company is currently testing the performance of AMI network communications for SCADA operations. Pending successful testing, through developing a robust SCADA system using AMI infrastructure, the Company gains an ability to implement advanced monitoring and remote control of its 27,000+ network protectors. This provides several fault identification and DER enablement benefits, discussed later.

Q. What is the scope of the Modernize Protective Relays project?

A. As mentioned above, this is a continuation and scale up of a multi-year program begun in 2017. To date, the Company has installed approximately 500 modernized network protector relays and 30 relays with SCADA capabilities, and projects the installation of an additional 400 by the end of 2019. During 2020-2022, the Company will complete approximately 600 network protector relay installations per year and an additional 200 relay upgrades per year with SCADA capabilities. In addition to the installations, enhancements to the back-end SCADA systems will be required to consume the data and provide visualization for engineers and operators. Because the total population of network protector relays is over 27,000, the Company prioritized installation in the locations where DER potential is highest, or where the load area is most constrained.

Q. Please describe the benefits associated with this project.

A. The benefits include increased system visibility, faster identification of feeder faults, reduced secondary faults, SCADA enablement, and soft transfer trip capability - which allows a trip signal to be sent to the respective network protectors on a feeder, and can reduce the number of times a feeder remains alive on backfeed ("ABF"). These benefits promote employee and public safety and well as enable resiliency.

Additionally, by installing these relays proactively in prioritized areas, this approach increases hosting capacity, facilitates lower cost interconnection, and enables DG customers to supply more energy to the system.

Market Services

Q. Please describe the Market Services category.

A. Market Services refers to functionality that enables greater access to market value through DER procurement, programs, and pricing. As described in the Company's 2018 DSIP filing, the Company has divided market services in four categories: procurement, market coordination, wholesale tariff, and settlement and billing. There are four projects that fulfill goals in one or more of these categories providing market services: DERMS, DMTS, DRMS, and DMAP. The DERMS and DMTS projects are described further below and the other two projects are discussed in Exhibit __ (CES-4).

Q. Please describe the DERMS project.

A. DERMS is a software solution designed to provide DER asset management, planning and forecasting, and monitoring and dispatch capabilities.

Q. Please describe DERMS efforts to date.

A. The Company has begun its implementation of DERMS. In 2017, the Company performed a benchmarking assessment of how peer utilities were thinking about DERMS implementations. The benchmarking effort, combined with a market assessment of vendor offerings, demonstrated that there was no available COTS offering suitable for the Company's network design. The Company also undertook requirements gathering to identify DERMS use cases, and a current and future state assessment based on those requirements.

Q. Please describe the next steps for DERMS during the rate years.

A. Based on the fit gap assessment, DERMS functionalities were divided into four phases: (i) DER Asset Management, (ii) DER Planning and Forecasting, (iii) DER Monitoring and Dispatch, and (iv) DER Markets and Settlement. For the rate period, work is focusing on phases (i) and (ii), to integrate planning functions with DER data capabilities in a DERMS environment. The Company will also pilot reliability and market optimization/dispatch work that will commence between 2020 and 2022. This phase of DERMS will include investments in software as well as communications, monitoring, and control infrastructure that will be vital to the real-time operation of DERMS.

Q. Please describe the benefits of DERMS.

A. DERMS will enable a holistic view of the various types of DER on the system and provide an automated process for visualizing and understanding DER as it is considered in the Company's planning process. DERMS will enable the

Company to understand the status and capabilities of DER on its system and will provide important data to the Company's Distribution Management System, and other key applications, such as GIS and DRMS. These capabilities will help the Company better manage an increasingly complex and bi-directional electric system.

The DERMS will also leverage many of the investments made between 2016 and 2018 in Hosting Capacity and IOAP projects as well as investment to be made through GIS, through registration of DER and mapping and visualizing that DER to real-world coordinates (described in the EIOP testimony, Grid Innovation section). This means that much of the valuable work already completed relative to the point registration and visualization of DER will be used for DERMS.

Q. Please describe the DMTS project.

A. DMTS currently tracks and records the performance of the Company's EEDM portfolio achievements. The DMTS serves as an important system of record and results in improved data governance related to reported achievements such as EE savings published in quarterly scorecards. Since it was put in production in 2014, the Company has increasingly relied on DMTS to track, record, and verify EE savings.

Q. Please describe the Company's plans for DMTS during the three year rate period.

A. The Company will expand DMTS capabilities, including enhancing Customer Relationship Manager functionality, developing and implementing an EE Measurement and Verification module, developing and expanding financial forecasting tools, and implementing new EEDM programs that are developed to reach EE targets. This work will also include maintaining DMTS as a repository and the system of record for reporting information related to EE and demand side programs, measures, and individual customer project data.

Q. Are there O&M costs associated with DMTS during the rate plan?

A. Yes. Four employees currently part of DSP capital funding authorized in the current rate plan will be moved to O&M as they will maintain and further develop the DMTS.

Information Sharing

Q. Please describe the Information Sharing category.

A. Information sharing refers to information technology enhancements that enable customer choice and participation of third-party vendors and aggregators in markets for DER. These investments either leverage or improve upon existing assets or are allocated for new systems that support required DSP functionality. The initial investments focus on building the necessary interfaces to engage customers, increase the volume and granularity of data, and enable greater DER penetration. There is one project in this category, Web Services Interface, described in further detail in Exhibit __ (CES-4).

Targeted Initiatives to Defer Electric Infrastructure

Q. How do targeted initiatives to defer electric infrastructure support the overarching CES objectives?

A. In addition to meeting locational load relief and reliability needs, the deployment of NWS can contribute to (i) reducing GHG and other emissions; (ii) enabling customers to leverage DERs to better manage their energy use; and (iii) providing valuable experience about the integration, implementation, and use of aggregations of DER, including use of advanced technologies, such as batteries and building management systems capable of delivering peak load reductions.

Q. Could you briefly describe what an NWS is and the benefits it provides?

A. An NWS is a cost-effective portfolio of non-traditional, typically customer-side solutions, that enable the elimination or deferral of a traditional asset that would be required to meet a reliability need. The Company implements NWS in an identified area of locational need where the NWS portfolio serves as an alternative to a traditional infrastructure solution. We develop NWS portfolios that are generally comprised of a variety of DER solutions that collectively satisfy the Company's ability to meet the customers' electric need in that area. In addition to deferring or eliminating the traditional solution, benefits can include decreased energy and capacity costs from the wholesale market, reductions in GHG emissions, marginal cost reductions to upstream transmission and distribution equipment as well as others described in the Benefit Cost Analysis Handbook ("BCAH").[18]

Q. Is the Company implementing NWS projects?

A. Yes. Con Edison remains committed to identifying and implementing cost-effective NWS projects. To date, in addition to the 41 MW of customer-sited solutions originally sought under the BQDM program, the Company is pursuing two new NWS projects representing 34 MW of required load relief, and is continually evaluating all suitable traditional projects for additional NWS opportunities.

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[18] Case 16-M-0411, In the Matter of Distributed System Implementation Plans, Con Edison Benefit Cost Analysis Handbook, issued July 31, 2018.

Q. Are there any NWS projects planned during the three rate years?

A. Yes. We have two NWS projects that the Company plans to implement to defer or eliminate traditional projects that would have been built within the rate plan years.

Q. Please briefly describe the BQDM program and its successes to date.

A. On December 12, 2014, the Commission issued its Order approving the Company's BQDM Program. Con Edison designed the BQDM Program to address a forecasted overload condition of the electric sub-transmission feeders serving the Brownsville No. 1 and 2 substations with a combination of traditional utility-side and non-traditional customer and utility side solutions.

Since then, the Company has been implementing the BQDM Program and achieving demand reductions while remaining under budget. The Company has achieved over 50 MW of peak hour non-traditional utility side and customer-side solutions.

We have achieved a majority of this load relief through installation of efficiency and DM measures at more than 6,900 small businesses, 1,770 multi-family buildings, 24,000 one-to-four family residences, and various commercial properties in the community.

Q. Is the Company proposing to alter cost recovery for BQDM?

A. No. The Company proposes to continue the existing BQDM cost recovery mechanism, which provides for recovery over ten years and a reconciliation subject to an overall program cap. BQDM implementation has been successful and the Company anticipates that the total cost of BQDM measures will be under the cap. As a result, the amount of requested BQDM recovery has decreased in this rate filings.

Q. Turning back to NWS, how does the Company identify NWS opportunities?

A. The Company performs the following as part of the distribution planning and NWS identification process:

i. The Company reviews load forecasts at least annually to identify areas on the electrical system with forecasted overloads where there is a projected need for load relief to maintain reliability.

ii. The Company performs an engineering analysis to identify and evaluate the traditional utility infrastructure solution.

iii. Separately, if the Company considers the need to be a suitable candidate for an NWS, the Company conducts a competitive solicitation for non-traditional solutions to determine if an NWS is feasible.

iv. If an NWS appears feasible for meeting the load relief need, the Company analyzes solicitation responses to determine if there is potential for a cost-beneficial NWS.

v. If the Company identifies a feasible, cost-beneficial NWS, it implements the portfolio and defers or eliminates the need for the traditional solution.

Q. How does the Company evaluate whether an NWS portfolio is cost-effective?

A. The Company evaluates an NWS portfolio using the Societal Cost Test ("SCT") defined in the BCAH. When the Company has reasonable certainty regarding NWS portfolio costs, it makes a BCA filing in accordance with its BCAH.

Q. Once cost-effectiveness of the portfolio is established, when does the Company begin implementation of an NWS?

A. The Company begins implementation after it has reasonable certainty that the portfolio passes the BCAH SCT. As the project progresses, the Company also updates implementation plans if a material increase or decrease of the amount of load-relief is warranted, or if there is a change in the length of the deferral period. As discussed below, the Company does not need Commission approval to implement a specific NWS project.

Q. How does the Company determine an NWS term?

A. The Company defines the beginning of an NWS to be the time when the Company has identified a viable cost-effective portfolio with reasonable certainty. The

Company defines the end of an NWS as the time when it has achieved the deferral or elimination of the traditional project that the original NWS portfolio had sought. If the Company determines that there are additional deferral opportunities for the same, or a new, reliability need in the same area where a prior NWS has ended, the Company will seek to develop a new NWS to enable that deferral.

Q. How does the Company classify an NWS as either a deferral or elimination of traditional infrastructure?

A. The Company classifies an NWS to be a deferral, and not elimination, if the traditional solution is still needed within the Company's 20-year plan. For those NWS that we forecast to defer the traditional infrastructure need beyond the Company's 20-year plan, the Company will use its best engineering judgment and, in consultation with Staff, either classify it as a deferral or elimination. If such an NWS is classified as a deferral, the Company will consider the traditional asset to be deferred to the 21st year, the first year beyond the Company's 20-year plan. Further, in the specific instance when a traditional project is needed for a certain number of years, i.e., the traditional project temporarily serves a reliability need and functions as a bridge to another traditional project further into the future, the Company will classify an NWS as elimination when that NWS enables the entire elimination of the need for the temporarily needed traditional project.

Q. Has the Company identified any NWS opportunities to implement in the near term that could potentially defer or eliminate otherwise necessary capital expenditures for traditional electric infrastructure?

A. Yes. The Company had identified two potential NWS opportunities that it had begun implementing as outlined in the table below. We will pursue the Water and Plymouth Street projects as one project as the load relief needs at both stations are required to eliminate common work at the supply station. As such, the portfolio will be pursued as one 32 MW portfolio. The Company has made the appropriate filings for these NWS and has moved ahead with them in accordance with the terms of its current rate plan.

Q. How is the Company proposing to recover the costs of these projects?

A. The Company is planning to recover the carrying costs for these projects in base rates. The Company has not included the capital costs of the traditional projects in this rate filing because the Company is planning to pursue these NWS projects as an alternative to these projects.

Q. Has the Company included the costs of these NWS projects in this rate filing?

A. No. The Company will include the costs of these projects in its preliminary update, after it has more certainty of the amount and timing of the payments for customer-side solutions. We are currently evaluating the RFP responses for development of a viable NWS portfolio this project. If, however, the Company determines that any of these NWS projects are not feasible, then the Company will include the cost of the traditional project in its preliminary update. Further, if the Company determines it is unable to fully implement the NWS during the rate plan period and instead needs to implement the traditional project, the Company proposes to adjust the electric net plant reconciliation, as discussed in the Accounting Panel testimony.

Q. Is the Company seeking approval for the costs of these NWS in this rate filing?

A. No. Under the Commission's NWS framework as approved in the Targeted Demand Side Management Order on December 17, 2015 in Case 15-E-0229, and as incorporated into the Company's current rate plan, the Commission does not approve individual NWS portfolios.

Q. Please provide a brief description of the Water Street and Plymouth Street NWS project.

A. The Water Street Substation, located in Brooklyn, supplies power to the Williamsburg and Prospect Park networks. The Plymouth Street Substation, located in Brooklyn, supplies power to the Borough Hall network. Per the Company's analysis, the substations will need a total of up to approximately 43 MW and 30 MW of load relief respectively, over the next 10 years.

To alleviate the projected deficiency using traditional infrastructure enhancements, a combination of two necessary traditional solutions were identified. The first traditional project would require installing cooling systems on the transformers at both substations as well their supply station, Farragut Substation. The second project would be to upgrade the supply feeders from Farragut to Plymouth. Since the constraint at the Farragut Substation would require load relief at both Water and Plymouth Substations, the Company will pursue these projects as one portfolio.

When the need for load relief was identified in 2016, the planned traditional projects described above were the best solution available that could be implemented within the required timeline. However, a more robust solution that will eliminate the constraint beyond the 20-year planning horizon, the Hudson Avenue Distribution Switching Station ("HADSS") was subsequently identified.

Q. Please describe that solution.

A. The traditional project comprises two new 138/27 kV transformers supplied by regulated 138 kV tie feeders from the Hudson Avenue East transmission station. The HADSS cannot be built in time to address the need in 2019, with the earliest in-service date possible by the summer of 2022. With a three-year NWS deferring the need for upgrades until 2022, the new plan is to eliminate the cooling and feeder upgrade projects entirely with a 32 MW portfolio, giving time to design and build the HADSS. The Company has currently developed a cost-effective portfolio of solutions to provide at least 32 MW of load relief that would defer the need for traditional upgrades from 2019 through 2021.

A white paper describing the HADSS is provided as Exhibit __ (EIOP-4) and will be evaluated for additional deferral with a separate NWS.

Q. Please provide a brief description of the Company's other potential NWS opportunities.

A. Additional details about other NWS projects Con Edison may pursue, if viable portfolios can be developed following market solicitations, are available in the most recent quarterly report filed by the Company in Case 16-E-0060. White papers for the traditional projects that these NWS would displace, can be found in Exhibit __ (EIOP-4). They include the following:

Table 6 – Other Potential NWS Opportunities

Project	Project Type	Required Load Relief (MW)	NWS Need-by-Date
W42 St. Load Transfer	Large	TBD	TBD
Newtown	Large	TBD	TBD
Hudson Avenue Distribution Switching Station	Large	TBD	TBD

Q. What is the Company’s plan for implementing future NWS projects?

A. The Company is seeking to continue the current NWS framework into this rate period. The Company intends to continue the current practice of developing NWS implementation plans on an annual basis or more frequently when new NWS opportunities are determined to be viable. The Company will also develop and file BCAs as viable NWS are identified and continue to provide reports on a quarterly basis for NWS that are being implemented. As discussed in the Accounting Panel, the Company is proposing to continue the cost recovery mechanism approved for the current rate plan for these kinds of NWS.

Q. Does the Company propose to add any personnel to support current and potential future NWS projects?

A. Yes, two incremental employees to support all aspects of the DM programs such as NWS. Additionally, the Department is currently charging four of the FTEs working on Targeted DM to the BQDM Program and is moving them into O&M in order to uniformly categorize all labor expenses.

Q. How does the Company propose to recover the costs of additional NWS opportunities that it identifies?

A. The Company proposes to continue the current rate plan provision for the recovery of such costs. That provision has proven effective to date and should be continued as is.

New CSS Implementation

Q. Please explain the background of the Company's proposal to replace its current CSS.

A. The Company, Staff, and rate case parties discussed a new CSS system in the last two rate cases, Cases 13-E-0030 and 16-E-0060. In addition, the current Commission-approved rate plan requires the Company to begin to replace the system. Specifically, the Commission approved the rate plan's recommendation that "the Company will begin to implement its plan to replace its current" CSS in 2019.

Since then, the Company has been working towards implementing a new CSS system by 2023, through a process that to date has included pre-implementation planning. Con Edison is conducting these pre-implementation planning activities jointly with its regulated affiliate, O&R. This work aligns with NorthStar's 2016 Management Audit recommendation to explore the potential synergies, cost savings, and operational and customer benefits of jointly developing a new CSS. The O&R portion of CSS was addressed in the recent O&R electric and gas proposal. That Joint Proposal provides that the replacement of the O&R legacy CSS in conjunction with Con Edison has an estimated cost of $34 million, compared to an estimated cost of $66 million to complete the replacement project independent of Con Edison.

The result of this effort will consolidate the respective system environments of the Con Edison legacy CSS, O&R's legacy Customer Information Management System, as well as the Con Edison Oracle Customer Care and Billing ("CC&B") environment for complex electric billing, onto a single CSS platform.

Q. How does the new CSS implementation support State policy goals and Con Edison's objectives?

A. The new CSS will enhance our customers' experience and optimize our systems to better integrate DER by serving as a scalable and flexible IT platform and billing system of record that, in combination with AMI, will provide a foundation for billing alternatives designed to meet the needs of our customers. As customers choose to adopt DER or elect to participate in other EE programs, this system will enable billing for those options.

In addition, the new CSS will provide critical support for facilitating public policy objectives. While the Companies have previously made significant customizations to their legacy billing systems (e.g., Oracle CC&B off-system billing) to support State policies, such as Community Net Metering, Recharge New York, Mandatory Hourly Pricing, Reactive Power, and low-income program changes, the new CSS will make such changes easier and quicker.

Q. Has the Company developed a business plan for replacing CSS?

A. Yes, CECONY is including its CSS Business Plan as Exhibit __ (CES-5).

MARK FOR IDENTIFICATION AS EXHIBIT __ (CES-5)

Q. Was the exhibit titled "Customer Service System Business Plan" prepared under the Panel's direction and supervision?

A. Yes, it was.

Q. Does the CSS Business Plan provide an explanation of the Company's process for implementing a new CSS?

A. Yes. The CSS Business Plan explains Company's process for determining that a system was necessary, the new system's needs, which system the Company chose, the implementation plan for the new system and a cost benefit analysis for the new CSS.

Q. What are the expected benefits of the new CSS system?

A. As explained in the CSS Business Plan, the replacement of key business and billing processes with the proposed CSS solution is cost effective and will provide significant customer benefits. These benefits include enabling CECONY to implement new customer programs, creating new rate options, and providing customers with an improved, customer-centric service experience. The financial and non-financial benefits are further explained in the CSS Business Plan, Exhibit __ (CES-5).

Q. Are there non-financial customer benefits?

A. Yes. As explained in more detail in the CSS Business Plan, a new CSS will directly benefit our customers as it will lead to the development of enabling tools and services that can help them better understand and manage their energy usage, costs, and needs.

Q. Please describe non-financial customer benefits associated with the technology innovations in customer service and their relevance to CSS.

A. The new CSS will play an important enabling role in providing the necessary data to analyze customer energy profiles to provide targeted DER and EE offerings to customers.

Q. Did the Company prepare a formal Cost Benefit Analysis to support the new CSS project?

A. Yes. Con Edison completed a comprehensive assessment of the costs and benefits associated with a new CSS. The current cost/benefit analysis is included in Exhibit __ (CES-5) and incorporates a range of benefits to our customers.

In addition to the benefits discussed above and detailed in the business plan, the Companies forecast a total project cost of $505 million as shown in the Table 7 below.

Table 7 – CSS Cost Allocation

Cost allocation	O&R	CECONY	Total Cost ($M)
Capital	$34	$421	$455
O&M	$4	$46	$50
Total	**$38**	**$467**	**$505**

Key factors that are embedded into the CSS cost estimate include an assessment of the current state business processes, integration and technical architectures, labor resources, non-labor costs, such as hardware and software, and indirect costs.

The capital and O&M determination for the labor costs were driven by an analysis of the activities that would be performed by resource type and role, for each phase of the project, to determine whether the effort for that phase should be capitalized or expensed. Similarly, for the non-labor costs, the capital and O&M determination followed Plant Accounting rules and Generally Accepted Accounting Principles.

The CSS Business Plan provides further information on how the Company developed this cost estimate.

Q. What is the Company’s capital funding request for its CSS project during the rate period?

A. The table below shows the projected expenditures for Con Edison during the rate period.

Table 8 – Projected CSS Expenditures (2020-2022)

Three year summary (millions)				
Year	**2020**	**2021**	**2022**	**Total**
Capital	130	100	119	349
O&M	7	6	10	23

The Company expended approximately $12 million in 2018 and expects to expend $16 million in 2019 in capital.

Q. Please describe the Company's estimated operating expenses for the new CSS.

A. The following table provides information on the expected O&M work associated with the new CSS.

Table 9 – Expected O&M work for CSS

O&M Category	O&M Description
Labor	IT and Customer Operations support • Includes O&M labor associated with maintaining the CSS system • Temporary employees to assist in call center operations post go-live
Change Management	Implementation O&M: This includes costs for training development, training delivery, and communications, to design and develop training materials and methodology to prepare the organizations for the transition to the new CSS
Facilities	Facilities rental, maintenance and tax charges for project working space and associated communal areas

The CSS Business Plan describes the total O&M expenditure of approximately $23 million over the rate period.

Advanced Metering Infrastructure

Q. Please describe the components of AMI.

A. AMI consists of three major components: (i) smart meters and associated gas modules (gas modules are installed on gas meters to provide smart meter and communications functionalities), (ii) a communications network that enables two-way communication with the smart meters, and (iii) AMI back office IT systems to integrate with legacy systems and new AMI-related applications.

Q. Please explain the status of the Company's AMI implementation.

A. The Commission approved the Company's AMI program in the AMI Order.[19] The Company is deploying AMI across the service territory. AMI program deployment is on schedule and on budget with deployment expected to be complete in 2022. At a high level, the AMI status is:

- The AMI Operations Control Center ("AOCC"),that monitors both the AMI communications network and the electric and gas endpoints, has been established and operates around the clock.

[19] Case 15-E-0050, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service, *Order Approving Advanced Metering Infrastructure Business Plan Subject to Conditions*, issued March 17, 2016.

- The communications network installation is on schedule to be completed across our service territory prior to mass meter/module deployment.
- A number of the AMI back-office software systems ("AMI Systems") are in service.
- As of year end 2018, the Company has installed nearly 800,000 AMI meters across the service territory.
- The Company has implemented a robust Customer Education Plan dedicated to increasing customer acceptance of AMI, facilitating implementation, and engaging customers to maximize the benefits of AMI.

Q. Has the Company updated the Commission on both the status of AMI implementation and the metrics previously approved for AMI?

A. Yes. The Company filed two metrics reports with the Commission in April and October 2018, including explaining the progress of AMI and updating metrics status for AMI Meter Deployment, Customer Engagement, Billing, Outage Management, and System Operation and Environmental Benefits.

Q. What does AMI do for the Company and customers?

A. AMI enhances our customers' experience by providing them with detailed information about their energy usage and tools that empower them to manage their energy use. AMI eliminates manual meter reading and the need for customers to provide access to read meters. As noted throughout this testimony, AMI enables the Company to better understand and operate the distribution system more efficiently. The visibility into the grid provided by AMI data enables further integration of DER as well as other benefits, including efficient outage management and restoration efforts.

Q. Please explain how AMI has helped in restoration efforts.

A. As an example, during Winter Storms Reilly and Quinn (March 2018), the Company used the AMI system then in place to perform pings and remotely read meters on impacted AMI meters to verify outage status and deploy crews where needed, instead of sending a crew to determine whether an area was impacted by the outage. In fact, since October 2017, the Company has been able to avoid over 800 truck rolls based on information received from AMI.

Q. Are the projected AMI costs in line with the prior forecasts?

A. Yes, the projected AMI costs are in line with prior forecasts.

Q. What are the forecasted AMI expenditures for the rate plan?

A. The AMI Program forecasted expenditures during the rate period are $573 million in capital and $145 million in O&M. Below is a summary of the total project capital expenditures and O&M projected in this rate period:

Table 10 – AMI Capital and O&M (2020-2022)

AMI Requirements ($M)	**2020**	**2021**	**2022**
AMI Project Capital	$322.00	$231.00	$20.00
AMI Project O&M	$46.13	$52.14	$46.18

Q. What is the status of the Customer Engagement activities?

A. The Company has a robust Customer Education Plan that is dedicated to increasing customer acceptance of AMI, facilitating implementation, and engaging customers to maximize the benefits of AMI. Detailed information on the other Customer Engagement activities, including the Company's Innovative Pricing Pilot, are provided below.

Q. Please provide an update on the AMI program's capital investment spending and provide a summary of funds included in this filing.

A. The Company's AMI program continues into this rate plan. Among other related AMI investments, the Company is planning to spend previously approved expenditures of an estimated $573 million between 2020 – 2022, shown in Table 10.

Q. Please describe the O&M costs that will be incurred to complete territory-wide AMI deployment.

A. The AMI Program O&M expenditures are separated into two overarching categories:

- AMI project
- Customer Engagement

We have an exhibit entitled, "Advanced Metering Infrastructure" prepared under the Panel's direction and supervision, which describes these costs in detail.

MARK FOR IDENTIFICATION AS EXHIBIT __ (CES-6)

Q. Please describe the AMI project expenditures.

A. AMI implementation required that the Company put new metering and computing infrastructure in place. As such, implementation and ongoing maintenance expenses are incurred to maintain the new infrastructure and systems that support AMI. These systems include, among others, Meter Asset Management System, Meter Data Management System, Head End System, Enterprise Data Analytics Platform, and the communications network.

During RY1-RY3, the Company has additional O&M program costs for AMI related infrastructure and systems that include:

- software system maintenance and hosting fees
- communication costs
- personnel to support both the internal AMI Systems and the deployed smart meters

- AOCC O&M costs

Q. Please discuss the customer engagement costs related to AMI.

A. The Company plans to continue its AMI customer engagement activities described in its Customer Engagement Plan filed with the Commission in July 2016 and the subsequent filed status reports. Customer Engagement activities include:

- work related to AMI customer education,
- identifying innovative rate structures that can enhance customer benefits resulting from AMI in a cost-effective manner, and
- evaluating potential third party applications to leverage the AMI network.

Q. Please describe what the Company intends to do for AMI customer education.

A. The Company has a broad education plan before, during and after AMI implementation. The plan includes educating: (1) elected officials, community resources and business leaders and (2) customers about AMI as well as using media channels to advertise AMI.

Prior to AMI deployment in each region, the Company will:

- engage with local elected officials, community resources, and business leaders through email and presentations to provide information about AMI and the benefits of smart meters, and

- advertise in various formats (e.g., social media) to create regional public awareness of the project.

Customer-focused activities will be scheduled prior, during, and post-installation including:

- customer surveys and focus groups
- pre-installation direct mail notifications
- mailers with energy reports and alerts
- door hangers

The Company's website and call center provide other resources to customers with more information, including information for residential customers regarding the option to opt-out of receiving a smart meter. As customer insights are gained, customer messaging and channels will be adjusted to fit customer preferences and needs.

Informational materials, promotional items, and presentations have been developed and will be provided to the community to raise customer awareness and serve as a resource to customers.

Regional energy forums will be used to reach current and potential third-party vendors in areas where smart meter deployment is in progress. Community activities will continue after deployment as a means of continuing to engage our customers.

The Company will continue to provide information on customer engagement activities in its semi-annual AMI Metrics reports.

Q. Does the Company have any new rate pilot programs as a result of AMI?

A. Yes. As a part of the AMI Order, the Commission required the Company to test new and innovative rate structures leveraging the functionality of AMI smart meters, including developing a pilot program to test new rate designs, such as demand-metered delivery rates, hourly supply pricing, peak rebate pricing, or other time and location-sensitive designs. On July 6, 2018, the Company filed a proposed Innovative Pricing Pilot for residential and small commercial customers.[20] The Commission approved the Innovative Pricing Pilot on December 13, 2018,[21] pending compliance filings.

The pilot is in the implementation phase and the Company expects to start enrolling customers to participate in the pilot in 2019.

[20] Case 18-E-0397 - Tariff filing by Consolidated Edison Company of New York, Inc. to Make Revisions to its Electric Tariff Schedule, P.S.C. No. 10, to Add New Riders Z (Residential) and AA (Small Commercial) Innovative Pricing Pilot to Implement Rate Structures for Residential and Small Commercial Customers, filed July 6, 2018.

[21] Case 18-E-0397 - *Order Approving Tariff Amendments with Modifications*, issued December 13, 2018.

In the rate years, the Company intends to implement other pricing pilots, such as the Company's Smart Home Rate REV Demonstration Project.

Q. What are the expected AMI O&M expenditures for both AMI project and customer engagement activities?

A. Total O&M costs anticipated to support the AMI Program and Customer Engagement activities are estimated to be $145 million from 2020 – 2022. The table below summarizes the O&M costs, and additional details for the O&M costs can be found in Exhibit __ (CES-6).

Table 11 - AMI Program O&M Costs (2020-2022)

AMI O&M Requirements	**$M**	**Request**	**Request**	**Request**
Year	**$M**	**2020**	**2021**	**2022**
AMI Project O&M	AMI Project O&M	$36.13	$42.14	$41.18
Customer Engagement	Customer Education	$5.80	$5.50	$2.70
Customer Engagement	Rate Pilots	$3.00	$3.30	$1.40
Customer Engagement	New Revenue Opportunities	$1.20	$1.20	$1.20
Total Costs	Total Costs	$46.13	$52.14	$46.48
Incremental Costs	From Test Year $18.53	$27.60	$6.01	$(5.66)

Q. Is there a reconciliation mechanism associated with the AMI Customer Engagement efforts under the current rate plan?

A. Yes. We reconcile actual customer engagement costs to the level allowed in rates over the three year term of the rate plan.

Q. Does the Company intend to continue this reconciliation?

A. Yes. The customer engagement effort is still underway and it is appropriate to continue this mechanism.

Q. Are there O&M expenditure savings discussed in other testimonies associated with the AMI Program?

A. Yes. The Company anticipates O&M cost reductions in both Customer Operations and Electric Operations. These savings are discussed in Customer Operations and EIOP testimonies and in the Exhibits titled O&M White Paper - AMI Customer Operations, Exhibit __ (CO-11) and O&M White Paper – AMI Electric Operations, Exhibit __ (EIOP-07).

Con Edison's Innovation Initiative

Q. Please describe the Company's Innovation Initiative.

A. The Company is establishing a corporate-wide Innovation Initiative to strengthen our existing capability to identify and facilitate the development of transformative innovation projects. The initiative complements and builds upon the Company's existing innovation efforts, REV Demonstration Projects and Research and Development ("R&D"). Under this initiative, the Company will develop and scale innovative ideas that are technically mature enough to not require further R&D investigation but whose path to customer and commercial success remains uncertain. We are requesting funding to establish an innovation center of excellence ("Innovation Hub") with associated O&M ("Innovation Common Fund").

Q. How will this work?

A. A small team of Innovation Hub employees will lead the effort to identify innovative ideas with the potential for growth, and provide support and oversight of the initiatives targeted. Innovative ideas that will need assistance from the Innovation Hub are those which require cross-departmental collaboration, do not have a natural "home" in any single Con Edison department, and whose outcome are uncertain. The Innovation Common Fund is the funding mechanism to provide resources for "owners" of these initiatives, subject matter experts and any required third-party support teams (e.g., IT, contract services), and to facilitate the development and testing of the ideas prior to scaling.

Q. Please explain why these types of projects may be different from other innovative projects that may be funded through R&D or by Demonstration Projects.

A. Con Edison's R&D team tests novel technological solutions in early-stage research and product development, with a focus on technology that has the potential to provide core operational and safety value. The results of R&D

projects are typically prototypes that do not go into commercial, productive use, but rather provide the underlying specifications for purchase orders of new equipment to be built by third-party manufacturers for procurement by various Company operating departments. REV Demonstration Projects test new technologies and innovative business models which meet the approved regulatory definition.

Q. Please provide more detail concerning Innovation Hub projects.

A. The Innovation Hub will evaluate projects that either: (1) have successfully completed an R&D effort and show potential for wider business model development and customer-focused innovation but do not warrant development into a Demonstration Project, or (2) do not have a natural home in any single business operating group. In addition, the Innovation Hub will look for ideas and applications of existing products coming from non-R&D sources that do not require further investigation from R&D. Finally, the Innovation Hub provides initiatives with the support and resources required to maximize the chances of the product creating the necessary customer and business value.

Q. Is there a document that further explains the Innovation Initiative?

A. Yes. There is a white paper entitled "Innovation Initiative."

MARK FOR IDENTIFICATION AS EXHIBIT __ (CES-7)

Q. Was this exhibit prepared under the Panel's direction and supervision?

A. Yes.

Q. Are you requesting funding for the Innovation Initiative?

A. Yes. The Innovation Initiative program will require O&M funding to institute the elements described above for RY1 through RY3. In total, the Company estimates that the expenses for this initiative will be $2.3 million in RY1 1, $2.5 million in RY2 and $3.5 million in RY3.

Demonstration Projects

Q. Please describe how the Company's Demonstration Projects are playing an important role in allowing the Company to test new technologies, prove conceptual business models, and inform DSP development.

A. Demonstration Projects adapt and explore innovative business models. These projects are a key means of advancing State policy goals including increased DER penetration, reduction of GHG emissions, increased EE, and enhanced customer engagement. Demonstration Projects allow the Company to test new business models that will help pave the way for a customer-centric, DER-enabled future.

Q. What is the Company authorized to spend on REV Demonstration Projects and what has it spent to date?

A. The REV Track One Order authorized the Company to spend an amount to "not exceed 0.5 percent of its delivery service revenue requirement."[22] Con Edison's total authorized amount was $135 million. As of December 31, 2018, the Company has spent $31.0 million and plans to spend an additional $43.8 million during 2019.

Q. What is the forecasted expenditure for Demonstration Projects through the rate period?

A. The Company projects to spend $34.6 million during the upcoming three year period on the existing and planned Demonstration Projects. These costs are currently expected to be $20.3 million, $9.4 million, and $4.9 million for 2020, 2021, and 2022, respectively. Though not developed at this time, if the Company plans new or expanded Demonstration projects, the Company would address the need for additional funding under the provisions included in the REV Track One Order (pp. 116-117).

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[22] Case 14-M-0101, Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, *Order Adopting a Regulatory Policy Framework and Implementation Plan*, issued February 26, 2015.

Q. Does the Company currently have a reconciliation mechanism for the REV Demonstration costs?

A. Yes. The Company will continue to defer annually the revenue requirement associated with program expenditures above or below the expected expenditures noted above. Given the nature of these projects and expenditures, the Company believes the existing reconciliation mechanism should continue.

Earnings Adjustment Mechanisms

Q. Please describe the background for the Panel's EAM proposal in this proceeding.

A. We developed the Company's EAMs proposal to align with the Commission's *Order Adopting a Ratemaking and Utility Revenue Model Policy Framework* in Case 14-M-0101, and the State's clean and distributed energy resource policy goals. The Company developed this proposed set of EAMs in advance of the December 2018 Commission NE:NY and energy storage orders, discussed earlier.

Q. Based on the EE Order and the Storage Order, will there be any proposals regarding EAMs in the preliminary update?

A. We do not plan to make changes to the EAMS proposed here but in its preliminary update, the Company may propose the two new earnings mechanisms discussed in those orders:

- a cost-reduction shared savings mechanism based on lifetime Btu achievement under the NE:NY Order
- an EAM as provided for in the Storage Order.

In addition to the cost-reduction-based shared savings incentive mechanism for lifetime Btu savings, the Company, however, plans to allocate some basis points from the EAMs it proposed in this testimony to any EAM developed as a result of the Storage Order that may be proposed in the preliminary update.

Q. Is the Panel sponsoring any EAM exhibits?

A. Yes. This Panel is sponsoring two exhibits that were prepared by or under the supervision of the Panel:

1. Exhibit __ (CES-8), entitled "EAM Formulas and Target Sources" which contains the formulas and input assumptions; and
2. Exhibit __ (CES-9), entitled "EAM Targets" which contains our calculation of the annual EAM baselines and targets.

MARK FOR IDENTIFICATION AS EXHIBIT __ (CES-8) AND EXHIBIT __ (CES-9)

Q. Please describe the EAMs that exist under the Company's current rate plan and how the Company has performed to date.

A. The Company's current rate plan consists of seven electric EAMs:

- Electric EE
- System Peak Reduction
- DER Utilization
- Energy Intensity Reduction
- GHG Emissions Reduction
- AMI Customer Awareness
- Interconnection

In 2017, the Company achieved the maximum EAM for Electric EE and System Peak Reduction, and did not achieve the minimum levels for the DER Utilization, Energy Intensity, and Interconnection EAMs. Also in 2017, the Company did not yet have sufficient AMI deployment to consider AMI Customer Awareness EAM achievement, and the GHG Emissions Reduction EAM is new for 2019.

Q. Are the results available for the Company’s 2018 EAM performance?

A. Not yet. The Company will report on its 2018 EAM achievements in March 2019 except that it will report on the AMI customer awareness EAM in April 2019 as part of the Company’s semi-annual AMI Metrics Report.

Q. Please describe how the current EAMs and the Company’s performance under those EAMs have informed the Company’s proposal in this rate filing.

A. Overall, the Company supports continuing the EAM construct, as it has demonstrated to be successful as an appropriate mechanism to spur utility action and drive achievement of outcomes in alignment with State policy. The Company's current EAMs and the Company's performance under those EAMs have informed the proposal in this rate filing as follows:

- As reflected in the Company's 2017 results, the EE and System Peak Reduction EAMs are well-designed, straightforward metrics under which the Company's actions and influence are appropriately linked to EAM achievement.
- The DER Utilization, GHG Emissions Reduction, and AMI Customer Awareness EAMs tie key State environmental and customer engagement outcomes with a reasonable level of Company influence toward EAM achievement.
- The Energy Intensity EAM is not designed to allow market participants and the Company to meaningfully influence the desired outcome and we do not propose to continue it.
- The intent of the Interconnection EAM may be better achieved through different means, and now DPS Staff

has recommended that the Interconnection EAM be eliminated.[23] (We are not proposing to continue the Company's existing Interconnection EAM in this rate filing and instead urge that bases points identified thereunder be allocated to other EAMs as proposed below).

Q. Please describe how you developed the Company's EAM proposal.

A. The Company's proposed EAMs build on progress to date under the Company's 2017-2019 EAMs structure and on the experience the Company has gained from engagement with stakeholders through collaboratives for both electric and gas.

The Company's proposed EAMs appropriately balance multiple objectives important to the State and stakeholders:

- supporting advancement of important State and municipal policy objectives, such as (i) growth of EE and DERs, including beneficial electrification technologies, such as heat pumps, and advanced technologies, including storage, (ii) lowering system

[23] Case 14-M-0429, In the Matter of Earnings Adjustment Mechanism and Scorecard Reforms Supporting the Commission's Reforming the Energy Vision, Interconnection Earnings Adjustment Mechanisms Staff Proposal, issued October 24, 2018, p.6.

peak to achieve State-wide delivery system efficiencies, and (iii) reducing GHG emissions,

- driving utility behavior with measurable outcomes by appropriately accounting for the Company's ability to both facilitate positive outcomes as well as directly influence these outcomes through the Company's portfolio of programs, and
- signaling to utilities and their third-party vendors the State's intent to drive real and measurable change annually and over the longer-term.

Q. Please summarize the Company's proposed EAMs.

A. The Company proposes to implement the following Electric EAMs:

- The Electric Energy Efficiency EAM ("E3 EAM") measures the energy savings achieved through increased efficiency of electricity use by our customers. The Company proposes the E3 EAM to be based on the total incremental, annual MWh reductions achieved through the Company's electric EE programs.
- The Electric Peak Reduction EAM ("EPR EAM") measures customers' reduction of system peak period electricity usage through both adoption of EE as well as DER, such as battery storage and clean cooling solutions.

- The DER Utilization EAM (“DER EAM”) measures the amount of incremental, annual MWh the Company’s customers do not need to rely on the grid for, through generating locally or through reductions by participation in the Company’s DR programs.
- The Electric GHG Emissions Reduction EAM (“EGHG EAM”) measures the amount of incremental lifetime GHG emissions reductions resulting from increasing adoption of beneficial electrification technologies, based on the technologies in the Company’s existing GHG Emissions Reduction EAM.

The Company proposes to implement the following Gas EAMs:

- The Gas Energy Efficiency EAM (“GE2 EAM”) measures the incremental annual energy savings achieved through increased efficiency or avoidance of natural gas use by our customers. The Company proposes to base the GE2 EAM on the total Dth reduction achieved by the Company and its customers through its portfolio of EE and four Smart Solutions programs.
- The Gas Peak Reduction EAM (“GPR EAM”) measures customers’ reduction of peak day gas usage. The Company proposes to base the GPR EAM on incremental, annual peak day gas usage reduction or avoidance by

our gas customers achieved through the Company's programs.

- The Natural Gas GHG Emissions Reduction EAM ("GGHG EAM") measures the amount of incremental lifetime GHG emissions reductions resulting from increasing adoption of technologies that reduce, replace, or avoid technologies that use natural gas, based on some of the technologies in the Company's existing GHG Emissions Reduction EAM.

The Company is not proposing any changes to the existing authorized AMI Customer Awareness EAM that measures customer awareness of AMI technology, features, and benefits.

Q. Please describe the Company's overall proposal regarding EAM earnings opportunities.

A. The Company proposes positive earnings adjustments, calculated as return on equity basis points, for each of the EAMs. Our proposed EAM earnings opportunities are at 100 basis points annually for the electric business. We also propose 70 basis points annually for the gas business. The allocation of these earnings opportunities is shown in Tables 12 and 13 below. As shown, the EAMs would be effective for RY1 through RY3.

Table 12 - Electric EAM Basis Points

		2020	2021	2022
Electric Energy Efficiency (E3 EAM)	Min	7.0	7.0	7.0
	Mid	21.0	21.0	21.0
	Max	35.0	35.0	35.0
Electric Peak Reduction (EPR EAM)	Min	5.0	5.0	5.0
	Mid	15.0	15.0	15.0
	Max	25.0	25.0	25.0
DER Utilization (DER EAM)	Min	4.0	4.0	4.0
	Mid	12.0	12.0	12.0
	Max	20.0	20.0	20.0
Electric Greenhouse Gas Emissions Reduction (EGHG EAM)	Min	4.0	4.0	4.0
	Mid	12.0	12.0	12.0
	Max	20.0	20.0	20.0
TOTALS	Min	20.0	20.0	20.0
	Mid	60.0	60.0	60.0
	Max	100.0	100.0	100.0

Table 13: Natural Gas EAM Basis Points

		2020	2021	2022
Natural Gas Energy Efficiency (GE2 EAM)	Min	7.0	7.0	7.0
	Mid	21.0	21.0	21.0
	Max	35.0	35.0	35.0
Natural Gas Peak Reduction (GPR EAM)	Min	4.0	4.0	4.0
	Mid	12.0	12.0	12.0
	Max	20.0	20.0	20.0
Natural Gas Greenhouse Gas Emissions Reduction (GGHG EAM)	Min	3.0	3.0	3.0
	Mid	9.0	9.0	9.0
	Max	15.0	15.0	15.0
TOTALS	Min	14.0	14.0	14.0
	Mid	42.0	42.0	42.0
	Max	70.0	70.0	70.0

Q. What EAM targets is the Company proposing in this testimony?

- The Company proposes that the mid-point targets for E3 EAM, EPR EAM, GE2 EAM, and GPR EAM be equal to or directly derived from the Company’s proposed targets, or updated targets following any changes made by the Company in its preliminary update as noted earlier in this testimony for its EE programs and consistent with the Company’s existing electric EAMs in the 2017-2019 rate period. The Company is proposing a minimum level at 75 percent of the mid-point target and a maximum level at 125 percent of the mid-point target for these four EAMs.

- For the DER EAM, EGHG EAM, and GGHG EAM, the Company proposes to file in its preliminary update baseline levels for 2020 that are to be derived from the formulas and forecast sources in Exhibit ___ (CES-8), and that the minimum targets be set at the baseline level, mid-point targets be set 10 percent above the baseline, and the maximum targets be set at 20 percent above the baseline. We also propose to file baseline, mid-point, and maximum target levels for these three EAMs annually by August 31, 2020 and August 31, 2021 for RY2 and RY3, respectively.

Q. Please continue.

A. The EAMs as described above would provide the Company with a meaningful incentive to undertake additional efforts to drive achievement consistent with State policy objectives that will also benefit our customers and stakeholders.

Q. Please describe how the Company will measure the E3 EAM.

A. The Company will measure the E3 EAM by calculating EE savings from the Company's EE programs.

Q. How would the Company calculate the midpoint target for this EAM?

A. The Company will use the EE targets developed in this rate proceeding as the mid-point target for this EAM.

Q. Please describe how the Company will measure the EPR EAM.

A. The Company will measure the EPR EAM through electric peak-coincident MW reductions at the customer level from EE technologies included in the Company's portfolio of programs and beneficial electrification technologies. The Company's EE programs' contribution to peak demand reduction will be calculated using the NYISO coincident system peak for each EE measure from the New York TRM and engineering analyses where the TRM does not provide peak coincidence values.

Q. How will the Company calculate the midpoint target for this EAM?

A. The Company will calculate the midpoint target for this EAM by calculating the expected peak coincidence of the Company's portfolio of EE and beneficial electrification programs authorized in this proceeding.

Q. Please describe how the Company will measure the proposed DER EAM.

A. For the DER EAM, the Company will track installations and calculate annualized MWh from air- and ground-source heat pumps, battery storage, battery and plugin hybrid light-duty EVs, Combined Heat and Power ("CHP"), electric DR, fuel cells, electric buses, ice energy storage, solar PV, and distributed wind energy. This tracking and measurement methodology will build on the Company's tracking methods for its 2019 DER Utilization EAM. We will measure DERs in terms of their rated capacity and related capacity factors, except for DR for which we will use the number of DR events and actual performance. To standardize across technologies, all measurements will be in annualized MWh using the formulae described in Exhibit ___(CES-8). For each DER type, Con Edison will determine MWh produced, consumed, discharged, or reduced from incremental resources. MWh are treated as positive values with the sum of produced, consumed, and reduced (in the case of DR and heat pump efficiency), energy determining achievement against a target; that is, one MWh produced is equivalent to one MWh consumed (or one MWh reduced in the case of DR and heat pump efficiency) for the purpose of the DER EAM.

Q. How will the Company calculate the baseline for this EAM?

A. The Company will calculate the baseline for this EAM as developed through stakeholder consensus in the Company's 2018-19 EAM collaboratives, i.e., by using a combination of (i) the MW of customer projects in the Standardized Interconnection Requirements ("SIR") inventory adjusted for historical cancellation rates, delay rates, and other historical trends by technology; (ii) for technologies not required to enter the SIR process (e.g., EVs, heat pumps, DR, electric buses, and ice energy storage), the Company will forecast expected DER adoption levels that would be reasonably expected to be reached absent Company efforts beyond initiatives identified in this testimony with the sources of forecast and formulas to convert forecasted technologies to annualized MWh identified in Exhibit __ (CES-8).

Q. Please describe how the Company will measure the EGHG EAM.

A. The Company will measure contributions to the EGHG EAM by tracking installations and calculating lifetime metric tons of carbon dioxide equivalent ("CO_2e" includes CO_2, CH_4, N_2O) emissions reduced from the following measures: battery storage, electric buses, electric DR, ice energy storage, medium-duty light-duty battery and plugin hybrid EVs, solar PV, the cooling efficiencies from air- and ground-source heat pumps, distributed wind energy, and voluntary renewable energy certificates ("VRECs"). To standardize measurement across technologies, all measurements will be in lifetime avoided metric tons CO_2e using the formulae described in Exhibit __ (CES-8). Metric tons CO_2e are treated as positive values with the sum of avoided kg CO_2e emissions, converted after initial calculation to metric tons CO_2e emissions, determining achievement. The avoided emissions measurements use electricity emissions factors of Grid kg CO_2e per MWh and/or Peak kg CO_2e per MWh, and other technology-specific factors, to determine lifetime avoided metric tons CO_2e. For the purposes of the EGHG EAM, the Grid kg CO_2e value is the New York City electricity emissions factor from the most recently published New York City GHG Inventory. The Peak kg CO_2e per MWh value is sourced from the Environmental Protection Agency ("EPA") Emissions & Generation Resource Integrated Database ("eGRID") for the Northeast Power Coordinating Council ("NPCC") NYC/Westchester sub region.

Q. How will the Company calculate the baseline for this EAM?

A. The Company will calculate the baseline for this EAM as developed through stakeholder consensus in the Company's 2019 EAM collaborative, i.e., by using a combination of (i) the MW of customer projects in the SIR inventory adjusted for historical cancellation rates, delay rates, and other historical trends by technology; (ii) for technologies not required to enter the SIR process (e.g., EVs, heat pumps, DR, electric buses, and ice energy storage), the Company will forecast expected DER adoption levels that would be reasonably expected to be reached absent Company efforts beyond initiatives identified in the CES panel testimony with the sources of forecast and formulas to convert forecasted technologies to lifetime avoided CO_2e emissions identified in Exhibit __ (CES-8).

Q. What data sources will the Company use for DER, EGHG, and GGHG EAM baseline development?

A. The Company will use the following for DER, EGHG, and GGHG EAM baseline development for: (i) battery storage, CHP, fuel cells, solar PV, and distributed wind energy, the Company will use historical SIR inventory and project tracking data, including cancellation rates, delay rates, and other historical trends by technology; (ii) battery and plugin hybrid EVs, the Company will use historical registration trends from the Department of Motor Vehicles; (iii) electric buses, the Company will receive data from the MTA and Westchester County; (iv) ice energy storage, the Company will utilize its own program data and customer project data; (v) air- and ground-source heat pumps, the Company will use its own program data; (vi) DR, the Company will use its own program data; and

(vii) VRECs, the Company will utilize its own program data and the New York Generation Attribute Tracking System.

Q. How are incremental resources defined for the Company's EAMs?

A. For each technology under the DER EAM, EGHG EAM, and GGHG EAM, incremental resources, for the purposes of determining achievement under these EAMs, are defined as all DERs belonging to the respective technology that becomes electrically connected to the Con Edison delivery system during the rate year.

Q. Please describe how the Company will measure the GE2 EAM.

A. The Company will measure contributions to the GE2 EAM by calculating energy savings achieved through increased efficiency or avoidance of natural gas use by our customers. Customers throughout the Company's gas service territory are eligible to participate in the Company's portfolio of gas EE and Smart Solutions programs.

Q. How will the Company calculate the midpoint target for this EAM?

A. The Company will use the EE targets developed in this rate proceeding as the mid-point target for this EAM, while considering any additional EE efforts approved as part of Smart Solutions' NPS portfolio.

Q. Please describe how the Company will measure the GPR EAM.

A. The Company will measure contributions to the GPR EAM by measuring customers' reduction or avoidance of peak day gas usage through both adoption of EE as well as DER installed as part of the programs authorized in this proceeding while also considering Smart Solutions initiatives.

Q. How will the Company calculate the midpoint target for this EAM?

A. The Company will calculate the midpoint target for this EAM through a combination of gas peak day reduction values from its Smart Solutions programs, gas EE program experience, and market research with its most recent gas EE potential study.

Q. Please describe how the Company will measure the GGHG EAM.

A. The Company will measure contributions to the GGHG EAM by tracking installations and calculate lifetime metric tons of CO_2e emissions reduced from air-source and ground-source heat pump heating loads, and heat pump water heaters that replace natural gas. To standardize measurement across technologies, all measurements will be in lifetime avoided metric tons CO_2e using the formulae described in Exhibit __ (CES-8). Metric tons CO_2e are treated as positive values with the sum of avoided kg

CO_2e emissions, converted after initial calculation to metric tons CO_2e emissions, determining achievement. The avoided emissions measurements may use electricity emissions factors of Grid kg CO_2e per MWh and/or Peak kg CO_2e per MWh, and other technology-specific factors, to determine lifetime avoided metric tons CO_2e. For the purposes of the GGHG EAM, the Grid kg CO_2e value is the New York City electricity emissions factor from the most recently published New York City GHG Inventory. The Peak kg CO_2e per MWh value is sourced from the EPA Emissions & eGRID for the NPCC NYC/Westchester sub region.

Q. How will the Company calculate the baseline for this EAM?

A. The Company will calculate the baseline for this EAM consistent with the stakeholder consensus developed through the Company's 2019 EAM collaborative, i.e., through a combination of (i) forecasting expected DER adoption levels that would be reasonably expected to be reached absent Company efforts beyond initiatives identified in the CES panel testimony with (ii) the formulas to convert forecasted technologies to lifetime avoided CO_2e emissions identified in Exhibit __ (CES-8).

Q. Please describe how the AMI EAM is measured.

A. As described in the Company's current rate plan, the Company measures its performance based on pre- and post-deployment surveys of customers in each of the six deployment regions (i.e., Staten Island, Westchester, Brooklyn, Manhattan, the Bronx, and Queens). Specifically, the Company conducts an initial survey three months prior to the deployment of AMI in each region to establish a baseline of customer AMI awareness, and then uses this baseline to establish with DPS Staff a regional post-deployment target for customer AMI awareness. At the end of AMI deployment in each region the Company conducts a post-deployment survey that measures customer AMI awareness using the same questions as the baseline survey. If the results of the post-deployment survey meet or exceed the established target, the Company receives a positive earnings adjustment of $250,000 per region.

Q. With respect to the measurement of AMI awareness, how many regions have established a baseline for AMI awareness?

A. The Company has established pre-deployment baselines for all regions except Queens, as provided in the semi-annual AMI Metrics Report. As of this filing, the Company has also established post-deployment awareness targets with DPS Staff for all of our regions except the Bronx and Queens: Staten Island (75 percent), Westchester (80 percent), Brooklyn (80 percent), and Manhattan (80 percent). The Company expects to finalize a target for the Bronx with Staff in the first quarter of 2019. The Queens pre-deployment survey is scheduled to be conducted in March 2019, after which the Company will agree upon a regional target with DPS Staff.

Q. Will the Company complete deployment in any regions during the current rate plan that would potentially be eligible for earnings adjustments during the proposed rate plan under this EAM?

A. Yes. The Company expects deployment in Westchester to be completed in December 2019. The Company will conduct a post-deployment survey in Westchester in or around January 2020 and expects to report the results in its April 30, 2020 AMI Metrics Report.

Q. Does the Company propose to continue the AMI Customer Awareness EAM for the 2020-2022 period for its remaining regions?

A. Yes. The Company proposes to continue the AMI Customer Awareness EAM for the 2020-2022 period, subject to the same methodology, regional incentive amounts, terms, and conditions as applied in the 2017-2019 rate period. We expect that the EAM will cover the following regions during the potential rate plan period: Bronx, Brooklyn, Manhattan, and Queens.

Q. How does the Company propose to report and collect EAM achievements?

A. The Company proposes to continue to report and collect EAM achievements consistent with the current rate plan provisions.

Q. Does the Company propose any changes to the Tariff?

A. Yes, the Company proposes to update Electric Tariff Leaf 26.1 and 343.1 related to the proposed electric EAMs. The Company also proposes to update Gas Tariff Leaf 183.5 related to the proposed gas EAMs.

Q. Does this conclude the Panel's initial testimony?

A. Yes, it does.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

MUNICIPAL INFRASTRUCTURE SUPPORT PANEL
ELECTRIC & GAS

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CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

MUNICIPAL INFRASTRUCTURE SUPPORT PANEL
ELECTRIC & GAS

INTRODUCTION

Q. Would the members of the Municipal Infrastructure Support Panel please state your names and business addresses?

A. (**Boyle**) Robert Boyle and my address is 1610 Matthews Avenue, Bronx, NY 10462.

(**Kong**) Theresa Kong and my address is 1610 Matthews Avenue, Bronx, NY 10462.

(**Minucci**) John Minucci and my address is 4 Irving Place, New York, NY 10003.

Q. What are your current positions at Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company")?

A. (**Boyle**) I am employed by Con Edison as the Vice President of Construction.

(**Kong**) I am employed by Con Edison as the General Manager in Construction's Public Improvement Department.

(**Minucci**) I am employed by Con Edison as a Construction Manager in Construction's Public Improvement Department.

Q. Please describe your educational backgrounds.

A. (**Boyle**) I graduated from Manhattan College in 1986 with a Bachelor of Science degree in Civil Engineering. I received an MBA in Finance from Manhattan College in 1989.

(**Kong**) I graduated from Steven's Institute of Technology in 2003 with a Bachelor of Engineering Degree in Industrial

Engineering. I graduated from Columbia University in 2013 with a Master's of Science degree in Construction Management.

(**Minucci**) I graduated from St. John's University in New York City with a Bachelor's degree in Accounting in 2001 and a Master's degree in Accounting in 2002.

Q. Please describe your work experiences.

A. (**Boyle**) I have been employed by Con Edison since 1986 when I joined the Company as a management intern. Since then, I have held various management positions of increasing responsibility, including Section Manager of Contract Administration and Inspection, General Manager of Public Improvement and Engineering, General Manager of Substation Operations Planning, General Manager of Substation and Transmission Construction, General Manager of Steam Distribution, General Manager of Gas Operations. In December 2015, I assumed my present position as the Vice President of Construction.

(**Kong**) I joined Con Edison in 2003 as a management intern in the Company's Growth Opportunities for Leadership Development ("GOLD") program. Since then I have held positions of increasing responsibility in Public

Improvement. Starting In 2005, I held the role of Chief Construction Inspector and then Project Specialist in Public Improvement. In 2013, I assumed the role as the Section Manager of Public Improvement Engineering in Regional Engineering ("Public Improvement Engineering") and in 2017 I assumed my present position as General Manager of Public Improvement.

(**Minucci**) I joined Con Edison in 2002 as a management intern in the Company's GOLD program. Since then I have held positions of increasing responsibility all within Public Improvement. Starting in 2004 as an Analyst, Senior Analyst, Chief Construction Inspector, Project Specialist and in 2015 I assumed my present position as Construction Manager in Public Improvement.

Q. Do you belong to any professional organizations?

A. (**Boyle**) I am a member of the American Society of Civil Engineers.

(**Kong**) No.

(**Minucci**) No.

Q. Please generally describe your current responsibilities.

A. (**Boyle**) My current responsibilities as Vice President of Construction are to oversee the installation of electric and gas facilities in the streets and capital improvements to our generating, substation and other facilities. Additionally, I have responsibility to maintain the integrity of our electric, gas and steam systems during municipal construction projects.

(**Kong**) My current responsibilities as General Manager of Public Improvement are to oversee all work in Public Improvement and maintain the integrity of Con Edison’s electric, gas and steam systems during the course of municipal construction projects. This requires planning, coordinating, engineering and negotiating with municipalities and their contractors to facilitate the completion of municipal projects.

(**Minucci**) My current responsibilities as Construction Manager of Public Improvement are to oversee the operational support for all municipal projects that impact Con Edison in the service territory. This requires planning, coordinating, operational support and negotiating with contractors to facilitate the administration of projects.

Q. Have you previously testified before the New York State Public Service Commission (“Commission”)?

A. (**Boyle**) Yes, I have provided testimony to the Commission in the Company's electric, gas and steam rate filings (03-G-1671, 03-S-1672, 04-E-0572, 16-E-0060, and 16-G-0061) with regards to Municipal Infrastructure programs and steam rate filing 13-S-0032 with regards to Steam Operations.

(Kong) No.

(**Minucci**) No.

Q. What is the purpose of your testimony?

A. Our testimony provides the Company's forecast for interference cost during the rate year, and we also provide forecasts for rate years two and three to provide a basis for settlement negotiations if the parties decide to seek a three-year rate plan settlement. In providing this forecast, we demonstrate the material costs the Company incurs to comply with its obligations to perform interference work. We will describe the nature of interference and the challenges faced in forecasting costs because this work is largely driven by factors outside of the Company's control. Accordingly, while we provide a forecast based on the best available information, because the Company's interference expenditures are significant and largely driven by the infrastructure work performed by the

City, State and other municipalities, the Company proposes a full, bi-lateral reconciliation for these costs. Finally, we will describe how the Company, within the limited ability it has to control interference work, has implemented an array of cost-mitigation measures.

Q. Please summarize the areas your testimony addresses.

A. Our testimony addresses:

(1) The definition and significance of “interference” as it relates to Con Edison’s system;

(2) Interference Forecasting Methodologies;

(3) Projected Operation and Maintenance (“O&M”) interference costs associated with the Company’s electric and gas facilities for the 12 months ending December 31, 2020 (“Rate Year” or “RY1”), and for two additional 12-month periods ending December 31, 2021 and December 31, 2022 (which we will refer to as RY2 and RY3, respectively, for ease of reference);

(4) Projected Capital interference costs associated with the Company’s electric and gas facilities for calendar years 2020 to 2022 (*i.e.*, RY1 through RY3);

(5) Mitigation measures the Company undertakes to reduce its interference costs; and

(6) A proposal for reconciliation of interference capital and O&M expenses.

DEFINITION AND SIGNIFICANCE OF INTERFERENCE

Q. Please explain the term “interference” as it pertains to the Company.

A. Con Edison has an extensive system of gas mains, gas services, electric cables, conduits, structures and poles, in addition to electric services and appurtenances of various sizes and operating voltages, within the streets of its gas and electric service territories, respectively. These service territories include Manhattan, Bronx, Queens, Brooklyn, Staten Island and Westchester County. These facilities share the space under the streets with privately-owned facilities such as telephone and cable TV, and municipal owned facilities such as water, sewer, transit and traffic facilities. In addition, electric overhead facilities share space above the streets with private and municipal facilities such as telephone, cable TV, fire alarm, street lighting and traffic signals. When a municipality plans to perform work, either underground or overhead, and is unable to complete the proposed plan absent our relocating or supporting Company facilities that are “in the way,” the term “interference” is used.

Q. Why is the Company required to perform interference work associated with municipal projects and some state projects?

A. On advice of counsel, it is our understanding that courts have held that Con Edison’s right to lay and maintain its facilities pursuant to a franchise granted by a municipality is subject to the municipality’s right to require Con Edison to remove or relocate its facilities at the Company’s expense whenever public health, safety, or convenience requires. If the Company fails to comply with such a request by the municipality, the Company may be liable for damages caused by its failure. The City of New York has enhanced its right to require utilities to perform interference work by enacting New York City Administrative Code sections 19-143 (Excavations for Public Works), 24-521 (Excavations for Public Works), and 19-150 (Civil Penalties) that, along with court decisions interpreting these franchise provisions, impose financial penalties up to $5,000 on the Company on a per day, per location basis, if the Company does not timely relocate or protect its facilities located at the site of public works projects undertaken for the benefit, health or safety of the residents of the City. New York State also has provisions for public utilities in New York Highway Law Article 52, and Part 131 of NYSDOT Rules and Regulations - NYCRR Title 17 (Accommodation of Utilities within State Highway Right-Of-Way) that specify the facility owners are required to maintain their facilities.

Q. Is there more than one kind of interference?

A. Yes. Interference can be “direct” or “indirect.” A direct interference is that in which an existing Con Edison facility occupies the space of a proposed municipal facility and must be located, identified, and relocated to a new location in order to accommodate and provide space for a new municipal facility.

An indirect interference is that in which Con Edison facilities do not occupy the space of the proposed municipal facilities, but requires the Company to identify the location of its facilities, monitor construction work by the municipality’s contractor, and take steps necessary to support and protect its facilities by compensating the contactor for utility work performed and any incremental changes to the construction means and methods that may be incurred. This includes, for example, a change to the proposed trench sheeting and shoring system to accommodate Company facilities.

Q. Please describe the cost responsibility for Company interference related to work by or for private entities as distinguished from work performed by or on behalf of municipal entities.

A. If a private developer performs work in the vicinity of the Company's facilities, and the Company determines that any component of its electric or gas systems needs to be supported, protected, adjusted or relocated to accommodate the work, then the private entity is required to reimburse the Company for costs the Company incurs.

If, however, the City of New York ("City") or another municipality performs work, such as installing or repairing a sewer or water main in the vicinity of the Company's facilities, then the Company bears all the costs to locate, move, support, protect and/or relocate the facilities affected by the municipality's construction activity.

There are some exceptions to this general rule. For example, certain governmental authorities, such as the New York City Transit Authority and Port Authority of New York

& New Jersey, may reimburse the Company for interference costs.

Q. Apart from the installation of municipal facilities, are there any other types of governmental activities that affect the Company’s interference expenses?

A. Yes. For example, when a City street is repaved or the pavement around Con Edison’s facilities is modified, the Company may need to raise or lower its structures (*e.g.*, castings of manholes). The costs that the Company incurs to raise or lower these castings or modify these structures are also considered to be an interference expense.

State projects also may have an impact on Company facilities. For example, when a New York State bridge is repaired, replaced or modified and the existing Company infrastructure is required to be supported, relocated or replaced.

Q. What types of municipal construction activities typically result in interference with Company facilities?

A. The typical municipal activities that affect Company facilities are the installation of water, sewer and drainage facilities, reconstruction of roads, highway bridges, curbs and sidewalks, and, as mentioned above, the repaving of roadways.

Q. How often does the Company have to support, protect and/or relocate its facilities due to interferences?

A. On any given day, there are hundreds of municipal projects being planned, engineered, or constructed within the Company's service area. These projects are initiated by various New York City organizations such as the Department of Design and Construction ("DDC"), Department of Transportation ("DOT"), Department of Environmental Protection ("DEP"), Department of Parks, Bureau of Bridges, and the Economic Development Corporation ("EDC"), in addition to various Westchester County municipalities. The projects may be planned or they may be the result of an emergency, such as responding to a water main break. In either case, any resulting municipal activities will typically impact Con Edison facilities located in that area and, therefore, may present interference issues.

Q. Does the Company coordinate with municipalities in order to mitigate interference costs?

A. Yes. The Company coordinates with municipalities to mitigate interference costs both during the design and the construction phases of municipal projects.

Q. Please explain further how the Company coordinates with municipalities.

A. During the municipal design phase, the Public Improvement Engineering section of the Company’s Regional Engineering Department works closely with City and municipal agencies to minimize the impact on Company facilities. The Company may request design changes and accommodations that minimize or eliminate Company interferences. For example, if an electric facility is identified to be either in direct or indirect interference with the proposed location of a water main and if a municipal design change is viable, the Company and the municipality would work together to implement an alternate design for the municipal facility. This will reduce or eliminate the interference. The Company would then pay the municipality for the incremental cost of their design changes with the goal of achieving an overall project synergy among all stakeholders and reducing the project’s duration and/or cost to the Company.

Similarly, the Public Improvement department continues to work closely with City and municipal agencies during the project construction phase to further minimize any impact on Company facilities. For example, if during construction a gas facility not previously identified is found to be in direct or indirect interference with the proposed municipal plan, the Company and the municipality work together and where viable, the municipality would approve and implement an alternate plan or a field modification to eliminate or mitigate the interference.

Q. Is it possible to avoid or mitigate all interference conditions through City and municipal design changes and construction-phase accommodations?

A. No, it is not. Despite best coordinated efforts, due to the heavy congestion of various underground facilities within the streets, relocating or supporting Company facilities is generally unavoidable.

Q. Is the City the primary municipality that drives the level of the Company’s interference expenditures?

A. Yes. The City’s Capital Infrastructure Improvement Program is the primary driver of the Company’s interference expenditures, both for capital and O&M. Other municipalities in Westchester County and certain New York State projects also results in interference costs, but generally on a smaller scale.

MUNICIPAL INFRASTRUCTURE EXPENDITURES - RESOURCE DATA

Q. Does the City develop a forecast for its infrastructure expenditures?

A. Yes. The City of New York Office of Management and Budget ("OMB") publishes its four-year Capital Commitment Plan ("Commitment Plan") three times a year, usually in May, September and February. This plan describes anticipated infrastructure projects to which the City expects to commit funding in the current fiscal year and each of the three upcoming fiscal years for the different categories of reconstruction work. The City's fiscal year runs from July 1st to June 30th.

Q. Is the Commitment Plan the primary resource document used by the Company to identify City projects for the purpose of forecasting interference expenditures?

A. Yes, the Capital Commitment Plan is the primary resource document because it includes the most current and the best available information relating to the forecasted City expenditures that impact the Company's interference costs.

Q. Where is the Capital Commitment Plan published?

A. The OMB publishes the report on the official website of the City of New York. The OMB's web address is: https://www1.nyc.gov/site/omb/publications/publications.page

Q. Are there any particular categories of City infrastructure work listed in the Commitment Plan that typically involve interference work?

A. Yes. The categories of City infrastructure work that typically result in interference work are Highways, Highway Bridges, Water Main 1, Water Main 6 and Sewers.

Q. Explain the funding sources for the projects comprising the Commitment Plan.

A. Projects under the Commitment Plan may be funded by the City ("City Cost") or by other sources ("Non-City Cost" or "NC Cost"). The Commitment Plan identifies both City Cost and Non-City Cost funding sources.

Q. Do the projects funded by Non-City sources reduce the Company's interference expenditures?

A. No. The impact is the same for City and Non-City funding sources. The aggregate of the two sources is the driver of the Company's expenditures.

Q. What is the forecasted City OMB Budget for City fiscal years 2020, 2021 and 2022 as it relates to the categories of City infrastructure work described above (*i.e.*, Highways, Highway Bridges, Water Main 1, Water Main 6 and Sewers)?

A. The OMB Capital Commitment Plan published in October 2018 forecasts $2.8 billion for 2020, $3.5 billion for 2021 and $3.6 billion for 2022 for these categories of City infrastructure work.

Q. Does the Company also review the City’s actual spending on infrastructure?

A. Yes, the Company reviews the OMB’s “Monthly Transaction Analysis” reporting for the infrastructure categories, Highways, Highway Bridges, Sewers & Water Mains, to review and track City and Non-City expenditures.

Q. Was Exhibit ___ (MISP-1), entitled “NYC OMB EXPENDITURES 2014-2018” prepared under your supervision or direction?

A. Yes, it was.

Q. What does this exhibit show?

A. Exhibit ___ (MISP-1) shows actual OMB expenditures for City fiscal years 2014 to 2018 for these interference-type categories, as well as the City’s current commitment forecast for 2019 to 2022.

Q. Why does the Company review the City’s actual expenditures?

A. The Company compares its actual O&M expenditures to the City’s infrastructure expenditures in order to validate the historical correlation between these expenditures. This correlation is discussed in more detail later in our testimony.

Q. Are there other resources of information used by the Company to identify projects other than the City’s Commitment Plan that impact interference costs?

A. Yes, the Company actively communicates with other key municipalities/agencies, such as various Westchester municipalities, NYSDOT, NYCDOT, EDC, NYC Parks Department, DEP and DDC to obtain additional project information and other details that impact the Company’s interference expenditures.

Q. What additional details are provided by these other resources?

A. For example, in Westchester, there are over forty independent municipalities who provide project specific information that the Company uses to develop its forecast for interference expenditures.

Q. Are there particular categories of infrastructure work listed by these resources that typically involve interference work?

A. Yes. Similar to New York City, the categories of infrastructure work that typically involve interference work are highways, highway bridges, parks, water mains, and sewers.

FORECASTING METHODOLOGY

Q. Did the Company modify the methodology used in its last rate filings (Cases 16-E-0060 & 16-G-0061) to forecast interference costs for the Rate Year in this filing?

A. Yes, the Company has expanded upon the existing methodology and incorporated additional analyses.

O&M Forecasting Methodology

Q. Please list the different analyses the Company used to develop its approach for forecasting O&M expenditures relating to municipal interference work.

A. The Company's O&M forecast was calculated using the following four methods of analyses:

1. Project-By-Project Analysis,

2. NYC Budget Calculation,
3. Exponential Growth Analysis, and
4. Regression Analysis.

Q. Please explain the Project-by-Project method.

A. The Company's O&M Project-by-Project forecast is comprised of costs associated with: (1) recurring annual programs ("Annuals"); (2) municipal projects with defined scopes ("Defined"); and (3) design phase municipal projects with undefined locations or scopes ("Design Phase").

Q. Please explain these Project-by-Project categories of expenditures and the different methodologies employed to forecast expenditures in these categories.

A. The first category includes annual programs that consist of recurring work. Examples of these programs are the excavation of test pits to locate facilities and the adjustment or replacement of manhole castings. The forecast of annual programs is based on the prior year's (*i.e.*, 2017) annual cost. This method of forecasting is used for this type of work because these items are fairly predictable and repeat annually.

Q. How is this approach different from the Company's past approach?

A. This approach is different because it uses a single year's costs rather than a three-year average. Due to the progressive cost escalations experienced in recent fiscal years, the use of a three-year average would have set a target lower than the reasonably anticipated costs. The annual programs after RY1 were then escalated three percent annually to account for anticipated year-over-year growth.

Q. Please continue with your description of the second category of Project-by-Project costs.

A. The second category includes projects with defined scopes, which include projects in construction, out for bid or awarded by the municipality. These projects are evaluated based on infrastructure design plans. The Company then develops a project specific scope of work and cost estimate using established unit work items and pricing.

Q. What is the third category of Project-by-Project costs?

A. The third category includes municipal projects in the design phase. The Company's cost estimates for this category of projects are developed taking into consideration a variety of factors and using two separate methods. The first method for developing a cost estimate is for projects with a defined location and undefined scope. For these projects, the Company evaluates the potential impact based on a variety of factors: the type of Company facilities existing within the project area, the location (*i.e.,* borough and specific geographic work area), the type of interferences anticipated (*i.e.*, support, protect, alter), the type of the municipal project (*i.e.*, water mains, sewers, drainage, curbs, sidewalk, roadway) and the cost estimate of the municipal project. These factors are then evaluated based on historical experience to develop the Company's "impact cost estimates" for these types of projects.

The second method is for developing a Company "impact cost estimate" for projects with undefined locations and defined scopes, (*e.g.*, Pedestrian ramp installations, catch basin replacements). For these projects, the Company extrapolates expenditure trends from available completed projects of a similar type.

Q. Please explain the NYC Budget Calculation analysis.

A. Using NYC OMB publications, the Company analyzes the Monthly Transaction Analysis for prior expenditures and the Capital Commitment Plan to identify future forecasts. In short, the Company extracts the categories of Highway,

Highway Bridge, Sewers, Water Mains 1, and Water Mains 6 to identify the correlation between City forecasts and City actual expenditures.

Q. Please explain the Exponential Growth analysis for forecasting.

A. The Exponential Growth analysis forecasts both City liquidations (*i.e.*, actual City expenditures) and Company expenditures. Using NYC OMB Monthly Transaction Analysis reports from prior fiscal years, the Company calculated the ten, seven and five-year growth rates of actual City liquidations. The Company used these growth rates to forecast future City liquidations.

Q. What were the growth rates for the ten, seven and five-year calculations?

A. As shown in the table below, the Company calculated the growth rates as follows:

Year Range	Span of City FY	Growth Rate
10 Year	2008-2018	7.26%
7 Year	2011-2018	7.90%
5 Year	2013-2018	10.27%

Q. What growth rate did the Company use to forecast City expenditures and why?

A. The Company used a seven-year growth rate to forecast City liquidations. The seven-year growth rate was selected because it accounts for both short and long term economic variables.

Q. How did the Company apply the forecasted City expenditures as it relates to Company expenditures?

A. To forecast City expenditures using a seven-year growth rate, the Company took the average of Company expenditures divided by City liquidations over the same seven-year period and applied that factor to the forecasted City liquidations from years 2020 to 2022.

Q. Please explain the Regression Analysis used for forecasting.

A. The Regression Analysis assumes that Company expenditures are dependent on City liquidations. The model runs a regression from forecasted City liquidations which in turn are used to forecast Company expenditures.

Q. How does the Company forecast future City liquidations?

A. The City liquidation forecast for years 2020 to 2022 is based on the analysis as explained in the Exponential Growth Rate method.

Q. Please explain the results of the Regression Analysis?

A. Assuming a perfect correlation between the City and the Company there would be a 1.0 correlation coefficient. A perfect one-to-one relationship would mean that the two variables move in the same direction. In fact, the Company derived a correlation between Company expenditures and City liquidations to be .90.

Q. Did the Company rely on one single analysis to develop its O&M forecast?

A. No. The Company used all four methods described above to develop its forecast, which also reflects aspirational cost mitigating efforts and initiatives, discussed later, that are within the range of the models.

Q. Please show how the results of the various analyses are used to calculate your Rate Year forecast.

A. Exhibit MISP-2 shows the four O&M methodologies and the total O&M forecast for fiscal years 2019 to 2023.

Q. Was Exhibit ___ (MISP-2), entitled “O&M Methodologies” prepared under your supervision?

A. Yes, it was.

Q. What does this exhibit show?

A. Exhibit ___ (MISP-2) shows the four O&M methods and the O&M forecast on a line chart to demonstrate the conclusions.

Capital Forecast Methodology

Q. How did you develop the Company's capital forecast?

A. The Company's capital forecast is derived from three of the four methods used in the O&M forecast: Project-By-Project, Exponential Growth Analysis and Regression Analysis.

The Company developed the cost estimates for the capital projects using the same methodologies as described earlier in the document.

Q. Please explain the challenges associated with relying solely on a Project-by-Project analysis to develop a forecast.

A. In recent years this methodology has resulted in forecasts that turned out to be lower than the actual costs incurred.

Q. Please explain.

A. From 2014 through 2018, the Company frequently incurred costs higher than forecast under the Project-by-Project methodology. For example, the Electric Capital forecast for 2017 was $91.2 million. Actual costs incurred were $127.9 million.

Q. Was Exhibit ___ (MISP-3), entitled "Forecasts versus Capital Expenditures" prepared under your supervision?

A. Yes, it was.

Q. What does this exhibit show?

A. Exhibit ___ (MISP-3) shows the Company's prior capital forecasts compared to actual costs from 2014 to 2018. As illustrated in this exhibit, material changes in municipal infrastructure forecasts may impact the Company's expenditures.

Q. How does the Company propose to mitigate these potential forecast variances from the Project-by-Project forecast analysis?

A. The Company seeks to improve on the Project-by-Project analyses by adding two additional methods to develop better financial estimates than would otherwise result from solely relying on a Project-by-Project approach. As discussed later, material changes in recent years have left the Company under-estimating costs relating to municipal projects when relying solely on the Project-by-Project approach.

Q. Why is the NYC Budget Calculation method that is used in the O&M forecast not used for the capital forecast?

A. Historically, the Company has applied this methodology to O&M forecasting only. There is no internal history to validate using this method for capital forecasting.

Q. Have there been any modifications in the gas capital program that have reduced MISP forecasts?

A. Yes, modifications were made to the Encroachments Program within the Company's gas capital budget that have reduced this Panel's forecasts. The Encroachment Program costs will be discussed by the Gas Infrastructure, Operations and Supply Panel ("GIOSP").

Additional Challenges

Q. What influence, if any, does the Company exercise over the scope and/or timing of the work performed by the City and other municipalities?

A. While the Company employs measures to mitigate the costs related to municipal interference work (as discussed in detail in the Mitigation section below), the Company has no control over project and contractor selection, bidding methodologies, availability of municipal contractor resources, start dates or the duration of City/municipal projects. Moreover, we do not control a municipal contractor's construction means and methods and we cannot forecast the resulting incremental cost impact.

Q. Are the projects identified by the City, State and other municipalities in their plans the only projects they execute in the target year?

A. No, projects are regularly added or delayed by the City and other municipalities as compared to their proposed municipal plans.

Q. Why is it reasonable to assume that the City and other municipalities will generally execute the projects reflected in the Company's forecast for the Rate Year?

A. The majority of the Company's forecast for RY1 is based on projects already in construction/design and recurring work.

Q. What do the City's actual expenditures, as set forth in Exhibit ___ (MISP-1), demonstrate with regard to the City's spending trends?

A. Exhibit ___ (MISP-1) demonstrates that the City's actual expenditures have been steadily increasing.

Q. Has the Company identified any trends in tracking the City's Capital Commitment plan forecasts that further supports anticipated increased spending?

A. Yes, in City FY-2014 to 2018, the City progressively increases its forecasts as it approaches the actual City fiscal year. For example, the City's October 2014 projection for fiscal year 2018 was $884 million. In September 2015, the target for fiscal year 2018 was $1.6 billion. In May 2017, two months before the 2018 City fiscal start, the projection had nearly tripled to $2.8 billion.

Q. Was Exhibit ___ (MISP-4), entitled "NYC-Historical Review of Capital Commitment Plan" prepared under your supervision?

A. Yes, it was.

Q. What does this exhibit show?

A. Exhibit ___ (MISP-4) shows the OMB's commitment plans for FYs 2014 through 2019 extracted from prior Capital Commitment Plans starting in September 2010 through October 2018.

Q. Let's turn our attention to commitments versus actual municipal expenditures. Was Exhibit ___ (MISP-5), entitled "NYC Initial Commitment versus NYC Actual Expenditures" prepared under your supervision or direction?

A. Yes, it was.

Q. What does this exhibit compare?

A. Exhibit ___ (MISP-5) compares the initial municipal commitment to actual municipal expenditures.

Q. What does this exhibit show?

A. This exhibit illustrates that a comparison of the City's initial commitments for fiscal years 2014 to 2018 (published in the Commitment Plans) versus the City expenditures for this same period, has resulted in average actual expenditures that are approximately 71.6% above initial forecasts.

Q. Does the Company assume that this relationship between projected and actual expenditures will change in the coming years?

A. Yes, but the exact scope of the change will remain uncertain. Based on some of the major initiatives currently planned by the City, as described elsewhere in our testimony, the Company expects actual expenditures to be above current levels for the foreseeable future.

Q. In past proceedings, Staff has proposed basing the forecast for O&M and capital interference expenditures on a five-year average of recent actual Company costs. Is a forecast based upon a five-year average of recent actual costs a reasonable basis for setting rates?

A. No, it is not.

Q. Please explain why using an average of recent actual costs is not reasonable.

A. From 2014 to 2018, Company costs have been increasing materially because municipal spending has been increasing materially. The five-year (2014-2018) average is $104.9 million for electric O&M and $95.6 million for electric capital. In contrast, the forecasts for the Rate Year are $129.6 million in electric O&M and $193 million in electric capital, with no reasonable expectation that actual spending would, under any circumstance, be anywhere near the five-year average. Accordingly, using an average approach would not be reflective of current municipal infrastructure spending and would result in interference being significantly underfunded.

Q. Aside from the use of an average formula, have actual expenditures resulted in underfunding for past periods?

A. Yes. Under the adopted electric and gas rate plans, capital expenditure targets have consistently been less than incurred costs. As demonstrated in MISP-3, in Electric and Gas, the actual costs incurred over this period were significantly higher than the targets set as shown in the tables below:

Electric Capital	2014	2015	2016	2017	2018
Target	$69.3	$63.7	$60.6	$91.2	$103.5
Actual	$77.0	$78.6	$92.6	$127.9	$101.8

Note: Dollars in Millions and rounded

Gas Capital	2014	2015	2016	2017	2018
Target	$76.0	$72.8	$61.0	$82.4	$82.1
Actual	$73.6	$85.3	$115.4	$123.1	$120.9

Note: Dollars in Millions and rounded

Q. Please explain further the challenges of exclusively using the historic average methodology and why using an historic average is unreasonable?

A. It is not reasonable to ignore the cost estimates and timing of planned municipal projects when forecasting future expenditures.

The Company is required to respond to City/municipality timetables for the projects that the City and other municipalities design and choose to execute and is subject to penalties for failure to respond.

Accordingly, for all of the foregoing reasons, using a simple average of recent Company expenditures is not a reasonable basis for forecasting expenditures for a future period in an environment where costs have been increasing and are expected to remain above the historic average.

Q. What is the percentage of actual City expenditures compared to actual Company O&M expenditures?

A. From 2011 to 2018, the Company’s actual expenditures have ranged between 9.7% and 13.7% of the City’s actual expenditures. Exhibit ___ (MISP-6) illustrates the correlation between escalating City expenditures and similarly increasing Company O&M expenditures.

Q. Was Exhibit ___ (MISP-6), entitled “NYC EXPENDITURES VERSUS CON EDISON EXPENDITURES” prepared under your supervision or direction?

A. Yes, it was.

Q. Has the correlation been closer to the middle of the historical range, 9.7% and 13.7%, in recent years?

A. Yes, in 2015 to 2018 the average was 11.5%. Although the Company has had higher expenditures year-over-year there has been a decrease in the ratio of City expenditures to Company O&M.

Q. What decrease has the Company seen?

A. The ratio of City expenditure to Company O&M expenditure has decreased progressively in recent years;

Year	Ratio
2015	12.3%
2016	11.8%
2017	11.3%
2018	10.5%

Q. Does the Company expect to continue this downward trend?

A. This will depend on several different factors. As mentioned elsewhere in this document, costs associated with interference work are directly impacted by the type of projects selected by the municipality, the location of the projects and the Company facilities identified to be in interference. For example, in Staten Island, the Company only has an electric system that is comprised of an overhead system and underground system that shares the street with other subsurface facilities with limited congestion. By contrast, in Manhattan, the Company has an extensive electric and gas underground system that shares heavily congested streets with other subsurface facilities. Therefore, there is a direct relationship between the location and types of projects selected by the municipality and the resulting facility impact to interference costs. In addition to heavily congested subsurface infrastructure in Manhattan, there are other work conditions such as: restrictive work-hours, extensive maintenance and protection of traffic requirements, and high volume of vehicular and pedestrian traffic that are also factors impacting interference costs that are not conditions indicative to Staten Island.

Q. Upon what basis is the Company forecasting that the City’s capital expenditures will continue at the current high levels?

A. Based on current City project plans, various publications and confirmations by municipal agencies, the Company anticipates the City’s capital expenditures to be above the current levels over the next several years.

Q. Are there other emerging programs that could affect interference costs during the rate years, which cannot be fully evaluated at this time?

A. Yes. The most significant example is that the City continues to be in active design on a coastal resiliency program to reinforce the southern perimeter coast line of

Manhattan from East 23rd Street to the Battery to West 23rd Street. The City states that it plans the first phase of the coastal resiliency program for construction starting in 2020 in the area along the East River from East 23rd Street to Montgomery Street to the south. The program goal is to provide flood protection by installing a coastal barrier to protect the surrounding neighborhood from future storm surges, while simultaneously providing new community space, recreational and economic opportunities.

Q. Are there published resources from the City regarding this project?

A. Yes, please see the NYC.gov web site for The East Side Coastal Resiliency Project at: https://www1.nyc.gov/site/escr/index.page

Q. Has the Company been communicating with the City regarding this project?

A. Yes. The Company has been in joint discussions with City representatives and their design consultant to complete the design plans. The Company has provided information as to the location of its existing transmission and distribution facilities incorporating Company infrastructure support and protection requirements into the City project.

Q. What is the current design status of this project?

A. The City announced on September 28th 2018, that it is pursuing an alternative design for part of the East Side Coastal Resiliency project. See https://www1.nyc.gov/office-of-the-mayor/news/493-18/fact-sheet-de-blasio-administration-faster-updated-plan-east-side-coastal

Q. Has the Company included this in its five-year forecast?

A. Yes, the Company has included this project in its five-year forecast with a preliminary forecast totaling approximately $250 million in capital electric transmission and distribution work combined based on the original design.

Q. What is the Company’s revised cost estimate for this project?

A. The Company is in the design phase with the City and therefore has not finalized the cost estimate for this project.

Q. Are the other interference costs that are currently included in the Company’s financial projections also subject to material changes?

A. Yes. The Company’s forecasts are based on the best information available at the time the forecasts are developed. However, there are many variables that may affect the Company's expenditures that cannot be reasonably forecasted.

Some examples are:

- Unanticipated large-scale emergency sewer or water main breaks beyond what is already included in the current financial projections.
- Critical infrastructure projects, such as the Van Wyck project, pose a risk to the Company because the design-build project model is fluid and the final design that is ultimately selected could have a significant cost impact on the Company.
- Should additional State or City design-build projects emerge during the rate period the Company will not have these projects included in current forecasts.
- Fast-track projects by City agencies, expansion of shared costs between the Company and the municipality (*e.g.*, City Engineering costs, Traffic Enforcement Agents, Pedestrian Managers), are other conditions that the Company cannot reasonably forecast at this time.

INTERFERENCE – O&M

Q. Please describe O&M interference costs.

A. As described earlier in our testimony, the Company's O&M interference costs are the maintenance expenditures incurred when the Company is required to support, protect or maintain facilities due to interference with proposed City or other municipal facilities. O&M interference costs are most often associated with indirect interference and there can be some associated with direct interferences.

Q. Please provide the Company's recent actual O&M interference costs for electric and gas (excluding Company labor) by calendar year and for the 12 months ended September 30, 2018 ("Historic Year").

A. The total O&M cost in 2014 to 2017 and the Historic Year ("H.Y.") were as follows:

O&M	2014	2015	2016	2017	2018	H.Y.
Electric	$99.9	$84.1	$92.3	$126.1	$122.2	$128.7
Gas	$27.6	$28.6	$31.1	$26.9	$27.2	$28.5

Notes: Excludes Company Labor, Dollars in Millions and rounded.

Q. Why has interference O&M spending increased between 2014 and 2018?

A. As noted above, the City's actual infrastructure expenditures in the project categories that typically generate interference work for the Company have increased during the period 2014 to 2018. As demonstrated by the historic data set forth in Company Exhibit ___ (MISP-6), the level of Company O&M costs are directly related to the level of City capital infrastructure costs, and have therefore increased accordingly.

Q. What are the Company's O&M cost projections for interference in the Rate Year (excluding Company labor)?

A. The Company is forecasting $129.6 million in electric O&M and $27.1 million in gas O&M expenditures in the Rate Year.

Q. Has the Company forecasted O&M interference expenses for periods beyond the Rate Year?

A. Yes. The Company has forecasted O&M interference expenses for two annual periods beyond the Rate Year. The Company is forecasting O&M expenditures (excluding Company labor) of $140.0 million in electric O&M and $28.1 million in gas O&M expenditures for RY2. For RY3, the Company has forecasted O&M expenditures (excluding Company labor) of $146.2 million in electric O&M and $28.9 million in gas O&M expenditures.

Q. Was Exhibit ___ (MISP-7), entitled “ACTUAL AND FORECASTED O&M EXPENDITURES” prepared under your supervision or direction?

A. Yes, it was.

Q. What does this exhibit show?

A. Exhibit ___ (MISP-7) shows actual electric and gas O&M expenditures for 2014 to 2018, as well as the historical year O&M expenditures. This exhibit also shows forecasted O&M expenditures for 2019 to 2023.

INTERFERENCE - CAPITAL

Q. Please describe the capital costs associated with interference.

A. As described earlier in our testimony, the Company’s capital interference costs are expenditures incurred when the Company is required to relocate its facilities to a new location due to interference with proposed municipal facilities. Capital interference costs are most often associated with direct interference.

Q. What were the total capital interference costs incurred between calendar years 2014 and 2018?

A. The total capital costs incurred from 2014 to 2018 were as follows:

Capital	2014	2015	2016	2017	2018
Electric	$77.0	$78.6	$92.6	$127.9	$101.8
Gas	$73.6	$85.3	$115.4	$123.1	$120.9

Note: Dollars in Millions rounded

Q. What is the forecast for capital expenditures related to interference going forward?

A. The Company is forecasting from 2019 to 2023 the following expenditures:

Capital	2019	2020	2021	2022	2023
Electric	$131.0	$193.0	$201.0	$210.0	$225.0
Gas	$126.0	$101.3	$109.3	$116.8	$127.0

Note: Dollars in Millions and rounded

Q. Was Exhibit ___ (MISP-8), entitled “ACTUAL AND FORECASTED CAPITAL EXPENDITURES” prepared under your supervision or direction?

A. Yes, it was.

Q. What does this exhibit show?

A. Exhibit ___ (MISP-8) shows actual capital expenditures for 2014 to 2018 for Electric and Gas. This exhibit also shows forecasted capital expenditures for 2019 to 2023 for Electric and Gas.

MITIGATION

Q. What measures has the Company undertaken to mitigate interference costs?

A. In addressing interference costs, the Company is required to adhere to state and municipal statutes, codes, regulations and other established protocols. Given the nature of interference work and that this work (and related expenditures) is driven by factors outside of the Company's control, our opportunities for mitigation measures are limited. As part of the Company's initiative to promote a cost conscious culture, while improving external relationships with the numerous municipal agencies, the Public Improvement department has implemented the following initiatives to mitigate interference costs:

<u>Strengthening Regional Engineering</u>:

Engineering is the first opportunity for cost mitigation when interfacing with various municipal agencies during the initial design and planning phases of a project. Engineering takes the opportunity to study the agencies' scopes of work and perform an in-depth analysis to determine the type, nature, and extent of the interferences. During the planning phase of agency projects, Engineering may suggest, request and/or discuss with the municipal agency possible scope changes to minimize interferences and request design accommodations, as discussed earlier in our testimony. The engineering group also provides consulting support to the field that assists to mitigate the impact of unanticipated, as-found subsurface field conditions during construction. Additionally, when the municipality determines the street will be excavated, Con Edison uses this opportunity to consolidate existing infrastructure and reduce maintenance costs while still providing the same level of service capacity. For example, when multiple service boxes or manholes exist on a block, the Company's engineering group may redesign, consolidate and reduce the number of structures, thereby lessening future maintenance costs. Moreover, consolidating structures provides for additional space in the streets for future use by the Company, the City and other utilities.

<u>Coordinate interference work with other Company capital projects for synergies and cost savings</u>:

The Company incorporates interference work with other Company capital project work to the greatest extent practicable that the municipal schedule allows. Our effort to coordinate the interference work with other Company capital projects is accomplished during the municipal engineering design phase or during the construction phase of the municipal projects.

When the Interference group receives notice from the City that a new municipal project is planned, it issues a notification of the project scope and locations to the Company’s Electric, Gas and Steam Engineering groups. During the municipal project design phase, internal Company meetings are scheduled between the Public Improvement Engineering section and other Company engineering groups that review the potential to include Company capital project work, (such as new business, system upgrades, gas main replacement program, and/or other system reliability work) with the proposed municipal project work. This effort results in minimizing adverse impacts to the community by reducing street opening redundancies and minimize delays to municipal projects.

Maximize Number of Section U Projects:

The protocol for Section U is established jointly by the City and the major utilities operating in the City. The

Section U protocol provides the Company with certain limited leverage to negotiate a fair market price with the City agency contractors for the Company's portion of interference work. Under the Section U protocol, the contractor of record for the Section U project negotiates in an attempt to reach an agreement with the utilities prior to the start of the project. If an agreement cannot be reached, the matter is submitted for arbitration to the American Arbitration Association and the result is final and binding.

Projects are not automatically classified as Section U until approved by the DDC. Through efforts undertaken by the Company's engineering department while meeting City requirements, the Company has been able to maximize the number of interference projects categorized under Section U. Benefits include early coordination and participation between the City and the utilities in the development of the overall project scope, resulting in municipal design changes and accommodations to minimize utility interferences.

Joint Bid Protocol:

For work performed under the Joint Bid protocol, the Company’s interference work is included in the City bid documents and is bid along with the City work. The City and the various utilities jointly coordinate their work from the outset of the project and both City and utility work is managed under singular project oversight, which generally results in improved project scheduling and more efficient construction management providing for an overall enhanced customer experience. The program has evolved from Lower Manhattan in 2004 to Citywide today.

Negotiating Team:

The Company uses a negotiating team concept when entering into agreements. The team consists of the estimator, the project engineer, the borough manager and the borough project specialist. The negotiating team has been extremely successful since its inception by facilitating pricing uniformity for work items throughout the boroughs thereby reducing prices for commonly used items that resulted from estimating time studies. Additionally, time studies support challenges from contractors in arbitration if the pricing offered by the company is perceived to be inconsistent with fair market value.

Unit Price Agreements

The Company has also used multi-year and multi-borough contractor agreements for macro work units to establish consistent pricing across its service area. This effort may also reduce Company administrative costs that would normally be associated with multiple negotiations for different projects with the same vendor.

Evaluate field conditions to create new macro work units:

Since the mid-1990s, Con Edison has been working with the communication utilities Time Warner (Time Warner is currently doing business as, Spectrum, a brand of Charter Communications Inc.) and Empire City Subway ("ECS"), which owns and maintains underground facilities for Verizon. The Company has worked with Time Warner and Empire City Subway to develop a list of common work units as a means of standardizing municipal field work. These standardized units are referred to as Con Edison, ECS and Time Warner ("C.E.T.") specification items. The list has expanded over time and presently includes more than 250 items that cover common utility work tasks.

Maximize Lump Sum Agreements:

The Company promotes lump sum agreements, which are single price agreements that encompass all labor, material and equipment to complete the defined work. This creates financial incentive for efficient construction management by the contractor instead of negotiating for extra work on a piecemeal basis. The agreements also reduce the Company’s risk by minimizing adverse impact on Company facilities and potential costs associated with project schedule delays. These project agreements also aid the Company in forecasting future budget years, but cannot remove the overall uncertainty.

Opportunities to reduce project costs by performing advanced relocation:

When feasible, the Company utilizes advanced relocation of Company facilities to avoid interferences with City facilities. The Company utilizes predominately in the outer boroughs where it is more feasible than in Manhattan’s congested streets. Recently and where operational flexibility has been afforded, the Company has been more aggressive in attempting to perform advance work in Manhattan to minimize the impact on the City schedule, the community, and reduce the financial exposure from having to negotiate pricing with the City’s contractor. The Company uses the Company’s existing contractors to perform the work in advance at a lower overall cost when compared to the costs of using the municipal City contractors to perform interference work. The advance work will result in less interferences, which in turn will minimize overall interference costs and potential delays.

RECONCILIATION

Q. Does the Company’s current electric and gas plans provide for reconciliation of capital and O&M expenditures related to interference?

A. For O&M expenses, the plans provide for full downward reconciliation of actual expenses below the targeted level of expenses and reconciliation of amounts (other than Company labor) for up to 30 percent above the target level of expenses, shared on an 80/20 basis between customers and the Company, respectively, with three exceptions as set forth in the rate plan.

For electric capital expenditures, Municipal Infrastructure Support costs are not subject to separate reconciliation.

They are part of electric net plant, which is subject to downward-only reconciliation.

For gas capital expenditures, Municipal Infrastructure Support costs are subject to full downward reconciliation as part of gas operations net plant with a limited upward reconciliation for certain interference capital costs.

Q. Is the Company proposing any modifications to these mechanisms as they apply to either capital or O&M expenditures?

A. Yes. The Company is proposing a full reconciliation of Municipal Infrastructure Support capital expenditures and O&M expenses, in the manner proposed by the Company's Accounting Panel.

Q. Why should the Commission adopt full reconciliation of Municipal Infrastructure Support capital expenditures and O&M expenses?

A. As we have explained in this testimony, interference costs are beyond the Company's direct control, are not subject to reasonable estimation, are driven by the infrastructure work performed by the City, State and other municipalities, and constitutes work the Company is required to perform pursuant to a schedule established by the municipality that often requires a significant diversion of Company resources and significant incremental costs. Moreover, there are a number of major City infrastructure initiatives under consideration that are not yet included in the Company's forecast, but which could potentially have significant cost impacts.

Accordingly, the Company believes that rates should reflect a reasonable estimate of these expenses and then be subject to full reconciliation, as further explained by the Company's Accounting Panel.

Q. Should there be a concern that the Company will not seek to minimize its interference costs if there is full reconciliation of these expenses?

A. There should be no concern. The Company has demonstrated a long-standing and consistent approach to mitigating these costs, to the extent practicable, and continued coordination between the City and the Company during the design phase, which is a critical component of the continued success in controlling rising costs. The Company has consistently followed this approach, including during periods when a bilateral reconciliation mechanism for interference expenses was in place (*e.g.*, as adopted in the

Commission’s April 2009 rate order in Case 08-E-0539). Moreover, these cost mitigation efforts are ingrained in the Company’s efforts to implement cost management improvements.

Q. Do you have any concluding remarks?

A. Yes. For all of the foregoing reasons, the Commission should adopt the Company’s forecasted O&M and capital expenditure levels for the Rate Year and the proposed reconciliation mechanisms for capital and O&M interference expenses.

Q. Does this conclude your direct testimony?

A. Yes, it does.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

CUSTOMER OPERATIONS PANEL

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CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

CUSTOMER OPERATIONS PANEL

I. <u>INTRODUCTION</u>

Q. Would the members of the Customer Operations Panel please state their names and business addresses?

A. Marilyn Caselli, Christopher Grant, Hollis Krieger, Michael Murphy, Christine Osuji, and Matthew Sexton. The business address of Ms. Caselli, Ms. Krieger, Mr. Murphy, and Mr. Sexton, is 4 Irving Place, New York, NY 10003; the business address of Ms. Osuji is 30 Flatbush Avenue, Brooklyn, NY 11217; and the business address of Mr. Grant is 1601 Bronxdale Avenue, Bronx, NY 10462.

Q. By whom are the Panel members employed?

A. We are employed by Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company").

Q. In what capacity are the panel members employed and what are their professional backgrounds and qualifications?

A. **(Caselli)** I am the Senior Vice President of Customer Operations. I have overall responsibility for the Company's customer service programs, including customer outreach, meter reading, billing, and answering customer inquiries. I also oversee the administration of the Company’s retail choice program that supports the competitive energy marketplace. I began my employment with Con Edison in 1974. From 1974 to 1989, I held positions of increasing responsibility within the

Company, rising to the position of General Manager, Customer Operations for Queens. In l992, I took the position of General Manager, Customer Operations for Brooklyn and then, in 1996, I took the position of General Manager, Gas Operations for Queens. In October 1997, I took the position of Vice President, Customer Services for Staten Island and, in May 2005, I was promoted to my current role of Senior Vice President, Customer Operations. I hold a Bachelor of Science degree in Business Administration from the State University of New York.

(Grant) I am the General Manager of Field Operations in Customer Operations. I am responsible for meter reading and field collections throughout the service territory. I am also responsible for theft-of-service investigations and the Field Operations Performance Management Group. I have been employed by Con Edison for almost 21 years and have held a variety of management positions within Customer Operations, in addition to a position in the Steam Business Unit. In 2014, I was promoted to General Manager, Field Operations. I earned a Bachelor of Science degree in Business Management from Cornell University.

(Krieger) I am the Department Manager for Customer Outreach and Education. I am responsible for the Company’s outreach and education program, including outreach to customers, community groups, and officials. I have held this position since January 2015. I joined Con Edison in 1980 and have held positions of increasing responsibility. The Customer Operations positions held prior to my current position include: Section Manager in Regulatory and Performance Analysis, Section Manager in Retail Choice, and Senior Specialist in various Customer Operations departments. I have a Bachelor of Arts in English from Queens College, City University of New York and a Masters of Arts in Creative Writing from Queens College, City University of New York. I also attended the Program for Manager Development at the Fuqua School of Business, Duke University.

(Murphy) I am General Manager of Strategic Applications. My current responsibilities include oversight of various operating components: the Final Bills collection group, Public Assistance processing group, and the replevin processing group. My organization also provides subject matter expertise and operational support in the areas of system design and implementation, metering and billing systems, credit/collections, and oversees analysis and improvements in the area of Customer Experience, including our Digital Customer Experience (“DCX”) program. I have been employed by Con Edison for over 18 years and have held a variety of positions within Customer Operations, in addition to an assignment as Section Manager Stores Operations in Supply Chain. My prior positions in Customer Operations include Department Manager Digital Customer Experience, Department Manager Operations and Applications Support, Section Manager Retail Choice Operations, Senior Specialist Corporate Customer Group, and Supervisor Specialized Activities. I earned a Bachelor of Science degree in Business Administration from the University at Albany. I also earned a Masters of Business Administration from Fordham University in Management of Information Systems.

(Osuji) I am General Manager of the Customer Assistance group in Customer Operations. My group includes the Company’s Customer Experience Centers (formerly known as the Call Center), back office functions including billing, credit operations, and customer investigations, as well as the Company’s Walk-in Centers. I joined Con Edison in 2000 as a specialist in Human Resources. I have held positions of increasing responsibility in Human

Resources Employee and Labor Relations, Leadership and Career Development, and Customer Operations. I earned a Bachelor of Science degree in Business Administration from State University at Buffalo.

(Sexton) I am the General Manager of Specialized Activities in Customer Operations. Specialized Activities includes the Corporate Customer Group, Retail Choice Operations, Executive Action Group, and Meter Action/Unmetered Services Group. I have held this position since December 2017. I joined Con Edison in 2004 as a Supervisor in Customer Operations, and have held a variety of positions within Customer Operations, in addition to an assignment as Section Manager for the NorthStar Management Audit in Business Finance. My prior positions in Customer Operations include: Department Manager Digital Customer Experience, Section Manager Accounting/Personal Service, Section Manager Process Excellence, Section Manager Off-Hours Call Center, and Senior Specialist Off Hours Call Center. I have a Bachelor of Business Administration degree in Financial Accounting from Baruch College and a Master of Business Administration in Human Resource Management from Baruch College.

Q. Have you previously submitted testimony or testified before the New York State Public Service Commission the “Commission”)?

A. Ms. Caselli, Mr. Grant, Ms. Krieger, Mr. Murphy and Ms. Osuji have submitted testimony in previous cases. Mr. Sexton has not submitted testimony before the Commission.

II. SUMMARY OF TESTIMONY

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

A. This Panel’s testimony presents an overview of planned programs for Customer Operations that are necessary, in conjunction with other Company programs addressed by other witnesses/panels, to achieve the following core objectives: 1) strategically transform operations to provide customers with a ‘Next Generation Customer Experience,’ 2) address ongoing operational priorities, including elimination of customer-funded credit and debit card transaction fees, increased resiliency of our customer care infrastructure, expanded use of electronic delivery (“e-delivery”) for written correspondence, and leveraging Automated Metering Infrastructure (“AMI”) data to achieve greater success in the revenue protection area, and 3) meet our Operations and Maintenance (“O&M”) savings targets identified as part of the Company’s Business Cost Optimization (“BCO”) initiative. The Panel will also discuss continuation of the Company’s Off-System Billing program and Electric and Gas Low Income programs, plans for Customer Outreach and Education, and a proposal to eliminate reconnection fees for some customers to reflect new operating procedures enabled by AMI technology.

Q. Please expand on the core objectives you outlined above and how they are addressed in this rate filing.

A. First and foremost, Customer Operations is committed to enhancing the customer experience. Customer Operations will achieve this through its Next Generation (“Next Gen”) Customer Experience (“CX”) initiative by meeting rising customer expectations, facilitating New York’s clean energy policy goals and programs, and driving operational efficiencies. The Company is working to provide industry-leading CX by listening to our customers, continuing to close the technology gap between utilities and other industries (*e.g.*, telecommunications and banking), and implementing a comprehensive CX strategy to increase customer satisfaction and drive cost efficiency.

The Company will continue addressing ongoing operational priorities that will enable us to provide quality customer service. In this testimony, we discuss planned programs to address the sustainability of our infrastructure, the use revenue protection analytics, expanded electronic communications with customers, and elimination of credit and debit card transaction fees for residential and small business customers.

We are working to meet our O&M savings targets identified as part of the Company’s BCO initiative by improving operational efficiencies and managing costs. Through the Next Gen CX initiative, the Company will invest in programs that will expand self-service resources and tools designed to meet customer needs and expectations, which we expect will lead to cost savings due to reduced calls to our Customer Experience Centers.

Finally, many of the programs described below support the Company’s efforts to implement the Commission’s Reforming the Energy Vision (“REV”) goals. The Company aims to continue to be a trusted energy advisor and facilitate REV goals by building trust with customers though excellent service and providing customers with choice, control, and convenience in the tools and products provided as part of its Next Gen CX initiative.

Q. What period does your testimony cover?

A. The Panel will present the programs planned for the 12 month period ending December 31, 2020 (“Rate Year” or “RY1”). While, as discussed by the Company’s Accounting Panel, the Company is not proposing a multi-year rate plan in this rate case, the Company is interested in pursuing, through settlement discussions with Staff and interested parties, a multi-year rate plan. To facilitate settlement discussions, we also address capital plant additions and other programs and initiatives for the two years following the Rate Year. We will refer to the 12 month periods ending December 31, 2021 and December 31, 2022 as “RY2” and “RY3,” respectively.

Q. What is the aggregate projected spending for Customer Operations activities described in this testimony?

A. In total, the Company projects expenditures of $26.69 million in RY1, $22.975 million in RY2, and $20.8 million in RY3 on customer-service related capital programs described in this testimony. The Company projects the programs discussed by this Panel will require additional incremental O&M expenditures of $7.419 million in RY1, $2.516 million in RY2, and $1.088 in RY3. We note that these expenditures do not include the O&M costs to achieve BCO savings, which are netted out of the Customer

Operations’ total BCO savings targets as discussed in the Accounting Panel. Customer Operations also anticipates O&M savings across the three Rate Years resulting from the Company’s ongoing AMI program. AMI-driven savings for Customer Operations are described below and in EXHIBIT__(CO-11).

Q. Are some of your programs applicable to both electric and gas services?

A. Yes. We note that the programs described in our testimony address the needs of both electric and gas customers and, therefore, the associated costs are allocated as common programs. The Accounting Panel describes and applies the allocation of these costs between electric and gas service.

Q. Does your testimony address any other topics?

A. Yes. Our testimony also addresses continuation of the Company’s Customer Service Performance Mechanism (“CSPM”) and the Residential Service Terminations and Uncollectible Bills performance mechanism established in the Company’s 2016 rate proceeding.

Q. Does your testimony propose any new incentives or mechanisms?

A. No. The Clean Energy Solutions Panel discusses continuation of the AMI Customer Awareness Earnings Adjustment Mechanism.

III. NEXT GENERATION CUSTOMER EXPERIENCE INITIATIVE

Q. Please summarize the Company’s Next Gen CX initiative.

A. The Next Gen CX initiative is a portfolio of investments that will allow the Company to continue to meet customer’s rising expectations, facilitate policy goals, and drive operational efficiencies. To achieve these objectives, the Company plans to make investments in proven technologies that will allow for the development of new customer services during this rate plan and lay the foundation for the future. We developed the Next Gen CX investments described below with a leading customer experience consultant that works across several industries, including banking, telecommunications, and retail. We incorporated current cross-industry customer expectations and technology investment trends.

The three major categories of investments included in the Company’s Next Gen CX initiative are Business Intelligence, Omni-Channel Optimization, and Back Office Automation and Agents Tools, described below:

- Business Intelligence – invest in a Data and Analytics program that uses advanced data and analytics to drive new customer and business insights;

- Omni-Channel Optimization – enable a seamless multi-channel self-service experience for customers with investments in DCX, Journey Mapping, Virtual Assistants, and Bill Redesign; and
- Back Office Automation and Agent Tools – develop intelligent tools designed to improve processes and operational efficiency, and concentrate on value-add customer focused activities.

Q. Please elaborate on the practical or real-world benefits that customers will see from the Next Gen CX investments.

A. Next Gen CX has two overarching benefits for customers. First, customers will see more streamlined, prompt, and accurate customer service in the customer’s channel of choice (e.g., web, phone, text, chat). This includes, for example, new enhanced self-service tools for managing payments and faster resolution of inquiries when interacting with the Company. Overall, customers will see more choice, control, and convenience when managing their energy and interacting with the Company. Second, customers will benefit from cost savings realized through operational efficiencies such as resolution of issues on lower-cost self-service channels, and automation of back office work.

Q. When will the Company be making these investments?

A. These investments are planned during the Rate Years 1-3. However, each investment will be foundational and we will use an iterative approach. This allows for continued value-based investment beyond the rate years to address rising customer expectations and the required services associated with new programs supporting the State's clean energy goals.

Q. How does this initiative intersect with other programs that the Company is proposing in this rate filing?

A. This initiative intersects with a number of programs and projects including AMI, the new Customer Service System ("CSS"), the Information Technology ("IT") Technology Enabler known as Data Analytics, and our Energy Efficiency and Demand Management ("EEDM") programs. Each of these initiatives impact customer facing processes, and therefore proper coordination will be essential. We have considered them in each initiative's development. In addition, this initiative supports the BCO initiative through cost savings, as explained in the BCO Savings section of this testimony.

Q. How will the Next Gen CX initiative advance the State’s clean energy and REV goals?

A. The Next Gen CX initiative supports advancement of the State’s clean energy and REV goals through the development of an overall flexible technology platform that can be cost effectively modified to support emerging program needs. For example, the Data and Analytics program will deepen the Company’s understanding of customer needs and behavior and will inform how different REV programs influence and impact different customer groups, enabling a deeper analysis for the expected success of each REV program. The DCX program will facilitate greater customer engagement and provide convenient, seamless experiences for customers to sign up and participate in demand-side management (including EEDM), distributed energy resources, new time-variant rates and other advanced energy technologies and programs. The DCX program is already supporting the State’s policy goals through the development of a new Home Energy Analysis tool that enables customers to better understand their energy usage and suggest actions to achieve savings. The Journey Mapping program will help deliver consistent, positive experiences, creating the potential for increased engagement in EEDM and other clean energy programs. Finally, the Bill Redesign program will provide customers with a paper bill that is available electronically and easy to read, provides graphics for a quick understanding of their energy usage, and has a flexible format that allows for customized product suggestions and program offerings directly on the bill, further encouraging customer adoption of innovative solutions that make sense for their home or business.

Q. Has the Company already begun to incur costs associated with the Next Gen CX initiative?

A. Yes – the Company conducted benchmarking and research to develop the business cases outlined below, and established a Customer Experience Center of Excellence ("CX COE") to oversee and coordinate implementation of the Next Gen CX initiative across the enterprise. Further information on this preliminary work is included in the program descriptions that follow.

A. BUSINESS INTELLIGENCE

1. DATA AND ANALYTICS

Q. Please summarize this Panel's Data and Analytics program.

A. The Data and Analytics program, a foundational component of the Business Intelligence category of investment for the Next Gen CX, will provide the Company with customer insights through the development and use of advanced data analytical tools that will help improve the customer experience and reduce operating costs. With this program, the Company seeks to gain a deeper understanding of our customers and unlock the business intelligence that is an enabler for the entire Next Gen CX initiative.

The Company already has a significant amount of data about its customers that resides in numerous internal systems and databases, including but not limited to, energy consumption, payment history, rate/program enrollment (e.g., EEDM programs, time of use ("TOU") rates, low income discounts), and the type and channel of historical interactions with the Company (including detailed interactive voice response ("IVR"), chat and web logs). The Data and Analytics program will connect these disparate data sources, and enable Con Edison to sort through the resulting data to identify patterns, trends, and correlations.

Q. What are the overall goals and objectives for the Data and Analytics program?

A. The Data and Analytics program seeks to:

- Develop a deep understanding of customer's needs through analysis of customer segmentation, program adoption, and interaction pain points;

- Recommend programs and services to customers through propensity analytics of customer behavior, resulting in actionable recommendations;
- Create actionable insights for employees such as cross channel usage analytics, operational analytics, and natural language analytics; and
- Enhance quality assurance through insights based on analysis of customer inquiry resolution at initial contact, operational efficiency and compliance analytics, and employee or customer fraud reviews.

Additional details and the work that will be done to achieve these goals are provided in EXHIBIT__(CO-1).

Q. Please describe the status of the Company's efforts related to the Data and Analytics program.

A. Con Edison conducted a study to define the business requirements, technical design, and architecture of the Data and Analytics platforms and tools. The Company also launched a pilot project in 2018 using data profiling and advanced analytics to identify outliers or anomalous behavior related to employee processing of customer related transaction such as customer refunds and transfers of funds between accounts.

Q. What benefits will the Data and Analytics program provide for customers?

A. The Data and Analytics program will analyze customer data to identify patterns, trends, and correlations, which will enable the Company to better identify customer pain points and future needs. Using these insights, the Company can anticipate and preemptively address customer pain points and future needs, resulting in more positive customer interactions. As the program matures, Con Edison expects to provide customers with more tailored recommendations on how to meet their energy usage and cost savings goals. Additionally, Con Edison will use customer interaction insights to provide front-line employees and customers with personalized real-time customer-specific assistance.

Q. Why is it important that these investments are made at this time?

A. Insights from the Data and Analytics program are essential to the successful execution of the Next Gen CX initiative. This program will be able to answer critical questions for other investment programs including, but not limited to:

- How customers interact with Con Edison across multiple channels and transaction types (Journey Mapping)

- Communication delivery preferences and engagement analysis for electronic delivery (Bill Redesign)
- Next best action identification engines and natural language analytics (Agent Tools)

Q. What is the projected capital cost of this project?

A. The capital costs for the Data and Analytics program is estimated to be $5 million for each Rate Year 1-3.

Capital funding requested for this program will cover the costs to incorporate data into platforms. The Company will be able to use these platforms to develop data models, and integrate these models with customer-facing and employee-facing systems to perform functions such as the creation of executive-level dashboards.

Q. Are there any cost savings projected from this program?

A. Yes. The Data and Analytics program will contribute to achieving Customer Operations' BCO Savings targets. Additional details regarding these savings are provided in the BCO section of this testimony and presented in Exhibit AP-3, Schedule 16.

Q. Have you prepared, or had prepared under your supervision, exhibits that detail the Company's proposed investment in the Data and Analytics program?

A. Yes. We have prepared two exhibits, entitled “DATA AND ANALYTICS” EXHIBIT__(CO-1) and “DATA AND ANALYTICS USE CASES” EXHIBIT__(CO-2).

MARK FOR IDENTIFICATION AS EXHIBIT__(CO-1) and EXHIBIT___(CO-2).

B. OMNI-CHANNEL OPTIMIZATION

1. DIGITAL CUSTOMER EXPERIENCE

Q. Please summarize the Company’s DCX program.

A. The DCX program is a core program for Omni-Channel Optimization, one of the three major categories of investments included in the Company’s Next Gen CX initiative, as explained above. The DCX program was established in 2016 to improve the digital experience for customers through a redesign that covered the www.conedison.com and www.coned.com external websites, with a new mobile-enabled design, My Account portal, and mobile apps (IOS and Android). Quarterly reports filed by the Company in Cases 16-E-0060 and 16-G-0061 provide additional implementation details.

Q. Have these digital investments been well-received by customers?

A. Yes. As a result of customers’ engagement with the new My Account features and positive customer experience, the Company’s Net Promoter Score (“NPS” – a common metric for websites that is also referred to as an online user’s ‘likelihood to return’ with a range from -100 to 100) has increased from –28.6 to +26.7. The average NPS score overall for utility websites is listed by Esource, an independent market research and consulting company, as -3.

Customers have also responded well to the Company’s new mobile applications for Apple and Android devices launched in 2018, with ratings of 4.8 and 4.6 (out of 5), respectively. Additionally, Esource ranked the new applications as the second best utility mobile applications, behind Florida Power & Light.

Q. Has the DCX program resulted in increased customer use of self-service tools and other benefits as outlined in the DCX business plan?

A. Yes. The DCX program has already begun is already successfully delivering improved customer satisfaction, customer engagement, and reduced costs because customers have their problems resolved without the need for a phone call. Since the launch of the new My Account experience in July 2017, the Company has seen monthly average users (i.e., the number of Con Edison and Orange & Rockland Utilities, Inc. users who log in at least once in a month) dramatically increase from approximately 99,000 to 376,000.

The Company has also seen positive trends in online/digital transactional activity that support the conclusion that increased customer engagement on digital platforms is, in fact, resolving issues without calls. An example of this is the positive performance of the recently-released Start/Stop/Transfer functionality, which has enabled over 250,000 completed transactions online since its launch in July 2017.

Q. Does the Company propose to continue investing in the DCX program through 2022?

A. Yes. Customers’ expectations of digital customer service will continue to rise based on interactions with companies outside of the energy industry. Examples of these rising expectations include customer-focused simplicity, mobile access, and real-time tracking and notifications. Over time, customers’ rising expectations will iteratively escalate base-level service expectations, making what was once extraordinary, ordinary. In recognition of this rapidly evolving digital landscape, the Company has made continued investment in DCX a foundational component of its Company Omni-Channel Optimization strategy, which, in turn, will help us achieve our goals of delivering a Next Gen CX. We, therefore, propose to extend the DCX program through 2022 to refine and build upon the digital platforms that we have developed to date.

Q. Does the Company intend to maintain the same guiding principles and project management approach for the DCX program if these digital investments continue through 2022?

A. Yes. The Company intends to maintain the same guiding principles for the DCX program during Rate Years 1-3, which are available in EXHIBIT__(CO-3).

The Company will also continue to use a customer-centric, “Agile” project management approach (i.e., an iterative and incremental method of managing the design and build of digital platform) that adapts project scopes to changing priorities based on customer feedback and analytics. The Company will continue to update Staff and stakeholders on the evolution of the DCX program by filing quarterly reports with the Commission as it has since 2017.

Q. Please describe the proposed scope and objectives of the DCX program for the 2020-2022 time-period.

A. The Company will continue to optimize and expand its digital platforms in order to offer additional online self-service tools, enhance mobile app functionality, provide customers with more personalization and control, consolidate additional existing digital channels into the DCX program scope (e.g., text and email), and expand customer payment options, among other things. Please refer to EXHIBIT__(CO-3) for a comprehensive description of each of the DCX program's key focus areas during Rate Years 1-3.

Q. What is the Company's forecasted capital cost to continue this program?

A. The Company proposes to spend $13 million in capital per year for Rate Years 1-3, for a total of $39 million.

Q. Is the Company planning to increase the amount of O&M associated with the DCX program?

A. Yes. The Company requests an increase of $79,000 for RY1 and additional increases of $152,000 and $159,000 respectively for RY2 and RY3. As the DCX program will contribute to achieving Customer Operations' BCO Savings targets, fifty percent of the incremental O&M costs associated with this program are treated as costs to achieve those targets. As such, the O&M costs shown have been adjusted to reflect this treatment.

The DCX program has introduced new IT infrastructure to support the experience on the Company's various digital platforms. As such, associated implementation and ongoing O&M funds are needed to maintain the new systems brought online. Non-labor expenses for this program include software-related fees charged by vendor support and ongoing costs for related technology solutions deployed by the DCX program. Labor expenses will fund additional full time equivalent ("FTE") resources to provide day-to-day maintenance and management of the new digital architecture, manage the customer experience, and create and introduce new creative content. Additional information on these expenses are included in EXHIBIT__(CO-3) and EXHIBIT__(CO-4).

Q. Are there any cost savings projected from this program?

A. Yes. The DCX investments described in EXHIBIT__(CO-3) are part of the BCO savings described later in this Panel's testimony.

Q. Have you prepared, or had prepared under your supervision, exhibits that detail the Company's proposed investment in the DCX program?

A. Yes. We have prepared two exhibits, entitled "DIGITAL CUSTOMER EXPERIENCE" EXHIBIT__(CO-3) and "DIGITAL CUSTOMER EXPERIENCE WORKSHEET" EXHIBIT__(CO-4).

MARK FOR IDENTIFICATION AS EXHIBIT__(CO-3) and EXHIBIT__(CO-4).

2. JOURNEY MAPPING

Q. Please summarize the Company’s Journey Mapping program.

A. Journey mapping, another component of the Company’s Next Gen CX Omni-Channel Optimization investment category, is a process improvement method that explores the full sum of a customer’s experience when interacting with a company, not just discrete interactions or transactions. Unlike other process improvement techniques, journey mapping focuses on the customer and is grounded in what is commonly referred to as Voice of the Customer (“VOC”) data, which is an amalgam of customer research, benchmarking data, and operational data.

Con Edison’s Journey Mapping program will undertake seven core customer journeys during Rate Years 1-3: Sign up for Service and Onboarding, Outage Communications, Billing and Payment Assistance, Billing and Payment Process, Energy Efficiency and Management, Emergency Services, and Account Changes.

Q. What are the overall goals and objectives for the Journey Mapping program?

A. The goals and objectives of the Journey Mapping program are:

- Meet the current and future expectations of Con Edison’s diverse customer base.
- Define and redesign customer interactions for experiences associated with each of the journeys.
- Improve customer satisfaction through identification and prioritization of pain points in each journey.
- Drive customer loyalty by delivering consistent and satisfying experiences across all channels.
- Build trust in Con Edison by redesigning journeys based on customer feedback, customer research, and external benchmarking.

Q. Please describe the status of the Company’s efforts related to Journey Mapping.

A. To date, Con Edison has started journey mapping efforts for two of the seven core journeys. The first effort began in January 2018 for the ‘Sign Up for Service and Onboarding’ journey. This journey seeks to improve the overall experience for customers requesting service regardless of whether they use a self-service channel or speak to a Customer Service Representative (“CSR”). This includes streamlining the process to make it more simple, and providing clear and timely notifications of the status of the customer’s request to initiate service.

The second effort began in March 2018 for Outage Communications, and focuses on delivering clear and more frequent Estimated Time of Restoration (“ETR”) communications on customer’s most preferred communication channels, and providing additional outage resources to customer facing employees.

Q. Has the Company already learned valuable information from the journey mapping done to date?

A. Yes. The Outage Communications journey mapping team conducted a survey of customers that experienced an outage in the past year. The findings indicated that a majority of customers want to communicate with Con Edison more frequently, via text message. As a result, the Outage Communications journey mapping team has created a series of new messages and revised wording to improve clarity and empathy of existing messages. In addition, the journey mapping team is working on a project to enable over one million customers to have the ability report an outage via text message. By expanding the text notification program, the Company expects to improve customer satisfaction and reduce the volume of emergency-related calls during a major outage event.

Q. Briefly explain the work involved in Journey Mapping.

A. The work involved for the Journey Mapping program can be categorized into five main process steps, which are detailed in EXHIBIT__(CO-6). Journey mapping follows a lifecycle of continuous improvement, which means that the journey mapping teams do not move linearly from step to step. This flexibility is necessary because customers and external influences are always changing.

Q. What is the projected capital cost of this project?

A. The estimated capital costs for the program are $1.19 million in RY1, $975,000 in RY2, and $600,000 in RY3. The estimated total capital cost of this program for the 2020-2022 period is $2.765 million. The capital funding requested for this program will fund capital improvement projects identified by each of the journey mapping teams, such as new processes and technology investments in new systems.

Q. Are there any cost savings projected from this program?

A. Yes. The Journey Mapping program will contribute to achieving Customer Operations' BCO Savings targets. Additional details regarding these savings are provided in the BCO section of this testimony and presented in Exhibit AP-3, Schedule 16.

Q. Have you prepared, or had prepared under your supervision, exhibits that detail the Company's proposed capital investment in the Journey Mapping program?

A. Yes. We have prepared two exhibits, entitled "JOURNEY MAPPING" EXHIBIT__(CO-5) and "JOURNEY MAPPING PROCESS OVERVIEW AND BENEFITS" EXHIBIT__(CO-6).

MARK FOR IDENTIFICATION AS EXHIBIT__(CO-5) and EXHIBIT__(CO-6).

3. VIRTUAL ASSISTANTS

Q. Please summarize the Company's Virtual Assistants program.

A. The Virtual Assistants program, another component of Omni-Channel Optimization, will deploy a conversational virtual assistant, or bot, to provide unique, interactive, and personal assistance to customers across the chat, IVR, web/mobile web, mobile app, social media, and text platforms. Virtual assistants will provide customers with a new form of frontline support that automates many simple interactions, such as Start/Stop/Transfer service, payment, and payment assistance, currently performed by a CSR on the phone or through the existing live chat tool. With this program, the Company will expand the channels of interactions that are already available to customers across a variety of industries.

Q. How will virtual assistants provide frontline support to customers?

A. Virtual assistants will use artificial intelligence (“AI”) to learn Company processes and interact with customers to answer customer inquiries. The bots are also programmed to detect customer frustration, respond appropriately, and initiate seamless transfers to live agents when necessary.

The Company will invest in a virtual assistant AI program that will integrate with all of the systems that manage customer data or serve as an interface for customer interactions. Once we integrate the virtual assistant AI program with these systems, the bots will be able to suggest Next Best Actions or communicate directly to CSRs or customers on behalf of the Company.

Q. What are the overall goals and objectives for the Virtual Assistants program?

A. The overall goals of the Virtual Assistants program are to improve the customer experience and achieve operational efficiencies that result in cost savings. Virtual assistants will provide an interactive and personal way for customers to obtain answers and assistance across multiple channels, 24 hours a day, 7 days a week, and 365 days a year without having to wait for a CSR to become available. Virtual assistants will also augment human capabilities and proactively solve a range of customer inquiries at every touchpoint, at any hour of the day or night, which will reduce the likelihood of a digitally-oriented customer needing to speak or chat with a CSR.

Q. Please describe the status of the Company's efforts related to Virtual Assistants.

A. Con Edison conducted a study to define the use cases, technical architecture, and suggested software for the Virtual Assistants program. Additional details are in EXHIBIT__(CO-7).

Q. Are there any cost savings projected resulting from this program?

A. Yes, the Virtual Assistant program will help the Company achieve its BCO savings targets associated with self-service optimization, which is described in the BCO section of this testimony and presented in Exhibit AP-3, Schedule 16.

Q. What is the projected capital cost of this program?

A. The estimated capital costs for the program are $2 million each rate year. The estimated total capital cost of this program for the 2020-2022 period is $6 million. The capital funding requested for this program will cover the purchase and installation of a virtual assistant AI program, and integrating that program with systems that manage customer data and act as an interface with customer interactions.

Q. Have you prepared, or had prepared under your supervision, exhibits that detail the Company's proposed investment in the Virtual Assistants program?

A. Yes. We have prepared one exhibit, entitled "VIRTUAL ASSISTANTS" EXHIBIT__(CO-7).

MARK FOR IDENTIFICATION AS EXHIBIT__(CO-7).

4. BILL REDESIGN

Q. Please describe the Company's Bill Redesign program.

A. We established in 2017 the Bill Redesign program, the final component of Omni-Channel Optimization, to implement changes to the customer bill and increase electronic delivery ("eDelivery") adoption. The Bill Redesign program will update and modernize the paper bill to highlight key customer information, such as bill amount and payment due, and align the paper bill with the Company's digital platform for consistent presentment of bill-related information. Aligning the bill with our digital platform is becoming increasingly important as more than 46% of customers are currently receiving their bill electronically. The program will also use insights drawn from the Journey Mapping and Data and Analytics programs proposed in this panel to encourage eDelivery adoption.

Q. Please elaborate on how the Journey Mapping and Data and Analytics programs support the Bill Redesign program.

A. The Company will begin a Billing and Payments journey mapping exercise in 2019, which will review the customer experience for customers on eDelivery, explore barriers to adoption, and identify solution or tools to encourage eDelivery adoption. The proposed Data and Analytics program proposed will also play a role in developing propensity models to identify customers with a high likelihood to enroll in eDelivery, which will be used to develop targeted messaging to encourage eDelivery adoption among select customer groups.

Q. What customer research has the Company completed or reviewed to support the need for the Bill Redesign program?

A. As part of Phase 1 of the Bill Redesign program, the Company conducted extensive research and benchmarking within the utility and telecom industries (e.g., Accenture, Info Trends, Chartwell, CS Week) to identify bill design best practices. Findings from the research are available in EXHIBIT__(CO-8).

The Company also conducted online customer surveys using the Con Edison Advisory Community to gather feedback on billing and bill prototypes. The Company performed a survey in 2017 for feedback on the bill and its contents, and one in 2018 for feedback on a bill prototype with our initial modifications that was developed based on the 2017 survey results and broader industry research discussed above. The Company will continue to seek this type of iterative customer feedback throughout the Bill Redesign program with additional customer surveys and focus groups.

Q. Please describe the status of the Company's efforts related to Bill Redesign.

A. Phase 1 of the program focused on researching bill design trends, analyzing customer feedback about the current bill and identifying bill enhancements that were easy to implement. This included migrating from a bill printed on paper with background images to plain white paper, introducing color, and highlighting certain key information with boxes. The Company also procured add-on modules for its software platform that generates customer bills, to increase operational flexibility to modify the bill design.

The Company also began Phase 2 of the Bill Redesign program in January 2019. In Phase 2, the Company is applying the insights gained from the Phase 1 research to develop new bill design prototypes, testing the new design with the Advisory Community surveys and customer focus groups, and coordinating with internal and external stakeholders to gain additional feedback and affirm compliance with regulatory requirements.

Q. What is the projected capital cost of this project?

A. The estimated total capital cost associated with the Bill Redesign program is $1 million in RY 1.

Q. What is the estimated level of incremental O&M costs associated with the Bill Redesign program?

A. The incremental O&M request for the Bill Redesign program is $200,000 in RY1, and $8,000 for RY2.

These O&M costs include staff time to manage the project, expenses to support customer surveys and focus groups for feedback on bill changes, customer communications to encourage eDelivery adoption, contractors to maintain the software, and training for CSRs on changes made as part of the Bill Redesign program.

The Bill Redesign program will also contribute to achieving Customer Operations' BCO Savings targets. By migrating from pre-printed paper forms to a plain, white paper form, the Company will save in back office costs and materials. The efforts to increase customer eDelivery adoption can help the Company reduce costs associated with postage from paper bill mailings.

Q. Have you prepared, or had prepared under your supervision, exhibits that detail the Company's proposed investment in the Bill Redesign program?

A. Yes. We have prepared two exhibits, entitled "BILL REDESIGN" EXHIBIT__(CO-8) and "BILL REDESIGN WORKSHEET" EXHIBIT__(CO-9).

MARK FOR IDENTIFICATION AS EXHIBIT__(CO-8) and EXHIBIT__(CO-9).

C. BACK OFFICE AUTOMATION AND AGENT TOOLS

Q. Please describe the Company's Back Office Automation and Agent Tools program.

A. The Back Office Automation and Agent Tools program is one of the major categories of investments included in the Company's Next Gen CX. With this program, the Company seeks to improve the customer experience by streamlining processes and providing enhanced CSR tools. The program encompasses a collection of investments that include:

- Robotic Process Automation (“RPA”) - automate repetitive back office tasks
- Exception Management Tool - improve and streamline the resolution process for discrepancies identified by the system or raised by customers requiring additional internal review
- CSR Tools – implement enhancements to tools CSRs use when responding to customer inquiries and invest in a single system knowledge management tool that can be used by all employees for quick access to information, procedures, and policies relating to customer queries.

Q. Why is it important for the Company to make these improvements now?

A. Currently, the Company uses a number of manual processes to resolve back office work that is time intensive, creates risk associated with employee error, and is operationally inefficient. With RPA, the Company will be able to automate back office processes more quickly and accurately, and be confident that the results will be consistent. Improvements in RPA have also now made it feasible to automate processes that incorporate multiple business rules and encompass actions across several software programs.

The Company also maintains exception management system tools that are outdated and no longer supported by the vendor. Not only is the system outdated, but also has limited functionality, which requires manual assignment and tracking of work. Upgrading to a new exception management reporting tool will result in improved overall management of exceptions including prioritizing and assigning work to employees.

Finally, with REV and the expansion of clean energy programs and the AMI pilot program(s), the Company needs to invest in CSR tools that enable CSRs to respond effectively to customer inquiries. Enhancements to the desktop tool will provide CSRs with a quick reference to critical customer information as well as past interactions. Development of a knowledge management tool will enable the integration of information in an organized and easy to access format, allowing for faster creation and management of new information, such as new clean energy programs associated with EEDM and distributed generation.

Additionally, the operationally efficiencies gained from this program will help the Company meet its BCO savings goals, as described below. For details on the BCO savings achieved through Back Office Automation and

Agent Tools, please refer to the BCO section of this testimony and Exhibit AP-3, Schedule 16.

Q. What is the projected capital cost of this program?

A. The estimated total capital costs associated with the Back Office Automation and Agent Tools program are $2 million in RYs 1 and 2, and $200,000 in RY3. The total capital cost for the program over the 2020-2022 period is $4.2 million.

Q. Have you prepared, or had prepared under your supervision, exhibits that detail the Company's proposed investment in the Back Office Automation and Agent Tools program?

A. Yes. We have prepared one exhibit, entitled "BACK OFFICE AUTOMATION AND AGENT TOOLS" EXHIBIT__(CO-10).

MARK FOR IDENTIFICATION AS EXHIBIT__(CO-10).

IV. BUSINESS COST OPTIMIZATION SAVINGS

Q. Are you familiar with the Company's BCO program as discussed in the direct testimony of the Company's Policy Panels?

A. Yes, we are. The Company has implemented the BCO program to enhance its cost optimization efforts. Following a comprehensive review of business processes, the Company's various business teams, including the Customer Operations organization, identified specific cost savings initiatives.

Q. Please discuss the types of O&M costs that the Customer Operations organization will incur.

A. Company labor accounts for approximately 90 percent of the Customer Operations organization’s O&M expenses. Company labor within Customer Operations consists primarily of CSRs who handle customer inquiries across multiple channels, as well as those CSRs who process back office transactions in support of these inquiries and other customer needs. For the purposes of the BCO program, reduced labor costs provides the greatest opportunity for cost reduction within the Customer Operations organization. However, the Company also identified savings opportunities in its postage and uncollectible bill costs, and has factored these additional savings into the Company’s revenue requirement calculation.

Q. Please describe the main cost reduction opportunities that Customer Operations identified as part of the BCO program.

A. Customer Operations separated the broader goal of cost optimization into three cost savings initiatives that present opportunities to reduce O&M costs: Self-Service

Optimization, Workforce Management, and Back Office Automation.

The Self-Service Optimization initiative serves to identify opportunities to allow customers to self-serve through channels, rather than using a CSR, and to reduce the need for customers to call the Company. Within this initiative, projects typically fall into one of two categories. The first category is an effort to direct customers to our digital platforms. Through technology enhancements, internal training, and customer awareness, we intend to broaden the services available through our digital platforms (as well as the convenience and accessibility of such services), thereby encouraging customers to self-serve on these platforms. The second category is an effort to improve the likelihood that customers will be able to meet their transaction objectives using the Company’s IVR system, thereby avoiding the need to speak with a CSR. Projects in this category are designed to identify and eliminate points in our IVR system that may lead to customer frustration or transaction failures. Customer Operations has formed several teams tasked with identifying specific projects that would support both efforts, including a full-time Self-Service Optimization team.

The Workforce Management cost savings initiative focuses on providing CSRs with the proper training and tools to respond to customer inquiries and meet customer expectations effectively and efficiently. This effort involves identifying and using data analytics, call volume forecasting and scheduling efficiencies to decrease the staffing required to handle customer inquiry demand. In parallel, CSR enablement projects in the form of skillset refinement and tool delivery will enhance the quality and efficiency of customer service so as to reduce the need for future calls, as well as the duration of each call. The Company also may realize further improvements in efficiency in the form of greater productivity per CSR. The initiatives in this category will result in labor expense savings through reduced overtime and staffing at the Company’s Customer Experience Centers.

Q. Please continue.

A. In addition to front-line CSRs, Customer Operations also employs a substantial back office workforce of approximately 150 FTEs. Our Back Office Automation initiatives will streamline and automate back office processes, consolidate work functions and eliminate manual tasks, thereby reducing labor and other expenses.

Key to achieving the savings identified for this category will be investment in RPA and a new exception management tool to facilitate workflows and enable back office areas to become more efficient. RPA will provide advanced process robotics that can handle specific billing errors or exceptions without requiring human intervention. A new exception management tool will allow the Company to process those back office exceptions that cannot be automated using RPA tools. This tool will allow supervisors to efficiently identify, prioritize, and route exception work to employees, and manage pending work with dashboards that provide a complete picture of work streams.

In addition to the BCO savings categories identified above, Customer Operations will achieve additional savings in postage and uncollectible bill charge-offs. We plan to achieve these savings through investments in Bill Redesign and continued work to limit uncollectible bills.

Q. Did you quantify the expected savings from these initiatives for Rate Years 1, 2 and 3?

A. Yes, the forecasted savings from the Self-Service Optimization, Back Office Automation and Workforce Management initiatives are presented in Exhibit AP-3, Schedule 16.

Q. Please explain how you arrived at these savings projections.

A. As noted above, we expect to realize Customer Operations' BCO cost savings primarily through lower staffing requirements. Within each of the three cost saving initiatives, Customer Operations assessed baseline projections of CSR count over the three Rate Years, as well as historical customer inquiry volume as compared with the projected inquiry volume once the aforementioned process and technology improvements are implemented. The Company then calculated the BCO savings amount based on the delta between the baseline CSR count (from end of year 2017) and future number of CSRs required to field the projected inquiry volume.

Q. Do your BCO costs savings account for any O&M costs that must be incurred to achieve your savings? If so, please explain.

A. Yes. As described in the Accounting Panel testimony, the BCO savings included in these rate filings are net values that reflect the total expected savings minus any O&M costs to achieve. As noted throughout this testimony, the O&M costs to achieve are not reflected in the program requests outlined in Customer Operations' white papers.

Q. Do any of the capital programs proposed in the Customer Operations Panel testimony support these BCO savings? If so, please explain.

A. Yes. The following table lays out the programs that support our BCO cost savings initiatives.

Customer Operations Capital Program	**BCO Cost Savings Initiative(s) Supported**
Digital Customer Experience (DCX)	Self-Service Optimization
Journey Mapping	Self-Service Optimization
Data & Analytics	Self-Service Optimization Workforce Management
Virtual Assistants	Self-Service Optimization
Back Office Automation and Agent Tools	Back Office Automation Workforce Management

Q. In addition to the direct BCO savings discussed above, are there other savings that the Company may realize within the Customer Operations function?

A. Yes. The Company has identified “influenced savings” associated with the Customer Operations function. “Influenced savings” refer to savings driven by initiatives implemented by Utility Shared Services, but that are allocated to another organization. For more detail on such savings, please see the direct testimony of the Shared Services Panel.

Q. What challenges does Customer Operations face in implementing its BCO-driven initiatives and realizing its cost savings?

A. External factors that drive customer inquiry volume are a constant challenge for Customer Experience Center staffing. For example, customer reaction to smart meter deployment and unexpected trends in weather all represent headwinds that may affect Customer Operations’ ability to achieve projected results from the BCO cost savings initiatives. In addition, as the Company implements more complex rates and distributed energy resource solutions, and opens new channels of customer interaction, our customers’ expectations will grow and evolve as well.

While the Company has endeavored to estimate the reduction in customer inquiry volume stemming from each of our cost savings initiatives, forecasts by their nature include certain assumptions that will vary from actual experience. The degree of variation will have a corresponding impact on the resulting savings. A piloted program may produce a smaller return than predicted because of the factors above. This poses risks to realizing our projected savings. Customer Operations’ primary means of managing such risks is through data-intensive baselining of our current state, paired with ongoing analysis of the results of our myriad initiatives, with the expectation that we will identify methods to close any gaps between expected and actual results on an ongoing basis.

V. ADVANCED METERING INFRASTRUCTURE SAVINGS

Q. Does the Company anticipate continued savings to O&M expenditures associated with the AMI smart meter initiative?

A. Yes. The Company expects continued O&M cost reductions from AMI deployment. O&M cost reductions are driven by labor savings in the following areas in Customer Operations: Meter Operations, Field Services, the Customer Experience Center, Billing, and Replevin.

Anticipated O&M labor cost reductions take into consideration the following:

- Meter Operations: Reduction in meter reader FTE staffing
- Field Services: Reduction in FTE staffing - includes turn-on / turn-off (“T&T”) staff, Special Forces staff (includes Replevin), Collections staff, and supervisory staff
- Customer Experience Center: Reduction in call volume translated into FTE staffing - includes reduction in account investigation listings (“AILs”), meter

reading and estimated read calls, T&T calls, and high bill complaint calls

- Billing: Reduction in call volume and work associated with billing AILs, and avoided PSC complaint costs, translated into FTE staffing

Q. What other O&M cost reductions are anticipated in the Customer Operations organization because of AMI?

A. The Company also expects the AMI program to result in non-labor reductions in O&M costs associated with Replevin through reductions in administrative fees associated with Replevin.

The incremental O&M cost savings associated with Customer Operations as a result of AMI deployment are summarized in the table below.

(‘000s)	RY1 2020	RY2 2021	RY3 2022
Labor	$(19,316)	$(12,120)	$(7,315)
Non-Labor	$(183)	$(75)	$(35)
Total	$(19,499)	$(12,195)	$(7,350)

Q. Are the AMI Savings identified included in the BCO savings described in this testimony?

A. No. The AMI-related O&M savings identified in this testimony are separate and distinct from the BCO savings described in this testimony and in the Accounting Panel testimony.

Q. Have you prepared, or had prepared under your supervision, exhibits that detail the Company's AMI Savings for Customer Operations?

A. Yes. We have prepared two exhibits, entitled "ADVANCED METERING INFRASTRUCTURE SAVINGS" EXHIBIT__(CO-11) and "ADVANCED METERING INFRASTRUCTURE SAVINGS WORKSHEET" EXHIBIT__(CO-12).

MARK FOR IDENTIFICATION AS EXHIBIT__(CO-11) and EXHIBIT__(CO-12).

VI. CREDIT AND DEBIT CARD FEES

Q. Please describe the Company's current policy regarding payments made using prepaid, credit, and debit cards (collectively "CC/DC").

A. Currently, customers can pay their Con Edison bills using CC/DC on the phone or through the Company's website or mobile app. Residential and small commercial customers pay a $3.35 transaction fee each time they pay using the CC/DC option. This fee is assessed and collected by the Company's CC/DC payment processing vendor and has no impact on the Company's revenues. Large commercial customers that choose to pay via CC/DC are subject to a transaction fee equal to 2.6 percent of the payment amount; the fee for large commercial customers is also assessed and collected by the vendor and does not impact

Company revenues. The Company does not currently accept recurring CC/DC payments because customers must actively accept the vendor's transaction fee at the time of each transaction.

Q. Does the Company propose to change its policy regarding CC/DC payments?

A. Yes. The Company proposes to include in base rates the estimated cost of residential and small commercial customers making CC/DC payments. This will eliminate the per-transaction cost to our customers, and the Company will become responsible for the aggregate costs of processing CC/DC payments. This is referred to as a "no-fee model." The Company proposes to recover the costs under the no-fee model in base rates.

Q. Please explain why the Company is making this proposal.

A. Credit and debit cards have become one of the most common payment methods for a variety of reasons, including convenience to customers. According to a 2016 Federal Reserve Payments Study, card payments (including credit, debit, and pre-paid cards) accounted for 72 percent of the total number of non-cash payments in the United States in 2015, up from 39 percent in 2000. EXHIBIT__(COP-1) demonstrates this economy-wide trend.

Customers expect the Company to provide billing and payment options on par with the options available to customers for their other day-to-day transactions, such as paying a wireless bill or a medical bill. Indeed, through its quarterly customer experience surveys, the Company has consistently received feedback from customers that they would like the ability to make CC/DC payments without a fee, or the ability to schedule recurring payments. This proposal will, therefore, bring the Company in line with what customers have come to expect, and will improve customer satisfaction.

Once this program is implemented, residential and small commercial customers will have the opportunity to pay their bills using all of our accepted methods without a fee. This will enhance the customer experience and allow customers to choose the payment option that best meets their needs.

The Company also expects that the number of customers using CC/DC payment options will increase with this program, and will lead to operational benefits including a reduction in returned payments and faster same-day payments. Additionally, a 2014 study by Fiserv, a CC/DC payment-processing vendor, showed that across 105 utilities, transitioning to a no-fee model led to increased use of self-service payment options, specifically more web payments and recurring payments.

The Company also believes transitioning to a no-fee model will benefit customers who receive public assistance benefits via pre-paid debit cards. Under the current model, such customers can pay their utility bill with their pre-paid debit card, but must use a portion of the benefits to cover the vendor fee for CC/DC payments, resulting in an added economic disadvantage. Adopting a no-fee model will eliminate the need for a portion of public assistance benefits to pay this administrative fee.

Q. Has the Commission approved utility proposals to shift to the no-fee model?

A. Yes. The Commission has approved similar models at New York State Electric and Gas Corporation, Rochester Gas and Electric Corporation, and Central Hudson Gas and Electric Corporation. Similarly, Orange and Rockland Utilities, Inc.'s pending Joint Proposal in its most recent base rate case provides for transition to the no-fee model. Con Edison's proposal in this testimony is consistent with the proposals made by other utilities and approved by the Commission and there are no particular circumstances in Con Edison’s service territory that warrant different treatment.

Q. Has the Company sought more competitive CC/DC transaction fees from vendors?

A. Yes. The Company recently completed a Request for Proposals seeking competitive CC/DC transaction fee rates from payment processing vendors and selected a vendor for the proposed no-fee model.

Q. What are the per-transaction costs under the no-fee model?

A. Upon Commission approval of the no-fee model, the Company’s cost per transaction for these customers will be $2.10 beginning in RY1, which translates to a reduction of 37% over the current fee of $3.35 paid by customers per transaction. The cost of large commercial CC/DC payments would remain unchanged at 2.6 percent of the payment amount.

Q. Does the Company anticipate seeing an increase in payments made via CC/DC under a no-fee model?

A. Yes. Based on benchmarking data provided by the vendor, the Company expects to see a 47% increase in CC/DC payments with the no-fee model in RY1, and incremental increases of 31% and 10% in RY2 and RY3, respectively.

Q. What are the Company’s estimated total annual O&M costs that would result from a transition to the no-fee model?

A. The Company estimates that the total annual O&M costs associated with this new program would be $6.3 million in RY1, $8.2 million in RY2, and $9.0 million in RY3.

Q. How does the Company propose to recover these incremental costs?

A. The Company proposes that any costs incurred by the Company associated with this payment option be considered among the general costs of doing business similar to fees paid for other payment methods (such as direct debit) and be included in the Company’s revenue requirement.

Q. Have you prepared, or had prepared under your supervision, an exhibit that details the Credit and Debit Card Fee proposal?

A. Yes. We have prepared three exhibits, entitled “CREDIT AND DEBIT CARD FEE ELIMINATION” EXHIBIT__(CO-13), “2016 FEDERAL RESERVE PAYMENTS STUDY” EXHIBIT__(CO-14), and “CREDIT AND DEBIT CARD FEE ELIMINATION WORKSHEET” EXHIBIT__(CO-15).

MARK FOR IDENTIFICATION AS EXHIBIT__(CO-13), EXHIBIT__(CO-14), and EXHIBIT__(CO-15).

VII. CUSTOMER EXPERIENCE CENTER DISASTER HARDENING

Q. Please summarize the Company’s Customer Experience Center Disaster Recovery program.

A. The Company proposes to harden its Internet Protocol (“IP”) telephony system to maintain operational reliability when multiple events occur, such as cyber attacks or physical disasters, which might affect the Company’s network infrastructure. Currently, the IP telephony system is supported by two physically separated server farms, and if one of the server farms supporting the IP telephony system experiences an outage, all call traffic is automatically processed via the alternate location. However, the IP telephony system is not designed to endure two simultaneous events (“double contingency events”) that might damage or compromise operation of both server farms at the same time.

In total, the IP telephony system processes nearly 100 million minutes of voice traffic annually, and millions of customer interact with the system each year. While double contingency events are unlikely, they would severely impede the Company’s ability to effectively assist customers with system related emergencies, such as power outages or gas leaks, and receive customer service inquiries.

In light of the growing threat of cyber security attacks, which could shut down multiple server farms at once, the current IP telephony system's single contingency configure is a risk that requires additional hardening to protect against double contingency events that would prevent the Company from learning about or responding to situations that threaten public safety and result in substantially lower volumes of customer-reported outages that aid in damage assessment and restoration planning.

Q. Please explain how the Company will harden the IP telephony system against double contingency events.

A. The Company will perform a comprehensive analysis of potential solutions in 2019 – including a combination of off-premises telephony design options – and will select a technology solution based on project feasibility, cost, time to implement, and integration compatibility with existing systems. The off-premises disaster recovery solution (e.g., cloud-based or software as a service) will be hosted by a qualified vendor and will integrate with the Company's customer information systems.

Q. What is the overall goal of the program?

A. The goal of the Customer Experience Center Disaster Recovery program is to harden the IP telephony system to maintain operational reliability in the event of simultaneous incidents that might damage or compromise operations of both server farms at the same time.

By hardening the IP telephony system, the Company will be able to maintain reliable access to the Call Center and IVR self-service during double contingency events, providing continuous system availability to service customers, and, provide uninterrupted flow of critical outage and public safety-related information.

Q. Why is it important that these improvements are made at this time?

A. The Company is taking a proactive stance to maintain reliable operation of its mission-critical IP telephony system. In the worst-case scenario of a double contingency event, the impact on customers would be particularly far-reaching and prevent the Company from learning about or responding to situations that threaten public safety.

Also, cyber attacks on utilities have become more prevalent in recent years, raising significant concerns among corporations and governments alike because of the impact such attacks could have on the power grid as well as utility customer service infrastructure. The

Information Technology Panel provides additional details on cybersecurity risks.

Q. What is the projected capital cost of this project?

A. The estimated total capital costs associated with the Customer Experience Center Disaster Recovery program is $1.5 million for Rate Year 1.

Q. Have you prepared, or had prepared under your supervision, exhibits that detail the Company's proposed investment in the Customer Experience Center Disaster Recovery program?

A. Yes. We have prepared one exhibit, entitled "CUSTOMER EXPERIENCE CENTER DISASTER RECOVERY" EXHIBIT__(CO-16).

MARK FOR IDENTIFICATION AS EXHIBIT__(CO-16).

VIII. OFF-SYSTEM BILLING

Q. Please explain what is meant by "off-system" billing and why the Company uses such processes.

A. The Company uses a number of billing processes to perform complex billing that occur outside of CIS, the front-end mainframe application for the existing CSS. These complex billing processes, which include new or modified rate structures and calculations, cannot be handled by CIS and instead are performed in the Company's satellite Customer Care and Billing ("CC&B") application to automate certain rates and programs, such as the Value of Distributed Energy Resources ("VDER") tariffs.

As the Commission continues to approve and refine complex rate designs and expand REV clean energy programs that rely on new billing approaches, the Company must adapt to new billing requirements. If the Company were to rely on manual billing processes for complex rates, the experience of participating customers would diminish and increase the risk of billing errors and delays in the application of bill credits and/or charges.

Q. Please describe the status of the Company's efforts related to off-system billing.

A. The Company continues to automate billing processes such as Standby Offset billing automation, Standby Reliability credit calculations, Distributed Generation Gas Load Factor Validation, Standby Multi-party Offset billing and Rider Q billing. Additionally, as a result of the Commission's *Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources and Related Matters* (issued March 9, 2017) in Case 15-E-0751, which among other things established the value stack paradigm for compensating distributed generation sources and directed the utilities to file VDER tariffs, the Company made upgrades to CC&B to automate the calculation of complex value stack credits and the application of those credits to customer bills.

Q. Why is it important that these improvements are made at this time?

A. The Company anticipates that the Commission will continue to approve new programs and rate designs under REV and other clean energy proceedings in conjunction with broader AMI deployment. The Commission has expressed its intent to make additional improvements to the VDER program, such as addressing rate design issues, in its September 14, 2017 *Order on Phase One Value of Distributed Energy Resources Implementation Proposals, Cost Mitigation Issues, and Related Matters*. In that Order, the Commission clearly stated that it had only taken the “first steps in the necessary evolution of compensation for Distributed Energy Resources (DER)…” While specific upgrades have not yet been defined, continued investment in off-system billing processes is necessary for the Company to deliver timely, accurate bills to customers participating in innovative new rates and programs. Delaying investments to update systems and automate processes will not only lead to poor customer experiences because of late or incorrect bills, but also stifle customer adoption of REV programs because of poor customer experiences. Continued work on billing automation will afford the Company greater flexibility to develop and modify billing processes to comply with future regulatory and /or legislative mandates and enable the Company to be responsive to evolving customer needs and interests.

Q. Will continued investment in off-system billing result in any stranded costs with the New CSS?

A. No. Continued investment in off-system billing automation will not result in any stranded costs as both programs use the CC&B platform. Customer Operations is working closely with the CSS team. Based on the technology used, the existing CC&B system will seamlessly integrate with the New CSS, allowing for a smooth transition for customers billed under complex rates and programs.

Q. What is the proposed capital cost for this project?

A. The Company proposes to make $1 million capital investment for RY1 to implement additional modifications and upgrades to its off-system billing processes to accommodate anticipated changes.

Q. Have you prepared, or had prepared under your supervision, exhibits that detail the Company’s proposed investment in off-system billing automation?

A. Yes. We have prepared one exhibit, entitled “OFF-SYSTEM BILLING” EXHIBIT__(CO-17).

MARK FOR IDENTIFICATION AS EXHIBIT__(CO-17).

IX. REVENUE PROTECTION ANALYTICS

Q. Please explain the Revenue Protection Analytics program.

A. The Revenue Protection Analytics program will use data from multiple data sources to analyze customer accounts for indications of potential theft of services or other irregular metering conditions. These data sources include our CSS, AMI Head-End System (“HES”), Meter Data Management System (“MDMS”), and the Revenue Protection Operations Optimizer system on the Company’s Enterprise Data Analytics Platform (“EDAP”).

Q. Please describe the role of the Revenue Protection Unit (“RPU”) in Customer Operations.

A. The RPU’s primary function is to investigate instances of possible theft of the Company’s gas and electric services. RPU conducts these investigations by visiting customer premises and conducting inspections on the Company’s metering equipment. Upon discovery of theft or other irregular metering conditions such as malfunctioning meters, RPU will work with Customer Operations’ Unmetered and Metered Services group to correct the condition and backbill customers in accordance with Commission regulations.

Q. How does RPU determine which customer(s) to investigate?

A. RPU receives leads for investigation from a variety of sources, including, but not limited to, reports from Company employees conducting other job functions, customers, local law enforcement, the Department of Buildings, and CSS-generated leads for account investigations.

Q. What will the Revenue Protection Analytics software do?

A. The Revenue Protection Analytics software will leverage the software used by the Company’s EDAP to generate leads for investigation based on analyzing data from a variety of sources. The Revenue Protection module will use machine learning to evaluate prior thefts or other irregular metering conditions to identify and flag accounts that have similar consumption patterns. It will also prioritize investigations based on the success and failure of investigations on an ongoing basis. The software module can incorporate data from a variety of sources, including AMI data, outage data, work management, or any other data accessible to the analytics platform.

Q. Why is this program necessary for RPU?

A. The Company expects that the Revenue Protection Analytics program will offset the loss of investigative leads that will result from the AMI implementation, as described below. One of the primary sources of leads for investigation is from the Customer Field Representatives (“CFRs”), our meter reading employees. Beginning in 2018, the Company began reducing CFR staffing due to the deployment of AMI meters. As AMI meter deployment progresses, the Company will further reduce the number of CFRs it employs. As a result, RPU will receive fewer leads from these resources. Reports from CFRs are among the highest in terms of successfully finding theft or other irregular metering conditions, because CFRs can visually confirm these conditions in the field. RPU will need to find an alternative means to determine which locations to investigate if it is to continue in its efforts to find theft of services.

Q. How much will this program cost?

A. This program will cost approximately $201,000 in RY1, and $509,000 each for RY2 and RY3. In addition to software, the program will require the addition of two FTEs. These two FTEs will be responsible for analyzing data, working with field forces to verify and report on investigation findings, and working with the software vendor to refine the machine learning models as needed.

Q. Have you prepared, or had prepared under your supervision, exhibits that detail the Company’s proposed investment in the Revenue Protection Analytics program?

A. Yes. We have prepared two exhibits, entitled “REVENUE PROTECTION ANALYTICS” EXHIBIT__(CO-18) and “REVENUE PROTECTION ANALYTICS WORKSHEET” EXHIBIT__(CO-19).

MARK FOR IDENTIFICATION AS EXHIBIT__(CO-18) and EXHIBIT__(CO-19).

X. ELECTRONIC CORRESPONDENCE EXPANSION

Q. Please summarize the Company’s proposal regarding electronic correspondence with customers.

A. The Company proposes to evolve its delivery practices for regulatory-required correspondence to match its existing practices for bills, customer education and other discretionary outreach. Specifically, the Company proposes to establish a pilot e-delivery/electronic document program applicable to all documents for customers who have indicated their preference to receive their bill electronically (“ebill”). With this pilot, the Company would deliver all communications, including those required by Commission directive, electronically in lieu of providing a paper copy via mail. The Company will monitor the success of this pilot and, based on the findings, expand the pilot to provide electronic documents for non-ebill customers that have provided the Company an email address.

Q. What led to the current state of correspondence delivery where some items are delivered electronically and others are mailed in hard copy format?

A. The Company has successfully moved a number of pieces of correspondence to electronic format over the past five years. This includes customer bills and bill inserts, non-regulatory required correspondence, and general customer education notices (e.g., information on energy efficiency programs, storm preparation tips, and gas safety messages). However, historically, the Company has continued to send certain forms of correspondence required by the Home Energy Fair Practices Act ("HEFPA"), such as credit-related disconnect notice, via regular mail.

Q. Does the Company believe that this differential treatment for certain kinds of correspondence has a meaningful impact on customer experience?

A. Yes, the Company believes its current practices are inefficient and diminish the customer experience for a number of reasons. Sending documents through both channels (email and U.S. mail) is duplicative and costly. As a result, the Company currently sends these mailings to U.S. mail. Where a customer has elected to enroll in ebill, they expect to receive communications through the email address provided (in many cases customers have elected to receive all of their bills and correspondence from all of the companies they do business with electronically, such as banking, retail and telecom, to this same email address) and the practice of then sending regulatory mandated correspondence via U.S. mail may make these customers less likely to respond timely (or respond at all) to important notices.

Additionally, delivering documents differently across different types of correspondence for the same customer is confusing for customers that prefer to receive all of their correspondence via digital channels. For instance, they might receive the email first, make immediate payment resolve a credit action, and then subsequently receive the same notice via U.S. mail. The customer could then be confused that their payment made after receipt of the initial email did not satisfy the issue. As described in the Next Gen CX section above, the Company wants to meet its digitally-oriented customers where they are, and encourage use of lower-cost self-service options. Continuing to send regulatory-mandated correspondence via mail is counter-productive to this goal and prevents the Company from achieving deeper savings on postage costs.

Q. Why does the Company feel that this is the right time for proposing this change?

A. The Company is proposing this change now for a number of reasons. First, the number of customers requesting to receive documents electronically has grown over the last five years from 8% in 2013 to 47% in 2018. This growth reflects the changing expectations of customers with respect to being able to choose the delivery method of all correspondence.

Also, as a result of these changing expectations, the Company has enhanced its e-delivery processes over the last few years to improve the experience. Specifically, today the Company has the ability to send any customer correspondence to a customer’s email address through a pin-protected pdf document. This means that the customer receives a secure copy of the exact same document in terms of content and look and feel that would otherwise be sent via U.S. mail. Finally, the Company received approval of an Electronic Deferred Payment Agreement Signature program that acknowledges the opportunity to improve engagement with customers by delivering important documents electronically.

Q. Please describe the actions that the Company proposes to take to assure proper consumer protections associated with the proposed change.

A. The Company proposes to track whether the customer has opened an email containing regulatory-mandated correspondence within three days of receipt. If the Company cannot confirm that the customer opened the email, a duplicate correspondence would be sent via U.S. mail. This process is identical to the process approved by the Public Service Commission as part of the Company's Electronic Deferred Payment Agreement filing.

Q. Has the Company conducted a risk assessment associated with this new pilot?

A. Yes. This pilot has the potential to pose the following risks: risk of human error in obtaining electronic mail addresses, risk of intrusion by an unauthorized third party; risk of repudiation; and risk of fraud. The Company is planning to implement the same risk mitigation measures for this pilot as it is for its Electronic Deferred Payment Agreement program.

XI. CUSTOMER OUTREACH AND EDUCATION

Q. Please explain the role of Customer Outreach.

A. The Company established Customer Outreach to develop and provide outreach and education activities and programs and materials to educate the Company's customers regarding their rights, responsibilities and options as utility customers. Over the years, its mission has expanded to include educating customers on safety, billing and payment options, programs and services available to help customers manage their energy costs, special services for elderly, blind and disabled customers, and options available for interacting with the Company. Customer Outreach activities include interacting with customers at community events and meetings where Outreach Advocates distribute literature and present information to customers and community organizations on various topics.

In addition, the Company develops outreach and education plans for new Company initiatives, including the AMI deployment project, the Company's AMI Innovative Pricing Pilot and Shared Solar pilot described in the Customer Energy Solutions Panel testimony. The annual report filed by the Company in Case 16-E-0060 provides more detailed information on the Company's Outreach and Education Plan.

Q. Is the Company planning to increase the amount spent on outreach initiatives?

A. Yes. An increase of $666,000 is needed for Rate Year 1. Additional increases of $103,000 and $107,000 respectively are needed in Rate Year 2 and Rate Year 3.

Q. How will this funding be used?

A. Funding will pay for the following activities:

1. Development of personalized online (website), offline (email), and mobile engagement (mobile app) campaigns that provide customer specific and actionable information to targeted audiences;
2. Expansion of email campaigns, including those associated with key customer journeys and Company work notifications;
3. Increased spending on customer research;
4. Expanded training for Company employees in CX and other topics, including REV initiatives and diversity and inclusion competency; and
5. Increased costs for postage and materials involved in direct mail campaigns and educational awareness materials.

Q. Have you prepared or supervised the preparation of an exhibit describing the Company’s planned expenses for general outreach and education programs?

A. Yes. We have prepared two exhibits. These are entitled "CUSTOMER OUTREACH AND EDUCATION," EXHIBIT___(CO-20), and "OUTREACH AND EDUCATION WORKSHEET," EXHIBIT___(CO-21).

MARK FOR IDENTIFICATION AS EXHIBIT___(CO-20)and EXHIBIT___(CO-21).

XII. <u>ELECTRIC AND GAS LOW INCOME PROGRAMS</u>

Q. What is the purpose of the Panel's testimony related to the Electric and Gas Low Income Programs?

A. This testimony discusses the continuation of the Company's Low Income Programs, in accordance with the Commission's Orders issued in its Proceeding on Motion of the Commission to Examine Programs to Address Energy Affordability for Low Income Utility Customers in Case 14-M-0565 ("Low Income Proceeding"). In particular, the Commission's May 2016 *Order Adopting Low Income Program Modifications and Directing Utility Filings* ("May 2016 Order") established a standard framework for all New York State utilities' low income programs. The Commission established a method to set the low income discount to achieve an average target energy burden (i.e., the percentage of a household's income that is spent on energy) of six percent of monthly household income – or three percent for customers taking electric or gas service only. The Commission also established a tiered discount system, with four levels of discounts for customers based on level of need. The framework also established a funding limit so that the total budget for each utility cannot exceed two percent of total electric and/or gas revenues for sales to end-use customers. Additionally, utilities are now required to enroll eligible low income customers in budget billing (referred to as a “Level Payment Plans” by the Company) on an opt-out basis. The Commission also established certain rules for utilities that choose to offer reconnection fee waivers to customers participating in low income discount programs, and set forth a new standardized quarterly reporting format for all utilities. In accordance with the May 2016 Order, the Company submitted an Implementation Plan outlining its proposal to conform its Electric and Gas Low Income Programs with the new framework as part of the 2017-2019 rate plan.

Q. Was the Company’s Implementation Plan approved by the Commission?

A. Yes, the Commission approved the Implementation Plan and the Electric and Gas Low Income Programs were revised as part of the 2016 Joint Proposal adopted by the Commission. Since 2017, the low income programs are in line with the Commission’s new framework for low income programs. Importantly, this includes an annual adjustment to discounts levels, if necessary, in accordance with the Commission's *Order Approving Implementation Plans with Modifications* (issued February 17, 2017). On December 1, 2017 and November 30, 2018, the Company filed Annual Low Income Program Update Reports in the Low Income Proceeding and the 2016 Rate Proceeding informing parties of updated discount amounts.

Q. Please describe the current Electric Low Income Program.

A. Effective January 1, 2019, the Company offers discounts to eligible low income electric customers as shown in the following table. Discounts were calculated pursuant to the formulas established by the Commission in the Low Income Proceeding.

Electric Low Income Discounts Effective 1/1/2019

Income Level	**Electric Non-Heat**	**Electric Heating**
Tier 1	$10	10
Tier 2	$10	10
Tier 3	$27	$27
Tier 4	$12	$12

Customers participating in the Electric Low Income Program are also eligible to receive a waiver of the reconnection fee if their electric service is terminated for non-payment – limited to one waiver per rate year as outlined in the Company's 2016 Rate Plan – and are automatically enrolled in the Company's Level Payment Plan ("LPP") on an opt-out basis.

Q. How do customers qualify for the Company's Electric Low Income Program?

A. Customers are eligible for electric bill discounts if they participate in one or more qualifying public assistance programs. Qualifying programs include the Home Energy Assistance Program ("HEAP"), Medicaid, Safety Net Assistance, Supplemental Nutrition Assistance Program ("SNAP"), Supplemental Security Income ("SSI") and the Temporary Assistance to Needy Persons/Families ("TANP") program. Customers are also eligible for the Low Income Programs if they are enrolled in a Direct Vendor or Utility Guarantee Program ("DV/UG Program"). All customers that the Company learns are participating in these qualifying programs are enrolled in the Electric Low Income Program, without limit.

Q. How does the Company assign eligible customers to each tier in the Electric Low Income Program?

A. The Company's tier-based system has the following eligibility criteria:

- Tier 1 – Customers who are participating in one or more qualifying public assistance programs – including Medicaid, Safety Net

Assistance, SNAP, SSI, and TANP – and/or have received a HEAP benefit in the preceding 12 months.

- Tier 2 – Customers who have received one HEAP "add-on"[1] benefit.
- Tier 3 – Customers who have received two HEAP "add-on" benefits.
- Tier 4 – Customers who are receiving utility bill payment assistance as part of the DV/UG programs. Note that when Tier 4 customers are no longer receiving bill payment assistance, their eligibility for the Company's Electric Low Income Program will be re-evaluated and, if warranted, assigned to a different tier.

Q. Is the Company proposing to continue the Electric Low Income Program?

A. Yes. The Company proposes to continue the Electric Low Income Program with the same terms.

Q. Is the Company proposing any updates to the Electric Low Income Program target cost or budgets for the Rate Year?

[1] An "add-on benefit", as defined in the Commission's Low Income Program Order, is an incremental payment that is provided to HEAP recipients if their household income is at or below 130% of the federal poverty level, or if their household contains a vulnerable individual (i.e., household member who is age 60 or older, under age 6, or permanently disabled). A customer can receive two add-on benefits if both of these conditions apply to their household.

A. Yes. The Company is proposing to update the targeted annual aggregate amounts for electric low income discounts and reconnection fee waivers, respectively, that are included in base rates. Specifically, the Company proposes a target amount of $52,782,102 for electric low income discounts for the Rate Year, and a target amount of $527,821 for electric reconnection fee waivers for the Rate Year.

Q. Why does the Company need to update the targeted amount for electric low income discounts?

A. Customer participation in the Electric Low Income Program is projected to decrease relative to the participation levels assumed in the 2017-2019 rate plan; additionally, the electric discount levels have increased slightly for Tiers 3 and 4, as indicated in the Company’s November 30, 2018 Annual Low Income Program Update Report. The Company is proposing to update the discount target amounts to reflect both of these changes. Please refer to EXHIBIT__(CO-22) for supplemental information.

Q. Why is the Company updating the targeted amount for reconnection fee waivers?

A. The May 2016 Order specified that utilities offering reconnection fee waivers as part of a low income program must limit spending on such waivers to 1% of the budget.[2] Since the Company is proposing to revise its target discount amounts as described above, it is also proposing to decrease the reconnection fee waiver target amount. It should be noted that for the first two years of the 2017-2019 rate plan, the Company granted waivers equivalent to 64% and 49% of its annual target amount ($547,000). As such, we do not expect this reduction to have a material impact on our Low Income Program participants.

Q. Does the Company propose to continue funding up to $50,000 per year of administrative costs for the New York City Human Resources Agency and Westchester Department of Social Services?

A. Yes.

Q. Does the Company propose any form of reconciliation if actual participation in the Electric Low Income Program is higher or lower than the Company's forecast, or if the annual updates to discount levels result in increased or decreased spending on electric bill discounts?

A. Yes. Consistent with the 2017-2019 electric rate plan, all over and under-recoveries associated with the electric low income discounts and the waiver of

[2] May 2016 Order, p. 38.

reconnection fees will be reconciled through the Revenue Decoupling Mechanism ("RDM") from all customers subject to the RDM for the Electric Low Income Program. The Company proposes to continue this reconciliation without modification.

Q. Please describe the Company's Gas Low Income Program.

A. Effective January 1, 2019, the Company offers discounts to eligible low income gas customers as shown in the following table. Discounts were calculated pursuant to the formulas established by the Commission in the Low Income Proceeding.

Gas Low Income Discounts Effective 1/1/2019

Income Level	**Gas Non-Heat**	**Gas Heating**
Tier 1	$3	$50
Tier 2	$3	$50
Tier 3	$3	$56
Tier 4	$3	$50

Customers participating in the Gas Low Income Program are also eligible to receive a waiver of the reconnection fee if their gas service is terminated for non-payment – limited to one waiver per rate year as outlined in the 2016 Joint Proposal – and are automatically enrolled in the Company's LPP on an opt-out basis.

Q. How do customers qualify for the Company's Gas Low Income Program?

A. The eligibility requirements for participation in the Gas Low Income Program are the same as those outlined above for the Electric Low Income Program. All customers that the Company learns are participating in the qualifying programs listed above and taking gas service are enrolled in the Gas Low Income Program, without limit.

Q. How does the Company assign eligible customers to each tier in the Gas Low Income Program?

A. The Company's tier-based system for gas discounts has the same eligibility requirements as those outlined above for electric discounts.

Q. Is the Company proposing to continue the Gas Low Income Program?

A. Yes. The Company proposes to continue the Gas Low Income Program with the same terms.

Q. Is the Company proposing any updates to the targets or budgets for the Gas Low Income Program?

A. Yes. The Company is proposing to update the target budget amount for gas low income discounts that are included in base rates. Specifically, the Company proposes a target budget amount of $15,935,526 for gas low income discounts for the Rate Year. The Company proposes to keep the target budget amount for gas reconnection fee waivers flat relative to the 2017-2019 rate plan (i.e., up to $75,000 per rate year).

Q. Why is the Company updating the targeted amount for gas low income discounts?

A. Customer participation in the Gas Low Income Program is projected to increase relative to the participation levels assumed in the 2017-2019 rate plan; additionally, the gas discount levels have increased slightly, as shown in the Company’s November 30, 2018 Annual Low Income Program Update Report. The Company is proposing to update the discount target amounts to reflect these changes. Please refer to EXHIBIT__(CO-23) for supplemental information.

Q. Does the Company propose any form of reconciliation if actual participation in the Gas Low Income Program is higher or lower than the Company’s forecast, or if the annual updates to discount levels result in increased or decreased spending on gas bill discounts?

A. Yes. Consistent with the 2017-2019 electric rate plan, all over and under-recoveries associated with the gas low income discounts and the waiver of reconnection fees will be reconciled through the Monthly Rate Adjustment (“MRA”) from all customers subject to the MRA for the Gas

Low Income Program. The Company proposes to continue this reconciliation without modification.

Q. What are the forecasted combined costs of the Electric and Gas Low Income Programs for the Rate Year, including both bill discounts and reconnection fee waivers?

A. The forecasted costs of the Electric and Gas Low Income Programs for the Rate Year are outlined below.

Projected Cost of Electric and Gas Low Income Programs ($ millions)

Period	Electric	Gas
January 1 – December 31, 2020	$53,329,102	$16,010,526

Q. Is it possible that the actual costs of the Electric and Gas Low Income Programs may change in subsequent years if the Commission approves a multi-year rate plan in this proceeding?

A. Yes. Based on past experience and the Commission’s required annual review and potential reset of low income discounts in each tier, actual participation in the Company’s Low Income Programs will vary over the course of a multi-year rate plan. However, the target amounts for both bill discounts and reconnection fee waivers outlined above will not be modified in RY 2 or RY3 of a multi-year rate plan. It should be noted that this method of recovering program costs in a second and third rate year is consistent with how the Company's Low Income Programs were funded during the 2017-2019 rate period.

Q. Does the Company plan to continue its existing enrollment reconciliation and reporting requirements from the 2016 Joint Proposal?

A. Yes.

Q. Have you prepared or supervised the preparation of an exhibit describing the Company's Low Income Program?

A. Yes. We have prepared two exhibits. These are entitled "LOW INCOME PROGRAM-ELECTRIC" EXHIBIT__(CO-22), and "LOW INCOME PROGRAM-GAS" EXHIBIT__(CO-23).

MARK FOR IDENTIFICATION AS EXHIBIT__(CO-22)and EXHIBIT__(CO-X3).

XIII. <u>ELECTRIC RECONNECTION FEES</u>

Q. Please explain the Company's proposal with respect to reconnection fees for electric customers with AMI meters.

A. As proposed on page 44 of the November 2015 AMI Business Plan, the Company is in the process of installing electric AMI meters that are capable of connecting and disconnecting from the distribution system via a remote wireless signal. (For the remainder of this testimony we refer to this functionality as "RCD-capable.") The vast majority of electric AMI meters installed through 2022 will be RCD-capable, with the exception being some commercial customers and customers that opt-out of receiving electric AMI meters.

There are a number of benefits to RCD-capable metering, including (but not limited to) faster service initiation and restoration after disconnections. RCD functionality also helps to reduce costs because in many cases it will obviate the need for an in-person visit to restore service following a disconnection for non-payment or tampering-related reasons.

As outlined in General Rule 15.2 of the Company’s Schedule for Electricity Service (“Tariff”), the Company currently charges a fee of $26-28 to reconnect service at the meter. This fee helps to defray the cost of sending a field representative out to the customer premises for reconnection purposes. Given that RCD-capable metering will significantly reduce the number of reconnection-related work orders, the Company proposes to eliminate the aforementioned reconnection fees for electric customers with RCD-capable meters whose service was shut off for non-payment or tampering-related reasons, if the customer’s service is able to be restored remotely. Reconnection fees will still apply for customers whose service restoration requires an in-person visit from Company personnel – including customers whose service is cut in the street as well as customers whose service cannot be restored remotely despite the presence of an RCD-capable meter.

It should be noted that the Company does not currently plan to install RCD-capable gas meters, so the above proposal is only applicable to electric customers. The Electric Rate Engineering Panel testimony describes the associated Tariff changes.

Q. What impact will this proposal have on the Company’s revenue during the Rate Year?

A. The Company projects that other operating revenue will be reduced by $224,000 in the Rate Year as a result of this proposal.

Q. Please explain how you developed this projection.

A. The Company reviewed data from October 1, 2017 – September 30, 2018 and determined that it collected $672,000 in fees for electric service reconnections at the meter (not including instances where low income customers received fee waivers and therefore the $26/$28 charges were reversed).

Given the uncertainty as to how many remote reconnections there will be in any given year, the Company reduced the $672,000 by 33 percent to estimate the loss of revenue associated with these charges.

Q. Does this proposal impact the reconnection fee waiver component of the Company's Electric Low Income program?

A. This proposal does not directly impact the reconnection fee waiver benefit for electric low income customers. It is true that if one assumes that a disconnected low income electric customer has an RCD-capable AMI meter and their service is successfully restored via remote signal, then this proposal would eliminate the need for that customer to receive a reconnection fee waiver. However, due to the timing of the Company's AMI meter deployment there will still be low income electric customers that are assessed reconnection fee waivers during Rate Years 1-3. The Company believes it is important to continue providing these customers relief from reconnection fees. As such, any customer participating in the Electric Low Income Program that is charged a reconnection fee during the rate plan will still be granted a fee waiver according to the terms outlined in the Electric and Gas Low Income Programs section of this Panel's testimony.

Q. Is this proposal reflected in any other testimony or exhibits included in this rate filing?

A. Yes. This proposal is reflected in the Accounting Panel testimony, Exhibit E-3, Schedule 5.

XIV. **CUSTOMER SERVICE PERFORMANCE MECHANISM**

Q. Do you have any proposals with respect to the Customer Service Performance Mechanism ("CSPM")?

A. The current rate plan provides for the CSPM to continue unless and until changed by the Commission. For purposes of this proceeding, the Company is not proposing to eliminate the CSPM.

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

A. No. Assuming continuation of a CSPM during the Rate Year, the Company is not proposing to modify the terms of the current CSPM.

Q. Has the Company incurred any revenue adjustments under the current CSPM?

A. No. The Company has not incurred any revenue adjustments in the last two rate years.

Q. Other than surveys required by the CSPM, is the Company conducting any other surveys?

A. Yes. Pursuant to the Commission's Order Authorizing Implementation of a Pilot Statewide Customer Satisfaction Survey, in 2019 the Company began a one-year transaction-based customer satisfaction survey. The Company will file quarterly reports with the results of this survey and will reconvene with Staff and the other electric and gas utilities after one year.

Q. Is this transaction-based survey part of the CSPM?

A. No, the pilot survey is not part of the CSPM and, although the Company will report its results, there are no metrics associated with this survey.

XV. RESIDENTIAL SERVICE TERMINATIONS & UNCOLLECTIBLE BILLS

Q. Please describe the Company’s current performance metric related to residential service terminations and uncollectible bills (“UB metric”).

A. The 2016 Joint Proposal established a UB metric for the 2017-2019 time period where the Company would earn a positive revenue adjustment for achieving certain targets for residential service terminations and bad debt write-offs. Any positive revenue adjustment earned will be allocated between electric and gas based on the common cost allocation for Customer Accounting Expenses (84%/16%).

Q. Did the Company meet the metric in 2017 and 2018?

A. Yes, in both years, the Company achieved performance levels below the targets listed under part (a) in the above excerpt (i.e., Terminations < or = 62,000 and Bad debt write-offs < or = $45.7M), thereby earning a two-year total of $12 million in incentives ($6 million for each year). Specifically, in 2017 the Company had 50,135 residential terminations and recorded a total of $37.8

million in residential UB. In calendar year 2018, the Company had 38,147 residential service terminations and residential UB of $37.9 million.

Q. What factors contributed to the Company's successful performance in 2017 and 2018?

A. There are a variety of factors that contributed to the ability of the Company to achieve the targets established for this metric. Some of those factors are within the Company's control, and others are not. For example, the Company is committed to working with customers early on in the arrears process in a variety of ways to help reduce the likelihood that they are terminated for non-payment. A few examples help to illustrate this point:

- Be flexible on deferred payment agreement ("DPA") terms and we give them multiple chances before we pursue credit action.
- Offer customers a variety of convenient ways to enter into a DPA, including on the phone with a CSR, in the IVR, at any of our Walk-in Centers, or online using the My Account portal. In 2018 we also began proactively offering customers most likely to call because they were eligible to be turned off for non-payment DPAs via e-mail. Results thus far have been positive.

- The Company goes above and beyond the terminations-related requirements of the Home Energy Fair Practices Act (HEFPA) by providing customers extra notices regarding the status of their account.
- If a customer's account is ultimately fielded for service termination, the Company accepts all forms of payment at the customer's premises and attempts to enter into a DPA with the customer prior to locking the meter.

In addition to the above efforts to work with customers, in 2018, the Company implemented a risk-based routing approach in fielding service terminations. Specifically, we began to field accounts for termination with a higher likelihood of writing off to UB. The new strategy has shown positive results thus far.

Also, it should be noted that the overall economy continued to improve over the 2017-2018 time period, which generally leads to fewer customers in arrears, lower volume of service terminations, and lower final bill balances.

Q. Does the Company propose to continue this performance mechanism in the coming Rate Year?

A. Yes. The Company recognizes that the Commission has established a UB Metric for all utilities. Therefore, despite the uncertainty associated with the ability to achieve these targets because it is, in part, dependent on factors outside the Company’s control, the Company is not proposing to eliminate the UB Metric.

Q. Does this conclude your testimony?

A. Yes.