CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

ELECTRIC INFRASTRUCTURE AND OPERATIONS PANEL

Table of Contents

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I. Introduction

A. Introduction and Qualifications of Panel Members

Q. Would the members of the panel please state their names and business addresses?

A. Milovan Blair, Robert Brantley, Patrick McHugh, Steve Parisi, and John Catuogno. The business address for all panelists is 4 Irving Place, New York, NY 10003.

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

A. **(Blair)**

I am Milovan (Milo) Blair, Senior Vice President of Central Operations for Con Edison. My responsibilities include the planning, design, operation and maintenance (O&M) of the Company’s electric transmission system, substations, primary control center, electric and steam generating plants, and steam distribution system. I am also responsible for the Company’s engineering and construction activities. I joined Con Edison in 1991 as a Management Intern and have served as General Manager, Substation Operations-Northern region, General Manager, System Operations; Vice President, System and Transmission Operations and Vice President Brooklyn/Queens Electric Operations.

I hold an MBA in information systems from St. John's University and a Bachelor of Science degree in electrical engineering from the City University of New York. I have completed the Senior Executive Program at Columbia University and the Siemens PTI Power Technology course. I currently serve on the executive board of the YMCA Bedford Stuyvesant Chapter and as a leadership council member of the City College of New York Grove School of Engineering.

(Brantley)

I am Robert Brantley, Vice President of Central Engineering for Con Edison. In my current role, I provide engineering leadership and oversight to maintain the safe and reliable operation and maintenance, including field support, of the electric transmission system, electric substations and steam generation and distribution systems. My organization also provides engineering services for Gas LNG plants and Company facilities. I joined the Company in 1993 as a management intern and have held positions of increasing responsibility including senior system operator, general manager in Substation Operations, chief engineer in Central Engineering, and most recently general manager of Manhattan Electric Operations. I hold a Bachelor of Engineering degree in electrical engineering from Cooper Union and a Master of Business Administration degree from the Wharton School of Business at the University of Pennsylvania.

(**McHugh)**

I am Patrick G. McHugh, Senior Vice President of Electric Operations for Con Edison. I assumed this position in July 2021, after serving as Vice President of Engineering and Planning for Con Edison. I currently have overall responsibility for Con Edison's Electric Distribution Operations, Engineering and Planning, and Con Edison's Energy Services organization, which coordinates all aspects of the delivery of electric service to customers.

I have been with the Company for over 30 years after joining in 1991 as a Management Intern and have held various positions with increasing responsibility including Vice President of Engineering and Planning, Vice President of Brooklyn/Queens Electric Operations, Chief Engineer of Distribution Engineering, General Manager Protective Systems Testing, Senior System Operator, and Chief District Operator. I hold a Bachelor of Science degree in electrical engineering from Clarkson University, a Bachelor of Arts degree in physics from Plattsburgh State University, and a master's degree in electrical engineering from Clarkson

University. I have also completed the Siemens PTI Transmission course.

(Parisi)

I am Steven Parisi, Vice President of Engineering and Planning for Con Edison. I assumed this position in June 2021, after serving as Vice President of Engineering for Central Operations. My responsibilities include overseeing energy services, engineering, and quality assurance. Engineering and Planning is also responsible for designing and monitoring the performance of the electric distribution system. I joined the Company in 1989 as a management intern and have held general manager positions in System Operations, Electric Operations, and Substations. I hold a Bachelor of Science degree in electrical engineering from Polytechnic University. I have also completed the Siemens PTI Distribution course.

(Catuogno)

I am John Catuogno, Director of the Commodity Forecasting Department for Con Edison. I am on this panel solely to support the electric peak demand forecast. I graduated from Polytechnic University with a Bachelor of Science degree in Mechanical Engineering in 1991 and with a Master of Science degree in Management in 2002. I have also completed the Siemens PTI Power System Transmission course/certification.

I am a licensed Professional Engineer in the State of New York and an Adjunct Assistant Professor in the Mechanical Engineering Department of Manhattan College, where I present graduate lectures on energy and sustainability.

I joined Con Edison in 1991 as a Management Intern and have held various positions of increasing responsibility in the Fossil Power, Nuclear Power Engineering, Steam Operations, and Energy Management Organizations. Since December 2013, I have been the Director of Energy Management's Commodity Forecasting. My responsibilities include oversight of daily peak, annual peak, monthly/annual energy revenue and volume forecasts for the electric, gas, and steam systems; and technical and analytical support for long range plans, strategies, and industry trends and issues that affect the Company.

I have submitted testimony in Case Nos. 21-G-0073, 21-E-0074, 19-E-0065, 19-G-0066, 18-E-0067, 18-G-0068, 16-E-0060, 16-G-0061, 13-S-0032, 09-S-0794, 09-S-0029, and 07-S-1315.

B. Purpose of Filing

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

A. We are presenting the Company's required electric projects and programs and their respective funding requirements. These investments are needed to: (1) maintain safe and reliable electric service, (2) enable clean energy, and (3) make our system more resilient.

Specifically, our testimony covers the electric peak demand forecasts that drive load growth and the capital and O&M funding requirements for the Company's transmission, distribution, and electric production functions. The transmission funding requirement, which includes the System and Transmission Operations ("S&TO") and Substation Operations ("SSO") groups, and the Electric Operations ("Distribution") funding requirements, are described together and are collectively referred to as Transmission and Distribution ("T&D"). The Electric Production funding requirement, the costs of which are shared with the steam system, is presented separately in Section V of this testimony. While we will highlight only a few of the Company's investments, each program and project for which the Company seeks funding is described in a "white paper" that includes scope of work, justification, cost, schedule, relationship to long-range plans, including climate change related goals where applicable, and discussion of alternatives.

Q. What period does this testimony cover?

A. This testimony presents the projects and programs planned for the 12-month period ending December 31, 2023 ("Rate Year" or "RY1").

Q. Does your testimony look beyond Rate Year 1?

A. Yes. We also address the capital plant additions and other programs and initiatives planned for the two years following the Rate Year. For convenience, we will refer to the twelve-month periods ending December 31, 2024 and December 31, 2025 as "RY2" and "RY3," respectively. As the Company's Accounting Panel explains, the Company is not proposing a multi-year rate plan in this filing but is interested in pursuing one in settlement discussions with Staff and interested parties.

Q. What is the Company's total capital expenditure for T&D and Electric Production in RY1, RY2, and RY3?

A. The Company's total capital expenditure for T&D and Electric Production is $2,484.8 million in RY1, $2,522.5 million in RY2, and $2,563.0 million in RY3.

C. Key Principles

Q. What are the principles driving the Company's funding request for electric operations?

A. The Company's investments are based on three principles: 1) Core Investments to that are often multi-value to maintain safe, resilient, and reliable electric service, 2) Clean Energy investments to help meet the State’s clean energy goals, and 3) Resilience investments focused on preparing our electric system for more frequent and severe weather, including heat. As noted above, the Company always seeks to develop multi-value projects that serve more than one goal, which increases the cost efficiency of our capital investments.

Q. Can you elaborate on what you mean by multi-value projects?

A. Multi-value projects serve more than one need. For example, we may see a reliability need in a particular area. In designing a solution, we will, to the extent practicable, look for opportunities to enhance resilience or facilitate the State achieving the clean energy goals established in the Climate Leadership and Community Protection Act (“CLCPA”). We think multi-value projects are ‘no regrets’ investments that provide a variety of capabilities, such as additional ‘headroom’ to integrate renewables or flexibility to accommodate intermittent resources. Multi-value projects help us maximize customer value by increasing the cost-effectiveness of our projects.

Q. Do the Company’s projects have other benefits?

A. Yes. The Company’s projects serve to increase economic development in our area. In addition to the construction jobs associated with Company projects, and the employees required to operate these projects, system expansion to accommodate anticipated load growth and accommodate clean energy investments supports further investments in homes, businesses, and renewable generation in the Con Edison service territory. These investments add jobs to the local economy in a myriad of areas, including clean energy jobs. Further, the Company’s efforts to promote and facilitate the adoption of electric vehicles (“EVs”), through the make-ready program discussed in this testimony, leads to investments and jobs associated with EVs, EV infrastructure, and in the overall transportation infrastructure.

1. Core Investments

Q. What are Core Investments?

A. Core Investments are required for safe and reliable service and many of the projects also provide resiliency. Among other things, they include investments to address load growth, replace equipment and assets that can no longer be maintained, keep assets in safe working condition, and enhance physical and cybersecurity. They are essential to maintaining the electric transmission and distribution systems.

Q. What is the relationship between Core Investments and the clean energy future?

A. The clean energy future must be accompanied by a safe and reliable electric system. Our system must be capable of reliably delivering new sources of clean energy to customers and reliably serving increasing customer demand from electrification. For example, as more customers adopt electric heating, our system will begin to experience significant winter load along with a summer peak. We must begin the work now so our system is able to withstand such new patterns of usage, even though we do not expect to become a winter-peaking utility until the mid-2030s. In addition, increased demand year-round will shorten outage windows available to perform required upgrades and maintenance. Core Investments are necessary to keep the system safe and reliable now and prepare it for the clean energy future. Furthermore, many Core Investments will make the system more resilient in the face of extreme weather events.

Q. Can you give an example of a Core Investment?

A. Yes, the Queensboro Bridge Risk Mitigation project. This project will relocate existing feeders from the Queensboro Bridge to a new trenchless crossing underneath the East River. The Company has identified Queensboro Bridge as a significant potential risk because failure could result in significant outages.

Q. Can you give an example of a Core Investment that is also a multi-value project?

A. Yes, the Williamsburg Network Improvement Project. That project will create two smaller load areas out of the Williamsburg Network by adding new distribution feeders connected to the Vinegar Hill Distribution Switching station. This will improve the reliability and resiliency of the Williamsburg Network, reduce average load per feeder, and accommodate future load growth in an area that has seen a 24 percent increase in load since 2014. At the same time, the project also contributes to meeting clean energy and resilience goals. For example, some of the future load growth in this area will come from building and transportation electrification; thus, the project is needed to accommodate the State's clean energy policy. In addition, this project will address the need for future load relief driven by a forecasted increase in temperature at the time of peak load due to climate change. This will be further discussed in the forecasting section. The project will also give the Company the ability to use sectionalizing switches to provide opportunities to transfer load.

Q. Can you give an example of a Core Investment that maintains safety?

A. Yes. The public may come in to contact with our facilities which may be underfoot in roadways, pedestrian spaces, and outdoor dining areas. We are committed to making sure that the public remains safe through programs like the Vented Covers for Underground Structures program, which are discussed later in this testimony.

2. Clean Energy

Q. Please explain the Company's objective to Enable Clean Energy.

A. Con Edison is committed to being a next-generation clean energy company to help the State achieve its clean energy goals. The Company's planned investments in electric infrastructure are geared towards facilitating retirement of downstate fossil fuel-fired "peaking" generation units, opening pathways for renewable generation to reach constrained Transmission Load Areas,[1] enabling customers' ability to adopt distributed energy resources ("DER"), and

[1] CECONY's Transmission System is comprised of seventeen Transmission Load Areas (TLA). These TLAs were designated based on the identification of existing Transmission System constraints, where supply internal to the TLA is insufficient to meet the internal TLA load. As a result, the TLA is dependent on transmission to balance supply and load.

expanding the system to reliably meet the needs of customers as they adopt EVs and electrify their buildings. The Company has placed significant focus on understanding the electric system's vulnerability to climate change, the potential impacts to customers, and creating plans to adapt to the impacts of climate change, and these efforts are discussed throughout this panel's testimony. The CLCPA and Con Edison's overall Clean Energy Commitment are discussed in much greater detail in the Company's CLCPA Panel testimony.

Q. Please elaborate on how the Company plans to support CLCPA goals through investment in the Transmission System.

A. In 2020, the State passed the Accelerated Renewable Energy Growth and Community Benefit Act[2] ("Benefit Act"), which established a process to expedite the development of renewable energy in New York, particularly through increased transmission. Subsequently, the Commission issued its Order on Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit

[2] *Accelerated Renewable Energy Growth and Community Benefit Act*. Full text of the legislation is available online. See https://www.budget.ny.gov/pubs/archive/fy21/exec/30day/ted-artvii-newpart-jjj.pdf.

Act[3] accelerating the timeline for key T&D upgrades to accommodate large-scale renewables. In response, Con Edison developed the Reliable Clean City Projects ("RCCPs") to enable the retirement of peaker generation units and provide new delivery pathways for renewable power to reach customers. The Company described the projects in its petition for cost recovery,[4] which the Commission approved.[5]

In addition to providing the best viable solution to the reliability needs resulting from the peaker retirements, the RCCPs provide an off-ramp that, collectively, will enable 900 MW of renewable energy carried on the 345 kV system highway to be delivered to our service territory. Together these projects represent $480.4 million in capital expenditure in RY1 through RY3 to support CLCPA goals.

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[3] Case 20-E-0197, *Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act*, Order on Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act (issued May 14, 2020) ("Order on Transmission Planning").

[4] See Case 19-E-0065, *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*, Petition of Consolidated Edison Company of New York, Inc. for Approval to Recover Costs of Certain Transmission Reliability and Clean Energy Projects, filed December 30, 2020.

[5] See Case 19-E-0065, *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 Regarding Transmission Investment Petition, issued April 15, 2021, p. 19.

In addition to the RCC projects, a number of the Core Risk Reduction/Reliability and System Expansion Transmission System investments that this panel discusses are considered multi-value projects as they also enable access to future renewable generation for the service area and provide additional capacity to accommodate increased load due to electrification. For example, the Gateway Park Area Station project that will commence in 2023 will address load growth on the Brooklyn networks, a portion of which will be the result of customer transportation and building electrification.

Q. How do the investments discussed by the Panel support the electrification of transportation and buildings for customers?

A. As discussed above, the RCCP projects and other core System Expansion projects will provide additional capacity that can support load growth associated with the charging of EVs and conversion of space and water heating from natural gas to electric. The Company is also focused on New Business capital investments to support EV charging infrastructure as part of the Company’s EV Make-Ready Program. Portions of the program are also discussed in the Company’s Customer Energy Solutions Panel testimony.

3. Climate Change Resilience

Q. Please elaborate on the Company’s Climate Change Resilience objective.

A. Con Edison’s investments in its electric system are designed to meet customer expectations by maintaining and improving reliability under normal conditions and providing resiliency during extreme weather events such as more frequent and severe major storms and prolonged heatwaves. Con Edison has historically made investments in the electric system’s resiliency. These have included $1 billion of expenditures in storm hardening and resilience projects between 2013 and 2016 following Superstorm Sandy. It also includes various initiatives to reduce system damage and customer outages and to improve restoration efforts following Winter Storms Riley and Quinn in early 2018 and tropical storm Isaias in 2020.

In the face of forecasted climate change, additional investment is needed to continue to meet customer’s current expectations for reliability and resiliency. Over the past two years, Con Edison has been working to understand the impacts of climate change on the electric system and position the Company to continue to meet customer’s expectations. This began with the development of the

Company’s Climate Change Vulnerability Study[6] published in December 2019. The study describes historical and projected climate changes across Con Edison’s service territory and evaluates 2019 design specifications and procedures against expected changes to better understand areas of vulnerability and risk. A year later the Company developed a Climate Change Implementation Plan (“CCIP”).[7] Key areas addressed in the CCIP include:

- Climate change pathways;
- Climate risk governance;
- Load forecasting;
- Load relief planning;
- Reliability planning for the sub-transmission and distribution systems; and
- Asset management

[6] *Climate Change Vulnerability Study*, December 2019. See https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/climate-change-resiliency-plan/climate-change-vulnerability-study.pdf.
[7] See Case 19-E-0065, *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*, Climate Change Implementation Plan, filed December 29, 2020.

Q. In what ways is the Company planning to adjust its planning and design criteria to account for the impacts of climate change?

A. In light of anticipated changes in climate and more frequent and severe weather, the Company has changed design standards and incorporated climate change impacts into its forecasts. As part of the CCIP, Con Edison adopted Representative Concentration Pathway ("RCP") projections for use in its new Climate Change Planning and Design Guideline. Pursuant to the Guideline, the load forecasting team will consider the RCCP climate change projections for temperature, Temperature Variable ("TV"), Heating Degree Days ("HDD"), and Cooling Degree Days ("CDD") in calculating the 10- and 20-year peak demand and volumetric forecasts annually. In addition, the Company plans to raise the TV design basis by one degree for 2030 and has begun the migration to a projected floodplain of FEMA +5. We will also use these climate projections as part of our power equipment ratings, load relief planning, reliability analysis, and cold weather design. In addition, the Company will incorporate the impacts of climate change into its coastal flood mapping, flood risk standard, and heavy rainfall considerations.

Q. Are any of the Company’s proposed investments in this case the result of the Company changing its planning and design criteria to account for the forecasts contained in its Vulnerability Study?

A. Yes. Investments, or incremental portions of investments, are directly driven by these new design standards.

Q. Can you give some examples?

A. Yes, as discussed more fully in our testimony and respective white papers, our investments in the following programs, among others, are directly driven by our new design standards: Non-Network Reliability and Unit Substation (“USS”) Switchgear Flood Protection, Critical Facilities, Selective Undergrounding, Primary Feeder Reliability, and Transformer Installation. These programs will increase the reliability and resiliency of electric system for customers in the face of more frequent and extreme weather events, warming temperatures, and sea level rise.

D. Testimony Format

Q. Please describe how the remainder of this testimony is organized.

A. Section II describes the Company’s T&D electric system to provide context for the Company’s planned projects and programs. Section III provides a summary of planned T&D

capital and O&M expenditures as well as a discussion of the Electric Load Growth Forecasts. Section IV covers the individual T&D projects and programs organized by categories of spend and then by type of work within each category. Section V describes planned Electric Production projects and programs. For sections IV and V, the Company provides a description of each spend category, lists all programs and projects in each category, and highlights select programs and projects in testimony. Additional detail on each program and project can be found in the respective white paper located in the EIOP exhibits. Finally, Section VI discusses special issues such as generator retirement, Reliability Performance Mechanisms, charges for special services, and tariff changes. Each special issue discussed in Section VI is listed in the Table of Contents.

Q. Is the Company describing all projects and programs in the testimony?

A. No. The Company is discussing the major projects and programs only in testimony. The other projects and programs are described in their whitepapers.

II. Electric System Description

A. Importance of Electric Infrastructure to Service Area

Q. Please describe the importance of the Company's electric infrastructure to its customers and to its service territory.

A. Since 1823 Con Edison has played the vital role of providing essential energy services to its customers and community. The electric service provided by the Company has been an engine for growth for New York City ("the City") and Westchester County, which have a combined population of over nine million people. The Company's service territory is home to two of the five largest cities in New York State – the City and Yonkers, and to businesses that are leaders in national and international commerce, finance, culture, health care, sporting events, and entertainment. The City is also an important center for international affairs as the host for the United Nations headquarters. The Company distributes electricity to approximately 3.5 million customer accounts.

With Con Edison's customers and the State embarking on efforts to electrify transportation and buildings, the Company's electric service will become even more essential. Customers expect safe and reliable electric service now and, moving forward will need electricity to heat their homes and water, in addition to the power and cooling that they currently rely on. The Company is actively working to meet those expectations with its planned investments for the electric system.

The Company's electric system is also critical to meeting the State's CLCPA goals. The same electrification that makes electricity even more of an essential service for customers is also key to reducing GHG emissions by reducing customers' need to burn fossil fuels. In addition, Con Edison is making investments in the transmission and distribution system to enable the integration of utility-scale renewables and DERs while creating the conditions to allow for the retirement of polluting peaker generation units.

B. Description of T&D Systems

Q. Please provide a general overview of Con Edison's electric energy delivery systems.

A. Con Edison's electric service territory covers 604 square miles and includes all of New York City, except the Rockaway Peninsula in Queens, and approximately two-thirds of Westchester County. The electric delivery system is comprised of approximately 96,800 miles of underground T&D lines and over 34,500 miles of overhead lines. The Company's underground T&D system is the largest in the

United States. Con Edison's service territory, while relatively small geographically, represents approximately 40 percent of New York State’s peak electricity demand.

The Company’s T&D systems are classified into three major categories: 1) System and Transmission Operations; 2) Substation Operations and 3) Distribution. Con Edison also has a small portfolio of facilities associated with its steam system that generate electric power, as discussed in Section V.

C. Transmission System

Q. Please describe the Company’s transmission infrastructure.

A. The transmission system includes both underground and overhead infrastructure. Con Edison's underground transmission system is the largest underground transmission system in the United States and delivers electric energy at 69 kilovolts (“kV”), 138kV, 230kV, 345kV, and 500kV from generating sources to Company substations located throughout its service territory. The transmission system plays a key role in delivering clean energy to the City and Westchester County and will therefore be pivotal to meeting the State’s CLCPA goals. About 85 percent of the underground transmission system is comprised of underground pipe-type cables, the largest system of its kind in the world. This type of cable system is composed primarily of steel pipe that houses three paper-insulated cables and is filled and pressurized with 8.3 million gallons of dielectric fluid. The dielectric fluid provides insulation as well as cooling for the cables. Over 200 facilities, located throughout the system, pressurize, circulate, and cool the dielectric fluid. In addition to pipe-type cable, the remaining 15 percent of Con Edison’s underground transmission system consists of other types of cable, such as self-contained, fluid-filled, and solid dielectric. The overhead transmission system, located in Dutchess, Putnam, Westchester, and Richmond Counties, consists of approximately 1,270 structures that support 370 circuit miles of cable situated along 113 miles of right-of-way. The Company also owns or jointly owns 387 structures that support 81 circuit miles in Orange and Rockland counties.

The transmission system is subject to high loading as well as a physically challenging underground environment. Accordingly, the Company must maintain, restore, and programmatically upgrade and replace system components to provide a safe and reliable service.

D. Transmission and Area Substations

Q. Please describe the Company’s transmission and area substation infrastructure.

A. Substations consist of components (circuit breakers, transformers, phase angle regulators, switches, relay systems, and communications systems) that are used to transform, sectionalize, control, and direct power on the electrical power system. On the Con Edison system, these substations are referred to as transmission stations and area substations or stations. Typically, transmission lines and generating units are interconnected to transmission stations, which step the voltage down using transformers, to deliver electric power to the area substations. Area substations receive power from the transmission stations and further step the voltage down to deliver electric power to the distribution system.

Currently, the Con Edison system has 40 transmission stations and 62 area substations. The transmission stations are operated at 345kV, 138kV, and 69kV. Of the 40 transmission stations, Academy, Mott Haven, Cricket Valley and West 49th Street are indoor Sulfur hexafluoride ("SF6") insulated stations; Dunwoodie is an outdoor SF6 insulated station; and all others are outdoor open-air insulated stations. Except for some of the older stations, most of the 62 area substations are indoor facilities, except for their power transformers. The area substations are operated at 33kV, 27kV, and 13kV.

As described in more detail in the T&D Programs/Projects section, the Company must build a new substation and expand certain substations due to increased capacity requirements in the coming years. The Company must also maintain, refurbish, and programmatically upgrade and replace components in each substation to continue to provide a safe and reliable system.

E. Distribution System

Q. Please describe the Company’s distribution infrastructure.

A. The electric system’s 62 area substations supply 84 networks and 17 non-network load areas. The distribution system is composed of network and non-network systems operating at voltages of 4kV, 13kV, 27kV and 33kV. Staten Island systems operate at 4kV, 13kV, and 33kV; Brooklyn, Bronx, and Queens at 4kV and 27kV; Westchester at 4kV and 13kV; and Manhattan at 13kV. Approximately 2,300 primary voltage distribution feeders supply network and non-network load.

Con Edison’s underground distribution system is the largest underground, low-voltage, network system in the world. It includes approximately 266,400 manholes and service boxes; 25,500 conduit miles of duct; 96,800 miles of underground cable; and approximately 27,000 network transformers that further step the voltage down from 33kV, 27kV, or 13kV to 265/470 volts and 120/208 volts to supply the low-voltage secondary distribution system.

The Company's underground network system uses second-contingency design, i.e., it is designed to sustain the loss of any two distribution feeders in a network under peak load conditions without any feeder overloads or adverse impact on service to customers.

The Company's (non-network) overhead distribution system includes approximately 198 auto loops; 217 unit substations; 11 multibank substations; approximately 202,000 poles; 51,800 overhead transformers; and approximately 34,500 miles of overhead wire including primary, secondary, and service wire. The non-network system uses a first contingency design, i.e., it is designed to sustain the loss of one distribution feeder under peak load conditions without any feeder overloads or adverse impact on service to customers.

The Company's distribution system must be maintained, upgraded, and expanded when necessary to provide safe, reliable electric service to its customers.

F. Distributed Energy Resources

Q. Please describe the DER on the system today.

A. The term DER covers a wide range of resources including energy efficiency, demand response ("DR"), and distributed generation (“DG”) that includes combined heat and power (“CHP”) generators, battery storage, and renewable energy such as solar.

Con Edison has over three decades of experience implementing programs and interconnecting these devices. Over this time, the Company has worked with its customers to increase the amount of DER connected to its system. Con Edison has made significant progress in advancing the State’s goals and building the capabilities that support greater DER adoption. Specifically, improvements to the interconnection process are providing enhanced value to developers by allowing viable projects that pass the State-developed screens to quickly advance to interconnection or using screening results to verify the need to perform a detailed study. These improvements have enabled the interconnection of over 202 MW of solar capacity connected to Con Edison’s distribution system since January 1, 2018, for a total of approximately 400 MW of distribution-connected solar. Similarly, distribution-connected energy storage has grown to 15.7 MW, representing an almost seven-fold increase since January 1, 2018.

The Company has and will continue to work with its customers to increase these resources through its initiatives. Additional information on the Company’s efforts to integrate DER can be found in the Customer Energy Solutions Panel testimony.

G. Electric Load Growth Forecasts

Q. What is the purpose of discussing the electric load growth forecasts as part of this testimony?

A. The purpose is to explain the electric system peak and network independent summer peak demand forecasts that have increased and caused the need for the electric infrastructure discussed by this Panel and in accompanying whitepapers.

Q. What are the electric system peak and electric network independent peak summer forecasts?

A. The electric system summer peak demand forecast is a 10-year outlook of the net load growth of the electric system. This forecast considers the factors that increase and decrease the summer peak hour demand at design weather criteria. The electric network independent summer peak demand forecast is a 10-year outlook of the net load growth of specific load areas that comprise the electric system's grid. This forecast considers the factors that increase and decrease the summer independent peak hour demand at design weather criteria for each individual load area. There are 83 Network Load Areas and 13 Radial Feeders, many of which peak at different hours.

Q. Are you presenting any exhibits as part of the forecast discussion?

A. Yes. We are providing an independent network peak demand forecast exhibit for the networks and radial feeders driving specific Load Relief, Non-wire Solutions, and major capital investments; and a specific load area exhibit to explain the need for the Gateway Park Area Station.

Q. Please describe the load growth and electric peak demand forecasts for Con Edison's service territory.

A. Electric system peak summer demand in Con Edison's service territory is forecasted to grow at a compounded annual growth rate of approximately 0.4 percent over the next five years (2022-2026) and at a compounded annual growth rate (“CAGR”) of 0.7 percent over the next 10 years (2022-2031). Both the electric system and independent network peak demand forecasts, when considering load growth, account for commercial, residential, and governmental new business; COVID-19 recovery, electric vehicles (“EV”), steam to electric chiller conversions, electrification of gas appliances, electrification of heating (“EoH”) (included in the winter peak forecasts), and adjustments for climate change. These forecasts also consider “negative load modifiers” such as Combined Heat and Power (“CHP”), distributed storage, photovoltaic (”PV”), conservation voltage optimization (“CVO”), certain demand response programs (“DR”), and Energy Efficiency, which include programmatic, organic, and codes and standards.

The forecasted electric system peak demand forecast is 12,570 MW for the summer of 2022, 12,590 MW for the summer of 2026, and 13,260 MW for the summer 2031. These forecasted values are net of all aforementioned load growth and negative load modifier contributions and are at design summer weather criteria. The current outlook is that our electric system and most of its network load areas will remain summer peaking for at least the next 15 years. As such the summer peak forecasts are the controlling peak demand forecasts.

Q. Please discuss in more detail the Company’s projection for load growth and its impact on this rate filing.

A. The overall ten–year electric system peak demand CAGR is 0.7 percent and this is net of major demand side management efforts, storage, CVO, PV, and DG. However, the independent summer peak demand load growth in several key individual load areas is projected to be higher than the aforementioned electric system CAGR. Mixed-use neighborhoods throughout Brooklyn and Queens continue to see a steady increase in new small and medium-sized commercial and residential developments, and this growth has accelerated over the last year. Major new projects in Midtown Manhattan such as Hudson Yards, the expansion of the 2nd Avenue Subway, and the Long Island Railroad ("LIRR") East Side Access are expected to drive load increases in their respective networks over the next five years. Additionally, much of the load reduction seen in Manhattan's Central Business District over the past two summers is expected to return as the New York City Region continues to recover from the impacts of the COVID-19 pandemic.

The Company also anticipates increased electric peak demand over the next 10 years due to the electrification of heating (only in the winter), electrification of gas appliances (stovetops, dryers, and hot water heaters), and transportation. With regards to electrification of heating, gas appliances, and light-duty vehicles, the associated load growth is expected to be most significant in lower density residential areas where the housing stock and geography is better suited for these respective technologies. In addition, widespread electrification of medium and heavy-duty vehicles will have very targeted impacts on electric networks where large transit or commercial vehicle fleets are based.

Q. Was the exhibit titled, "CECONY Network & Radial Feeder 10-Year Independent Summer Peak Demand Forecast (MW)" prepared under your direction?

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT EIOP-2

Q. Is the increase in the network or radial feeder summer independent peak forecast going to drive the need for additional capital investment over the next 5-to-10-year horizon.

A. Yes. Increases in the network and radial feeder summer independent peak demand forecasts are driving capital investments in new infrastructure in specific networks across the system. These include load areas served by the

- Brownsville 1 & 2 Area Stations (Crown Heights, Ridgewood, and Richmond Hill networks and the 9B91 – 9B94 radial feeders)
- Glendale and Newtown Area Station corridor (Borden, Sunnyside, Maspeth networks, Radial Feeders 6Q83 and 6Q84, and the Sunnyside Amtrak load)
- Plymouth and Water Street Area Stations (Williamsburg, Prospect Park, and Borough Hall Networks)
- Parkview Area Station (Triboro Network)

- Bruckner Area Station (West Bronx & Randall's Island Networks)
- West 42nd Street 1 Area Station (Pennsylvania Network)
- Jamaica Area Station and Network

Q. Was the exhibit titled, "Brownsville 1 & 2 - Changes Between 2021 & 2020 Summer Peak Demand Forecasts (MW)" prepared under your direction?

A. Yes, it was.

Q. What is driving the change in the load forecast for the networks and radial feeders served by the Brownsville 1 & 2 areas stations in the 2021 forecast relative to the 2020 forecast?

A. The 2021 cumulative 10-year electric load forecast for the networks and radial feeders served by the Brownsville 1 & 2 load area, whose networks and radial feeders generally peak during the same hour in the summer, increased by approximately 85 MW relative to 2020's forecast. This increase is due to several factors including: increases in proposed new business, a decrease in expected energy efficiency, and the inclusion of additional electrification technologies, including electric medium & heavy-duty vehicles and electrification of appliance gas in the Brownsville 1 & 2 load area. This exhibit represents the reconciliation of the amounts of weather adjusted peak demand to our design weather criteria, new business, EV, electrification of appliance gas, EE, COVID-19 adjustment, climate change, CHP, energy storage, DR, CVO, and load transfers. The values in this exhibit are cumulative and rounded to the nearest MW. The primary drivers of the increase are discussed as follows:

- New Business: In the 2021 forecast, an additional 75 new large applications were active relative to the 2020 Forecast. The increase in overall applications is due to continued new development and latent demand for new construction occurring as the region continues to recover from the economic downturn driven by COVID-19, as described in the Electric Forecasting Panel testimony. The largest of these jobs is an affordable housing complex located in the Richmond Hill network.
- Energy Efficiency (EE): The Company reevaluated its load forecasting methodology prior to developing this year’s forecast. The Company determined that in areas with active Non-Wires-Solutions (NWS) programs (which includes the networks served by the Brownsville 1 & 2 Area Stations in the Brooklyn Queens Demand Management (“BQDM”) Program), we would not allocate any systemwide programmatic EE. This approach differs from previous years where programmatic EE

was allocated to all networks, regardless of their participation in an NWS program. The Company made this change because the prior approach did not consider possible competition between BQDM and CECONY systemwide programs or saturation of EE from a focused initiative like BQDM. The reduced negative load modifier resulted in an approximately 30 MW increase in the total forecast for these networks.

- Electrification: The 2021 forecast includes the impact of electrification of medium and heavy-duty vehicles and electrification of appliance gas.
    - While some distinct Medium and Heavy-Duty electrification efforts were considered in the 2020 forecast, a more wide-spread and higher magnitude of adoption of Medium and Heavy-Duty electric vehicles were included for the first time in the 2021 forecasts.
    - The electrification of appliance gas includes hot water heating, cooking, and dryer gas. This accounts for the impact of New York City’s gas ban which results in new heating load from new construction being almost exclusively electric. It also includes the impact of the conversion of existing heating appliances from gas to electric.

Q. How does this forecast affect the need for capital investment in the electric system?

A. Based on the outlook for the BQDM Load Area, there is a need to advance the development of the Gateway Park Area Station and, as such, the Company will begin engineering, planning, equipment procurement, and construction during the rate plan. The Gateway Park Area Station will eventually be supplied with renewable energy by the Brooklyn Clean Energy Hub and will address load growth in the area.

Q. Was this the only impact?

A. No, but this is the most significant direct impact. As is discussed elsewhere in this testimony, these peak demand forecasts demonstrate in general that significant changes should be expected from the clean energy transition, e.g., the move to electrification, and more extreme weather.

III. T&D Capital and O&M Summary

A. Summary

Q. What is the Company's projected T&D capital spend for the three rate years?

A. The Company is planning to spend $2,458.4 million in RY1, $2,500.0 million in RY2 and $2,543.4 million in RY3.

Q. What is the Company's T&D Operations and Maintenance ("O&M") expenditure for the historic test year (the period October 1st, 2020 through September 30th, 2021) for T&D?

A. The Company's total T&D O&M expenditure for the Historic test year for T&D is $455.4 million.

Q. What are the Company's O&M program cost changes for T&D in RY1, RY2 and RY3?

A. The Company is planning an increase of $22.7 million for program changes in RY1, an increase of $6.8 million for program changes in RY2, and an overall decrease of $6.6 million for program changes in RY3. All the amounts discussed above are exclusive of escalations, which are described by the Accounting Panel.

B. Program and Project Type Categories

Q. How will the Company present its projected T&D capital and O&M expenditure for specific programs and projects?

A. Con Edison's projected T&D capital and O&M requirements for specific programs and projects are presented under the following categories: Risk Reduction/Reliability, New Business & System Expansion, Replacement, Equipment Purchases, Safety and Security, Environmental, and Information Technology.

Q. How do these categories relate to the three expenditure priorities (Core Investments, Enabling Clean Energy, and Climate Change Resilience) discussed previously?

A. The categories describe the nature of a specific program or project and have been traditionally used by the Company to categorize investments. Because projects and programs can be multi-value, each category has projects and programs that reflect one or more of our three expenditure priorities.

Q. Please provide a description of each category.

A. Each of the Company’s program and project type categories are described below:

a. Risk Reduction/Reliability – This category consists of projects and programs that support the reliability and/or availability of a facility or an operational function and that reduce or mitigate a risk associated with a facility or operation through proactive replacement/upgrade strategies. The Company will invest $957.1 million in RY1, $969.8 million in RY2, and $980.1 million in RY3 in this category.

b. New Business & System Expansion – New business consists of projects and programs that connect new customers to the Company’s electric system. System Expansion consists of projects and programs that increase system capacity or that address the impact of customer demand growth or supply retirements. The Company will invest $487.4 million in RY1, $553.2 million in RY2, and $729.1 million in RY3 in this category.

c. Replacement – This category consists of projects and programs to replace failed equipment or equipment that has degraded performance, has become difficult or costly to maintain, or is approaching the end of its useful life. The Company will invest $541.8 million in RY1, $555.8 million in RY2, and $558.8 million in RY3 in this category.

d. Equipment Purchases - This category consists of projects and programs for the purchase of necessary equipment such as transformers, network protectors, switches, and meters. The Company will invest $146.0 million in RY1, $159.6 million in RY2, and $159.6 million in RY3 in this category.

e. Safety and Security – This category consists of projects and programs primarily intended to reduce the likelihood of injury or risk to public safety, enhance physical or cyber security, or comply with regulatory requirements. The Company will invest $22.3 million in RY1, $22.6 million in RY2, and $22.7 million in RY3 in this category.

f. Environmental – This category consists of projects and programs primarily intended to enhance environmental performance, reduce environmental impact, or comply with environmental requirements. The Company will invest $51.9 million in RY1, $51.6 million in RY2, and $52.1 million in RY3 in this category.

g. Information Technology – This category consists of projects and programs to improve computer systems, system development, and information and communication systems. These investments are listed in the Information Technology section of this panel but detailed testimony and white papers can be found in the Company’s IT Panel testimony.

C. Expenditure Summary

Q. Was the document titled “T&D Capital and O&M Summary” prepared under your direction or supervision?

A. Yes.

MARK FOR IDENTIFICATION AS EXHIBIT EIOP-1

Q. What does this exhibit show?

A. This exhibit presents an overall summary of the total T&D capital expenditures that are presented in the Panel’s testimony. The exhibit first presents a summary of the Company’s planned capital and O&M expenditures for each of the rate years, for the S&TO, SSO, and Electric Operations organizations. The exhibit also shows planned capital expenditures for each of the rate years for common capital expenditures that are charged to the electric business. The exhibit also shows planned O&M expenditures by organization and a summary of program changes. Note that this Exhibit does not reflect any escalation in expenses in the calculations of the total rate year forecasts for each item. Escalation is discussed by the Accounting Panel.

Q. Please provide an overview of capital expenditures for the rate years.

A. The expenditure details are described in their respective sections of the testimony, but we provide a general overview here. Exhibit EIOP-1, Schedule 1 shows the rate year capital T&D budgets for S&TO, SSO, and Electric Operations. For the purposes of this overview, we describe S&TO and SSO collectively as the Transmission budget.

First, Electric Operations' spend in the Risk Reduction and Reliability category represents 27 percent of its planned capital expenditure. The need for increased Core and Climate Change Resilience investments in this category is driven by the expected increase in severity and frequency of major weather events because of climate change. The need is furthered by increased customer dependency on electricity from the ongoing adoption of EVs and electrification of buildings.

New Business projects to address increasing load also make up a significant portion, 19 percent, of Electric Operations' capital spend. Total electric demand in Con Edison's service territory is expected to grow at approximately 0.4 percent per year over the next five years (2022-2026). Significant load growth in specific residential and mixed-use neighborhoods coupled with increased electrification of buildings and transportation drives the need for investment in New Business projects. The full breakdown for Electric Operations is shown in Exhibit EIOP-1, Schedule 3.

Q. Please continue with a description of Transmission investments.

A. On the Transmission system, most of the spending is for Risk Reduction and Reliability projects, making up 53 percent of capital expenditures. Increased investments in Transformers, Protective Relay and Control Systems, Transmission Cables, and Other Energy Delivery Equipment are driven by the anticipation of additional stress on the system from extreme weather, electrification, and reduced maintenance/replacement windows. Additionally, the increase of remote monitoring will help the Company identify equipment that requires replacement. The full breakdown for Transmission is shown in Exhibit EIOP-1, Schedule 3.

Q. Please provide an overview of the O&M increases for the rate years.

A. Exhibit EIOP-1, Schedule 2 shows the rate year O&M T&D budgets for S&TO, SSO, and Electric Operations. The major drivers of O&M increases during the rate years are the Safety Inspection Program, the Line Clearance/Vegetation Management Program, and Meters and Customer Equipment. The Panel discusses the increases in each of these programs in the proceeding Details of T&D Programs/Projects section.

Q. Does the Company plan to seek any funding for T&D infrastructure made available through the Infrastructure Investment and Jobs Act ("IIJA") passed by Congress and signed into law November, 15, 2021?

A. The Company is currently reviewing potential grant opportunities as outlined in the IIAJ. As the Department of Energy develops these programs over the first half of 2022, the Company may identify current or new programs or projects that align with the grant programs that are developed and apply for grants if/when it is appropriate.

Q. Do all expenditures described by the Electric Infrastructure and Operations panel match those presented by the Company's Accounting Panel?

A. No. The capital expenditure plans for aspects of our Area Substation Load Relief Program has been recently adjusted as a result of the Company’s latest load forecast. Changes may include projects that are currently planned to be in service well beyond the rate years needing to be moved forward to a point where initial work on the projects (real estate, planning, etc.) may need to begin during the rate years. In addition, the Company will make adjustments as appropriate to address project changes and adjustments in response to any significant Commission orders, such as those that may relate to planned CLCPA projects. Finally, the Company’s O&M forecast will require updates for O&M expenses associated with the purchase of new utility vehicles and the Company’s Safety Inspection Program. Any required adjustments will be reflected in the Company’s preliminary update, including white papers.

IV. Detail of T&D Programs/Projects

A. Risk Reduction/Reliability Capital and O&M Expenditure Requirements

Q. Was the exhibit titled, “T&D Risk Reduction” prepared under your direction?

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT EIOP-3

Q. What does Exhibit EIOP-3 show?

A. Exhibit EIOP-3, Schedules 1 and 2 list the capital program and project funding requirements and O&M program changes required to support the Company's Risk Reduction and Reliability work conducted by S&TO, SSO, and Electric Operations for RY1, RY2, and RY3. In addition, the exhibit contains white papers that provide more detailed information on each of the capital and O&M programs/ projects in this category.

Q. Please provide an overview of this category of work.

A. Con Edison's Risk Reduction/Reliability programs and projects are designed to maintain the operational capability, reliability, and safety of the transmission, substation, and distribution systems. The Company's programs in this category address near and long-term reliability issues. The Company analyzes, assesses, and adjusts its capital programs to focus expenditures on systems and components most in need of attention, driven by risk and impact of asset failure, load growth, climate change impacts, building and transportation electrification, or other factors. Where necessary, Con Edison programmatically upgrades and proactively replaces system components before they become degraded or obsolete.

Risk reduction/reliability projects and programs are divided into four sub-categories for this rate filing:

- System Resilience;
- Transformers, breakers, and other energy delivery equipment;
- Monitoring, supervisory, protection, and auxiliary systems; and
- Structures, housings, buildings, and other miscellaneous assets.

1. System Resilience

Q. Please describe the System Resilience category.

A. Investments in the System Resilience category are designed to strengthen the Company's electric distribution system, reducing the amount of damage sustained during severe weather events, lowering the number of customers impacted by component failures, and improving the Company's ability to repair damage and restore service after extreme weather events. This category takes on increased importance as the severity and frequency of major weather events is expected to increase.

Q. What specific resilience projects does the Company plan to invest in for the rate plan period?

A. The Company plans to invest in the projects listed below. Additional detail on each of these projects can be found in their respective white papers.

- “Condition Based Monitoring Program” ($1.5 MM RY1, $15.0 MM RY2, $15.0 MM RY3)
- “Control Cable Upgrade Program” ($4.0 MM RY2, $4.0 MM RY3)
- “Critical Facilities Program” ($9.0 MM RY1, $9.0 MM RY2, $9.0 MM RY3)
- “Erosion Protection and Drainage Upgrade Program” ($5.0 MM RY2, $5.0 MM RY3)
- “Non-Network Reliability” ($73.6 MM RY1, $87.1 MM RY2, $87.1 MM RY3)
- “Non-Network Resiliency with FLISR” ($2.1 MM RY1, $2.1 MM RY2, $2.1 MM RY3)
- “Overhead Insulator Resiliency Program” ($6.7 MM RY1, $6.7 MM RY2, $6.7 MM RY3)
- “Pole Inspection and Treatment (PIT) Program” ($2.3 MM RY1, $2.3 MM RY2, $2.3 MM RY3)
- “Primary Feeder Reliability” ($75.5 MM RY1, $77.0 MM RY2, $78.5 MM RY3)
- “Queensboro Bridge Risk Mitigation” ($20.0 MM RY1, $80.0 MM RY2, $80.0 MM RY3)
- “Replacement of Feeders M51 and M52” ($10.0 MM RY3)
- “Selective Undergrounding” ($60.0 MM RY1, $80.0 MM RY2, $100.0 MM RY3)

- "Underground Secondary Reliability" ($25.5 MM RY1, $25.8 MM RY2, $29.7 MM RY3)
- "Upgrade Light and Power System Program" ($1.0 MM RY1, $1.0 MM RY2, $1.0 MM RY3)
- "USS Switchgear Flood Protection" ($8.5 MM RY1, $8.5 MM RY2, $8.5 MM RY3)
- "Wainwright – Willowbrook Stepdown Transformer Installation" ($8.5 MM RY1, $1.0 MM RY2)

Q. Please describe some of the key capital programs in this category starting with the Primary Feeder Reliability Program.

A. The Primary Feeder Reliability Program is aimed at maintaining and improving the reliability and resiliency of Con Edison's networks and non-network load areas. The program relies on the Network Reliability Index ("NRI"), a measure used to gauge the reliability and resiliency of all 65 second contingency networks on the Con Edison distribution system. The lower the index, the less likely for that network to experience cascading feeder outages. In addition, poor NRI performance has been associated with the need for voltage reduction actions, which can negatively impact customer equipment, especially those of commercial, industrial, and government customers. Con Edison has expended significant effort through Core Investments over the past decade to improve all its networks to below an NRI of 1.0, and as of summer 2021 the top 25 networks have an average NRI of 0.51. As a result, the probability that a voltage reduction action is needed is lowered.

Q. What factors impact NRI?

A. Factors that impact the NRI include the number of components in the network, component failure rates, expected periods of heat stress, feeder/network loading, and the load shifts during contingencies.

Q. Does Con Edison’s plan to raise the TV design basis by one degree Fahrenheit by 2030 to account for projected climate change affect NRI?

A. Yes. Raising the TV to account for projected climate change will have a direct impact on NRI, particularly as it relates to heat stress. Applying the increased TV to current network NRI calculations results in eight networks with NRI levels greater than 1.0 and the average of the top 25 networks rises from 0.51 to 0.87.

Q. Are these results driving any proposed investments?

A. Yes. Because increasing the TV for projected climate change raises the NRI, we need significant investments, during the rate plan, to maintain current NRI levels, namely an NRI below 1.0 on all networks and an average NRI for the top 25 networks that is close to the present 0.5. The work required between now and 2030 to maintain system reliability in the face of increased temperatures, load growth associated with electrification, and other factors falls into three broad categories: 1) Paper Insulated Lead Covered ("PILC") cable replacement to reduce failure rates in summer months; 2) underground interrupter installation to allow isolation of a faulted segment of a feeder while the un-faulted portion remains energized; and 3) new and extended feeders to increase resiliency and accommodate future load growth, to include growth driven by electrification.

Q. Please continue by describing the USS Switchgear Flood Protection Program.

A. As a result of climate change, the Company's service territory is facing an increased risk of coastal flooding. The USS Switchgear Flood Protection Program provides mitigation measures to minimize damage from flooding. Post-Sandy Storm Hardening efforts brought all stations in the 100-year flood plain to FEMA +3. Based on design standards adopted following the CCVS, the Company is already installing some assets based on a FEMA +4/5 standard, due to future increasing vulnerability to coastal flooding. Additionally, historic torrential rainfall, such as that experienced during Hurricane Ida in 2021, puts unit substations outside of the floodplain at risk of flood damage.

To protect the unit substation switchgear from increased flood risk, this program upgrades the USS switchgear by installing new elevated recloser switches instead of traditional switchgear. Platforms will elevate critical switchgear components above anticipated flood levels to minimize exposure to flood waters. Use of standard and widely available recloser switch installations will enable fast repairs at a lower cost when damage does occur.

Few third-party specialty vendors can repair the Company’s custom designed unit substation switchgears. Limited vendor availability and long lead times associated with these repairs put customers at risk of prolonged outages while also adding significant cost. Recloser switches are self-contained devices that can be repaired or replaced individually, offering modular features that traditional switchgear breakers lack. Installing recloser switches will allow for expedited and lower cost repairs. These switchgear upgrades will improve resiliency in the presence of increased flooding risk while also providing remote, secure access to digital data to prioritize system restoration.

Q. Please describe the Company’s new Selective Undergrounding Program.

A. Con Edison’s Selective Undergrounding Program is a significant part of the Company’s climate adaptation strategy to mitigate the extent of customer outages resulting from major storms and generally increase system resiliency. The Company plans to spend $240 million during the rate years to convert approximately 24 miles of overhead distribution to underground distribution. With the expectation that major storms will increase in both severity and frequency because of climate change, the program will identify and prioritize sections (spurs) of Con Edison’s overhead distribution system, where customers frequently experience outages caused by severe weather, for undergrounding. In addition to entirely avoiding some storm-related outages, the Selective Undergrounding Program will also improve the Company’s major event restoration performance on a system-wide and local basis through the minimization of long-duration, low customer impacted outages, freeing restoration crews to address other outages. Finally, the program is consistent with the CLCPA because it prioritizes disadvantaged communities.

Q. Please elaborate on how the program prioritizes disadvantaged communities.

A. The Company’s typical prioritization looks at the circuit performance as it relates to customer interruptions during normal and weather events. The model currently in use to analyze our circuit performance is called Overhead Program Optimization Tool (“OHPOT”). For Selective Undergrounding, we are incorporating disadvantaged community data into the OHPOT model and have created a weighting system to determine the prioritization of circuits.

Q. Will this be Con Edison’s first time launching a selective undergrounding program?

A. No, we are currently conducting an undergrounding pilot program.

Q. Please discuss the pilot program and its status.

A. The pilots are in three locations 1) Queens, 2) Westchester, and 3) Staten Island. The Queens pilot included undergrounding portions of overhead primary and secondary distribution to improve the system reliability for 500 customers and was completed in January 2022. The Westchester pilot is undergrounding an overhead sub spur that has a history of outages caused by tree limb contact, including 244 hours of outage resulting from winter storms Riley and Quinn. Construction has commenced on the

Westchester pilot with an expected completion in mid-2022. Con Edison was not able to gain customer participation for the first location selected for the Staten Island pilot. The Company is currently in the process of engaging with customers for a second location. Per the settlement agreement approved by the Commission in Case 20-E-0422 et al., Con Edison agreed to pay from shareholder funds all costs customers would otherwise be responsible for under the pilot program up to $750,000. As of January 2022 the Company has paid approximately $236,000 in Customer Undergrounding Costs.

Q. Please describe the Non-Network Reliability Program.

A. The overhead distribution system is comprised of non-network circuits, including 4kV primary grids and 4kV, 13kV, and 27kV auto loops. This program increases reliability for customers by ranking non-network circuits and proactively investing in the lowest performing circuits. This program is a multi-value investment because it will make the non-network system more resilient in the face of more frequent and severe storms in addition to improving reliability.

Q. How does the Company conduct the non-network circuit ranking?

A. The Company uses standard industry metrics, combined with analysis of outages through the OHPOT system so that it can identify and target the lower performing networks for remediation.

Q. Please explain the work involved in this program.

A. The Company uses three primary approaches for improving the reliability of the non-network system: 1) addressing primary reliability, which involves replacing overhead and underground feeder cables which connect the distribution system to the substations; 2) rebuilding the overhead secondary distribution system, which includes replacing poles and conductors supplied by feeder cables; and 3) reconfiguring circuits by adding new segments and associated equipment, which typically includes poles, wires, and switches.

Q. Please describe the Queensboro Bridge Risk Mitigation Project.

A. There are six 138kV feeders and six 69kV feeders that traverse the Queensboro Bridge. The bridge has been identified as a potential common mode failure and significant potential risk because failure could result in significant outages. If failure were to occur it would take out most of the supply to the east side of Manhattan. The 138kV feeders have previously experienced joint failures and the 69kV feeders have experienced nitrogen leaks that are costly to repair and could impact cable life. This project will remove the six feeders and replace them with new cable in trenchless crossings underneath the East River. The 138kV feeders will be prioritized for replacement under the project but the design will consider the need to eventually move the remaining feeders off the Queensboro Bridge.

Q. Please describe the Company’s plans to replace Feeders M51 and M52.

A. Feeders M51 and M52 were installed in 1974, and within the past ten years have seen over 250 leaks totaling 197,000 gallons of dielectric fluid released, roughly 25 percent of the total volume of dielectric fluid contained in the two feeders. As a result, the Company will replace both 345kV feeders M51 and M52 (each approximately 17 miles long) utilizing a new route to the W49th Street Substation. High pressure fluid filled (“HPFF”) cable will be replaced with cross-linked polyethylene insulated (“XLPE”) cable. The XLPE portion will be a combination of submarine cable and underground cable in duct banks.

Q. Please describe the importance Feeders M51 and M52.

A. Feeders M51 and M52 have been critical transmission assets moving upstate generation to the load center in New York

City. As more bulk renewables connect to the Con Edison transmission system, Feeders M51 and M52 will play an even more critical role as they will be integral to moving clean energy to other parts of the service territory.

Q. What are the environmental and cost benefits of replacing feeders M51 and M52?

A. Replacement of M51 and M52 with XLPE cable would eliminate dielectric fluid leaks in two of the worst performing feeders on the system and eliminate environmental risks associated with the Harlem River crossing. Feeders M51 and M52 also present a maintenance burden for the Company. The feeders average 1,500 to 2,000 hours per year in corrective maintenance, which is 3.5-5 standard deviations above the mean for the rest of the 345kV feeder population. Leak response and remediation has also required a considerable amount of funding, averaging approximately $5 million a year in recent years. The elimination of the maintenance and emergency response burden associated with Feeders M51 and M52 will reduce expenses and free up Company resources for other work on the system. Further, it would also make conduit available to facilitate the future transfer of clean energy into the area, supporting the State’s CLCPA goals.

Q. What is the Company’s funding request in this rate case?

A. The Company is requesting funding of $10 million in 2025 to begin a more detailed route study, involving test pitting and geotechnical surveys. Construction is estimated to be completed by the end of 2028.

Q. Please describe the Overhead Insulator Resiliency Program.

A. Through this program, which is a new program targeting system resiliency, the Company will systematically replace crack prone insulators on critical overhead transmission lines. Specifically, some porcelain insulators on the transmission lines have been found to be prone to cracks that can ultimately lead to failures. The program scope involves the replacement of 8,595 porcelain insulator bells on 573 insulator strings on lines that include critical overhead transmission feeders supplying power to the City and Westchester County. The replacement of these insulators will increase system resiliency by lowering the risk of load shedding and large-scale outages resulting from multiple failures during a high-load period or contingency, a risk that increases due to warming and more frequent and severe storms.

Q. Please describe the Condition Based Monitoring Program.

A. This program will install different monitoring devices on substation power transformers and other equipment. Some of these devices include temperature monitoring devices;

Intelligent Electronic Devices that interface with instruments and other equipment; monitoring devices for substation battery banks; Geomagnetically Induced Current monitoring devices that detect tank heating on select units; and in some cases associated software platforms.

Q. Why is this program important?

A. Substation power transformers are critical to delivering electricity and, along with battery banks, are essential to re-energizing a substation after an emergency. This program will allow us to more accurately receive data on temperatures and substation battery bank status without requiring and in-person reading. This enables operations to make the best possible decisions. It also provides the ability to understand the effects of climate change on equipment over the long term to improve planning in the form of ratings and replacement cycles. The lack of continuous data makes long-term decisions about transformer load and ratings more difficult. Moreover, during peak and/or contingency scenarios, the ability to remotely monitor transformer temperatures allows operators and engineers to make informed and timely decisions regarding operation of the system. The increased frequency, intensity, and duration of heat waves that are projected in the Company’s Climate Change Vulnerability Study and CCIP make real-time monitoring of substation equipment more critical than ever.

Q. Please describe the Control Cable Upgrade Program.

A. This program will replace all the copper control cable in a substation as well as the troughs and raceways that house these cables as needed. Control cables represent a critical component within substations as they connect local cabinets at devices like breakers, transformers, and relay panels to the substation’s control and/or automation system, among other things. These cables can degrade over the life of the substation or as the result of extreme weather causing the insulation to break down, potentially providing an entry point for water that corrodes the copper and creates grounds. This program will begin in 2024, will target two substations at a time, and assumes each station will take 5 years to complete. Extreme weather, such as heavy rain events, poses a significant risk to substations that have pervasive problems with degrading control cabling. In order to adapt to changing weather patterns driven by climate change, this program is necessary to mitigate the risk of dropping customers as the result of a substation event.

Q. Since it also focuses on adapting to extreme weather, please continue by describing the Erosion Protection and Drainage Upgrade Program.

A. This program will install reinforcements and upgrade drainage systems in select substations to protect from erosion that may occur during extreme rain events. Extreme rain events, such as Tropical Storm Ida, have produced rainfall of 4 to 8 inches in just a few hours. This type of deluge can cause pooling and in some cases erosion that could undermine substation equipment. If extreme enough, these impacts could cause critical substation equipment to lose control power or inadvertently trip out, resulting in outages. Erosion caused by extreme rain events could also create unsafe conditions for substation personnel. The program will start in 2024 and will target upgrades at roughly two substations per year.

Q. Please describe the Non-Network Resiliency with FLISR Program.

A. This program will replace older sectionalizing equipment with new technology that will further enhance Fault Location, Isolation, and Service Restoration (“FLISR”) capabilities. Con Edison has progressively developed FLISR capabilities on the Non-Network portion of its distribution system through the deployment of protective devices like reclosers and sectionalizing switches. These devices allow the Company to locate faults, isolate the damaged conductors and/or equipment, and restore service to customers on undamaged portions of the circuit(s). Work completed via this program will expand these capabilities through deployment of Smart Switches – i.e., devices with Supervisory control and data acquisition ("SCADA") capability and/or the ability to operate automatically without operator intervention.

The SCADA capability of the newer sectionalizing equipment provides greater visibility and remote control of the switch, and the dead front and enclosed bus design requires less maintenance, is safer for mechanics to work on, and is less prone to outages caused by animal infestation. The new smart switches will also provide additional information to the Outage Management System ("OMS"), which, along with additional controllable devices, will provide greater flexibility for restoration when a failure occurs.

2. Transformers, Breakers, and Other Energy Delivery Equipment

Q. Please provide an overview of programs and projects focused on transformers, breakers, and other energy delivery equipment.

A. The Company's T&D systems transmit power through equipment located within substations and above or below the streets of New York City and Westchester County. Each type of equipment has its own purpose, historical performance, and functional lifecycle. This rate filing contains projects and programs to address: 1) proactive upgrades and replacements of these assets and 2) replacements or upgrades when the equipment will exceed its design basis.

Q. Does the Company anticipate an increase in investment in transformers, breakers, and other energy delivery equipment in the rate years when compared to years past?

A. Yes. The increased investment is primarily driven by the projected impacts of climate change. Warming, including an increase in hotter days, along with increasing loads due to transportation electrification, will place additional stress on transformers, breakers, and other energy delivery equipment that could lead to higher failure rates and the need for more replacements prior to failure.

More targeted inspection programs and the introduction of remote monitoring has helped the Company identify an increasing number of pieces of equipment that require replacement.

Q. Please describe the Company’s proactive equipment replacement/upgrade programs and projects.

A. The programs in this category include those that replace equipment based on asset management methodology, installations of equipment that enhance reliability, and address equipment that has an elevated risk of failure or that is no longer supported by manufacturers.

The projects listed below involve proactive equipment replacement. Details on each of these projects can be found in their respective white papers in Exhibit EIOP-3, Schedule 3.

- “4kV USS Switchgear House Replacement” ($13.2 MM RY1, $13.2 MM RY2, $13.2 MM RY3)
- “Area Substation Phased Replacement Program” ($30.0 MM RY1, $30.0 MM RY2, $30.0 MM RY3)
- “Area Substation Reliability” ($11.5 MM RY1, $11.5 MM RY2, $11.5 MM RY3)
- “Auxiliary Station Equipment Program” ($1.1 MM RY1, $1.1 MM RY2, $1.1 MM RY3)
- “Circuit Switcher Replacement Program” ($1.4 MM RY1, $1.4 MM RY2, $1.4 MM RY3)
- “Disconnect Switch Capital Upgrade Program” ($5.2 MM RY1, $5.2 MM RY2, $5.2 MM RY3)
- “Feeder 38R51 and 38R52 Replacement Project” ($122.0 MM RY1)
- “Feeder Replacement Program” ($2.5 MM RY1, $3.5 MM RY2, $3.5 MM RY3)

- “Gas Insulated Substation Replacement Program” ($13.0 MM RY1, $28.5 MM RY2, $28.5 MM RY3)
- “High Voltage Circuit Breaker Capital Upgrade Program” ($25.4 RY1, $23.4 MM RY2, $24.8 MM RY3)
- “High Voltage Test Set Program” ($2.8 MM RY1, $2.8 MM RY2, $2.8 MM RY3)
- “Other Capital Equipment Upgrades Program” ($3.5 MM RY1, $3.5 MM RY2, $3.5 MM RY3)
- “Joint Replacement Program” ($10.5 MM RY1, $13.0 MM RY2, $13.0 MM RY3)
- “Reinforced Ground Grid Program” ($6.1 MM RY1, $6.1 MM RY2, $6.1 MM RY3)
- “Substation Loss Contingency – Rapid Recovery of an Area Substation/Transmission Resiliency Transformers” ($4.0 MM RY1)
- “Substation Transformer Replacement Program” ($124.0 MM RY1, $124.0 MM RY2, $124.0 MM RY3)
- “Unit Substation Transformer Replacement Program” ($3.9 MM RY1, $3.9 MM RY2, $3.9 MM RY3)
- “U-Type Bushing Replacement Program” ($5.6 MM RY1, $5.1 MM RY2, $4.4 MM RY3)

Q. Please describe the two most significant investments in this category, starting with the Transformer Installation Program.

A. This program involves the replacement of electrical distribution equipment (primarily underground network transformers and their associated network protector, cable, conduit, and structures) that have defects indicative of failure or eventual failure. Defective equipment replacements account for approximately 55 percent of all transformer installations. These components are identified for removal based on equipment condition determined from visual inspection, dissolved gas in oil analysis, and remote sensors which report pressure, temperature, and oil level and prioritization based on the risk of failure.

Con Edison has instituted more comprehensive underground transformer inspection program and has also installed remote monitoring equipment on transformers to provide real-time pressure and temperature readings. As a result of this increased monitoring, the Company has identified an increased number of units needing replacement to maintain system reliability. This program improves reliability by identifying transformers for replacement prior to failure, avoiding the loss of multiple feeders in the same network, which could result in customer outages.

In addition, the program also improves public safety by reducing the risk of transformer ruptures.

Q. Please continue by describing the Substation Transformer Replacement Program.

A. This program is designed to proactively replace transformers that the Company has determined are nearing the end of their useful lives and cannot be maintained in reliable operating condition. There are 422 power transformers on the Con Edison system, of which 185 have been in service for over 40 years. As these units age, there is an increase in required corrective maintenance and the potential for malfunction, especially during high load periods and/or coincident with other outages. Replacing defective transformers prior to failure improves reliability. During the past two decades, an increased replacement frequency of power transformers is positively associated with a significant reduction in the number of failures comparing to those in the prior two decades.

Given the age of the transformer fleet, more proactive replacements per year will be needed to reduce in-service failures and maintain current reliability levels for customers. The Company’s analysis indicates that eight proactive replacements are required to maintain current reliability levels. Further, the Company’s CCIP suggests that over the coming decades there will be more days per year with maximum daily temperature above 95 degrees Fahrenheit, potentially more than doubling from today’s average. Increased frequency of high ambient temperature days will mean that transformers are operating in challenging conditions more often, as well as being more heavily loaded as hot weather translates to higher electrical demand. In addition, building and transportation electrification will increase demand on the electric system, particularly in the winter months, resulting in accelerated transformer aging. These factors could lead to an increase in transformer failure rates over the course of the next ten years. For these reasons, the Company must perform eight proactive transformer replacements per year for the next five years to maintain reliability. Failure rates will also be closely monitored to determine if increased proactive replacements are needed in the second half of the decade due to climate change and electrification.

Q. How does the Company determine, in a given planning period, which specific transformers to replace?

A. The Company uses a health index to prioritize units for replacement.

Q. What factors does the transformer health index consider?

A. The factors include, but are not limited to, dissolved gas in oil analysis ("DGOA"), insulation condition as indicated by oil analysis, the presence of leaks, and the insulation condition of units of the same vintage that have already failed in service or have been replaced.

Q. Please describe the final Risk Reduction subcategory, which addresses assets that have exceeded their design basis.

A. The Company must address risks associated with equipment that no longer meets the design basis, including by adding new equipment. The Company has two capital projects in this category. Details on each of these projects can be found in their respective white papers in EIOP-3, Schedule 3.

- "Shunt Reactor" ($5.0 MM RY1, $5.0 MM RY2, $5.0 MM RY3)
- "Retrofit Overduty 13kV and 27kV Circuit Breaker Program" ($13.8 MM RY1, $13.8 MM RY2, $13.8 MM RY3)

3. Monitoring, Supervisory, Protection, and Auxiliary Systems

Q. Please provide a general overview of this category.

A. To reliably operate its T&D assets, the Company makes Core Investments to maintain monitoring, supervisory, protection, and auxiliary systems. Monitoring systems measure and communicate key parameters of operating performance to engineers and operators, who use this data to proactively identify equipment maintenance issues and/or early stages of failure. Supervisory systems include automation systems for substation operators and systems that aid Energy Control Center ("ECC") operators in reacting to system events, faults, and contingencies while balancing changes in generation and electrical demand. Auxiliary systems facilitate the operation and monitoring of various components of the transmission system and include direct current systems that provide control power to switching and protection equipment, pressurization systems that help maintain the dielectric properties of transmission feeders, and Capacitive Coupling Potential Devices ("CCPD") that measure system voltages and power flow. Finally, to reliably operate its substation and transmission system, the Company uses over 60,000 protective relays, which sense system disturbances and irregularities and automatically remove equipment from service that may be at risk of damage or failure. The Company makes investments annually in its protective relay systems to improve their operation, maintain regulatory compliance, and reduce specific risks that may contribute to transmission system forced outages.

Q. What investments does the Company plan to make within the monitoring, supervisory, protection, and auxiliary systems category?

A. The Company has 21 capital projects to support the development and upgrade of its monitoring, supervisory, protection, and auxiliary. Details on each of these projects can be found in EIOP-3, Schedule 3.

- “138kV Disturbance Monitoring Program” ($4.8 MM RY1, $4.8 MM RY2, $4.8 MM RY3)
- “Category Alarm Program – Various” ($2.3 MM RY1, $2.1 MM RY2, $2.2 MM RY3)
- “DC System Upgrade Program” ($5.1 MM RY1, $5.1 MM RY2, $5.1 MM RY3)
- “Distribution Order Enhancements” ($0.3 MM RY1, $0.3 MM RY2, $0.4 MM RY3)
- “Dynamic Feeder Rating System” ($1.0 MM RY1, $1.5 MM RY2, $1.5 MM RY3)
- “East River Automation – Upgrade the 69kV Yard” ($3.0 MM RY1)
- “EMS DevOps Upgrade” ($2.5 MM RY1, $2.5 MM RY2, $3.3 MM RY3)
- “Fire Suppression System Upgrades” ($12.1 MM RY1, $12.4 MM RY2, $12.3 MM RY3)

- “Overhead Transmission Reliability Program” ($1.0 MM RY1, $1.5 MM RY2, $1.5 MM RY3)
- “Pothead Pressure Alarms Program” ($0.2 MM RY1, $0.2 MM RY2, $0.2 MM RY3)
- “Pressure, Temperature and Oil Sensors” ($2.0 MM RY1, $2.0 MM RY2, $2.0 MM RY3)
- “Protection, Control and Automation” ($38.5 MM RY1, $33.5 MM RY2, $20.0 MM RY3)
- “Pumping Plant Improvement Project” ($4.8 MM RY1, $3.9 MM RY2, $3.9 MM RY3)
- “Relay Modifications Program” ($78.4 MM RY1, $89.9 MM RY2, $76.4 MM RY3)
- “Relay Protection Communications Upgrade Program” ($16.5 MM RY1, $16.5 MM RY2, $16.5 MM RY3)
- “Remote Monitoring System” ($3.2 MM RY1, $3.2 MM RY2, $3.2 MM RY3)
- “RTU Upgrade Program” ($2.5 MM RY1, $2.5 MM RY2, $2.5 MM RY3)
- “Smart Sensors” ($15.1 MM RY1, $15.1 MM RY2, $15.1 MM RY3)
- “System Operations Enhancements” ($0.4 MM RY1, $0.4 MM RY2, $0.5 MM RY3)

- “Transmission Station Metering and SCADA Upgrades Program” ($3.2 MM RY1, $3.1 MM RY2, $3.1 MM RY3)
- “Unit Substation Modernization” ($0.6 MM RY1, $0.6 MM RY2, $0.6 MM RY3)

Q. Please describe some of the key programs in this category starting with the Remote Monitoring System Program.

A. This program replaces defective units and installs new Remote Monitoring System (“RMS”) third and fourth generation transmitters at various network transformer vault locations in all regions. Third generation transmitters are data collection, consolidation, and transmission devices, and fourth generation transmitters have two-way communication. Both generations transmit data via power line carrier (“PLC”) communication on the secondary of the transformer to the RMS database. An average of 2,000 third generation units and 1,500 fourth generation units will be installed per year by the Company.

The remote monitoring system provides insight into the health and operational status of network transformers. Data from this system can indicate an alive on backfeed (“ABF”) condition, helping to expedite feeder restoration during an outage. Both third and fourth generation transmitters also communicate transformer oil levels, which could identify leaks before catastrophic failures. In addition, this ongoing work is required to comply with the Reliability Performance Mechanism ("RPM") associated with the RMS mandated by the PSC.

Q. Why is it important for the Company to invest in its protective relay systems?

A. While robustly designed and well maintained, the Company's substation and transmission system is operated at high voltage and carries very high levels of energy. During normal operation, the system is designed to reliably transmit electricity. However, various events may cause system instability or faults, potentially damaging equipment and creating risk to employees and the public. The Company's protective relays are designed to sense instabilities in the delivery of electric power and, in combination with interrupting devices like circuit breakers and switchers, de-energize components and remove them from service before faults can cause damage to equipment and/or cascade to affect greater areas of the transmission system.

Q. Have electrification, climate change, and renewable generation affected the significance of investing in relay protection and control systems?

A. Yes, electrification, climate change, and renewable generation all increase the importance of investing in relay protection and control systems.

Q. Please explain how electrification impacts investment in protection and control systems.

A. Electrification of buildings, along EV charging will place a much greater demand on system capacity for longer periods throughout the year. Consequently, seasons that were previously “off-peak” may now exhibit capacity demands that match or exceed previous summer peaks. The introduction of a significant winter load will reduce the available time to de-energize equipment for maintenance, replacement and/or testing. For relay protection and control systems, this means that the ability to retrieve, analyze and adjust performance parameters must be modernized and streamlined. Relay and control systems that must be locally and manually tested will become very difficult to maintain under the increased demand cycle that is coming with electrification. Conversely, relay and control systems that are self-diagnostic and can be remotely accessed by operators and engineers will streamline and reduce the necessity for planned outages.

Q. Please explain why increased investment in relay protection and control systems is important in light of climate change.

A. The increased frequency and variation of extreme weather events will require relay protection and control systems to be weather hardened. Relay panels that are installed outdoors and in degraded condition are susceptible to water intrusion from extreme rain events. Along the same lines, degraded copper control wiring will exhibit grounds when water pools during these types of events. Installing weather hardened relay panels and fiber optic communication networks in substations will help adapt these systems to climate change.

Q. Please describe how renewable generation interconnecting to the transmission system affects investment in relay protection and control systems.

A. Renewable generation may subject the transmission system to more power swings, frequency excursions and lower fault currents. Adapting protection and control systems to handle these changes will require remotely accessible data and the ability to adjust system protection and control parameters quickly and efficiently. Adapting to these changes while using electromechanical relay systems, that are manually set and adjusted, will not only be inefficient but will also provide no advanced warning of improper settings. An expansion of cyber secure connections, microprocessor-based systems and data bases are required to meet the challenges of bulk renewables to the transmission system.

Q. Please describe the Company's three investments related to relays and control systems starting with the Relay Modifications Program.

A. This program replaces relays protection systems at area and transmission substations, continuing to target transmission relays that exhibit reliability issues. The program will also be expanded to include upgrades to area station bus and feeder protection, installations that eliminate single points of failure, and replacement for some early microprocessor relays. The Company plans for approximately eight transmission relay upgrades, eight to ten area station bus section/feeder upgrades, legacy microprocessor relay upgrades at eight stations, two single point of failure upgrades, and ten Under Frequency Load Shedding ("UFLS") panel upgrades per year.

The Company has always prioritized relay upgrades because of the vital role they play. However, events in recent years, such as the West Side Outage (2019) and Fresh Kills (2021) have shown that some strategic changes to relay upgrade philosophy, including more standardization and prioritizing area station relay systems, would be beneficial. Legacy systems with known reliability issues on the transmission system will continue to be prioritized for replacement under this program, but it will also be expanded to focus on area station relays, USFL panel upgrades, and single point of failure projects, all critical to avoiding events like the West Side Outage and Fresh Kills in the future. In addition, the upgrade to relay systems that are either self-resetting or can be reset remotely will improve outage recovery times following extreme weather events, expected to become more frequent and severe due to climate change. Standardization, and the associated modularity, will also better facilitate the quick replacement of relay components following extreme weather events that may have caused their failure.

Q. Please continue by describing the Relay Protection Communications Upgrade Program.

A. The intent of this program is to replace older relay communications infrastructure. For most locations, this program will also provide two independent communication systems for relay protection. The work will take place at various locations throughout the system and will be divided into three categories: 1) upgrade of the Corporate Communication Telephone Network (“CCTN”), 2) upgrade of the Verizon communications infrastructure, and 3) upgrade of relay protection equipment.

The program’s primary objective is upgrade or replacement of relay communication lines that have exhibited repeated disruptions or have failed. In addition, degraded communication infrastructure, particularly copper lines, are more vulnerable to extreme weather events. Flooding from extreme rain or other weather events can cause disruptions to communication lines that can lead to a loss of protection or potentially cause relay systems to mis-operate or delay recovery following events. The upgrade to CCTN is an important component of resiliency and the Company’s Climate Change Resilience approach. Finally, eliminating single point mode of failure in the relay protection communication networks will also increase the reliability of the electric.

Q. Please describe the Protection, Control, and Automation Program.

A. This program will upgrade substation protection, control, energy management system (“EMS”) interfaces, and/or operator interfaces. It includes upgrading the SCADA systems to human machine interface (“HMI”), microprocessor-based systems, replacing copper wiring with a fiber optic network, and weather hardening relay panels to protect from extreme weather and flooding. In addition, the installation of data diodes as part of this program will increase cybersecurity and facilitate NERC compliant data retrieval and event analysis capabilities at all substations.

Locations for upgrade will be prioritized based on substations that have exhibited reliability issues in the past and those in which upgrades will best facilitate the migration to the latest protection and control protocols. This program will also allow the Company to have remote, secure access to digital information to be able to make timely decisions and restore equipment to service as quickly as possible when system disturbances do occur.

Q. Please continue by describing the Smart Sensors Program.

A. Con Edison plans to build upon existing sensor platforms through new sensor hardware and analytical solutions. Specifically, the Company will focus on two main aspects of the program: 1) the Structure Observation System ("SOS") that monitors structures or any other asset for energized objects and manhole event precursor environmental changes, such as hot spots in cables or accessories or the presence of combustible gases, leveraging available sensor technology and 2) Network Protectors ("NWPs") that expand sensing capability by adding condition monitoring and enable software algorithms to improve reliability of the network protector.

The SOS is a general platform that includes both an integrated environmental monitoring solution as well as a platform for integrating other equipment sensor data and algorithms. An example of the integration of devices and analytics is thermal imaging, which uses infrared sensors to identify hot spots and trigger a field response to make a repair on the defective condition. The Company is developing machine learning algorithms that analyze these images to automatically identify defects as images are received from sensors or inspections. Another example is the smart primary splice with embedded sensors that will provide information on the primary network and condition of primary cable and splices, which will improve public/employee safety, facilitate monitoring of the health of the network primary assets, and improve feeder restoration.

The NWP is a general platform that includes both the integrated pressure, temperature solution as well as a platform for integrating other equipment sensor data and algorithms. Historically pressure monitoring of network transformers has proven successful at maintaining equipment reliability. It is expected this same benefit will be extended by installing additional sensors. A specific example of a sensor to be installed is the NWP Pressure Sensor which will be added to submersible NWP housings to help determine if there is a leak or fault in the housing. Similarly, pressure and temperature sensors on transformers will help the Company determine the status of network transformers and provide data to trigger a field visit. These data driven field visits are a more efficient and effective use of resources than time-based inspections. Another example is the NWP Auto Exercise capability which enables a self-diagnostic test of NWP functionality. Failed tests trigger a field visit for troubleshooting and repair. This can reduce ABF events by ensuring malfunctioning NWPs are addressed before an operation is needed. This acceleration of sensing technologies, currently deployed on a targeted reliability-focused basis, will provide greater situational awareness of the electric system and leverage data analytics and advanced management systems to more effectively plan and operate the system. The deployment of these sensors offers public safety benefits, operational efficiencies, and increased reliability and resiliency of the electric system.

4. Structures, Housings, Buildings, and Other Miscellaneous Assets

Q. What is the next category of Risk Reduction/Reliability work that you will be discussing?

A. The next type of equipment within the Risk Reduction/Reliability category includes non-power carrying assets that house or structurally support energy delivery, supervisory, communication, or protection assets, or that support general T&D operations.

Q. Please describe the Company’s projects and programs in this category.

A. The Company is planning to invest in such systems to proactively address degraded structural support systems that, upon failure, would pose a risk to maintaining the availability of important energy delivery equipment. In addition, many of these projects enhance the safety and security of the Company’s employees and the public. The Company’s equipment, feeders, cables, and wires require structural support systems to maintain proper electrical clearances and support substantial assets such as power transformers. As with many other aspects of the system, Con Edison anticipates that structures, housings, buildings, and other miscellaneous assets will experience the impacts of climate change, especially major storms and torrential rain which are expected to become more frequent and severe in the coming years.

The Company plans to invest in the eight projects listed below to address risks associated with these assets. Details on each of these investments can be found in their respective white papers in EIOP-3, Schedule 3.

- “Overhead Transmission Structures Program” ($3.0 MM RY1, $3.0 MM RY2, $3.0 MM RY3)
- “Right of Way Roadway Access” ($1.0 MM RY1, $1.0 MM RY2, $1.0 MM RY3)
- “Roof Replacement Program” ($4.8 MM RY1, $4.8 MM RY2, $4.8 MM RY3)
- “Stabilization of Pothead Stand Supports/Settlement” ($2.5 MM RY1, $2.5 MM RY2, $2.5 MM RY3)
- “Structural and Infrastructure Upgrades Program” ($6.7 MM RY1, $14.4 MM RY2, $14.4 MM RY3)
- “Substation Enclosure Upgrade Program” ($1.9 MM RY1, $1.9 MM RY2, $1.9 MM RY3)
- “Transformer Vault and Structures Modernization” ($41.1 MM RY1, $42.3 MM RY2, $43.5 MM RY3)
- “Unit Substation Upgrade and Improvement” ($1.0 MM RY1, $1.0 MM RY2, $1.0 MM RY3)

Q. Please describe the largest investment in this group, the Transformer Vault and Structures Modernization.

A. This program involves the proactive repair of structural deficiencies in deteriorated transformer vaults, manholes and service boxes. These structures are located in the streets and sidewalks throughout our service territory. Structural deficiencies include settlement, cracked concrete, spalled concrete, collapsed walls, collapsed ceilings, corroded steel beams and columns, and corroded rebar. If unrepaired, structural deficiencies in deteriorated vaults present a risk of collapse that can be a hazard to the public and employees and can compromise system reliability by causing damage to electric infrastructure or delays in work on equipment and cables. Program funding has been increased to reduce the number of structures identified with deficiencies, while also helping to identify structures impacted by extreme weather and torrential rainfall driven by climate change.

5. O&M Program Changes

Q. Is the Company proposing any Risk & Reliability O&M program changes?

A. Yes. The Company is proposing changes to the Line Clearance/Vegetation Management Program and the Storm Emergency Vehicle Maintenance Program. The Company’s Storm Response and Resilience Panel will discuss the maintenance for the Company’s emergency response vehicles.

Q. Please discuss the Company’s proposed changes to the Line Clearance/Vegetation Management Program.

A. The Company plans to increase funding for line clearance and vegetation management to further mitigate storm damage, as severe weather events are expected to increase in frequency and severity because of climate change. Specifically, the Line Clearance/Vegetation Management Program will focus on cycle trimming, on right of way tree removals, tree toppings, tree related customer inquiry investigations, and hazardous tree removal. Much of the increased funding for this program will be driven by Company's plan to replace the current tree topping process with a full tree removal. Con Edison is currently in negotiations with the NYC Parks Department on the implementation of a Memorandum of Understanding ("MOU") to that effect. This program change will require an increase of $2.8 MM in RY1, $0.4 MM in RY2, and $0.4 MM in RY3.

6. Staffing

Q. Does the Company need additional staffing?

A. Yes. As described throughout this panel's testimony, the Company is planning to expand several programs to strengthen its electric distribution system, reduce the damage sustained during severe weather events, lower the number of customers impacted by outages, and improve the Company's ability to repair damage and restore service following extreme weather events. This additional work, which is explained in this testimony and associated whitepapers, requires additional personnel. For example, compared to 2022, our planned capital work volume is expected to increase by over 45 percent by 2023. The Company estimates that it will need at least 200 new employees to complete this capital work and will need to purchase trucks and equipment for these employees, as described in the Shared Services Panel testimony. As noted in that testimony, we will be providing the number of employees to the Shared Services Panel, prior to the preliminary update so that Shared Services can update its capital request at that phase.

Q. Is this additional work Company labor, contract labor, or both?

A. Both Company labor and contract labor will be used to execute the additional work.

Q. What is the estimated cost associated with these additional positions?

A. The cost associated with these positions is included in the costs of the programs/projects we have discussed throughout this panel’s testimony. As explained by the Shared Services Panel, because we are still in the process of finalizing the number of new employees, we have not yet made final determinations about the equipment or vehicles needed to support them, and thus the Company has not yet estimated the O&M or capital associated with the new equipment and vehicles. The Shared Services Panel will provide the capital information for the new vehicles and EIOP will provide the required O&M information when the Company files its preliminary update.

B. New Business and System Expansion Capital and O&M Expenditure Requirements

Q. Please describe how content in this section is organized.

A. This section contains four subsections: 1) Investment Approach Overview, which provides a high-level description of how the Company approaches system expansion investment decisions; 2) Non-Wires Solutions, which contains an overview of how non-wires solutions are used to address load growth; and 3) Utility Solutions, which contains a description of the traditional utility solutions required to address load growth.

1. Investment Approach Overview

Q. Was the exhibit titled, "T&D New Business and System Expansion” prepared under your direction?

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT EIOP-4

Q. What does Exhibit EIOP-4 show?

A. Exhibit EIOP-4, Schedules 1 and 2 list the capital program and project funding requirements and O&M program changes required to support New Business and System Expansion work conducted by S&TO, SSO, and Electric Operations for RY1, RY2, and RY3. The exhibit also contains white papers for each capital and O&M program/project in this category that provide more detailed information, such as program and project work description, justification, alternatives, estimated completion date, current status, relationship to long-range plans, and forecasted funding.

Q. Please discuss the Company’s plans to reinforce its T&D system to support new business and the associated load growth.

A. As stated previously, the forecasted increase in customer demand and transportation and building electrification in certain networks results in forecasted capacity constraints that the Company must address. The Company must invest in its transmission system, substation infrastructure, and local distribution system to relieve those capacity constraints and serve the additional customer load. Following its well-established process, the Company uses the following approaches to mitigate capacity constraints on the system: 1) engage customers to reduce demand through non-wires solutions; 2) replace existing assets with ones that have higher capacity ratings; 3) install additional assets to increase system capacity, and 4) transfer load to other areas with spare capacity.

2. Non-Wires Solutions

Q. Please describe how the Company engages customers to reduce demand.

A. When the Company identifies a system constraint driven by customer demand it evaluates the ability of an NWS to meet that need.

Q. How does the Company define NWS and how may they be used to address increased demand?

A. Con Edison has worked with Staff and stakeholders to define NWS. The Company defines NWS as a cost-effective portfolio of non-traditional, typically customer-side, solutions that enable the offset or deferral of traditional utility asset investments while continuing to maintain the same high levels of reliability for its customers. NWS portfolios are generally comprised of a variety of DER that collectively satisfy an identified reliability need in place of a traditional asset investment.

Q. How does the Company identify NWS opportunities and consider them as part of its capital planning process?

A. The Company starts by identifying areas of its system that have forecasted overloads and require load relief to maintain reliability. The Company then determines whether the identified need is a suitable candidate for a NWS by assessing it against the Company’s NWS suitability criteria. The suitability criteria identify projects that: 1) are for load relief, 2) have enough lead time to pursue a NWS without foreclosing the opportunity to install a traditional solution if needed, and 3) meets the financial threshold. If the Company’s suitability criteria are satisfied, the Company conducts a competitive solicitation for non-traditional solutions to determine if a NWS portfolio is feasible and cost beneficial.

Q. Has the Company identified any new NWS opportunities based on the NWS suitability criteria?

A. In addition to the Company’s active NWS portfolios, Con Edison has identified two potential NWS opportunities related to the 1) Jamaica Substation - Replace Limiting 27kV Bus Sections Project and 2) the Parkview TR5 and Feeder 38M85 Project. These traditional solutions are each currently being evaluated for viability to defer with NWS.

3. Utility Solutions

Q. How does the Company identify the appropriate utility solution to use, when required?

A. The Company considers multiple approaches to cost-effectively mitigate capacity constraints on the system. During the rate plan years for this filing, the Company has projects that include one or more of the following traditional system expansion categories: 1) upgrade or replace existing assets with ones that have higher capacity ratings; 2) install additional assets to increase system capacity, and 3) transfer load to other areas with spare capacity.

Q. Please describe how upgrading or replacing existing equipment is used to alleviate capacity constraints.

A. Where feasible, the Company will replace limiting cable, bus, and/or transformers with new equipment that has a higher capacity and/or higher rating.

Q. Please continue by describing the next type of traditional utility solution used to address load growth, installing additional equipment.

A. In cases where capacity constraints cannot be relieved through demand reduction or equipment replacement, the Company will install additional equipment to handle the increased load and relieve capacity constraints. This category includes the installation of additional assets such as equipment on primary feeder cables, transformers, secondary cables and wires, on-site utility energy storage equipment, as described further in the Company’s Customer Energy Solutions Panel, and underground and overhead services.

Q. Please continue with a description of the final traditional utility solution type, load transfers, and how they are used to alleviate capacity constraints.

A. Load transfers involve shifting load from an overloaded, or soon to be overloaded, substation, transmission feeder, or network to an adjacent network that has spare capacity. Load transfers allow the Company to maximize use of its existing infrastructure and are done when the Company finds them to be more cost effective than building new substation capacity. This option, however, is becoming increasingly difficult as spare substation capacity decreases.

Q. Please list the capital programs within the New Business and System Expansion work category.

A. The Company's New Business and System Expansion investments include:

- "179th St Area Substation Reconstruction" ($0.5 MM RY1)
- "Amtrak PSA – OAK" ($5.0 MM RY1, $5.0 MM RY2)
- "Brownsville Area Load Relief" ($35.3 MM RY1, $26.0 MM RY2, $27.0 MM RY3)
- "Crown Heights Network Split" ($12.5 MM RY3)
- "Ed Koch Queensboro Bridge 13kV Riser Replacement" ($0.8 MM RY2, $1.6 MM RY3)

- “Emergent Load Relief Program” ($1.1 MM RY1, $1.1 MM RY2, $1.1 MM RY3)
- “Farragut STATCOM” ($22.0 MM RY1, $74.0 MM RY2, $34.0 MM RY3)
- “Gateway Park Area Station” ($30.0 MM RY1, $20.0 MM RY2, $200.0 MM RY3)
- “Goethals Shunt Reactor R26” ($1.0 MM RY1, $3.5 MM RY2, $5.5 MM RY3)
- “Jamaica Substation – Replace Limiting 27kV Bus Sections” ($2.0 MM RY1, $2.0 MM RY2, $2.0 MM RY3)
- “Light Duty Electric Vehicle Make-Ready Program” ($26.9 MM RY1, $39.4 MM RY2, $47.9 MM RY3)
- “Meter Installations” ($30.0 MM RY1, $30.0 MM RY2, $30.0 MM RY3)
- “Network Transformer Relief” ($10.8 MM RY1, $10.9 MM RY2, $11.0 MM RY3)
- “New Business Capital” ($179.3 MM RY1, $198.6 MM RY2, $195.1 MM RY3)
- “Newtown TR4 and 138kV Feeder 38Q05 from Vernon” ($10.0 MM RY1, $33.0 MM RY2, $33.0 MM RY3)
- “Non-Network Feeder Relief (Open Wire)” ($7.3 MM RY1, $7.3 MM RY2, $7.3 MM RY3)

- “Overhead Transformer Relief” ($2.3 MM RY1, $2.3 MM RY2, $2.3 MM RY3)
- “Parkview TR5 and Feeder 38M85” ($30.0 MM RY2, $72.0 MM RY3)
- “Primary Cable Crossing (B/W City Island, Riverdale, Croton River, and BQ Flushing)” ($21.5 MM RY1, $11.6 MM RY2, $2.5 MM RY3)
- “Primary Feeder Relief” ($10.4 MM RY1, $10.4 MM RY2, $10.4 MM RY3)
- “Secondary Mains Load Relief” ($7.1 MM RY1, $7.1 MM RY2, $7.1 MM RY3)
- “Vinegar Hill Distribution Switching Station” ($33.0 MM RY1)
- “W42nd St No. 1 to Astor Transfer” ($2.0 MM RY1, $2.0 MM RY2)
- “West Bronx/Randall’s Island Reconfiguration” ($16.1 MM RY1, $4.1 MM RY2)
- “Williamsburg Network Improvement” ($17.8 MM RY1, $23.7 MM RY2, $23.8 MM RY3)
- “Yorkville Crossings and Feeder Relief” ($16.0 MM RY1, $10.5 MM RY2, $3.0 MM RY3)

Q. Please discuss the New Business Capital Program.

A. When the Company connects new load, it often finds that its distribution system is at or beyond its capability and that it cannot serve the new load by simply extending a service lateral from its distribution system. In fact, many new residential and commercial projects require the Company to make extensive infrastructure investments such as reinforcing secondary mains, extending primary feeders, and installing transformer vaults. The New Business Capital Program is the vehicle for these investments. As the Company determines the customer’s summer and winter peaks loads for all electric heating projects, additional reinforcements and/or equipment may be required to handle winter peak loads. With these investments, the Company can provide service to new customers.

Q. Please describe the nature of new business projects driving the need for investment under the New Business Capital Program.

A. As discussed in the load forecast section of this testimony, the Company is experiencing growth in numerous areas of the five boroughs from new commercial and residential developments, rail and air transportation projects, and residential growth within existing communities. In addition, there continues to be large scale development along waterfront areas, particularly in

Brooklyn, Queens, and the Bronx. Two examples include the East River waterfront in Brooklyn (discussed below as part of the Williamsburg Network Improvement project) and along the Harlem River waterfront in the Bronx (discussed as part of the West Bronx/Randall's Island Reconfiguration project). However, there are a significant number of new business jobs that individually consist of relatively smaller loads but collectively make up a significant portion of new business work planned. Growth in specific neighborhoods as well as jobs postponed during the pandemic have all led to an increase in the number of jobs in the new business queue.

Q. How does the Company plan to adapt to the potential for extreme weather as part of the New Business Capital Program?

A. The Company will design new facilities in accordance with the Company's new Climate Change Planning and Design Guideline.

Q. Please continue with a description of the Light Duty Electric Vehicle Make-Ready Program.

A. This program provides incentives for make-ready infrastructure for EV charging stations for light-duty vehicles in the Company's service territory. As directed by the Order Establishing Electric Vehicle Infrastructure

Make-Ready Program and Other Programs[8] the Commission has authorized the Company to provide incentives for third parties to install 18,539 Level 2 and 457 Direct Current Fast Charging ("DCFC") charging plugs over the five-year program.

In addition to the incentives for work on customer property, the Make Ready Order authorized the Company to recover in rates two additional items – the "new business" costs and utility-side make ready incentives costs (also generally known as excess distribution facility ("EDF") charges associated with the electric infrastructure. These are utility-side grid infrastructure capital costs and utility future proofing costs for EV make-ready. These costs include, for example, utility electric infrastructure needed to connect and serve the load associated with new EV charger(s); any additional infrastructure that would have otherwise been paid by the Participant; and, any costs associated with installing additional infrastructure to accommodate future EV charging at the location.

[8] Case 18-E-0138, Proceeding on Motion of the commission Regarding Electric Vehicle Supply Equipment and Infrastructure, Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs (issued July 16, 2020)("Make Ready Order").

EVs are a critical component to achieving the emission reductions called for in the CLCPA, and EV charging stations will serve as a key element to support EV adoption. This program supports the acceleration of EV charging station deployment and contributes to the achievement of the State’s CLCPA goals.

Q. Given the complexity and quantity of capital initiatives, please provide a summary of the needs for Brownsville Substation load relief.

A. The long-term solution to Brownsville load relief is to construct the new Gateway Park Area Substation, to be supplied by the new Brooklyn Clean Energy Hub. The Company does not believe it is feasible to energize the new Gateway Park Area Substation prior to summer 2028. Because of the risk that subsequent load growth in the area will create a reliability issue before 2028, the Company must use other projects to provide interim load relief for the Brownsville Substation. Some of these interim measures include continued use of Customer Sided Solutions and small network transfers. The most significant interim measures are installing Feeder 38Q05 and a fourth transformer at Newtown Substation and the Brownsville Area Load Relief Program.

Q. Why does the Company need the Gateway Park Area Substation?

A. The Company first identified the need for a new substation to provide relief for the Brownsville Substation in 2014. Since then, the Company has been successful in deferring the need through its BQDM Program, which uses a combination of traditional infrastructure and non-wires alternatives. Prior load forecasts showed BQDM deferring the need for a new substation until 2032. But, as discussed in the load forecast section above, the Company's annual demand forecast now shows that the Company must construct the new Gateway Park Area Station by summer 2028.

Q. What is driving load growth in the area?

A. The load growth in the area is partially driven by near-term electrification of light-, medium-, and heavy-duty vehicles and early adoption of building electrification. Thus, the project is needed to reliably facilitate electrification. In addition, the Gateway Park Area Station will help the State meet CLCPA goals by facilitating the delivery of renewable energy through the Brooklyn Clean Energy Hub, reducing the dependency on local fossil fuel plants. The project will also support future energy storage projects and programs for disadvantaged communities.

Q. Earlier, the Gateway Park Area Station was referred to as the long-term solution for Brownsville load relief, please describe this project in more detail.

A. The Gateway Park Area Station will be a new indoor 27kV substation supplied from the new Brooklyn Clean Energy Hub via four new 138kV sub-transmission feeders. The land procurement process is expected to begin in 2022, engineering and long lead equipment procurement will begin in early 2023, construction is expected to begin in 2025, and the projected in-service date is May 2028.

Q. What other work will the Company do in conjunction with the Gateway Park substation?

A. After completing the Gateway Park Area Station, this project will split the Crown Heights network into two load areas, 3B North (Crown Heights) and 3B South (Remsen). The new Remsen network will be supplied by the Gateway Park substation, transferring 117 MW of load from Crown Heights to the new substation. This transfer will alleviate overloads on the 138kV feeders supplying the Brownsville load pocket projected to occur as a result of increased new business, EV adoption, and building electrification. The Crown Heights Network Split will create capacity headroom in the Brownsville substation. The establishment of the Gateway Park Area Station will also allow the Company to de-load the Bensonhurst load pocket if it becomes necessary. In addition to relieving forecasted overload, by splitting the network into smaller pockets fed by separate substations, the Company will increase reliability and resiliency as the two smaller load pockets are transferrable from one station to the other and vice-a-versa. Further, the Crown Heights Network Split will facilitate customer's electrification of transportation and buildings, supporting the State meeting its CLCPA goals.

Q. Please describe the interim measures the Company will take, starting with a description of the Newtown Transformer 4 and Feeder 38Q05 project and an explanation of how the project provides load relief for Brownsville Substation.

A. This project will install a new 138kV sub-transmission feeder (38Q05) from Vernon Substation to Newtown Substation along with a fourth 138kV/27kV transformer there. Newtown Substation is currently supplied by three 138kV feeders that also originate from the Vernon Substation. These three feeders (38Q02, 38Q03 and 38Q04/Q04T) also supply, along with Feeder 38Q01 from Vernon Substation, the Glendale Area Substation. The addition of Feeder 38Q05 to supply Newtown Substation increases the available capacity on Feeders 38Q01-38Q04 and, thus, the capacity at Glendale Substation. This increased capacity at Glendale Substation allows it to accept a 60MW network transfer from Brownsville Substation (Brownsville Area Load Relief Program) to provide load relief for the latter.

Q. Is load relief for Brownsville Substation the only benefit of the project?

A. No, it is not the only benefit. As a result of the anticipated increase in customer load related to new business, EV adoption, and electrification, the Newtown 27kV area station is projected to exceed its station capability by 2029. This creates the need for 38Q05 and Transformer #4 at Newtown Substation.

Q. So the need for Brownsville load relief is only accelerating the service date of Newtown Transformer #4 and Feeder 38Q05?

A. Yes, the Brownsville need is accelerating the service date of the project from 2029 to 2027.

Q. Please continue discussion of the interim measures by describing the Brownsville Area Load Relief Program.

A. As previously discussed, load relief solutions must be implemented to provide near-term relief while the Company works to place Gateway Park Area Station into service by 2028. The Company plans to implement four measures to address forecasted near-term load growth. First, the Company will transfer two MTA transit rectifier stations, for a total of 6MW, to nearby networks. Second, the Company will transfer 60MW from Brownsville No.1 substation to the Glendale substation, which has the capacity to support the load relief while also being close in proximity, minimizing the extent of conduit and cable installation required. The third measure connects the new load to the Flatbush network to avoid furthering existing constraints at Brownsville No.2 substation. Lastly, the program will install a number of capacitor banks that will provide approximately 20MVAr resulting in approximately 5 to 6MW of effective load relief. Collectively, this program will focus on measures to address the significant near-term load growth in the area, including the adoption of electric vehicles and electrified heating, until the Gateway Park Area Station can be completed and is able to accommodate the continued growth.

Q. Please discuss other key System Expansion projects, starting with what factors are driving the need for the Williamsburg Network Improvement Project.

A. Over the last few years, the Williamsburg network has underperformed other networks in terms of NRI and reliability. Within the current ten-year forecast, it is expected that the Williamsburg network will exceed the upper limit of 1.0 for NRI. The Williamsburg area has seen a 24 percent increase in load since 2014 and it is expected to grow another 19 percent by 2030. Sixteen of the 20 primary distribution feeders are running at over 90 percent on base and ten feeders are running over 90 percent of the emergency rating. Further, by 2028 an estimated 560 sections will be overloaded.

Q. Please continue by describing the Williamsburg Network Improvement Project.

A. This project will create two smaller load areas out of the Williamsburg Network through the establishment of multiple new distribution feeders facilitated by the Vinegar Hill Distribution Switching station. Eight new feeders will be established out of the Water Street Substation in four feeder bands, with the separation line between the two load areas being Flushing Avenue. The load pocket north of Flushing Avenue will consist of sixteen feeders, and the south load pocket will consist of twelve feeders. After the eight new feeders are established, the load will be rebalanced to create two independent secondary load pockets. Through the utilization of newer design primary Interrupter switches, additional resiliency is created by the transferability of load between these two load pockets.

The introduction of the eight new feeders is critical for supplying the expected load growth and will also improve NRI, and in turn reliability. This work will also de-load existing feeders and minimize the risk of cascading feeder failures. In addition, it will prepare this network to accommodate future development in this area of Brooklyn, prepare for increased electrification of buildings and transportation, and increase reliability and resiliency in the face of rising summer temperatures driven by climate change.

Q. Please discuss the Parkview TR5 and Feeder 38M85 Project.

A. Forecasted loads for the Parkview 13kV Substation are expected to exceed the station’s design capability by the summer of 2027. Rapid load growth in the near term is primarily driven by the expansion of the Metropolitan Transportation Authority’s (“MTA”) 2nd Avenue Subway line along with associated economic activity in the area. This project will construct 138kV supply feeder 38M85 from the Mott Haven 345kV Substation to the Parkview 13kV Substation and includes the installing a fifth 138/13kV transformer at Parkview Substation and a fifth 345/138kV transformer at the Mott Haven 345kV Substation. Engineering and long lead equipment procurement will begin in 2024, construction is expected to begin in 2025, and the projected in-service date of this project is May 2027.

Q. Please continue by describing the Farragut STATCOM Project.

A. The Company has identified Fault-Induced Delayed Voltage Recovery (“FIDVR”) issues on the Con Edison 138 kV transmission system. The FIDVR issues are attributable to future load growth, including building and transportation electrification. FIDVR issues may also result from, among other things, the retirement of local units, which Con Edison is supporting through the development of local transmission projects such as the three Reliable Clean City Projects, in line with the State’s CLCPA goals. The installation of a static synchronous compensator (“STATCOM”) unit will provide dynamic voltage support to address reliability needs driven by FIDVR issues. The Company will build a 425 MVA STATCOM at the Farragut 345kV Substation, remove Phase Angle Regulator TR12 and Shunt Reactor R12, and modify and reserve the currently out-of-service 345 kV feeders B3402 (Farragut to Hudson in New Jersey) and C3403 (Farragut to Marion in New Jersey). Engineering and long lead equipment procurement will begin in 2022, construction is expected to begin in late 2022, and the projected in-service date of this project is May 2025.

Q. What factors are driving the need for the Yorkville Crossings and Feeder Relief Project?

A. The Yorkville network, located in Manhattan, is supplied from 29 13 kV distribution feeders that originate from the Hellgate Area Substation located in the Bronx. The distribution feeders reach Manhattan via six active underwater crossings. Four of these crossings span across the Harlem River near the Willis Avenue and Third Avenue Bridges, containing 23 of the 29 feeders that supply the Yorkville network. The fifth and sixth crossings route the distribution feeders via Randall’s Island, and these crossings contain the remaining six primary feeders that supply the Yorkville network as well as the distribution feeders that supply the Randall’s Island network.

The four underwater crossings that span between Manhattan and the Bronx all have high duct occupancy and have few remaining spare conduits. Spare conduits are critical in maintaining the reliability and resiliency of the Yorkville network for both accommodating future load growth and for cable replacements due to failures. With the complete loss of any of these four crossings, there are not adequate spares to reroute the distribution feeders and place them back in service without significant temporary reroutes. As a result, the loss of one of the Yorkville feeder crossings represents a significant high impact, low probability risk since recovering from the loss of one of the feeders would be particularly difficult and could lead to a protracted network shutdown. In addition, the majority of the distribution feeders that supply the Yorkville network are heavily-loaded. By 2030 approximately 60 percent of the distribution feeders will operate at or above 90 percent of their normal rating and more than 40 percent of the feeders will operate at above 95 percent of their normal rating. The risk of losing one of the crossings completely could lead to a network shutdown that would be difficult to recover from.

Q. Please describe the Yorkville Crossings and Feeder Relief Project.

A. A new underwater crossing beneath the Harlem River between Manhattan and the Bronx will be established and the existing 13 kV primary feeders will be diversified by the creation of an additional crossing. The addition of this crossing helps to mitigate the risk of network shutdown due to the loss of one of the Yorkville feeder crossings and helps maintain the reliability of the network. Increasing the feeder diversity, via new underwater crossings, is the most effective tool in reducing feeder overloading under second contingency conditions. Construction activities for the crossings will begin in 2022 and last until 2023 with the new systems completed and commissioned prior to the end of 2024.

Q. Please describe the West Bronx/Randall’s Island Reconfiguration Program.

A. The ten-year load forecast projects load growth on the West Bronx (2X) network of 1-2 MW per year due to electrification and significant new business load along the Harlem River. To avoid overloading the distribution feeders, the West Bronx/Randall's Island Reconfiguration Program will extend four feeders from the Randall's Island (14M) network and two feeders from the West Bronx (2X) network. Using primary interrupter switches, the Company will operate the Randall's Island and West Bronx network as one network with the ability to separate during contingencies. This load relief program will allow for continuous load growth, preventing equipment damage and service interruptions associated with distribution feeder overloads. An alternative approach to addressing these overloads was proposed in the Company's previous rate case, but during the design review, Company engineers developed a more comprehensive and resilient solution at a lower cost. The new approach involves the installation of two underground interrupters per 14M feeder to allow for separate processing of load from both networks, creating a more resilient design that could help prevent a network shutdown.

Q. Please continue with a description of the W.42nd No. 1 to Astor Transfer.

A. Based on an analysis of the area substations and sub-transmission feeders in the W.49th Street load pocket, Con Edison projects the W.42nd Street No. 1 Substation will exceed its capability by the summer of 2024. The main driver of this new demand is significant new business load growth in the Pennsylvania Network. This network serves many large customers including Hudson Rail Yards, Brookfield Properties, the Javits Center expansion, Moynihan Station, and several skyscrapers along the newly constructed Hudson Blvd. Additionally, the No. 7 Subway Line extension to W.34th Street and 11th Avenue is expected to attract new tenants to the neighborhood. To serve this new load without overloading that substation, the Company plans to transfer 55 MW of load from W.42nd Street No. 1 Substation in the Pennsylvania Network to Astor Substation. As a result of this transfer, the W.42nd Street No. 1 Substation will be operating within its capability while maintaining capacity for future load growth, improving network reliability. The project will also relieve the feeder breaker capability in order to supply the new business growth at the Hudson West Yard.

4. O&M Program Changes

Q. Is the Company proposing any O&M changes related to its system expansion programs?

A. Yes, the Company is proposing three O&M program changes.

Q. Please begin by describe the changes to the Meters and Customer Equipment Program.

A. Since most customer meters have now been replaced as part of Con Edison's Advanced Metering Infrastructure ("AMI") deployment, the Company is establishing meter maintenance and test cycles to comply with the PSC's mandate and to ensure proper functionality and accuracy of metering equipment. This program will fund several different expenses/work activities associated with customer requests, meter and customer premises work, a variety of tasks pertaining to the inspection and testing of meters on the customer's premises, and the work associated with disconnecting and/or reconnecting meters. This program change will require an increase of $4.5 MM in RY1, $1.2 MM in RY2, and $0.1 MM in RY3.

Q. Please describe the Transmission Operations Capital Projects O&M program change.

A. As described above, the Company is planning several projects to accommodate load growth and electrification and to facilitate the delivery of electricity from large-scale renewable resources to the Con Edison service territory. The Transmission Operations organization is responsible for planning and implementing all activities for the successful construction, testing, and energization of major projects and programs in the Transmission capital portfolio. To implement the Company' planned projects, including the Brooklyn Clean Energy Hub, Gateway Park Area Station, and the Parkview TR5 and Feeder 38M85 Project, Transmission Operations will require an increase in staffing and associated vehicles. These specific staffing requirements include ten Splicers, twelve Mechanics, and two Welders. Management oversite of these positions needed include one Planner, three Supervisors and two Chief Construction Inspectors. Associated vehicles include eleven box trucks, two welding trucks, and six Management vehicles. This additional staffing will facilitate site preparation, construction of underground facilities, welding activities, cable pulling of both pipe and solid dielectric 345kV cable, associated splicing activities, and testing for planned projects.

Q. Please continue by describing Transmission Planning Staffing Needs to Support Clean Energy Agenda O&M program change.

A. In addition to the resource needs described above, three new positions are needed to support the planned transition to the clean energy future. Employees in these positions will be responsible for, among other things, implementing

CLCPA and Con Edison Transmission Master Plan requirements; studying and planning for offshore wind, solar, energy storage, and associated transmission system upgrades; coordinating, reviewing, and performing interconnection studies for large-scale renewables; and analyzing the retirement of fossil generation and the impact of intermittent resources connected through inverter-based interconnections.

C. Replacement Capital Expenditure Requirements

Q. Was the exhibit titled, "T&D Replacement" prepared under your direction?

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT EIOP-6

Q. What does Exhibit EIOP-6 show?

A. Exhibit EIOP-6, Schedule 1 lists the capital program and project funding requirements that support replacement work planned by S&TO, SSO, and Electric Operations for RY1, RY2, and RY3. The exhibit also contains white papers for each capital program and project in this category that provide more detailed information such as program and project work descriptions, justifications, alternatives, estimated completion dates, current status, and forecasted funding.

Funding for each program under the Replacements category is based on the historical failure or degraded performance rates of each component covered by the program. The exhibit normalizes the historical rates to account for any circumstances that may have caused a major deviation to the equipment failure rate in any given year. These programs do not include proactive replacement of components before they experience degraded performance or fail.

Q. Please provide an overview of the work performed under the Replacement category.

A. Through the programs in this category, the Company replaces failed transmission and substation equipment, including transmission and sub-transmission class feeders, transformers, reactors, and phase angle regulators. The program also funds the replacement of potheads, circuit breakers, bus enclosures, instrument transformers, and equipment monitoring and control devices. In addition, the program funds the replacement of distribution system equipment, including burned-out underground and overhead primary and secondary cable or wire, conduit, transformers, and meters and services. Examples of this work are cable and splice abnormalities (AKA “C” or “D” faults) or transformers that need to be taken off the system due to leaks or other serious defects. Other types of work covered by this program include repair and upgrade of overhead poles, wire, and equipment that fails during storms or other emergencies.

Q. What programs and projects does the Company plan to invest in to support required replacement work?

A. The Company plans to invest in the following projects. Additional detail on each of the projects below can be found in their respective white papers in Exhibit EIOP-6, Schedule 2.

- “Failed Substation Equipment Other than Transformers” ($11.5 MM RY1, $11.5 MM RY2, $11.5 MM RY3)
- “Failed Substation Transformer Program” ($46.5 MM RY1, $46.5 MM RY2, $46.5 MM RY3)
- “Hellgate Dock Refurbishment” ($15.6 MM RY1)
- “Overhead Emergency Response” ($61.5 MM RY1, $72.2 MM RY2, $74.0 MM RY3)
- “Primary Cable Replacement (OAs, FOTs, C&D Fault)” ($98.7 MM RY1, $101.9 MM RY2, $101.9 MM RY3)
- “Secondary Open Mains” ($128.7 MM RY1, $140.8 MM RY2, $142.0 MM RY3)
- “Service Replacements (Temporary Services and Bridges)” ($68.5 MM RY1, $72.4 MM RY2, $72.4 MM RY3)
- “Streetlights (Including Conduit)” ($27.2 MM RY1, $27.2 MM RY2, $27.2 MM RY3)

- “Targeted Direct Buried Cable Replacement” ($14.0 MM RY1, $14.0 MM RY2, $14.0 MM RY3)
- “Telecom – Underground Facilities” ($0.3 MM RY1)
- “Transformer Installation” ($51.2 MM RY1, $51.2 MM RY2, $51.2 MM RY3)
- “Transmission Feeder Failures” ($15.0 MM RY1, $15.0 MM RY2, $15.0 MM RY3)
- “Transmission Feeder Failures – Other” ($3.0 MM RY1, $3.0 MM RY2, $3.0 MM RY3)

Q. Please elaborate on the Failed Substation Transformer Program.

A. This ongoing program provides funding for the restoration work required to replace transformers in Area and Transmission Substations on an emergency basis. This program covers the cost of replacing three failed transformers (transformers, phase angle regulators and reactors) per year, and the basis for that projection is the historical average number of failures per year from 2011 to 2020. Power transformers in substations are critical components of the transmission and distribution systems. The Company has a separate Substation Transformer Replacement Program to proactively replace eight transformers per year before they fail. This program is discussed elsewhere in this testimony. Nevertheless, some transformers will likely fail in service and must be replaced on an emergency basis in order to maintain reliability. Further, the increasing frequency of heat events projected by the Company in its Climate Change Vulnerability and CCIP may accelerate the effective aging of power transformers, resulting in an increased likelihood of transformer failures. The criticality of this program will only increase with more extreme weather events.

Q. Please continue by describing Hellgate Wharf Refurbishment.

A. Hellgate wharf, located in the Bronx, supports Electric Operations’ flush truck facility for wastewater barges and Substation Operations’ heavy lift area for transformers delivered via barges. This project will remediate identified structural deficiencies, restore the full functionality of the dock, and extend the high-capacity loading area deck to allow for the use of longer multi-axle trailers for offloading transformers.

Con Edison’s review and analysis of the wharf identified numerous structural issues that the Company plans to address. In the heavy lift area, the concrete encased beams exhibit corrosion, spalling, and/or cracking. Currently all ten pier walls within this vicinity show signs of significant deterioration, including concrete spalling and erosion and steel rebar corrosion. Conditions in this area of the wharf have diminished load capacity, restricting use of the wharf to lighter loads. The Flush Truck Facility portion of the wharf exhibits similar deficiencies to those identified in the heavy lift area. The northernmost of the three bays is missing mooring hardware and fenders and the Company has deemed it unsafe for personnel to access. The full list of specific repairs and installations can be found in the corresponding white paper.

The refurbishment of the Hellgate Wharf will allow for the long-term offloading of effluent from the Flush Truck Facility and the movement of heavy equipment, such as transformers, in a safe and efficient manner from the SSO portion of the wharf. The expansion of the heavy lift area will allow more flexibility in positioning the existing multi-axle trailers and allow the use of longer transport vehicles in the future. The project will benefit the Company by reducing the likelihood of personnel injuries and establishing a more reliable offloading facility.

The Hellgate Wharf Refurbishment project was first introduced in the Company’s previous rate case filing, but unanticipated permitting requirements have delayed the start of the project. Due to the nature of the project, the required permitting involves review and approval from the US Army Corp of Engineers, DEC, NYC Department of Buildings, and NYC Department of Small Business Services (“NYC SBS”). The DEC process to review the scope of work resulted in delays because of a moratorium on shoreline work put in place to protect Striped Bass migration. After discussing the project scope with the DEC, a period of time for construction has been agreed upon. Presently the Company is in the review process with NYC SBS.

Q. Please describe the Overhead Emergency Response Program.

A. This program funds high-priority emergency work to replace non-network overhead infrastructure and associated equipment after failure or when imminent failure is identified. Diagnostic testing such as infrared, ultrasonic, or visual inspection are used to identify potential failures of cable, overhead transformers, and open-wire along the associated structures and accessories. Climate change, specifically more frequent and severe major storms and rising temperatures, will likely increase the stress on existing infrastructure and equipment and thus increase the need for replacement. These replacements will improve reliability by shortening or avoiding customer interruptions associated with equipment failure and minimize the time the system is in a vulnerable configuration. This program also helps mitigate public safety risk including hazards associated with downed wires and hit poles as well as the environmental impact associated with leaking and/or damaged transformers and other equipment. The Overhead Emergency Response Program supports the achievement of PSC reliability performance goals (SAIFI and CAIDI).

D. Equipment Purchase Capital and O&M Expenditure Requirements

Q. Was the exhibit titled, “T&D Equipment Purchases” prepared under your direction?

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT EIOP-7

Q. What does Exhibit EIOP-7 show?

A. Exhibit EIOP-7, Schedule 1 lists the capital program and project funding requirements that support Equipment Purchases for Electric Operations for RY1, RY2, and RY3. The exhibit also contains white papers for each capital program/project in this category that provide more detailed information, such as program and project work description, justification, alternatives, estimated completion date, current status, and forecasted funding.

Q. Please provide an overview of the work performed under the Equipment Purchase category.

A. Through the programs in this category, the Company purchases necessary equipment such as transformers, network protectors, switches, and meters. These purchases support various programs, including both proactive replacements and those that take place after failures.

Q. What are the equipment purchase programs for which the Company is seeking funding?

A. The Company is seeking funding for the following two programs:

- “Equipment Purchase” ($10.0 MM RY1, $20.0 MM RY2, $20.0 MM RY3)
- “Transformer Purchase” ($136.0 MM RY1, $139.6 MM RY2, $139.6 MM RY3)

Q. Please further describe the Transformer Purchase Program.

A. This program will fund the purchase of new and reconditioned capital electrical distribution equipment, to include underground network transformers, overhead transformers, padmount transformers (including mini-pads), capacitor banks, emergency generators, and network protectors to support distribution system relief, reliability, emergency, and load growth programs. These purchases provide electrical distribution equipment in order to complete active and planned burnout, new business, and system relief and reinforcement projects, supporting the Transformer Installation Program, the Network Transformer Relief Program. The budget for this program is expected to increase in the rate years, driven by the need for additional equipment to serve new EV charging and electrified space heating load, purchase of more submersible dry type transformers and other submersible equipment, and increasing replacements. The purchase of more submersible equipment will allow for the Company to comply with its new Climate Change Planning and Design Guideline, specifically the eventual migration to a projected floodplain of FEMA +5. The introduction of more submersible equipment will also help harden the system against more frequent and severe torrential downpours driven by climate change. Con Edison has instituted more targeted underground transformer inspection programs utilizing remote monitoring equipment on transformers to provide real-time pressure and temperature readings. As a result, the Company has identified an increased number of units needing replacement in order to maintain system reliability.

Transformer purchases and replacements improve public safety and system reliability by removing defective transformers, and in turn the number of unplanned feeder outages is also reduced, since every transformer failure results in de-energization of the entire feeder that supplies it. This program and the associated replacements also reduce the probability and frequency of violent equipment failures, which decreases the risks of injury to the public and Company employees along with damage to property. Con Edison purchases transformers that offer the best safety and environmental performance, such as high fault energy tank and dry type transformers. In addition, the purchase and installation of more submersible equipment increases resiliency as the Company adapts to the impacts of climate change.

E. Safety and Security Capital and O&M Expenditure Requirements

Q. Was the exhibit titled, “T&D Safety and Security” prepared under your direction?

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT EIOP-8

Q. What does Exhibit EIOP-8 show?

A. Exhibit EIOP-8, Schedule 1 lists the capital program and project funding requirements to support Safety and Security work conducted by S&TO, SSO, and Electric Operations. In addition, the exhibit contains white papers for each capital program/project in this category that provide more detailed information, such as program and project work descriptions, justifications, alternatives, estimated completion dates, current status, and forecasted spending.

Q. Please describe the Company’s capital safety program.

A. Con Edison maintains a high level of safety and holds safety as a paramount consideration in each and every task. Many of the projects described in this testimony have safety benefits; those discussed here are primarily driven by safety.

Q. Please describe the Company’s efforts related to the security of the electric system.

A. Con Edison closely monitors and actively manages the risks that have arisen in the last decade related to physical and cyber security. Businesses have seen an alarming rise in attempted cyber-attacks. Like many major businesses, Con Edison is devoting more resources to protect against cyber and physical attacks. The Company is addressing the cyber risk through compliance with NERC CIP Standards. These standards provide a cyber-security framework for the identification and protection of Critical Cyber Assets (“CCA”) to support the reliable operation of the Bulk Electric System (“BES”).

Q. What types of programs make up the Safety and Security work category?

A. This category includes a number of programs that increase both physical and cyber security for substations and the electric system. Some examples include physical security enhancements at the Company's control centers, upgrades to mitigate physical security threats and vulnerabilities at substations, and cyber security enhancements at substations to align with NERC CIP version 6 requirements. See the Company's Information Technology and Shared Services Panel testimony for details on the Company's enterprise cyber and physical security efforts respectively.

Q. Please list the capital programs within the Safety and Security work category.

A. The Company's Safety and Security investments include:

- "Cable Termination Platform Program" ($0.6 MM RY1, $0.6 MM RY2, $0.6 MM RY3)
- "Cap and Pin Insulator Replacement Program" ($1.0 MM RY1, $1.0 MM RY2, $1.0 MM RY3)
- "Critical Infrastructure Protection (NERC) Cyber Security Upgrade Program" ($1.0 MM RY2, $1.0 MM RY2, $1.0 MM RY3)
- "Cyber Security and NERC Compliance" ($1.3 MM RY1, $1.6 MM RY2, $1.6 MM RY3)
- "ECC and AECC Facility Security Enhancements" ($0.4 MM RY1, $0.4 MM RY2, $0.5 MM RY3)

- “Overhead Tower Rapid Rail” ($5.0 MM RY1, $5.0 MM RY2, $5.0 MM RY3)
- “Substations Security Enhancements Program” ($12.0 MM RY1, $12.0 MM RY2, $12.0 MM RY3)
- “Vented Covers for Underground Structures” ($1.0 MM RY1, $1.0 MM RY2, $1.0 MM RY3)

Q. Due to its importance, please describe the Vented Covers for Underground Structures Program.

A. This program funds the targeted installation of vented metallic covers on structures located in publicly accessible locations such as roadways, street crosswalks, and sidewalks. The program entails identifying structures that have elevated risk to public safety and replacing solid with vented versions of the covers. While many covers have been replaced, approximately 90,000 unvented structures remain on the system. Covers are prioritized for replacement by the following factors: 1) structures located in higher pedestrian traffic areas; 2) based on past events, new data analytics, or geographical and logistic concerns; and 3) structures with cables and cable combinations that have elevated failure rates. The installation of vented covers helps reduce the buildup of combustible gases associated with events on the low-voltage secondary system, thereby reducing the severity of underground events and enhancing public safety. Since the inception of the vented cover program, there have been approximately 135,000 vented covers installed. The total count of manhole events in 2021 was 24 percent lower than the previous five-year average (2016-2020), which equates to approximately 538 fewer events. There was a 24 percent reduction in Smoking Manholes; a 23 percent reduction in Manhole Fires; and a 29 percent reduction in Manhole Explosions compared to their respective five-year averages. Manhole Explosions causing public impact are at the lowest since the inception of the program in 2004 and is a 47 percent reduction from 2020. The use of vented latched covers is also currently being explored for explosion mitigation. These covers could further decrease the risk to the public in the case of a more severe event occurring.

Q. Are there additional projects that contribute to safety and security?

A. Yes. In addition to the investments listed above as part of the Safety and Security category, numerous other Con Edison projects and programs contribute to safety and security. For example, the Pressure, Temperature, and Oil Sensors Program and other transformer failure mitigation programs help identify and replace equipment prior to failure, decreasing the risk of violent failures and the risk to public safety. Another example is the Smart Sensors Program, discussed in the Risk Reduction/Reliability section of this panel testimony, which provides real-time data for facilities and equipment for which failure, damage, or an error in operation or maintenance could jeopardize public and employee safety.

Q. Are there any O&M program changes to discuss in the safety and security category?

A. Yes, the Company is proposing one O&M program change related to safety.

Q. Please describe the Company's O&M program change associated with safety.

A. The Safety Inspection Program includes the inspection of all Company-owned underground/underground residential development ("UG/URD") structures. Starting in 2021 UG structures were classified as High, Medium, and Low Priority and inspected on five-, eight-, and ten-year cycles respectively. URD structures remain on a five-year inspection cycle. This program includes enhanced inspection techniques using infrared and current readings. The increase in O&M funding in rate year 1 is partially driven by the increased number of inspections to comply with the Commission's directive to prioritize completion of the facilities not yet inspected under the previous eight-year cycle. The previous eight-year cycle would have ended in 2022. Those structures that are in the Low Priority group are inspected on a 10-year cycle, and facility inspections that would have taken place in 2021 and 2022 are now due for inspection during the rate years. At the end of the inspection cycle, costs tend to increase as the Company works to complete inspections on structures that could not be completed during routine inspections. These inspections, referred to as “stopped inspections,” could not be inspected because they have been paved over or are blocked by equipment or structures installed by others. Increased costs are also associated with the completion of backlogged repairs prior to the end of 2024. This program change will require an increase of $7.5 MM in RY1, $0.9 MM in RY2, but a decrease of $11.4MM in RY3 once the overlapping cycle inspections conclude.

F. Environmental Capital and O&M Expenditure Requirements

Q. Was the exhibit titled, “T&D Environmental” prepared under your direction?

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT EIOP-9

Q. What does Exhibit EIOP-9 show?

A. Exhibit EIOP-9, Schedule 1 lists the capital program and project funding requirements to support Environmental work conducted by S&TO, SSO, and Electric Operations. In addition, the exhibit contains white papers for each capital program/project that provide more detailed information, such as program and project work descriptions, justifications, alternatives, estimated completion dates, current status, and spending.

Q. Please provide an overview of the Company’s environmental work category.

A. The environmental work category focuses on work designed to minimize the Company’s environmental footprint. Specifically, the Company strives to reduce the number and impact of dielectric fluid (i.e., oil) spills and SF6 gas emissions to the environment. The Company uses dielectric fluid in its electric system as an insulating and cooling medium and also uses SF6, which is a greenhouse gas when it leaks, for insulation and current interruption in electric transmission, substation, and distribution equipment. In the rate case years for this filing, the Company’s SF6 leak mitigation work is part of a larger effort that also addresses risk reduction and is described in the Risk Reduction section of this testimony. The capital programs discussed here are focused on preventing dielectric fluid spills, detecting and responding to dielectric fluid spills, and upgrading facilities and containments so that dielectric fluid leaks or spills can be captured before they affect the environment.

Q. Please describe the capital programs within the environmental work category.

A. The Company has six capital programs within the environmental work category, most of which are designed to reduce the risk of dielectric fluid release from the underground transmission system by addressing potential leaks in transmission feeder cable pipe, substation equipment, and distribution equipment.

The programs listed below address leak prevention, detection, and containment. Details on each of these projects can be found in their respective white papers.

- “Environmental Enhancements” ($0.9 MM RY1, $0.9 MM RY2, $0.9 MM RY3)
- “Mobile Program for Transmission Feeder Leak Detection” ($0.3 MM RY1, $0.3 MM RY2, $0.3 MM RY3)
- “Oil Minders” ($1.7 MM RY1, $1.7 MM RY2, $1.7 MM RY3)
- “Pipe Enhancement Program” ($28.0 MM RY, $29.3 MM RY2, $29.8 MM RY3)

- “Substation EH&S Risk Mitigation Program” ($15.5 MM RY1, $14.0 RY2, $14.0 RY3)
- “Underground Transmission Structure Modernization” ($5.4 MM RY1, $5.4 MM RY2, $5.4 MM RY3)

Q. Please describe some of the key programs within this category starting with the Pipe Enhancement Program.

A. The Pipe Enhancement Program is a proactive program designed to reduce dielectric fluid leaks and increase the availability of transmission facilities. It focuses on addressing corrosion in suspect areas on the pipe-type transmission feeder system and includes the large-scale installation of welded barrels or carbon fiber wrap to encase heavily corroded pipe sections, the installation of new pipe coatings, and the associated required excavation, coating removal, inspection, and backfill/restoration tasks.

Dielectric fluid leaks in pipe-type cable are a problem from both an environmental and reliability perspective. Mitigating the release of dielectric fluid to the environment is a critical component of the Company’s efforts to achieve environmental excellence. In addition, dielectric fluid leaks can result in the Company removing feeders from service. If the leak rate exceeds the flow rate capability of the fluid pressurization pumps, the

Company might need to take an extended outage to complete repairs. In cases where fluid pressure can be maintained, a feeder with a large leak may still be forced out of service to clamp and repair the leak. These issues can have detrimental effects on overall system reliability, especially during high load periods.

Work packages appropriated under this program to date have focused on suspect areas of Feeders M51 and M52 since they contribute the highest percentage of dielectric fluid lost to the environment of any feeders on the Con Edison Transmission System. The Company will focus a large majority of this program’s funding in 2022-2023 on addressing portions of M51 and M52 that have shown leaks in recent years.

By addressing corrosion issues in suspect areas before the pipe leaks occur, Con Edison will be able to reduce the amount of dielectric fluid that is lost to the environment and the associated costs for emergency leak response and remediation. For these suspect areas, this program also provides increased reliability, extends the life of existing pipe-type feeder facilities, and prevents or reduces the likelihood of dielectric fluid release from the pipe-type feeder system.

Q. Please continue by describing the Environmental Enhancements Program.

A. This program will cover the installation of cathodic protection rectifiers along select High Pressure, Fluid Filled Feeders to supplement existing pipe cathodic protection. Buried sections of pipe-type cables are cathodically protected to prevent corrosion that can result in dielectric fluid leaks. The Company also plans to expand monitoring capabilities through new sensors that either utilize infrared imaging, can detect dielectric fluid in manholes, or measure cathodic protection voltages. This program will reduce the likelihood of dielectric fluid leaks which can improve environmental performance and feeder availability. The Company plans to target approximately four feeder group installations per year.

Q. Are there other projects or programs that help support the Company’s efforts to achieve environmental excellence?

A. Yes. In addition to the investments listed above as part of the Environmental work category, numerous other Con Edison projects and programs contribute to minimizing the Company’s environmental footprint. For example, the Gas Insulated Substation Replacement Program replaces switches, bus sections, and ancillary equipment at existing gas insulated substations (“GIS”), eliminating GHG emitting equipment, and replacing it with components with a smaller overall SF6 footprint. Similarly, the High Voltage Circuit Breaker Capital Upgrade Program replaces or upgrades 33kV, 69kV, 138kV, and 345kV breakers, including addressing those with SF6 leaks and installing more modern breakers with a lower volume of SF6. Another example is the Unit Substation Upgrade and Improvement Program, which includes preventative measures and corrective actions to repair deteriorating conditions affecting transformer moats to avoid oil spills or leaks that could cause environmental harm and the need for soil remediation work. The Company is also introducing biodegradable dielectric fluid in some cases to further minimize the environmental impact of a potential fluid release.

G. Information Technology Capital and O&M Expenditure Requirements

Q. Please explain the Company’s plans to incorporate technology to enhance how it manages the operation of its electric T&D systems.

A. Con Edison uses a number of sophisticated technology applications. The Company continues to explore opportunities to employ the latest technologies to improve performance and streamline work processes.

Q. Are there projects described in the Company’s IT Panel testimony that will support Con Edison’s electric system?

A. Yes, a number of the projects described by the IT Panel will enhance the operation of the Company’s T&D system.

Q. Please provide a list of some of the more significant IT projects related to T&D operations.

A. The following IT projects are sponsored by the IT Panel. Details on the projects can be found in Exhibit IT-1 and Exhibit IT-4.

Central Operations Battery Monitoring Systems - The Company will invest in systems that will continually assess the condition of some substation battery banks.

Distribution Equipment Management System (“DEMS”) Replacement Project – The Company is proposing to replace the legacy DEMS to enable better automation and data accuracy.

Electric ARM Replacement (Phase 0) – The Company is proposing to conduct a Phase 0 assessment to determine the feasibility and scope to migrate the Electric Work and Asset Management (“WMS”) system to the enterprise Maximo WMS platform to realize the full benefits of a true enterprise solution across all business areas.

Electric ARM Replacement – The Company is proposing to migrate the Electric WMS system to the enterprise Maximo

WMS platform. This is in keeping with IT organization's strategy of moving to a "One Enterprise" Work and Asset Management solution for all Con Edison's business areas.

Outage Management System IT System Hardening – The Company is proposing to address the technical and systematic issues experienced during winter storms Riley and Quinn identified by Storm Assessment Team and a study performed by McKinsey and Company. The proposed enhancements will enable high availability architecture mitigating the need for prolonged maintenance outages for patching, significantly reduce disaster recovery times during failover, facilitate regulatory required testing requirements, and set the building blocks for future integrations, enhancements, and testing.

Operations Network for EMS – The Company is proposing to improve and expand the network infrastructure at the primary and alternate Energy Control Centers to support operational reliability of System Operation's computer systems. This project will allow the Company to implement best security practices and meet NERC CIP Standards

Outage Management System (Phase 4) - The Company is proposing to continue efforts to identify and incorporate enhancements within the modules used by the OMS to supplement efforts to better identify opportunities for enhanced operator training.

Protective Relay Settings Repository – The Company will procure a software package that will store all protective relay settings and asset registry information. This project will facilitate improved understanding of relay performance and lifecycle management.

Substation Technology Improvements – The Company will continue to make upgrades that automate substation processes to improve maintenance, data collection and data storage.

WMS Sustainability Project - In order to support the current electric WMS until it is migrated to an enterprise Maximo WMS platform the Company is proposing to add enhancements and interfaces required by the Company’s new Customer Service System (“CSS”) and eGIS. A number of additional automations and interfaces that will facilitate efficiency and cost savings are also planned. This investment is necessary to maintain the efficient functioning of the WMS until its replacement which is estimated to be 2027.

V. Electric Production

A. Electric Production Overview

Q. Please describe the Company's Electric Production facilities.

A. The Electric Production facilities are: 1) cogeneration unit East River 6/60, which is comprised of Turbine Generator 6 and Boiler 60; 2) unit East River 7/70, which is comprised of Turbine Generator 7 and Boiler 70; and 3) five gas turbines ("GT"s), one located at the 59th Street Generating Station ("59th Street"), two located at the 74th Street Generating Station ("74th Street"), and two located at the Hudson Avenue Generating Station ("Hudson Avenue"). Five GTs are planned for retirement in 2023 to 2025 timeframe as a result of the DEC Peaker Rule (Part 227-3) regulation which goes into effect in May of 2023. Electric Production also covers O&M for East River Units 1 and 2 combustion turbine generators, (also referred to as the East River Repowering Project ("ERRP")). Details on ERRP O&M are provided by the Company's Accounting Panel.

B. Summary

Q. Was the exhibit titled, "Electric Production" prepared under your direction?

A. Yes, it was.

MARK FOR IDENTIFICATION AS EXHIBIT EIOP-10

Q. What does Exhibit EIOP-10 show?

A. Exhibit EIOP-10, Schedules 1 and 3 lists the Company’s projected capital expenditures and O&M program changes required for Electric Production for each of the rate years. The exhibit also includes white papers for all capital expenditures listed in this section of testimony. O&M program changes for Electric Production in the rate case years are also included in the exhibit.

Q. Please briefly describe the planned capital spending for Electric Production.

A. The Company projects to spend approximately $26.4 million in RY1, $22.5 million in RY2, and $19.6 million in RY3. The Company’s proposed Electric Production capital spending varies based on the outage schedule for East River 6/60 and 7/70. Boiler 60 has capital turbine projects in RY1. Boiler 70 has planned capital turbine projects and boiler projects in RY2, which results in a capital expenditure increase in RY2. The planned expenditure levels decrease from RY2 to RY3, as there are no capital investments currently scheduled for RY3.

Q. What are the Electric Production capital programs for which the Company is seeking funding?

A. The Company is seeking funding for the following eight programs:

- "East River Balance of Plant Replacement Projects" ($0.4 MM RY1, $1.0 MM RY2, $2.5MM RY3)
- "East River Civil & Structural Projects" ($2.1 MM RY1, $2.0 MM RY3)
- "East River Instrumentation & Control Replacement Projects" ($1.9 MM RY1)
- "East River Major Equipment Replacement Projects" ($0.4 MM RY1, $16.0 MM RY2, $6.0 MM RY3)
- "East River Power Distribution Replacement Projects" ($4.8 MM RY1, $1.0 MM RY2, $9.0 MM RY3)
- "74th Street Environmental" ($0.5 MM RY1, $0.5 MM RY2, $0.1 MM RY3)
- "59th Street Environmental" ($0.5 MM RY1)
- "East River Environmental" ($16.0 MM RY1, $4.0 RY2)

C. Details of Programs/Projects

Q. What are the Electric Production project category used by the Company?

A. The Company divides projects into four categories that support Electric Production: 1) Replacement, 2) Risk Reduction, 3) Environmental, and 4) Safety and Security.

Q. Please describe the planned capital expenditures for the Company's Replacement projects.

A. The Replacement category contains projects and programs to replace failed equipment or equipment that has not yet failed but has degraded performance, has become difficult or costly to maintain, or is approaching the end of its useful life. Capital Replacement projects supporting Electric Production are organized in programmatic subcategories, which are listed below. The Company tracks and reports on its Electric Production Replacement capital spending under these programs:

- Major Equipment
- Balance of Plant
- Power Distribution Equipment
- Instrument and Controls
- Civil and Structural

Q. Please describe the Major Equipment subcategory for Electric Production equipment replacement.

A. This subcategory includes the replacement of boilers, furnace tubes, reheaters, superheaters, brick, refractory, insulation, lagging, and casings. Boilers produce the steam required to drive the Company's turbine generators and produce electricity and account for a significant portion of the total work performed in this subcategory on Electric Production assets.

The furnace walls within boilers are lined with banks of tubes that help maximize the efficiency of converting water to steam. These tubes degrade over time. To maximize the efficiency and reliability of the boilers, the Company replaces degraded tubes. The capital work that the Company has currently planned for the boilers involves replacing tubes along the furnace walls in Boiler 60, replacing tubes in the reheater and superheater in Boiler 70, and is based on the schedule for respective Boiler’s capitalized maintenance.

Q. Please describe the next Replacement subcategory, Balance of Plant Equipment.

A. This subcategory includes the replacement of pumps, valves, heat exchangers, air compressors, and tanks that are necessary to generate steam.

Q. Please provide additional details regarding East River Log Screens 4/5/6 Replacement.

A. Con Edison will remove the Log Screens in Bays 4, 5, and 6 and replace them with new upgraded stainless-steel screens, coated with epoxy to protect from corrosion. Log Screens were installed in 2013 and have significantly corroded due to continuous immersion in salt water. Loss of the panel inserts leaves the traveling screens, which are located downstream of the log screens, exposed to floating debris and risk of damage.

Q. Please describe the next Replacement subcategory, Power Distribution Equipment.

A. This subcategory typically includes the replacement of electrical equipment such as switchgear, transformers, batteries, uninterruptible power supplies, inverters, breakers, motors, cables and backup generators. The Company has identified a number of these systems – including load centers, emergency battery systems, and uninterruptable power systems ("UPS") – for capital replacement because they are nearing the end of their useful life. Load centers and their associated switchgear comprise the electric supply for critical station equipment, such as circulator pumps ("CP"), boiler feed pumps ("BFP"), and forced draft ("FD") and induced draft ("ID") fans. Load centers and switchgear also power many of the plant's primary and auxiliary components. If a plant's auxiliary power supplies are interrupted, the battery systems and UPS systems provide emergency power.

Q. Please describe the next Replacement subcategory, Instrumentation and Controls Systems.

A. This subcategory includes the replacement of control systems, including transmitters, digital control systems, control panels and terminals, monitoring instrumentation, and wiring. The Company will periodically identify control equipment and systems such as protective relays, instrumentation, and programmable logic controllers ("PLCs") that are obsolete or present a cyber or operational risk. The Company also upgrades or replaces these systems to reduce the likelihood or impact of forced outages.

Q. Please describe the type of planned Replacement projects in the Instrumentation and Controls subcategory.

A. Replacement projects related to several auxiliary electrical systems are listed below and represent typical projects that would be captured in the Instrumentation and Controls program going forward.

Q. Please explain the Civil and Structural subcategory.

A. This subcategory contains projects that include facility upgrades for heating, ventilating, and air-conditioning ("HVAC") systems and structural building elements. These projects are required to maintain a proper operating environment for both critical plant equipment and Company personnel.

Q. Please describe the type of planned Replacement projects in the Civil and Structural subcategory.

A. Replacement projects in the Civil and Structural subcategory are listed below and represent the typical projects that would be captured in the Civil and Structural program going forward.

Q. Please describe the type of project in the Company's Risk Reduction category.

A. Risk Reduction projects and programs support the reliability and/or availability of a facility or an operational function and reduce or mitigate a risk associated with a facility or operation through proactive replacement strategies. The Company's capital Risk Reduction projects for Electric Production are organized in three programmatic subcategories, which are listed below. The Company plans to track and report on its Electric Production Risk Reduction capital spending going forward:

- Balance of Plant Equipment
- Power Distribution Equipment
- Instrumentation and Controls
- Civil and Structural

Q. Please explain the Balance of Plant Equipment subcategory for Risk Reduction and the risks being addressed.

A. This subcategory includes the replacement of pumps, valves, heat exchangers, air compressors, and tanks. To avoid the likelihood of potential de-rating or unit shutdowns, the Company plans overhauls to replace and refurbish equipment components of boilers and turbines based on manufacturer and industry guidelines, actual length of operation, unit performance, inspections, and engineering assessments. Additionally, equipment improvements are required to address malfunctions and failures that could potentially lead to unreliable operations and contribute to plant unavailability.

Q. Please describe the Power Distribution Equipment subcategory for Risk Reduction and the risks being addressed.

A. This subcategory typically includes upgrades of electrical equipment such as switchgear, transformers, batteries, uninterruptible power supplies, inverters, breakers, motors, cables, and backup generators. The Company upgrades or replaces these systems to also reduce the likelihood or impact of forced outages.

Q. Please describe the Instrumentation and Controls subcategory for Risk Reduction and the risks being addressed.

A. This subcategory typically includes upgrades to control systems, including transmitters, digital control systems, control panels and terminals, monitoring instrumentation, and wiring. Proper operation and dependability of the instrumentation and control systems is a cornerstone to the overall reliability and performance of the Electric Production assets. Failures of these systems could result in forced outages and deratings. Additionally, the Company will periodically identify control equipment and systems such as protective relays, instrumentation, and programmable logic controllers ("PLCs") that are obsolete or present a cyber or operational risk. The Company upgrades or replaces these systems to also reduce the likelihood or impact of forced outages.

Q. Please describe the capital expenditures under Environmental.

A. In general, projects in this category are intended to enhance environmental performance, reduce environmental impact, or comply with regulatory requirements. The Company currently plans to implement projects in this category to convert current backup fuel assets to use a cleaner burning fuel, reduce GHG emissions and reduce the risk of oil leaks into the environment. These projects are representative of projects that will be captured in the Environmental program moving forward.

Q. Please describe the Company's plans to convert its Electric Production assets to use a cleaner burning oil as a backup fuel source.

A. The New York City Department of Environmental Protection ("NYCDEP") has prohibited the use of No. 6 fuel oil as of January 1, 2020, unless a fuel oil user agrees to go to No. 2 or lighter fuel oil by January 1, 2022; it has also prohibited the use of No. 4 fuel oil as of January 1, 2025. Pursuant to PSC, NYISO, and Con Edison gas tariff requirements and to maintain reliable operations year-round, the Company maintains a backup fuel for its electric and steam production facilities. The Company determined, based on fuel oil prices and conversion costs that it was in the customers' best interest for the Company to convert to No. 4 oil as an interim step prior to 2020 and then convert to No. 2 oil prior to 2025.

The affected stations are: East River 6/60 and 7/70, East River South Steam Station ("ERSSS"), 59th Street, 74th Street, and the Ravenswood A-House ("RAV"). The specific affected assets impact both Electric and Steam customers — Electric Production and Steam Production.

Q. Please discuss the conversion plan for the East River Electric Production assets.

A. In Fall 2018, the Company converted the backup fuel for East River Electric Production Units 6/60 and 7/70 from No. 6 to No. 4 oil. The Company is now planning its conversion to No. 2 oil. Detailed engineering for this process began in 2019 to meet the January 1, 2025 regulatory deadline.

Q. What is involved in converting to No. 2 oil?

A. Any fuel oil conversion involves three considerations: 1) delivery/storage, 2) forwarding/conditioning, and 3) combustion efficiency. Fuel delivery and storage takes into account contracts, piping, tank capacity, tank condition, and environmental and safety hazards. Fuel oil forwarding and conditioning includes pump design, pump capacity, heating requirements, and metering. Boiler combustion efficiency involves evaluating how fuel is applied to the furnace.

Q. Please describe the conversion process.

A. First, the Company will pump down, clean, and inspect the fuel oil storage tanks at East River. Second, the Company will install equipment required for the conversion. Lastly, the Company will commission, test and tune the equipment to optimize operation. The Company’s fire risk assessment determined that it must upgrade the East River Tank Farm to store No. 2 oil; specifically, it must upgrade the tank internal foam system, the external foam monitor system, the fire detection system, and install a redundant water supply from a separate city water main.

The Company must also install new pumps at the tanks to shuttle, recirculate, and forward fuel oil from the tanks to the boilers. The pumps are required to establish and maintain the minimum flows and pressures needed to get the appropriate amount of fuel to each boiler. The existing pumps will not work because of the consistency of No. 2 oil. In addition, the pumps are submerged and continuously touched by the fuel oil. The change to No. 2 oil requires a change in pump and seal material.

When the Company used No. 6 oil, it needed heaters to maintain the proper conditions for burning. While No. 4 oil is much less viscous than No. 6 oil, it still has the potential to become very thick in low temperatures. The heaters were retained during the No. 4 oil conversion to mitigate this potential scenario. No. 2 oil is a much lighter fuel than both No. 6 oil and No. 4 oil and the viscosity will not become so high in low temperatures that combustion cannot be maintained. Consequently, the Company will remove and retire the four East River fuel oil heaters located on top of fuel oil storage tanks No. 2 and No. 3.

This involves capping, closing, and retiring the steam piping supplies and returns, and adding fuel oil piping where the fuel oil heaters are located.

Burner changes are also necessary for conversion to No. 2 oil. The control stations that regulate the fuel to each boiler were originally designed for a much thicker, denser fuel. The systems are not adequately sized to effectively control the fuel flow to each boiler. Each burner has an oil gun and/or oil gun tip that regulates the flow of fuel to each burner. The Company must also replace these oil guns and/or tips to ensure adequate combustion. These mechanical changes require controls tuning to address the valve, piping, and instrumentation upgrades for safe and reliable operation.

D. O&M Program Changes

Q. Is the Company proposing any Electric Production O&M program changes?

A. Yes. The Company is proposing one change related to East River Units 6/7 Major Overhauls. The steam turbines and generators of East River Units No. 6 and No. 7 are overhauled on an approximate 50,000 operating hour frequency and a nine-to-twelve-year basis respectively. The next overhauls for Unit No. 6 are scheduled in 2022 when the Low-Pressure ("LP") Turbine will be opened and inspected and 2023 when the High-Pressure (“HP”) Turbine, and the HP and LP generators will be overhauled. The overhauls for Unit No. 7 are scheduled as follows, 2024 HP Turbine and HP/LP generators, 2025 LP Turbine, and 2026 Intermediate Pressure Turbine. The degradation of a steam turbine is not typically detected through performance evaluations or limited inspections, so opening the steam turbine to remove, inspect, and repair its components is required to ensure its continued reliable operation. Conducting major overhauls at pre-determined intervals increases steam turbine generating assets reliability and minimizes the risk that the assets will be unavailable because of emergent and unforeseen repairs.

VI. Special Issues

A. Generator Retirement

Q. Does the Company have any proposals related to third-party Generator retirements?

A. Yes. Third-party generators may retire or announce their retirements during RY1, RY2, or RY3. Generators may retire as a result of market forces. They may also be affected by environmental regulations, such as the CLCPA. Some aspects of CLCPA implementation are still being developed, meaning the full picture of what ultimately will be required for CLCPA compliance is not yet clear and depends on forthcoming guidance from the Climate Action Council and the New York State Department of Environmental Conservation ("DEC"). The resulting guidance could force earlier retirement of fossil fuel generators. The recent denial of the DEC Air permits for the Astoria Gas Turbine Replacement Project exemplifies the magnitude and pace of change to power generation that comes with CLCPA. Generator retirements or retirement announcements may create reliability needs that the Company has to address during the term of the rate plan through upgrades to its electric delivery system. As the Company cannot know in advance whether generator retirements will occur, or the precise upgrades required, it is proposing to recover through a surcharge the costs for any upgrades necessary to maintain reliability because of a generator retirement, to the extent not otherwise recovered, as described in more detail in the Accounting Panel.

B. Reliability Performance Mechanisms

Q. Please describe the cases in which the Company would like to change existing metrics for System Average Interruption Duration Index (SAIDI.)

A. The Company proposes to replace its SAIFI and CAIDI metrics with SAIDI for both non-network and network systems.

Q. Why is the Company proposing to adopt SAIDI and to eliminate SAIFI and CAIDI?

A. SAIDI, which measures how long the average customer experiences a sustained interruption, is a more meaningful metric than CAIDI. CAIDI measures the average duration of an interruption for the few customers that experience an interruption in a given year. While this metric is important, it provides only limited information about customer experience, especially when a high percentage (e.g., 80 to 90 percent) of customers do not experience any interruption at all.

CAIDI may also be inordinately affected by a single interruption, especially if the total number of interruptions is low. For example, in 2007 a lightning-induced transmission-substation outage interrupted service to 137,000 customers in the Yorkville and West Bronx networks for 45 minutes and 48 minutes, respectively. Before the interruption, network CAIDI was 4.49 hours. After the interruption, it dropped to 1.17 hours. The final CAIDI for that year was 1.58 hours. The lightning strike drove a record low CAIDI that was not indicative of performance prior to the event.

SAIFI measures how many customers, on average, are interrupted. It does not account for how long customers are out of service when interrupted. So, like CAIDI, it provides and incomplete measure of the customer experience.

For the reasons described above, neither SAIFI nor CAIDI are independently meaningful measures of system performance. SAIDI, in contrast, measures both frequency of interruption and duration. In other words, SAIDI measures the average of customer interruptions for all customers, taking into account that some customers experience no interruptions at all.

Q. What SAIDI thresholds is the Company proposing?

A. For the same reasons previously stated, the Company proposes the network SAIDI threshold be set at 8.30 minutes, which is one standard deviation above the Company's ten-year historical performance. The chart below shows the Company's performance over the last ten years.

Network SAIFI CAIDI SAIDI without Storms

	SAIFI	CAIDI Hours	SAIDI Minutes	**SAIDI + 1 SD**
2012	12.08	6.35	4.60	8.30
2013	12.44	5.62	4.19	8.30
2014	13.96	6.57	5.50	8.30
2015	16.12	6.75	6.53	8.30
2016	16.18	6.88	6.68	8.30
2017	16.72	6.51	6.53	8.30
2018	17.42	6.31	6.60	8.30
2019	22.25	5.41	7.22	8.30
2020	85.82	1.78	9.17	8.30
2021	17.02	3.56	3.64	8.30

Total	**230.01**	**55.74**	**60.66**	
Average	**23.00**	**5.57**	**6.07**	

Q. Do the same reasons you just gave for SAIDI being preferable to SAIFI and CAIDI support the Company's proposal to use SAIDI instead of SAIFI and CAIDI as its non-network performance metric?

A. Yes.

Q. What Non-Network SAIDI threshold is the Company proposing?

A. The non-network SAIFI and CAIDI targets should be replaced by SAIDI. SAIDI is calculated by multiplying SAIFI times CAIDI in minutes. The Company proposes to set the threshold at 69.06 minutes, which is one standard deviation above the Company's ten-year historical performance. The chart below shows the Company's performance over the last ten years.

Non-Network SAIFI CAIDI SAIDI without Storms					
	SAIFI	CAIDI (Hours)	CAIDI (Min)	SAIDI (Minutes)	**SAIDI + 1 SD**
2012	0.358	2.02	121.2	43.39	69.06
2013	0.396	2.02	121.2	48.00	69.06
2014	0.334	1.84	110.4	36.87	69.06
2015	0.349	1.95	117	40.83	69.06
2016	0.435	1.87	112.2	48.81	69.06
2017	0.357	1.93	115.8	41.34	69.06
2018	0.398	1.91	114.6	45.61	69.06
2019	0.526	2.73	163.8	86.16	69.06
2020	0.469	1.89	113.4	53.18	69.06
2021	0.488	1.93	115.8	56.51	69.06

Total	**4.11**	**20.09**	**1205.4**	**500.70**	
Average	**0.411**	**2.01**	**120.54**	**50.07**	

C. Charges for Special Services

Q. Please discuss the Company’s proposal to update charges for special services performed by the Company.

A. The Company is proposing to update charges for special services performed by the Company as follows:

- Reinspection Charge:
  - Increase to $279.00 (currently $260.00)
- High potential proof test
  - Per visit to the premises, up to four hours: $2,076.00 (currently $1,740.00)
  - For each additional hour or portion thereof: $519.00 (currently $435.00)
- Megger Test
  - Two people for one hour: $519.00 (currently $435.00)
- Dielectric Fluid Test
  - First sample: $1,066.00 (currently $1,168.00)
  - Each additional sample taken at the same time: $670.00 (currently $836.00)
  - Each sample taken by the Customer: $547.00 (currently $733.00)

Q. What is the basis for the proposed charges?

A. These charges were last updated January 1, 2018. The proposed charges reflect the Company's 2021 cost for labor, vehicles, corporate overhead, and chemical lab. The change in costs for these charges is the result of the overhead allocation to these tasks. Please see the Electric Rate Panel Testimony for the specific Tariff language related to these changes.

D. Tariff Changes

Q. Is the Company supporting any tariff changes as part of this panel?

A. Yes. This panel is supporting three tariff changes related to 1) the Selective Undergrounding Program, 2) Street and Sidewalk Service, and 3) the Charge for Replacement of Damaged AMI Meters.

1. Selective Undergrounding Program

Q. In what ways does the Company's Selective Undergrounding Program require adjustments to the current tariff so that the installation cost, including the cost on the customer side of the meter, is socialized to all customers?

A. The Company is proposing to add a new provision to General Rule 7.1 – Customer Wiring and Equipment (Leaf 64). This provision stipulates that for customers served by the Company's Selective Undergrounding Program, the Company will bear the cost of furnishing and installing customer wiring and equipment provided that the customer will maintain the wiring and equipment. This tariff change will eliminate the need for an individual customer to bear the installation costs of equipment associated with the undergrounding their service when part of the Selective Undergrounding Program.

Q. Why does the Company believe that this cost should be recovered in rates?

A. First, as discussed in the Storm Panel, enhanced storm response is a high priority, and one way for the Company to enhance restoration is to move this program forward by socializing the cost of undergrounding on the individual customer. We note that all customers benefit when there are fewer outages resulting from a major storm. The fewer outages there are from the storm's impact, the quicker the Company will be able to restore remaining customers. In addition, if there are fewer outages, then the Company's storm restoration cost will ultimately be lower. Finally, as further justification for socializing this cost through rates, disadvantaged communities are included in the model used to determine prioritization of circuits for undergrounding.

Q. What specific Tariff language does the Company propose?

A Please see the Electric Rate Panel Testimony for the specific Tariff language proposed to be added to General Rule 7.1.

2. Street and Sidewalk Service

Q. Please describe proposed General Service Rule 5.2.8, Street or Sidewalk Service.

A. Proposed General Rule 5.2.8 is a new tariff section that prospectively addresses the installation and maintenance of overhead and underground facilities providing service to structures and equipment in the public right-of-way. Facilities such as newsstands, bus shelters, kiosks, communication equipment, computers, advertising and other display panels will receive service under the Street or Sidewalk Service provision. These customers will be required to pay in advance to the Company the estimated cost of the Company's service installation. The Company will charge the customer for removal costs when the equipment is removed.

Q. Why is the new tariff section for Street and Sidewalk Service needed?

A. Under General Rule 5.2.1, Con Edison installs electric services, in most instance at no cost to the customer, when the service is provided to a building or premises. All other customers are only eligible for temporary service under General Rule 5.2.7. The Company anticipates that the number and types of customers requiring service in the public right of way will increase prospectively. These types of equipment have long been considered temporary service customers. In order to clarify the tariff since the Company expects this type of equipment to increase, the Company is proposing this new section to make clear that customers that install facilities within a public right-of-way, as opposed to premises, and are subject to removal by the local municipalities, must bear the costs of service installation.

Q. Please explain how the Company’s proposed tariff change will distinguish between Temporary Service and Street or Sidewalk Service.

A. Previously, the Company provided an electric service to all customers with non-permanent structures under the Temporary Services tariff section. Going forward, customers that need service for construction sites, street fairs, other temporary activities or non-permanent structures will continue to receive Temporary Service. The customer pays the estimated cost of installation and removal in advance. The defining characteristic of Street and Sidewalk Service is that customers locate their equipment and structures in the Public right-of-way. While rules vary by municipality, street and sidewalk occupants are generally subject to removal, relocation, or replacement. Street and Sidewalk Service customers will pay the installation costs up front and the removal costs when the service is removed. These customers are not eligible for reimbursement for service installation costs because the risk or removal, relocation, or replacement of their equipment is a possibility for the duration of their occupancy in the Public right-of-way.

Q. Why are you proposing that Street and Sidewalk Services customers pay for a service installation in advance?

A. Because the public right-of-way is the inalienable property of the local municipality, the customer's right to occupy the public right-of-way will be for a limited term, and the customer's equipment will be subject to removal or re-location. Therefore, the Company does not have reasonable assurances that it will recover the costs for the service installation due to risk of relocation or removal.

Q. Are there any other changes related to the proposed Street and Sidewalk service.

A. In General Rule 5.2.7, the Company has removed the term "non-recoverable." Going forward, the non-recoverable costs for temporary service such as construction sites and street is the full cost of the installation. This is what was intended by this provision but the word non-recoverable has been subject to misinterpretation. There are also several minor additional changes. In General Rule 5.1 the definition for “Applicant” has been updated to include a customer requesting service “at a location in the Public right-of way.” Also, in General Rule 5.2.7, the types of customers receiving temporary service is clarified. Finally, General Rule 17.2, Special Services at Cost, has been updated to include installation and removal of Street and Sidewalk Service, and removal of Temporary Services.

Q. What specific Tariff language does the Company propose?

A Please see the Electric Rate Panel Testimony for the specific Tariff language proposed to be added.

3. Charge for Replacement of Damaged AMI Meters

Q. Are there proposed changes to the charges for replacing a damaged meter?

A. Yes. We propose to modify General Rule 16.1 to update the cost of replacing a damaged meter. Currently, the Tariff imposes a charge of $282 to replace a demand meter damaged because the customer did not exercise reasonable care, or the meter was damaged due to tampering.

Q. Why do the costs need to be updated?

A. The Company has updated these costs and the costs have gone down. The updated labor cost plus the average cost of an AMI meter is $262.

Q. What specific Tariff language do you propose?

A. Please see the Electric Rate Panel Testimony for the specific Tariff language proposed to be added to General Rule 16.1.

Q. Does this conclude your direct testimony?

A. Yes. It does.

Exhibit_(EIOP-1)

T&D Capital and O&M Summary

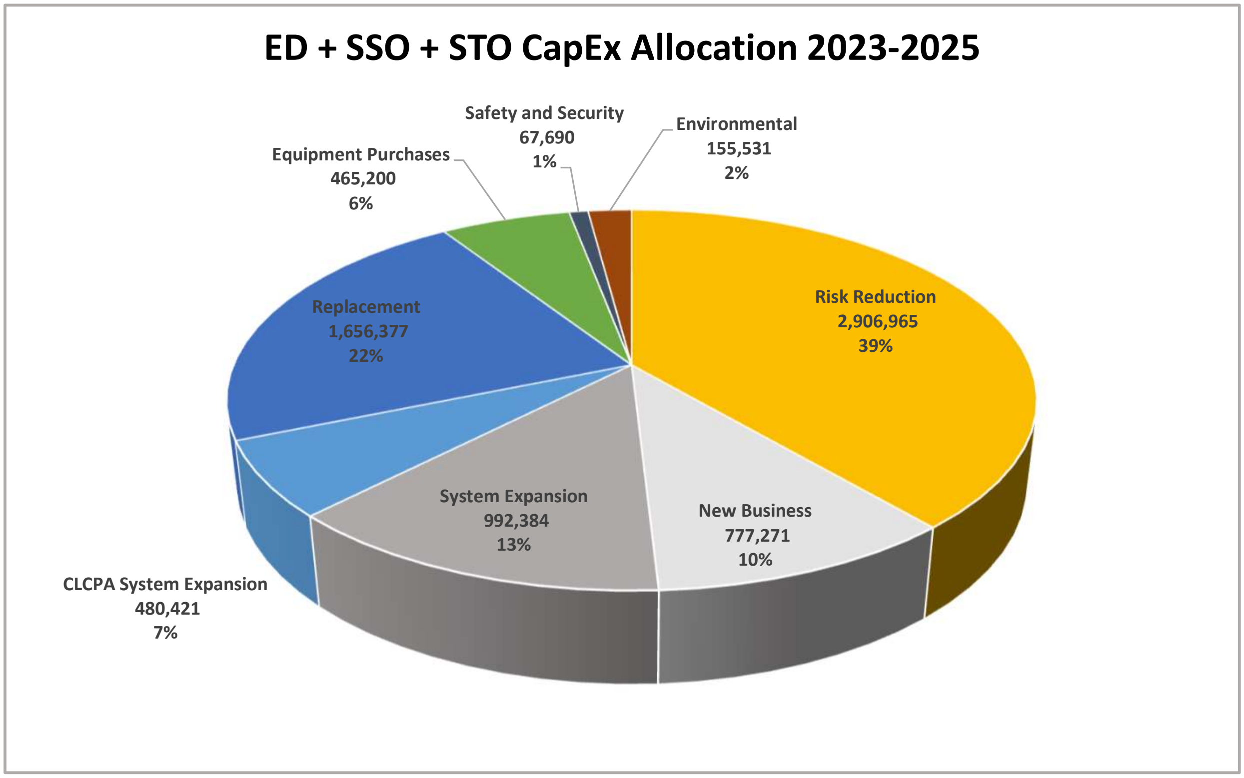
Schedule 1: T&D Capital Program and Project Summary

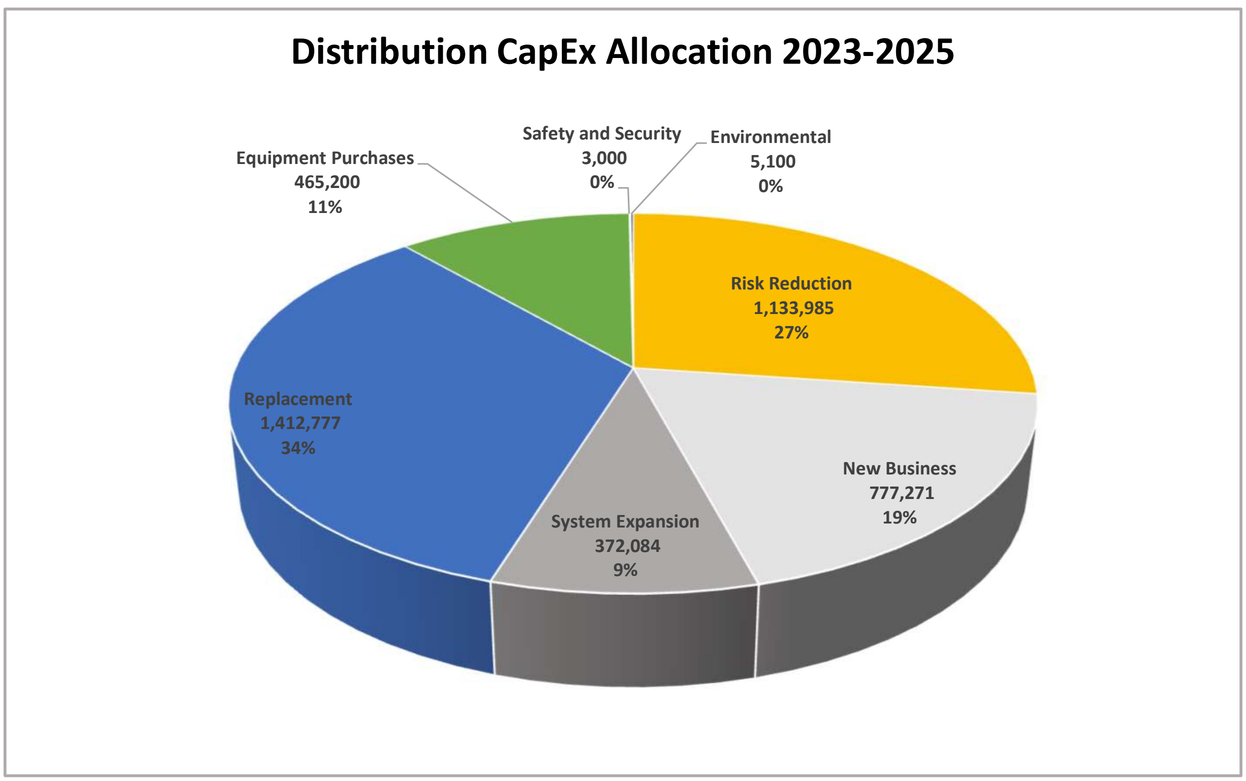
	Year Total			
	Current Budget			
	Total Dollars ($000)			
ELECTRIC	**RY1**	**RY2**	**RY3**	**3 Yr. Total**
Electric Transmission				
Risk Reduction	169,892	111,892	122,864	404,648
System Expansion	5,000	5,000	-	10,000
CLCPA System Expansion	251,969	187,401	41,051	480,421
Replacement	18,000	18,000	18,000	54,000
Safety and Security	6,700	7,000	7,100	20,800
Environmental	34,633	35,883	36,383	106,899
Electric Transmission Sub-Total	**486,194**	**365,176**	**225,398**	**1,076,768**
Electric Substations				
Risk Reduction	437,044	478,822	452,467	1,368,333
System Expansion	99,100	163,600	347,600	610,300
Replacement	73,600	58,000	58,000	189,600
Safety and Security	14,630	14,630	14,630	43,890
Environmental	15,532	14,000	14,000	43,532
Electric Substations Sub-Total	**639,906**	**729,052**	**886,697**	**2,255,655**
SSO+S&TO Total				
Risk Reduction	606,936	590,714	575,331	1,772,981
System Expansion	104,100	168,600	347,600	620,300
CLCPA System Expansion	251,969	187,401	41,051	480,421
Replacement	91,600	76,000	76,000	243,600
Safety and Security	21,330	21,630	21,730	64,690
Environmental	50,165	49,883	50,383	150,431
Electric Distribution				
Risk Reduction	350,144	379,067	404,773	1,133,985
New Business	236,233	268,010	273,028	777,271
System Expansion	147,024	116,611	108,449	372,084
Replacement	450,221	479,794	482,762	1,412,777
Equipment Purchases	146,000	159,600	159,600	465,200
Safety and Security	1,000	1,000	1,000	3,000
Environmental	1,700	1,700	1,700	5,100
Electric Distribution Sub-Total	**1,332,322**	**1,405,783**	**1,431,312**	**4,169,417**
Electric T&D Total	**2,458,422**	**2,500,011**	**2,543,407**	**7,501,840**
TOTAL ELECTRIC				
Risk Reduction	**957,080**	**969,781**	**980,104**	**2,906,965**
New Business	**236,233**	**268,010**	**273,028**	**777,271**
System Expansion	**251,124**	**285,211**	**456,049**	**992,384**
CLCPA System Expansion	**251,969**	**187,401**	**41,051**	**480,421**
Replacement	**541,821**	**555,794**	**558,762**	**1,656,377**
Equipment Purchases	**146,000**	**159,600**	**159,600**	**465,200**
Safety and Security	**22,330**	**22,630**	**22,730**	**67,690**
Environmental	**51,865**	**51,583**	**52,083**	**155,531**
Total	**2,458,422**	**2,500,011**	**2,543,407**	**7,501,840**

Schedule 2: T&D O&M Program Change Summary

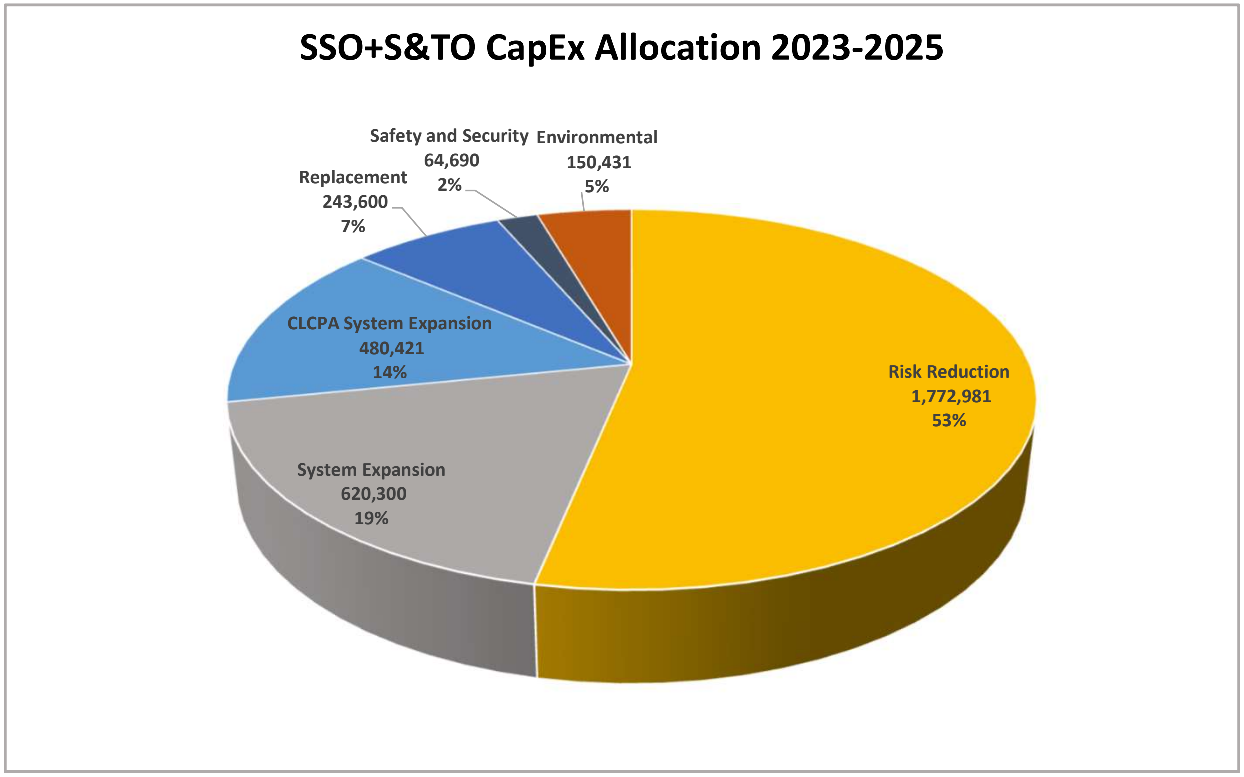
Infrastructure Investment Panel O&M Program Changes Summary ($000)		**RY1 Program Change**	**RY2 Program Change**	**RY3 Program Change**
Electric Transmission	**Program Change**			
System Expansion	Transmission Operations Capital Projects	3,915	3,915	3,915
System Expansion	Transmission Planning Staffing Needs to Support Clean Energy Agenda	405	405	405
	Sub-Total	**4,320**	**4,320**	**4,320**
Electric Distribution	**Program Change**			
Risk Reduction	Emergency Response	3,522	-	-
Risk Reduction	Line Clearance/Vegetation Management Program	2,819	368	375
New Business	Meters and Customer Equipment Program	4,538	1,196	144
Risk Reduction	Safety Inspection Program	7,487	945	(11,403)
	Sub-Total	**18,366**	**2,509**	**(10,884)**
	TOTAL	**RY1 Program Change**	**RY2 Program Change**	**RY3 Program Change**
	Grand Total	22,686	6,829	(6,564)

Schedule 3: T&D Capital Allocation Categories





ED = Electric Distribution SSO = Electric Substations S&TO = Electric Transmission



ED = Electric Distribution SSO = Electric Substations S&TO = Electric Transmission

Exhibit_(EIOP-2)

Electric Peak Demand Forecast

Schedule 1: CECONY Network & Radial Feeder 10-Year Independent Summer Peak Demand Forecast (MW)

CECONY Network & Radial Feeder 10-Year Independent Summer Peak Demand Forecast (MW)							
This Exhibit only includes Networks and Radial Feeders driving specfic Load Relief, NWS, and major Capital investments.							
Area Type	**Area Station**	**Network/Radial**	**Region**	**2022**	**2026**	**2031**	**10-Year CAGR**
Network	Brownsville 1	Crown Heights	Brooklyn	207	222	236	1.6%
Network	Water Street	Prospect Park	Brooklyn	62	65	70	1.5%
Network	Brownsville 2	Richmond Hill	Brooklyn	317	347	384	2.0%
Network	Brownsville 1	Ridgewood	Brooklyn	219	232	249	1.5%
Network	Water Street	Williamsburg	Brooklyn	324	353	388	2.3%
Network	West 42^{nd} Street	Pennsylvania	Manhattan	184	261	281	6.7%
Network	Parkview	Triboro	Manhattan	141	183	199	4.0%
Network	Hellgate	Yorkville	Manhattan	275	288	301	1.1%
Network	Newtown	Borden	Queens	123	156	179	4.7%
Network	Jamaica	Jamaica	Queens	436	491	531	2.0%
Network	Glendale	Maspeth	Queens	247	264	289	1.7%
Network	Newtown	Sunnyside	Queens	76	83	88	1.8%
Radial	Brownsville 2*	Brownsville 2*	Brooklyn	34	29	30	-1.3%
Radial	Sunnyside Radial	Sunnyside Radial	Queens	17	20	24	7.3%
*The forecast for Brownsville 2 includes a planned Load Transfer and reduces the forecasted growth.							

Schedule 2: Brownsville 1 & 2 - Changes Between 2021 & 2020 Summer Peak Demand Forecasts (MW)

Brownsville 1 & 2 - Changes Between 2021 & 2020 Summer Peak Demand Forecasts (MW)**
Values are Cumulative

Year of Forecast	Weather Adjusted Peak	New Business	Electric Vehicles	Electrification of Gas Appliances	COVID Adjustment	Programmatic Energy Efficiency	Organic Energy Efficiency	Other Load Modifiers*
Year 1	-14	1	1	0	0	4	2	-4
Year 2	0	15	3	0	2	8	3	-3
Year 3	0	19	4	1	3	14	4	-8
Year 4	0	17	4	2	3	20	5	-8
Year 5	0	16	5	3	3	28	5	-8
Year 6	0	16	5	5	3	29	6	-8
Year 7	0	18	7	7	3	30	6	-8
Year 8	0	19	10	11	3	30	6	-8
Year 9	0	20	12	15	3	30	7	-8
Year 10	0	21	15	21	3	30	7	-9

*Other Load Modifiers include distributed energy storage, distributed generation, demand response, and conservation voltage optimization. Adjustments for Climate Change and Load Transfers are also included.

**The Brownsville 1 & 2 Area Stations = Crown Heights Network, Ridgewood Network, Richmond Hill Network; and Radial Feeders 9B91, 9B92, 9B93, and 9B94

Exhibit_(EIOP-3)

T&D Risk Reduction

Schedule 1: T&D Risk Reduction Capital Program and Project Summary

Electric T&D *Risk Reduction*		**Year Total Current Budget Total Dollars ($000)**			
		RY1	**RY2**	**RY3**	**3 Yr. Total**
RISK REDUCTION					
Organization	**White Paper**				
Distribution	4kV USS Switchgear House Replacement	13,227	13,227	13,227	39,682
Substations	138kV Disturbance Monitoring Program	4,800	4,800	4,800	14,400
Substations	Area Substation Phased Replacement Program	30,000	30,000	30,000	90,000
Substations	Area Substation Reliability	11,500	11,500	11,500	34,500
Substations	Auxiliary Station Equipment Program	1,100	1,100	1,100	3,300
Substations	Category Alarm Program - Various	2,250	2,078	2,156	6,484
Substations	Circuit Switcher Replacement Program	1,400	1,400	1,400	4,200
Substations	Condition Based Monitoring Program	1,500	15,000	15,000	31,500
Substations	Control Cable Upgrade Program	-	4,000	4,000	8,000
Distribution	Critical Facilities Program	9,000	9,000	9,000	27,000
Substations	DC System Upgrade Program	5,100	5,100	5,100	15,300
Substations	Disconnect Switch Capital Upgrade Program	5,175	5,175	5,175	15,525
Transmission	Distribution Order Enhancements	300	300	400	1,000
Transmission	Dynamic Feeder Rating System	1,000	1,500	1,500	4,000
Substations	East River Automation - Upgrade the 69kV Yard	3,000	-	-	3,000
Transmission	EMS DevOps Upgrade	2,492	2,492	3,264	8,248
Substations	Erosion Protection and Drainage Upgrade Program	-	5,000	5,000	10,000
Transmission	Feeder 38R51 and 38R52 Replacement Project	122,000	-	-	122,000
Transmission	Feeder Replacement Program	2,500	3,500	3,500	9,500
Substations	Fire Suppression System Upgrades Program	12,140	12,406	12,273	36,819
Substations	Gas Insulated Substation Replacement Program	13,000	28,500	28,500	70,000
Substations	High Voltage Circuit Breaker Capital Upgrade Program	25,400	23,400	24,800	73,600
Substations	High Voltage Test Set Program	2,800	2,800	2,800	8,400
Transmission	Joint Replacement Program	10,500	13,000	13,000	36,500
Distribution	Non-Network Reliability	73,550	87,061	87,061	247,672
Distribution	Non-Network Resiliency with FLISR	2,100	2,100	2,100	6,300
Substations	Other Capital Equipment Upgrades Program	3,485	3,485	3,485	10,455
Transmission	Overhead Insulator Resiliency Program	6,700	6,700	6,700	20,100
Transmission	Overhead Transmission Structures Program	3,000	3,000	3,000	9,000
Distribution	Pole Inspection and Treatment (PIT) Program	2,333	2,333	2,333	6,999
Substations	Pothead Pressure Alarms Program	150	150	150	450
Distribution	Pressure, Temperature and Oil Sensors	2,000	2,000	2,000	6,000
Distribution	Primary Feeder Reliability	75,500	77,000	78,545	231,045
Substations	Protection, Control and Automation Program	38,500	33,500	20,000	92,000
Substations	Pumping Plant Improvement Program	4,800	3,900	3,900	12,600
Transmission	Queensboro Bridge Risk Mitigation	20,000	80,000	80,000	180,000
Substations	Reinforced Ground Grid Program	6,100	6,100	6,100	18,300
Substations	Relay Modifications Program	78,352	89,852	76,352	244,556
Substations	Relay Protection Communications Upgrade Program	16,500	16,500	16,500	49,500
Distribution	Remote Monitoring System	3,222	3,222	3,222	9,666
Transmission	Replacement of Feeders M51 and M52	-	-	10,000	10,000
Substations	Retrofit Overduty 13kV and 27kV Circuit Breaker Program	13,800	13,800	13,800	41,400
Transmission	Right of Way Roadway Access	1,000	1,000	1,000	3,000
Substations	Roof Replacement Program	4,800	4,800	4,800	14,400
Substations	RTU Upgrade Program	2,510	2,510	2,510	7,530
Distribution	Selective Undergrounding	60,000	80,000	100,000	240,000
Distribution	Shunt Reactor	5,000	5,000	5,000	15,000
Distribution	Smart Sensors	15,100	15,100	15,100	45,300
Substations	Stabilization of Pothead Stand Supports/Settlement	2,500	2,500	2,500	7,500
Substations	Structural and Infrastructure Upgrades Program	6,700	14,400	14,400	35,500
Substations	Substation Enclosure Upgrade Program	1,900	1,900	1,900	5,700
Substations	Substation Loss Contingency - Rapid Recovery of an Area Substation/Transmission Resiliency Transformers	4,000	-	-	4,000
Substations	Substation Transformer Replacement Program	124,000	124,000	124,000	372,000
Transmission	System Operations Enhancements	400	400	500	1,300
Distribution	Transformer Vault and Structures Modernization	41,103	42,266	43,465	126,834
Substations	Transmission Station Metering and SCADA Upgrades Program	3,182	3,066	3,066	9,314
Distribution	Underground Secondary Reliability Program	25,483	25,752	29,714	80,949
Distribution	Unit Substation Modernization	638	638	638	1,915
Distribution	Unit Substation Transformer Replacement Program	3,902	3,902	3,902	11,705
Distribution	Unit Substation Upgrade and Improvement	1,000	1,000	1,000	3,000
Substations	Upgrade Light and Power System Program	1,000	1,000	1,000	3,000
Distribution	USS Switchgear Flood Protection	8,466	8,466	8,466	25,398
Substations	U-Type Bushing Replacement Program	5,600	5,100	4,400	15,100
Distribution	Wainwright - Willowbrook Stepdown Transformer Installations	8,520	1,000	-	9,520
TOTAL ELECTRIC					
	Total Risk Reduction	**957,080**	**969,781**	**980,104**	**2,906,965**

Schedule 2: T&D Risk Reduction O&M Program Change Summary

Infrastructure Investment Panel
O&M Program Changes
EIOP - Risk Reduction
($000)

		RY1 Program Change	RY2 Program Change	RY3 Program Change
RISK REDUCTION				
Organization	**Program Change**			
Distribution	Emergency Response	3,522	-	-
Distribution	Line Clearance/Vegetation Management Program	2,819	368	375
Distribution	Safety Inspection Program	7,487	945	(11,403)
TOTAL ELECTRIC				
	Total Risk Reduction	**13,828**	**1,313**	**(11,028)**

Schedule 3:

T&D Capital and O&M White Papers

Risk Reduction

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☐ Project ☒ Program	**Category: ☒ Capital ☐ O&M**
Work Plan Category: ☐ Regulatory Mandated ☒ Operationally Required ☐ Strategic	
Project/Program Title: 4 kV USS Switchgear House Replacement	
Project/Program Manager: Colin Ramjohn	**Project/Program Number (Level 1): PR.9ES0501 10036283**
Status: ☐ Planning ☐ Design ☐ Engineering ☐ Construction ☒ Ongoing ☐ Other: ____________	
Estimated Start Date:	**Estimated Date In Service:**
A. Total Funding Request ($000) **Capital: $59,280** **O&M:** **Retirement:**	**B.** **☐ 5-Year Gross Cost Savings ($000)** **☐ 5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:
This program will replace aging and deteriorating unit substation switchgear houses with new selected switchgear houses in their entirety. The new switchgear house includes switchgear compartments, circuit breakers, protective relays, batteries, automatic transfer switch (ATS), instrument transformers and SCADA equipment. Existing circuit breakers will be upgraded to vacuum circuit breakers. Existing relays will be upgraded to microprocessor relays.
There are 237 unit/multibank substation switchgear houses in the Con Edison non-network system. Their ages range from 1-73 years old with an average age of 54 years.

Current plans are to purchase and install six switchgear houses annually.

This program also includes replacement of the unit substation batteries, which is critical to the performance of the system protection functions. Presently, USS batteries experience a failure rate of approximately 2%.

Justification Summary:
Structural members of switchgear houses have deteriorated due to aging and environmental conditions. These factors have resulted in circuit breakers that do not fit into their cubicles properly. In many instances, pinch bars are used to force the breakers into the cubicles. Forcible insertion or removal of a circuit breaker into or out of its cubicle due to structural degradation often requires de-energization of the unit substation's 4 kV bus and all feeders. This typically results in a delay in station availability of two or three days.

Rather than attempt to repair the structural problems, this program funds complete replacement of switchgear houses. Spare parts for most of the existing switchgear components are unavailable as many of the original equipment manufacturers are either no longer in business or no longer supply replacement parts.

In addition to the structural problems noted, problems are being experienced with circuit breaker components. Close/trip coils and auxiliary switches have an unacceptably high failure rate (on average 19 failures per year among the older circuit breakers). Rachet pins, which are utilized in the spring charging mechanism on the older General Electric circuit breakers, fail and are replaced 60 times per year across the system on average. The average time required to repair one of these failed components is between 16 and 32 man-hours. Many spare components (diode/resistor boards, hickory rods, rachet pins) must be fabricated in company machine shops since many of them are no longer available from manufacturers, and the spare inventory from old, decommissioned circuit breakers has been depleted.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

The 4kV USS Switchgear House Replacement program ensures the reliability of those 4kV Unit Substations by proactive replacement of potentially failure-prone switchgear house components. The replacement of failure-prone components is prioritized by a health index, which, as explained in the ELRP, is a single number that expresses asset health in terms of both its probability of failure and the impact of such failure. For the 4kV USS Switchgear House Replacement program, the prioritization is done based on each switchgear house's previous history of maintenance, age, and other relevant factors.

The 4KV grid design provides significant redundancies to minimize customer outages within. In order to achieve this all switchgear in this system must be maintained in good working condition. Breaker failures often do not result in customer outages, due to the resilient design of the system. However, failures can and have resulted in the loss of the entire unit substation which result in customer outages. The 4KV grids offer operational options that help mitigate the risk of Network Shutdown, an Enterprise Risk, through radialization, preventing cascading failures causing the collapse of the grid, and in the most extreme case isolation of the grid. Failures in the 4KV grid that result in outages impact the Electric Operations department risks associated with Regulatory Penalties, as they could trigger the Major Outage RPM, and could contribute to triggers for the SAIFI and/or CAIDI RPMs.

2. Supplemental Information

Alternatives:
Continue to operate and maintain the existing deteriorating switchgear houses. However, as described above, cases of misalignment of circuit breakers and switchgear cubicles result in higher operating and maintenance costs. The older air magnetic circuit breaker technology used in these switchgear houses is less reliable and more costly to maintain than current technology.

There are some limited cases where it may be possible to upgrade the circuit breakers, protective relays and other components individually, if the overall condition of the switchgear house is deemed structurally sound. However, the cost to upgrade individual components of a switchgear house will exceed the cost of a new switchgear house altogether. An example of this was the Sommer Place #2 feeder breaker upgrade. Costs for this upgrade are summarized in the table below with appropriate escalation to show present worth values:

Item Cost
Feeder breaker upgrades: $94,000
Labor (testing, equipment group, etc.) $187,000
Relay upgrades $408,000
Total $689,000

Despite the new equipment installed, this upgrade retained the existing battery, the 40 plus year old switchgear house and the original "bank circuit breaker".

Alternative 1 description and reason for rejection
Replace the switchgear houses at the rate of 4 per year and assume that the older switchgear houses 60 years and above are selected for replacement. Then the average age would remain at 54 years. This is beyond the average life expectancy for electrical equipment.

Alternative 2 description and reason for rejection

Alternative 3 description and reason for rejection

Risk of No Action:
Failure to implement these switchgear house replacements will cause a rise in the overall failure rate due to continued rusting, corrosion and deterioration. This will result in lower reliability due to equipment failure and higher operating, maintenance, and restoration costs.

Risk 1

If the units are allowed to deteriorate and age at the current rate, failures are projected to rise to almost double in 20 years, and average age goes up by one year per year (20 in 20 years)

Risk 2
If the oldest, switchgear houses (60 years old or more) are replaced at the rate of 6 per year, the average age should decrease slightly from the current average age of approximately 54 years:

Risk 3
If we were to replace less than four per year, then the average age will continue to increase and ultimately we may be forced to drastically increase the number of replacements annually in order to improve the average age and system reliability.

Non-Financial Benefits

Some of the older switchgear houses have asbestos-containing wire insulation requiring special precautions which increase maintenance costs. For example, Westinghouse circuit breakers contain "Rockbestos" control wiring which are (Asbestos Contain Material) ACMs. There are 53 Westinghouse units among the 237 switchgear houses. In addition, the arc chutes of certain circuit breakers such as Allis Chalmers also contain asbestos. There are 30 Allis Chalmers circuit breakers among the 239 switchgear houses. When abatement is required during the repair of switchgear or circuit breakers, the repair time increases an average of 30%. The new switchgear houses do not contain asbestos and thus maintenance will be less complex and require less time, saving operating costs.

The new switchgear houses are free of known environmentally unfriendly components.
Some additional features of the new switchgear houses include microprocessor-based "smart protective relays" that better protect the switchgear and feeders and provide expansion capability for smart grid technologies, an indoor climate-controlled environment which would extend the life expectancy of components and a covered aisle which will provide a safe and efficient working environment for maintenance personnel.

Additionally, with the replacements of the old switchgear houses, system reliability will improve thus improving customer satisfaction.

Summary of Financial Benefits and Costs (attach backup)

New switchgear requires less frequent maintenance and has fewer parts to maintain resulting in lower maintenance costs over its lifetime. The projected maintenance expenditures for all 4 kV unit substation switchgear houses for 2021 is $ 4.3M. This is a 14% decrease over the 2020 maintenance expenditure of $5.0M for 4 kV switchgear houses.

As a result of the structural and component problems outlined, periodic maintenance inspections for the older air circuit breakers (ACB) are twice as frequent and twice as costly as compared to the newer vacuum circuit breakers (VCB) employed in new switchgear houses. Since vacuum breaker contacts operate in a vacuum which results in reduced wear on the contacts when the breaker operates, the inspection cycle for most vacuum breakers is six years; the inspection cycle for air circuit breakers is three years. Less frequent inspections for vacuum circuit breakers results in a 50% lower inspection cost as compared to air circuit breakers.

1. Cost-benefit analysis (if required)

2. Major financial benefits

3. Total cost

4. Basis for estimate

5. Conclusion

Project Risks and Mitigation Plan

Risk 1
USS Switchgear prioritized for replacement fail prior to scheduled replacement.

Mitigation plan
Replacements are scheduled based on priority determined by calculating the Health Index. The plan identifies the equipment that is in need of replacement and establishes a schedule to make replacements at a rate that minimizes the likelihood of in-service failures.

Technical Evaluation / Analysis

The Company began utilizing a model/matrix in 2016 to calculate a health index for its unit substation switchgear houses. Based upon that model/matrix, units that have a score outside of the target are recommended for replacement. A unit substation switchgear house with a health index score above the goal runs the risk of an in-service mis-operation that would lead to extended repair and having that breaker/feeder out of service for an extended time compromising reliability. There are currently 20 unit substation switchgear houses that are recommended for replacement based upon their health index score. The model/matrix utilizes the following factors in its health index calculation:

- Age
- Reliability
- Maintenance expenditure
- Asbestos/lead cables
- Number of feeders
- Loading
- Field personnel recommendation
- Field inspection frequency
- Status of equipment upgrades
- Physical condition
- Flood susceptibility
- Safety

Based on the switchgear house asset health index, the following switchgear houses have been recommended or replacements in the specified years.

Replacement Year/ Unit Substation

2023
Glen Oaks
Oakland
Arlington #4
Clearview #1
Howard Beach
Ralph Ave #1

2024
Centerville
Cunningham West
Silver Lake #1
Clearview #2
Fort Totten
Utica Ave

2025
Ralph Ave #2
Chisolm
Willowbrook #1
Floral Park #2
Whitestone East
Rosedale

2026 Alley Park Little Neck Floral Park #1 Dongan Hills East 86th St. Union
Project Relationships (if applicable) USS Transformer Replacement Program Unit Substation Load Relief USS Feeder Breaker Replacement USS Life Extension Program USS Protection and Feeders Relay Upgrade Program USS Site Improvement for SPCC Plans

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Projected 2021
Capital					**6,000**
O&M*					
Retirement					

Total Request ($000): $49,708

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**6,000**	**13,227**	**13,227**	**13,227**	**13,526**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	1,092	2,418	2,418	2,418	2,462
M&S	2,290	5,049	5,049	5,049	5,162
Contract Services	1,207	2,661	2,661	2,661	2,721
Other	242	534	534	534	546
Overheads	1,169	2,565	2,565	2,565	2,635
Subtotal	**6,000**	**13,227**	**13,227**	**13,227**	**13,526**
Contingency**					
Total	**6,000**	**13,227**	**13,227**	**13,227**	**13,526**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Central Operations/ Substation Operations
2022

1. Project / Program Summary

<table>
<tr><td>Type: ☐ Project ☒ Program</td><td>Category: ☒ Capital ☐ O&M</td></tr>
<tr><td colspan="2">Work Plan Category: ☒ Regulatory Mandated ☐ Operationally Required ☐ Strategic</td></tr>
<tr><td colspan="2">Project/Program Title: 138kV Disturbance Monitoring Program.</td></tr>
<tr><td>Project/Program Manager: John Penza</td><td>Project/Program Number (Level 1): PR.20223866</td></tr>
<tr><td colspan="2">Status: ☐ Planning ☐ Design ☐ Engineering ☐ Construction ☒ Ongoing ☐ Other: ___________</td></tr>
<tr><td>Estimated Start Date: Ongoing</td><td>Estimated Date in Service: Ongoing</td></tr>
<tr><td>A. Total Funding Request ($000)
Capital: $21,400
O&M:
Retirement:</td><td>B.
☐ 5-Year Gross Cost Savings ($000)
☐ 5-Year Gross Cost Avoidance ($000)
O&M:
Capital:</td></tr>
<tr><td>C. 5-Year Ongoing Maintenance Expense ($000)
O&M:
Capital:</td><td>D. Investment Payback Period:
(Years/months)</td></tr>
</table>

Work Description:

This program will increase the amount of Disturbance Monitoring Equipment (DME) deployed throughout the Con Edison 138kV transmission system by installing dedicated DME. This program will also leverage technology to deploy an Automated Substation Control System (ASCS) at each of the 138kV substations to assist in the continuous improvement of operation and controls. This improvement would be achieved through continuous monitoring and analysis of the power system, ensuring a more reliable and robust system. The system would help document and record all system event chronology as well as all impacted relays and equipment. This program will primarily focus on protective relay operations, asset health and indexing, monitoring of protective relay alarms and by generating reports and trends for engineering analysis.

The automatic collection of microprocessor event files will be used for the following functionality:

- Disturbance Monitoring
- Relay Health Monitoring
- Equipment Asset Health Monitoring
- Relay System Maintenance and Testing

The ASCS is a system that includes the DME which is a device capable of recording and monitoring power system data pertaining to system disturbances, and includes digital fault recording (DFR), sequence of event recording (SER), and dynamic disturbance recording (DDR).

The ASCS is required for post incident analysis and fault reporting. It will be the major tool used to analyze system events and take corrective actions. Based on analysis done, fourteen 138 kV transmission substations were required to have DMEs installed based on a high fault level on these stations (greater than 20% of the median per North American Reliability Corporation (NERC) guidelines. We prioritize by Operational Need (Strategical).

The following 12 transmission substations are scheduled for 2022-2026:

- Astoria East 138kV DME
- Hudson Ave. 138kV DME
- Dunwoodie North 138kV DME
- Buchanan 138kV DME
- Fresh Kills 138kV DME
- Tremont 138kV DME
- Sprainbrook FEEDER Y49 DME
- Eastview 138kV DME
- Vernon 138kV DME
- Queensbridge 138kV DME
- Jamaica 138kV DME
- Hellgate 138kV DME

Justification Summary:
Installation of the ASCS on our 138kV system will provide operational and analytical benefits that have proven to be instrumental in the analysis of previous Con Edison system events. If DMEs are not available, it will be extremely difficult and time consuming to analyze the system events and it will cause delay in restoring the transmission system after a fault.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
This program impacts the SSO Risk of Loss of substation. This program reduces the likelihood of losing a substation by increasing the amount of DME. This program will also leverage technology to deploy an ASCS at each of the 138kV substations to assist in the continuous improvement of operation and controls detecting relay mis-operation that can affect the reliability of the electric system and possibly result in the loss of load as well as allows for quicker restoration times and reduces the likelihood that overlapping trip outs will lead to the loss of a substation.

2. Supplemental Information

Alternatives
There are no specific alternatives to DMEs but some limited DME function can be provided by Microprocessor relays in the system. However, in our transmission system, most of the 138kV transmission stations have electromechanical relays which do not have this capability. Also, it will be difficult and time consuming to get this data from the microprocessor relays as these cannot be accessed remotely due to cybersecurity concerns.

Risk of No Action
No action would lead to continued difficulty in monitoring and analyzing electrical disturbances which occur on the 138kV portion of the Bulk Electric System.

Non-Financial Benefits
This program will increase Con Edison's ability to analyze system disturbances, post event analysis, determine root causes of incorrect relay operations, and validate dynamic models of power system equipment.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis: N/A

2. Major financial benefits
This program will increase Con Edison's ability to analyze system disturbances, post event analysis, determine root causes of incorrect relay operations, and validate dynamic models of power system equipment.
3. Total cost **$21,400**

4. Basis for estimate:

The funding request for this program is based on the historical average of $1.8M per location and 3 locations per year.

5. Conclusion: N/A

Project Risks and Mitigation Plan

Risk 1: Outage scheduling conflicts with other initiatives.

Mitigation: Outages to be coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs to avoid conflict with other program/ projects resulting in a more predictable budget and manageable outage scheduling.

Risk 2: Delays due resources support coordination.

Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Risk 3: **Lack of alignment between resources support and outages.**
Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction to avoid alignment conflicts with outages.

Technical Evaluation / Analysis: Controls Systems Engineering performed a study of all the 138kV buses and determined buses needed for sequence of events recording and digital fault recording. replacement of the 69 kV breaker failure relays and the primary relay protection systems, which is part of this project.

Project Relationships (if applicable) N/A

3. Funding Detail

Historical Spend

	Actual 2017	**Actual 2018**	**Actual 2019**	**Actual 2020**	**Historic Year** (O&M only)	**Forecast 2021**
Capital	$2,590	$1,283	$12	$8		$749
O&M						
Retirement	0	$35	0	0		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**$2,500**	**$4,800**	**$4,800**	**$4,800**	**$4,500**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	868	1,680	1,681	1,682	1,587
M&S	0	0	0	0	0
Contract Services	825	1,579	1,579	1,579	1,481
Other	0	0	0	0	0
Overheads	807	1,541	1,540	1,539	1,433
Subtotal					
Total	**$2,500**	**$4,800**	**$4,800**	**$4,800**	**$4,500**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations/ Substation Operations
2022

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Area Substation Phased Replacement Program	
Project/Program Manager: Brian Brush	**Project/Program Number (Level 1): PR.23287740**
Status: ☒ **Planning** ☐ **Design** ☒ **Engineering** ☐ **Construction** ☐ **Ongoing** ☐ **Other: ___________**	
Estimated Start Date: Ongoing	**Estimated Date in Service: Ongoing**
A. Total Funding Request ($000) **Capital: $131,000** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period:** **(Years/months)**

Work Description:
This program will replace 13kV, 27kV or 33kV (medium voltage) equipment at various area substations based on condition assessments. The scope of the program may also include civil work associated with the switchgear, direct current (DC) control cable system replacements and the addition of automation packages for overall station control. The scope of individual projects under this program will be evaluated along with other capital programs, such as 13/27kV Breaker Retrofits, to leverage outage and construction synergies. Through assessments of medium voltage equipment, switchgear housing condition, and DC control cable failures at various area substations, E63rd Street and Plymouth street Substations have been prioritized under the program. Area substation locations beyond E63rd Street Substation and Plymouth will be evaluated for similar projects in the future. Engineering and procurement for this program will begin in 2022 and construction will begin in 2023. Due to the complexity of the outage requirements for the East 63rd Street project, construction is expected to continue beyond 2025.

Justification Summary:
The Company typically approaches equipment upgrades in substations at the asset level, through the use of capital programs. This programmatic approach to equipment replacement provides an effective means of managing asset classes at a fleet level while addressing replacement needs at the station level. Under most circumstances this is the most efficient way to maintain the reliability of an individual station. Some substations, due to overall station health, are in need of an approach that is more holistic than the programmatic approach in order to maintain system reliability standards. An assessment of power carrying auxiliary and structural equipment at a group of area substations has determined that certain locations require capital investment beyond the scope of existing capital programs.

Medium voltage switchgear is the fundamental power carrying component of an area substation. To maintain a reliable distribution system, it is essential to have substation breakers, bus, switches, and metal clad housing in good working order. The longer a substation is exposed to seasonal extremes, the increased likelihood that the equipment is subject to water intrusion, corrosion, and subsequent reliability concerns. Medium voltage switchgear and metal clad housing at some of Con Edison's outdoor area substations have degraded over 40-60 years of service. Historically, the Company has made repairs to metal clad switchgear and attempted to install newer sealing technologies to combat weather related degradation. This strategy has been effective with some locations but, even where effective, does not address the actual switchgear. The Area Substation Phased Replacement Program will replace medium voltage switchgear and metal clad housing at locations that are beyond improvement through corrective maintenance.

DC control and instrumentation systems provide remote operability of power carrying equipment, metering, and component status indication to operators. A control cable and indication system that is built of copper circuits must be free of corrosion and grounds to provide remote operability. When insulation on these lines degrade and grounds persist, it is labor intensive to locate failures and there is a risk that proper instrumentation and control will be lost. During high load periods or contingency conditions, the impact a DC ground on a control cable has on feeder restoration times can be significant. When equipment status indication is unknown due to DC grounds on the station mimic circuitry, the uncertainty brings a risk to operations locally at the substation and remotely at the Energy Control Center (ECC). This program will prioritize the upgrade of copper ground prone control cable systems with networks primarily constructed of fiber optic cables. The program will also replace copper-based mimic boards with automation packages. These upgrades will eliminate troubleshooting, provide operators better indications, and help to improve the reliability of area substations.

The civil structures that house metal clad switchgear and control cable systems provide environmental protection for the equipment and help operators to perform switching in a safe environment. When exposed to outdoor conditions, civil structures degrade, allowing water intrusion to electrical equipment and the un-evening of surfaces. Water intrusion can lead to corrosion and failure of electrical equipment. Uneven walkways and surfaces can make safe breaker racking and other switching moves more labor intensive for operators. The added labor resource required to conduct these operations safely can present a reliability risk during contingency or high load periods. This program will make civil upgrades to walkways and structures in conjunction with switchgear replacement and control cable upgrades.

To maintain individual locations, it is important to look beyond individual asset health and recognize conditions that present a systemic risk to the reliability of the substation. Degradation of individual assets can be addressed with corrective maintenance and or capital upgrade programs. When a substation is exhibiting degradation across multiple, interrelated systems, there is a greater reliability risk.

A comprehensive assessment of a substation is an essential part of recognizing overlapping risks and deriving a holistic approach to equipment renewal at the station. This program will prioritize capital projects at area substations that need switchgear replacement, control and indication upgrades and civil improvements. This top to bottom approach will improve the reliability of the candidate stations and complete the upgrades in the most efficient manner.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):

This program addresses the Substation Operations departmental risk "Equipment Failures increasing reliability of equipment and facilities, eliminating possible inadvertent trips including outages to equipment and customers, and reduced personal safety hazards with relationship to equipment failure causing property damage and/or injuries to the public in the immediate vicinity of the substation

Climate Change and Resiliency:
Also, program focus on increasing the flooding protection with focus on changing average climate and increasing severity/frequency of extreme weather events /major storm.

2. Supplemental Information

Alternatives
o Repair civil structures, metal clad switchgear and DC control cable systems. This alternative is viable at locations in need of a small volume of repairs. At locations where environmental conditions have combined with vulnerabilities of older technology, a more comprehensive approach is needed to combat systemic risks.
o Replacement of metal clad switchgear, DC control cable, automation installation and civil upgrades will reduce the overall reliability risk at the station.

Risk of No Action
If no action is taken at program targeted area substations, there is a risk that overlapping failures of power carrying and/or control systems will result in customer outages.

Non-Financial Benefits
This program has reliability and safety benefits. The upgrades made through this program will impact reliability by reducing the risk of customer outages due to overlapping equipment failures. The civil structure improvements made through this program will create a more ergonomic environment for operators to perform electrical switching. Increase the flooding protection with focus on changing average climate and increasing severity/frequency of extreme weather events are affecting our energy infrastructure.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis: N/A

2. Major financial benefits
The new switchgear and control cable replacements will reduce current O&M expenditures at targeted stations.

3. Total cost **$131,000**

4. Basis for estimate: The annual funding for this program is based on projects for two substations per year at a cost of approximately $15M per substation. The $15M is the approximate cost to replace one medium voltage bus section per year.
5. Conclusion: N/A

Project Risks and Mitigation Plan
Project Risks:
Risk 1: Outage scheduling conflicts with other initiatives.

Mitigation: Outages to be coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs to avoid conflict with other program/ projects resulting in a more predictable budget and manageable outage scheduling.

Risk 2: Delays due resources support coordination.

Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Risk 3: Lack of alignment between resources support and outages.
Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor and construction to avoid alignment conflicts with outages.

Technical Evaluation / Analysis:
The priority for this program was established through analysis of labor hours associated with troubleshooting DC grounds, civil inspections/assessments and feeder processing hours and considerations.

Project Relationships (if applicable)
The upgrade project at East 63rd Street will reuse the medium voltage breakers installed on PN20233-00 as part of the 13kV/27kV Breaker Retrofits Program.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	0	0	0	0		474
O&M						
Retirement	0	0	0	0		0

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**$11,000**	**$30,000**	**$30,000**	**$30,000**	**$30,000**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	1,320	3,600	3,600	3,600	3,600
M&S	1,320	3,600	3,600	3,600	3,600
Contract Services	5,403	14,782	14,786	14,791	14,836
Other	220	600	600	600	600
Overheads	2,737	7,418	7,414	7,409	7,364
Subtotal					
Total	**$11,000**	**$30,000**	**$30,000**	**$30,000**	**$30,000**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations/ Substation Operations
2022

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☒ **Regulatory Mandated** ☐ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Area Substation Reliability	
Project/Program Manager: Jim Neilis	**Project/Program Number (Level 1): PR.2ES8500 / 10030249**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other: ___________**	
Estimated Start Date: N/A	**Estimated Date in Service: N/A**
A. Total Funding Request ($000) **Capital: $59,000** **O&M:** **Retirement: $10,000**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:
This program provides for the installation of high side switching circuits in the substation transformer vaults to provide for redundant clearing. The high side switching circuits shall consist of a circuit switcher and /or an interrupter. Digital Transfer Trip (DTT) could be substituted for one or both switching devices where installation is impossible due to space limitations.

After the August 3, 1990 Seaport area substation fire, Con Edison modified substation designs to provide more reliable high-speed clearings of transformer secondary faults and reduce the possibility of loss of the area substations during a protracted fault incident. This program provides for the installation of two independent lines of protracted fault protection with electrical and physical separation for the area station transformers. The first line of protection is provided by the installation of a circuit switcher, which is tripped by normal primary protection. The second line of protection is provided by an interrupter, which is tripped by a separate and independent back-up protracted fault protection system located in the transformer vault. If space is limited, then the second line of protection can be provided by a transfer trip relay scheme.

The Auto Ground Switch ("AGS") retirement program has been combined with this reliability program because the AGS can only be retired when either a circuit switcher or transfer trip relay scheme is installed. Where feasible, the retirement of the AGS will be performed simultaneously.

Of the remaining 134 transformers that need to be addressed, fifty-four (54) vaults can accommodate a local high side clearing device (original scope). Due to space limitations and bus-work design, the remaining eighty (80) vaults will be designed with two lines of DTT with a motor operated disconnect or removable flexible link (modified scope).

Substation Reliability Program High Level Status								
Item	Substations	No. of Substations	No. of Transformers (Plan)	No. of Transformers with Two Means of High Side Clearing Devices (2017)	Engineering Phase	Procurement Phase (Long Lead Equipment)	Construction Phase	Estimated Completion Date
1	W65 No.1 and No.2	2	10	0	90%	100%	0%	2023
2	Cherry Street	1	2	0	0%	0%	0%	2022
12	E63rd No.1 and No.2	2	14	0	0%	0%	0%	2024
13	Bruckner	1	5	0	0%	0%	0%	2022
14	Buchanan	1	3	0	0%	0%	0%	2024
16	Parkchester No.1	1	4	0	0%	0%	0%	2027
17	Avenue A	1	5	0	0%	0%	0%	2027
18	West 19 Street	1	5	0	0%	0%	0%	2027
19	Elmsford No. 2	1	4	0	0%	0%	0%	2024

Justification Summary:

Con Edison initially developed a single-mode failure concept to prevent extensive damage and station shutdown from a sustained 13kV fault. The concept includes the addition of an independent line of protracted fault protection, installation of a 138 kV transformer circuit switcher and interrupter, the provision for control cable system route separation, separate direct current (DC) supply systems, switchgear compartmentalization, and improved fire rated design. The design concept changed in 1991 after some substations had been designed and constructed. Upgrading existing area substations to meet the present design concept will reduce the possibility of loss of the area substation during a protracted fault incident. Also, as part of this program Con Edison will look to retire the AGS where feasible.

Con Edison determined that this program offers tremendous value, either through a local high side clearing device (original scope) or two lines of DTT and a motor operated disconnect or removable flexible link (modified scope). In addition to the Seaport type incident protection, these designs allow for faster fault clearing and switching capabilities, which increases operational reliability. The Company evaluated this program in late 2010 /early 2011 and at that time, 134 transformers needed to be addressed to meet the 1991 recommendation. Fifty-four of these transformers were in vaults that have sufficient space to accommodate a local high side clearing device. In these locations, Con Edison will pursue the original program work. Due to space limitations and bus work design, the Company will implement a modified scope with two lines of DTT and either a motor operated disconnect or removable flexible link in the remaining eighty vaults.

Con Edison's proposed revision to the original scope of work It was determined that the revised plan was a reasonable alternative considering both space constraints and newly available technology.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):

This program addresses the Substation Operations risks "Equipment Failures" and "Loss of a Substation". High side clearing and/or DTT reduce the likelihood of a protracted fault on an area substation bus. A protracted fault can lead to further equipment failures and possibly the loss of an area substation.

The Company has a plan to install DTT or high side clearing at all area substations. The removal of AGSs, as part of the program, improves the recovery time following trip outs (because an AGS has to be reset). The remote operability that DTT provides, as compared to an AGS, improves the company's recovery time and is part of its climate change adaptation strategy.

2. Supplemental Information

Alternatives

- Do nothing: Given the 1991 commitment to complete this program, this would no longer be a viable alternative.

Risk of No Action
No action would increase the likelihood of a sustained fault on a bus, which can result in extensive damage and the shutdown of an area substation.

Non-Financial Benefits
As noted previously, this program increases overall system reliability and reduces the potential for equipment and facility damage in the event of a protracted equipment fault.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis: N/A

2. Major financial benefits
N/A

3. Total cost **$59,000**

4. Basis for estimate: The annual funding request is based on the average annual expenditures of the last 5 years.
5. Conclusion: N/A

Project Risks and Mitigation Plan
Risk 1: Outage scheduling conflicts with other initiatives.

Mitigation: Outages to be coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs to avoid conflict with other program/ projects resulting in a more predictable budget and manageable outage scheduling.

Risk 2: Delays due resources support coordination.

Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Risk 3: **Lack of alignment between resources support and outages.**
Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor and construction to avoid alignment conflicts with outages.

Technical Evaluation / Analysis: N/A

Project Relationships (if applicable) Installation of new equipment for transformers requires outages of the applicable equipment and is subject to system conditions. Where possible, outages for other projects are combined to maximize overall equipment availability on the system

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	15,324	9,350	12,406	15,333		13,477
O&M						
Retirement	1,109	302	2,365	2,897		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	13,700	11,500	11,500	11,500	10,800
O&M*					
Retirement	2,000	2,000	2,000	2,000	2,000

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	5,696	4,797	4,810	4,815	4,527
M&S	2,192	1,840	1,840	1,840	1,728
Contract Services	478	418	405	402	407
Other	411	345	345	345	324
Overheads	4,923	4,100	4,100	4,098	3,814
Subtotal					
Total	**$13,700**	**$11,500**	**$11,500**	**$11,500**	**$10,800**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations/ Substation Operations
2022

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Auxiliary Station Equipment Program	
Project/Program Manager: Gregory Jimenez	**Project/Program Number (Level 1): PR.22672293**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date: Ongoing	**Estimated Date in Service: Ongoing**
A. Total Funding Request ($000) **Capital: $5,050** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

Work Description:

All substations have critical sections of auxiliary equipment that are required to maintain system reliability, provide accurate feedback for metering/protection, and protect from distressing system transients. These pieces of equipment include coupling capacitor voltage transformers, surge arresters, bushing potential devices, and potential transformers. The ancillary equipment mentioned above has been analyzed on the Con Edison system at the 345kV, 138kV, and 69kV levels. By upgrading these components system reliability will be significantly increased and environmental health and safety improved. This will be accomplished through the Bus Auxiliary Equipment Program using strategic asset replacement approaches.

<u>The objective of this program is as follows:</u>

1. Replace capacitor voltage transformers (CCVT's) and surge arrester's system wide with the potential transformers and bushing potential devices to follow.
2. Upgrade the CCVT's, surge arresters, potential transformers (PT's), and bushing potential devices (BPD's.)
3. Prior to and during labor, all aspects of safety will be assessed and handled accordingly to ensure employee and equipment safety.
4. Increase reliability and accuracy over existing voltage feedback equipment. This will provide relay protection and metering equipment more dependable analog signals.
5. Increase reliability of the system under voltage transients.
6. Increase safety of substation personnel by lowering the potential for high energy faults and contaminated spills.
7. Increase protection of high value primary substation equipment by lowering the potential for high energy faults propagating.

8. Decrease potential for negative environmental impact by upgrading equipment with unfavorable dielectric fluid.

CCVT Replacement Basis:

CCVT's serve as major pieces of substation equipment essential to maintaining proper operation and protection. Some of the conditions that could force CCVT failures are described below.

Failure in any of the high voltage capacitor elements within the capacitor stack C1

- A failure within this section can lead to a catastrophic failure based on the energy associated with these devices
- This can also lead to a percentage of secondary voltage feedback distortions based on the number of shorted capacitors in the circuit

Failure of any of the capacitive elements in the Capacitor 2 grounding stack

- This can lead to a catastrophic failure dependent on connections and voltage conditions
- This can also lead to a percentage of secondary voltage feedback distortions based on the number of shorted capacitors in the circuit

Failure of a voltage transformer or series component for voltage feedback

- This can lead to incorrect voltage response or incorrect phase angle shift

Failure of harmonic suppression filter

- This can lead to distortions in voltage waveforms or create an unexpected phase shift

Weakening or failure of spark gaps

- This can lead to an increased level of wear on the secondary voltage transformers leading to inaccurate secondary voltage readings or an undesired phase shift

Multiple possibilities for mechanical failures including but not limited to

- Gasket failures
- Low oil due to prolonged leaks
- Expansion skin failure between capacitive elements and oil insulation

Under the failure condition that a CCVT ruptures oil will be lost into the surrounding area. Depending on the type of CCVT it can contain levels of Polychlorinated Biphenyls (PCB) this is undesirable from the health and environmental perspective.

Surge Arrester Replacement Basis:

Surge arresters play a pivotal role in the protection and stability of power systems. Conditions described below can prevent metal-oxide varistor and silicon carbide type surge arresters from protecting during voltage transients.

- The most common failures associated with surge arresters can be attributed to moisture ingress. If water intrusion transpires an increase in leakage current and partial discharge can develop leading to over-heating of the arresters and eventually a failure.
- Aging surge arresters can develop an on-going increase in the resistive element which increases the leakage current creating thermal instability of the arrester.
- This dielectric integrity can be compromised due to the following conditions
    - Surge arrester sealing imperfections. Over time the seals will weaken and naturally any flaws from the manufacturing process or installation can develop into areas of concern.

  - Mechanical fractures in varistor elements attributed to thermal runaway from significant current surges.
  - External housing weakening due to pollution which can vary voltage distribution across the petticoat insulation stacks.

Bushing Potential Device Replacement Basis:

Bushing potential devices are a key component to step voltages down to a level where protection relays and metering can safely input them. There are numerous components that are required to enable these devices to function properly. If a problem occurs with one of them the device can give false feedback.

- Common failures associated with bushing potential devices can be related to the lead-in-cable. This cable runs from the capacitance tap on the high voltage bushing to the primary of the main bushing potential device transformer.
  - This cable has 7000VAC+ potential (under transients) with a relatively small amount of insulation. This insulation can breakdown over time or be damaged more easily on units that have had more exposure to harsh conditions and human interference.

2. **Other failures associated with bushing potential devices can be attributed to a failure of internal components.**

Throughout the bushing potential device are multiple transformers and capacitors used to achieve desired voltage output. If one of these components fails it can lead to a dysfunctional device.
This can lead to inaccurate inputs to protection which can trip equipment on incorrect feedback.

Potential Transformer Replacement Basis:

Additionally, potential transformers play a crucial role in substation protection and metering. It is essential to have them functioning in a proper and safe manner.

- A significant number of potential transformers that are on the system have early designs which can increase the potential for failure.
  - These failures can be contributed from multiple factors including excessive voltage transients placed on equipment, excessive heating of potential transformers, or internal winding failures.
  - If a potential transformer fails with a rupture, an oil release will occur. It is crucial to minimize these incidents especially if PCB oil is still existent in the potential transformer. To mitigate these risks upgrades are necessary.

Many of the issues described are more likely to occur with equipment that has been in service for extended periods of time and are reaching their end of life. By upgrading the CCVT's, surge arresters, bushing potential devices, and potential transformers using a strategic asset management program the risk of failures can be minimized.

Justification Summary:

Through the bus auxiliary program, a significant system wide upgrade will be achieved. Over time there is potential degradation of these devices based on the amount of time in service and if the equipment has been subject to a high number of transients. Due to the high energy associated with these pieces of equipment if a failure is to occur a threat is posed to employee safety in addition to high value equipment in proximity physically and electrically. Undertaking this project will lead to an entire transmission system increase of equipment reliability for Con Edison. Progressing with this asset management program will lead to an overall improvement of safety, asset protection, and operational/maintenance efficiency.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
This program mitigates the Substation Operations Departmental Risk of likelihood of Equipment Failures by upgrading critical sections of auxiliary equipment that are required to maintain system reliability, provide accurate feedback for metering/protection, and protect from distressing system transients. By upgrading these components system reliability will be significantly increased and environmental health and safety improved also minimizing the likelihood of the operations risk of Loss of a Substation.

2. Supplemental Information

Alternatives

1. Increase Maintenance and Testing

One of the alternatives would be to increase maintenance and testing of system wide auxiliary equipment. This would require an impractical number of outages and maintenance. Even if a piece of equipment was found defective through this testing it would need to be replaced on the current outage or soon. As an example, to complete one watts-lost test on a surge arrester requires a bus section outage and the arrester to be disconnected from the high voltage connection. To emphasize the magnitude of this there are over 1,000 surge arresters throughout Con Edison transmission stations. The testing for a surge arrester is the least complex and time consuming compared to the other targeted equipment in this program.

Risk of No Action

1. Taking no action in this scenario would be leaving existing high priority substation equipment in place. If no action is taken system reliability could be compromised. With the current maintenance intervals and equipment status over an extended period there is room to miss the signs of approaching failure.
    a. In the case that any of these fail aggressively the fault propagation can negatively impact surrounding in-service equipment.
    b. If feedback signals are skewed there is room for protective relays to operate erroneously.
    c. Hazard can increase to human safety, high value equipment, system reliability, and the environment.

Non-Financial Benefits

1. This program will increase safety for all personnel working in and around transmission substations.
2. This program will increase the reliability of the entire Con Edison power system from transmission level and downstream.
3. This program will increase the system protection by increasing accuracy of bus voltage feedback.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis: N/A

2. Major financial benefits Through the strategic replacement of bus auxiliary equipment there are multiple financial advantages that will be produced.

1. These upgrades will prevent major equipment from being damaged under failure conditions

a. If a failure occurs and a transient is produced the lifespan of primary substation equipment can be reduced.

b. If a violent failure occurs the potential exists for dielectric fluid to be spilled and for major assets to be damaged.

• It is an expensive process to clean up dielectric fluid and can have additional fines due to environmental impact.

c. If failure occurs on the transmission level there is potential for downstream equipment to be affected which can lead to customer outages.

d. More time and manpower would be used to resolve an unexpected outage or complete maintenance/testing related to that situation.

Upgrading of CCVT's, surge arresters, bushing potential devices, and potential transformers will provide long term cost reduction by better protecting high value assets, reducing environmental health and safety risks, and keeping customers lights on ensuring company revenue.

3. Total cost **$5,050**

4. Basis for estimate: The annual funding of $1.1M for this program is based on the average of expenditures for the years 2019 and 2020.

Project Risks and Mitigation Plan

Risk 1: Outage scheduling conflicts with other initiatives.

Mitigation: Outages to be coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs to avoid conflict with other program/ projects resulting in a more predictable budget and manageable outage scheduling.

Risk 2: Delays due resources support coordination.

Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Technical Evaluation / Analysis: As described above without the bus auxiliary equipment upgrade there are multiple layers of reliability that can be compromised to the overall system. Due to system constraints on testing and evaluating equipment health it is more economical to strategically replace equipment throughout the system. After an overall technical assessment of the transmission system current equipment status, future equipment status, and from past failures that have occurred there is no question that this strategic replacement is necessary.

Project Relationships (if applicable) The strategy that is going to be applied to this system will work in parallel with other projects and outages that are occurring. However, the initial priority will be to replace the most vulnerable assets reaching the end of operational lifespan.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	0	83	908	1,203		933
O&M						
Retirement	0	35	61	111		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**$750**	**$1,100**	**$1,100**	**$1,100**	**$1,000**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	139	206	206	206	189
M&S	0	0	0	0	0
Contract Services	413	605	605	605	550
Other	0	0	0	0	0
Overheads	198	289	289	289	261
Subtotal					
Total	**$750**	**$1,100**	**$1,100**	**$1,100**	**$1,000**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations/ Substation Operations
2022

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Category Alarm Program – Various	
Project/Program Manager: John Penza	**Project/Program Number (Level 1):** PR.8ES3000/ 10035178
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date: Ongoing	**Estimated Date in Service: Ongoing**
A. Total Funding Request ($000) **Capital: $10,434** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:
The program consists of replacing failing substation electro-mechanical and solid-state-based alarm systems, which are components of legacy alarm systems that control the activation of alarm points and that are currently electromechanical switches or solid-state devices. They are replaced with a standardized programmable logic controller (PLC), input/output units, and human machine interfaces (HMI). The new alarm annunciator will be equipped with the capability to monitor all the individual station alarms and display their condition on a local computer and panel mounted touch screen. The PLC will provide local alarm functionality to the station operators and sends category alarms to the Energy Management System (EMS) at the Energy Control Center/Alternate Control Center (ECC/AECC).

Justification Summary:

The station alarm system provides the operator a general overview of the status of the station equipment, and its reliability and expandability allow for a quicker response time to abnormal conditions. It is of utmost importance that station operations personnel can rely upon the indication and alarms presented to them through the station alarm annunciator.

The legacy alarm annunciator systems have experienced operational problems over the recent years, which results in reliability concerns and high maintenance costs. Many are now at the end of their useful life. These legacy annunciator systems are generally not expandable and unable to accommodate new alarm input points. These systems do not contain alarm history logging, communication capabilities, component redundancy or a backup system in case of a failure. The deficiencies associated with these legacy alarm systems present a risk to system operations.
When an alarm annunciator failure exists, operating personnel need to rely on constant field verification of the station equipment for any abnormal status or alarms, thus the station needs to be

staffed around the clock, increasing labor costs. There is limited technical and material supply support from the manufacturers of the targeted systems.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
This program directly address the Substation Operations (SSO) risk of "loss of substation" reducing the likelihood of losing a substation for 24 hour or more by replacing existing alarms that are not working properly with new alarm systems. These replacements facilitate timely response to station conditions that, if unknown, could lead to the loss of the station.

2. Supplemental Information

Alternatives
Repair of legacy alarm system is not possible in many cases as the panel manufacturers no longer supply spare parts or field services for these systems. As these systems reach the end of their useful life, the reliability risk increases. In addition, these systems cannot be modified to accommodate system and operational changes.

An alternative would be to use any existing spare parts from legacy systems that have been removed. This alternative is not recommended as the reliability of these used parts cannot be verified, nor is there any certainty that this strategy will ensure availability of needed parts.

Risk of No Action
This is not recommended as the failure of the legacy alarm annunciator system increases operational costs and reliability risk. Dedicated station personnel would be required to perform periodic checks on station equipment should the alarm system fail, and no spare parts are available for replacement.

Non-Financial Benefits
A new category alarm system substantially improves and simplifies the station's alarm annunciation and alarm management. It provides the station operator, ECC, and AECC with critical station information not available through the legacy system.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis: N/A

2. Major financial benefits the new alarm annunciator system would reduce the high maintenance costs associated with maintaining a failed legacy alarm annunciator system. Without alarms, the operator must monitor the substation equipment periodically to determine operating conditions.

3. Total cost $**10,434**

4. Basis for estimate: Near term work based on unit cost per unit installed of $350K, also outer term work based on cost of similar types of work done in the past. As this is an ongoing program, work scopes are generally similar in nature.

5. Conclusion: N/A

Project Risks and Mitigation Plan
Project Risks:
Risk 1: Outage scheduling conflicts with other initiatives.

Mitigation: Outages to be coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs to avoid conflict with other program/ projects resulting in a more predictable budget and manageable outage scheduling.

Risk 2: Delays due resources support coordination.

Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Technical Evaluation / Analysis: The new alarm annunciator was developed by Con Edison engineering personnel, tested and field proven at multiple company locations. The logic and HMI applications are both standardized to a level where the system requires minimal engineering programming/configuration efforts for individual installations. A core localization text file can be edited either offline using text editing programs or via pop-up windows while the system is running. This file carries the parameters needed for each Substation. The debugging of logic and HMI applications will not be required.

The system acceptance testing can be limited to verifying that each individual alarm input will trigger a single expected action (i.e., that it is wired properly) and to visual inspections of point configurations at the alarm tile screen(s) (verifying that the displayed information, coming directly from the logic controller, matches the intended operation for each point). The Con Edison universal alarm annunciator system is configurable to provide additional information for each alarm point (drawing references, directions to operators, etc.) and to provide alarm event logs and system configuration data to authorized users or systems, including those residing elsewhere at the corporate network if required.

Project Relationships (if applicable) This alarm system upgrade program is also linked to the SSO Cyber Security program. The upgrade to a PLC based annunciator system would classify the alarm annunciator system as a Bulk Electric System Cyber Asset. The SSO Cyber Security program would capture the security procedures and guideline required for these alarm systems.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	2,556	1,630	515	879		844
O&M						
Retirement	38	353	143	78		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	$1,750	$2,250	$2,078	$2,156	$2,200
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	753	971	899	934	954
M&S	315	405	374	388	396
Contract Services	42	57	50	51	59
Other	0	0	0	0	0
Overheads	641	817	755	783	791
Subtotal					
Total	$1,750	$2,250	$2,078	$2,156	$2,200

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations/ Substation Operations
2022

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Circuit Switcher Replacement Program	
Project/Program Manager: Gregory Jimenez	**Project/Program Number (Level 1):** PR.9ES3200/ 10036395
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date: Ongoing	**Estimated Date in Service: Ongoing**
A. Total Funding Request ($000) **Capital: $7,000** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This program will replace circuit switchers based on their health ranking. This ranking is based upon multiple factors including jumpers, service type, station risk, SF6 emissions, O&M costs, model, age, and interrupter age reduction factor. This program will upgrade or replace one switch per year with a reliable upgraded model. As the program progresses, other circuit switchers will be considered for replacement based on performance, reliability, and lack of replacement parts availability due to obsolescence. This is the switches that have been identified as priority.

Justification Summary:

Circuit switchers function to provide electrical isolation to substation equipment or transmission lines during planned outages and/or fault conditions. If a circuit switcher does not operate as intended, more equipment will need to be isolated than would otherwise be required (overtripping). Overtripping can lead to contingencies that may require load shedding. Some circuit switchers are targeted for replacement because they are leaking SF6 gas, which is a greenhouse gas (GHG). Replacing circuit switchers that are in poor health will help maintain reliability and help the with climate change mitigation efforts.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
Replacing circuit switchers that are beyond their useful life reduces the likelihood of equipment failures. This program mitigates probability of the Substation Operations Departmental Risk Equipment Failures and is expected to improve system reliability by preventing or minimizing outage duration and/or extension required for failure repair or replacement, or unexpected part replacement

during circuit switcher preventive maintenance. Currently, the lead time for some circuit switcher components is up to 20 weeks. This can cause cascading delays in the outage scheduling system, which can affect time sensitive work.

The replacement of circuit switchers that are leaking SF6 gas will reduce GHG emissions. This is a part of the Company's climate change mitigation efforts.

2. Supplemental Information

Alternatives
•One alternative is to replace the entire unit with a new circuit breaker; this would require new wiring, civil construction for a new pad, and more space in the substation would be more costly than performing the recommended upgrade or replacement of the existing circuit switcher.

Risk of No Action
This is not recommended as the unavailability of spare parts increases the risk of extended outages, reduces system reliability, and increases costs for emergency repair in the event of equipment failure.

Non-Financial Benefits
This program is expected to improve system reliability by preventing or minimizing outage duration and/or extension required for failure repair or replacement, or unexpected part replacement during circuit switcher preventive maintenance. Currently, the lead time for some circuit switcher components is up to 20 weeks. This can cause cascading delays in the outage scheduling system, which can affect time sensitive work. If the circuit switcher is leaking SF6 gas this has a detrimental effect on the environment.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis: N/A

2. Major financial benefits
The replacement circuit switcher will have lower maintenance costs than the existing circuit switcher in poor health condition and no costs associated with maintaining/repairing SF6 leaks.

3. Total cost **$7,000**

4. Basis for estimate: The annual funding of $1.4M is based on the average of projects completed between 2016 and 2020.

5. Conclusion: N/A

Project Risks and Mitigation Plan
Project Risks:
Risk 1: Outage scheduling conflicts with other initiatives.

Mitigation: Outages to be coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs to avoid conflict with other program/ projects resulting in a more predictable budget and manageable outage scheduling.

Risk 2: Delays due resources support coordination.

Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Risk 3: **Lack of alignment between resources support and outages.**
Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor and construction to avoid alignment conflicts with outages.

Technical Evaluation / Analysis: At present, there are limited options for repairing any problems that occur on the Siemens Linebacker and ABB Vacuum Capacitor Switch (VCS) circuit switchers as spare parts are limited, and long lead time and support offered by ABB is very limited. These circuit switchers are known SF6 leakers which can have a detrimental impact to the environment. They are difficult and expensive to maintain. No other manufacturers fabricate or supply these parts. If the above-mentioned circuit switcher fails, this would cause extensive outage duration, reduce system resiliency and reliability, and delay the outage scheduling process due to long lead time for part procurement and the lack of technical advisers.

Project Relationships (if applicable) N/A

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	1,311	605	486	1,731		1
O&M						
Retirement	**64**	**77**	**119**	**166**		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**$1,400**	**$1,400**	**$1,400**	**$1,400**	**$1,400**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	420	420	420	420	420
M&S	123	127	127	127	131
Contract Services	420	420	420	420	420
Other	0	0	0	0	0
Overheads	437	433	433	433	429
Subtotal					
Total	**$1,400**	**$1,400**	**$1,400**	**$1,400**	**$1,400**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations/ Substation Operations
2022

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Condition Based Monitoring Program	
Project/Program Manager: STEVEN BRYAN	**Project/Program Number (Level 1). PR.2ES7900/ 10030243**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other: ___________**	
Estimated Start Date: 1/1/2023	**Estimated Date in Service: 12/31/2026**
A. Total Funding Request ($000) **Capital: $33,000** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This program will install temperature monitoring devices on substation power transformers. Part of the scope will include Intelligent Electronic Devices (IEDs) that interface with the instruments, as well as other transformer equipment, and facilitate the remote and secure retrieval of real time data. This program will also include monitoring devices for substation battery banks. Previously, this program included the installation of dissolved gas in oil analysis (DGOA) monitors (Kelmann Units) on all substation power transformers. In the future, this program may also include funding for the replacement of those Kelmann Units as necessary. This program will also include the installation of the ECLIPSE Geomagnetically Induced Current (GIC) monitoring devices to be able to detect tank heating on select units.

In order to accurately and remotely monitor transformer temperatures other components must be installed or upgraded. Existing analog temperature gauges on transformers must be replaced with digital (Qualitrol) devices. These devices will be connected to the IEDs and communications infrastructure. A central server and new software will also be included in the program to facilitate remote retrieval of the data provided by the Qualitrol devices. The Kelmann units will also be integrated with this infrastructure.

The initial funding for 2023 will include the software platform and installation of the Qualitrol devices and IEDs will begin in 2024.

Justification Summary:

Climate change will shift the operation of the electric transmission system in several ways and new monitoring equipment is necessary for the adjustment. In the short term, the ability to understand in real time what is happening with equipment like transformers and battery banks enables operations to make the best possible decisions. In the long term, the ability to understand the effects of climate change on equipment will improve planning in the form of ratings and replacement cycles. Power transformers are critical components of the transmission system and battery banks are essential in re-energizing substations after an emergency.

The increased frequency, intensity and duration of heat waves that are projected in the Company's Climate Pathway make real time monitoring of substation equipment more critical than ever before. Substation power transformers are critical, and often electrically limiting, assets in the transmission and distribution of power. During peak and/or contingency scenarios, the ability to remotely monitoring transformer temperatures allows operators and engineers to make informed and timely decisions regarding operation of the system. Existing analog temperature gauges are less accurate than digital ones and cannot be remotely accessed – an operator must be sent out to take readings from them. The time and resources taken to manually collect this data may prohibit effective decisions. The lack of continuous data makes long term decisions about transformer load and ratings more difficult. The installation of digital temperature monitoring and the infrastructure to be able to securely retrieve and store it is critical to operations in more extreme heat events and the increased load cycles that will come with electrification of heating.

Battery banks provide an emergency power source for station DC loads after a loss of AC supply. All the control and protection equipment in a substation are supplied by the DC system and battery banks must be able to energize these systems in an emergency. One of the inherent risks with these battery systems is that they may not operate properly when needed. The ability to remotely monitor these systems enables operators and engineers to detect and correct a problem during normal conditions when the battery does not need to operate. This ability will reduce the risk that batteries do not operate properly during an extreme weather (or any other event) that causes a loss of AC.

Digital temperature monitoring of transformers, battery monitoring systems and the infrastructure to remotely and securely monitor them are essential components of the Company's Climate Change Adaptation efforts.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):

The Qualitrol devices and battery monitoring systems, along with their communications infrastructure, address the Substation Operations "Equipment Failures Risk". These components reduce the likelihood of equipment failures (transformers) by enabling operators to see and anticipate operating conditions that could be indicative of impending failure.
This program is part of the Company's Climate Change Adaptation efforts because it provides operations with the ability to understand the real-time effects of extreme heat on asset ratings and degradation.

2. Supplemental Information

Alternatives
The main alternative to this program is continue manual data collection from transformers and battery systems. This alternative is inefficient and does not provide comprehensive information nor does it provide it in a timely fashion.

Risk of No Action
The short-term risk of not pursuing this program is that a condition that could lead to a failure might not be realized in time to prevent it. The long-term risk of not pursuing this program is that the

Company will not be fully prepared for changing weather because there will not be enough data to understand its true effects.

Non-Financial Benefits
The data collected by these systems can be potentially used to understand the effects of climate change on other assets.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis: N/A

2. Major financial benefits

3. Total cost **$33,000**

4. Basis for estimate: The 2023 funding request of $1.5M is for software and platform for transformer temperature monitoring/analysis. The 2024 and 2025 annual funding requests of $15M include $3M per year for battery monitoring and $12M per year for IED installations (approximately $600K for a typical substation and targeting 20 substations per year)

5. Conclusion: N/A

Project Risks and Mitigation Plan
Project Risks: Risk 1: Outage scheduling conflicts with other initiatives.

Mitigation: Outages to be coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs to avoid conflict with other program/ projects resulting in a more predictable budget and manageable outage scheduling.

Risk 2: Delays due resources support coordination.

Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Risk 3: **Lack of alignment between resources support and outages.**
Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor and construction to avoid alignment conflicts with outages.

Technical Evaluation / Analysis: N/A.

Project Relationships (if applicable) N/A

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	7,027	12,428	13,115	11,421		9,326
O&M						
Retirement	0	0	0	0		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**$0**	**$1,500**	**$15,000**	**$15,000**	**$1,500**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	0	364	3,639	3,640	364
M&S	0	600	6,000	6,000	600
Contract Services	0	45	456	459	49
Other	0	24	241	241	24
Overheads	0	467	4,664	4,661	463
Total	**$0**	**$1,500**	**$15,000**	**$15,000**	**$1,500**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations/Substation Operations
2022

1. Project / Program Summary

Type: ☒ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Control Cable Upgrade Program	
Project/Program Manager: TBD	**Project/Program Number (Level 1): 25775000**
Status: ☒ **Initiation** ☐ **Planning** ☐ **Execution** ☐ **On-going** ☐ ☐ **Other:** ___________	
Estimated Start Date:	**Estimated Date In Service:**
A. Total Funding Request ($000) **Capital: $8,000** **O&M:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months) (If applicable)**

Work Description:

This program will replace all the control cable in a substation. Control cables include, among other things, the copper wiring that connects local cabinets at devices like breakers, transformers, and relay panels to the substation's control and/or automation system. The troughs and raceways that house control cable may also be upgraded as part of this program. The program will target substations that have high relative frequency and the associated labor hours spent troubleshooting DC grounds. This program will begin in 2024 and will target two substations at a time and assumes each station will take five years to complete.

Justification Summary:

Control cable is the electrical wiring that provides connections between substation equipment such as the station mimic panel or Human Machine Interface (HMI), Coupling capacitor potential devices (CCPDs), current transformers (CTs) , breakers transformers and direct current (DC) load boards. When the wiring insulation degrades, it is subjected to water intrusion and it creates paths to ground. These grounds can create alarms and adversely impact the operation of control and indication systems, including causing relay systems to mis-operate.

Control cable systems are installed when a substation is built or expanded and are vulnerable to extreme weather. Control cables that are installed in the outdoor portion of substations can be direct buried or installed in troughs. Although these cables are designed for outdoor conditions, they degrade over the life of the substation and the insulation breaks down. The breakdown in insulation provides an entry point for water that corrodes the copper and creates grounds. These conditions are exacerbated by extreme weather, such as heavy rain events. These types of events can impact an entire substation by causing spurious trip outs if there is a systemic problem with the control cabling in the station.

Control cable systems are a critical component of the indication and control of a substation. These cable systems connect to everything that affects the protection and operation of a station; if there is a systemic problem with these systems it can cause many components to trip out simultaneously. Extreme weather events, including rain, pose a significant risk to substations that have pervasive problems with degrading control cabling. In order to adapt to changing weather patterns, this program is necessary to mitigate the risk of dropping customers from a substation event.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):

This program affects the Substation Operations risk "Loss of a Substation". Station control cabling that is upgrading by this program will reduce the likelihood of losing a substation. DC control cable systems connect many substation components together. When there is a high instance of degrading cabling in a particular substation, there is a risk that an extreme weather event can cause many coincident trip outs.

This program is part of the Company's climate change adaptation efforts. Extreme rain events are expected to increase in frequency and intensity with changing weather patterns. When a substation has degrading control cable to the point that it is a systemic issue, extreme weather events can impact the entire substation through coincident trip outs.

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection

One alternative to completely replacing the control cable in a substation is to continue to troubleshoot DC grounds as they arise. This strategy is inefficient and while it will correct localized issues, it does not address the broader systemic issue in a particular substation. This strategy does not reduce the likelihood that an extreme weather event can impact the entire substation.

Risk of No Action

Risk 1

The risk of no action is that DC grounds at particular substations will persist. When extreme weather events occur, they may cause spurious trip outs of substation equipment. These trip outs could affect the whole substation and/or cause the dropping of load.

Risk 2

Risk 3

Non-Financial Benefits
Examples:
- This program improves the resiliency of a substations DC control and indication systems by adapting the substation to changing weather patterns.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis (if required)
N/A

2. Major financial benefits

3. Total cost: **$8,000**

4. Basis for estimate: The funding request for this program assumes that it will cost approximately $10M over 5 years to replace all the control cable at a typical substation. The annual funding request includes work at two substations per year. The $10M figure is based on prior estimates for similar work scope.

5. Conclusion

Project Risks and Mitigation Plan

Risk 1: Outage scheduling conflicts with other initiatives.

Mitigation: Outages to be coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs to avoid conflict with other program/ projects resulting in a more predictable budget and manageable outage scheduling.

Risk 2: Delays due resources support coordination.

Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Risk 3: Lack of alignment between resources support and outages.
Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor and construction to avoid alignment conflicts with outages.

Technical Evaluation / Analysis

This program will utilize work management system data on troubleshooting DC grounds to prioritize locations for upgrades.

Project Relationships (if applicable)
N/A

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	0	0	0	0		0
O&M						
Regulatory Asset						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	$0	$0	$4,000	$4,000	$0
O&M*					
Regulatory Asset					

Capital/Regulatory Asset Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	0	0	548	549	0
M&S	0	0	1,680	1,680	0
Contract Services	0	0	480	480	0
Other	0	0	193	193	0
Overheads	0	0	1,099	1,098	0
Total	**$0**	**$0**	**$4,000**	**$4,000**	**$0**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Critical Facilities Program	
Project/Program Manager: Frantz St. Phar	**Project/Program Number (Level 1): PR.23291640/24155657/24155570**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date: January 2020	**Estimated Date In Service: 12/31/2023**
A. Total Funding Request ($45270) **Capital: 45,270** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M: 400 per year** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

Con Edison will further enhance circuit hardening to critical facilities located and fed via non-network distribution circuits. Examples of Critical Facilities include fire departments, police departments, municipal buildings used in a command and control capacity during severe weather events, pumping stations, strategic major food retailers and those facilities identified by municipal leaders. The Company has initiated an outreach and has met with and will continue to meet with the various municipalities throughout Westchester, in an effort to further enhance those facilities deemed critical by their leadership. Efforts are also underway in the Bronx, Brooklyn, Queens and Staten Island to identify critical facilities which will benefit from enhanced circuit hardening.

The Company will implement the following strategies to enhance system resiliency during an overhead storm event.

<u>Undergrounding of Overhead Infrastructure</u>

Where there is an opportunity and it is cost effective, we plan to underground selective feeders in order to maximize the benefits to resiliency. In lieu of directly burying the power lines as the sole solution, we will look to deploy aerial cable systems as a predominant method of enhancing reliability during storms. The non-current carrying steel messenger cable, which suspends the aerial conductors, is far stronger and less likely to be downed by tree/limb impact. Aerial cable systems have a far greater likelihood (when compared to open wire) to remain energized during storms - even if knocked to the ground - due to the resilient design of this underground-type cable.

In addition, we will look to create more Automatic Transfer Switch (ATS) fed transformer systems. An ATS system allows for two supplies (a preferred and a redundant alternate) to maintain first contingency design for our customers. With many of the supply feeders being partially underground and partially aerial cable, the chances of the customer remaining in service during storms are significantly higher.

We'll also explore additional options for reliability improvements such as

- Installing additional SCADA switches on feeder main runs to facilitate faster outage restoration
- Utilizing loop design on the overhead system (4kV and auto-loop) to provide an alternate supply to the critical facilities
- Converting open-wire installations with aerial cable super spans where feasible to improve system resiliency

Justification Summary:
Emergency Management data predicts that the Northeast Region will experience an increase in severe storms in the future as a result of climate change. Currently, Category 1 and 2 hurricanes affect the region once every 19 years and major hurricanes, Category 3 or greater, affect the region once every 74 years.

In 2018, our overhead system experienced severe damage from Nor'easter's Quinn, Riley and Tobey. In addition to these larger named storms, we experienced a number of large unnamed storms that were also devastating, including the April windstorms experienced over April 14th to April 16th where wind gusts reached over 50 mph and a windstorm on May 15th where wind gusts were seen as high as 60 mph in the Bronx. More recently in August 2020, we experienced major storm Isaias which took the place as the 2nd largest storm in the company's history. Recent history indicates that the number of these severe weather events is increasing.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

Overhead Storms are a major corporate risk at Con Edison. Improving the reliability of the overhead infrastructure will support reduction of damages to said infrastructure and also reduce customer outages, more specifically to critical customers in this case.

The Risk Management sub-section of the Electric Long Range Plan (ELRP) states that part of the minimization of risk to employee and public safety is "proactive replacement of high-risk components" and the use of "data and analytics to prioritize our response to any potential problems revealed." The Critical Facility Program does just that for the targeted critical customer/municipal facilities.

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection
The alternative is to continue with our current practices. While these result in industry leading System Average Interruption Frequency Index (SAIFI) performance on a blue-sky days, the system remains vulnerable for a large storm event for municipalities and communities which can expect multi-day outages on a more frequent basis. These storms are likely to become more frequent and more severe as a result of climate change.

Alternative 2 description and reason for rejection

Alternative 3 description and reason for rejection

Risk of No Action

Risk 1

The possibility exists that no severe weather event or storm will hit our service area, but in the event that a major storm does hit the Con Edison service area we will experience severe electric infrastructure damage. This damage is extremely costly to the local communities, the Company, and our ratepayers. Blocked streets, lost power and expensive repairs take its toll on the NYC and Westchester County areas. Loss of power to critical customers such as first responders and designated shelter facilities could increase the impact of these events, hampering the ability to execute a coordinated and timely response and recovery effort.

Risk 2

Risk 3

Non-Financial Benefits

Municipalities and communities will be better able to cope and manage through severe weather events that have caused significant damage to the electric infrastructure and power outages. Critical facilities will have a higher probability of remaining in electric service or be restored more expeditiously with emergency generation.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)

N/A

2. Major financial benefits

N/A

3. Total cost

The Program is currently estimated to cost $45.3M

4. Basis for estimate

Estimates are based on historical unit costs

5. Conclusion

Although difficult to quantify, the benefits of the program are ensuring enhanced reliability during a major storm. It would enhance local municipalities' ability to manage during severe weather events and provide communities with resources needed while avoiding extensive travel to obtain those same resources.

Project Risks and Mitigation Plan

Risk 1
Main risk to this project timeline is the availability of contractor resources to complete the issued work.

Mitigation plan
The Company has committed to secure adequate contractor resources to complete the required work. If unable to honor that commitment, Company crews will be diverted to complete the associated projects.

Risk 2

Technical Evaluation / Analysis
We will follow the standards set in Corporate Instruction CI-260-4 Corporate Response to Incidents and Emergencies which establishes guidelines for determining the appropriate level of response and mobilizing the appropriate Company and external resources in a timely manner in response to any incident. It also describes the Company's Electric Emergency Response Plan (ERP) – The Company's Electric ERP details the organization for the response to storms and manmade events affecting the overhead and underground electric system in accordance with the requirements of Part 105 of the Rules of the New York State Department of Public Service.

The Company's Corporate Coastal Storm Plan (CCSP) provides a comprehensive overview that attempts to identify the potential effects of a severe tropical storm and/or hurricane, prepare strategies to mitigate these identified risks, and guides the subsequent corporate response to such an event. This guide focuses on ensuring public and employee safety while maintaining and restoring the integrity of our energy delivery services.

Adhering to these processes will also help ensure that Environmental, Health and Safety compliance, resource conservation, risk reduction and alternate design considerations are incorporated in the early planning and design stages of project work.

Project Relationships (if applicable)
Electric Emergency Response Plan (ERP)

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital				**1,556**		**6,139**
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**9,000**	**9,000**	**9,000**	**9,000**	**9,270**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	930	930	930	930	958
M&S	793	793	793	793	818
Contract Services	5,479	5,479	5,479	5,479	5,643
Other					
Overheads	1,798	1,798	1,798	1,798	1,851
Subtotal	**9,000**	**9,000**	**9,000**	**9,000**	**9,270**
Contingency**					
Total	**9,000**	**9,000**	**9,000**	**9,000**	**9,270**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2020	2021	2022	2023	2024	2025
O&M	**200**	**400**	**400**	**400**	**400**	**400**
Capital						

Central Operations/ Substation Operations
2022

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: DC System Upgrade Program	
Project/Program Manager: Seda Steck	**Project/Program Number (Level 1): PR.2ES8300/ 10030247**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other: ___________**	
Estimated Start Date: N/A	**Estimated Date in Service: N/A**
A. Total Funding Request ($000) **Capital: $25,718** **O&M:** **Retirement: $2,873**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

The Direct Current (DC) System Upgrade program replaces the DC system batteries in substations that require new batteries (while accounting for DC load growth) and other upgrades to DC system equipment such as disconnect switches, battery chargers, load boards with monitoring instrumentation, DC to Alternating Current (AC) converters, automatic transfer switches, and associated cables and conduits. The program also addresses Heating, Ventilation, and Air Conditioning (HVAC) and civil upgrade needs that are specifically related to the previously mentioned work. Delaying these projects can have a negative impact on substation reliability.

The goal of this program is as follows:

<u>Assess the DC Systems in Substations and replace equipment, as necessary, to ensure:</u>

1. The system is continuously served with a reliable DC System, including batteries and battery chargers and all other components.
2. HVAC systems are capable of temperature and hydrogen control for the existing battery room installations to achieve optimal equipment performance and a safe working environment.
3. The highest standard of working conditions for employee health, safety as well as ergonomic considerations.
4. Reliable battery charger and battery bank operations by maintaining specified battery float voltages
5. Sufficient DC Power supply to fully meet load demands as per battery design basis.

Battery Replacement Basis
Based on historical test data, battery bank replacement criteria use a combination of battery age and battery condition. Accordingly, the program prioritizes battery replacement banks throughout the system. The Asset Management Group in conjunction with the DC Project Team prioritizes the battery replacements based on age, evaluation of the periodic inspection data, physical condition, in-service experience gathered on different brands, as well as the criticality of the application.

Battery Charger Replacement Basis
To ensure the battery is kept fully charged and available for a loss of AC power, the DC system needs a battery charger that is operating properly. A properly operating battery charger exhibits stable voltage regulation and can maintain optimal battery float voltage. Battery chargers should be replaced if they exhibit excessive voltage drift or ripple current. Battery charger performance can have a significant impact on the battery and its ability and readiness to perform its function.

Load Board Replacement Basis
Load boards serve as the main distribution point for the DC system. Conditions that could force load board replacement are:

- Instrument failure that cannot be replaced due to unavailability of parts.
- Insufficient spare slots for branch circuit breakers, or room on the bus bar to add links, to support station expansion.
- Branch circuit breakers are degraded and cannot be replaced due to unavailability for purchase.
- New DC Load Boards are equipped with the capability of parameter data monitoring and storage as well as a ground detection system on the individual branch circuit. The benefits of these improvements will be factored in during future evaluation of the DC Load Board replacements.

A new DC Load Board was established this year for supplying the newly developed product with the following new features:

- DC system monitoring system, equipped with storage and trending capabilities, and HMI (Human Machine Interface).
- Feeder Ground Detection system which will significantly improve the DC ground troubleshooting
- DC monitoring system to meet the criteria of the NERC monitoring system in multiple DC parameters
- DC circuit breakers will have fast tripping characteristics when needed
- DC load board will have optional transfer switch or tie switch as needed

Justification Summary:

All substations have redundant DC power systems to provide a reliable source of power during both normal station operations and if all AC power is lost. Each DC system consists of battery banks, battery chargers (rectifiers)/DC converters, load boards with monitoring instrumentation, cables, distribution panels, and disconnect switches. Automatic transfer switches are included for most systems. The DC System Upgrade Program seeks to maintain the highest reliability of substation DC power systems through a targeted asset replacement strategy.

Per Environment, Health & Safety (EH&S) direction the DC Project Team ensures the battery upgrade scopes of work are evaluated in a more formal and comprehensive manner by evaluating the entire DC Environment, which ensures a safe working environment for employees.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
The DC system in a substation provides control power for the operation of critical components like circuit breakers, relay systems, alarms and fire protection systems. The substation batteries themselves provide an emergency source of power for these critical loads should there be a loss of AC supply to the substation. Having a reliable DC system in a substation helps mitigate the risk of losing a substation (i.e. when the station loses power) and improves the recovery time in the event that the station is lost. This program has a direct effect on the likelihood and controllability of the risk "Loss of a Substation". Maintaining a reliable DC system is not only a part of mitigating these risks but is an ongoing part long term asset replacement needs in substations.

2. Supplemental Information

Alternatives

1. **Maintain (only mandated PMs)** – Under this course of action, only preventative maintenance mandated by outside agencies (those for battery banks) would be performed. Degraded components would not be repaired through corrective maintenance. The material state of certain components, such as individual cells with bad resistance readings or visible damage, would not result in the replacement of such components. This option is rejected for the following reasons:
a. Individual cells of a battery bank could completely fail, resulting in an open circuit condition for the battery bank; this would render the entire bank useless.
b. When a battery bank weakens or losses capacity, the failure might not be known to have occurred until the bank is called upon to operate in a loss of the normal power source. This scenario would result in a reduced or zero-time duration supply of emergency power to station DC loads.

2. **Maintain (PMs and CMs) –** Under this course of action, preventative as well as corrective maintenance would be performed on system components. Despite the expansion of maintenance practices, this is rejected for the following reasons:
a. A battery bank would still ultimately fail and as stated above, this failure might not be known until the exact time the battery bank is needed as a source of emergency power for station DC loads. This would result in a reduced or zero-time duration supply of emergency power to station DC loads.

3. **Capital Overhaul** – Although there is currently no provision for capital overhauls, this course of action could be pursued through the targeted replacement of multiple cells within a battery bank. This option is rejected for the following reasons:
a. When cells of the same age within a bank are replaced with brand new cells, there is a difference in electrical potential between cells of different ages. This difference in potential accelerates the degradation of the older portions of the battery bank and reduces life expectancy even further; this is especially true of battery banks that are nearing end of life.
b. The same risk of unknown failure mentioned in options 1 and 2 above still exists and has not been mitigated by this course of action.

4. **Retire or Employ Different Technology** – This alternative could only be implemented for the portions of certain systems after a thorough Engineering evaluation is performed. This option is being pursued where feasible, by retirement of 48VDC battery banks and the installation of DC to AC converters in locations where there is sufficient capacity in 125V battery banks to.

Risk of No Action
No action would be to choose not to replace the battery or other system components described above, which would be unacceptable. The basic functionality of a Transmission or Area Substation relies on having reliable, continuous, and properly sized DC power available always.

Non-Financial Benefits
This program provides reliability, a safe working environment and a sufficient DC power supply. Emergency systems are installed to provide a remediation path in extreme circumstances. In the context of the DC system, this circumstance would be a loss of offsite power. It has been deemed an unacceptable risk to allow a station to lose control or supervisory power because it would result in the loss of a substation. The indication of a battery bank failure may be observed in its inability to hold a charge, but it might not be observed until the bank is called upon to meet the demands of the design basis. This uncertainty differentiates battery banks from other pieces of equipment where a run to failure philosophy may be acceptable due to designed redundancy built into the system.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis: N/A

2. Major financial benefits
Limit the cost of damage to operating equipment, personnel, environment and public.

3. Total cost **$25,718,000**

4. Basis for estimate: The estimate is based on average units cost per DC project cost of $440K to $500K for recent projects with high level scopes that are representative of typical DC Program projects.

Typical DC Projects can contain replacements or upgrades to the battery banks, upgrade of the battery chargers (rectifiers) or installation of DC converters, load boards upgrades or replacements, cable upgrades or installations, distribution panel work, disconnect switch upgrades, new automatic transfer switches, installation or overhaul of the ventilation system, and the upgrade of battery room doors.
5. Conclusion: N/A

Project Risks and Mitigation Plan
Project Risks:
Risk 1: Outage scheduling conflicts with other initiatives.

Mitigation: Outages to be coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs to avoid conflict with other program/ projects resulting in a more predictable budget and manageable outage scheduling.

Risk 2: Delays due resources support coordination.

Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Risk 3: Lack of alignment between resources support and outages.
Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor and construction to avoid alignment conflicts with outages.

Technical Evaluation / Analysis:
As described above, our current policy is replacement of vented lead acid (VLA) station battery banks at the 15-year mark. At the same time periodic tests performed on batteries along with the visual

conditions, are used for evaluating the battery banks, and expected performance and recommendations are provided accordingly for maintenance and replacements. To bring elements of condition-based maintenance to the battery replacement criteria, Central Engineering has created a Battery Bank Health Index Spreadsheet prioritizing the battery banks in need for replacement based on overall condition and criticality of the application.
Project Relationships (if applicable) At times, other capital projects may interfere with the ability to accomplish this work as planned. The interference can be from resource availability, clear physical access, or outage restrictions.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	5,090	5,077	5,575	2,399		3,868
O&M						
Retirement	420	878	464	94		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	5,318	5,100	5,100	5,100	5,100
O&M*					
Retirement	575	575	575	575	575

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	1,494	1,377	1,377	1,377	1,377
M&S	1,472	1,517	1,523	1,525	1,527
Contract Services	657	606	602	601	611
Other	0	0	0	0	0
Overheads	1,694	1,600	1,599	1,598	1,585
Subtotal	0	0	0	0	0
Total	**$5,318**	**$5,100**	**$5,100**	**$5,100**	**$5,100**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations/ Substation Operations
2022

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Disconnect Switch Capital Upgrade Program	
Project/Program Manager: Gregory Jimenez	**Project/Program Number (Level 1): PR.0ES0700/ 10028085**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date: On going	**Estimated Date in Service: Ongoing**
A. Total Funding Request ($000) **Capital: $20,025** **O&M:** **Retirement: $5,016**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This is an ongoing program to retrofit or replace transmission voltage class disconnect switches found to be unreliable based on performance. This program will replace approximately fifteen switches per year, starting in 2023. Six of the fifteen replacements per year will be done at waterfront stations and utilize special glazed insulators (RG) that are more resistant to arcing and flashovers during extreme weather events.

Disconnect Switches are upgraded using an overall performance ranking tool, which focuses on three factors:

1. Total number of thermal hot spots
2. Total number of emergency maintenance outages
3. Total O&M labor hours expended to maintain the existing switches

The entire population is reviewed on a periodic basis by Substation Operations and Engineering. Candidate switches that are chosen for upgrade are then reviewed to determine the overall work scope—retrofit or replacement. Both work scopes consist of the replacement of all current carrying components. A replacement is typically done based on factors such as the structural integrity of the switch itself and/or foundation integrity, and the condition of the porcelain insulators.

Justification Summary:

This program maintains the current reliability of the system by proactively addressing disconnect switch performance issues on an annual basis. As disconnect switches deteriorate the risk of injury to the public, employees, and interruption of service due to a malfunction increase. Replacing the assets on an emergency basis increases the replacement cost and impacts reliability and safety. Replacement parts are no longer available for many of the assets that meet the criteria of this program.

The program targets switches that have frequently been removed from service on an emergency basis to correct hot spots. These Off on Emergency (OOE2) outages leave the system more vulnerable to service interruptions, particularly during the summer period. Switches that are difficult or impossible to operate are also targeted. These switches can require Operators to "switch around" these assets during both planned and unplanned events. In these cases—additional equipment must be removed from service in order to provide the isolation that would have been provided by the problematic disconnect switch, and this increases the potential for service interruptions.
Starting in 2023, the program will target disconnect switches that meet the above criteria and are located at waterfront stations. Waterfront stations are at higher risk of storm surge or other extreme weather conditions leading to arcing and flashover of insulators. The disconnects target at these locations will be replaced utilizing RG insulators that are more resilient during extreme weather.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):

This program addresses the Substation Operations departmental risk "Equipment Failures". The replacement of disconnect switches that are in poor health reduces the probability that they could electrically fail.

Six of the fifteen switches that will be replaced per year by this program will be at waterfront substations and will utilize RG insulators. These insulators have a special glaze that makes them more resistant to arcing and flashovers that can occur during extreme weather events. This portion of the program is part of the Company's Climate Change Adaptation efforts.

2. Supplemental Information

Alternatives
Disconnect switches could be maintained according to a time-based maintenance program, however this approach does not focus maintenance dollars on the most unreliable disconnect switches. Of the two options noted above, the lowest cost alternative that will address the existing issues with a particular switch is chosen.

Risk of No Action
Another alternative is to take no action and allow the disconnect switches to run to failure. The failure of a disconnect switch to operate properly impacts the ability to operate the system reliably and efficiently. Failure to maintain disconnect switches can also result in catastrophic failures, which can have severe system consequences resulting in decreased reliability and safety of operating personnel.

Non-Financial Benefits
As noted above, this program helps maintain overall system reliability, and reduces the likelihood for catastrophic failure of a switch, which is a reliability and safety concern.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis: N/A

2. Major financial benefits
This program removes the need to repeatedly repair problematic switches that can no longer be reliably maintained, and for which there is limited or no parts availability.

3. Total cost **$20,025**

4. Basis for estimate: The annual funding for this program is based on replacing nine disconnect switches at an approximate unit cost of $325K per switch and six disconnect switches at an approximate cost of $375K per switch.

5. Conclusion: N/A

Project Risks and Mitigation Plan
Project Risks:
Risk 1: Outage scheduling conflicts with other initiatives.

Mitigation: Outages to be coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs to avoid conflict with other program/ projects resulting in a more predictable budget and manageable outage scheduling.

Risk 2: Delays due resources support coordination.

Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Technical Evaluation / Analysis:
The worst performing disconnect switches are identified by the Disconnect Switch Peer Team through a qualitative and quantitative performance evaluation. The quantitative factors consist of hot spots, O&M labor hours, and emergency maintenance outages (i.e., OOE1 or OOE2).The qualitative factors considered includes parts availability originating from models discontinued or manufactures no longer in business, model, type, year, damaged insulators, and special consideration such as lessons learned from a specific event. The scope of work determined can be unique to each asset however, best management and engineering practices are employed during the scoping, design, planning, and construction process to produce a cost effective and viable solution.

The retrofit work scope typically includes the following:

- Replacement of all Current Carrying Parts
• Blades
• Jaw Assembly
• Manual or motorized operating mechanism
- During the replacement of the current carrying parts, the overall switch is checked for operability, and the following work may be done to ensure that the switch is operating correctly:
• Ground Switch Operator - - Refurbished.

The full replacement work scope is used when the replacement of just the current carrying parts of the switch will not restore design function of the disconnect switch.

The full replacement work scope includes:
- Replacement of the entire disconnect switch and, where applicable, ground switch, including the current carrying parts and operating mechanisms
- Upgrade of the steel support structure (where required) *
- Upgrade of the switch foundation (where required) *
- Replacement of porcelain insulators (where required)

*Note - Reinforcement of the existing Disconnect Switch Stand and/or foundation is required only after a civil engineering evaluation determines that the asset does not meet current IEEE/EPRI findings standards for electrical and structural loads.
Project Relationships (if applicable) The Corona Substation has disconnect switch issues that are also related to settlement that occurs on equipment foundations in that station. Switches that are being addressed in that station may need to be coordinated with settlement work there, to ensure newly replaced switches will not be subject to settlement concerns. The white paper that references this work is Stabilization of Pothead Stand Supports/Settlement.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	5,175	2,348	2,316	2,483		635
O&M						
Retirement	659	572	391	228		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	1,700	5,175	5,175	5,175	2,800
O&M*					
Retirement	1,003	1,003	1,003	1,003	1,003

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	544	1,656	1,656	1,656	896
M&S	351	1,075	1,081	1,083	588
Contract Services	102	311	311	311	168
Other	146	451	446	445	247
Overheads	557	1,683	1,681	1,680	901
Subtotal					
Total	**$1,700**	**$5,175**	**$5,175**	**$5,175**	**$2,800**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations/System & Transmission Operation
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Distribution Order Enhancements	
Project/Program Manager: Richard Scholz	**Project/Program Number (Level 1):** 22249001
Status: ☐ **Initiation** ☒ **Planning** ☐ **Execution** ☒ **On-going** ☐ ☐ **Other:** ___________	
Estimated Start Date: 1/1/2022	**Estimated Date In Service: 12/31/2026**
A. Total Funding Request ($000) **Capital: $1,672** **O&M:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☒ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months) (If applicable)**

Work Description:
This project will implement enhancements to the applications running on the Operations Management Systems (OMS) that are used by the District Operators for issuing operating work orders. These enhancements are a collection of new capabilities which include, but are not limited to the following:

- Improvements to the programming for electronic issuance of operating orders
- Creation of new interfaces to corporate data and systems that interface with the existing programming
- Enhanced disaster recoverability
- Increased automation of field operations
- Upgrades to the diagrams that help the operator visualize connectivity of the distribution feeders within the network
- Appropriate upgrades and modifications will be developed and implemented during real-time use that further support reduction in feeder processing times, improvements to productivity, or aid in the prevention of operating errors

Justification Summary:
The operators currently rely on the OMS to aid in processing work and making operating decisions. The complexity of the transmission and distribution systems and their overlapping relationships rely heavily on informed operators equipped with state of the art tools. The interconnection of generation and the nature of interconnected operations continue to create challenges that require fast and well-informed responses to system conditions.

In order to further reduce feeder-processing time, additional areas in distribution order processing need to be automated and enhanced in order to keep up with changing technology requirements and to support the increased needs for efficiency.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
This project is related to the likelihood of System and Transmission Operations department risk of operating errors. The program does not address any climate adaptation, mitigation or decarbonization concerns, and it is not a CLCPA investment activity.

2. Supplemental Information

Alternatives
Not continuing upgrades and new function additions to the OMS systems will cause unsafe work conditions and the loss of reliability of the electric network.

Risk of No Action
The current system could be maintained without needed upgrades or support; however, this would significantly reduce system reliability and the ability to update the system to reflect electric system upgrades/changes. There would be decreased automation and limited functionality in the future.

Non-Financial Benefits
This project will also increase work processing efficiency in addition to improved safety and reliability.

Summary of Financial Benefits and Costs (attach backup)

Project Risks and Mitigation Plan

Risk 1	Mitigation plan
Risk 2	Mitigation plan

Technical Evaluation / Analysis

N/A

Project Relationships (if applicable)

N/A

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	369	350	171	306		272
O&M						
Regulatory Asset						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	272	300	300	400	400
O&M*					
Regulatory Asset					

Capital/Regulatory Asset Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	48	53	53	71	71
M&S					
Contract Services	194	215	215	286	286
Other					
Overheads	30	32	32	43	43
Total	**272**	**300**	**300**	**400**	**400**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations/STO
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Dynamic Feeder Rating System	
Project/Program Manager: Vernon Schaefer	**Project/Program Number (Level 1):** 22679442
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date:	**Estimated Date In Service:**
A. Total Funding Request ($000) **Capital:** 7,000 **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This program will provide for a complete system upgrade of existing Dynamic Feeder Rating (DFR) equipment and communications systems to address technology enhancements and parts obsolescence.

This program will include upgrading all instrumentation consisting of Remote Terminal Units (RTUs), input/output signal conditioning, and communication hardware to the latest technologies. Communication systems will be converted from leased third-party hardwire copper systems, including the system DDSII and analog lease lines, to the Con Edison private Ground Penetrating Radar System (GPRS) or Corporate Communications Transmission
Network (CCTN) fiber optic network.

Upgrades of the DFR systems will be performed on the following targeted systems:

Feeders: 25, 26, 45, 46, 47, 48, M51, M52, M54, M55, 61, 62, 63, 71, 72, Q11, Q12, 15055, 29211 and 29212, 18001, 18002

In addition, new ambient temperature earth trees will be installed in selected locations to supplement existing earth ambient temperature measurements utilized for thermal modelling calculations.

This DFR system upgrade program will target two system upgrades per up from one previously. The general priority, based on the material condition of the communication circuits and system criticality, is as follows:

1. M51/M52
2. 61/62/63
3. 25/26
4. M54/M55

5. 45/46/B47/48
6. 71/72
7. Q11/Q12
8. 15055
9. 29211/29212
10. 18001/18002

Justification Summary:
The DFR system is a unique standalone customized system that monitors load, temperature, and the system hydraulic status (forced cooling, circulation, and static) and adjusts feeder ratings accordingly. The installation of a DFR system on a transmission feeder, on average, will increase the power transfer capability. The purpose of a dynamic rating system is to maximize the cable system's available capacity in real-time by utilizing critical thermal measurements without exceeding industry defined limits. In order to accomplish this, critical thermal parameters required to execute the rating calculation must be monitored continuously. A dynamic thermal model driven by measured load continuously identifies critical rating parameters. The resulting identified parameters are then used in the rating algorithm that produces the dynamic feeder ratings. Data is received from RTUs installed along the length of the feeder. The data is communicated back to the CPU, which executes the thermo-hydraulic model and associated rating algorithm once every five minutes to establish the dynamic rating of the feeder. This information is then communicated back to a centralized server located at the Energy Control Center, which is then forwarded to the SCADA System. This allows System Operations to operate the electric bulk transmission system utilizing real-time ratings to effectively transfer power during normal and contingency conditions. Since the Company started installing DFRs in the early 1990's, a total of 24 transmission feeders have been equipped and are being operated using the increased power transfer capability obtained from having the DFR rating system. No new DFR installations are currently planned but the Company will continue to consider whether new installations are warranted. T

The majority of the DFR instrumentation was installed in the 1990s and each RTU runs an 8085 processor in the DOS environment. This hardware is no longer available and the DOS Operating system is no longer supported. In addition, compilers are not available to compile the source code (prohibiting changes to the source code to support changes to the system).

The weakest link in providing near 100% availability of these systems is communications. The existing copper communications infrastructure in the NYC area has deteriorated and is not a priority repair for the third-party communications companies. Their focus going forward is on fiber optic links and wireless communication. As a result, to provide the required reliability, communications must be upgraded to Con Ed owned fiber where available and third-party wireless.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
This program will also be utilized to reduce the severity of oil leaks which is a corporate goal. .

2. Supplemental Information

Alternatives
If the DFR system is unavailable for an extended period of time, System Operators of the bulk transmission system must default to published tabulation ratings, which are typically less than the ratings that are calculated by the DFR system utilizing real-time thermal measurements.

Risk of No Action
Risk of No Action System Operators at the Energy Control Center and their ability to respond to system contingencies on the transmission system will be impacted if the DFR system is out of service.
Non-Financial Benefits Several of the feeders selected for DFR system upgrades are also protected by leak detection systems. For these systems, the processing and communication equipment is shared by the leak detection and DFR systems. As a result, the DFR upgrades will also enhance the reliability of the leak detection systems.
Summary of Financial Benefits and Costs (attach backup) The cost is based on a historical average of $450k per 345kV project
Project Risks and Mitigation Plan
Technical Evaluation / Analysis
Project Relationships (if applicable)

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	457	216	998	488		235
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	1,500	1,000	1,500	1,500	1,500
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	340	230	340	340	340
M&S	30	20	30	30	30
Contract Services	660	440	660	660	660
Other	49	30	53	53	57
Overheads	421	280	417	417	413
Total	1,500	1,000	1,500	1,500	1,500

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations/ Substation Operations
2022

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: East River Automation - Upgrade The 69kV Yard	
Project/Program Manager: John Mazzani	**Project/Program Number (Level 1): PR.2ES4302/ 10036422**
Status: ☐ **Planning** ☐ **Design** ☒ **Engineering** ☐ **Construction** ☐ **Ongoing** ☐ **Other: ___________**	
Estimated Start Date: Ongoing	**Estimated Date in Service: Ongoing**
A. Total Funding Request ($000) **Capital: $6,000** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:
This project installs a microprocessor-based automation system to perform operating, protective, and monitoring functions for the 69 kV circuit breakers, transformers, phase angle regulators, feeders, and buses at the East River Substation as well as several 138 kV circuit breakers at East 13th Street. This system includes approximately 100 protective relay panels, an operating console with monitors, control and supervisory equipment, and all associated peripheral and support systems including a 125Vdc and 208/120Vac control/auxiliary power distribution. The new components are in the control room of the 69 kV yard at East River thereby completing relocation of all operating, protective, and monitoring functions from the 8th floor of the East River generating station. The project also retires the existing operating, control, and protective systems and devices currently located in the generating station control room, terminal board room, and various relay rooms.

Con Edison has completed nine of thirteen outages to transfer operating, protective and monitoring functionality to the microprocessor-based automation system. The Company plans to complete the remaining four section outages by 2023.

Justification Summary:
This project will enhance system performance, improve operator response time and productivity, and upgrade the protection and control systems, thereby increasing reliability. This project is required to support the retirement of the existing operating, control, and protective systems and devices currently located in the generating station control room, terminal board room, and various relay rooms.

Relationship to Broader Company Plans and Initiatives (e.g., Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
This project is expected to improve reliability and reduce the risk of customer outages. Upgrading this equipment will provide better monitoring and control of the station, both within the station control room and from the Con Edison Energy Control Center. This will allow for quicker response to alarms

and trip out events, thereby lessening their impact. In addition, this project will reduce the clearing time for faults that occur under certain scenarios, reducing the likelihood of extensive equipment damage in the event of a fault.

2. Supplemental Information

Alternatives

Option 1 - Continue to operate the East River Substation as it presently exists. This has three major unacceptable features:

a. The substation facility would remain undivided from the generating station.

b. Increased relay misoperations and forced outages, caused by the existing wiring and the end-of-life control and relay protection equipment. In addition, much of the existing relay equipment is known to be a cause of misoperations.

c. The three-phase Critical Clearing Time, a Con Ed specification determined by transmission operations planning and engineering, for breaker failure scenarios cannot be met.

Option 2- Implement the cut-over of selected Bus Sections and leave the remaining Bus Sections using the present wiring and equipment. Sections would be selected based on their connection to either Leonard Street feeders (whose required Area Reliability Phase II work was included in the East River automation design drawings) or to Generating Station outlets.

a. The existing wiring and equipment were impacted by flooding from Hurricane Sandy. The current configuration will not be sustainable.

b. New design requirements specify that elevations for all electrical equipment must be above a minimum of the FEMA plus 3 feet standard.

Risk of No Action

Lower reliability of the power supply to the Leonard Street substation, and lower reliability for the outlet for East River Gen. #1.

Non-Financial Benefits

This project is expected to improve reliability and reduce the risk of customer outages. Upgrading this equipment will provide better monitoring and control of the station, both within the station control room and from the Con Edison Energy Control Center. This will allow for quicker response to alarms and trip out events, thereby lessening their impact. In addition, this project will reduce the clearing time for faults that occur under certain scenarios, reducing the likelihood of extensive equipment damage in the event of a fault.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis: N/A

2. Major financial benefits
Avoid Customer service outages.
.

3. Total cost **$6,000**

4. Basis for estimate: Near term work based on Engineering estimates. Outer term work based on cost of similar types of work done in the past. As this is an ongoing project, work scopes for each bus section are generally similar in nature. This is an ongoing program and has been working for some time. There are also multiple appropriation estimates for various segments of the project.

5. Conclusion: N/A

Project Risks and Mitigation Plan
Project Risks:
Risk 1: Lower reliability of the power supply to the Leonard Street substation, and lower reliability for the outlet for East River Gen. #1. Customer service outages.

Mitigation Plan: installs a microprocessor-based automation system to perform operating, protective, and monitoring functions for the 69 kV circuit breakers, transformers, phase angle regulators, feeders, and buses at the East River Substation as well as several 138 kV circuit breakers at East 13th Street.

Technical Evaluation / Analysis: This project provides for the modernization and life extension of aging plant and equipment. The result of the changes made by this project will be the improved operability and reliability of a substation that serves as an outlet for power generation and supplies two (2) area substations in Manhattan. The completion of the East River Repowering Project at the end of 2005 added 195 MW of new generation flowing through the 69kV substation. This provided an added need to modernize and extend the life of the East River Substation.

Substation Operations started the program to modernize this aging facility in January 2001. Con Edison completed the project to erect a new building in the 69KV substation, which includes a control room for the 69 kV substation. It was built with adequate space for a new operating console, relay panels, and all support/peripheral equipment required operating the 69KV substation locally or remotely from the Energy Control Center.

When completed, this project will provide Real Time Human Machine Interface (HMI) screens and protective relay fault/event/oscillography for the East River Substation to selected users via the Con Edison Wide Area Network. Access to the real-time data shall be read only thru a secure firewall. Implementation of the substation automation and protection upgrades proposed by this project is the completion of the multi-phase program started in 2001.

In addition, the East River 69 kV Critical Clearing Time (CCT) for three-phase fault breaker failure scenarios is 12 cycles. The existing relay protection systems cannot meet this CCT. The 12 cycle CCT can be met by replacement of the 69 kV breaker failure relays and the primary relay protection systems, which is part of this project.

Project Relationships (if applicable) Implementation will require an outage of each of the East River 69 kV Bus Sections. These outages are contingent on other scheduled and emergency outages at East River and East 13th Street substations.

Previous projects appropriated against this parent budget reference number are 20092-99, 20138-99, and 20156-99 for other East River (ER) substation improvements and upgrades. Expenditures for these projects are included in the cash flow shown below

3. Funding Detail

Historical Spend

	Actual 2017	**Actual 2018**	**Actual 2019**	**Actual 2020**	**Historic Year** (O&M only)	**Forecast 2021**
Capital	7	1	0	0		750
O&M						
Retirement	**0**	**0**	**0**	**0**		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	$3,000	$3,000	$-	$-	$-
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	887	893	0	0	0
M&S	0	0	0	0	0
Contract Services	1,200	1,200	0	0	0
Other	0	0	0	0	0
Overheads	913	907	0	0	0
Subtotal					
Total	$3,000	$3,000	$-	$-	$-

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations/System & Transmission Operation
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: EMS DevOps Upgrade	
Project/Program Manager: Michael Threet	**Project/Program Number (Level 1): 25443006**
Status: ☐ **Initiation** ☐ **Planning** ☐ **Execution** ☒ **On-going** ☐ ☐ **Other: ___________**	
Estimated Start Date: 1/1/2022	**Estimated Date In Service: 12/31/2026**
A. Total Funding Request ($000) **Capital: 13,232** **O&M: 500**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☒ **5-Year Gross Cost Avoidance ($000)** **O&M: 2500** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M: 500** **Capital: 0**	**D. Investment Payback Period: (Years/months) (If applicable)**

Work Description:
This project will replace the existing Energy Management System (EMS) that monitors and controls both the electric transmission and distribution systems over a period of five years. This system provides the users with an EMS that provides reliable system operability using the latest technologies and user interfaces. The dual redundant primary and standby systems are designed for complete independent operation from either control center. Phase 1 of this This project started in 2021. Phase 2 will start in 2022 and will be completed in 2025. Another phase will start in 2026.

Justification Summary:
Periodic replacement/upgrade of the EMS is necessary to ensure that the computer systems can continue to be supported and to take advantage of the latest operator tools being provider by EMS vendors. This is needed to ensure that the system will provide improved features for operators and support staff and meet the ever-evolving cybersecurity challenges and emergent compliance requirements such as the North American Electric Reliability Council (NERC) Critical Information Protection (CIP) standards.

Vendor software releases occur approximately every eighteen months, and computer hardware life of the product is about five years, which makes it necessary to complete an upgrade cycle every five years. The upgrade will include EMS ancillary systems and services such EMS instances on different less restricted networks/security zones and data historian systems. Also, the replacement of the hardware is necessary to maintain the capability of meeting performance requirements and to avoid losing hardware and software support provided by our vendors.

This project will change of the approach of large upgrades & long testing cycles to an approach of a continuous development continuous delivery, utilizing our test and quality assurance systems. This approach will reduce testing cycles, make deployment schedules more manageable, take advantage of recent functional innovation and security features more quickly and reduce the overall risk of the project by reducing the need for disruptive, unpredictable, and long cycle software upgrade projects, and allowing our resources to absorb new functionality as it is introduced versus extended training sessions where a multitude of new release features are included. As an added benefit that is of significant value is gaining the support of the same vendor team for the five-year duration of the project.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
This program is related to the Cybersecurity Risk and Loss of EMS Risk. The program does not address any climate adaptation, mitigation or decarbonization concerns, and it is not a CLCPA investment activity.

2. Supplemental Information

Alternatives.
Alternative 1 description and reason for rejection
Leave the system software and hardware at their current levels and do not take advantage of enhancements or system upgrades. This option risks the loss of security patch support, placing the system without antivirus / malware protection. It also could result in the loss of vendor support for the baseline software fixes and enhancements. Not providing the ability to enhance the EMS would cause the system to eventually become less effective in meeting our operational goals and would not provide the benefit of using the latest features.

By not maintaining operating systems and system hardware at near industry standards, the EMS systems and software would no longer be supported by the vendor and its third party suppliers. The loss of vendor support for security patch releases would make the EMS non-compliant with NERC CIP regulations, resulting in potential financial penalties for non-compliance.

Risk of No Action.
Risk 1
Not enhancing the EMS would cause the system to eventually become less effective in meeting our operational goals. In addition, by not maintaining operating systems and system hardware at industry standards, the EMS systems and software would run the risk of no longer being supported by the vendor and its 3rd party suppliers. The loss of vendor support for security patch releases would make the EMS non-compliant with NERC CIP reliability standards, resulting in the potential for the Company to incur financial penalties for non-compliance.

Non-Financial Benefits
The EMS replacement will take advantage of the latest vendor functionalities and make the system more secure. This will be achieved by keeping current when it comes to bug fixes and security patches are released, an important criterion for meeting NERC CIP requirements. The new hardware will also provide added computational power and increased memory speed, which are essential in the ever-increasing demand for processing power required by new tools and feature.

Summary of Financial Benefits and Costs (attach backup)
The total cost between 2022 and 2026 is estimated to be $13.732M. The estimate is based on a vendor quote and actual costs of the last EMS Replacement project. The EMS DevOps program is needed to maintain regulatory compliance, cybersecurity, and operational excellence.

Project Risks and Mitigation Plan

Technical Evaluation / Analysis
Project Relationships (if applicable) EMS Reliability AECC and ECC, which will be merged with this project.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital						2,199
O&M						
Regulatory Asset						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**2,492**	**2,492**	**2,492**	**3,264**	**2,492**
O&M*					
Regulatory Asset					

Capital/Regulatory Asset Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	227	227	227	297	227
M&S					
Contract Services	2,087	2,089	2,089	2,736	2,091
Other					
Overheads	178	176	176	231	174
Total	**2,492**	**2,492**	**2,492**	**3,264**	**2,492**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance	500	500	500	500	500
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M	100	100	100	100	100
Capital					

Central Operations/Substation Operations
2022

1. Project / Program Summary

Type: ☒ Project ☒ Program	**Category: ☒ Capital ☐ O&M ☐ Regulatory Asset**
Work Plan Category: ☐ Regulatory Mandated ☐ Operationally Required ☒ Strategic	
Project/Program Title: Erosion Protection and Drainage Upgrade Program	
Project/Program Manager: TBD	**Project/Program Number (Level 1): 25774996**
Status: ☒ Initiation ☐ Planning ☐ Execution ☐ On-going ☐ ☐ Other: ___________	
Estimated Start Date:	**Estimated Date In Service:**
A. Total Funding Request ($000) **Capital: $10,000** **O&M:**	**B.** **☐ 5-Year Gross Cost Savings ($000)** **☐ 5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months) (If applicable)**

Work Description:

This program will install reinforcements and upgrade drainage systems in select substations. The reinforcements will protect substations from erosion issues that may occur during extreme rain events. Some reinforcements may include hardening of existing cable troughs and transformer vaults. This program will start in 2024 and will target upgrades at roughly two substations per year.

Justification Summary:

Changing weather patterns have produced, among other things, an increasing frequency of extreme rain events. These types of events, Hurricane/Tropical Storm Ida being an example, have produced anywhere from four to eight inches of rain in a few hours. This type of deluge has impacted substations through large amounts of pooling water and, in some cases, erosion of topsoil in substations cited on uneven terrain. This erosion has undermined substation equipment, such as cable troughs, and poses reliability and safety risks.

Many outdoor substations have structures, such as troughs, installed at grade that contain control cable or other critical substation equipment. During extreme rain events, erosion can undermine these structures and cause them to shift. If shifting is extreme enough, critical substation equipment could lose control power or inadvertently trip out. These types of events can lead to outages that impact customers.

The erosion caused by extreme rain events could create unsafe conditions for substation personnel. These conditions may not be limited to the time of the extreme rain event. Undermined or eroded spots within substations could lead to injury to personnel.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):

This program affects the Substation Operations risk "Major Storm". This program will reduce the severity of major storm events by improving drainage and fortifying substations against extreme rain.

This program is part of the Company's climate change adaptation efforts. Extreme rain events are expected to increase in frequency and intensity with changing weather patterns.

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection

One alternative is to reconfigure outdoor facilities as indoor facilities that are better protected against extreme weather. This alternative would require extensive outages to complete and is cost prohibitive.

Risk of No Action

Risk 1

The risk of no action is that extreme rain events lead to erosion of soil and the undermining of critical substation facilities. This undermining could lead to substation trip outs and injuries to Company personnel.

Risk 2

Risk 3

Non-Financial Benefits

Examples:

- This program improves the resiliency of a substation.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)
N/A

2. Major financial benefits

3. Total cost: **$10,000**

4. Basis for estimate: The funding request for this program estimated that it will cost approximately $2.5M per substation to make necessary upgrades and that two station per year will be completed.

5. Conclusion

Project Risks and Mitigation Plan
Evaluate and describe any risks that might extend the project timeline, prevent completion, or lead to cost overruns. Explain plan to minimize these risks.

Risk 1: Delays due resources support coordination.

Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Technical Evaluation / Analysis
Describe any specific studies or analysis related to the project such as: trend analysis, internal/external studies, social studies, and related KPI's (e.g. System Average Interruption Frequency Index (SAIFI) or Customer Average Interruption Duration Index (CAIDI)). Load forecasts, failure trends, etc., may also be presented in this section. However, these analyses are not available for all projects or programs.

Project Relationships (if applicable)
N/A

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	0	0	0	0		0
O&M						
Regulatory Asset						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**$0**	**$0**	**$5,000**	**$5,000**	**$0**
O&M*					
Regulatory Asset					

Capital/Regulatory Asset Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	0	0	685	686	0
M&S	0	0	2,100	2,100	0
Contract Services	0	0	600	600	0
Other	0	0	242	241	0
Overheads	0	0	1,373	1,373	0
Total	**$0**	**$0**	**$5,000**	**$5,000**	**$0**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

Central Operations / STO
2022-2026

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Feeder 38R51 and 38R52 Replacement Project	
Project/Program Manager: Elissa Seidman	**Project/Program Number (Level 1):** 23289097
Status: ☐ **Planning** ☒ **Design** ☐ **Engineering** ☐ **Construction** ☐ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date:	**Estimated Date In Service:**
A. Total Funding Request ($000) **Capital: 234,000** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:
This project will replace Staten Island 138kV feeders 38R51 and 38R52. Feeders 38R51 and 38R52 originate from Fresh Kills Substation and are the only two supplies for Wainwright Substation. The existing circuits are directed buried, medium pressure fluid filled (MPFF) cables and will be replaced with cross-linked polyethylene (XLPE) cables in new duct banks. Feeders 38R51 and 38R52 have been prioritized for replacement due to environmental, maintenance, and reliability performance. Engineering, design and permitting are in progress for this project and some long lead equipment has been ordered. Construction will begin in the first quarter of 2022 and the project is expected to be completed by the end of 2023.

Justification Summary:
The design, physical configuration, routing, maintenance requirements, and overall performance of feeders 38R51 and 38R52 present the Company with operational challenges and risks. The feeders are without conduits or protection plates (having only a thin, easily-removed concrete layer over the direct-buried cables), route through protected wetlands and have a submarine crossing at the Fresh Kills Creek. Feeders 38R51 and 38R52 are the only two supplies to the Wainwright Substation. Pressurization of the dielectric fluid needed to maintain the insulation strength of the feeders is provided via dielectric fluid reservoirs at various points along the path of the feeders. This type of cable (having a lead sheath as the only pressure boundary to contain the dielectric fluid) and pressurization system requires frequent outages and a great deal of labor hours to repair and maintain. All of these factors increase the probability that a failure or defect will have an environmental impact or affect the reliability of the transmission system on Staten Island. Due to the obsolete design, topological configuration, and maintenance requirements, feeders 38R51 and 38R52 need to be replaced.

Conduits and steel plating play an important role in protecting underground transmission feeders from dielectric fluid leaks, insulation failures, or other damage inadvertently caused by excavation activities. Current design standards would require new feeder installations to utilize some type of conduit and, possibly, steel protection plates. Feeders 38R51 and 38R52 are direct buried cables without steel protection plates and are protected solely by an approximately three-inch thick layer of non-reinforced concrete. This configuration carries the risk that subsurface construction activities along the feeder route may damage the circuits, causing a dielectric fluid leak or outage. Given that the circuits follow the same route and are physically close together (only separated by two to three feet in many areas), there is a risk that both feeders could be damaged by such activities at the same time. In 2007, while excavating, a third party contractor damaged feeder 38R52, resulting in an electrical failure. The feeder was out of service for more than two weeks before repairs were completed. During the length of this outage, Wainwright Substation was in service via one supply feeder (38R51). Any further outage associated with the station would have required load shedding and deployment of mobile generation.

Dielectric fluid leaks on MPFF cable systems pose reliability risk unlike that for high pressure fluid filled (HPFF) cable systems. Unlike HPFF circuits, MPFF circuits must be de-energized to safely facilitate leak repairs. This requirement means that any time either 38R51 or 38R52 is leaking dielectric fluid, an outage must be taken to make repairs. In addition to leak repairs disrupting scheduled outages, they also leave Wainwright Substation in a position where a further contingency will result in loss of customers. Since 2007, feeders 38R51 and 38R52 have had over ten leaks that required circuit de-energization to make repairs. Some of these leaks have been on buried joints and many have been in manholes. As the circuits continue to age, more leaks and associated outages are likely to occur.

A manhole, as a leak location for 38R51 or 38R52, poses another unique reliability risk. Per OSHA regulations, a structure housing an MPFF circuit found to be leaking (considered a D fault condition) cannot be re-entered until such circuit is de-energized. Feeders 38R51 and 38R52 share the same route and have common manholes. This configuration allows the possibility that both circuits could have a leak in the same manhole at the same time. De-energizing both circuits at the same time to facilitate repairs would require temporary transfer of load to stations adjacent to Wainwright and massive deployment of mobile generation.

The routing of feeders 38R51 and 38R52 brings the risk of dielectric fluid leaks to environmentally sensitive areas (wetlands and the Fresh Kills Creek) where repair access may be very difficult. In 2017, 38R52 developed a leak in the Fresh Kills Creek section of the feeder. This event resulted in the loss of over 1,600 gallons of dielectric fluid to the waterway and required multiple, extended outages to make permanent repairs. One of the outages needed to make temporary repairs occurred during a high load period and required the deployment of mobile generation for contingency planning. The cause of the leak was a crack in the lead sheath of the cable due to settlement and movement over time. As feeders 38R51 and 38R52 continue to age and settle further, more leaks of this nature will likely occur.

Due to their design, feeders 38R51 and 38R52 require a great deal of maintenance hours relative to other 138kV circuits. The fluid pressurization reservoirs must be read and adjusted on a routine basis. If one of the feeders is leaking, the frequency of these adjustments increases and continues until the leak is located and repaired. These feeders have historically required between 300-400 labor hours per year to maintain. An analysis of the entire 138kV feeder population in terms of labor hours shows that these feeders are above the average by several standard deviations. XLPE cable systems already in use tend to be significantly less maintenance intensive than MPFF circuits.

Maintaining and repairing feeders 38R51 and 38R52 requires a specialized workforce and non-standard spare inventory. Given that these are the only MPFF circuits owned by Con Edison, new employees do not get many opportunities to splice or perform other repairs on feeders 38R51 and

38R52. Maintaining qualifications and expertise on these circuits is a challenge for the Company. Spare inventory must be carefully managed as the original equipment manufacturer no longer makes the cable used to construct 38R51 and 38R52. Although other manufacturers are willing to make this type of cable, they do so at a financial premium and contingent on long lead times. The replacement of both circuits with a standard, commonly used design would alleviate the personnel and spare inventory burdens associated with MPFF cable.

The replacement of 38R51 and 38R52 with XLPE cable in duct bank would eliminate the environmental and significantly reduce the reliability risks associated with feeders 38R51 and 38R52. The use of an XLPE cable system would eliminate 300-400 hours of maintenance, reduce unplanned outages, improve environmental performance, and help to standardize labor expertise and spare inventory.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
This project is related to reducing the likelihood of dielectric fluid spills. This project will increase the resiliency of the system by ensuring that the only two supplies to Wainwright would not need to be taken out in the result of a leak.

2. Supplemental Information

Alternatives

- Two additional alternatives were looked at for replacement of this project:
    - T-Tapping feeders 38R56 and 38R57 and establishing connections to Wainwright Substation. This option would use two of the three supplies to Woodrow Substation by adding wye joints and 2.75 miles of new XLPE ties to Wainwright Substation. This option was rejected for its increased reliability risk. Under this configuration, one feeder outage would affect two area stations and contingency planning.
    - A hybrid XLPE/overhead option. This option would utilize overhead transmission for a portion of the feeder route. This option was rejected because it would introduce the risks associated with overhead transmission such as lightning and storms.

Risk of No Action
Not replacing or deferring the replacement of feeders 38R51 and 38R52 will increase the risk of dielectric fluid leaks and reliability concerns for Wainwright Substation as the feeders continue to age. By not replacing feeders 38R51 and 38R52, the Company will continue to spend a disproportionate number of hours maintaining the existing circuits. Maintenance and leak response hours will likely increase as feeder leaks become more frequent. Because these feeders are the only two supplies to Wainwright substation, there is a high impact if one or both of these feeders are out of service. Loss of this substation impacts 91MW of load and almost 25k customers. There are several risks which could impact this scenario which include cable which continues to have leaks, the risk of another contractor dig-in, and the risk of a double D-fault in one structure. In the event that there is an outage, repair could be delayed if there is a need to special order cable and obtain skilled employees able to complete this work.

Non-Financial Benefits
Improved reliability and environmental performance are benefits of replacing these circuits. Replacement of the circuits with XLPE reduces dielectric fluid inventory and, the risk of a leak into an

environmentally sensitive area. Without having to perform maintenance specific to these feeders (the "Read and Adjust" work orders) labor hours will made available for other work on the transmission system. Replacement with XLPE also allows Con Edison to move to more standard equipment which reduces the need for special ordering or special inventory.

Summary of Financial Benefits and Costs (attach backup)
In Company labor alone, Con Edison is spending 30 times more on each of 38R51 and 38R52 than other 138kV circuits. Typical spend for Con Edison labor can range from $50K to over $500K, averaging about $350K per year. Including contractor costs for leaks and emergencies, Con Edison has had several years where over a million dollars in expense have been spent on these circuits. Projecting the maintenance trend forward, it is not unreasonable that the company is projected to spend well over million a year on these circuits. Replacing these circuits with XLPE would eliminate this maintenance need due to the more updated technology.

Project Risks and Mitigation Plan

Technical Evaluation / Analysis

Project Relationships (if applicable)

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	**N/A**	**N/A**	**N/A**	**N/A**		**7,099**
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**112,000**	**122,000**			
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	410	800			
M&S	8,009	2,950			
Contract Services	95,478	104,158			
Other	1,930	2,349			
Overheads	6,173	11,743			
Total	**112,000**	**122,000**			

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations/STO
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Feeder Replacement Program	
Project/Program Manager: Mark Bauer	**Project/Program Number (Level 1): 24004190**
Status: ☒ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☐ **Ongoing** ☐ **Other: ___________**	
Estimated Start Date: 2021	**Estimated Date In Service:**
A. Total Funding Request ($000) **Capital: 15,500** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:
This program will replace underground transmission cable- 69kV, 138kV, or 345kV. The projects done under this program will perform proactive section replacements, or in some cases, entire circuit replacements. For 2022 through 2024, this program will prioritize the replacement of low pressure feeders 37041/69, 37042/69, 37043/69, and 37044/69 at East River Substation.

Justification Summary:

ConEdison has one of the most expansive systems of underground cable, with an average cable age of 46 years. Replacement of underground cable is often costly, lengthy, and logistically difficult given the tight footprint of the underground system in ConEdison's territory. Given the number of circuit miles on the underground transmission system, the Company needs a long-term replacement plan. This program will replace transmission feeder cable, either by sections or entire circuits, in order to avoid an "asset wall", where failure rates may exceed the Company's ability to reliably perform replacements. The Company will use a feeder health index and analyses of operating challenges, such as failures and dielectric fluid leaks, to prioritize circuits for replacement.

Over the next four years this program will be used to address feeders 37041/69, 37042/69, 37043/69, and 37044/69. These feeders interconnect Phase Angle Regulator Units and Bus sections within East River Substation in Manhattan and were energized in 1956. These Low-Pressure Fluid Filled (LPFF) Feeders, along with their dielectric fluid reservoirs, have experienced repeated leaks with their advancing age and need replacement. In addition, the reservoirs are obsolete with no parts available for repair and replacement poses significant interference challenges due to the change in design and changes within the Substation.

Most recently, in May 2019 Feeder 37043/69 experienced a significant leak on the base lead wipe of one of the B phase potheads which had to be addressed on an expedited basis prior to the critical summer period. The leak had to be monitored daily until repairs could be made due to the significant leak rate and the limited reservoir volumes. A similar leak developing on any of these feeders during the summer period in the future represents a significant risk to overall system reliability

These low pressure fluid filled cables will be replaced over the next four years with solid dielectric cable and the existing reservoirs will be removed to prevent future leaks.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
This project is related to system resiliency and feeder failures. As clean energy generation increases in NYC, ensuring that the feeders on the system will be robust enough to move it to other parts of the state.

2. Supplemental Information

Alternatives
Generically speaking, the alternatives to feeder replacement include partial feeder replacement, whole feeder replacement, or run to failure of the feeder. The best option for the feeder needs to be determined by looking at the cost and feasibility versus the benefit.
For the East River feeders, the reservoirs could be replaced although this does not entirely eliminate the risk or maintenance required on these feeders.

The risk of no action would mean the cables would need to be replaced after they fail or need repair. While this would delay the cost of replacement, it means an unplanned outage and impact to the system.

Non-Financial Benefits
Oil Filled cable requires more maintenance than non-oil filled cable. At East River, the replacement of the existing cable will significantly reduce the maintenance required on these feeders.

Summary of Financial Benefits and Costs (attach backup)
The estimate is based on historical costs

Project Risks and Mitigation Plan

Technical Evaluation / Analysis

Project Relationships (if applicable)

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	N/A	N/A	N/A	N/A		75
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	2,500	2,500	3,500	3,500	3,500
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	875	875	1,100	1,100	1,100
M&S	600	600	1,000	1,000	1,000
Contract Services					
Other	143	151	222	223	232
Overheads	882	874	1,178	1,177	1,168
Total	2,500	2,500	3,500	3,500	3,500

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations/ Substation Operations
2022

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Fire Suppression System Upgrades Program	
Project/Program Manager: Sara Gherman	**Project/Program Number (Level 1): PR.2ES8800/ 10030252**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date: N/A	**Estimated Date in Service: N/A**
A. Total Funding Request ($000) **Capital: $58,559** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This program will perform upgrades, replacements, and/or new installations of fire protection, suppression, deluge system, detection, and alarm systems at various substations. The fire detection upgrades include the replacement of fire/heat/smoke detection equipment (inclusive of wiring, control systems, alarm devices, panels, etc.) which is used to detect a fire and initiate an alarm; in many cases this activates a deluge system. The deluge system upgrades include the replacement of piping, pumps, spray nozzles, wiring, control systems, and enclosures associated with delivering water to a fire once a fire is detected. In addition, this program includes the installation of FM 200 Clean Agent System.

This program funds the modification of existing substation fire protection fire pump piping. These modifications include adding fire pump test headers, valve replacement, piping replacement and work associated with recovering fire system capacity. This covers multiple substations, and it is a multi-year initiative that started in 2008.

This program will also fund the installation of clean agent fire suppression systems in various dielectric fluid enclosures (pumping/cooling/Public Utility Regulating Station - PURS plants). This is an ongoing program that began in 2012. ConEdison has identified 57 Phase I locations. This project is a multi-year, multi-phase effort. As part of the Phase I effort, Central Monitoring addition is required on the New York City installations at 27 locations.

Central Monitoring is also required at any location with a lawfully installed Fire Alarm Control Panel. As part of the Letter of Approval initiative, Central Monitoring is required to obtain acceptance of such systems within New York City (NYC). This program will fund the installation of third-party Central Station Monitoring system upgrades to the existing fire suppression and detection systems at the various substations.

The traditional deluge systems moats capacity is designed to contain at least 20 minutes of water flow from the Deluge Water Spray System. A system to limit the amount of water flow once "no fire" has been detected has been developed and is called a "Cycling Deluge Water Spray System". This Cycling System will automatically shut down the deluge system after ten minutes of water flow if no heat is being detected. This Cycling system will reduce exposure to spills by minimizing water flow and assist in the Company meeting Spill Prevention Control and Counter Measures (SPCC) regulations. To install Cycling deluge systems requires the replacement of obsolete deluge valves, in some applications, and in some applications upgrading of deluge valves trim to allow this remote automatic resetting feature. Lastly this automatic re-setting deluge valve is controlled by our standard Fire Control Panel. Likewise, here the fire control panel in some locations will require replacements and, in some applications, upgrading of the standard fire control panels circuitry is required.

Justification Summary:
The fire detection and deluge systems represent a critical component in our ability to respond to a fire event quickly and safely in our substations. The systems we identified not only protect our equipment, but personnel, emergency responders, and the public. The systems installed at our substations are required to comply with National Fire Protection Association (NFPA) and NYC Codes and Regulations, and it is critical that they are maintained in proper working order. Some deluge systems are approaching their expected end of service life, and they are beginning to show signs of deterioration or decreased reliability. Some systems have begun to show excessive leaking, failure to provide adequate flow rates, and/or maintain adequate pressure. At several stations, we have determined that the entire deluge system—including pumps, piping, and controls should be replaced. Several of our fire detection systems show similar end of service life issues. In many cases, replacement detection heads can no longer be obtained, control panel parts are unavailable, and system reliability is compromised.

In past years Con Edison has suffered three incidents that resulted in damage to pumping plants or cooling plants. These events have demonstrated the vulnerability of these enclosures and systems. There are several potential consequences to pumping plant fires. One is the sudden loss of pressurization at the plant, which could affect multiple transmission feeders and electric service to many customers. The other consequence is the potential impact to the public or surrounding structures.

Substation Operations and Electrical Engineering performed a review of existing plants and provided recommendations (report dated 12/21/10) stating that certain facilities (pumping plants, cooling plants, Public Utility Regulating Stations (PURS)) should be upgraded with fire suppression systems based on their proximity to public property or critical system infrastructure.

System Operations and Electrical Engineering also conducted a study of the importance of each pumping plant on the system during the peak summer load period (refer to white paper "Pumping Plant Improvements – Based on Lessons Learned from Recent Fire Events", by Electrical Engineering Rev 0 dated 5/31/11) and provided recommendations. Efficient Frontier Curves were developed which illustrated the relative efficacy of options to reduce the risk of load drop. The most efficient capital solution to this risk was the deployment of FM-200 fire suppression systems. The pumping, cooling, and PURS Plants listed were identified by one or both studies as candidates to be retrofitted with a fire suppression system.

The Fire Department now requires official Central Station Monitoring of all new and significantly upgraded fire suppression and detection systems. As such, the company has initiated a project to programmatically install Central Station Monitoring at the various substations that will be connected to the existing fire protection systems and new systems in the future.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
Fire Protection, suppression, and detection systems help to protect essential equipment from extensive damage during a fire. These systems also help guard against collateral damage to neighboring equipment as well as improve personnel and public safety. A new system substantially improves and simplifies the station's alarm annunciation and alarm management that can affect the reliability of the electric system and possibly result in the loss the loss of a substation.

2. Supplemental Information

Alternatives
1) Some existing systems cannot be upgraded because spare parts are no longer produced. This could leave critical parts of the substation without fire detection and the existing system could become noncompliant with New York City fire codes and standards.

2) Rely on the operator to routinely check for fire. The system would then not meet current New York City codes and standards. In addition, this is not a practical long-term solution, or an efficient use of personnel.

Risk of No Action
Continuing to operate existing fire detection and suppression systems without upgrades will reduce the reliability and availability of the fire protection systems and increase the possibility of damage to the equipment, environment, personnel, and the public. In addition, we could potentially not remain in compliance with the current New York City fire codes and standards.

Non-Financial Benefits
Fire Protection, suppression, and detection systems help to protect essential equipment from extensive damage during a fire. These systems also help guard against collateral damage to neighboring equipment as well as improve personnel and public safety.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis: N/A

2. Major financial benefits
Limit the cost of damage to operating equipment, personnel, environment and public.

3. Total cost **$$58,559**

4. Basis for estimate: The annual funding request for this program is based on completing 14-22 projects of various types, at a cost range of $200K to $2.3M each.

5. Conclusion: N/A

Project Risks and Mitigation Plan
Project Risks:
Risk 1: Outage scheduling conflicts with other initiatives.

Mitigation: Outages to be coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs to avoid conflict with other program/ projects resulting in a more predictable budget and manageable outage scheduling.

Risk 2: Delays due resources support coordination.

Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Risk 3: **Lack of alignment between resources support and outages.**
Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor and construction to avoid alignment conflicts with outages.

Technical Evaluation / Analysis:
The capability to alert personnel both locally and remotely at the Energy Control Center (ECC) during a fire is critical to the operation and reliability of the station. Lack of functional fire alarm systems could result in extensive damage to substation equipment and could impact personnel safety.

The ability to alert the Fire Department quickly in the event of a fire is also critical. The quicker the response to a fire and the faster it can be brought under control results in less damage to equipment and disturbance to the operating system. The installation of third-party Central Station Monitoring systems associated with the existing fire protection systems at the various substations will improve the notification and response by the Fire Department.

Modifications, including the addition of valves and a fire pump test header, are required to comply with NFPA and NYC Codes and regulations. The fire pump test header installation will also provide a means to test and evaluate the condition of the fire pumps to ensure proper performance for adequate protection of transformers. The addition of the fire pump discharge valve will improve equipment availability by eliminating the need to shut down all transformer deluge system valves and all fire department Siamese connections while performing the monthly required fire pump operating test.

In reference to new fire protection, detection, suppression systems, the existing systems have been repaired and/or serviced to the extent possible, but some continue to suffer from unreliable operation or have poor availability. When replaced, the systems are upgraded to meet current local and national fire codes.

Project Relationships (if applicable) Replacement or new installation of fire detection on transformers requires outages of the applicable equipment and are subject to system conditions.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	12,837	8,483	5,083	900		1,088
O&M						
Retirement	68	340	48	2,112		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**$11,740**	**$12,140**	**$12,406**	**$12,273**	**$10,000**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	3,898	4,030	4,119	4,075	3,320
M&S	1,052	1,103	1,117	1,103	920
Contract Services	2,989	3,108	3,192	3,163	2,583
Other	0	0	0	0	0
Overheads	3,802	3,898	3,979	3,932	3,177
Subtotal					
Total	**$11,740**	**$12,140**	**$12,406**	**$12,273**	**$10,000**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations/ Substation Operations
2022

1. Project / Program Summary

Type: ☐ Project ☒ Program	**Category: ☒ Capital ☐ O&M**
Work Plan Category: ☐ Regulatory Mandated ☐ Operationally Required ☒ Strategic	
Project/Program Title: Gas Insulated Substation Replacement Program	
Project/Program Manager: Jim Neilis	**Project/Program Number (Level 1): PR23287705**
Status: ☒ Planning ☐ Design ☐ Engineering ☐ Construction ☐ Ongoing ☐ Other: ___________	
Estimated Start Date: Ongoing	**Estimated Date In Service: Ongoing**
A. Total Funding Request ($000) **Capital: $ 114,500** **Retirement:**	**B.** **☐ 5-Year Gross Cost Savings ($000)** **☐ 5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:
This program will replace switches, bus sections, and ancillary equipment at existing Gas Insulated Substations (GIS). The Company has four GIS facilities on the transmission system; W49th Street Substation, Dunwoodie 345kV Substation, Mott Haven Substation and Academy Substation. In a GIS facility, the major high voltage equipment is contained in a sealed environment with sulfur hexafluoride gas (SF6) as the insulating medium.

GIS technology originated in Japan, where there was a substantial need to develop technology to make substations as compact as possible. The clearance required for phase to phase and phase to ground for all equipment is much lower than that required in an air insulated substation; the total space required for a GIS is 10% of that needed for a conventional substation

This program will prioritize replacement of GIS switchgear at W49th Street Substation. The 138kV sections of GIS equipment at West 49th Street have exhibited the highest frequency of leaks and will be the first sections targeted by this program. The 345kV section replacements will follow the completion of the 138kV sections at W49th Street Substation. Based on ongoing condition assessments, Dunwoodie 345kV Substation may also be prioritized for partial or full switchgear replacement.

Engineering for the W49th Street Project is already in progress and procurement and part of construction started in 2021. Due to the complexity of outage scheduling, equipment lead-times and construction requirements, the W49th Street project is expected to be completed by 2030.

Justification Summary:

Over time, GIS facilities develop leaks that result in environmental releases of SF6 gas that can lead to moisture ingress into high voltage equipment. SF6 is a greenhouse gas (GHG). West 49th Street Substation is the lowest performing GIS facility in terms of SF6 leakage and forced outages due to moisture ingress. Due to the environmental, reliability and supply chain challenges presented by SF6 leakage, a program is needed for the phased replacement of GIS equipment and W49th Street Substation is the priority location.

SF6 leaks are not the only potential source of unplanned or long-term outages associated with GIS switchgear. Disc insulators provide support for the center conductor and form a pressure boundary between different portions of the GIS equipment. During some inspections of the bus and disc insulators, electrical treeing has been observed. If a disc insulator has failed, the replacement parts are typically custom ordered, and an extended outage is necessary to complete repairs. This type of failure mode, and the lead time required for repair parts, underline the complexity of reliability and supply chain risks associated with the older generation of GIS equipment.

Dunwoodie 345kV and West 49th Street substations were constructed using early GIS technology that has diminishing industry usage and support. ITE was the original equipment manufacturer (OEM) and was absorbed by another company. Technical oversight is necessary to make many replacements on the GIS switchgear and associated breakers and there are few personnel available with knowledge of the old ITE equipment. As other utilities continue to phase out this vintage of equipment, technical oversight and replacement parts will become increasingly difficult to obtain.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
This program address the Substation Operations risk “Equipment Failures”. This program reduces the likelihood of equipment failures by proactively replacing GIS equipment that may leak or fail and cause a forced outage.

As this program replaces SF6 containing equipment that is leaking, it is part of the Company’s climate change mitigation efforts. The upgrade of GIS with equipment with newer technology not only eliminates GHG emitting equipment but it utilizes components with a smaller overall SF6 footprint.

2. Supplemental Information

Alternatives

- Repair

The methods to repair GIS include colt clamping, welding, and overhaul of sections of the system. The installation of a clamp is a temporary fix and very costly. The clamps add weight to the bus structure and could impact structural integrity. Repairing disc insulators is a current practice, however, it requires long duration outages reducing reliability.

- Replacement with like-in-kind equipment

This approach is not desirable as the existing design has much higher than desired leak rate. In addition, keeping the existing GIS technology may continue to incur high O&M costs. Like-in-kind will also be secondhand equipment as this equipment is no longer manufactured.

- Replacement with new technology

A small section of the W49 Station (bus section 9-10) has been replaced with current GIS technology (similar to Mott Haven). There has been minimal SF6 leak at the Mott Haven station; indicating new technology reduces the SF6 emission significantly.

Risk of No Action

- Moisture ingress negatively affects dielectric strength. Once getting onto the system, water molecules may react with SF6, producing corrosive hydrogen fluoride. In case of a fault, the presence of water may lead to toxic substance, generating safety threats, outages are taken to address high moisture level problems, significantly impacts system reliability

- A high number of temporary repairs (clamps) on the GIS may become the spots for leaks in the future, sustaining high material cost for the SF6 gas leaks and significant corrective maintenance expenditures.

- Disc insulators require long duration outages to replace.

- The supply risk in the event of a serious failure since the related OEM parts may require long lead-time. Moreover, there are only a few similar GIS systems in service worldwide, and the chance manufacturer might stop supporting this generation of GIS technology if other similar stations were replaced.

Non-Financial Benefits
Non-financial benefits include improved environmental performance and avoidance of unscheduled outages to repair GIS leaks.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis: N/A

2. Major financial benefits
o In sum, annual O&M costs to manage SF6 issues at W 49th SS are very high, averaging about $600,000 per year only in parts ordering and O & M repairs. This replacement could save approximately $1.3 million per year in SF6 if emergency response and outage management, parts ordering and O&M repairs are factored in.

3. Total cost **$114,500**

4. Basis for estimate: The 2023 funding for this program is based on a 138kV section (approximately $8M) plus $5M in procurement of the equipment needed for the subsequent year. The 2024 and 2025 funding is based on approximately $23M for two 345kV sections and $5M in equipment procurement.
5. Conclusion: N/A

Project Risks and Mitigation Plan
Project Risks:
Risk 1: Outage scheduling conflicts with other initiatives.

Mitigation: Outages to be coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs to avoid conflict with other program/ projects resulting in a more predictable budget and manageable outage scheduling.

Risk 2: Delays due resources support coordination.

Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Risk 3: **Lack of alignment between resources support and outages.** Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor and construction to avoid alignment conflicts with outages.
Technical Evaluation / Analysis: N/A .
Project Relationships (if applicable) N/A

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	0	0	0	5,374		4,900
O&M						
Retirement	0	0	0	0		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**$13,000**	**$13,000**	**$28,500**	**$28,500**	**$31,500**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	2,340	2,340	5,130	5,130	5,670
M&S	1,690	1,690	3,744	3,752	4,159
Contract Services	5,443	5,467	11,949	11,945	13,250
Other	0	0	0	0	0
Overheads	3,527	3,503	7,677	7,672	8,421
Subtotal					
Total	**$13,000**	**$13,000**	**$28,500**	**$28,500**	**$31,500**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations/ Substation Operations
2022

1. Project / Program Summary

Type: ☐ Project ☒ Program	**Category: ☒ Capital ☐ O&M**
Work Plan Category: ☐ Regulatory Mandated ☐ Operationally Required ☒ Strategic	
Project/Program Title: High Voltage Circuit Breaker Capital Upgrade Program	
Project/Program Manager: Gregory Jimenez	**Project/Program Number (Level 1): . PR.10105998**
Status: ☐ Planning ☐ Design ☐ Engineering ☐ Construction ☒ Ongoing ☐ Other: ___________	
Estimated Start Date: N/A	**Estimated Date In Service: Ongoing.**
A. Total Funding Request ($000) **Capital: $105,700** **O&M:** **Retirement: $7,957**	**B.** **☐ 5-Year Gross Cost Savings ($000)** **☐ 5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

The program scope has expanded to include 12kV, 27kV, 33kV and 69kV breaker replacement or upgrades. This program will replace or upgrade 33kV, 69kV, 138kV and 345kV breakers. This program primarily targets SFA, PK4C and SF/P breakers for replacement but may also be used to replace oi filled breakers as well. The Company considers breaker health, reliability, SF6 leakage, corrective maintenance hours and/or major maintenance requirements when prioritizing breakers for replacement.

This program will target approximately 17 breakers per year for replacement at cost of $1M to $2M per breaker. Included in the plan is the replacement of approximately 38 breakers (over 5 years) that utilize SF6 as the insulating medium.

Justification Summary:
The reliable operation of circuit breakers is required during any system disturbance to effectively isolate that disturbance from the system. Failure to do so can have serious system consequences and impact customer service reliability. The proper isolation of system disturbances is also critical in maintaining a safe working environment for station personnel as well as safety to the public. Breakers are targeted for replacement under this program because they either exhibit poor health, leak SF6 and/or have higher volumes of SF6 gas than more modern breakers. Breakers that utilize lower volumes of SF6 (as an insulating medium) will be used as replacements done under this program. Although SF6 breakers remain a technology that the Company will utilize, replacement of legacy

breakers that exhibit leaks and/or have higher volumes of gas will reduce the Company's contribution to green house gas emissions (GHG).

SFA breakers and SF/P breakers are prioritized for replacement as part of the Company's climate change mitigation strategy. SFA breakers have frequent leak issues which contribute to GHG emissions. The Company has four remaining SFA type breakers that will be replaced as part of the program. SF/P breakers contain roughly 700 pounds of gas and the replacement breaker of choice has less than 1/10 of this volume (~64 pounds). By prioritizing SF/P breakers for replacement, Con Edison's SF6 footprint is reduced and the volume of gas that can potentially leak is reduced with it.

Breakers are essential components of the transmission system. They function, among other reasons, to isolate equipment during fault conditions and if they do not work properly, further equipment damage and/or customer outages can occur. Utlizing SF6 gas is a necessary fact of operating a modern and reliable transmission system but the Company strives reduce volumes of the gas wherever possible.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):

This program addresses the Substation Operations Enterprise Risk Management "Equipment Failures". The proactive replacement of High Voltage breakers reduces the likielihood of equipment failures in two ways: 1. Replaces degraded breakers that may electrically fail themselves and 2. Replaces a degraded component that may fail to open during a fault and subject other equipment to transient conditions that could result in their failure.

This program is part of the Company's climate change mitigation efforts. SF6 is a greenhouse gas and breakers that leak are contributing to climate change. Additionally, more modern breakers that are used as replacements contain a smaller overall volume of SF6 gas.

2. Supplemental Information

Alternatives

•Alternatives: An alternative is to overhaul or replace circuit breakers based on lifetime of the unit. This method was employed up through 2008. While it did maintain the reliability of circuit breakers, it was not the most effective or efficient method to maintain the circuit breaker fleet. Advances in database record keeping, on-line monitoring systems, and maintenance ranking programs have allowed the circuit breaker maintenance program to be more accurately evaluated through a performance-based method. The time-based maintenance method is therefore not recommended.

Another alternative is to perform no overhauls or replacements of circuit breakers. This is not recommended because of reliability, system performance, environmental, and safety concerns.

Risk of No Action

Failure to replace these breakers would significantly affect the operation of the electric system as well as result in environmental and safety concerns. The failure to address the deteriorating oil circuit breaker population would have similar effects.

Non-Financial Benefits

Replacement of the identified class of breakers has helped Con Edison to reduce environmental incidents such as SF6 gas emissions and oil spills.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis: N/A

2. Major financial benefits
The 345kV SFA breakers have been targeted for replacement. A new overhaul to address the various problems of this breaker type was approaching $900k, while the total replacement cost for this unit is approximately $2 million dollars (labor and material). There are currently two classes of 138kV breakers that have been identified for replacement (OCB and Westinghouse 1380) due to their high failure rate, high cost of repairs and overhaul, and maintenance history problems. The 33kv class of breakers has been recently added to the overall breaker replacement program due to observed degradation. These increased failures have impacted both residential and commercial customers, which affects SAIFI performance.

3. Total cost **$105,700**

4. Basis for estimate: The program funding is based on replacing approximately 17 breakers per year at a cost of $1M-$2M per breaker.
5. Conclusion :N/A

Project Risks and Mitigation Plan
Project Risks :
Risk 1: Outage scheduling conflicts with other initiatives.

Mitigation: Outages to be coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs to avoid conflict with other program/ projects resulting in a more predictable budget and manageable outage scheduling.

Risk 2: Delays due resources support coordination.

Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Risk 3: **Lack of alignment between resources support and outages.**
Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor and construction to avoid alignment conflicts with outages.

Technical Evaluation / Analysis :
The reliable operation of circuit breakers is required during any system disturbance to effectively isolate that disturbance from the system.

The replacement of the selected breakers will address the operational, reliability, environmental, and cost concerns. The new breaker types that are being installed have been used extensively in our 345kV and 138kV circuit breaker upgrade program, and have provided an improved maintenance record and have enhanced the reliability of the system.

Project Relationships (if applicable) N/A

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	15,338	9,500	9,309	9,153		5,182
O&M						
Retirement	1,677	2,215	1,053	1,421		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	12,100	25,400	23,400	24,800	20,000
O&M*					
Retirement	1,591	1,591	1,591	1,591	1,591

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	3,793	7,991	7,383	7,833	6,326
M&S	2,420	5,080	4,680	4,960	4,000
Contract Services	1,592	3,372	3,085	3,265	2,676
Other	363	762	702	744	600
Overheads	3,932	8,195	7,550	7,999	6,398
Subtotal					
Total	**$12,100**	**$25,400**	**$23,400**	**$24,800**	**$20,000**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations/ Substation Operations
2022

1. Project / Program Summary

Type: ☐ Project ☒ Program	**Category: ☒ Capital ☐ O&M**
Work Plan Category: ☐ Regulatory Mandated ☐ Operationally Required ☒ Strategic	
Project/Program Title: High Voltage Test Set Program	
Project/Program Manager: Steven Bryan	**Project/Program Number (Level 1): PR.2ES8400/ 10030248**
Status: ☐ Planning ☐ Design ☐ Engineering ☐ Construction ☒ Ongoing ☐ Other: ___________	
Estimated Start Date: On going	**Estimated Date in Service: Ongoing**
A. Total Funding Request ($000) **Capital: $18,300** **O&M:** **Retirement:**	**B.** **☐ 5-Year Gross Cost Savings ($000)** **☐ 5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This program funds the purchase and installation of direct current (DC) and alternating current (AC) high voltage test sets that are used for feeder processing on the Con Edison distribution system. It also provides funding for required ancillary equipment, such as a power feed for the test set, or test leads that bring the set outputs to the feeders being tested throughout the station. In addition, this program funds the purchase and installation of typical AC/DC test sets, which will provide the critical functionality of both types of test sets into a single unit.

Justification Summary:
Currently, we need to use both an AC test set and a DC test set to process feeders. Maintaining both AC and DC test sets in a station is difficult, as there is insufficient space to house these units. Our goal is to move to a dual function test set and place these sets in networks that have had 80% of the paper cable replaced. We are working with test set manufacturers to develop a dual function test set that will give us the AC & DC capability to perform hi-pots, fault conditioning and fault locating in one unit, thus enabling us to perform all feeder processing activities with a single test set. We have tested and accepted the first manufactured prototype. We are starting the purchase and installation of these units in stations that still require AC testing capability. We are testing a second prototype from a different manufacturer this year. The prototypes will be placed in service for extended testing to prove the capabilities and resolve any operating issues with the prototypes. We are hopeful that both prototypes will be successful and result in a competitive market. We anticipate receiving manufactured AC/DC combination sets available for installation going forward and are transitioned away from future purchases of AC and DC only test sets.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
This program addresses the Substation Operations departmental risk probability of Equipment Failures by proactively replacing equipment it is anticipated that the frequency of in-service failures reducing with new technology outage frequency and duration.

2. Supplemental Information

Alternatives
AC Test Sets - As noted above, we are working to develop an AC/DC test set. This would reduce our overall funding needs for this program, as it would halve the number of test sets that we would be required to purchase and maintain in our stations. We will continue to work with the equipment manufacturers to help develop the equipment to serve are company's needs.

We could also move back to DC hi-pots on our distribution feeders, negating the need to purchase AC hi-pot sets. This alternative is not recommended, as AC hi-pots have proven to be better at detecting incipient faults on solid dielectric feeders and reducing the time to the next in-service failure.

DC Test Sets - Our primary alternative is to stop replacing DC test sets and continue to repair our problematic sets. This alternative is not recommended. Test set availability is critical to our ability to process feeders expeditiously. Leaving units in place that are likely to break down when called upon to perform will result in an increase in feeder processing times.

Risk of No Action
Failure to maintain our fleet of test sets will lead to extended feeder processing times, as work will need to be suspended in order to repair defective test sets. If additional feeders open auto while this is happening, customers may experience low voltage conditions, or load shedding could occur.

Non-Financial Benefits
The benefit to keeping the test program current with new technology reduces outage frequency and duration.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis: N/A

2. Major financial benefits
Financial benefits are realized with the installation of a combination set in a DC position. An AC/DC combination set could be installed in a current DC Set position thereby eliminating the need to purchase additional DC Sets. The cost of purchasing an AC set is $313k and a DC Set is $120k or $433k together. We anticipate an AC/DC combination set will cost between $400 and $450k, but a second manufacturer will affect costs through increased competition. We do expect there will be cost avoidance savings where a DC set is directly replaced by an AC/DC combination set, as shown below:

- o Cost to install a separate Test Bus $300k - $500k
- o Cost to build a Test facility $700k - $1.3 million

3. Total cost **$18,300**
4. Basis for estimate: Because of the variability in costs per location, the annual funding request of $2.8M per year is based on the per year average expenditure of the last 10 years.

The estimated unit purchase cost of the equipment (excluding installation materials, costs, and commissioning tests) is:

- DC test set: $120k
- AC VLF test set: $313k
- AC/DC Test set: $400k

Installation costs can range from approximately $215k-$2 million, depending on the exact scope that is required. Some substations require minimal amount of material and labor while others might require more. The amount of bus sections in a station has a direct correlation to the increase in scope. Typically, a test bus must be installed, and its length and complexity greatly affect the cost of the job. In some cases, additional facilities or facility upgrades are required to provide adequate space for the test set within the station. We expect the development of the AC/DC test set to minimize the need for additional facilities or facility upgrades.

5. Conclusion: N/A

Project Risks and Mitigation Plan
Project Risks:
Risk 1: Outage scheduling conflicts with other initiatives.

Mitigation: Outages to be coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs to avoid conflict with other program/ projects resulting in a more predictable budget and manageable outage scheduling.

Risk 2: Delays due resources support coordination.

Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Technical Evaluation / Analysis: N/A

Project Relationships (if applicable) N/A

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	2,936	2,054	1,083	862		498
O&M						
Retirement	15	0	142	77		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**$3,400**	**$2,800**	**$2,800**	**$2,800**	**$6,500**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	952	784	784	784	1,820
M&S	1,338	1,108	1,109	1,109	2,591
Contract Services	0	0	0	0	0
Other	0	0	0	0	0
Overheads	1,110	908	907	907	2,089
Subtotal					
Total	**$3,400**	**$2,800**	**$2,800**	**$2,800**	**$6,500**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations/STO
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Joint Replacement Program	
Project/Program Manager: Mark Bauer	**Project/Program Number (Level 1):** 22679448
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date:	**Estimated Date In Service:**
A. Total Funding Request ($000) **Capital: 53,000** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

The purpose of this program is to replace joints on existing transmission feeders that are at risk of failing electrically and/or mechanically and cannot be addressed through routine corrective maintenance. This is a program that will improve the reliability of the transmission system.

While the initial scope of this program targeted between one and two joints per year, following the replacement of 15 joints on the Brownsville feeders, the scope of this project will increase to three joints per year in 2023 and then four joints per year in 2024, in order to increase system resiliency. The joints selected for inspection/replacement will be based upon priority (as determined by Transmission Engineering), and feeder outage availability.

Engineering has developed a prioritized list of transmission feeder joints based on feeder performance and investigations that are being addressed under this program and include:

Priority	Feeder	MH
1	Q11	M-15523
2	71	M-27001
3	M51	M-61727
4	702	M-55952(3?)
5	72	M-26595
6	71	M-26595
7	72	M-26594
8	71	M-26594
9	Q12	M-15523
10	15054	M-458

Future joints will be identified by Engineering for outer years.

Justification Summary:
There have been failure events (both electrical and mechanical) associated with joints on transmission feeders during the past few years that have motivated investigation into whether similar vulnerabilities exist in other locations. These investigations have identified transmission feeder joints that are at risk of electrical and/or mechanical failures that will adversely affect reliability.

Electrical failures and cable damage encountered on Feeders M51 (2011), 69M05 (2012), 38B05 (2012) and 72 (2014) exhibited root causes that suggested the potential for other locations with similar conditions. The April 2011 failure of Feeder M51 was in a semi-stop joint (on Broadway in Manhattan). The observed failure mechanism led to digital x-ray investigation of other joints of similar design on 345kV Feeders M51 and M52. These x-ray results led to the opening of another semi-stop joint on Feeder M51 in March of 2012 to determine if similar damage occurred; significant damage was found, which led to the semi-stop joint's proactive replacement with two buried joints and a cable insert. The failure of High Pressure Gas Filled (HPGF) Feeder 69M05 in manhole M58297 led to investigation of other 69kV feeders with similar joint casing configurations that could have inadequate joint support. The further investigations of 69kV feeders resulted in a joint opening on Feeder 69M06; significant damage was found and that led to the proactive replacement of the joint with two joints and a cable insert. Failures on 138kV Feeder 38B05 and 345kV Feeder 72 were deemed to be due to shielding damage and splice connector vulnerabilities that led to similar x-ray investigation and joint openings, and subsequent joint replacements.

Compromised pipe integrity due to loss of wall thickness has led to many leaks on various High Pressure Fluid-Filled (HPFF) transmission feeders in manholes. Pipe integrity is maintained by pipe coatings and, in buried sections, cathodic protection. Cathodic protection is ineffective in manholes due to the absence of surrounding fill material to act as an "electrochemical cell" allowing the flow of cathodic protection current. Thus, compromised pipe coating in manholes has an increased likelihood of developing leaks. The high leak rate of some of these events can result in a loss of feeder pressure sufficient to require that the feeder be removed from service to maintain its dielectric integrity and to make necessary repairs. Repeated corrosion issues, feeder leaks, and complex repair solutions on joint casings and auxiliary piping systems in certain locations have led to conditions that can no longer be addressed with corrective maintenance. These locations exhibit leaks that have a significant impact on feeder availability- and thus overall system reliability- as leaks can necessitate emergency de-energization of the associated feeders.

Engineering inspections have led to the identification of multiple locations on 138kV Feeder 702 and 345kV Feeder M51 that required splice joint replacement due to corrosion conditions that are beyond the normal scope of corrective repair.

Based upon these recent developments, this program will target joints on the underground transmission system that exhibit the susceptibility for electrical or mechanical failure. Engineering has developed a prioritized list of suspect transmission feeder joints to be addressed under this program going forward; however, future evaluations may result in an expanded list and a new priority order with which to address them.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
This program is related to the reducing the departmental goal of reducing the likelihood of equipment failure. Identified joint issues are imperative to address in order to maintain system resiliency as joint failures is a cause of feeder failure on the transmission system.

2. Supplemental Information

Alternatives
Perform Corrective Maintenance: Corrective maintenance cannot address the potential electrical and mechanical failure causes in various transmission splice joints or joint casings that have been identified through engineering inspections because the material conditions require wholesale replacement.

Risk of No Action
No action on replacing these joints is allowing them to "Run to Failure" . This course of action would allow the joints to fail in service, requiring emergency replacement and restoration. This course of action leads to unscheduled outages that may occur during periods of either high demand or concurrent to planned system outages, affecting transmission system reliability and potentially its ability to supply the required load. Unplanned outages may also cause the cancellation of planned outages to perform scheduled reliability work as well as result in increased expenditure on the deployment of emergency resources. See "Risk of No Action" for more detail.

Non-Financial Benefits
The benefits of this program are improved system reliability and a reduction in the likelihood of dielectric fluid leaking to the environment.

Summary of Financial Benefits and Costs (attach backup)
The unit cost of this project is based on the historical average with adjustment for cost increase of replacing these joints. The unit rate for replacing joints is $4M per 345 kV joint and $2.5M per 138kV joints. The program funding is based on replacing two 345kV joints and one 138kV joints in 2023 and this will increase to two 345kV joints and two 138kV joints in 2024 and beyond.

Project Risks and Mitigation Plan

Technical Evaluation / Analysis
Some recent transmission joint failures have, upon inspection, displayed damage characteristics that indicate the presence of potential common modes of failure that may exist on certain joints on the transmission system. As technology advances and non-destructive inspection methods (including digital x-ray) become more sophisticated, opportunities to identify and proactively address reliability concerns

before joint failure are increasing. Issues related to joint movement and the mechanical strength of splice connectors have already been identified as affecting joint reliability. Under this program, these issues and others in the future will continue to be addressed to increase overall system reliability.
Project Relationships (if applicable)

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	**3,814**	**4,224**	**111**	**12,821**		**10,026**
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**7,500**	**10,500**	**13,000**	**13,000**	**9,000**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	1,245	2,800	2,800	2,800	2,800
M&S	575	575	575	575	575
Contract Services	3,200	3,750	5,750	5,750	2,550
Other	253	250	263	266	273
Overheads	2,227	3125	3612	3609	2802
Total	**7,500**	**10,500**	**13,000**	**13,000**	**9,000**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☒ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Non-Network Reliability	
Project/Program Manager: Frantz St Phar	**Project/Program Number (Level 1):** 10027523, 10032097, 10027742, 10034624, 10028391, 10032020, 10035714
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date: 2017	**Estimated Date In Service:**
A. Total Funding Request ($371,220) **Capital: $371,220** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

The non-network system is comprised of non-network circuits including 4 kV primary grids and 4, 13, 27 kV autoloops. Their reliability is ranked by standard industry metrics including SAIFI and CAIDI. The ranking process takes into consideration the reliability of the segment (based on SAIFI and CAIDI); as well as dominant failure contributors and produces circuit-specific reliability improvement options and recommendations based on cost-benefit studies. We will also target 33 kV feeders in Staten Island installed along the Staten Island Rapid Transit (MTA/SIRT) right of way. Access restrictions on the right of way prohibit expedited feeder processing and subsequent restoration.

The Company will implement strategies to enhance non-network feeder performance and improve system resiliency during blue sky and overhead storm events. Poorly performing and aged components will be replaced and upgraded to items that are manufactured to the design and performance standards of today.

Improve source reliability
The non-network system is supplied by a combination of underground and aerial feeder cable systems. In areas where poor performing vintages of aerial and underground cable (PILC, Okonite etc.) leave our customers vulnerable to outages, we will proactively replace the cable with more reliable alternatives.

Overhead Network Secondary Rebuild
Portions of certain secondary networks are fed from overhead facilities typically found on non-network feeders. In some cases, the poles and conductors are nearing the end of their useful life.

Locations will be prioritized for rebuild based on failure rate, age, and pedestrian traffic volume. This work will include pole replacement, re-conducting, and adding additional capacity as required.

Improvement of Non-Network Feeder Reliability Via Reconfiguration of Circuit
Individual autoloops performance can be improved through reconfiguration, minimizing spur size and the addition of segments through the installation of new poles, wire, and switches.

Individual 4kV feeders' performance can be improved through reconfiguration, minimizing spur size, addition of automated emergency ties and the addition of segments through the installation of new poles, wire, and switches.

Improve Resilience due to Significant Weather Events
The Company expects to experience more frequent and severe major storms as a result of climate change. There were two consecutive nor'easter storms in March of 2018 that impacted the Con Edison's service territory. Winds from these events were significant with peak sustained winds lasting for more than 36 hours. These storms caused devastating damage to our overhead electrical systems across our service territory. In 2020 Isaias caused significant damage throughout the service territory, second in severity only to Superstorm Sandy. The Company conducted post storm reviews and issued reports with findings for these storms. Based upon these findings and in anticipation of more frequent and severe storms as a result of climate change, the Company will initiate the following projects to further enhance the resilience of its non-network circuits.

Open Wire Cable Replacement
Replace portions of the open wire system, particularly long spans (greater than 1000') with no load and single-phase load with aerial and/or Spacer cable.

Add Breakaway Service Connectors
Install breakaway service connectors to enhance the speed of restoration due to tree damage to a service. Target municipalities with a history of "On and Off" the Right of Way tree damage.
Target Areas: Heavily treed service areas

Enhance Reliability to Underground Residential Development (URD) customers
Add additional supply feeder to URD developments with >100 customers where feasible. The additional supply feeder will supply an Automatic Transfer Switch (ATS) which will then feed the URD development.
Target URD Developments: Cortlandt, Quaker, and Tarrytown loops

Reconfiguration Of 13kV Auto-loops
Extend 13kV distribution feeders and create additional supply sources allowing the splitting of large auto-loops into smaller segments, minimizing the customer impact and allow for quicker restoration should a future event occur. Reviews of outage data indicate a correlation with the length of an auto-loop and the damage incurred during significant weather events.
Target Loops and Municipality: Windmill loop (Pleasantville, Millwood)

Trip Savers
Install fused trip savers on spurs on our primary feeders to minimize the number of customers momentarily interrupted due to damage to the feeder on a given spur. The trip saver will react before the autoloop recloser and attempt to reclose if a momentary fault occurs. Installation of these devices will also be deployed on 4 kV spurs.
Targeted areas: 4 kV Grids using OHPOT

Cross-Commodity Undergrounding
Based on a 2013 study, the estimated cost to underground an overhead system would cost approximately $8.5M / mile. To take advantage of synergies between commodities and limit the disturbances to customers within the municipalities, electric plans to partner with the gas department in a Cross-Commodity bundling of work and convert overhead facilities to underground facilities where feasible.

Double Wood Remediation
Installing new poles is essential to maintaining safe, adequate, and reliable electric service, however, the removal of older, often structurally unsound poles has not kept pace with new installations. One of the main drivers of this issue is that there are multiple companies that attach equipment and conductors to utility poles. In general, the companies need to transfer their attachments in a specific order. If one company fails to complete the transfer in a timely fashion, the process is extended for all connected parties. Another reason is that there are some cases in which the transfers are more complex – specifically riser installations. Primary feeder riser transfers by Con Edison require a feeder outage and the work required during the outage is more extensive than an overhead wire transfer. Factors such as these result in a partial transfer of facilities by utilities and pole attachment entities of all or part of its equipment to the new pole while facilities remain on the old pole. Where transfers are not completed in a reasonable period, or never completed, a double pole situation is created.

Based on a survey completed in 2012, there were approximately 17,600 double pole conditions on hand in Con Edison's service region. The cost to correct each situation varies based on the amount of equipment installed at the location. The funding for this program is used to complete all Con Edison work associated with remediating double pole conditions noted in the 2016 survey. In 2016, Con Edison initiated a plan is to reduce the on-hand number of poles down to the normal annual turn-over in a ten year period. This program includes the inspection of approximately 1,760 poles per year through 2026, and update the National Joint Use Notification System (NJUNS). Where work is still pending completion by Con Edison, it is scheduled for completion.

There are multiple entities with pole attachments other than Con Edison and Verizon including New York City Department of Transportation (DOT), New York City FDNY, Time Warner, Cablevision, and other communication companies. To remove a pole, each company is required to send a crew to transfer their facilities after a new pole is set. Con Edison, Verizon, and most of the other companies with pole attachments are currently using NJUNS to provide timely notifications to each party attached to a pole when wire and equipment need to be transferred.

Relocation of 33 kV Feeders on Staten Island Railroad
The 33 kV distribution system on Staten Island is single contingency. When 33 kV feeders are removed from service, it is crucial to process the feeders promptly to maintain safe and reliable service for customers on Staten Island.

Approximately ten (10) miles of 33 kV feeders are installed on property owned or previously owned by Staten Island Rapid Transit (SIRT/MTA). Access to these 33 kV feeders is more restricted than access to similar equipment installed in the public right of way. Employees that work along the railroad need additional training associated with the hazards and SIRT/MTA procedures. All work on SIRT/MTA property requires SIRT/MTA oversight by MTA employees. An employee that works for the railroad needs to be present for all Con Edison switching and construction. This can lead to delays for emergency work on off shifts, particularly unforeseen Con Edison emergent work. The SIRT/MTA maintenance of this property does not include ensuring Con Edison access to work on its distribution equipment. Thus, at times 33 kV work is delayed to clear vegetation and other impediments to Con Edison accessing its equipment. Work done near train traffic needs to be scheduled and coordinated to have minimal impact on public transportation, leading to delays. If work is not completed when trains need to pass, at times jobs need to be stopped temporarily for train traffic. In some locations portions of Con Edison's underground infrastructure exists directly beneath the railroad tracks. This had led to the dismantling of the rails to gain access to perform work. This has a negative impact to the reliability of the train service, as well as the logistical challenges associated with such disturbance.

A portion of the feeders on the north side of Staten Island are in underground manhole and conduit that the railroad no longer owns. Therefore, the right of ways are no longer maintained and access is very difficult. Accessibility becomes more challenging in times of inclement weather, when it is common for Con Ed to experience issues with our distribution system.

The 33 kV feeders associated with this program feed 4 kV grids. Delays in feeder processing and restoration increase the risk associated with 4 kV grid shutdown and customer outages.

Justification Summary:
Customers experience interruptions on average once every 2-3 years discounting storms. Circuits and customers that experience outages on an average higher than the system average are reviewed for potential redesign. The goal of this work is to improve service to the customers on each circuit supplies as measured by SAIFI/CAIDI statistics.

Additionally, on May 25, 2011 the New York State Public Service Commission issued its Order Adopting Implementation of a Standardized Facility and Equipment Transfer Program in Case 08-M-0593. One of the requirements of this order was for pole owners to "to submit a report to Staff, either jointly or if necessary, individually, discussing how pole owners propose to reduce the number of double poles currently in existence, describing impediments to reducing the number of existing double poles, and setting forth possible solutions." Con Edison complied and submitted a proposal on January 3, 2012. In the report Con Edison indicated that the extent of the issue could not be quantified and that the annual stray voltage inspection program would be used to assess the issue. Based on information gathered from the inspection program, there are approximately 17,607 double pole conditions in Con Edison's service territory.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection
The alternative to this reliability program is to respond solely to equipment failures and outages. This alternative is rejected as we want to be more proactive and avoid customer outages as much as possible.

Risk of No Action

Risk 1
The overhead system performance will decline and customers will experience less reliable service in select areas.
Risk 2
Component failures could potentially injure the public in some cases.

Risk 3
No action on this program would result in the associated 33 kV feeders on the SIRT ROW remaining out of service for longer periods of time and the system remaining in an abnormal, vulnerable configuration. We expect to experience continued delays in feeder processing and restoration increasing the risk associated with 4 kV grid shutdown and customer outages.

Non-Financial Benefits

The risk of injury to the public will be decreased by fewer non-network system component failures. Hardened components will also lead to fewer outages. Newer, smarter capital equipment will lead to shortened restoration times. With the decrease in power outages and restoration times, customer satisfaction will be enhanced.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis (if required)

Although difficult to quantify, the benefits of this program include enhanced reliability of the system during a blue sky day and major storm.

2. Major financial benefits

3. Total cost

4. Basis for estimate

Historical unit costs.

5. Conclusion

Project Risks and Mitigation Plan

Risk 1 Mitigation plan
Equipment availability
Due to COVID and the scarcity of resources, a potential risk is obtaining the equipment needed. We're working with manufacturers, stores, and supply chain to maintain inventory and anticipate requirements prior to project commencement.

Risk 2 Mitigation plan
Storms and ICS deployments
Storms present a risk as contractors used to supplement the field forces for construction may be called to assist in storm impacted regions. We maintain timely release of layouts and work requests and active management of our projects and resources to allow us to maintain contractors on site.

Technical Evaluation / Analysis

Each project will be evaluated in terms of improvement to the indices of importance for the system. Any source reinforcement projects will be evaluated in terms of reduced future rates for that supply feeder. Any other project will be evaluated in terms of SAIFI/CAIDI improvement.

Project Relationships (if applicable)

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	6,580	8,971	35,173	40,795		36,524
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	35,000	73,550	87,061	87,061	88,548
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	6,475	13,607	16,106	16,106	16,651
M&S	9,555	20,079	23,768	23,768	24,174
Contract Services	11,270	23,683	28,034	28,034	28,512
Other	(1,680)	(3,530)	(4,179)	(4,179)	(4,520)
Overheads	9,380	19,711	23,332	23,332	23,731
Subtotal	35,000	73,550	87,061	87,061	88,548
Contingency**					
Total	**35,000**	**73,550**	**87,061**	**87,061**	**88,548**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Non-Network Resiliency with FLISR	
Project/Program Manager: Kevin Oehlmann	**Project/Program Number (Level 1): 23288073, 23291837, 23339097**
Status: ☒ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date: 2021	**Estimated Date In Service: 2025**
A. Total Funding Request ($11,713) **Capital: $10,563** **O&M: $1,150** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

Con Edison's Non-Network System is comprised of 4 kV primary grids and 4/13/27 kV autoloops. In Staten Island, the Non-Network System also includes Fox Hills and Fresh Kills 33 kV load areas. Autoloops are looped circuits that are fed power from both ends, and which may have small spurs off the main line to distribute power throughout a neighborhood. A typical Con Edison circuit runs for several miles. A failure at a certain point of the circuit will affect other customers on the same circuit to the location of the closest upstream protective device. In some cases, damage or faults on spurs can flow up to the main feeder line, potentially causing outages for many more customers.

Con Edison has progressively developed Fault Location, Isolation, and Service Restoration ("FLISR") capabilities on the Non-Network portion of its distribution system through the deployment of protective devices like reclosers and sectionalizing switches. These devices allow the Company to locate permanent faults, isolate the damaged conductors and/or equipment, and restore service to undamaged portions of the circuit(s).

This program will replace older sectionalizing equipment with new technology that will further enhance FLISR capabilities. The Supervisory Control And Data Acquisition (SCADA) capability of the newer sectionalizing equipment provides greater visibility and remote control of the switch, and the dead front and enclosed bus design requires less maintenance and is less prone to outages caused by animal infestation.

Work completed via this program will expand these capabilities through deployment of Smart Switches – i.e., devices with SCADA capability and/or the ability to operate automatically without operator intervention. Smart Switches are a key component of a FLISR capability. Types of Smart Switches in this program include reclosers, SCADA gang switches, Automatic Transfer Switches (ATS), PulseClosers/Intellirupters, and SCADAMate switches.

These switches will enable the following automated control schemes:

- Automatic transfer of customer load from the normal source to an alternate source. Automatic control schemes are deployed using pad mounted switch gear as well as pole mounted reclosers.
- Looped feeders are reconfigured via an automated sequence of operations that commences after the fault. This results in a reconfiguration where two automated switches closest to the damaged portion of the loop open, and normally open automated switches close, to restore all customers not in the faulted portion of the loop.
- Radial spurs fed off the main run of an auto-loop are reconfigured to develop “spur loops.” In this design two spurs are supplied from two different segments of an autoloop to an automatic normally open tie switch. When a portion of the main run of the loop is de-energized as described above, the spur loop re-configures via automatic switching such that the portion of the spur loop connected to de-energized, faulted segment of the main run is fed from the non-faulted segment of the loop. This allows the customers on the spur connected to the faulted segment of the main run to remain in service in cases where they would have been de-energized due to the fault.
- Additional branch protection may be added in series with existing branch protection by using technology to achieve greater coordination of the series devices. This will reduce the number of customers affected by faults at the end of a radial spur line.
- New FLISR schemes will allow the addition of automatic switching devices to 4 kV grid feeders. The additional devices reduce the number of customers on each feeder segment and thus reduce the number of customers impacted by a fault on a line.

Justification Summary:
The Non-Network Resiliency FLISR program will expand Con Edison’s reliability and resiliency in two ways, (1) through greater visibility and automated control, and (2) limiting the impact of customer outages.

By installing additional smart switches, the Company will increase the number of automatic protective devices per circuit and further segment its circuits. This reduces the number of customers that are impacted from a single point of damage on the system, which in turn improves System Average Interruption Frequency Index (SAIFI) and Customer Average Interruptions Frequency (CAIDI) metrics. The new smart switches will also provide additional information to the Outage Management System (OMS) (STAR)

The installation of additional smart switches with SCADA communications will facilitate quicker restoration of outages by more quickly identifying the fault in the OMS system, and updating the operator on the state of the system. In addition to the benefit of automatic operation, having additional controllable devices also allows greater flexibility for restoration when a failure occurs.

Relationship to 5-Year and Long-Range Plans and Enterprise Risk Management Strategy

The ELRP recognizes that weather is trending towards more frequent and severe events. As such, and key tenet of the plan is to make the system more resilient. This program is directly contributing to that improvement on the non-network system.

Enterprise Risk: New York Regulation – The regulator will respond to customer demand for a more resilient system. The expectation is that the system will improve in it’s ability to withstand severe weather events, and where outages occur, they are restored quickly. The Regulator will make changes to Regulations to enforce this performance through punitive actions or specific directives

Major Storm – similar to above.

Regulatory Penalties – System performance is monitored and there are revenue performance mechanisms in place that are triggered by poor SAIFI and CAIDI performance or major outages.

2. Supplemental Information

Alternatives

Manual switches can be installed in lieu of Smart Switches and Automatic Transfer Switches. Manual switches require a crew to be dispatched to the appropriate location to operate them. This does not support the overall Grid Innovation goals of reliability, resiliency, and flexibility, and it would also result in an increase in the outage duration.

Risk of No Action

With no action non-network customer outages will not be reduced. Risk of cascading outages that result in the loss of a 4 kV grid will not be reduced.

Non-Financial Benefits

With the decrease in, or mitigated results of, power outages, customer experience will be enhanced.

Technical Evaluation/Analysis:

Each project will be evaluated in terms of the resiliency and reliability improvement, the customer count between reclosers and the indices of importance for the system. All projects will be evaluated in terms of SAIFI/CAIDI improvement.

Summary of Financial Benefits and Costs (attach backup)
Although difficult to quantify, the benefits of this program include enhanced reliability and resiliency of the distribution system during both blue-sky days and major storm events.

2. Major financial benefits
Reduce truck rolls, increase safety and reduce O&M expenditures.

3. Total cost

4. Basis for estimate
Historical unit costs.

5. Conclusion
The project should be done in order to enhance the reliability and resiliency of the distribution system.

Project Risks and Mitigation Plan	
Risk 1	Mitigation plan
Risk 2	Mitigation plan

Technical Evaluation / Analysis
Each project will be evaluated in terms of the resiliency and reliability improvement, the customer count between reclosers and the indices of importance for the system. All projects will be evaluated in terms of SAIFI/CAIDI improvement.

Project Relationships (if applicable)
No other project or program impact.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital				**590**		2,230
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**2,100**	**2,100**	**2,100**	**2,100**	**2,163**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	530	530	530	530	546
M&S	857	857	857	857	882
Contract Services	**135**	135	**135**	135	139
Other					
Overheads	**578**	578	578	578	595
Subtotal	**2,100**	**2,100**	**2,100**	**2,100**	**2,163**
Contingency**					
Total	**2,100**	**2,100**	**2,100**	**2,100**	**2,163**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M	$210	$220	$230	$240	$250
Capital	**$2,100**	**$2,100**	**$2,100**	**$2,100**	**$2,100**

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Central Operations/ Substation Operations
2022

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Other Capital Equipment Upgrades Program	
Project/Program Manager: TBA	**Project/Program Number (Level 1): PR.0ES3200/ 10028202**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other: ___________**	
Estimated Start Date: On going	**Estimated Date in Service: Ongoing.**
A. Total Funding Request ($000) **Capital: $16,291** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This program funds various small and limited scope projects that are not covered by other capital program lines. Modifications and upgrades at individual substations for equipment related upgrades are generally executed as required. Minor equipment improvements, such as the following, are covered under this program:

- Cable Trough Replacement
- Replacement of Potential Transformers and other instrument transformers
- Barksdale Switch Installations
- Bird Netting in Transformer Vaults
- Emergency Diesel Generator Repairs/Upgrades

The following projects represent a sample of Other Capital Equipment Upgrade Projects identified as candidates to be funded via this program in 2022-2026.

- Piping Modification for Emergency Diesel Generators - Various Locations
- Bird Netting - Sedgewick
- Farragut Various New Barksdale Switch Installations
- Brooklyn/Queens Barksdale Switches Installations.
- Rainey - PA system for the upper yard
- Bird Netting Phase I Sherman Creek Yard
- Replace Dock Transformer - 59th St

Other projects like those listed above make up the entire candidate listing. We expect additional projects to emerge and be part of future candidate listings.

Justification Summary:

This program is necessary to fund small projects that are not covered by other capital programs. These projects are necessary to improve the substation facilities and the electrical system as well as avoid impacts to related projects, improves planning, enabling a more efficient operational performance.

Given the variation in the type of equipment and cost associated with replacements, the funding for this program is based on historical failure averages.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
This program affects the Substation Operations risk "Equipment Failures". This program reduces the likelihood of equipment failures. Projects completed under this program reduce the likelihood of equipment failures by performing small equipment modifications and facilities upgrades at individual substations reducing the degradation.

2. Supplemental Information

Alternatives
The alternative is to take no action. This is not recommended as the improvements described are necessary to maintain both facilities and equipment in working order. Taking no action will increase the chance of degradation of all components requiring periodic and corrective maintenance. This would eventually lead to potentially hazardous conditions that could impact equipment reliability and the safety of company personnel as well as the public.

Risk of No Action
The risk of no action is that the continued degradation of equipment and facilities could lead to potentially hazardous conditions. These conditions could impact equipment reliability and the safety of company personnel and the public.

Non-Financial Benefits
o Enhances the safety of company personnel and the public.
o Minimizes degradation of equipment and facilities which could lead to potentially hazardous conditions impacting equipment reliability

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis: N/A

2. Major financial benefits
N/A

3. Total cost **$$16,291**
4. Basis for estimate: The annual funding request for this program is based on the approximate average annual expenditure over the last 10 years.

5. Conclusion: N/A

Project Risks and Mitigation Plan

Risk 1: Outage scheduling conflicts with other initiatives.

Mitigation: Outages to be coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs to avoid conflict with other program/ projects resulting in a more predictable budget and manageable outage scheduling.

Risk 2: Delays due resources support coordination.

Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Technical Evaluation / Analysis: N/A

Project Relationships (if applicable) Some projects such as Barksdale switch installations, replacement of potential transformers or Coupling Capacitor Potential Devices (CCPD's) require outages on the system, and these outages are subject to system conditions

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	4,511	2,789	2,970	1,300		2,577
O&M						
Retirement	431	219	151	279		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**$2,351**	**$3,485**	**$3,485**	**$3,485**	**$3,485**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	776	1,150	1,150	1,150	1,150
M&S	314	475	476	477	486
Contract Services	494	732	732	732	732
Other	0	0	0	0	0
Overheads	767	1,128	1,127	1,126	1,117
Subtotal					
Total	**$2,351**	**$3,485**	**$3,485**	**$3,485**	**$3,485**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations/STO
2022-2026

1. Project / Program Summary

Type: ☐ Project ☒ Program	**Category: ☒ Capital ☐ O&M**
Work Plan Category: ☐ Regulatory Mandated ☒ Operationally Required ☐ Strategic	
Project/Program Title: Overhead Insulator Resiliency Program	
Project/Program Manager: Ken Chu	**Project/Program Number (Level 1): 24004206**
Status: ☒ Planning ☐ Design ☐ Engineering ☐ Construction ☐ Ongoing ☐ Other: ___________	
Estimated Start Date: 2021	**Estimated Date In Service:**
A. Total Funding Request ($000) **Capital: 26,200** **O&M:** **Retirement:**	**B.** **☐ 5-Year Gross Cost Savings ($000)** **☐ 5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:
This program will address problematic overhead transmission equipment by systematically replacing this equipment. Recently, Con Edison has been having issues with cracked insulators. Following several insulator string failures on feeder W99 and drone inspections detailing damaged bells with hairline cracks, this program was developed. Insulators provide insulation between the line conductors and prevent any leakage current. Previously installed insulators were made of porcelain and some types installed are prone to cracks which can lead to failures. Historically, the records as to where these were installed are limited. This means in order to replace problematic ones, it makes the most sense to go line by line. In 2022, this program will be used to replace insulators and dead-end connectors on the E transmission line of feeder W99. The scope includes replacing 8,595 porcelain insulator bells (573 insulator strings with 15 bells per string) toughened glass insulators and install dead-end reinforcement (Clamp Star Dead-End Shunts) on 372 existing dead-end connectors and install in-line splice reinforcement (Clamp Star In-Line Splice Shunts) on all (approx. 20) in-line splices.

Justification Summary:
Feeders W99 is a critical feeders within the Con Edison overhead transmission system supplying power to New York City and Westchester County. The configuration of Feeders W99 is a vertical double-circuit 345kV overhead transmission line located on the E-Line between Millwood and Eastview Substations. The E-Line in this corridor has sixty-four (64) lattice structures and traverses approximately nine miles through both relatively flat and mountainous terrain. This line was originally built in 1956 as a 138kV line and was upgraded in 1970 to 345kV. The structure types are made up of 34 suspension structures and 30 strain structures.

W93 and W99 experienced two failures that indicated a potential problem with the LAPP brand insulators used to upgrade the line to 345 kV in 1970. There was also a similar failure on the G-Line and it is believed that the same LAPP insulators were used to re-build the G-Line. It is believed that a phenomenon called cement growth occurred and ultimately led to these failures. Cement growth can occur on both strain and suspension insulators.

Feeders Y88 & Y94 are also critical feeders within the Con Edison overhead transmission system supplying power to New York City and Westchester County. The configuration of Feeders Y88 & Y94 is a vertical double-circuit 345 kV overhead transmission line located on the G-Line between Buchanan Substation and the Hudson River Crossing tower. The G-Line has eight (8) steel monopole structures and traverses approximately 1.3 miles through relatively flat terrain. This line was originally built in 1961 as a 138kV line and was upgraded in 1972 to 345kV. The structure types are made up of three suspension structures and five strain structures. These feeders will be addressed in the future.

Con Edison is looking to create a more robust approach to identifying and mitigating potential issues that could affect the reliability of the overhead transmission system by implementing an overhead transmission line inspection, assessment, and this asset management program. Historical failures are also being used in the determination of mitigation projects that will be generated from this program. Types of equipment issues that can affect overhead lines include insulator failure, inline splices, and dead-end connector weaknesses. Sometimes a certain vintage or type of equipment can be identified as a problem, but the extent and location of the problematic equipment is unknown. Additionally, inspection of this equipment can be extensive and costly.

In 2022, the priority for this program is to replace the insulators and dead-end connectors on the E transmission line between Eastview and Millwood (W99) and in the future as well as on the G transmission line (Y88 & Y94) that traverses from Buchanan SS to the East Hudson River Tower. These have been identified as problematic based on previous failures and recent testing. The in-line splices and dead end connectors are also potential "weak" links in the system due to past failures and connection aging in general. It is determined that these items should be addressed and reinforced as part of this project in order for these enhanced connections to act in conjunction with the new insulators to extend the service life of the line.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
This project is related to the departmental goal of equipment failures. Maintaining overhead resiliency is imperative for system resiliency.

2. Supplemental Information

Risk of No Action
The risk of no action can jeopardize the reliability of the Transmission System. If multiple failures were to occur during a high load period or while other critical facilities are out of service, load shedding and large-scale customer outages can result. Emergency mobilization

and fault locating costs are also avoided by addressing the reliability issues proactively. Removing the suspect configurations and enhancing feeder reliability also helps avoid significant job cancellation costs for working groups throughout the Company due to the far-reaching effects on scheduled transmission facility work when a transmission pothead fails.
Non-Financial Benefits
Summary of Financial Benefits and Costs (attach backup) The cost of this program in 2023 is based upon doing 67 towers at a rate of $100k per tower.
Project Risks and Mitigation Plan
Technical Evaluation / Analysis
Project Relationships (if applicable)

3. Funding Detail

Historical Spend

	Actual 2017	**Actual 2018**	**Actual 2019**	**Actual 2020**	**Historic Year** (O&M only)	**Forecast 2021**
Capital	**N/A**	**N/A**	**N/A**	**N/A**		**N/A**
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	**Request 2023**	**Request 2024**	**Request 2025**	**Request 2026**
Capital	**3,800**	**6,700**	**6,700**	**6,700**	**2,300**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	**2022**	**2023**	**2024**	**2025**	**2026**
Labor	1,074	750	750	750	257
M&S	215	750	750	750	257
Contract Services	1,322	3,500	3,500	3,500	1201
Other	58	66	67	68	23
Overheads	1,132	1634	1633	1632	560
Total	**3,800**	**6,700**	**6,700**	**6,700**	**2,300**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations/STO
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Overhead Transmission Structures Program	
Project/Program Manager: Ken Chu	**Project/Program Number (Level 1):** 22679501
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date:	**Estimated Date In Service:**
A. Total Funding Request ($000) **Capital: 17,600** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:
This program will upgrade 345 kV steel lattice towers selected based on feeder criticality, engineering analysis and accessibility. An analysis performed on a corridor-by-corridor basis was performed and priority was given to critical corridors as specified by System Operations and Transmission Planning. Approximately 18% on average every year will need reinforcement. Reinforcement of these overhead towers will increase structural capacity and system reliability and prevent tower cascading. The first priority was given to the approximately two-mile corridor south of Millwood Substation consisting of six 345kV circuits known as the "Six Circuits South of Millwood". The current design criteria for this program is to induce a full broken wire scenario on the structure and reinforce it to become a dead-end structure for that criteria. Due to a backlog of work, additional funding will be utilized in 2022-2025 for contractor work to complete 12-13 towers per year.

This program will continue to identify potential failure scenarios that will be used to prioritize other work to be done in future years. Based on this ongoing evaluation, selective tower element reinforcement projects will be identified that mitigate the possibility of tower failures or severe cascading events.

***High-level schedule**: Upgrade as follows;*
- 500 towers to be evaluated on the remainder of D, E, and K lines in 2022 and 2023
- G line (8 towers)
- L Line (76 towers)
- M Line (23 towers)
- Hudson River Crossing Tower

Addressing these concerns will also reduce the likelihood of potential failures during severe weather conditions.

Justification Summary:
This program is necessary because upgrading existing structures will reduce potential tower failures, thus reducing operating constraints and improving reliability. Through selective reinforcement of towers, this project will decrease the likelihood and impact of multiple failures resulting from tower cascading (when an event causes the conductors on one side of a tower to be cut and the ensuing uneven force on the tower pulls down the structure; this cascades from tower to tower).

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
This program is related to the Major Storm corporate risk. This program increases system resiliency by strengthening the overhead structures. In the event of a tower failure now, there is a potential for cascading failures. By upgrading the existing structures, this reduces that risk and strengthens system resiliency.

2. Supplemental Information

Alternatives
The alternative is to not upgrade structures and accept the risk of potential cascading in the event of a tower failure which could result in lengthy outages.

Risk of No Action
Potential cascading in the event of a tower failure, could result in lengthy outages. Con Edison currently has ten Linsey portable emergency transmission towers , two 120 ft wooden poles, and eleven 100 ft wooden poles available for emergency use following the loss of a tower or multiple towers. This discretionary program addresses the higher risk areas of the overhead transmission system.

Non-Financial Benefits
Non-financial benefits include employee safety, increased reliability, and increased security in the more vulnerable areas of the overhead transmission system.

Summary of Financial Benefits and Costs (attach backup)
The estimate is based on a historical average of $40k per tower.

Project Risks and Mitigation Plan

Technical Evaluation / Analysis
Structural analysis of the existing towers is currently on-going with support from consultants and company engineers. Engineering analysis for prioritizing additional tower upgrades on other overhead lines is in progress.

Project Relationships (if applicable)

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	29	970	1,129	1,288		1,532
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	5,600	3,000	3,000	3,000	3,000
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	1,620	1,220	1,220	1,220	1,220
M&S	500	96	96	96	96
Contract Services	1,500	444	444	444	444
Other	244	200	201	202	212
Overheads	1,736	1,040	1,039	1,038	1,028
Total	**5,600**	**3,000**	**3,000**	**3,000**	**3,000**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Pole Inspection and Treatment (PIT) Program-Restorable	
Project/Program Manager: Chris Rodriguez	**Project/Program Number (Level 1): 10031938, 10032018, 10032061, 10032095, 10032137**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other: ___________**	
Estimated Start Date:	**Estimated Date In Service:**
A. Total Funding Request ($10,735) **Capital: $10,735** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This program funds the installation of "C-trusses" or braces to extend pole lives or secure utility poles where decreased strength requires the installation of additional support. The C-truss provides external bracing for poles that do not pose an immediate threat to the safety of the public or the distribution system. The five-year average for poles requiring additional support is approximately 550 units per year.

Justification Summary:

Pole inspections are performed to maintain the reliability of installed poles and promote safety of the public as referenced Con Edison's specification EO-10345, Inspection and Ground line Treatment of Standing Wood Poles. As inspections are completed and it is determined that pole does not have the required strength, they either must be replaced or restored to full strength and functionality by way of C-trussing. Installing C-trusses defers the need to replace poles and create a double wood pole condition. It is more cost effective as compared to pole replacement.

Maintaining wood pole strength directly supports the resiliency of the overhead electric system, especially in the face of more frequent adverse weather conditions as a result of climate change. These measures prevent pole damage from the most severe weather effects such as fallen trees, and very large limbs, these measures will help the system withstand less severe effects of adverse weather.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

Wood poles over time experience deterioration (internal or external decay progresses), without any pole inspection program, there would be a potential impact which may cause unnecessary customer interruptions, property damages, and safety hazards to the public.

By installing a heavy-duty galvanized steel reinforcer (aka "C-Truss") to restore and meet the National Electric Safety Code (NESC) specified pole strength requirements, the wood pole is rehabilitated and the potential safety hazard is reduced. The Risk Management sub-section of the Electric Long-Range Plan (ELRP) goes on to cite that part of the minimization of risk to employee and public safety is "proactive replacement of high-risk components" and the use of "data and analytics to prioritize our response to any potential problems revealed." The C-Truss installation program does just that for wood poles.

Alternatives

An alternative to implementing the pole reinforcement (C-truss) program is to replace a pole in its entirety. This would be done when the pole structure is compromised for reasons such as extreme weather conditions or decaying composition. In addition, replacing poles in their entirety is more time consuming and labor intensive than simply reinforcing a pole with a truss. It also creates a "double pole" condition at the pole location until all attached parties attachments are transferred to the new pole and the old pole is removed. Using a C-truss can significantly extended the useful lifespan of a pole at a lower total cost than replacement.

Risk of No Action

Pole failures could adversely impact public safety and system reliability. Additionally, there would be a greater cost for emergency response after a pole failure as compared to planned pre-emptive work.

Non-Financial Benefits

Reinforcing poles with reduced strength improves system reliability as weakened poles are more susceptible to breaking and falling, which can pull down overhead cable and cause outages. Pole reinforcement has the potential to positively impact the Company's reliability metrics (system average interruption frequency index – SAIFI - and customer average interruption duration index - CAIDI). Moreover, downed wires and poles create public safety concerns making C-truss reinforcement a viable program in enhancing public safety.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)

Not required.

2. Major financial benefits

The current Pole Inspection and Treatment program is reporting an average of 500 reinforceable poles per year. There is a major cost savings to reinforcing a pole versus replacing a pole, an average cost of \$2.8k to reinforce vs. an average cost of \$17k to replace.
Reinforcing the pole via C-Truss has the potential to avoid an emergency situation (which may incur additional costs of emergency responders or emergency customer restoration work), or to defer the need of pole replacement at a higher cost.

3. Total cost

$10.7M over 5 years.

4. Basis for estimate

The basis for the estimate used in this program is the historical unit cost for C-truss installations.

5. Conclusion

The pole reinforcement ("C-truss") program should continue to enhance public and personnel safety, system reliability, and avoid significantly higher costs associated with prioritized and/or emergency pole replacement.

The C-truss installation restores mechanical integrity and extends service life of the poles, as well as avoiding present costs by deferring pole replacements.

Project Risks and Mitigation Plan

Risk 1
Contractor unit-cost increase during contract renewal

Mitigation plan 1
Proactive RFQ/Procurement process to attract competitive pricing and expand vendor pool

Risk 2
Unexpected Contractor labor force reduction or shortage of material

Mitigation plan 2
Proactive RFQ/Procurement process to expand vendor pool

Technical Evaluation / Analysis

Pole reinforcement has been used successfully to restore strength to decayed poles for more than 50 years. The devices restore code-mandated strength and add years of service life to the pole. Transverse and longitudinal loads applied to reinforced poles are applied to the truss instead of the pole. This allows the load to circumvent the decayed portion of the pole at the groundline.

Project Relationships (if applicable)
None.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	**1,367**	**1,242**	**1,668**	**1,149**		**4,193**
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**1,333**	**2,333**	**2,333**	**2,333**	**2,403**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	332	582	582	582	599
M&S	126	221	221	221	228
Contract Services	499	874	874	874	900
Other	22	39	39	39	40
Overheads	352	617	617	617	635
Subtotal	**1,333**	**2,333**	**2,333**	**2,333**	**2,403**
Contingency**	-	-	-	-	-
Total	**1,333**	**2,333**	**2,333**	**2,333**	**2,403**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Central Operations/ Substation Operations
2022

1. Project / Program Summary

Type: ☐ Project ☒ Program	**Category: ☒ Capital ☐ O&M**
Work Plan Category: ☐ Regulatory Mandated ☐ Operationally Required ☒ Strategic	
Project/Program Title: Pothead Pressure Alarms Program	
Project/Program Manager: TBA	**Project/Program Number (Level 1): PR.22100446**
Status: ☐ Planning ☐ Design ☐ Engineering ☐ Construction ☒ Ongoing ☐ Other: ___________	
Estimated Start Date: Ongoing	**Estimated Date in Service: Ongoing.**
A. Total Funding Request ($000) **Capital: $750** **O&M:** **Retirement:**	**B.** **☐ 5-Year Gross Cost Savings ($000)** **☐ 5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

The purpose of this program is to install wireless sensors to be used in a dielectric fluid pressure monitoring system. This system is specifically intended to be installed at Transmission Feeder potheads, where currently only general high/low pressure alarms exist. The advantages of this type of monitoring system include knowledge and remote indication of actual pressure readings, low power consumption, relatively low-cost components, high speed inspection, and long inspection distances without significant trenching and cable installation. The system concept has been proven on two feeders, 38W10 and 99153M, at Dunwoodie Substation, however additional development of the concept is needed to create a system that can be integrated into existing company infrastructure and provide all the intended benefits.

This second phase will include:

•Task 1: Develop wireless pressure sensors with increased server update rate for near real time data availability
•Task 2: Address and implement wireless cyber security for the system
•Task 3: Implement variable data rates and alarming during emergency conditions
•Task 4: Demonstrate pressure sensors at Jamaica Substation (Feeders 18001 and 18002), W49th St. Substation.
•Task 5: Build a knowledge-based notification and visualization system

Once the system is determined to be feasible and provide the expected benefits, the technology can be commercialized for implementation throughout the Con Edison system based on a prioritization plan.

Justification Summary:
As a result of the June 2010 Dunwoodie fire, Con Edison lost one pumping plant, which subsequently led to seven 345 kV feeders connected to the substation ring bus tripping. The pumping plant fire directly led to depressurization of four 345 kV feeders, causing two of the four to fail catastrophically. The other two feeders had other means of maintaining minimum pressure long enough for the feeders to be taken out of service prior to failing. There is currently no means of remotely monitoring feeder pothead pressures. The existing alarm system only generates a high/low pressure category alarm, which must be locally verified by the operator reading a pressure gauge at the potheads.

Currently there can be a significant delay before the substation operator can physically read and verify feeder pressure after receiving a pothead pressure alarm. Remote pressure monitoring would allow for a quick way to verify pressure alarms and would also allow remote monitoring from the Energy Control Center. For low pressure conditions, quicker notification and verification would allow time to take the feeder out of service prior to failure. This system can also be integrated into a dielectric system visualization and notification system to incorporate field data and system knowledge and create a smart display for the dielectric system.

The capability of detecting the decaying pressure on a feeder can prevent catastrophic failure on the transmission system, as well as provide a means to detect potential feeder leaks. In both cases, this would also prevent or lessen the environmental impact of dielectric fluid release to the environment. This technology can also be used to replace existing "simple" alarm systems, some of which need to be replaced due to their condition

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
Program reduces events can result in extensive damage and the shutdown of an area substation and reduces the likelihood causes will lead to the loss of a substation as well prevent loss of dielectric fluid systems resulting in loss of feeder pressure. (e.g., pump houses).

2. Supplemental Information

Alternatives
• Literature search and discussions with the Electrical Power Research Institute (EPRI) have indicated that no similar work has been done.

Risk of No Action
Given the consequences, including enterprise risks that might arise, by not doing the project/program. Quantify the risks, if applicable.

Non-Financial Benefits
o Maintain the reliability of our HPFF (high-pressure, fluid-filled) transmission system, reduce potential environmental impact, and provide real time remote monitoring

o Improve the quality of our normal operating practices and aid in emergency response

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis: N/A

2. Major financial benefits N/A

3. Total cost **$750,000**

4. Basis for estimate: The funding request is based on historical expenditures.

5. Conclusion: N/A

Project Risks and Mitigation Plan

Risk 1: Outage scheduling conflicts with other initiatives.

Mitigation: Outages to be coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs to avoid conflict with other program/ projects resulting in a more predictable budget and manageable outage scheduling.

Risk 2: Delays due resources support coordination.

Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Technical Evaluation / Analysis: N/A

Project Relationships (if applicable) N/A

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	0	0	0	0		0
O&M						
Retirement	0	0	0	0		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**$150**	**$150**	**$150**	**$150**	**$150**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	41	41	41	41	41
M&S	0	0	0	0	0
Contract Services	51	50	50	50	50
Other	14	15	15	15	15
Overheads	44	44	44	44	44
Subtotal					
Total	**$150**	**$150**	**$150**	**$150**	**$150**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Pressure, Temperature and Oil Sensors	
Project/Program Manager: Jane Shin	**Project/Program Number (Level 1): 10029268, 22975789, 22011059, 10029403**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date: 2010	**Estimated Date In Service:** 2025
A. Total Funding Request ($10,060) **Capital: 10,060** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This program funds the installation of Pressure, Temperature, and Oil level (PTO) sensors on Con Edison's network distribution transformers. As of January 1, 2022, approximately 23,971 network transformers had PTO sensors installed. Con Edison crews are expected to install approximately 500 additional PTO sensors in 2022 for a total of 24,471 installed. All 25,966 network transformers connected to the Remote Monitoring System (RMS) are targeted to have sensors installed by December 2025.

Justification Summary:

In-service transformer failures are a public safety concern, and PTO sensors help mitigate such concerns by identifying a suspect transformer prior to failure. Network transformers used by Con Edison are installed in underground vaults and manholes in public areas.

The PTO program is one of the transformer failure mitigation programs that have contributed to an 85.8% reduction in transformer failures since 2006. In 2020, approximately 200 transformers were preemptively removed from service due to problems detected via PTO sensors.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

RMS PTO is one of the key technologies that enables Computerized Inspection of Network Distribution Equipment (CINDE to become a Data Driven process. It is imperative for PTO to be installed at all locations to reap the benefits of Data Driven CINDE.

Data Driven CINDE will allow the company to prioritize inspections based on monitored equipment parameters as opposed to time based inspections.

Transformer Failure is recognized as an Enterprise risk. This program directly contributes to the mitigation of that risk. The Risk Management sub-section of the Electric Long-Range Plan (ELRP) states that part of the minimization of risk to employee and public safety is "proactive replacement of high-risk components" and the use of "data and analytics to prioritize our response to any potential problems revealed". The PTO Sensors program does just that for network transformers.
In addition, this program supports other aspects of Enterprise Risk Management as cited in the Risk Management sub-section of the ELRP, including:

- Resiliency and Reliability (achieved through the redundancy built into the secondary network design, and maintained through replacement of failure-prone components, including transformers)
- Climate Change Vulnerability (again, achieved through network redundancy and contingent design)
- Critical Infrastructure Reliability (with service to critical infrastructure built into the impact of component failure)

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection
. To maintain a condition assessment on units without sensors installed similar to those with sensors installed, the frequency of routine physical inspections will need to be increased to detect transformers at risk of failure. More frequent vault inspections will require a significant increase in maintenance costs and provide less information regarding the condition of the transformer. Even this however does not capture the same amount of data the continuous data monitoring does.

Alternative 2 description and reason for rejection
Maintain Current Inspection Frequency on Units without Sensors – Cease PTO sensor installation and continue inspecting network transformers at the same rate. Units without PTO sensors installed will be a greater failure risk than units with sensors.

Risk of No Action

Risk 1
When a network transformer fails, there is a chance that it may rupture and oil may escape from the vault. Transformer rupture can result in public injury, property damage and/or environmental contamination.

Non-Financial Benefits
Non-financial benefits include increased public and worker safety, reduced risk of oil spills (environmental impact), and increased feeder reliability due to reduction in transformer failures.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis (if required)

2. Major financial benefits

3. Total cost

4. Basis for estimate
The basis for the estimates used in this program is the historic unit cost for the installation of pressure, temperature, and oil level sensors. There are approximately 2,400 remaining to be installed.

5. Conclusion

Project Risks and Mitigation Plan

Risk 1
Remaining locations are the most difficult to install and have led to higher unit costs.

Mitigation Plan for Risk 1
Bundle PTO installations when possible with other work

Technical Evaluation / Analysis
The PTO program, among other transformer failure mitigation programs, has contributed to a significant reduction to in-service transformer failures. The table below shows the number of in-service transformer failures from 2006 through 2020. The number of in service failures in 2020 was 17, an 85.8% reduction since 2006.

Year	In Service Transformer Failures
2006	120
2007	70
2008	52
2009	34
2010	42
2011	27
2012	27
2013	14
2014	21
2015	22
2016	16
2017	30
2018	27
2019	14
2020	17

Project Relationships (if applicable)
The Remote Monitoring System Program is required to support the PTO program, as PTO sensors require 3rd and 4th generation transmitters to function properly.

3. Funding Detail

Historical Spend

EOE	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Labor	745	809	118	331		718
M&S	155	155	63	421		1033
A/P	0	0	0	0		7
Other	27	1	0	19		17
Overheads	539	541	82	215		230
Total	**3,944**	**4,273**	**263**	**986**		**783**

Total Request ($000):

Total Request by Year:

EOE	Budget 2022	Request 2023	Request 2024	Request 2025	Request 2026
Labor	913	913	913	913	941
M&S	464	464	464	464	478
Contract Services	14	14	14	14	15
Other	0	0	0	0	0
Overheads	608	608	608	608	626
Total	**2,000**	**2,000**	**2,000**	**2,000**	**2,060**

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	718	718	718	718	740
M&S	1033	1033	1033	1033	1065
Contract Services	7	7	7	7	7
Other	17	17	17	17	17
Overheads	230	230	230	230	236
Subtotal	**2,000**	**2,000**	**2,000**	**2,000**	**2,060**
Contingency**					
Total	**2,000**	**2,000**	**2,000**	**2,000**	**2,060**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Primary Feeder Reliability	
Project/Program Manager: Stephen Pupek	**Project/Program Number (Level 1):** 10031927, 10034471, 10032002, 10035597, 10032050, 10034580, 10032207
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date: Ongoing	**Estimated Date In Service:** Ongoing
A. Total Funding Request ($000) **Capital: $335,958** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

The goal of the Primary Feeder Reliability program is to ensure we have an executable and sustainable work plan that maintains and improves the reliability and resiliency of Con Edison's networks (and non-network load areas) for the short term and for the coming years. The Network Reliability Index (NRI) is a measure used to gauge the reliability and resiliency of all 65 second contingency networks on the Con Edison distribution system. The lower the index, the less likely for that network to experience cascading feeder outages during extreme weather events. Con Edison has worked over the last decade to improve all of its networks to below an NRI of 1.0. As of Summer, 2021 all networks are below 1.0 and the top 25 have an average NRI of 0.51. This goal remains to keep all networks below 1.0 and to maintain the margin below 1.0 that we presently have for all networks. The aim is to maintain this level of reliability, resiliency and to minimize the need for Voltage Reduction as we ramp up our Temperature Variable design basis by 1 deg F by 2030 to account for the impact of climate change.

Factors that impact the NRI include the number (and age) of components in the network, component failure rates, longer and elevated predicted periods of heat stress, and feeder/network loading, and the load shifts during contingencies. It is projected that by 2030 that our design temperature variable of 86 deg F will need to rise by 1 deg F to 87 deg F.

Calculations of the NRI of the Networks in their present state with the increased Temperature Variable of 1 deg F results in 8 networks with NRI levels greater than 1.0 and the average of the top 25 networks rises from 0.51 to 0.87. The 8 Networks with NRI above 1.0 range from 1.1 to 1.6. Significant investment is required to maintain each of these networks NRI below 1.0 as well as maintain the average of the top 25 closer to the present 0.5. It is estimated that over the eight (8) years leading up to 2030 that the following work would need to be in these top 25 networks to bring all the networks below an NRI of 1.0.

- 3,200 of the 5,500 remaining sections of Paper-Insulated-lead-Covered (PILC) cable in the top 25 networks would need to be pro-actively replaced
- 160 of the 300 manual 13 & 27kV switches would need to be replaced with the new Interrupter (in existing structure)
- In addition, in certain networks, significant feeder extensions using new breaker positions and new interrupters in new structures will be required. These networks are typically those with limited levels of PILC remaining and/or heavily loaded primary feeders and so other solutions are required.

To ensure that the plan to reach the design goal (of all networks with NRI's less than 1.0 by 2030 and maintain the average of the top 25 networks at 0.5 when the design TV rises to 87 deg TV) the work on the above plan needs to be spread out over the 8 years from 2022-to-2029 inclusively. Therefore, the annual plan for each of the rate case years is:

- 400 Sections of PILC with 160 Conduit Sections (Historical 40% Obstruction)
- 20 Interrupters installed in existing manual switch locations (structures)
- 40 Sections of Conduit per year + 80 Sections of new cable extensions + 2 Interrupters in new Structures

Note that although we are aiming to remove only approximately 60% of the remaining PILC in the top 20 NRI networks, the targeted population factors in the cable as well as the removal of the problematic Stop or Transition Joints to maximize the reliability benefit.

Justification Summary:

<u>PILC Cable Removal Program</u>

The program began in the mid 1980's due to concerns over the reliability and potential environmental impact of PILC cable. PILC cable contains a dielectric fluid (usually a mineral oil) and a lead sheath that are potential environmental contaminants. Failure data collected during the 1980's also showed that older PILC cable had a higher failure rate in summer months.

PILC cable and the associated transition splices (stop-joints connecting PILC cable to the newer solid dielectric cable) have elevated failure rates, especially during summer heat-waves. Transition splices have been responsible for cascading feeder failures where multiple outages have put the network at an increased risk of shutdown. The replacement of the PILC cable and associated transition splices reduces that risk.

<u>Underground Interrupter & Sectionalizing Switches Program</u>

Sectionalizing switches reduce the amount of load shifted to other distribution feeders by allowing isolation of faulted segments of a feeder. The un-faulted portion of the feeder and associated transformers may then be re-energized. This in turn reduces the likelihood of failure of adjacent feeders that pick up the load of the faulted feeder.

The interrupter device prevents feeders from automatically opening out of service when a fault occurs downstream from the interrupter. The interrupter device operates instantaneously to isolate primary faults detected downstream from the device. The interrupter device is coordinated to operate before the corresponding Area Station feeder breaker thereby preventing the entire feeder from going out of service. Un-faulted sections remain in service. The faulted and isolated cable sections can be processed from the interrupter device to reduce restoration time.

Feeder restoration time plays an important role in network reliability and as more feeders are out of service, the higher the probability of a network going into a cascading event. Reliability models assume components will be unavailable for some time during which they are repaired. Since this program replaces the first generation manually operated sectionalizing switches with remote control units, the restoration time for a faulted feeder is reduced since the un-faulted portion of the feeder can be returned to service.

The first generation of underground sectionalizing switches that were deployed on the distribution system were motor operated three phase SF6 (sulfur hexafluoride) gas insulated switches. Over time these switches have become problematic to operate due to motor failure, or loss of SF6 gas. These switches are being selectively targeted for replacement with the newest variant, which is a vacuum based switch.

New Feeders

This program improves reliability by establishing new distribution feeders. This is achieved by either splitting or "de-bifurcating" existing feeders (supplying from individual breakers, two feeders formerly supplied from a single breaker) to create two separate feeders. The program utilizes existing spare feeder positions in area substations, or constructs new area substation cubicles where necessary, to accommodate the new distribution feeders.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

The key metric for the Primary Feeder Reliability Program is the NRI Ranking. the NRI ranking tells us the probability of having a catastrophic failure leading to a network shutdown which subsequently is a distribution ERM. The NRI calculation has the agility to be updated to factor in changing variables including equipment age / failure rate and Temperature Variable.

With expected climate change, the NRI model has been adjusted to recognize the increase in temperature. By working with resources supporting the New York State Climate Leadership and Community Protection Act (CLCPA) we have determined that the acceptable TV value for forecasting should move from 86 to 87 degrees. By taking this approach, it has become apparent that we need to accelerate our efforts to enhance the reliability of the primary system to support the goals of this program.

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection
An alternative to the PILC cable replacement portion of this program would be to replace only the high failure rate transition splices with a newer, more reliable splice design. This would reduce the cost of the program by one-third but would not have the same impact on reliability as removing both the cable and the transition splice. The PILC cable is the oldest cable on our system with a failure rate two and one half times that of modern ethylene propylene rubber-insulated (EPR) and ethylene alkene copolymer (EAM) cable. Replacing the nearly 7,000 in-service transition splices would take nearly the

same amount of time as replacing the PILC cable sections however will result in a less reliable system. This is because modern transition splices still have a higher failure rate than non-transition splices.

Alternative 2 description and reason for rejection
Another alternative to the PILC cable replacement portion of this program would be a cable diagnostic system that could accurately determine the "health" of our PILC cable system. We could then target only un-healthy cable for replacement. Although there are several systems available, including: Partial Discharge and Tan-Delta, none have proven to be effective on our primary distribution system.

Alternative 3 description and reason for rejection
An increased use of the Hipot testing (both DC and VLF) could be used to ferret out defective cable that could fail while in service. While Hipot testing has increased the amount of PILC cable and stop-joint removals, the frequent use of this cable diagnostic has increased the number of in-service failures since it is a destructive test.

Alternative 4 description and reason for rejection
Voltage reduction during heat events has proven to be effective in avoiding system failures. As equipment continues to age the specification (EOP-5022) governing voltage reduction could be updated to reduce voltage more preemptively on circuits to avoid failures. This is not ideal as it can lead to power quality issues for some customers using voltage sensitive equipment.

Alternative 5 description and reason for rejection
During high load events, we have load shedding programs in place that provide guidance on dropping customers from the grid in order to preserve the operational integrity of the system. An alternative could be to institute aggressive load shedding / rolling blackout programs to preserve the system integrity and avoid equipment failure. This alternative is not desirable because it will result in poor customer experiences and have a negative impact on the SAIFI and CAIDI metrics

Risk of No Action

Reliability projects are required to maintain all 65 networks below 1.0 and to maintain the margin below 1.0 that we presently have for all networks. The NRI of the networks changes from year to year as failure rates and loading on the components change. These changes often lead to an increasing NRI for specific networks. In order to maintain the reliability of the entire network distribution systems, CECONY has established a goal to have each of its 65 networks below of 1.0 per unit. This goal has been established in order to reduce the potential risk of a network shutdown. Work in this program lowers the NRI index for each network. Without these projects the index would grow above the corporate goal and translate into a higher risk of a network shut down occurring.

If this reliability project is not acted on, Operations will need to increase the use of extreme mitigation measures such as more aggressive load shedding and voltage reductions during peak loading times. This will be necessary in order to mitigate the added risks of cascading events that could result from unreliable feeder integrity.

Non-Financial Benefits

The PILC Cable Removal Program has an environmental benefit of removing potentially hazardous material, like lead and oil, from the environment.

The Underground (UG) Sectionalizing Switch Program reduces the potential to leak SF6 gas (a greenhouse gas) into the environment as the new Elastimold underground switches contain no SF6 gas.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)

2. Major financial benefits

The reliability performance mechanism in the current rate agreement provides for up to $25 million in RPM adjustments for a single major outage to a network. By increasing NRI above the 1.0 per unit threshold, the reliability projects detailed reduce the risk of a significant network event and the associated penalties.

The new remotely operated sectionalizing switches reduce the maintenance costs associated with the mandatory operation of the existing switches once every six months. The SCADA equipment installed on the new vacuum switches has remote diagnostics capability and only requires a field visit for repairs if it fails. There is no recurring communication expense associated with the remote operation of the switches.

3. Total cost

4. Basis for estimate

The basis for the estimated costs in the program are the historical unit costs for installation of cable sections, stop-joints, underground switches, sub surface infrastructure and new feeder positions.

5. Conclusion

Primary feeders are evaluated annually for normal and emergency capacity using the Company's Poly Voltage Load Flow Program (PVL).

The Company will review all System Expansion projects to determine the Non-Wires Candidates as part of the Distribution planning process. The Company will then provide information regarding these candidates and their progress on its website as well as via periodic NWS filings.

Project Risks and Mitigation Plan

Risk 1 Skilled Labor Availability	Mitigation plan Work with Work and Resource Management group to schedule resources around known busy periods in order to maximize productivity. In addition, projects are prioritized to have resources focus on higher impacted jobs first. Barring significant system emergencies we should be able to progress this work as planned
Risk 2 Material Availability	Mitigation plan Engineering to work with Work and Resource Management and supply chain to establish a cohesive

	plan to align with vendor lead times and stay engaged with vendors to ensure that lead times are maintained and if shortages are encountered, plan is adjusted as needed.

Technical Evaluation / Analysis

Primary feeder reliability is effectively managed through the Network Reliability Index (NRI) ranking that leverages current system conditions and historical data to provide a proven method for targeting problem issue throughout the electric system. In using the available data and defined modeling criteria, we have been able to determine that the most cost-effective method of improving reliability is to take a holistic approach and target the replacement of PILC Cable that has 3W-1W Raychem joints, Introducing Modern interrupter switches and expanding/introducing feeders.

Transition splices continue to be the largest contributor to primary feeder failures during the summer period. Raychem 3W-1W Stop-Joints, which comprise only five percent of the network splice population, account for 45 percent of the primary network splice failures. The only practical method to remove these heat sensitive transition splices is through the removal of the attached PILC cable. The primary network system is currently comprised of approximately nine percent PILC cable while the associated transition splices make up around five percent of the splice population.

In addition, the summer network PILC cable failure rate is, on average, three and one-half times greater than the newer extruded EPR cable (0.156 vs. 0.045). The network summer failure rate for Transition splices (stop-Joints), connecting PILC cable to extruded type cables, is, on average, nine and one-half times greater than extruded cable splices (0.471 vs. 0.049).

The introduction of new interrupter switches will address known flaws with legacy equipment and expand the utilization of interrupter technology in the distribution system. The incorporation of these switches into circuits allows for partial circuit isolation rather than a full feeder outage resulting from a fault. This reduces system impact and improves the restoration time for the faulted section.

Project Relationships (if applicable)

Primary Feeder Relief

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	11,202	3,402	5,666	13,600		20,270
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**24,327**	**75,500**	**77,000**	**78,545**	**80,586**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	6,288	19,514	19,902	20,301	20,829
M&S	6,887	21,376	21,801	22,238	22,815
Contract Services	3,696	11,470	11,698	11,933	12,244
Other	243	754	769	784	805
Overheads	7,213	22,385	22,829	23,288	23,894
Subtotal	**24,327**	**75,500**	**77,000**	**78,545**	**80,586**
Contingency**					
Total	**24,327**	**75,500**	**77,000**	**78,545**	**80,586**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Central Operations / Substations
2022

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Protection, Control and Automation Program	
Project/Program Manager: Jim Neilis	**Project/Program Number (Level 1): 24652095**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date :1/1/2022	**Estimated Date in Service: N/A**
A. Total Funding Request ($000) **Capital: $126,000** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This program will upgrade substation protection, control, energy management system (EMS) interfaces and/or operator interfaces. The scope includes changing the supervisory, control and data acquisition (SCADA) systems from Programmable Logic Controller (PLC) based systems to human machine interface (HMI), microprocessor-based systems. This includes the replacement of component dedicated copper wiring with a fiber optic network and weather hardening relay panels that are exposed to extreme weather. The migration from copper lines to fiber optic systems will facilitate the use of intelligent electronic devices (IEC 61850) protection and control systems. This program will also install cyber secure, one-way data retrieval connections (Data Diode) in substations.

The upgrade portion program will utilize two strategies for prioritizing work locations. The first strategy will focus on substations that have exhibited reliability issues, such as spurious relay operations, due to rain and water intrusion and degraded protection and control systems and direct current (DC) grounds. Projects prioritized under this first strategy will install a new automation system, a fiber optic network, upgrade substation equipment to facilitate IEC 61850 protocols and the replacement of all protection and control systems. The second strategy will target substations that have prioritized multiple breakers and/or relay systems upgrades and replace their automation systems to facilitate the use of IEC 61850 in the breaker and relay work.

The installation of Data Diodes will prevent data leakage, eliminate the threat of malware, and fully protects the sending network from external threats through the data diode's network path helping to analyze events and triggers from remotely accessed electronic devices to proactively identify and avoid mis-operations or poor behaving systems as data diodes are only physically capable of sending data one-way, a data diode creates a physical barrier or "air gap" between the two points, with initiatives such as:

- Install interface panels for substation equipment such as breakers and transformers to facilitate migration to IEC 61850
- Perform holistic upgrades to protection and control systems to entire substations with Sherman creek as the initial project.
- Install data diode to facilitate NERC compliant data retrieval and event analysis capability at all substations.

Justification Summary:

This program will upgrade the protection, automation, and control at substations to modern systems that are more weather-hardened, more reliable, and provide greater operational visibility. Relay and control systems are essential to power transmission and distribution and when they do not operate per design, can have an impact on many power carrying assets simultaneously. Legacy equipment utilizes copper control wiring and panels or other components that were not designed with climate change mitigation as a fundamental design consideration. When system disturbances do occur, it is imperative that operations have remote, secure access to digital information to be able to make timely decisions and restore equipment to service as quickly as possible. Performing station-wide upgrades to protection and control systems and installing Data Diode will help to make substation and transmission systems more adapted to increasing frequency of weather events and more capable of quick restoration following system disturbances. Providing station-wide control wiring and mitigating relay vulnerabilities decreasing the risk of large-scale trip outs and loss of substation with updated relay systems, fiber networks and remote data collection ability improve reliability and recovery times following forced outages.

Substations that utilize copper protection and control circuits are vulnerable to conditions that can impact reliability. Control cables are often installed in troughs that are susceptible to becoming submerged during heavy rainfall and this frequently leads to DC grounds. When DC grounds occur on these circuits, they can cause spurious trip outs of substation equipment as well as generate nuisance alarms and make the status of certain components unknown. This program will target locations that have had a high frequency of these types of occurrences, such as Sherman Creek Substation, and replace the automation, control, and protection systems. Sherman Creek has experienced 44 instances of DC grounds that had to be repaired since 2012 and nine spurious trips of transmission equipment since 2018. The upgrade of this station, and others like it, to a fiber optic network with IEC 61850 protection and control systems will eliminate copper wiring, DC grounds, and provide greater reliability, particularly during extreme weather events and facilitate better data collection.

Company-wide adoption of industry-standard protocols and processes enables consistent, understandable, and maintainable protection and control solutions. For substations prioritized for upgrade through the second strategy (where upgrades are coincident with other planned work), a transition to communication-based protection and control system engenders an order-of-magnitude increases in the quantity and quality of data available from the substation systems. This strategy will take advantage of outage synergies with other planned capital work and move portions of substations towards a more modern and climate adapted protection and control systems.

Remote access to secure, digital data is essential to recovery and restoration from system events. Data diodes are only physically capable of sending data one-way, and create a physical barrier or "air gap" between the two points. The installation of data diodes will prevent data leakage, eliminate the threat of malware, and fully protect the sending network from external threats. The data diode helps to analyze events and triggers from remotely accessed electronic devices and to identify and avoid mis-operations or poorly behaving systems.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):

This program helps mitigate the likelihood and controllability factors for both the risk of Loss of a Substation and Major Storm. Relay mis-operations, which can be triggered by water intrusion and DC grounds on control wiring (from a major storm), can lead to the Loss of a Substation.

Climate Change and Resiliency:
One of the priorities for work scope planned under this program is to weather-harden relay systems that are vulnerable to water intrusion from extreme weather events. Another priority of this program is to migrate control system design away from copper wiring (that is also vulnerable to mis-operation due to water intrusion) to fiber optic systems.

2. Supplemental Information

Alternatives
The alternative to this program is to continue troubleshooting DC grounds, accepting spurious trips and to perform relay and breaker upgrades utilizing like and kind replacements. Under this alternative, the reliability risks associated with trip outs will persist and future asset management decisions will be more challenging because of the limited availability of data.

Risk of No Action
Reliability risks due to spurious trip outs and limited data availability.

Non-Financial Benefits

- IEC 61850 enables better data collection on the function and health of various substation equipment. This data can be used to make more informed operational and asset management decisions.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis (if required)
N/A
2. Major financial benefits
N/A

3. **Total cost $126,000**

4. Basis for estimate: The funding for this program is based on a project at Sherman Creek Substation ($25M spread over 2022-2025), the installation of data diode at 101 substations ($79M over the years 2022-2025), automation replacements at various stations (4 at $3.5M each) and Network Model Management ($8M).

Project Risks and Mitigation Plan

Risk 1: Outage scheduling conflicts with other initiatives.

Mitigation: Outages to be coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs to avoid conflict with other program/ projects resulting in a more predictable budget and manageable outage scheduling.

Risk 2: Delays due resources support coordination.

Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Risk 3: **Lack of alignment between resources support and outages.**
Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor and construction to avoid alignment conflicts with outages.

Technical Evaluation / Analysis
N/A

Project Relationships (if applicable)
N/A

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	0	0	0	0		4,587
O&M						
Retirement	0	0	0	0		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**$4,000**	**$38,500**	**$33,500**	**$20,000**	**$30,000**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor					
M&S					
Contract Services					
Other	$4,000	$38,500	$33,500	$20,000	$30,000
Overheads					
Total	**$4,000**	**$38,500**	**$33,500**	**$20,000**	**$30,000**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations/ Substation Operations
2022

1. Project / Program Summary

Type: ☐ Project ☒ Program	**Category: ☒ Capital ☐ O&M**
Work Plan Category: ☐ Regulatory Mandated ☐ Operationally Required ☒ Strategic	
Project/Program Title: Pumping Plant Improvement Program	
Project/Program Manager: TBA	**Project/Program Number (Level 1): PR. 8ES4200/ 10035274**
Status: ☐ Planning ☐ Design ☐ Engineering ☐ Construction ☒ Ongoing ☐ Other: ___________	
Estimated Start Date: N/A	**Estimated Date in Service: N/A**
A. Total Funding Request ($000) **Capital: $$21,654** **O&M:** **Retirement: $2,694**	**B.** **☐ 5-Year Gross Cost Savings ($000)** **☐ 5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This program consists of improvements to the pumping and cooling plants that support the company's 69kV, 138kV, and 345kV underground transmission systems. These improvements are upgrades to modernize existing equipment, or they are complete plant replacements if necessary. Focus is given to projects that reduce environmental risk associated with dielectric fluid release into the environment.

A Pumping Plant is a facility that pressurizes and fills underground transmission lines with dielectric fluid. This fluid is required for the operation of the electric cables. A Cooling Plant is a facility that extracts fluid from an underground transmission cable and then cools this fluid before pumping it back into the underground line. A cooling plant allows existing transmission lines to carry more power. A Public Utility Regulating Station (PURS) Plant is a particular type of cooling plant that is installed exclusively on the 345kV system.

The scope of work can be summarized as follows:

•**<u>Control Panel Upgrades:</u>** A skid replacement consists of replacing control panels and upgrading hydraulic components. We further evaluated those and decided that for the most part, the pumps and ladders are in generally good condition, but the control panels are in poor condition. Furthermore, a root cause analysis determined that the control panels, which have electrical and dielectric/mechanical components residing in a common control cubicle, increase the likelihood of catastrophic fire. A cost benefit analysis was performed and has shown that with this new approach, we can effectively replace two control panels for approximately the same cost as one skid replacement, thereby addressing twice as many of the more serious pump plant issues. Control Panel Upgrades consist of the removal of the existing control panel, segregation of the dielectric and electric components, installation of pipe mounted transducers, a Programmable Logic Controller (PLC) with human machine interface (HMI) and cyber-secure 1- way communication to Energy Control Center (ECC) and replacement of leaking ladder and header valves as needed. Our current target for control panel replacements is six per year or four Control Panels and one skid replacement.

•**Partial ("Skid Replacements") and complete pumping plants replacements:** This consists of full control panel replacements plus replacement and upgrades to all hydraulic components (Pumps and Ladders) to improve the operability of the facilities. In a skid replacement, some of the existing components of the original pumphouse are left in place, most notably the storage tank and the existing structure house. In a complete replacement, none of the original components are left in place, everything is replaced. Since skid replacements are typically a lower cost alternative than a full replacement, we look to use this scope where possible versus a full replacement.

•**PURS Plant upgrades:** This consists of the installation of variable frequency motor drives (VFD's) for energy efficiency and reliability; replacement of existing analog controls systems with new digital systems; replacement and upgrades to hydraulic components; installation of new communications systems.

•**Cooling Plant upgrades:** This consists of replacement of existing analog controls systems with new digital systems and replacement/upgrades to hydraulic and cooling components. It also may include replacement of the heat exchangers, cooling towers and oil and water pumps as needed based on current condition, maintenance history, and vintage.

•**Cooling Plant Heat Exchanger replacements:** Each cooling plant and each PURS plant has a series of heat exchangers. This work consists of the replacement of heat exchangers as conditions warrant.

•**Pressurization Plant Communication System**: These projects involve replacing existing telephone line dial-up communication systems between Pressurization Plants and the Shift Managers at the ECC with a new fiber optic, cyber-secure communication system. This new system will provide real-time Pressurization Plant alarms, including existing Leak Warning Alarms, and plant data to the ECC. The scope of this program is to replace the communication systems in plants that were upgraded in the 1990s and 2000s. The communication system and Leak Warning alarms for the current control panel upgrade projects will be addressed in the Environmental Enhancements Program.

Upgrading the communication system includes the installation of fiber optic cables, conduits, associated accessories (e.g., patch panels, connectors, pigtails), media converters, and switches, to connect new generation Programmable Logic Controllers (PLCs) installed at Pressurization Plants in various Substations to the ECC Supervisory Control and Data Acquisition (SCADA) system. To do this, either a new Remote Terminal Unit (RTU) will be installed or an existing RTU with spare data input points will be utilized. Without detailed engineering for these projects at this time, it is assumed that stations with one pressurization plant will be connected to an existing station RTU. This will be evaluated for each substation. A communication link will be established between the RTU at the substation and the SCADA system at the ECC. For the Shift Managers to collect and analyze the plant data, dedicated servers with customized software programs will be installed at both the ECC and Alternate ECC (AECC).

Justification Summary:
The nature and vintage of these units warrants either full or partial replacement. These units all warrant a control panel replacement that segregates oil-containing components from electrical components and greatly reduces the risk of fire. Our direction to primarily focus on partial replacement has been based on a cost analysis that determined we can essentially replace two control panels for the cost of one full replacement, thereby more effectively mitigating more risk of catastrophic event.

The highest priority these initiatives would improve the ability to detect and stop leaks, which decreases the potential for oil leaks into the environment. Furthermore, a root cause analysis determined that the control panels, which have electrical and dielectric/mechanical components residing in a common control cubicle, increase the likelihood of catastrophic fire. No action would result in equipment failure, causing damage to equipment and/or personnel, and continued degradation of equipment, resulting in oil leaks to the environment.
Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation): This program directly impacts risks of "equipment failures and loss of substation". This program reduces the severity and likelihood of equipment failures and loss of substation. Projects completed under this program reduce the risks by upgrading and/or replacing existing equipment at pumping and cooling plants with modernized devices with the ability to detect and stop dielectric fluids escapes, segregate oil-containing components from electrical components reducing the risk of fire and improving the ability to control station operations greatly reducing failures and potential loss of station. Is also important to note that this program impacts the risk of "Loss of Dialectic Fluid Systems" decreasing the severity and likelihood of the potential for oil release into the environment when outdated equipment is replaced with this program new initiatives and solutions.

2. Supplemental Information

Alternatives There are no feasible alternatives but, as noted above, Substation Operations will implement the most cost-effective feasible project dependent upon the circumstances.
Risk of No Action No action would result in equipment failure, causing damage to equipment and/or personnel, and continued degradation of equipment, resulting in oil leaks to the environment. As noted above, this program mitigates several environmental and operational concerns that we have in the pump houses, PURS, and cooling plants. For example, the importance of removing the capillary tubing from the pump house control cabinets was re-emphasized following the pump house #2 fire at Dunwoodie.
Non-Financial Benefits These initiatives would improve the ability to detect and stop leaks, which decreases the potential for oil leaks into the environment.
Summary of Financial Benefits and Costs (attach backup) 1. Cost-benefit analysis: N/A 2. Major financial benefits These improvements avoid maintenance costs, increase reliability, and lower failure rates associated with microprocessor-controlled pressure control system. In addition, these improvements help avoid costs from fines for regulatory noncompliance. 3. Total cost **$$21,654** 4. Basis for estimate: Based on the cost of similar types of work done in the past. As this is an ongoing program, work scopes are generally similar in nature.

5. Conclusion: N/A

Project Risks and Mitigation Plan
Project Risks and Mitigation Plan

Risk 1: Outage scheduling conflicts with other initiatives.

Mitigation: Outages to be coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs to avoid conflict with other program/ projects resulting in a more predictable budget and manageable outage scheduling.

Risk 2: Delays due resources support coordination.

Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Risk 3: **Lack of alignment between resources support and outages.**
Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor and construction to avoid alignment conflicts with outages.

Technical Evaluation / Analysis:
The nature and vintage of these units warrants either full or partial replacement. These units all warrant a control panel replacement that segregates oil-containing components from electrical components and greatly reduces the risk of fire. Our direction to primarily focus on partial replacement has been based on a cost analysis that determined we can essentially replace two control panels for the cost of one full replacement, thereby more effectively mitigating more risk of catastrophic event.

Project Relationships (if applicable) Plants located in stations targeted by the storm hardening efforts will be upgraded under that program. All other upgrades under this program will consider any storm hardening mitigation that may be needed to meet current standards.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	3,901	2,756	1,999	2,177		8,206
O&M						
Retirement	859	426	619	252		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	5,154	4,800	3,900	3,900	3,900
O&M*					
Retirement	539	539	539	539	539

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	1,907	1,776	1,443	1,443	1,443
M&S	992	924	750	750	750
Contract Services	374	363	296	298	310
Other	103	96	78	78	78
Overheads	1,778	1,641	1,332	1,331	1,319
Subtotal					
Total	**$5,154**	**$4,800**	**$3,900**	**$3,900**	**$3,900**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations/STO
2022-2026

1. Project / Program Summary

Type: ☒ Project ☐ Program	**Category: ☒ Capital ☐ O&M**
Work Plan Category: ☐ Regulatory Mandated ☐ Operationally Required ☒ Strategic	
Project/Program Title: Queensboro Bridge Risk Mitigation	
Project/Program Manager: Mark Bauer	**Project/Program Number (Level 1): 23289170**
Status: ☒ Planning ☐ Design ☐ Engineering ☐ Construction ☐ Ongoing ☐ Other: ___________	
Estimated Start Date: 2021	**Estimated Date In Service:**
A. Total Funding Request ($000) **Capital: 200,000** **O&M:** **Retirement:**	**B.** **☐ 5-Year Gross Cost Savings ($000)** **☐ 5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:
This project will address risks associated with the feeders on the Queensboro Bridge by relocating bridge span sections of the existing circuits. New cable sections will be installed in trenchless crossings underneath the East River. There are six 138kV feeders and six 69kV feeders that traverse the Queensboro Bridge. The 138kV feeders connect Vernon Substation to E40th, Murray Hill and West 49th Street Substations. The 69kV feeders connect Queensbridge Substation to East 63rd Street Substation. This project will relocate six of the cables, prioritizing the 138kV feeders, with new cross-linked polyethylene (XLPE) cable sections.

Justification Summary:
This project will re-route six of the twelve bridge crossings on the Queensboro Bridge. This addresses some of the risks that the 69kV, 138kV, and the bridge itself pose on reliability. There are three main concerns; the bridge itself, the 69kV feeders, and the 138kV feeders.

The bridge itself has been identified as a common failure mode. In a previous study, the bridge was identified as the number one risk in High Impact, Low Probability. The probability of the bridge collapsing is low, however, if the bridge fails, it would take out most of the supply to the east side of Manhattan.

On the 138kV solid dielectric feeders, the feeder pipes act as conduits providing physical protection and support. If the pipe walls are compromised due to wear or stress, the insulation wall of the solid dielectric cable may be physically impacted and eventual failure may occur once the remaining insulation wall thickness can no longer withstand the voltage stresses. There have been multiple joint failures on these feeders due to cable movement in the last few years. In 2015, $56M was spent on replacing 11 of these joints, however additional joint issues continued, in 2019, there was a failure on feeder 38M01. Every time there is a failure it requires extensive repairs that include coordination with the NYC DOT and construction of scaffolding. The scaffolding costs a minimum of $4.5M. Each repair also becomes more difficult because of the growing number of joints already replaced on the feeders. In order to replace a joint on these feeders, two joints with a cable insert in between are needed to replace one joint. Additionally, due to the fact that the pipe is tight to the bridge, during repair the pipe needs to be lowered toward the pier and due to repeated repairs, the pipe is getting close enough to the pier where it cannot be lowered anymore. Issues are expected to continue due the fact that the pipe is only welded in the middle and when it is cold, the pipe follows ambient temperature but the cable moves differently. When the pipe is shrinking, the cable is expanding, and these repeated fluctuations will continue to cause stress on the joints.

The 69kV high-pressure nitrogen-filled feeders have pipes that act as conduits (providing physical protection and support) and pressure boundaries to contain the nominal 200 psi nitrogen pressure required to provide the needed insulation level for proper high voltage cable operation. Pressure excursions due to repeated, significant leaks may impact cable life. There have been constant nitrogen leaks on these feeders, to the extent that Con Edison was spending $300k annually on nitrogen for about 20 years. The duration that a cable is in service at pressures below the minimum specified operating pressure will adversely affect the useful life of the cable once the voltage stresses exceed the capability of the insulating system to withstand them. As pressure on a pipe-type feeder system decreases, the insulating capability of the system decreases and ionization (and eventual electrical breakdown) of the paper insulation can result. Even if a specific leak incident does not result in immediate failure of the cable, the long-term effective life of the cable may have been reduced. Due to these leaks, ConEdison repaired the riser sections for these cables with a carbon fiber wrap, however, there still continues to be nitrogen leaked.

The only way to mitigate these risks is to remove the feeders from the bridge and replace the cable. This will reduce the risk of a large event taking out all 12 feeders, and in the future in the case of repairs make them more manageable and less costly.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans , CLCPA Initiatives, Risk Mitigation):
This is related to system resiliency and feeder failures. Addressing these feeders and moving them off of the bridge will increase systemic robustness and reduce risk. This program could be adjusted in the future due to NYC Clean Energy Hub #2 project receiving approval to proceed.

2. Supplemental Information

Alternatives

- No action will require the Company to continue to spend money on nitrogen leak repairs and joint repairs, which could rangefrom $200k to several million annually. It also means there is still the risk of an event on the bridge taking out all 12 feeders.
- Relocation of all 12 feeders, though this would increase the cost extensively.

Risk of No Action The primary risk of no action would be an increasing trend of potential pipe and/or cable failures on the transmission feeders crossing the Queensboro Bridge in the future. If multiple failures were to occur during a high load period or while other critical facilities are out of service, load shedding and large-scale customer outages could result. Emergency mobilization and fault locating costs are also avoided by addressing the reliability issues proactively. Implementing this project and enhancing feeder reliability also helps avoid significant job cancellation costs for working groups throughout the Company due to the far-reaching effects on scheduled transmission facility work when a transmission feeder does fail or must be removed from service on an emergency basis.
Non-Financial Benefits Removal of the feeders from the bridge would also benefit the DOT.
Summary of Financial Benefits and Costs (attach backup) The project cost is based on an estimate based on a conceptual scope.
Project Risks and Mitigation Plan
Technical Evaluation / Analysis
Project Relationships (if applicable)

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	N/A	N/A	N/A	N/A		N/A
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	-	20,000	80,000	80,000	20,000
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor		300	3,000	3,000	300
M&S		1,260	8,050	8,050	1,250
Contract Services		15,000	56,000	52,000	5,440
Other		2,326	5,609	5,831	3,931
Overheads		1,114	7,341	11,119	9,079
Total	-	**20,000**	**80,000**	**80,000**	**20,000**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations / Substations
2022

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Reinforced Ground Grid Program	
Project/Program Manager: Steven Bryan	**Project/Program Number (Level 1):** 1ES7400/ 10029070
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date: Ongoing	**Estimated Date in Service: Ongoing.**
A. Total Funding Request ($000) **Capital: $20,880** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This program reinforces the ground grid at substations based on results from periodic testing. The intent of this program is to enhance the effectiveness of the grounding system at each substation. Typical work consists of trenching the new grounding patterns throughout the area to reinforce the existing grounding grid. The trenching is filled in by new grounding conductors and cadwelds that are required to connect these conductors. Once connected and tested the trenches need to be backfilled and the grounding (pigtails) connected to the proper equipment. Also, we are required to remove mechanical connections that are found connected in the ground while performing the work for reinforcement, since they are weak points for corrosion. Beginning in 2023, this program will also include the expansion of lightning protection in select substations by installing additional lightning masts.

Current substation projects include:

2022 – 2023 Projects:
- Jamaica Substation - 2022
- Glendale Substation – 2022
- Gowanus Substation -2023

Justification Summary:

In August 2005, lightning struck a transmission tower at the Astoria East Substation and caused extensive damage to a current transformer revenue metering and its associated wiring. An investigation revealed that the A-frame Tower was not properly grounded and various substation structures and equipment within the Astoria East yard had high grounding impedance. Inspections to determine the cause of the high impedance revealed several instances of damaged ground connection cables and one of the two main 1000 MCM (million circular mills) cables that made up the existing main ground grid were badly corroded.

The excessive corrosion and deterioration of ground cables and underground connectors due to age related degradation require the ground grid be reinforced to minimize damage, in the event of lightning strikes, switching surges, and equipment and/or feeder faults. Ground grid deficiencies are identified through the Company's periodic ground impedance test program. Ground grid continuity measurements were taken at Stations that were built at the same time as the Astoria East Substation.

This program is driven by Con Edison specifications CE-ES-2002-10 (Design Criteria) and CE-ES-1001 (Testing). Key criteria driving action are ground grid impedance and ground grid continuity. The stations targeted do not meet acceptable levels in one or both categories. The work covered under the program represents the requirements to bring the station ground grid back to spec.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):

This program affects the Enterprise Risks Safety and Equipment failures. The program reduces the likelihood of safety events and equipment failures that can occur if lightning or fault currents are not dissipated to ground through the grounding grid.

Climate Change and Resiliency:

The expansion of this program to install additional lightning masts is a climate change adaptation initiative. Among other things, climate change is expected to produce an increased frequency of thunderstorms and lightning strikes. Lightning strikes pose a risk to transmission equipment, particularly equipment at outdoor substations. The absence of adequate lightning protection increases the risk that strikes will damage or destroy equipment and this can lead to customer outages.

2. Supplemental Information

Alternatives

One option is to install new ground grids. This would require extensive outages while the new ground grids are being installed. The extent and location of corrosion are unknown and would require extensive excavation, isolation, and testing to determine the repair requirements. This option is not recommended as testing and repair costs are far greater than the cost of reinforcement. Reinforcement of the ground grids does not require system outages.

Risk of No Action

Taking no action is not recommended as existing ground grids can pose a potential public safety issue with ungrounded fences and high resistance connections within the existing station grids. Both conditions can result in high ground potential rises during fault conditions that could endanger personnel and cause equipment damage.

Non-Financial Benefits

- The reinforcement of the ground grid minimizes damage in the event of lightning strikes, switching surges, equipment, and/or feeder faults.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required) N/A

The reinforcement of the ground grid helps avoid costly repairs to damaged equipment and protect the safety of personnel in the event of a fault. This helps to minimize the costs associated with an incident.

Basis for Estimate: The funding request for this program is based on a $1.1M historical spend on ground grid reinforcement plus $5M per substation for the installation of additional lightning masts.

Project Risks and Mitigation Plan
Risk 1: Delays due resources support coordination.

Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Risk 2: Outage scheduling conflicts with other initiatives.

Mitigation: Outages to be coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs to avoid conflict with other program/ projects resulting in a more predictable budget and manageable outage scheduling.

Technical Evaluation / Analysis
As a result of a 2005 lightning incident at Astoria East Substation, a program has been implemented, as specified in Con Edison procedure CE-ES-1001, to test the ground mats of all substations periodically. Most of the ground grid reinforcement candidates have been in service since the 1960s. Standards at the time did not require fence grounding and mechanical connectors to be installed. High resistance grid connections exist because of the corrosion of ground cables and the deterioration of the mechanical connectors. By reinforcing the grounding system, including the fencing grounds, the performance of the ground grids will be substantially improved.

Project Relationships (if applicable)
N/A

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	1,314	957	2,334	1,038		2,391
O&M						
Retirement		57	3			n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**$1,350**	**$6,100**	**$6,100**	**$6,100**	**$1,230**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	405	1,891	1,830	1,830	369
M&S	194	835	834	833	170
Contract Services	324	1,444	1,529	1,532	309
Other	0	0	0	0	0
Overheads	427	1,931	1,907	1,905	381
Subtotal					
Total	$1,350	$6,100	$6,100	$6,100	$1,230

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations/ Substation Operations
2022

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Relay Modifications Program	
Project/Program Manager: Jim Neilis	**Project/Program Number (Level 1): PR.2ES7800/ 10030242**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date: N/A	**Estimated Date in Service: Ongoing**
A. Total Funding Request ($000) **Capital: $290,656** **O&M:** **Retirement: $11,500**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This program replaces relays protection systems at area and transmission substations. This program will continue to target transmission relays that exhibit reliability issues such as HCB /LCB, legacy microprocessor systems and multicomponent semi-conductors (MCO) systems. This program will be expanded to include upgrades to area station bus and feeder protection, installations that eliminate single points of failure (TPL-001-5 Upgrades) and replacement for some early microprocessor relays including (UFLS) panels.

This program will target approximately eight transmission relay upgrades, eight to ten area station bus section/feeder upgrades, legacy microprocessor relay upgrades at eight stations, two TPL-001-5 Upgrades and ten UFLS upgrades per year.

Justification Summary:

Relay systems are critical in the protection of electric transmission and distribution systems. The reliable and timely operation of a relay system electrically isolates a faulted piece of equipment and protects the rest of the transmission and distribution system from any conditions that may cause further damage. The Company has always prioritized relay upgrades because of the vital role they play. Events in recent years, such as the West Side Outage (WSO) (2019) and Fresh Kills (2021) have shown that some strategic changes to the relay upgrade philosophy, including more standardization and prioritizing area station relay systems, would be beneficial. Legacy systems with known reliability issues on the transmission system will continue to be prioritized for replacement under this program. A more standardized approach to upgrades, however, and an expansion of the program to include area station relays, USFL panel upgrades and TPL projects is critical to avoiding events like WSO and

Fresh Kills in the future. The standardized approach will help the Company adapt to changing climate conditions by improving restoration times following extreme weather events.

Relay performance at BES substations has historically been the key driver for capital upgrades under the Relay Modifications program. WSO and the Fresh Kills event were both rooted in relay mis-operations at non-Bulk Electric System (BES) substations. These events had significant customer impact in terms of outages and an analysis of the root causes identified some process changes needed as well as the need for more area substation relay upgrades. Newer, microprocessor based systems make identifying issues easier and provide engineers and operators with expanded ability to avert situations that could impact multiple stations and customers. Upgrades to area station systems also improve restoration time by installing relays that either self-reset or can be reset remotely. This capability is important not only in an event like WSO, but also events where extreme weather may cause system outages.

Under Frequency Load Shedding (UFLS) panels are critical in gaining faster recovery from decaying frequency to maintain the balance between generation and load followed by a major system disturbance. Existing Clark relays associated with UFLS design needs replacement due to their unreliable operation, impacting our ability to shed the load when needed. Systemwide upgrade of UFLS panels is required to retire the early generation of UFLS microprocessor relays. Strengthening the components of UFLS panel will improve our ability to respond to system imbalance and to prevent cascading events.

This project aims to correct single points of failure (SPF) in the relay system that are identified during the TPL-001-5 planning assessment. Additionally, it will develop a compliance program to ensure the information gathered during the planning assessment is incorporated into work management systems and that future relay work adheres to TPL-001-5 and data such as clearing times are updated in necessary planning databases. SPF can result in equipment damage by delayed clearing or overtripping which can lead to cascading tripping of transmission elements. Mitigation actions will include installation of redundant protection systems starting with overhead feeders in the northern region.

Relays act as the central monitoring apparatus for operation of the transmission and substation system. Modernizing relay systems by moving away from legacy electromechanical systems towards microprocessor-based systems facilitates real time data collection on health and the ability to remotely recover from events. Increased replacements of area substation relay systems is essential to preventing events that may impact many customers simultaneously, as well as recovering from these events or ones triggered by extreme weather.

Additionally, the newer microprocessors offer increased intelligence and integrate advanced technology to provide security against common industry wide issues leading to misoperations. Targeting the replacement of early generation of microprocessor relays that have reached their life expectancy (15 to 20 years) with modern microprocessor relays further strengthens the reliability of our system and reduces the chances of loss of load events.

Provision for future modification is an important factor to consider when planning and designing the new relay upgrades. Modularity offered by utilization of standard 19" rack design for all new microprocessor relays and associated devices will increase the resiliency and efficiency for future modifications.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
This program addresses the Substation Operations risks Relay mis-operations and Equipment failures. Projects completed as part of this program would reduce the likelihood of misoperations by replacing riskier systems or systems that are prone to malfunction. Upgraded relay systems are more likely to operate as designed during fault conditions, reducing the likelihood that equipment may be damaged due to slow clearing times.

This program is part of the Climate Change Adaptation effort, specifically recovery. The upgrade to relay systems that are either self-resetting or can be reset remotely will improve recovery times following extreme weather events that cause outages. Additionally, standardization, and the modularity that will be part of it, will better facilitate the quick replacement of relay components following extreme weather events that may have caused their failure.

In the company long range plan is looking to integrate into a 10-year plan to incorporate relay protection and communication systems as a major driver for prioritizing capital investment.

2. Supplemental Information

Alternatives

The alternative to this program is to only replace relay systems as they fail. This alternative will not reduce the potential risk of misoperations causing trip outs or customer outages. This alternative will also mean the continue used of legacy systems that do not provide remotely retrievable data or system diagnostics.

Risk of No Action
The concerns associated with no action for each project are listed below:

o Replace HCB and LCB Relays (Replace 1st and 2nd Line Relay Protection): Continued use of the existing HCB and directional ground relays with the existing direct current transfer trip (DCTT) system may cause inadvertent loss of the feeders due to mis-operations; continued use of the existing LCB relays increases the risk of inadvertent loss of feeders due to mis-operation of the relays.

o Replace MCO Relays: No action may risk the loss of a substation.

o Replace Electromechanical and solid-state distance relays
With the continued use of the existing protection system, there is risk of inadvertent loss of feeders due to relay mis-operations affecting the transmission reliability.

- Replace obsolete Area Station relays which are prone to mis-operate during communication line disturbances for resiliency enclosing in hardened environment and to gain full benefits of standardization and modernization

TPL 001-5
No action will form non-compliance with NERC standards.

ULFS Panel upgrade:
No action can lead to delays in load shedding activities increasing the possibilities for cascading events.

Non-Financial Benefits
This program increases overall system reliability, as it is aimed at reducing the likelihood of relay system mis-operations. In cases where protective relay systems should have caused a trip out, but did not, equipment may be damaged and require long term repairs or replacements. In cases where a protective relay system inadvertently trips out equipment, load trips may occur if this occurs during another system disturbance or when a station is already in an N-1 or N-2 condition.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis: N/A

2. Major financial benefits
N/A

3. Total cost **$290,656**

4. Basis for estimate: The funding request for this program is based on $15M-$20M for area station upgrades, (10) Area Substation Relay Upgrade $1.5M-$2M based on historical project data from the past 5 years

$20M for legacy microprocessor upgrades with focus on (6) Full Transmission Relay Upgrades $3.2M based on historical project data from the past 5 years.

$10M for work standardization, $10M for TPL upgrades are based on order of magnitude estimates.

$10M for UFLS panels (10) UFLS Panels Upgrades $1M based on historical project data from the past 10 years.

5. Conclusion: N/A

Project Risks and Mitigation Plan
Risk 1: Outage scheduling conflicts with other initiatives.

Mitigation: Outages to be coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs to avoid conflict with other program/ projects resulting in a more predictable budget and manageable outage scheduling.

Risk 2: Delays due resources support coordination.

Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Risk 3: **Lack of alignment between resources support and outages.**
Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor and construction to avoid alignment conflicts with outages.

-

Technical Evaluation / Analysis:
Replace HCB and LCB Relays (Replace 1st and 2nd Line Relay Protection): Replace 1st and 2nd Line HCB Relay Protection systems that can no longer be maintained to meet the Original Equipment Manufacturer (OEM) specifications. The newly installed relays will have self-diagnostics and event recording capabilities which contribute to increased system reliability.

The existing 1st and 2nd Line LCB Relay Protection System is provided by solid-state relays. Replace solid-state relays with microprocessor type relays with inherent design features that can override communication line disturbances. The new relays will also have built-in oscillography and sequence of events recording capabilities, which will contribute to increased system reliability.
Project Relationships (if applicable) N/A

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	13,897	14,166	15,811	27,664		24,933
O&M						
Retirement	1,125	2,090	1,425	2,336		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	26,100	78,352	89,852	76,352	20,000
O&M*					
Retirement	2,300	2,300	2,300	2,200	2,300

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	11,137	33,629	38,590	32,811	8,662
M&S	4,176	12,536	14,376	12,216	3,367
Contract Services	522	1,567	1,797	1,527	400
Other	783	2,351	2,696	2,291	400
Overheads	9,482	28,269	32,393	27,508	7,171
Total	**$26,100**	**$78,352**	**$89,852**	**$76,352**	**$20,000**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations/ Substation Operations
2022

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Relay Protection Communications Upgrade Program	
Project/Program Manager: Karen Bruce	**Project/Program Number (Level 1): PR.21562316**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other: ___________**	
Estimated Start Date: On going	**Estimated Date in Service: Ongoing**
A. Total Funding Request ($000) **Capital:** ***$56,000*** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

The intent of this program is to remove from service inadequate communications infrastructure used, in part or in whole, for relay protection and replace it with modern, actively supported, and reliable communications infrastructure. For most locations, this program will also provide two independent communication systems for relay protection, which will increase the reliability of the electric system by eliminating single point mode of failure in the relay protection communication networks. This second objective is in line with Con Edison's relay protection design philosophy. The work is to take place at various locations throughout the system. The work shall be divided into three categories.

1) The upgrade of Corporate Communication Telephone Network (CCTN upgrades)
2) The upgrade of Verizon communications infrastructure (Verizon upgrades)
3) The upgrade of relay protection equipment (relay comm. upgrades)

A CCTN upgrade will include the extension of the CCTN network to a facility that currently does not have it. Work will include extending fiber optic cable from the nearest feasible source to the substation that requires it. In addition, a CCTN node will be installed consisting of the appropriate equipment to allow for service to be available at the station. The installed equipment will be the property of Con Edison.

A Verizon upgrade will include the installation of a Verizon fiber optic node in our stations that currently only have Verizon copper service or where the fiber service is insufficient to meet relay protection needs. The installation of the Verizon node will be carried out by Verizon, with Con Edison supporting the installation by providing cabinet, conduit, and cable installations as necessary. Some additional equipment may be required to interface with relay protection for adequate protection system operation. All the Verizon equipment supplied and installed by Verizon and paid for by Con Edison will remain the property of Verizon while all the support equipment installed by Con Edison

will be Con Edison property. We forecast the cost of such an upgrade to be $300K. There are an estimated eight upgrades required system wide.
A relay comm. upgrade will include the upgrade, modification, addition, or replacement of those relay elements necessary for, or directly related to, the communications of the relay protection system, such that the existing protection system can use the upgraded communications infrastructure properly. This is not intended to be a complete relay system replacement, but rather, only a partial or minor replacement of the relay systems' communication elements.

Justification Summary:
The underlying reasons for proposing the upgrades are multifaceted, with each aspect adding to the overall goal of increasing system reliability and resiliency. Of primary concern is the migration of relay protection systems off failed, failing, or problematic communication links. At several locations and for several elements, the relay protection systems have been out of service for time periods ranging from hours to months due to failed communication links. In the past five years, there have been over 50 occurrences of loss of protection on a high-tension transmission feeder due to a copper communication line being out of service, with some resulting in equipment outages. Since the repair of these circuits is not under the authority of Con Edison it is difficult to control the timeframe in which the equipment is returned to service as we rely on the service provider (usually Verizon) to repair the copper communication line. Verizon is generally losing the expertise and desire to repair these copper circuits. The solution that Verizon often proposes is to switch to a fiber communication line and their timeframes fluctuates from project to project.

Of secondary concern is the mitigation of single mode point of failure situations that may exist in the communication networks that serve independent relay protection systems protecting the same power system elements. The design philosophy about relay protection communications given in Con Edison's EOM-CE-0111, which is based on Northeast Power Coordinating Council (NPCC) Directory #4, dictates that communication systems of two independent relay protection systems protecting a single power system element shall also be independent. The reason for this is to prevent a single mode point of failure in the relay protection system in which the loss of a single element of the protection system (which includes its communication elements) would cause both independent relay protection systems protecting a single power system element to be defeated simultaneously. If both relay protection systems protecting a single element were to rely on a single fiber network only, be it Verizon or CCTN, and that network were to be compromised, then with a single failure, the power system element would be unprotected. Furthermore, if there is only one communication system servicing a station, and that communication system was to be compromised, then the entire station could lose protection for multiple elements simultaneously. Such a situation must be avoided as it has the potential to leave a large, contiguous portion of the system at risk of outage if a failure were to occur. Two independent communication networks are necessary to mitigate this, which Con Edison proposes to implement using CCTN and Verizon fiber services.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
In the Company long range plan is looking to integrate into a 10-year plan to incorporate relay protection and communication systems as a major driver, increasingly embedding resiliency and reliability our portfolio of projects/programs keeping the focus on:

- Reduction of equipment failure that causes property damage and/or injuries to the public in the immediate vicinity of the substation which can result in extensive damage and the shutdown of an area substation and reduces the likelihood causes will lead to the loss of a substation.
- Reduction of misoperation of the relay system can affect the reliability of the electric system and possibly result in the loss of load.

Degraded communication infrastructure, particularly copper lines, are more vulnerable to extreme weather events. Flooding from extreme rain or other weather events can cause disruptions to communication lines. Communication lines related to relay protection systems can lead to a loss of protection (LOP) or potentially cause relay systems to mis-operate or delay recovery following events. The upgrade to CCTN is an important component of resiliency and climate change adaptation.

2. Supplemental Information

Alternatives

Rely on Verizon to upgrade its infrastructure to Con Edison stations. This option is undesirable because of the lack of control over the schedule of the upgrades. Verizon may elect to upgrade service immediately or defer it until complete failure occurs. Furthermore, even when Verizon upgrades its service, Con Edison may have to do additional work to interface old relay systems with the new communications infrastructure. Finally, this option does not address the proposed CCTN upgrades, nor does it resolve single mode point of failure concerns.

Find other means of providing two completely independent relay protection systems. This option is undesirable because it involves a large investment of engineering time to develop a new philosophy that may be unproven or untested. Several existing technologies that satisfy this, such as the use of automatic ground switches, are currently being phased out because of their inadequacy. This also does not address immediate problems and concerns.

Risk of No Action

Taking no action leaves the system in a state of increased vulnerability to communication system failures, which may cause equipment to be taken out of service or to be operated with limited protection. In addition, taking no action would fail to address current existing communication problems.

Non-Financial Benefits

Non-financial benefits include increasing system reliability by decreasing protection system outages caused by communication failures. The expansion of CCTN would also provide, as a secondary benefit, better corporate LAN network access to stations that currently rely on third party providers for network access, increasing Con Edison's control over LAN functionality at those stations. This expansion would also strengthen Con Edison's physical security and cyber security objectives by providing controlled and secured paths for security-critical data transfers at locations that currently do not have them. Finally, the upgrade will provide increased redundancy for SCADA and other control related communications to some stations by providing independent and redundant communications systems (current service provide by AT&T and Verizon may use the same equipment in the station to provide access).

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis: N/A

2. Major financial benefits N/A

3. Total cost **$56,000**

4. Basis for estimate: The funding request for this program is based on $1.5M for substation work and $5M for extension of CCTN to a substation (with 3 such projects planned for each year)

5. Conclusion: N/A

Project Risks and Mitigation Plan
Project Risks:

Risk 1: Outage scheduling conflicts with other initiatives.

Mitigation: Outages to be coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs to avoid conflict with other program/ projects resulting in a more predictable budget and manageable outage scheduling.

Risk 2: Delays due resources support coordination.

Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Technical Evaluation / Analysis: A survey was conducted to observe the number of communication failures over the past five years. There were over 50 occurrences of communication line failures that resulted in protection systems being out of service, with several of them resulting in equipment being taken out of service. There were several repeated failures as well. Most failures occurred on systems that used copper-based communication lines.

Project Relationships (if applicable) This proposed program shares relationships with the Relay Modifications program and the Area Reliability program. Both of those programs have been used to provide a limited number of relay communication infrastructure upgrades in the past but have not been able to address many of the remaining problems.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	2,241	916	2,271	1,132		428
O&M						
Retirement	66	15	19	40		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**$3,500**	**$16,500**	**$16,500**	**$16,500**	**$3,000**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	1,050	4,950	4,950	4,950	905
M&S	0	0	0	0	0
Contract Services	1,380	6,548	6,553	6,557	1,194
Other	0	0	0	0	0
Overheads	1,070	5,002	4,997	4,993	901
Subtotal					
Total	**$3,500**	**$16,500**	**$16,500**	**$16,500**	**$3,000**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Electric Operations / DE
2022-2026

1. Project / Program Summary

<table>
<tr><td>Type: ☐ Project ☒ Program</td><td>Category: ☒ Capital ☐ O&M</td></tr>
<tr><td colspan="2">Work Plan Category: ☒ Regulatory Mandated ☐ Operationally Required ☐ Strategic</td></tr>
<tr><td colspan="2">Project/Program Title: Remote Monitoring System</td></tr>
<tr><td>Project/Program Manager: Various</td><td>Project/Program Number (Level 1): 10029645, 10031933, 10032007, 10032090, 10032132, 23440191</td></tr>
<tr><td colspan="2">Status: ☐ Planning ☐ Design ☐ Engineering ☐ Construction ☒ Ongoing ☐ Other: ___________</td></tr>
<tr><td>Estimated Start Date: Ongoing</td><td>Estimated Date In Service: Ongoing</td></tr>
<tr><td>A. Total Funding Request ($000)
Capital: $14,807
O&M:
Retirement:</td><td>B.
☐ 5-Year Gross Cost Savings ($000)
☒ 5-Year Gross Cost Avoidance ($000)
O&M: $1,750
Capital:</td></tr>
<tr><td>C. 5-Year Ongoing Maintenance Expense ($000)
O&M:
Capital: N/A</td><td>D. Investment Payback Period: (Years/months)</td></tr>
</table>

Work Description:

This program provides funding for the replacement of defective units and installation of new Remote Monitoring System (RMS) 3rd and 4th generation transmitters at various network transformer vault locations throughout all regions. 3rd generation transmitters are data collection, consolidation, and transmission devices installed for transmitter replacements for 24-point terminal network protector designs, and Remote Monitoring System Pressure, Temperature, and Oil level sensor (RMSPTO) field conversions. 4th generation transmitters, known as Remote Communicating Transmitters (RCT), have two-way communication with the Communicating Micro-Processor Relays (CMPR) and are installed for new transformer installations and transmitter replacements for the 25-point terminal or Vault Data Acquisition System (VDAS) network protector design. Both generations transmit data via power line carrier (PLC) communication on the secondary of the transformer to the RMS database.

Both the 3rd and 4th generation transmitters are necessary because the 4th generation, or RCT, is only compatible with the VDAS network protector design and VDAS is a new design, only making up 16.7% of the network protector population.

An average of 2,000 3rd generation units and 1,500 4th generation units will be installed per year by Company Regional I&A (Installation and Apparatus) equipment personnel. As units fail in service new transmitters need to be installed.

Justification Summary:

This ongoing work is required to comply with the Reliability Performance Mechanism (RPM) associated with the Remote Monitoring System mandated by the New York State Public Service Commission. The RPM requires 85% of all transformers within a network to report real time equipment information once a month for the first, third and fourth quarters of the year and 90% during the second quarter of the year.

Failure to comply with the Remote Monitoring System RPM metric will result in a revenue adjustment of $10 million per violation and up to a cap of $50 million annually.

In order to meet the RPM, both the 3rd and 4th generation transmitters are necessary so that both of network protector designs have a compatible transmitter.

In addition, the 3rd and 4th generation transmitter have a power flow direction feature which indicates the occurrence of a reverse power flow, Alive on Backfeed (ABF) condition. An ABF condition occurs when one or more network protector(s) fail to open during a feeder outage. When these network protectors fail to open power flows backwards from the secondary grid into the primary feeder due to a potential voltage difference. The 3rd and 4th generation transmitters' capability to indicate ABF conditions will help identify back feeding network protectors and expedite the feeder restoration process.

Finally, the 3rd and 4th generation transmitter communicate transformer oil levels, which is a critical indicator used for the safe and reliable operation of network transformers. Oil leaks can result in low oil levels and catastrophic failures. Using 3rd generation transmitters to report low oil level conditions allows for preemptive identification of failed transformers, transformer replacements or oil refills prior to failure.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

The remote monitoring system is a key platform providing insight into the health and operational status of our network transformers. Data from this system feeds key analytic systems to identify transformers that may be leaking and therefore at risk of catastrophic failure due to water ingress. The system also provides real-time operational data that informs decisions such as transformer cooling, the need to troubleshoot performance, and in extreme cases the need to take action to prevent a major secondary event. It is a critical tool in mitigating the risk of Transformer Failure, Network Shutdown, as well as Reliability Performance Metric triggers.

Actual loading data can be used to confirm studies and calculations based on models, to refine those models, or to inform engineering decisions around system reinforcement, which is critical to meet not only the current load demands, but those forecasted.

2. Supplemental Information

Alternatives

<u>Alternative 1 description and reason for rejection</u>
An alternative to the installation of 3rd and 4th generation RMS transmitters would be to leave the existing transmitters in place. Critical information on transformer oil level would not be available and acted upon thus impacting system reliability.

In some cases we are replacing failed units, and failure to replace these could result in losing critical system data needed to avoid a major outage (i.e., "another LIC"), furthermore it could result in triggering the RPM associated with RMS reporting.

<u>Alternative 2 description and reason for rejection</u>

Alternative 3 description and reason for rejection

Risk of No Action

Risk 1

Failure to install new equipment may result in lower RMS reporting rates which can lead to RPM penalties described in the justification. In addition, transformers which do not report due to a failed transmitter can lead to safety and reliability implications, since no transformer data is available to warn of impending catastrophic failure.

Non-Financial Benefits

Non-financial benefits include increased public and worker safety, reduced risk of oil spills (environmental impact), and increased feeder reliability due to reduction in transformer failures.

A 3rd and 4th generation transmitter allows for a more reliable send out of critical RMS transformer and protector information used for load flow studies and modeling. In addition, the RMS information is used by control center operators to make operating decisions based on system conditions.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)

2. Major financial benefits

The installation cost for a 3rd and 4th generation transmitter, including material and labor, is approximately $3,000. A leaking transformer without oil level information would have to be replaced during an unscheduled emergency outage if it fails. The cost for an in-service transformer, emergency replacement is approximately $130,000.

In addition, studies show that having a reverse power flow indication saves approximately 3 hours per ABF condition. Con Edison's feeders experience an average of 700 ABF conditions annually. Once these transmitters are fully deployed, applying this potential savings to the average number of conditions predicts a potential of $350,000 of operational savings per year.

3. Total cost

4. Basis for estimate

The basis for the estimate for this program is the historical unit costs of installation of a 3rd and 4th generation RMS/PTO transmitter.

5. Conclusion

Project Risks and Mitigation Plan

Risk 1	Mitigation plan
Material Availability	Engineering to work with Supply Chain to establish a cohesive plan to align with vendor lead times and stay engaged with vendor to ensure that lead times are maintained and if shortages are encountered, plan is adjusted as needed.

Risk 2	Mitigation plan

Technical Evaluation / Analysis

The 3rd and 4th generation transmitter provides greater reliability in comparison to the previous generation of transmitters. The additional oil level and ABF indicator functionality will reduce the risk of catastrophic failure. 3rd and 4th generation transmitter units can be more effectively tracked, as serial number and manufacturing information is transmitted remotely. See the justification section for further detail.

Project Relationships (if applicable)

Pressure Temperature and Oil Sensors

3. Funding Detail

Historical Spend

EOE	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Forecast 2021
Capital	**3,357**	**4,389**	**3,002**	**2,308**	**1,485**
O&M					
Retirement					

<u>Total Request ($000)</u>:

Total Request by Year:

EOE	Budget 2022	Budget 2023	Budget 2024	Budget 2025	Budget 2026
Total	**1,822**	**3,222**	**3,222**	**3,222**	**3,319**
O&M					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	671	1,187	1,187	1,187	1,222
M&S	580	1,025	1,025	1,025	1,056
Contract Services	30	52	52	52	54
Other	7	13	13	13	14
Overheads	534	945	945	945	973
Subtotal	**1,822**	**3,222**	**3,222**	**3,222**	**3,319**
Contingency**					
Total	**1,822**	**3,222**	**3,222**	**3,222**	**3,319**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings	350000	350000	350000	350000	350000
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Central Operations/STO
2022-2026

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Replacement of Feeders M51 and M52	
Project/Program Manager: Mark Bauer	**Project/Program Number (Level 1):** 23289178
Status: ☒ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☐ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date:	**Estimated Date In Service:**
A. Total Funding Request ($000) **Capital:178,000** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

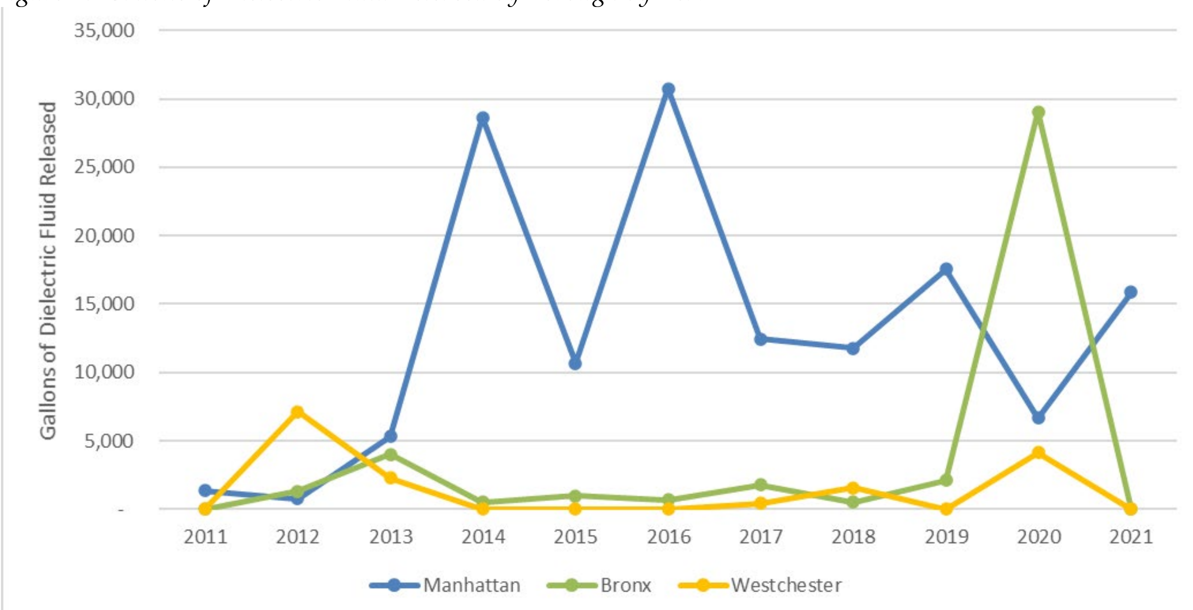
Work Description:
This project will replace 345kV feeders M51 and M52 with new cables along a new route. Feeders M51 and M52 run between Sprainbrook Substation in Yonkers, through the Bronx, to W49th Street Substation in Manhattan. This project will replace approximately 17 miles of high pressure fluid filled (HPFF) cable with cross-linked polyethylene insulated (XLPE) cable along a new route to W49th Street Substation. The XLPE portion will be a combination of submarine cable and underground cable in duct banks. The estimated cost for the project is $1.2B. The Manhattan portion of M51 and M52 has been previously prioritized for replacement due to significant leak history and life cycle cost considerations, though leaks have also occurred on other sections of this feeder. Engineering activities for this project will begin in 2025 and construction is estimated to be completed by the end of 2028.

Justification Summary:
Feeders M51 and M52 were installed in 1974. The feeder routes are each over 17 miles long and go through significant portions of Westchester, the Bronx, and Manhattan. These feeders have been critical transmission assets in order to move upstate generation to the load center and will continue to be in the future as more generation is established around NYC in order to move clean energy to the rest of the state.

Within the past ten years, these feeders have seen over 250 leaks totaling 197k gallons of dielectric fluid released. This figure represents roughly 25% of the total volume of dielectric fluid contained in the two feeders. The Pipe Enhancement Program, which restores the integrity of the cable pipe, has been the primary method used to reduce the frequency of dielectric fluid leaks. Although Pipe Enhancement has reduced the frequency of dielectric fluid leaks in many areas, the Manhattan portion of feeders M51 and M52 has presented unique challenges that have affected the longevity of this solution.

Since 2011 through July of 2021, the majority of leaks on feeders M51 and M52 have occurred in Manhattan and along Sedgwick Avenue in the Bronx. During this time, these areas experienced 228 leaks totaling 182K gallons of dielectric fluid released. Over the years, 8K and 17K trench feet of Pipe Enhancement have been completed in Manhattan and along Sedgwick Avenue, respectively. Pipe Enhancement has been effective in reducing leaks along Sedgwick Avenue, although new areas continue to pop up in the Bronx. The response in Manhattan has been more successful with the introduction of Carbon Fiber Wrap in areas, though there continue to be leaks in other areas.

Figure 1: Gallons of Dielectric Fluid Released by Borough by Year



The Manhattan portion of feeders M51 and M52 along the Harlem River Drive has been particularly challenging with 28,161 gallons in that section alone leaked from 2015 to 2018, despite over 5,000 trench feet of Pipe Enhancement being completed in the same timeframe.

Stray direct current (DC) electrical current along the Harlem River Drive from transit systems has accelerated corrosion, deteriorated the pipes, and caused feeder leaks in sections that have already undergone Pipe Enhancement. After numerous leaks along the Harlem River Drive, an extensive study, testing, and the installation of voltage recorders helped identify the presence of stray current. One of the sources of stray current was narrowed to an MTA facility and new rail insulating joints were installed to mitigate the issue. An additional source was found to be a Metro-North facility in the Bronx, where defective rail isolation joints were found and subsequently replaced to interrupt the stray current return path. Further refurbishment of areas that were heavily affected by stray current and have exhibited dielectric fluid leaks is still being pursued, including the potential installation of carbon fiber wrap in these areas. It is not possible to know the full extent of the pipe damage caused by stray current without fully excavating and visually inspecting the Harlem River Drive portion of feeders M51 and M52. Given the proximity of the area affected by stray current to the Harlem River itself, there is a risk that the submarine crossing section can also affected. To date, no leaks have occurred in the submarine portion of either M51 or M52.

Feeders M51 and M52 also present a maintenance burden for the Company. The feeders average 1,500 to 2,000 hours per year in corrective maintenance, which is 3.5-5 standard deviations above the mean for the rest of the 345kV feeder population. Over the past ten years, about 60% of this work took place in the Manhattan portion, and over the past few years this figure is closer to 80%. Leak remediation has also required a considerable amount of funding – averaging around $5M a year or $350K per section leak, with several leaks costing over $1M in recent years.

Replacement of M51 and M52 with XLPE cable would eliminate dielectric fluid leaks in two of the worst performing feeders on the system and eliminate environmental risks associated with the Harlem River crossing. It would also ensure that as generation increases in the area, there is a conduit available to ensure transfer of this clean energy. The elimination of the maintenance and emergency response burden associated with Feeders M51 and M52 will reduce expenses and free up Company resources for other work on the system as well as within any capital programs such as Pipe Enhancement.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
This project relates to the Dielectric Fluid Loss Corporate risk.
As clean energy generation increases in NYC, these feeders will be vital in ensuring that it is able to be moved to other parts of the state. In addition, clean energy injection downstate will require an expansion of the transmission system and with these feeders moved, the existing pipe will provide a potential conduit for future circuits.

2. Supplemental Information

Alternatives
Several additional alternatives were looked at for replacement of this project:

- Performing Pipe Enhancement along the whole Manhattan portion with Carbon Fiber Wrap. The estimated cost for this project would be upwards of $700M. The advantage to this option is that new construction is avoided and the Company essentially "replaces the pipe in place." This still does not, however, reduce the dielectric footprint and it also does not address the river crossing. Permitting may also be an issue in congested areas. The duration of work would likely extend over several years due to the labor-intensive nature of the work over such a large portion of the feeder. This also does not address the recent leaks seen in the Bronx.
- Performing traditional Pipe Enhancement. In order to address the remaining sections in Manhattan and the Bronx, approximately 3,500 trench feet of pipe enhancement will need to be completed through 2030. At the current unit cost of $6,500 per trench foot, this means spending over $22M per year on these feeders in Pipe Enhancement over the next ten years while continuing to address any new leaks.

- Replacement of just the Manhattan portion of M51 and M52 which would include replacement of approximately 8M of HPFF with XLPE. The project would also install a gas insulated substation (GIS) to transition between the HPFF and XLPE cable sections. This would cost $680M. This addresses the historically worst performing section of these feeders, however in recent years, there have been leaks in other areas of the feeders requiring a response.
- Replacing M51 and M52 with approximately 8 miles of XLPE in new lanes that follow the route of the existing feeders from the Sedgewick PURS site to W49th St Substation. At Sedgewick this would include two new 345kV disconnect switches with ground switches, a new pumping plant, and two incoming and outgoing sets of SF_6 potheads. W49th Street includes two new sets of SF_6 potheads for the incoming feeders. The estimated cost for this project is $590M and it is expected that this option would have

the longest study and route construction time. Some advantages to this option are that it is cheaper than the submarine option. The major challenge with this option is that finding routes for the feeders through Manhattan streets will be difficult.

- Another option explored for this project is the use of triplex, XLPE cable in the existing pipe, which is being developed under an R&D project. Although this option avoids most of the trenching costs that would normally be required, outage constraints would extend the schedule considerably. The use of this type of cable in pipe would also require a significant de-rating of the two circuits from the current rating. The magnitude of the de-rate might require the Company to submit the project to the NYISO Interconnection queue for approval and may require other system upgrades to compensate for the loss of capacity.

Additional funds will be used to perform a more in depth route study and other exploratory activities to facilitate getting a more accurate picture of overall project costs and constraints.

Risk of No Action

Without action, there is a risk that leaks along the Harlem River Drive will continue to occur, or new areas along this feeder may also start to experience stray current and/or leak issues. Trending shows that leaks are continuing to occur more and more frequently along the Manhattan portion of these feeders. Without proactive remediation, Con Edison will continually be responding to leaks along these feeders with the risk that the feeder will need to be replaced in the future anyway.

Non-Financial Benefits

Protection of the environment and increased reliability are added benefits. Replacement of the circuits with XLPE reduces the dielectric inventory and reduces the risk of a leak into an environmentally sensitive area. The elimination of the corrective maintenance and leak response labor hours associated with the Manhattan portion of feeders M51 and M52 will free up Company personnel to focus efforts on other parts of the system.

Summary of Financial Benefits and Costs (attach backup)

In Company labor alone, Con Edison is spending 150-200 times more on each of M51 and M52 than other 345 circuits. Typical spend for Con Edison corrective maintenance on these circuits can range from $50K to over $500K, averaging about $350K per year, the bulk of which is in the portion that will be replaced. Including costs for leaks and emergencies, it is not unusual for Con Edison to spend several million dollars in expense on these circuits, just in Manhattan. Based on the trend of frequency of leaks, it is likely that these circuits will continue to cost several million dollars per year in the current configuration.

Project Risks and Mitigation Plan

Technical Evaluation / Analysis

By replacing these feeders with XLPE, approximately 770K gallons of dielectric fluid will be eliminated from the system, reducing the potential for an environmental event in an area prone to leaks. In addition, these feeder leaks impose a risk to system reliability if the feeder needs to be taken out of service to repair the leak. If the leak is severe enough and pressure cannot be maintained, it could lead to an electrical failure.

Project Relationships (if applicable)

3. Funding Detail

Historical Spend

	Actual 2017	Actual 208	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	N/A	N/A	N/A	N/A	N/A	N/A
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital				10,000	168,000
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor				1,000	8,000
M&S				2,500	41,000
Contract Services				4,000	98,000
Other				1,246	4,142
Overheads				2,154	16,858
Total	0	0	0	10,000	168,000

Total Gross Cost Savings / Avoidance by Year:

	2020	2021	2022	2023	2024
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2020	2021	2022	2023	2024
O&M					
Capital					

Central Operations/ Substation Operations 2022

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Retrofit Overduty 13kV and 27kV Circuit Breaker Program	
Project/Program Manager: Nicalos Graham	**Project/Program Number (Level 1): PR.0ES1300/ 10028113**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other: ___________**	
Estimated Start Date: N/A	**Estimated Date In Service: N/A**
A. Total Funding Request ($000) **Capital: $66,400** **O&M:** **Retirement: $9,595**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:
This program focuses to replace several existing 13 & 27 kV circuit breakers installed in Con Edison's substations that currently are not rated to interrupt maximum fault. Circuit breakers will be replaced where the maximum fault current exceeds their rating. It is currently a Con Edison rate plan requirement to perform a minimum of 50 13kV or 27kV breaker retrofits per calendar year and complete an average of 60 per year within a 3-year period). The Company currently targets a combined total of 60 breaker replacements per year, which allows for the maximum number of replacements per year within the delivery and resource constraints associated with this equipment.

Justification Summary:
Based on a 2017 analysis performed by the Company and verified by an independent consultant (ABB), fault currents exceed breaker interrupting capability at 35 area substations. The analysis assumes a worst-case scenario based on all the equipment in the station being online, a failure occurring across all three phases at or near the station switchgear, and perfect conductivity between the phases at the failure point.

Con Edison established a long-term system enhancement program to replace and/or upgrade all the 13kV and 27kV circuit breakers. Under this program, the priority is given to the stations where the potential of over-duty is 10% or greater. The second priority is given to the substations where the potential over-duty is between 3% and 10%. Finally, the substations with less than 3% potential over-duty are being addressed as the third priority.

In addition, upgrading the existing equipment with state-of-the art, modern, rack-out type circuit breakers will provide the capability to interrupt fault currents and maintain system integrity. Completing these retrofits now will help meet reliability standards, lower life-cycle costs and reduce forced outage rates. Additionally, this will extend the service life of the existing switchgear.

Relationship to Broader Company Plans and Initiatives (e.g., Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
This program impacts the Enterprise Risks of Equipment Failures and Loss of a Substation. If a breaker is not capable of interrupting fault current due to the failure of a distribution feeder (or other piece of equipment), the breaker itself may fail and take out several pieces of equipment. During high load periods this could lead to the overload and subsequent loss of a substation. This program reduces the likelihood of both events.

Climate Change and Resiliency:
Distributed generation (DG) plays a part in the transition to clean energy and climate change mitigation. In order for DG resources to connect to the distribution system, substation equipment must be adequately sized to accommodate the increased source capacity. This program facilitates those interconnections and is part of transitioning to a clean energy future.

2. Supplemental Information

Alternatives

Install a fault current limiting device at substations that are over duty – while there has been some research & development activity in this area, currently there is no commercially available device that meets system design requirements.

Risk of No Action
Equipment failure is possible if not replaced.

Non-Financial Benefits
Once stations are fully upgraded, it removes a potential barrier for Distributed Generation interconnection with networks supplied by the station. In addition, at certain stations replacement of the existing breakers with smaller, lighter, modern breakers allows for one person switching.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis: N/A

2. Major financial benefits
Benefits include the avoided cost of a possible environmental impact, damage to neighboring equipment or property due to failure. Also, a typical replacement would be less costly than a failed unit.

3. Total cost **$66,400**

4. Basis for estimate: Funding request is based on historical spend completing 60 breakers per year at a unit cost around $230K per breaker

5. Conclusion: N/A

Project Risks and Mitigation Plan

Risk 1: Outage scheduling conflicts with other initiatives.

Mitigation: Outages to be coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs to avoid conflict with other program/ projects resulting in a more predictable budget and manageable outage scheduling.

Risk 2: Delays due resources support coordination.

Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Risk 3: **Lack of alignment between resources support and outages.**
Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor and construction to avoid alignment conflicts with outages.

Technical Evaluation / Analysis: The earlier vintage 13kV and 27kV circuit breakers at Con Edison substations have fault current interrupting ratings ranging from 20kA to 40kA in the 13kV Area Substations and 30kA to 40kA in the 27kV Area Substations. Switchgear and circuit breakers currently available on the market have a fault current rating of 63kA at 13kV and 44kA at 27kV. The review of system fault currents at the area substations in the Con Edison system has indicated that for certain 13kV and 27kV circuit breakers, the available fault current exceeds the nameplate interrupting rating. The switchgear bus, associated insulation, and protection equipment have been evaluated by Engineering and are within the fault current rating of 63kA for 13kV switchgear and 44kA for 27kV switchgear.

Project Relationships (if applicable) N/A

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	11,540	11,878	7,393	10,340		10,345
O&M						
Retirement	1,465	1,701	842	688		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	12,500	13,800	13,800	13,800	12,500
O&M*					
Retirement	1,919	1,919	1,919	1,919	1,919

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	1,875	2,070	2,070	2,070	1,875
M&S	6,327	7,480	7,490	7,494	6,792
Contract Services	238	273	265	263	255
Other	468	0	0	0	0
Overheads	3,591	3,977	3,975	3,973	3,578
Subtotal					
Total	**$12,500**	**$13,800**	**$13,800**	**$13,800**	**$12,500**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

Central Operations / STO
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Right of Way Roadway Access	
Project/Program Manager: Ken Chu	**Project/Program Number (Level 1): 25502308**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date:	**Estimated Date In Service:**
A. Total Funding Request ($000) **Capital: 5,000** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:
This program will target access road improvements which include installation of crushed stone in conjunction with geotextile fabrics to address both the poor draining soils and the runoff issues. Design details include the use of swales and water bars to direct water away from the road and neighboring properties. Culverts will be installed at low-lying flood prone areas to redirect standing water across the road. Realignment of the roadways will be required at some locations where the road has become impassable.

Justification Summary:
Transmission Line Maintenance is responsible for inspection and maintenance of the Company's entire overhead transmission system, located in Westchester, Putnam, Dutchess and Richmond Counties. There are approximately 113 miles of right-of-way (ROW) access road to reach the lines and the associated structures. Transmission Operations requires that these access roads be passable by truck to facilitate the inspection and repair of the lines and structures as well as the ability to perform the required vegetation management for the ROW.
The right-of-way access roads are unpaved and there are few storm water controls in place. Water currently flows off the ROW and onto adjacent properties and roadways. In addition, portions of the access roads have deteriorated due to environmental factors such as poor-draining soil and overland water flow. The uncontrolled storm water has caused problems such as increased sediment runoff to regulated water bodies and wetlands. It has also increased water runoff to adjacent property owners resulting in complaints. The roads at these sites have become rutted, unstable and difficult for Company vehicles to navigate, resulting in increased vehicle maintenance costs. Additionally, in low-lying areas standing water accumulates, making the roads impassable, inhibiting natural drainage and increasing the level and frequency of complaints from adjacent property owners.

Based on site visits and inspections, approximately six of the 113 miles of access roads (5% of total) in Westchester, Putnam and Dutchess Counties have been identified as being in need of improvement. These sites are located along the K-Line, D- Line, E- Line, P- Line and L- Line

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
The program does not address any climate adaptation, mitigation or decarbonization concerns, and it is not a CLCPA investment activity.

2. Supplemental Information

Alternatives
There are no other alternatives.

Risk of No Action
Not addressing these restricted access roads will prevent company vehicles from being able to access transmission line equipment for necessary upgrades or emergency repairs.

Non-Financial Benefits

Summary of Financial Benefits and Costs (attach backup)
This is based on an average estimated cost.

Project Risks and Mitigation Plan

Technical Evaluation / Analysis

Project Relationships (if applicable)

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	N/A	N/A	N/A	N/A	N/A	N/A
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**1,000**	**1,000**	**1,000**	**1,000**	**1,000**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	96	94	94	94	94
M&S	20	20	20	20	20
Contract Services	634	636	636	636	636
Other	16	18	19	19	20
Overheads	234	232	231	231	230
Total	**1,000**	**1,000**	**1,000**	**1,000**	**1,000**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2020	2021	2022	2023	2024
O&M					
Capital					

Central Operations/ Substation Operations
2022

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Roof Replacement Program	
Project/Program Manager: TBA	**Project/Program Number (Level 1): PR.2ES8200/ 10030246**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other: ___________**	
Estimated Start Date: On going	**Estimated Date in Service: Ongoing**
A. Total Funding Request ($000) **Capital: $18,216** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☒ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This program provides replacement of roofing on buildings and major equipment at Con Edison substations, pumphouses and pressurizing plants, where the roofing has deteriorated or when leaks are found. The Company has an ongoing program to inspect each of the 554 roofs approximately once every five years (more frequently for older roofs, less frequently for newer roofs), averaging 100 roofs per year. Many of our facility roofs have deteriorated and have been repaired numerous times. The roof inspection program reveals which of our roofs have deteriorated beyond repair. Roofs are replaced when needed. Typically, the two types of roof systems used are ethylene propylene diene monomer (EPDM) and Kemper. EPDM roofs consist of a rubber membrane adhered to rigid insulation which is fastened to the existing roof deck. The Kemper system consist of a primer applied to the existing roof deck then a fleece layer saturated with polyester resins. Removal of existing roofing materials will also assure any asbestos issues, if present, are alleviated.

Central Engineering has also established an inspection program to monitor and assess the structural condition of substation facilities (external and internal) to ensure safe conditions for members of the public, company employees and the equipment housed in the facilities. This request proposes the establishment of a comprehensive maintenance program to correct material issues which can no longer be addressed through routine maintenance. The impacted areas include major sections of the structure, both interior and exterior, that are too significant to be addressed with minor repairs.

This program will replace approximately twelve roofs per year starting in 2023.

Justification Summary:

Roofs are fundamental components of substation facilities. The integrity of a roof is important to maintain the reliability of equipment, as well as the safety of personnel working in the substation. In the face of changing weather patterns and the expectation of more extreme weather events, roofs will need to be upgraded to maintain the reliability of substation equipment.

Roofs provide primary weather protection for power carrying equipment in substations and personnel. Water intrusion into substation equipment can cause immediate issues like trip outs. Trip outs create contingencies on the transmission and distribution systems that can lead to customer outages. Water intrusion also causes long term issues like rusting. Rust can not only impact metal parts of equipment, such as cladding on switchgear, but also copper control and protection lines installed in substations. As copper lines rust, they create grounds on the DC control systems. These systems do not operate as design when these grounds are present, and this can lead to trip outs and customer outages. Water intrusion can also lead to unsafe conditions for personnel working in substations. Standing water from leaking roofs can cause employees to slip and creates an unsafe condition for employees that are performing electrical switching on nearby equipment.

In summary, roofs are important for the safe and reliable day to day operation of a substation. The Company's Climate Pathway projects more instances of extreme weather, including tropical storms and other extreme rain events. Roofs that are in need of replacement provide a vulnerability to substation equipment during these weather events. Water intrusion from tropical storms and other weather phenomena can lead to trip outs on substation equipment and potentially cause customer outages.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):

This program addresses the Substation Operations risk Major Storm. This program mitigates the severity of a major storm impacting substation equipment. If a roof is upgraded and in reliable condition, it is more likely to prevent water intrusion into substation equipment.

2. Supplemental Information

Alternatives
Repair existing roofs. This alternative would be a temporary solution at best and repairs would increase in scope and cost on an annual basis. For roofs with a certain rating, as discussed below in the Technical Evaluation, it provides an unacceptable service life and does not eliminate the potential operational and safety concerns. Another less desirable alternative for this program is to cover with tarps. This approach is not recommended as prolonged exposure to the elements will result in water intrusion that will consequently result in further degradation of the roofing system. Since equipment housed within the substation buildings is not designed to be exposed to the elements, water intrusion will adversely affect the equipment, thereby affecting system reliability.

Risk of No Action
This work is required to avoid permanent damage to equipment, accelerated structural deterioration and personal safety hazards.

Non-Financial Benefits
Increased reliability of equipment and facilities, eliminating possible inadvertent trips including outages to equipment and customers, and reduced personal safety hazards.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis: N/A

2. Major financial benefits
This program will remove the need to make repeated O&M repairs to these roofs.

3. Total cost: **$18,216**

4. Basis for estimate: Historical average (since 2011) is ~$400K per roof project done under the program. The program funding request is based on 12 roof projects per year.

5. Conclusion: N/A

Project Risks and Mitigation Plan

Risk 1: Outage scheduling conflicts with other initiatives.

Mitigation: Outages to be coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs to avoid conflict with other program/ projects resulting in a more predictable budget and manageable outage scheduling.

Risk 2: Delays due resources support coordination.

Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Risk 3: **Lack of alignment between resources support and outages.**
Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor and construction to avoid alignment conflicts with outages.

-

Technical Evaluation / Analysis:
In order to provide reliable service, we must maintain our electric delivery facilities in good working condition and toward that end have continued the roofing program. This program is committed to inspecting each of the 554 roofs every five years (more frequently for older roofs, less frequently for newer roofs), averaging 100 roofs per year, and to repair or replace roofs as needed. The results from the roof inspections determine if a particular roof can be repaired or needs to be replaced. The roofs are rated on a standardized 1-9 scale, with 1 being a roof in excellent condition and 9 being a roof requiring immediate attention. Roofs scoring 7 or above are scheduled for replacement, all others are repaired as required. Generally, roofs scoring below a 7 can be effectively repaired to address issues found. Repairs are short term fixes that will extend the life of the roof by a few years. Replacement roofs are typically good for 20 years. Typically, roofs requiring replacement are not candidates for repair, except on an emergency basis.

RATINGS DESCRIPTION
1. New Roof 1 to 2 years old, no work needed.
2. Roof more than 2 years old, no work needed.
3. Roof has no leaks, less than 5% of the roof area to be repaired. This also includes repairs to gutters, drains, leaders, and painting of metal roof and debris removals.
4. Roof has no leaks, 5-10% of the roof area needs repairs.
5. Roof has no leaks, 10-20% of the roof area needs repairs.
6. Roof has leaks; up to 20% of the roof area needs repairs.
7. Roof has leaks; up to 40% of the roof area needs repairs.
8. Roof leaks and requires replacement. No structural damage to deck or framing.

9. Roof leaks are bad, and roof requires replacement. Structural damage to deck and/or framing is present and represents a hazard to occupants and equipment.

Water intrusion due to roof leaks can result in equipment damage and affect substation reliability. Standing water on floors and roofs causes slippery conditions and electrical hazards that are personnel safety concerns. Prolonged exposure to water intrusion causes concrete spalling, corrosion of rebar, and degradation of the structural integrity of the building. The installation of new roofing will eliminate leaks and the operational and safety hazards associated with water intrusion and accumulation.

Project Relationships (if applicable) N/A

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	2,030	2,545	1,591	307		573
O&M						
Retirement	258	390	343	600		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**$1,689**	**$4,800**	**$4,800**	**$4,800**	**$2,127**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	338	960	960	960	425
M&S	17	48	48	48	21
Contract Services	726	2,069	2,073	2,074	920
Other	152	437	434	433	195
Overheads	456	1,287	1,286	1,285	565
Total	**1,689**	**4,800**	**4,800**	**4,800**	**2,127**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					

Central Operations/ Substation Operations
2022

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: RTU Upgrade Program	
Project/Program Manager: Steven Bryan	**Project/Program Number (Level 1): PR.20987016**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other: ___________**	
Estimated Start Date: Ongoing	**Estimated Date in Service: Ongoing**
A. Total Funding Request ($000) **Capital: $11,040** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This program will upgrade remote terminal units (RTUs) at select substations. This program will also upgrade Human Machine Interface (HMI) systems at select substations.

RTU:

There are three variations of RTUs installed in area substations - Tejas, Quindar (QEI), and Systems Northwest (SNW). This program will upgrade Tejas and Systems Northwest type RTUs with Schneider Electric SAGE 2400 or 4400 processors. Part of this upgrade will also include the replacement of the card frame assembly while maintaining some existing hardware. All the Quindar RTU hardware will be completely replaced with the Schweitzer Engineering Labs (SEL) AXION RTAC platform.

For the Schneider Electric application, the upgraded RTU will be functionally equivalent to the existing unit. The field wiring for the status and analog panels will be left untouched and undisturbed. The field wiring to the Relay Control Output panels will not be modified in any way. It will be simply lifted from the existing Control Relay Panels and then reconnected onto the new Relay Panels using the same wire landing positions.

For the Quindar RTUs, the existing RTU cabinet will be reused, and no new external wiring will be run. The new SEL RTU will replace all internal hardware and will be wired to the existing terminal blocks in the panel with the external connections. The SEL RTU come with a built in HMI and has the option to replace the mimic board if desired.

Communications to the Energy Control Center (ECC) will use the existing frame relay communication devices, which will be left in place. Two serial ports from the new RTU will connect to the redundant frame relay units. The point mapping will be replicated in terms of the ordered lists of status, analog and control points but the upgraded RTU will be configured to use DNP3.0 protocol instead of the L&G protocol currently in use. The ECC database for the upgraded RTU will be reconfigured for the DNP3.0 protocol.

Due to the short amount of time required to complete the Tejas/SNW retrofits, several can be done per year. The work is discretionary based on which station is more critical. A high-level schedule would be about three months for procurement, one month for design, and one week for construction.

The QEI RTU replacements have added work in rewiring all the internals of the cabinet, therefore it is much more work to complete. A high-level schedule would be about one months for procurement, two months for design, and five weeks for construction.

HMI:

The remaining portion of this program will replace GE HMI systems with up-to-date hardware and software that follows the standard used by the Electrical Control Systems (ECS) group. The new HMI system will contain substation hardened equipment, designed for both robustness and redundancy, to limit the likelihood and impact of a component failure. The HMI includes the station one-line with breaker indications and controls, metering values and alarms of critical equipment. It is used by the substation operator for monitoring of the substation.

Justification Summary:

Current HMI and QEI RTUs installed in various Area Substations are based on an old design and are experiencing component failures at a gradually increasing rate. The original equipment vendor no longer exists as an entity or does not supply parts for these RTUs. Due to the age of these RTU units, and that many of the board level components used in its design are obsolete, it is no longer possible to obtain new spares or to repair boards that have failed.

The unavailability of spare replacement parts leaves Con Edison vulnerable to future failures. Any other RTU components that fail in the future will either degrade the RTU functionality or totally shut the RTU down (as in the case of a processor failure, for example). This risk needs to be eliminated and/or mitigated.

Recently Con Edison has had failures of these units at various stations some of them were able to be repaired, but not without significant down time. Other stations are currently in the replacement process, at which point its spare parts can be used. This is expected to continue until all units have been upgraded.

Recently, several GE HMI systems at substations (such as White Plains, Mott Haven and Trade Center, etc.) have begun to exhibit hardware and software failures, e.g., “Stale Data Alarm”. Nine stations contain systems of a similar build and age and it is expected that additional failures will follow.

When an HMI failure occurs (e.g., issue with “stale” data), it requires a reboot of the HMI server or in more severe cases, a power cycle of the physical server. An HMI system failure reduces or eliminates the ability of the SCADA system to transmit data, which has a significant impact on substation operations. In such cases, the station must be controlled manually in coordination with the ECC. Meanwhile, the operators cannot be certain that the HMI is properly reporting all alarms, indications, and controls.

The new system will provide reliable, safe, and secure control and supervision for the power substations, and allow for its unmanned operation. The new Automation System will communicate with existing protection Intelligent Electronic Devices IEDs, Input / Output hardware, and the Energy Control Center (ECC). The new Web-based HMI system will be designed as open architecture, and modular, comprising only of standard elements performing standard functions and using certain communication protocols.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
This program impacts the Substation Operations Departmental Risk of Equipment Failures. This program reduces the likelihood of equipment failures by proactively replacing legacy RTU and HMI systems prior to failure.

2. Supplemental Information

Alternatives
•Alternatives: The alternative would be to replace each RTU as it fails. During the time in which a replacement is procured, the station will not be controlled by the ECC. This means that the station will have to be staffed 24 hours a day. Due to how long it might take for the manufacturer to build the replacement unit, it could be months before it is replaced. This is not recommended.

The alternative would be to maintain the existing HMI systems. Maintaining the existing systems does not address the ongoing issues because they are caused by obsolescence. As such, the company could expect to continue to see periodic HMI system failures. These failures reduce the reliability of substation data provided by these devices, requiring the relevant substation to be manned full time. In addition, these HMIs lack manufacturer support (e.g., Windows 2000/XP operating system is no longer supported), and lack of spare parts, such as PLA viewer workstation HDD, which is no longer available. For these reasons, continuing to maintain the existing GE HMIs is not recommended.

Risk of No Action
No action can result in an unexpected and unprepared RTU failure. It would result in the station having to be staffed 24 hours a day until it is replaced.

HMI system failures reduce or eliminate the ability to access critical substation information, which impacts substation operations. In such instances, the station must be controlled manually as well as from the ECC. Meanwhile, the operators do not receive critical information about whether the substation is properly reporting all alarms, indications, and controls.

Non-Financial Benefits
The non-financial benefits include increased reliability and efficiency.
Ensure ECC accurate and effective monitoring and control of substations. Outage times and maintenance costs associated with the new web-based HMI system will also be reduced significantly. The substation operators will have new graphic displays connected to the HMI computer which will display equipment status, control, alarming, and metering.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis: N/A

2. Major financial benefits N/A
These upgrades will prevent major equipment from being damaged under failure conditions

3. Total cost **$11,040**

4. Basis for estimate: The annual funding for this program is based on a unit cost estimate of $300K-$400K for an RTU (assumed 2-3 units per year) and $1.5M for an HMI upgrade (1 unit per year)
5. Conclusion: N/A

Project Risks and Mitigation Plan
Risk 1: Outage scheduling conflicts with other initiatives.

Mitigation: Outages to be coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs to avoid conflict with other program/ projects resulting in a more predictable budget and manageable outage scheduling.

Risk 2: Delays due resources support coordination.

Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Risk 3: **Lack of alignment between resources support and outages.**
Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor and construction to avoid alignment conflicts with outages.

Technical Evaluation / Analysis: The replacement of the GE HMI systems will improve substation functionality and reliability by providing the station operator with modern state of the art units. The new HMI system will contain substation hardened equipment, designed for both robustness and redundancy, to limit the likelihood and impact of a component failure.

Project Relationships (if applicable) N/A

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	1,645	239	210	127		558
O&M						
Retirement	0	0	6	0		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**$1,000**	**$2,510**	**$2,510**	**$2,510**	**$2,510**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	296	749	749	750	754
M&S	298	748	748	748	748
Contract Services	40	100	100	100	100
Other	40	100	100	100	100
Overheads	326	813	812	812	807
Subtotal					
Total	**$1,000**	**$2,510**	**$2,510**	**$2,510**	**$2,510**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Selective Undergrounding	
Project/Program Manager:	**Project/Program Number (Level 1): 20470148, 21282229, 25383821**
Status: ☒ **Initiation** ☐ **Planning** ☐ **Execution** ☐ **On-going** ☐ ☐ **Other:** ___________	
Estimated Start Date: 2023	**Estimated Date In Service: 2023**
A. Total Funding Request ($000) **Capital: $345,000** **O&M:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months) (If applicable)**

Work Description:

The Selective Undergrounding program entails the implementation of Con Edison's climate adaptation strategy to mitigate the scale of outages and make the Con Edison system more resilient. The program will identify and prioritize problematic and vulnerable sections of Con Edison's overhead distribution system for potential undergrounding to meet the stated program goals below. Approximately twenty-four (24) miles of overhead distribution will be converted to underground distribution in 2023-2025 at the estimated unit cost of $10 million per mile.

During the initial phases of the program, the dedicated program team will determine the optimal undergrounding design and how best to address the identified/prioritized spurs for undergrounding. The solution could range from:

1) selectively undergrounding a problematic portion of the spur
2) selectively undergrounding a portion of the spur and creating a tie to a neighbouring circuit, and/or
3) to selectively undergrounding the entire spur segment.

There will be detailed engineering and constructability reviews to determine the best mitigation actions to address the spur segment. This analysis will coincide with evaluating alternatives for undergrounding, such as enhanced vegetation management, reclosers or express aerial cable which may mitigate the cause of poor performance with lower cost.

The objectives of this program are to:

- Improve the overall climate resiliency of the Con Edison overhead distribution system in the face of increasingly frequent and intense weather events
- Improve Con Edison's major event restoration performance on a system-wide and local basis through the elimination of long-duration, low customer impacted outages and via optimization of restoration crews across the entire system

- Support Con Edison's goals of environmental and economic justice through the prioritization of spurs to be underground based upon poverty and ethnic minority indices

While Con Edison is currently conducting three undergrounding pilots throughout the service territory, the costs associated with this expected program will require location specific analysis regarding feasibility, design constraints, customer connection complexity, among other factors. The Company is also incorporating disadvantaged community data into the model used to determine prioritization of locations for undergrounding.

This program is expected to become a "standard toolkit solution" for Con Edison as part of the Company's climate change vulnerability improvement strategy. Individual undergrounding projects may require up to a year from the point of prioritizing a potential undergrounding spur, through feasibility assessment, design, customer outreach, and construction.

Justification Summary:
Climate change is presenting increasing risks to the current electrical distribution system. Con Edison's plan is to improve climate change resiliency alongside the existing focus on system reliability. Given the increasing frequency and magnitude of severe weather events and its associated impacts, resiliency efforts need to increase commensurately. Developing a plan to identify, prioritize, and execute on selective undergrounding will provide a core component to Con Edison's long term resiliency improvement strategy.

To make the Con Edison system more resilient from the impacts of severe weather events, a solution is necessary that allows more the system to remain in service in severe weather conditions and increases the overall rate of restoration of customers. The existing solutions, that include traditional system hardening (build to higher wind speeds / flood level standards) and enhanced vegetation management (e.g., wider clearances and / or more frequent trimming cycles), focus on the more traditional question of how to make the system more reliable. This Selective Undergrounding program focuses on improving the overall system resiliency. Undergrounding of the existing overhead power lines presents a way to accomplish the main objective for the faster overall restoration of customers.

After assessing the various approaches to accomplish the main objective, the selective undergrounding of overhead spurs was determined to be the optimal solution. The traditional approach would favour undergrounding the "main run" of primary distribution lines. Since the main run is the supply for each circuit, selectively undergrounding this portion benefits more customers and has a more direct impact on the system level performance. However, the main run is typically fed from two sources whereas spurs are generally fed from one. On the main run damage on a small portion can be "cut clear" and the majority of customers restored. This is not an option for similar damage at the beginning of a spur in which repairs must be completed to restore customers. Under this proposed program the typical storm restoration strategy would continue to target road clearance and restoring the main run of primary distribution lines. As these circuits are energized, the undergrounded spurs having avoided significant damage could now more easily be restored. This will advance total restoration. A key cause for the long duration of restoration is necessarily restoration work is prioritized to restore as many customers as quickly as possible. To do this, repair work is executed in order of largest customer outage to smallest. Since repairs on spurs impact less customers, these would be some of the last repairs to be completed. They tend to be more difficult to fix (restoration crews generally have easier access to the main run of primary lines as compared to spur lines), and restore fewer customers once completed compared to repairs on main runs. Undergrounding of the spurs shortens the overall storm restoration response by potentially eliminating outages from happening (reducing the overall number of customers impacted) as well as freeing up crews to work on more effective (i.e., - more customer impacted) portions of the restoration.

For the reasons outlined above, spur segments should be targeted for undergrounding to meet Con Edison's goal of becoming more resilient as the Company adapts to climate change.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

The undergrounding program is linked closely to Con Edison's strategic plans and climate adaptation strategy. As stated in the current long-range plan:
Over the next 20 years, [Con Edison] will implement a host of new capabilities that will increase the delivery system's flexibility and enable customers to better manage their energy use and costs. The bulk of our investment in new capabilities falls within two broad plans: our grid modernization plan and our customer engagement plan. As part of both plans, [Con Edison] is also working with policymakers and other stakeholders to evaluate alternatives to the current rate structure that would more effectively promote efficient use of the electric delivery system.1
The undergrounding plan will support Con Edison's goals on both counts of grid modernization and customer experience improvement. The process of identifying and prioritizing spurs for undergrounding will be conducted as another tool of the grid modernization effort, meaning data analytics and localized resources can and will be levered in conjunction with undergrounding. Similarly, undergrounding will further the goal of improving customer engagement. Given that customer experience is heavily affected by outage events, the undergrounding program will both avoid outages and also improve the ability for the Company to respond more efficiently and rapidly when outages do take place.

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection
Aggressive vegetation management has historically been and will continue to be the first line of defence against storm related outages. However, since the intensity of storms is increasing due to climate change, further enhanced vegetation management would require removal of more hazardous trees and further expansions of the clearance zones (beyond the current right-of-way). It is also unlikely to be sufficient to address other causes for outage.

Alternative 2 description and reason for rejection
A second alternative is to continue hardening the overhead system. Installation of stronger poles and aerial cables to higher construction standards can help the system withstand higher wind speeds and potentially some number of tree limb caused outages. However, the risk for outage from weather exposure is not eliminated, only reduced.

As this program is "selective" in nature, it is intended to identify specific spurs or spur segments which are optimal recipients of undergrounding. This program will rank spurs by performance and by customer attributes. Spurs with lower ranking targets may be hardened in the intermediate years prior to eventually being undergrounded.

Alternative 3 description and reason for rejection
Underground the entire Con Edison overhead system. This would mitigate a large portion of the weather and climate related risks. This blanket undergrounding approach however, will be very costly in terms of physical work to be done and time needed to carry out. The undergrounding of the entire system will improve overall system resiliency and reliability but will be amongst the most intrusive and expensive options to address the risks faced.

[1]Source: *ConEdison Electric Long Range Plan 2019-2038*, January 2019.

Risk of No Action

If no actions are taken, Con Edison's overhead system and customers will still be exposed to weather related risks. This could lead to more frequent and increased outages and decreased customer satisfaction.

Risk 1
Customer well-being is a risk that is present from a decision not to pursue this program. The prioritization methodology emphasizes undergrounding spur circuits for the most vulnerable customers. These are the customers who may not be able to afford evacuating, a generator, nights in a hotel, or a refrigerator full of spoiled food. As storms become more frequent and severe, the health and safety of these customers' needs to be prioritized.

Risk 2
Overhead distribution spurs will see increasing risk of damage and service losses as climate change driven events intensify in magnitude and frequency. As storm systems effect larger areas of the US, mutual assistance resources will become more difficult and costly to engage.

Risk 3
Reflective of Con Edison's climate change vulnerability report as well as numerous other third-party studies of climate change impact on the electrical grid, the most vulnerable sections of Con Edison's overhead network can only be protected to a limited extent as long as they remain overhead and subject to weather exposure. As conditions worsen over time, keeping the system in its exact current state may result in longer and more severe outages.

Non-Financial Benefits
- Increased resilience
- Increased safety for most vulnerable customers
- Increased customer satisfaction
- Improved restoration crew repair efficiency and dispatch
- Stronger relationships with communities, municipalities, and regulators

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis (if required)

2. Major financial benefits

The primary financial benefit of the program will be reduced cost of restoration.

The calculated benefits will need to be estimated based upon the current pilot programs in progress. As the storm restoration curve becomes shortened, a further analysis will be needed on the reduced cost of mutual assistance labor needs.

3. Total cost

The total cost of the program is yet to be determined pending further findings from the pilot projects. Con Edison plans initiate this long-term program in 2023 and which is expected to invest $240 million from 2023 – 2025. Prior to the Selective Undergrounding program initiating and then ramping up, an organizational structure will be created to manage all components of this program. Customer and

Stakeholder Outreach, Marketing, Engineering design and prioritization, Project Management, and Construction.

4. Basis for estimate
Based on the estimates for the pilot installations, it will cost approximately $10 million per mile to convert overhead distribution lines to underground distribution lines.

5. Conclusion
The projects should be done in instances where there is a clear benefit for the customer and a calculable challenge related to the specific section of the system which is vulnerable to major storms. Con Edison will be able to learn from other utilities across the US which have pursued similar programs with great success as well as from pilot programs conducted by Con Edison. Additionally, throughout the program results will be evaluated and learnings applied.

Project Risks and Mitigation Plan

Risk 1 – Lack of customer engagement
The most substantial risk is related to customers withholding necessary easements needed for project completion. This can add significant time to the project schedule and require potential reworking or redesign of a portion of the project, which can further exacerbate the schedule impact.

Risk 1 Mitigation plan
This risk can be mitigated through a variety of efforts, but most important is that this program become a core component of Con Edison's long-term strategy and therefore be driven internally by a dedicated team across engineering, customer communications, legal, regulatory, strategy, and marketing. All functions must work in concert to de-risk potential roadblocks to a project efficiently progressing from feasibility analysis through construction. Second, Con Edison has, and will continue to make, use of lessons learned from peer utility undergrounding programs as it relates to design, customer planning, and execution strategies. Third, detailed tracking of project progression over time (including lessons learned from the pilots) will be critical to maintain cost accuracy over the 10+ years of this anticipated program.

Considering the impact that undergrounding may have upon customers in terms of trenching, excavation, changing of tap line connections etc., customer's willingness to participate is critical. If customers do not provide approval, a project may fail. As such, customer outreach and proper sequencing of outreach is critical. Depending on the specific portion of the service territory, Con Edison will need to establish clear and consistent channels to communicate the benefits of this program through the appropriate municipalities as well as individually with customers. Conducting this outreach early in the process will provide to the opportunity to alleviate any customer concerns or assess whether a certain project is not feasible before meaningful time and capital is expended.

Risk 2 – Inability to achieve scale and standardization
The second substantial risk to the program is not being able to execute the engineering and/or construction at the planned scale, relying on existing resources as currently organized. This could have additional consequences in terms of standardization of design and equipment used, or in the construction methods and techniques used. Without engineering and construction resources scaled to scope, there will be risks to current construction costs, future repair and maintenance costs (due to potential lack of standardization in engineering, design, and construction). This could significantly alter the project costs.

Risk 2 Mitigation plan
This risk can be mitigated by deploying a dedicated team, similar to the mitigation plan for Risk 1. This dedicated team would be scaled to scope and bring about a specific set of knowledge drawn from peer utility undergrounding programs as well as previous projects completed at Con Edison.

Technical Evaluation / Analysis
Con Edison developed a quantitative model as well as the qualitative justification for this program. This analysis reflects a combination of environmental, demographic, and system performance data to determine spur rankings for undergrounding. The investigation calculates the implied improvement of total system restoration from previous storms (such as Isaias). This analysis is flexible such that it can be updated over time with tree density / hazard tree data, socio-economic data, and major storm restoration performance. The focus of this analysis and justification was on improving system resilience which is quantitatively reflected by customer minutes of interruption (CMI) following major events and the customer experience.

Project Relationships (if applicable)
In order to maximize benefit, this program should be incorporated with existing hardening and resiliency capital programs and customer engagement initiatives. The undergrounding program will entail involvement and leadership from a broad cross section of the company, from engineering to customer outreach to regulatory and legal. Establishing a dedicated team within Con Edison to spearhead this program may be desired.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	2,084	140	70	14		3,743
O&M						
Regulatory Asset						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	5,000	60,000	80,000	100,000	100,000
O&M*					
Regulatory Asset					

Capital/Regulatory Asset Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	1,000	11,500	15,300	19,100	19,100
M&S	1,200	14,100	18,900	23,600	23,600
Contract Services	1,200	14,900	19,900	24,800	24,800
Other	0	200	200	300	300
Overheads	1,600	19,300	25,800	32,200	32,200
Total	**5,000**	**60,000**	**80,000**	**100,000**	**100,000**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Project Status:

- Initiation – New project, not authorized yet
- Planning – Project authorized, not started yet
- Executing – Project in-flight
- On-going – Annual program

Electric Operations / DE
2022 - 2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Shunt Reactor	
Project/Program Manager: Robert Szabados	**Project/Program Number (Level 1):** 10032010, 10035763
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date: Ongoing	**Estimated Date In Service: Ongoing**
A. Total Funding Request ($22,650) **Capital: $22,650** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period:** **(Years/months)**

Work Description:

This program is for the installation of Shunt Reactors on primary feeders to provide compensation for overvoltages on a back feed condition that could damage company and customer equipment within the Brooklyn/Queens and Staten Island load areas where feeders have been determined to need compensation.

Units per Year:

The plan for the Brooklyn/Queens region is to install approximately 18 reactors per year. Currently, there are 170 feeders from a recent compensation study that require compensation and a shunt reactor. The plan for Staten Island region is to upgrade one shunt reactor and install one new shunt reactor each year until the year 2025. The projected schedule is as follows:

Brooklyn/Queens

Year	Projected Number of Shunt Reactors
2021	18
2022	18
2023	18
2024	18
2025	18

Staten Island

Year	Projected Number of Shunt Reactors
2021	2
2022	2
2023	2
2024	2
2025	2

In addition to the required installations, it is estimated that two replacement units per year for these regions will be required.

Justification Summary:

Shunt Reactors are required to be installed on selected 27kV and 33kV feeders as per Company specification EO-2069. The installation of these reactors is required in order to prevent over voltages, which would damage Company and customer equipment during back feed conditions.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

This project reduces the risk of damage to customer's equipment, while also reducing risk to system components and improving feeder processing time. The combined mitigation of damage to system components and reduction in feeder processing time increase the system overall resiliency.

The Risk Management sub-section of the Electric Long-Range Plan (ELRP) states that part of the minimization of risk to employee and public safety is "proactive replacement of high-risk components" and the use of "data and analytics to prioritize our response to any potential problems revealed". The Shunt Reactor program does just that for the 27kV and 33kV network feeders in Brooklyn, Queens, and Staten Island.

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection

The only alternative to installing shunt reactors is to deploy crews during abnormal back-feed conditions to block open network protectors in order to eliminate the over voltages. However, this does not fully protect customer equipment from damage since over voltages will persist until crews find and correct the back-feed condition. Due to the large number of network transformers on a feeder it is not a practical solution.

Installing shunt reactors limits over voltages and reduces the potential for damage to customer equipment and Con Edison equipment. In addition, shunt reactor installation improves feeder processing productivity.

Alternative 2 description and reason for rejection

Alternative 3 description and reason for rejection

Risk of No Action

Risk 1

A 27 kV and 33 kV network feeder that is not properly compensated with a shunt reactor has the potential to cause over voltages on the secondary system and primary feeders during a back feed condition. The magnitude of the over voltage condition could result in more than 140 Volts line to neutral on the secondary side of the back feeding transformer, and 20% to 40% overvoltage condition on the primary back fed feeder. These overvoltage conditions have the potential to do damage to the Company's equipment as well as customers' equipment.

Risk 2

Risk 3

Non-Financial Benefits

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)

2. Major financial benefits

3. Total cost

4. Basis for estimate

The estimate for this project is based on the historical cost of performing similar work.

5. Conclusion

The cost of the program includes the installation of new vaults, installation of ducts, and the installation and splicing of new primary cable. When feasible, existing vacant vaults will be used to minimize the cost of this work. When no vacant vaults are available, a new vault will be placed as close as possible to existing manholes in order to minimize the length of the duct run and associated costs. Compensating for overvoltage on the primary feeders will also prolong the life of primary cables and transformers since they will not see excess overvoltage during their life cycle. Overvoltage conditions have the potential to lead to equipment damage at customer locations and result in a customer claim for damages and loss of use of that equipment.

Justifications: Customer Service – mitigates risk of damage to customer equipment, mitigates risk of widespread loss of service.

Project Risks and Mitigation Plan

Risk 1	Mitigation plan
Risk 2	Mitigation plan

Technical Evaluation / Analysis

A back-feed condition in a network system is an operating problem which occurs because, occasionally, a network protector will fail to open when the network primary feeder is taken out of service. When this occurs, the primary feeder remains energized from the network although it is disconnected at the area substation. Under this condition, the back-feeding transformer will supply the cable charging kVA of the network primary feeder and the magnetizing kVA of all the transformers connected to the network primary feeder. The network primary feeder charging kVA are the result of the cable capacitance to ground (capacitive kVA) and the magnetizing kVA are due to transformer excitation requirements (inductive kVA). For a 27 or 33 kV network primary feeder, the cable charging kVA are usually far in excess of the magnetizing kVA of the transformers connected to the feeder. As a consequence, the charging kVA that are not compensated by the magnetizing kVA will raise the voltage in the network secondary mains that supply the back-feeding transformer, particularly so in its immediate vicinity. By transformer action, the network primary feeder will also experience the overvoltage condition. It is necessary, therefore, to install shunt reactors to limit back-feed over-voltages to safe values for customer and company equipment.

Project Relationships (if applicable)
None.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	**319**	**1,038**	**359**	**634**		75
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**2,500**	**5,000**	**5,000**	**5,000**	**5,150**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	348	696	696	696	717
M&S	338	676	676	676	696
Contract Services	935	1,870	1,870	1,870	1,927
Other	28	56	56	56	58
Overheads	851	1,702	1,702	1,702	1,753
Subtotal	**2,500**	**5,000**	**5,000**	**5,000**	**5,150**
Contingency**					
Total	**2,500**	**5,000**	**5,000**	**5,000**	**5,150**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Smart Sensors	
Project/Program Manager: Andrew Reid	**Project/Program Number (Level 1): 24388419**
Status: ☒ **Planning** ☐ **Design** ☒ **Engineering** ☐ **Construction** ☐ **Ongoing** ☐ **Other:** ____________	
Estimated Start Date:1/1/2020	**Estimated Date In Service: Ongoing**
A. Total Funding Request ($72,003) **Capital: $72,003** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period:** **(Years/months)**

Work Description:

Recent advances in sensing and communications technologies provide utility operators and planners unprecedented visibility and information about system assets. Fortunately, we are not "starting from scratch" as the Company has been – and is currently – deploying sensors across the energy system, i.e., electric, gas and steam.

At Con Edison, we are strengthening our focus on sensing platforms to monitor underground structures and the assets within the structure, e.g. cables, transformers, network protectors, etc., and remotely manage control inputs. As more and more sensors are deployed, more and more data is generated. The Company seeks to leverage data to develop new analytical solutions to draw even greater knowledge and understanding that can lead to step change improvements in public safety, operational excellence, and customer experience.

In order to achieve these objectives, the company has defined sensor as a device that detects or measures an electrical or physical property or status of our infrastructure and transmits that data to the Company over selected communications infrastructure. The sensor may be single and/or multi-functioning and perform an action or configuration adjustment in response to control commands or automatically in response to sensor measurement.

To maximize the value of this technology and increase visibility at the grid edge, Con Edison plans to build upon and expand our existing sensor platforms through new sensor hardware and data analytical solutions as part of the Grid Innovation effort. Specifically, Con Edison will (1) deploy structure observation systems that monitor structures or any other asset for energized objects and manhole event precursor environmental changes using innumerable types of sensors and (2) expand sensing capability at network protectors by adding condition monitoring (e.g. pressure sensing) and enable software algorithms (e.g., Network Auto Exercise) to improve reliability of the network protector.

<u>Structure Observation System (SOS)</u>
The SOS is a general platform that offers several integrated sensors and makes the evolution of software and hardware easier. This includes both the integrated environmental monitoring solution as well as a platform for integrating other equipment sensors and algorithms. A platform approach enables faster iterations of the sensing solution depending on the environment it is deployed, making scaling easier and reducing costs.

Environmental monitoring sensors may include but not limited to,

- Combustible gas sensor
- Ambient temperature sensor
- Visible and infrared imagery
- Contact voltage sensor

Integrated equipment sensor devices include but not limited to,

- Smart crabs
    - Measurement of current from each connected pocket of a secondary crab. These measurements will be analyzed for maximum and average loading to support planning decisions of cable and crab replacement and reinforcement. The smart secondary crab will also capture significant short-term changes to indicate whether an immediate response may be required. This is possible by observing when appreciable current drops to zero, indicating a limiter has blown open.
- Smart primary splices
    - Primary distribution cable splices with embedded sensors will provide the Company with more information on the primary network and condition of primary cable and splices. The sensors will improve employee/public safety, provide data to monitor the health of network primary assets, and improve feeder restoration. The sensors may include status of feeder (energized/de-energized), voltage, current, phase angle, temperature, and presence of partial discharge. Partial discharge monitoring will provide information on the condition of both the splices and the cable it is joining. The information collected from these sensors will be used in stages.

The SOS will transmit the environmental sensor data it collects, in addition to information from smart equipment sensors, over a wired network or secure wireless network, such as Radio Frequency (RF), e.g., Cellular or Advanced Metering Infrastructure ("AMI") network. The data will be securely received, processed, and analyzed by the Company's Enterprise Data Analytics Platform ("EDAP"), for several uses:

- Immediate for operational use for imminent equipment failures
- Short term for inspection, repair, and program optimization
- Long term for optimized capital planning

In some cases, vendor supplied, or third-party applications could be used to ingest, store, and perform analytics as well as perform sensor device management. The sensor data and associated analytics will then be accessible by Con Edison within the vendor's platform or transferred from the vendor to Con Edison for storage and further analytics.

The combination of the environmental sensing and data transmission functionalities presents an opportunity to transform the way the Company monitors its assets and maintains situational awareness. In lieu of a single data point collected every eight years through an inspection cycle the Company will have a history of data through its sensor platforms as well as on-demand visibility. In the future, this increased visibility and functionality will allow the Company to make improvements to our inspection programs using continuous remote monitoring.

Currently, the detection and mitigation of underground electrical abnormalities is mandated by New York Public Service Law §65(15) Case 04-M-0159. The Order is currently fulfilled through a manual inspection process. The primary goal of this capital expenditure is to improve detection capabilities, periodicity of detection and program efficiency and effectiveness by directing more resources to proactive work. A partial or full transition of the inspection program to a virtual approach, relying on sensor platform and data analytics, would occur after establishing performance as equivalent if not improved over the current manual process and include notification to regulators.

The installation of SOS monitoring devices may occur with routine and targeted work selected for safety and reliability. Targeted Company and non-Company locations may include statistical safety for manhole events and energized objects as well as for reliability such as structures with multiple feeders.

The planned annual equipment deployed in this program includes:

Equipment	Approximate # of units
Structure observation system	2500
Splices with sensing ports	250
Voltage detectors for use with sensing splice	20

Network Protector (NWP)
The NWP is a general platform that offers several integrated sensors and makes the evolution of software and hardware easier. This includes both the integrated pressure, temperature solution as well as a platform for integrating other equipment sensor data and algorithms.

- NWP Pressure Sensors
  - The Company is nearing the completion of the deployment of pressure, temperature, and oil ("PTO" sensors) on underground network transformers. Building off that success , this project will add the pressure sensors to submersible network protector ("NWP") housings. . The pressure sensor would help to determine if there is a leak or fault in the NWP housing. The NWP pressure sensors require a communication channel to backhaul the asset data. Pressure sensors would be connected on locations with existing SCADA communications.

- NWP Auto Exercise
  - Company operations continue to be impacted by ABF events. The Auto Exercise effort aims to reduce the ABF rate by intermittently operating network protectors in service. AE is enabled via a software update within the network protector relays with 25 point boards. Other locations will require additional cables. Misoperations can be addressed prior to feeder outages by dispatching crews to perform maintenance thereby reducing ABF events.

The planned annual equipment deployed in this program includes:

Equipment	Approximate # of units
Network protector housing pressure sensor	300
Auto Exercise	400

The installation of network protector pressure sensors and auto exercise may occur with routine and targeted work selected for reliability.

Justification Summary:
Provide an understanding of why the project/program should be done. ***Give a detailed description of the situation background and work to be completed.*** *If it is a primary driver for doing the work, include a discussion of the ERM addressed by the project or program. Be sure to include financial and non-financial benefits.*

One of the defining features of the Grid Innovation program is using sensing technology to provide greater situational awareness of the electric system, and then using data analytics and advanced management systems to more effectively plan and operate the system. This acceleration of sensing technologies, currently deployed on a targeted reliability-focused basis, will develop the above capabilities more quickly. The deployment of these sensors offers public safety benefits, operational efficiencies, and potential cost savings. Each sensor serves a specific purpose with specific benefits, described below:

<u>Structure Environmental Monitoring</u>
As demonstrated in its pilots, the SOS' environmental monitoring provides safety and reliability benefits. The goal of the program is to effectively replace the need for physical inspections by providing critical system data needed to migrate to data driven maintenance. It will provide operators, engineers, and planners with insight into system performance and how they manage it, resulting in greater safety and reliability.

In addition to the improvements in public and employee safety, the increased grid edge visibility, to the extent that it can remotely perform structure inspections, could provide cost savings. Once remote monitoring is proven successful and fully deployed, the Company expects the majority of its high priority structure inspections to be done virtually - eliminating the need for costly labor consuming practice of site visits.

The ability to rapidly respond to an underground electrical cable failure will potentially reduce collateral property damage, evacuations from carbon monoxide, and injury. In an average year, there are over 2,000 manhole events. While a majority of cable failures are singular and isolated, some failures develop into fires and explosions. The reduction of a fraction of these escalated events could lead to significant cost savings by alerting operators to manhole event precursors and addressing them before they progress to more dangerous and damaging situations. Through earlier warnings, collateral damage is reduced.

<u>Streetlight Contact Voltage Sensor</u>
Contact voltage presents a danger to people and/or animals that may come into contact with an energized object on the sidewalk or street. Con Edison has a contact voltage testing program which periodically performs mobile scans monthly in the underground network areas, and deploys manual contact voltage testing annually in the overhead electric system areas. While mobile scanning and manual contact voltage testing can detect inadvertently electrified metal object like street lights, the street light's metal must be electrified when the mobile scanning and manual contact voltage tests are performed. Therefore, a continuous monitoring solution will better safeguard the public from electric shocks.

<u>Smart Sensors in Cable Equipment</u>

Smart secondary crabs provide sensing of the condition of secondary crab joints, where there is currently no visibility. This visibility offers both short-term operational benefits and long-term planning benefits. Without the smart secondary crab, the Company may be unaware of blown limiters until a more serious equipment failure manifests. Through earlier detection of failing secondary cable connections, the Company is able to address operational issues before they become significant enough to result in customer outages. On a longer time horizon, the Company is able to take readings of loading and status to inform planning decisions to optimize long term capital spend.

The smart primary splice offers similar benefits on the primary portion of the distribution system. In the short term, crews on site can take measurements to determine cable status and loading conditions, offering another measurement point for safely conducting field work. As remote monitoring is enabled over 5-10 years, the operational and planning benefits of smart primary splices include avoiding feeder faults and loss of system reliability.

<u>Network Protector Pressure Sensor</u>
With visibility to detect leaks or pressure loss in the network protector housing, the Company will have an earlier indication of moisture intrusion which can compromise the performance of the switch, keeping it from operating when required and reducing grid performance. A pressure spike could indicate a fault in the NWP housing and crews could then respond more quickly to high priority repairs, improving reliability and yielding public safety benefits.

<u>Auto Exercise</u>
The addition of this self-diagnostic feature ensures that equipment defects are identified before the network protector is needed, allowing crews to repair defective equipment without service disruption or compromising system reliability. It also provides valuable data to engineers and operators when analyzing an abnormal condition. This helps streamline the troubleshooting process adding speed and efficiency to the recovery effort.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

The company has analyzed operational risks arising from the failure of, or damage to, the company's electric assets and has developed strategic framework of prevention, detection and response/mitigation that this program helps to achieve.

The failure of, or damage to, these facilities, or error in operation or maintenance of these facilities could jeopardize public safety and employee safety, cause property damage, or interrupt service. As a result of Climate Change, a natural disaster such as a major storm, heat wave or hurricane could damage facilities, and further damage could result if facilities are operated during or after such events.

The Smart Sensors program minimizes the following Corporate and Department Risks, 1) Safety, 2) Low Voltage Cable Failure, 3) Network Shutdown, 4) Major Storm, 5) Cost Control, 6) Power to Sensitive Customers, and 7) Regulatory Penalties, by using sensing technology to provide greater situational awareness of the electric system and proactively responding to conditions or quickly responding to events to minimize their impact and speed recovery time.

2. Supplemental Information

Alternatives

Alternative 1
In lieu of continuous remote monitoring, project alternatives would include both reactive and proactive protection mechanisms.

Reactive:
- Run assets to full life failure, wherein the condition is publicly observed, reported, site secured and mitigated
- Install latched vented covers which will help contain explosive energy from resulting in a projectile

Proactive:
- Accelerate scope of Secondary Rebuild Program to cover additional structures

Alternative 2
The current process of inspections, whereby a person enters a structure once every five, eight, or ten years, can continue at the same rate but with an enhancement. A technical alternative to the deployment of continuous remote monitoring would be a through-cover camera inspection platform to augment the current manual inspections that would allow an operator to inspect a structure from street level. One benefit of through cover inspection is the immediate location targeting and focused image and infrared data to identify potential cable failures; the downside is the information is intermittent and still requires significant administrative overhead and expenditure to manually inspect structures. Therefore, deploying continuous remote monitoring immediately is the optimal path.

RMSPTO

An alternative to RMSPTO is to use modeling and more frequent on site inspections. This is a more costly and less accurate methodology, and is therefore not recommended. Alternative technologies for communications have been explored and are being deployed, which extend RMSPTO capabilities to transformers locations that could not communicate over power line carrier which is the primary system for RMS.

Auto Exercise
Alternatives to the AE feature include manual testing and SCADA controlled remote testing. Manual testing is labor intensive and therefore not as cost effective as AE. SCADA controlled remote testing would require additional infrastructure, and in cases where the additional functionality that SCADA brings would make that investment worthwhile. However, in most cases the simplicity of self-diagnostic test initiated from the relay are the most efficient and effective solution.

Risk of No Action

Risk 1
The Company has recently adopted an asset management approach that inspects underground facilities based on whether the facility is considered a high, medium, or low risk for an asset failure. In the long run, this approach requires the use of contract resources to inspect structures and report back. This approach foregoes the potential efficiency benefits associated with remote monitoring for structures and

equipment. By not taking the opportunity to capture a developing asset failure in its infancy, the risk of injury to a member of the public or employee, property damage or loss of reliability is increased.

The following enterprise risks risk by not doing the program, 1) Safety, 2) Low Voltage Cable Failure, 3) Network Shutdown, 4) Major Storm, 5) Cost Control, 6) Power to Sensitive Customers, and 7) Regulatory Penalties.

Non-Financial Benefits

The primary non-financial benefits of this program are an increase in public and employee safety due to proactive removal and replacement of low performing distribution equipment, increase efficiencies in work prioritization and emergency response, particularly in peak event periods (such as storms). Lastly, the Company expects an increase in reliability and customer satisfaction due to faster return of service and resulting less time the network is overloaded.

If the deployment of sensors can enable remote inspections of distribution assets, the reduction and elimination of the underground inspections will have an overall benefit to the safety and reliability for customers and employees, and tangentially quality of life advantages. Manual inspections involve the disruption of traffic and pedestrian patterns, whereas the SOS devices will be transparent to the public.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis (if required)

This SOS is an ongoing program and a new vendor has recently entered the marketplace to give competition to the sole source supplier of the SOS type equipment. The costs include equipment, installation, and software maintenance/communications. The average installed cost for each device is $6,000 for the equipment and installation, and $142 for the annual data storage and communication.

A major financial benefit is the avoidance of costs associated with underground events, we estimate the costs as follows:

Manhole explosion $50k per occurrence
Manhole fire $20k per occurrence
Smoking manhole $1.5k per occurrence

<u>Auto Exercise</u>
See summary in Justification section

2. Major financial benefits

The structures targeted for installation, as detailed in Our plan is to install the SOS into high priority structures which we feel have properties which classify them as having a high risk for an event. With continual monitoring, we will be able to preemptively respond to a condition before it manifests into an underground event.

Additionally, with continual monitoring, these structures will not need to be manually inspected on a cycle basis.

<u>Auto Exercise</u>
See summary in Justification section

3. Total cost

Structure Observation System:
The total project implementation includes 2,500 devices installed at $4,000 cost per unit. This equates to $10,000,000 over the rate period.

Annual data storage and communications costs is approximately $142 per device installed. At 9,000 units installed, this equates to approximately $1,300,000 annually.

Auto Exercise
See summary in Justification section

4. Basis for estimate
Explain the method used to create the estimate. Include all key assumptions.

Structure Observation System
The average cost for each device is $4,000 for the equipment and installation, and $142 for the annual maintenance/communication. The cost of a full sensor device is $6,000 for equipment and installation but not all structures may received all sensors.

The cost estimates used for this analysis conservatively use 2018 costs for long-term projections. The Company anticipates the cost of technology may decrease over time as more vendors develop the associated technologies, and the deployment rate of the sensors could then be accelerated. In contrast, there is a high probability that manual inspection costs, including both the unit cost and the procurement and oversight required will continue to increase. The avoidance of collateral damage to public property and personal injury is difficult to quantify yet can't be overstated.

Auto Exercise
See summary in Justification section

5. Conclusion

Structure Observation System
Smart sensors offer financial benefits by reducing the reliance on contractors for manual inspections and reducing the amount of damaging manhole events. On an annual basis, as SOS devices are deployed, they begin to immediately offset the cost of contractor inspections. The average annual contractor inspection budget is $7M for an eight-year cycle of inspections. Smart sensors also produce benefits by reducing the collateral damage associated with the low-probability but high-impact manhole events that escalate to fire or explosions. Conservative estimates for the damage associated with all events are $2M per year, and the benefits associated with avoiding these events would scale linearly with the deployment of the SOS.

Auto Exercise
See summary in Justification section

Project Risks and Mitigation Plan

Risk
Sole source supplier of sensors increases risks such as inability to meet deployment schedule, product quality issues and/or high per unit costs.

Mitigation
The Company is diversifying the suppliers of Smart Sensor devices, e.g., SOS, in order to introduce competition to reduce costs to customers, drive higher product quality, and reduce supply chain risk that would inhibit the company from meeting its desired project timelines.

Technical Evaluation / Analysis

Structure Observation System
The generation of combustible gasses, such as CO, from the burning of insulation in Company assets has been well established. The detection of these gasses can be accomplished through electrochemical and infrared based gas detectors. Likewise, voltage present on an energized object can also be measured regularly for abnormal conditions. What has changed substantially is the wireless infrastructure through which data can be sent. Current wireless technologies can be deployed cheaply, at low power, and high bandwidth. As data is retrieved on a more frequent basis from sensors embedded in cable splices, the Company will be able to make longer term capital replacement decisions based on historical stresses and asset condition.

Auto-Exercise:
See summary in Justification section

Project Relationships (if applicable)

This project is dependent on the AMI communications infrastructure or a suitable wireless alternative and the data analytics platform to most effectively utilize the data generated. The proliferation of sensing technology will also bring more data back to operators. A future Advanced Distribution Management System ("ADMS") would receive the data inputs and translate those for operator decision support, particularly Reginal Engineering and Control Centers.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital				513		3,517
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	11,300	15,100	15,100	15,100	15,403
O&M*		1,300	1,300	1,300	1,300
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor					
M&S					
Contract Services	6,112	9,799	9,799	9,799	10,093
Other	14	22	22	22	23
Overheads	851	1,702	1,702	1,702	1,753
Subtotal	**11,300**	**15,100**	**15,100**	**15,100**	**15,403**
Contingency**					
Total	**11,300**	**15,100**	**15,100**	**15,100**	**15,403**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

Auto Exercise per unit (goal: 400/year)

Cost Breakdown	
Material:	$3,500
Labor:	$1,216
Total:	**$4,716**

Auto Exercise per year

EOE	Request 2022-2025 (in thousands)
Labor	$486
M&S	$1,400
A/P	-
Other	-
Overheads	-
Total	**$1,886**

Splices with Sensing Capabilities

As the implementation of these splices will be accomplished as part of regular business the costs would only be incremental capital costs due to additional cost of the splice and the detectors used to determine if the splice is energized. Total for 250 units and 10 detectors is $23,600.

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Central Operations/ Substation Operations
2022

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Stabilization of Pothead Stand Supports/Settlement	
Project/Program Manager: Steven Bryan	**Project/Program Number (Level 1): PR.2ES4302/ 21676680**
Status: ☐ **Planning** ☐ **Design** ☒ **Engineering** ☐ **Construction** ☐ **Ongoing** ☐ **Other: ___________**	
Estimated Start Date: Ongoing	**Estimated Date In Service: Ongoing**
A. Total Funding Request ($000) **Capital: $10,000** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:
This is a multi-year project to correct equipment settlement problems at all substations. The project is being completed in stages. The scope of work typically includes stabilizing pothead and disconnect switch stands, prefabricated concrete control cable trenches, junction boxes, and direct buried conduits.

Due to continued settling, installation of trenches is the first required action to allow for the replacement of existing control cables affected by the current settlement. This trench system is required to mitigate the problem created by equipment foundation settlement. Con Edison uses helical screw piles and continuous concrete-grade beams to support the trench.

This program will prioritize projects to mitigate settlement issues at Eastview and Astoria East Substations but may also be used for other locations should they exhibit problems.

Justification Summary:

A settlement study was performed by Muser Rutledge Corporation to determine if settlement will continue or if we have reached the end of settlement. Their report states that the ground surface settlement will continue to occur as the result of secondary compression of organic, marsh soils immediately beneath site fills, but at a decreasing rate.

If the disconnect switch stands, junction boxes and conduits are not reinforced they will continue to bend and will eventually cause the disconnect stands to sink. The bus conductor becomes misaligned, and cables and conduits will break away from the control cabinet junction boxes. This would force unscheduled outages at the station, jeopardize the integrity of the equipment and the station, and create safety issues for the employees working at the station.

At both Eastview and Astoria East Substations, settlement of the strand has caused pothead leaks on internal transmission circuits. In order to repair these leaks, an outage must be taken on the feeders, at times on an emergency basis. If the effect of the settlement on the stand is not addressed, the potheads will have recurring leaks. Eventually this could require a replacement of the pothead and, in the near term, has a negative impact on system reliability.

Given projections for more instances of extreme weather, such as tropical storms and extreme weather events, more settlement issues in substations are possible.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):

This program impacts the Substation Operations risks Major Storm and Equipment failures. Projects completed as part of this program reduce the likelihood of equipment failures; when settlement issues are corrected, there is less likelihood that it will cause control systems or cable potheads to fail. This program reduces the severity of storm events by hardening structures that are vulnerable to settlement.

2. Supplemental Information

Alternatives
Increase the size of the existing footings to further spread out the structural loads in the surrounding soil. This alternative was rejected because it will only decrease the rate of settlement, but not prevent it.

Risk of No Action
The stabilization of the disconnect switch stands, junction boxes and conduits is required to prevent further bending and damage to the existing electrical conduit risers that connect to the equipment. If the disconnect switch stands, and junction boxes and conduits are not reinforced, they will continue to bend and will eventually cause the disconnect stands to sink. The bus conductor becomes misaligned, and cables and conduits will break away from the control cabinet junction boxes. This would force unscheduled outages at the station, jeopardize the integrity of the equipment and the station, and create safety issues for the employees working at the station.

Non-Financial Benefits
This program will improve overall system reliability by reducing operational issues with equipment, primarily disconnect switches, at the affected stations.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis: N/A

2. Major financial benefits
This program is expected to reduce the costs for ongoing maintenance issues caused by settlement on affected pieces of equipment.
3. Total cost **$10,000**

4. Basis for estimate: Funding request is based on historic settlement work that has been previously completed and is of a similar nature to the work planned in the future.

Conclusion :N/A

Project Risks and Mitigation Plan

Risk 1: Outage scheduling conflicts with other initiatives.

Mitigation: Outages to be coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs to avoid conflict with other program/ projects resulting in a more predictable budget and manageable outage scheduling.

Risk 2: Delays due resources support coordination.

Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Technical Evaluation / Analysis: A settlement study was done at one substation and is mentioned in the justification summary. The plan moving forward is to monitor foundations at the three mentioned substations to determine what movement is active and stabilize them.

Project Relationships (if applicable) The Disconnect Switch Replacement Program and Area Reliability Projects are influenced by this program. These projects work in conjunction with each other, i.e., if equipment to be replaced is sitting on settled foundations, then the two scopes would have to be coordinated.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	0	0	0	0		0
O&M						
Retirement	0	0	0	0	0	0

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**$-**	**$2,500**	**$2,500**	**$2,500**	**$2,500**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2021	2022	2023	2024	2025
Labor	0	450	450	450	450
M&S	0	0	0	0	0
Contract Services	0	1,400	1,400	1,401	1,405
Other		0	0	0	0
Overheads	0	650	650	649	645
Total	**$ 0**	**$2,500**	**$2,500**	**$2,500**	**$2,500**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

Central Operations/ Substation Operations
2022

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Structural and Infrastructure Upgrades Program	
Project/Program Manager: TBA	**Project/Program Number (Level 1): PR.0ES3100/ 20183107**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date: N/A	**Estimated Date in Service: N/A**
A. Total Funding Request ($000) **Capital: $51,250** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

Central Engineering has established an inspection program to determine the structural soundness of substation facilities (external and internal) to ensure public and employee safety as well as the integrity of equipment protection contained within substation facilities. This program continues ongoing Capital and Maintenance Programs to correct issues that can no longer be addressed through routine maintenance. The impacted areas range from major sections, both interior and exterior, to the entire structure. The ongoing program will include addressing three to four initiatives per year for maintenance and one to two Capital initiatives per year. Work will be optimized and prioritized based on the inspection results and criticality.

This program funds facility improvements and upgrades at individual substations. The following types of facility structural improvements are covered under this program:

- Façade
- Foundation
- Retaining Walls
- Lifts and platforms
- Floors
- Heating and Ventilation
- Lighting
- Plumbing (i.e., backflow preventers)
- Large scale drainage modifications
- Paving
- Fencing
- HVAC
- Elevators and Access/Egress

Starting in 2024, this program will also include the construction of an additional facility at Millwood Substation for the storage of spare transformer units. The Company utilizes the Astoria property for storage of spare substation power transformers but requires additional storage space.

Justification Summary:
These projects are necessary to improve and maintain substation facilities to ensure safe and reliable operations and are not covered by other Capital Programs. In addition, these projects will enable the Company to discontinue the use of temporary office facilities, which will support continued efficient deployment of personnel and will provide employees a safer and more professional work environment.

The structural inspection program will address issues stemming from the vintage of the stations, as opposed to the current alternatives and solutions, which consist of temporary measures. The temporary measures address the current safety issues and equipment protection; however, problems continue to expand and increase in scope. In addition, the cost to maintain these temporary measures continues to increase and ultimately neglects to address the root cause of the problem. Maintenance and replacement are required based on the condition and age of the structures within the scope of this project, all of which were built between 1948 and 1991.

Spare transformers are essential to restoring the transmission system in a timely manner following the failure of a unit. Keeping spare transformers allows the Company to deliver a replacement unit to a substation after a failed bank has been removed. Maintaining the spare inventory requires the Company to have storage space and to keep units in strategic places to minimize transport. Having a spare yard in Westchester will provide adequate space for storage as well as providing a strategically located facility.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
Increase reliability of equipment and facilities, eliminating possible inadvertent trips including outages to equipment and customers, and reduced personal safety hazards with relationship to equipment failure causing property damage and/or injuries to the public in the immediate vicinity of the substation. Increase the flooding protection with focus on changing average climate and increasing severity/frequency of extreme weather events /major storm.

2. Supplemental Information

Alternatives
Substation Operations has various office facilities that are temporary in nature, currently housing numerous employees daily. The first alternative is to relocate employees currently working in these temporary locations to existing facilities, where required improvements and additional space would have to be made. In addition, where sufficient space is unavailable, new space would need to be leased or developed. Some combination of all three previously mentioned options may be required to relocate employees most efficiently and cost-effectively to permanent facilities. This program also funds a project to install backflow preventers on water supplies designed to bring existing substations into compliance with current cross control connection device codes and New York State and New York City requirements. As non-compliance locations are identified, a scope of work for each facility is developed and a construction cost estimate determined.

Risk of No Action
The risk of no action is that the continued degradation of facilities could lead to hazardous conditions that impact equipment reliability and the safety of company personnel and the public.

Non-Financial Benefits
This program provides employees a safe and professional work environment and ensures a safe and reliable operation of the substations.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis: N/A

2. Major financial benefits
N/A

3. Total cost **$51,250**

4. Basis for estimate: The 2023 funding request is based on historical average completing seven to nine projects of similar nature with varying scope, in a cost range of $200K to $1.7M. The 2024-2025 funding request includes $12.5M for the installation of a spare transformer yard at Millwood Substation.
5. Conclusion: N/A

Project Risks and Mitigation Plan

Risk 1: Delays due resources support coordination.

Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Risk 2: **Lack of alignment between resources support and outages.**
Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor and construction to avoid alignment conflicts with outages.

-

Technical Evaluation / Analysis:
N/A

Project Relationships (if applicable) N/A

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	6,232	5,616	4,248	1,571		7,833
O&M						
Retirement	486	344	527	157		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**$7,600**	**$6,700**	**$14,400**	**$14,400**	**$8,150**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	1,444	1,273	2,736	2,736	1,548
M&S	920	816	1,745	1,743	1,001
Contract Services	3,151	2,785	5,999	6,004	3,398
Other	0	0	0	0	0
Overheads	2,085	1,826	3,920	3,917	2,202
Subtotal					
Total	**$7,600**	**$6,700**	**$14,400**	**$14,400**	**$8,150**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations/ Substation Operations
2022

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Substation Enclosure Upgrade Program	
Project/Program Manager: Seda Steck	**Project/Program Number (Level 1):** PR.23287694
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date: Ongoing	**Estimated Date in Service: Ongoing**
A. Total Funding Request ($000) **Capital: $8,900** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:
This program will upgrade selected outdoor enclosures throughout the system by providing weatherproof canopies for switchgear cubicles & relay cabinets. This is typically supplemented with sealing existing metal enclosures with a sealing material (typically Kemper Seal) or providing the installation canopies as long-term solution. In some cases, cubicle doors are replaced or refurbished, the enclosure structural supports are reinforced, or other steel/sheet metal work is performed to preclude deterioration of the while providing for safe inspection, maintenance, and repairs under most weather conditions.

The installation of the canopies is a long-term solution to protect relay cabinets & switchgear cubicles from inclement weather and enhance the reliability of the electric system.

The canopies will consist of a structural frame with a roof and siding to protect the top and upper sides of the cabinets. In some cases, the canopy frames can be mounted onto the existing relay cabinet foundations.

Justification Summary:

<u>Justification Summary for Switchgear Cubicles:</u>

The switchgear cubicles in several substations require upgrading. These outdoor switchgear housings have been weathered by exposure to the elements. Their construction is typically a painted sheet metal enclosure resting on a concrete slab. Many steel components are corroded. The exterior doors no longer close and seal correctly. Many slabs are deteriorated and do not allow proper drainage accelerating corrosion of the structural supports. Lastly, for some enclosures, the roofs leak.

The upgraded enclosures will reduce weather intrusion related trip outs, unscheduled outages, and alarms.

Justification Summary for Relays:

Relays are usually housed in heavy gauge steel cabinets designed to be watertight. When these steel cabinets are exposed to weather, they will deteriorate with time. In various substations, several of these outdoor relay cabinet installations are deteriorated and jeopardize the reliability of the electric system.

Relays are used to detect electrical problems or faults in transmission and area substations. When these relays detect a fault, they send a signal that operates protective equipment, such as a circuit breaker, which will isolate the fault and limit the damage. Relays will also send a signal to the control room and notify the station operator of the electrical hazard. It is important to ensure that these relays will always function because the detection of electrical problems in the substation will protect the operators in the area, limit the potential damage on substation equipment, and will minimize the number of customer outages. For these reasons, relays must be maintained in a dry and safe environment.

The metal relay cabinets are exposed to the elements and they have deteriorated over time. This has allowed water to enter the cabinets, and we run the risk of compromising the equipment and jeopardizing the reliability of the station. Installation of canopies will preclude deterioration of the relay cabinets while providing for safe inspection, maintenance, and repairs under typical weather conditions. The installation of the canopies is a long-term solution to protect relay cabinets from inclement weather and enhance the reliability of the electric system. The canopies will consist of a structural frame with a roof and siding panels attached to the frame. These frames and panels will enclose and protect the existing relay cabinets.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
This program affects the Substation Operations risk "Major Storm". This program reduces the likelihood of a major storm impacting substation equipment by replacing enclosures that may be susceptible to water intrusion. Water intrusion can cause inadvertent trip outs of equipment during extreme weather events.

For the reasons discussed above, this program is an ongoing part of the Company's climate change adaptation efforts.

2. Supplemental Information

Alternatives

- Alternatives to Switchgears Cabinets: There are two alternatives to taking steps to weatherproofing the existing enclosures. The first alternative is to replace the switch gear, which is extremely costly. The second alternative would be to enclose the station, which is also cost prohibitive.

- Alternatives for Relays House Enclosures: An alternative to the current solution is to build masonry structures to provide protection for the relay cabinets. This is a higher cost option, sometimes not feasible due to space constraints and therefore not recommended.

Risk of No Action
Doing nothing would allow the enclosures to deteriorate thereby exposing the system to repeated outages and increased frequency of repairs and inspections and reduced reliability.

Non-Financial Benefits This program will improve system reliability, as it will reduce the number of unplanned outages associated with trip outs from water intrusion. Enhance the reliability of equipment by protecting the relay cabinets from inclement weather.
Summary of Financial Benefits and Costs (attach backup) 1. Cost-benefit analysis: N/A 2. Major financial benefits This program will defer the need to replace entire switchgear sections if they could continue to deteriorate. It will also reduce the costs associated with trip outs by water intrusion. 3. Total cost **$8,900** 4. Basis for estimate: • **<u>Basis for Estimate for Switchgear Cabinets:</u>** This funding request is based on the cost of actual work done in prior years under this program. The average cost per unit is $500K and is budgeted for one unit per year. • **<u>Basis for Estimate for Relay Enclosures</u>**: This funding request is based on the cost of actual work done in prior years under these programs. The average cost per unit is $1.4M with one enclosure budgeted per year. 5. Conclusion: N/A
Project Risks and Mitigation Plan **Risk 1: Outage scheduling conflicts with other initiatives.** **Mitigation:** Outages to be coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs to avoid conflict with other program/ projects resulting in a more predictable budget and manageable outage scheduling. **Risk 2: Delays due resources support coordination.** **Mitigation:** Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts. Risk 3: **Lack of alignment between resources support and outages.** Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor and construction to avoid alignment conflicts with outages.
Technical Evaluation / Analysis: N/A.
Project Relationships (if applicable) N/A

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	1,674	892	1,358	839		479
O&M						
Retirement	0	4	0	0		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**$1,300**	**$1,900**	**$1,900**	**$1,900**	**$1,900**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	201	296	296	296	299
M&S	416	608	608	608	608
Contract Services	325	475	475	475	475
Other	0	0	0	0	0
Overheads	358	521	521	521	518
Subtotal					
Total	**$1,300**	**$1,900**	**$1,900**	**$1,900**	**$1,900**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations/ Substation Operations
2022

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Substation Loss Contingency - Rapid Recovery of an Area Substation/Transmission Resiliency Transformers	
Project/Program Manager: John McCoy	**Project/Program Number (Level 1): 21384664**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other: ___________**	
Estimated Start Date: 1/2015	**Estimated Date In Service: 12/2023**
A. Total Funding Request ($000) **Capital: $4,000** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

In the event the Company incurs a loss of an area substation, this equipment would be deployed in conjunction with other operational measures which may include load management initiatives such as voltage reductions, rolling blackouts, network cutouts, temporary generator installations, and other similar temporary solutions.

There were two projects included under this Program, Transmission Resiliency Transformers which has been completed and Rapid Recovery of an Area Station to be completed in 2023.

Rapid Recovery of an Area Substation (PN 26141-15)
This project will provide for the purchase of equipment required for the rapid recovery of a three-bank area substation with 24 dual feeder positions. Equipment includes:
a) Three Mobile Resiliency Area transformers, each rated 138/69kVpri, 58/65/93MVA KDWF, 13/27/33kv secondary procured in 2021.
b) Three 138 kV dead tank circuit breakers remaining balance for 2023.

Justification Summary:
<u>Rapid Recovery of an Area Substation / Substation Loss Contingency</u>
The loss of a single area substation would result in a significant interruption of electric service to our customers. Much of the focus of the work at area substations has been on reducing the risk of the likelihood that a catastrophic loss would occur. Capital and O&M programs such as the preventive maintenance program, breaker replacement program, security programs and procedures, pumping plant improvement program, and storm hardening efforts all address this risk.

Recent weather events, equipment failures and past terrorist events have shown the possibility of the extended loss of an area substation. These include flooding, fire, and a building collapse (9/11/2001). Additionally, the 2013 attack on the Metcalf utility substation in California increased concern about physical attacks. In some of these instances, the customers supplied by the failed substation were restored to service from mobile generators or shunts from physically adjacent area substations.

A review of all Con Edison's area substations shows the ability to restore customers by using portable generation or transfers to a nearby area substation is not always feasible due to the station loading, distance or impracticality due to the amount and locations of shunts and/or mobile generators that would be required. As a result, alternate sources of power to restore must be developed. In response to a loss of an area substation for 24 hours or longer at some of our area substations, the only means to quickly restore electric service to all of the customers affected includes the construction of a rapid deployment area substation in the vicinity of the failed substation. The resiliency area transformers and mobile switchgear are for use at any of the 64 area substations, with a higher priority application for 27kV double-syn-bus stations in Brooklyn and Queens, and partial applications in the Bronx.

<u>Transmission Resiliency Transformers / Substation Loss Contingency</u>
Large transmission substations interconnect circuits to form the transmission grid, sending and receiving power, transforming voltages, and directing flows so that the circuits operate within their current carrying capacity and voltage limits. Potential causes of the loss of transformers include items such as weather events like significant flooding or wind, a fire or building collapse at a property adjacent to a substation or acts of terrorism or vandalism.

The Company's current spare transformer philosophy ensures that we have at least a 90% probability of having a spare when a failure occurs. The number of spares is determined using a Poisson probability distribution function considering the number of in-service transformers, failure rates, and lead times for replacements. This philosophy ensures that we have sufficient spare transformers on-hand for historical type failures, not high-impact low-frequency (HILF) events. To recover from HILF events, dedicated equipment will be required.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
The construction of a rapid deployment area station reduced the likelihood of loss of electric service to customers and the availability of Transmission Resiliency Transformers reduces the likelihood of the loss of a transmission substation and promotes controllability to mitigate the loss of a substation increasing reliability, resilience (including climate adaptation) improving our response to changing average climate, enhancing efficiency, or customer satisfaction.

Enhance Resiliency: The resiliency transformers are for use at any of the 33 transmission substations. The loss of any of these transmission substations would result in severe issues with system power flows and stability and/or a loss of supply to several area substations that serve critical load in our service territory potentially impacting many customers.

The project addresses the current inability to quickly restore power to customers following the loss of an area substation for 24 hours or longer in instances where it is either impractical or not viable to restore electric service via typical distribution solutions (generators, shunts, switching). In such cases, a new rapid deployment area substation will be installed adjacent to the failed substation to restore power to those customers not able to be restored via other means. This also assists in addressing the current inability to quickly restore reliable power flows through one or more area substations during certain catastrophic events. In such cases, these new transformers would be dispatched to the transmission stations to restore reliable power flows, or to feed area substations to restore power to those substations, hence to the customers supplied by those area substations.

2. Supplemental Information

Alternatives
The alternative solution considered was to reduce the size of the networks and/or build additional new area substations and transfer load accordingly. This is not viable or cost effective because too many new area substations would have to be built at considerable cost.

Risk of No Action
System power flow control issues, system reliability concerns, and/or possible outages at multiple area substations resulting in a significant number of customer outages for an extended period. This is not recommended due to the potential inability to maintain reliable system power flows, or the inability to restore electric service to all of our affected customers during a loss of one or multiple substations.

Non-Financial Benefits
• **Rapid Recovery of an Area Substation / Substation Loss Contingency**
The project addresses the current inability to quickly restore power to customers following the loss of an area substation for 24 hours or longer in instances where it is either impractical or not viable to restore electric service via typical distribution solutions (generators, shunts, switching). In such cases, a new rapid deployment area substation will be installed adjacent to the failed substation to restore power to those customers not able to be restored via other means.

Transmission Resiliency Transformers / Substation Loss Contingency
The project addresses the current inability to quickly restore reliable power flows through one or more area substations during certain catastrophic events. In such cases, these new transformers would be dispatched to the transmission stations to restore reliable power flows, or to feed area substations in order to restore power to those substations, hence to the customers supplied by those area substations.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis: N/A

2. Major financial benefits N/A

3. Total cost **$4,000**

4. Basis for estimate: Based on the cost of similar types of work done in the past. As this is an ongoing program, work scopes are generally similar in nature.

5. Conclusion: N/A

Project Risks and Mitigation Plan
Project Risks :

Risk 1: Outage scheduling conflicts with other initiatives.

Mitigation: Outages to be coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs to avoid conflict with other program/ projects resulting in a more predictable budget and manageable outage scheduling.

Risk 2: Delays due resources support coordination.

Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Technical Evaluation / Analysis:
A technical study to evaluate the loss of each area substation for 24 hours or longer has been updated by Electric Operations / Regional Engineering. It is estimated that five stations need a rapid deployment solution, and a rapid deployment station may be the most viable solution since a distribution solution is estimated to take longer. Additionally, the complete loss of any of our eleven double area substations likely requires a distribution solution and a rapid deployment solution to pick up the two substations. Finally, Electric Operations / Regional Engineering is reviewing the ability to restore a substation with the likely availability of emergency diesel generators during a "blue sky" day. Generator availability has been reviewed with our vendors and was identified to be lower than anticipated, thus it is likely the number of stations needing a rapid deployment solution will increase. Although technical solutions exist for each station, there are multiple cases where the solution is not readily feasible or practical due to various reasons as previously noted.

Project Relationships (if applicable) N/A

3. Funding Detail

Historical Spend

	Actual 2017	**Actual 2018**	**Actual 2019**	**Actual 2020**	**Historic Year** (O&M only)	**Forecast 2021**
Capital	21,576	3,713	3,194	5,963		6,537
O&M						
Retirement	0	0	0	0		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	**Request 2023**	**Request 2024**	**Request 2025**	**Request 2026**
Capital		**$4,000.00**			
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2022	2026
Labor		760			
M&S		0			
Contract Services		1,665			
Other		520			
Overheads		1,055			
Subtotal					
Total		**$4,000.00**			

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2022	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2022	2026
O&M					
Capital					

Central Operations/ Substation Operations
2022

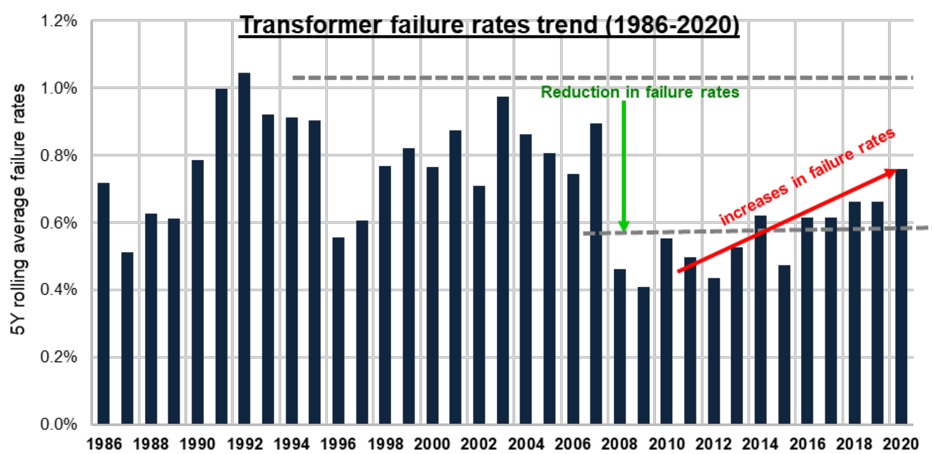
1. Project / Program Summary

<table>
<tr><td>**Type:** ☐ **Project** ☒ **Program**</td><td>**Category:** ☒ **Capital** ☐ **O&M**</td></tr>
<tr><td colspan="2">**Work Plan Category:** ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**</td></tr>
<tr><td colspan="2">**Project/Program Title: Substation Transformer Replacement Program**</td></tr>
<tr><td>**Project/Program Manager: C. Davoren**</td><td>**Project/Program Number (Level 1): PR.2ES8000/ 10030244**</td></tr>
<tr><td colspan="2">**Status:** ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other: ___________**</td></tr>
<tr><td>**Estimated Start Date: N/A**</td><td>**Estimated Date in Service: Ongoing**</td></tr>
<tr><td>**A. Total Funding Request ($000)**
Capital: $508,000
O&M:
Retirement: $22,500</td><td>**B.**
☐ **5-Year Gross Cost Savings ($000)**
☐ **5-Year Gross Cost Avoidance ($000)**
O&M:
Capital:</td></tr>
<tr><td>**C. 5-Year Ongoing Maintenance Expense ($000)**
O&M:
Capital:</td><td>**D. Investment Payback Period: (Years/months)**</td></tr>
<tr><td colspan="2">**Work Description:**
This program is for the replacement of substation power transformers that are at the end of their useful life and cannot be maintained in a reliable operating condition. The scope of the transformer replacement includes the installation of a moat containment system (if necessary) for the vault, a new fire protection system, and a transformer condition monitoring system. This program also includes the procurement of spare units to facilitate quick replacement of failed transformers.</td></tr>
<tr><td colspan="2">**Justification Summary:**

There are 422 power transformers on the system, of which 185 have been in service for over 40 years. As a transformer ages, more corrective maintenance is required and the risk of in-service failure increases. In-service failures impact reliability because they can occur at high load periods and/or be coincident with other outages. Additionally, the replacement of a transformer typically takes several weeks. In-service transformer failures also pose substantial environmental and safety risks due to the possible rupture of the main tank and subsequent oil release or fires. Degradation of the insulation is directly dependent on the duration of time that transformers are operated at higher temperatures. Con Edison's climate change projections include longer and higher intensity heat waves. This uptick in heat events will mean that power transformers are more heavily loaded for longer periods throughout the year and possibly accelerated aging of the units. Additionally, electrification of heating (EOH) is anticipated to significantly increase in the latter part of this decade and the shift will mean that transformers will be more heavily loaded during a period of the year (winter time) that they were not previously. Given fleet demographics, the lead time in replacing a failed transformer, the risks associated with in-service failures, the anticipated increase in heat waves and EOH the planned replacement of transformers must be increased from three units to eight units per year.</td></tr>
</table>

During the past two decades, an increased replacement frequency of power transformers is positively associated with a significant reduction in the number of failures comparing to those in the prior two decades. Proactively replacing higher risk units reverses the increasing trend of failure rates against age and lowered the failure rates in the older population to a level associated with random failures (please see Figure 1)
Given the fact of an aging transformer fleet, more proactive replacements per year will be needed to reduce in-service failures and maintain current reliability levels. The Company's analysis indicates that eight proactive replacements are required to maintain current reliability levels. Maintaining the proactive replacement rate at three units per year would lead to higher failure rates in later years. Eight or more proactive replacements per year would yield a decreasing failure rate across the next five years.

Figure 1



The Company's climate pathway suggests that over the coming decades, there will be more days per year with maximum daily temperature above 95 degrees F. A current baseline of four such days per year (on average) could increase to eleven days in the 2030s. Increased frequency of high ambient temperature days will mean that transformers are operating in challenging conditions more often, as well as being more heavily loaded as hot weather translates to higher electrical demand. These factors could lead to an increase in transformer failure rates over the course of the next ten years.

EOH will put a higher demand on the electric system, including transformers in the next decade or so. Varying network to network, EOH may introduce a winter peak that is similar to current summer peaks. This pattern would not necessarily trigger a substation expansion or other load relief measure (because design criteria would still be adequate) but would mean that a particular set of transformers in a substation are subjected to significantly higher demand than what was previously seen in the winter. This second peak in demand reduces the available time to take scheduled outages for maintenance or replacements and would accelerate aging of the insulation, ultimately leading to an increase in failure rates over the next ten years.

Analyses performed on impacts of proactive replacements on fleet average age and future fleet age profile come to the same conclusion: an annual rate of eight proactive replacements is optimal. With this higher proactive replacement rate, the in-service transformer failure rate is expected to remain low, close to random failure rates, and thus help to maintain system reliability, employee and public safety, and environmental responsibility. As heat events increase and electrification of heating occurs, failure rates may increase, if fewer than 8 proactive replacements per year are done in the next five years. It is imperative that the Company proactively replace at least eight transformers per year and potentially increase that target in subsequent years. Moreover, an increased flat annual replacement rate may help Con Edison to avoid a "replacement wall" of transformers, resulting in a more predictable budget and manageable outage scheduling.

Planned Work 2022

Spring

- Avenue A Substation– Transformer #2 – Complete Replacement
- East 63rd St Substation – Transformer #6 – Complete Replacement
- Fresh kills Substation – Transformer #21W (plus a L&P) – Complete Replacement

Fall

- Corona Substation – Transformer #6 – Begin and Complete Replacement
- Granite Hill Substation – Transformer #2 – Begin and Complete Replacement
- E179th St Substation – Transformer #1 –Retirement of Bank

Planned Work 2023

Spring

- W 42nd St Substation – Transformer #9 – Begin and Complete Replacement
- Parkchester Substation – Transformer 5S – Begin and Complete Replacement
- Corona Substation – Transformer #5 – Begin and Complete Replacement

Fall

- East River Substation – Tie Transformer #1 – Begin and Complete Replacement
- E 13th St Substation –Transformer #17 – Begin Replacement
- Fresh kills Substation – Transformer #TA-1 – Begin Replacement
- Millwood Substation – Transformer TA-1 – Begin Replacement

Relationship to Broader Company Plans and Initiatives (e.g., Long-Range Plans, CLCPA Initiatives, Risk Mitigation):

This program mitigates probability of the Substation Operations Departmental Risk Equipment Failures. By proactively replacing transformers, it is anticipated that the frequency of in-service failures will be reduced.

Climate Change and Resiliency:

As discussed, EOH and increase frequency of heat events may result in increased failure rates for substation transformers. Additionally, EOH may produce winter peaks that prohibit scheduled outages for more days per year. In order to minimize in-service failures from these climate related phenomena, at least eight transformers per year must be replaced.

2. Supplemental Information

Alternatives

An alternate strategy would be operating the transformers until failure. This strategy has been rejected because failures can occur at inopportune times, leading to customer outages, as well as result in large repair costs and can have environmental impacts.

Risk of No Action

Failures can occur at inopportune times, leading to customer outages resulting in large repair costs and can have environmental impacts. The lack of a replacement strategy would lead to a deteriorated transformer fleet that could not maintain system reliability.

Non-Financial Benefits

The project will result in a reliable transformer fleet, leading to reliable service and greater customer satisfaction. Besides reliability benefits, an increased flat annual replacement rate may help Con Edison to avoid a "replacement wall" of transformers, resulting in a more predictable budget and manageable outage scheduling.
Summary of Financial Benefits and Costs (attach backup) 1. Cost-benefit analysis: N/A 2. Major financial benefits Benefits include the avoided cost of a possible environmental impact, damage to neighboring equipment or property due to failure. Also, a typical replacement would be less costly than a failed unit. 3. Total cost **$508,000** 4. Basis for estimate: The annual funding is based on completing 8 transformer replacements at an estimated unit cost of $15.5M. The unit cost is based on an order of magnitude estimate for a recent transformer project. 5. Conclusion: N/A
Project Risks and Mitigation Plan **Project Risks:** Risk 1: **Outage scheduling conflicts with other initiatives.** Mitigation: Outages to be coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs to avoid conflict with other program/ projects resulting in a more predictable budget and manageable outage scheduling. Risk 2: **Lack of alignment between resources support and outages.** Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction to avoid alignment conflicts with outages.
Technical Evaluation / Analysis: The transformer replacement strategy is condition based. The condition and health of the transformers have been determined using several different assessment tools: one is an on-going research project with EPRI (Electric Power Research Institute) for the Intelligent Fleet Management of our transformers, which has led to the development of a program to evaluate transformers through data-based repair/replace decisions. Additionally, a similar one-time study was completed by ABB, which has worldwide experience with transformer design and manufacturing, along with a health-index ranking tool developed by Equipment and Field Engineering, a section of Central Engineering. As a result of all these programs, transformers are evaluated and prioritized for replacement. All retired transformers are inspected and tested to assess the condition of each transformer. An additional program was initiated in 2010 to assess the condition of transformer insulation by testing every transformer for Furans. Analysis of the transformers that have been selected for replacement has confirmed a proper replacement selection.
Project Relationships (if applicable) Transformer outages are required for replacement. Outages are coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs with the outage or to avoid conflict with other program/ projects.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	51,364	53,218	46,110	53,888		44,976
O&M						
Retirement	2,494	4,469	4,447	2,194		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	40,000	124,000	124,000	124,000	96,000
O&M*					
Retirement	4,500	4,500	4,500	4,500	4,500

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	5,435	16,929	16,995	17,020	13,201
M&S	16,800	52,080	52,080	52,080	40,320
Contract Services	4,800	14,880	14,880	14,880	11,520
Other	1,926	6,058	5,990	5,976	4,748
Overheads	11,039	34,053	34,055	34,045	26,211
Subtotal					
Total	**$40,000**	**$124,000**	**$124,000**	**$124,000**	**$96,000**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations/System & Transmission Operation
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: System Operations Enhancements	
Project/Program Manager: Richard Scholz	**Project/Program Number (Level 1):** 21925929
Status: ☐ **Initiation** ☐ **Planning** ☐ **Execution** ☒ **On-going** ☐ ☐ **Other:** ___________	
Estimated Start Date: 1/1/2022	**Estimated Date In Service: 12/31/2025**
A. Total Funding Request ($000) **Capital: $2,200** **O&M: $800**	**B.** ☒ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M: $800** **Capital: 0**	**D. Investment Payback Period: (Years/months) (If applicable)**

Work Description:
These enhancements will allow the District Operators at the energy control center (ECC) and alternate ECC (AECC) to issue groups of operating orders to various field operations groups through an automated process using predefined sets of operating orders based on standardized jobs. Major software changes and new applications need to be developed to support this enhanced processing sequence and its system dependencies. This project provides tools and applications that focus on improving the operators' effectiveness, helping to reduce manual transfer of data between systems, provide automated guidance when actions are necessary, and check work orders against predetermined rules to ensure proper instructions are given to field organizations.

This project will further automate parts of the electrical operating order process by utilizing a computer directed format to set up an automated sequence of operating orders. This will be accomplished by making use of existing systems and through the deployment of new interfaces. These systems, new and existing, will interface seamlessly with one another. For example, an Out of Service Work Permit (OSWP) request application that is given to the control center by email and manually transferred by the operator will now be directly uploaded into Feeder Management System (FMS)/ Transmission Operation Management System (TOMS) for the District Operators to review and process, helping to eliminate the manual data transfer step.

Justification Summary:
The District Operators perform over 500,000 operations per year. The sheer volume of work, coupled with the complexity of the systems, the variety of equipment types, and associated set of operating rules and requirements make the District Operators' job extremely challenging. The District Operators coordinate and directs all switching operations and permits to work on Con Edison's transmission and distribution systems, ensuring safety to personnel and safe operation of equipment while minimizing downtime.

These process automation enhancements will improve the operating environment by eliminating routine handoffs, allowing the District Operators to devote more time to analyzing complicated situations thoroughly prior to issuing orders. This reduces the opportunity for an operating error while also improving feeder restoration time.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
This project is related to reducing the likelihood of the System and Transmission Operations departmental risk of Operating Error. Continuous improvement in District Operator Systems is paramount to safe and reliable feeder operations. Without new hardware and systems, field activities will be impacted and delayed, causing unsafe conditions.

2. Supplemental Information

Alternatives
There are no alternatives.

Risk of No Action
Risk 1
Less efficiency and flexibility to work with changing field processes, less reliability, and less secure systems.

Risk 2
Unsafe work conditions across the entire electric network

Non-Financial Benefits
This project will also allow for safer operating environment; safer field switching; more productivity.

Summary of Financial Benefits and Costs (attach backup)
These enhancements will support the effort to continuously improve our operating efficiency by increasing the productivity of field and substation personnel as well as reducing feeder-processing time. The total capital cost between 2022 and 2026 is estimated to be $3.0M. These enhancements will support the effort to continuously improve our operating efficiency by increasing the productivity of field and substation personnel as well as reducing feeder-processing time.

Project Risks and Mitigation Plan

Technical Evaluation / Analysis

Project Relationships (if applicable)

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Actual 2021
Capital	407	495	465	91		131
O&M						
Regulatory Asset						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	400	400	400	500	500
O&M*					
Regulatory Asset					

Capital/Regulatory Asset Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	48	48	75	93	93
M&S					
Contract Services	318	318	280	351	352
Other					
Overheads	34	34	45	56	55
Total	**400**	**400**	**400**	**500**	**500**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M	160	160	160	160	160
Capital					

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Transformer Vault and Structures Modernization	
Project/Program Manager: Jane Shin	**Project/Program Number (Level 1): 10029254, 10029333, 10029383, 10029458, 10029530**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other: ___________**	
Estimated Start Date: ongoing	**Estimated Date In Service: ongoing**
A. Total Funding Request ($000) **Capital: 166211** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:
This program provides funding for proactive repair of structural deficiencies in deteriorated transformer vaults, manholes and service boxes. If unrepaired, structural deficiencies in deteriorated vaults present a risk of collapse that can be a hazard to the public and can compromise system reliability by causing damage to electric infrastructure. Program funding has been increased in order to reduce the number of on-hand structures identified with deficiencies.

The program objectives are to identify and prioritize structures with defects and proactively repair those defects. Proactive repair of structures is significantly less costly than repair after collapse.

Structural deficiencies found include settlement, cracked concrete, spalled concrete, collapsed walls, collapsed ceilings, corroded steel beams and columns, and corroded rebar. These deficiencies involve deteriorated roofs, walls, and floors. Repairs require significant rebuild involving steel, concrete, and masonry components along with the associated inspection, excavation, waterproofing, and backfill/restoration tasks.

This program addresses any civil work required to fix these structures that is ruled capital.

Justification Summary:
Severe structural deficiencies must be addressed due to the following:

- Public safety risks related to slips, trips or falls, sunken roofs, or structural collapses
- Employee injury risk due to falling concrete or structural collapses

- Reliability risk due to damaged transformers and cable from falling debris
- Impact to customers due to water intrusion at customer service entrances
- Fines from the municipalities due to settled and defective structures

At locations where temporary steel plates and barricades are installed, these plates present trip/fall hazards along with the potential for city fines. In addition, steel plates prevent air-flow to structures reducing the capability of transformers may impact system performance during summer peak periods.

Transformer vault defects and repairs are prioritized based on electrical deficiencies and other external factors, such as:

- Customer complaints
- Mitigation of potential lawsuits
- Coordination with other Company priority programs

Structural repairs incorporate the latest engineered materials including epoxy-coated rebar, concrete roof waterproof membranes, embedded steel beams, anti-corrosive galvanizing paint over beams, and welds and enhanced cathodic protection.

Relationship to 5-Year and Long-Range Plans and Enterprise Risk Management Strategy

Through the Company's Enterprise Risk Management (ERM) program, Con Edison manages an array of risks, including those associated with system reliability and employee and public safety. Our ERM program considers operational risks and identifies capital and O&M investments that prevent, detect and respond to such risks. The Transformer Vault Modernization program increases the reliability of non-network feeders by proactive renewal (replacement or substantial overhaul) of failure-prone underground structures that house network transformers.

The Risk Management sub-section of the Electric Long-Range Plan (ELRP) goes on to state that part of its minimization of risk to employee and public safety is "proactive replacement of high-risk components" and the use of "data and analytics to prioritize the Company's response to any potential problems revealed". The Transformer Vault Modernization replacement program does just that for underground structures that house network transformers.

2. Supplemental Information

Alternatives

The alternative to performing structural repairs is to install temporary shoring within structures to address imminent collapse. However, since degradation is progressive, repairs must eventually be completed. The Company devotes significant effort to evaluating and prioritizing structural deficiencies to reduce costs. Deficiencies initially identified during inspections by field crews are further evaluated by engineering personnel to ensure that they are properly categorized and prioritized. The structural deficiencies deemed significant after evaluation must be addressed as they pose safety risks to the public and Company personnel as well as to the equipment.

Risk of No Action

Failure to address deteriorated structures will risk the safety of the public and Con Edison employees, impact system reliability, and expose the Company to fines from New York City.

Non-Financial Benefits
The non-financial benefits of this program are:
- Improved public and employee safety
- Improved system reliability
- Improved relationships with external stakeholders

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis (if required)

2. Major financial benefits
The financial benefits of this program are:
- Extending the useful life of Company assets and thereby reducing costs
- Reducing the costs associated with fines from NYC due to structural defects
- Reducing the number of environmental events related to oil release from transformers

3. Total cost

4. Basis for estimate
Cost estimates used for this project are based on the following:
- Active vault repair contract
- Active area trenching contract
- Repairs completed by Subsurface Construction

5. Conclusion
This program is necessary and needed to reduce public safety risk, reduce employee injury risk, increase reliability of the network, and extend the useful life of the company's assets.

Project Risks and Mitigation Plan

Risk 1	Mitigation plan
Risk 2	Mitigation plan

Technical Evaluation / Analysis
The following photos show the condition of some actual structures:

Figure 1: Collapsed roof

Figure 2: Corroded beam

Figure 3: Delaminated concrete and debonding rebars - rood replacement is required

Project Relationships (if applicable)

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	**18,359**	**12,042**	**16,050**	**21,551**		30,163
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**21,506**	**41,103**	**42,266**	**43,465**	**17,871**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	4,574	8,742	8,990	9,245	3,801
M&S	1,858	3,551	3,651	3,755	1,544
Contract Services	7,303	13,958	14,353	14,760	6,069
Other	48	91	94	97	40
Overheads	7,723	14,760	15,178	15,609	6,418
Subtotal	**21,506**	**41,103**	**42,266**	**43,465**	**17,871**
Contingency**					
Total	**21,506**	**41,103**	**42,266**	**43,465**	**17,871**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Central Operations/ Substation Operations
2022

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Transmission Station Metering and SCADA Upgrades Program	
Project/Program Manager: Karen Bruce	**Project/Program Number (Level 1):** PR.21510977
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date: Ongoing	**Estimated Date in Service: Ongoing**
A. Total Funding Request ($000) **Capital: $14,946** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

In recent years, the number of outstanding deficiencies and faulty equipment on the Company's systems for the Bulk Electrical System (BES) has increased. A system wide survey is performed daily to log metering and SCADA deficiencies, and determine possible additional deficiencies, that may impact the reliable operation of the Company's electric system, as well as to identify conditions that do not comply with Company specifications and/or regulatory requirements. The results of this survey are tabulated and used to prioritize and implement any necessary remediation measures, often in the form of capital work. Equipment to be addressed includes Coupling Capacitor Potential Devices (CCPDs), Potential Transformers (PTs), Current Transformers (CTs), Bushing Potential Devices (BPDs), metering transducers and intelligent electronic devices (IEDs), and associated cabling.

These existing deficiencies are classified into different groups depending on the cause of the problem and the approach to be taken for their resolution. To date, we have identified several program categories, including, but not limited to:

- Unavailability of devices: This category will include all metering devices, instrument transformers, and wiring that are malfunctioning, obsolete, or had been previously removed or retired in place. In this case, the system will be re-engineered to be functional per latest requirements, and new equipment will be installed.
- Lack of accuracy: Aging and underrated equipment will fall in this category. These devices will be upgraded to at least meet the minimal requirements set by the regulatory bodies. New settings and configurations will be reissued when applicable, unless further material upgrades are needed.
- Compliance with regulatory requirements: This category will include metering that is required by regulation or policy. Work from this category generally requires more extensive effort because the metering system may be non-existing and will have to be fully designed and implemented. Additional

opportunities to bring legacy metering into compliance with current standards will be reviewed in conjunction with major modifications to transmission station equipment and protective relaying.

Stations currently identified for upgrade include, E179th Street, Farragut, Sherman Creek, Sprainbrook, Goethals and Dunwoodie 345kV/South/North. Additional substations will be evaluated and are expected to be recommended for replacement under this program.

Justification Summary:

The State Estimator (SE) is a program that uses available real-time telemetered analog measurements (e.g., MW, MVAR, Amps, kV) and digital measurements (e.g., breaker status, switch status) to determine or estimate a consistent set of voltages (magnitude and phase angle) at each node where metering is available. Using the set of estimates (solution), the SE calculates other quantities (e.g., branch flows, loads, tap information) to compare their corresponding measurements and provides them to the contingency analysis (CA) program to use in running what-if scenarios and providing the operators with alerts and valuable data. The accuracy of the SE is proportional to the measurement accuracy and redundancy. The more accurate the telemetered data and the more sources available for a specific measurement, the more accurate the solution.

The accuracy and availability of metering, SE, and CA systems is also tied into and governed by various regulatory requirements. In addition, the North American Electric Reliability Corporation (NERC) Event Analysis Program (EAP) requires that loss of the SE or contingency analysis capability lasting 30 continuous minutes or longer be reported. Also, the Company is registered as a Transmission Operator (TOP) as of July 1, 2016. NERC EOP-004 requires the same but with an additional form and tighter timeframe, and NERC standard TOP-006-2 on Monitoring System Conditions requires the "use [of] sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations" (Requirement 6). These standards are based on New York Independent System Operator (NYISO) Manual 21. Furthermore, TOP-010, a NERC standard, establishes certain quality guidelines for real-time monitoring and analysis capability available to BES operators. The current draft requires operators to have visibility of data quality discrepancies (e.g., data outside of a prescribed data range or not updated within a predetermined time period).

References from the Final Task Force Report on the August 2003 Blackout: "A principal cause of the August 14 blackout was a lack of situational awareness, which was in turn the result of inadequate reliability tools and backup capabilities…The need for improved visualization capabilities over a wide geographic area has been a recurrent theme in blackout investigations. Some wide-area tools to aid situational awareness (e.g., real-time phasor measurement systems) have been tested in some regions but are not yet in general use. Improvements in this area will require significant new investments involving existing or emerging technologies."

Undoubtedly, lack of accurate and reliable telemetered data and the loss of SE or CA due to lack of accurate and reliable telemetered data would result in regulatory liability, reputational damage, and decreases in reliability.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):

This program affects the Substation Operations risk "Equipment Failures". This program reduces the severity of equipment failures. Projects completed under this program reduce the severity of equipment failures by restoring/replacing equipment that has failed.

2. Supplemental Information

Alternatives
• Repair existing metering equipment and restore to original configuration. This alternative would restore non-functioning metering points to the SE, however this alternative may not improve the accuracy of the restored metering data points because of the low accuracy class of the older type PTs, CCPDs and CTs. Older transducer models are obsolete and no longer manufactured. Additionally, legacy circuit breaker Bushing Potential Devices (BPDs) that provide voltage to metering systems, are often unreliable and obsolete. For these reasons the repair alternative is not recommended as a long-term system-wide solution.

Risk of No Action
No action will leave the system in a heightened state of risk and will place Con Edison at risk of regulatory liability. There is also diminished operational capability that may impact transmission and distribution system operability and reliability.

Non-Financial Benefits
Non-financial benefits include increasing operational visibility and the operator's ability to effectively control the system. Additional benefits include the possible deferment of projects intended to increase power system capacity.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis: N/A

2. Major financial benefits: N/A

3. Total cost: **$14,946**

4. Basis for estimate: Engineering Estimate

5. Conclusion: N/A

Project Risks and Mitigation Plan

Risk 1: Outage scheduling conflicts with other initiatives.

Mitigation: Outages to be coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs to avoid conflict with other program/projects resulting in a more predictable budget and manageable outage scheduling.

Risk 2: Delays due to resource support coordination.

Mitigation: Anticipate, schedule, and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delay alignment conflicts.

Risk 3: **Lack of alignment between resources support and outages.**
Mitigation: Anticipate, schedule, and pre-plan with resource requirements such as engineering, labor, and construction to avoid alignment conflicts with outages.

Technical Evaluation / Analysis: Substation metering in many stations was built using single-phase voltages and currents, connected to single-element (Amps, Volts, MW, MVAR) transducer style meters and corresponding mechanical gauges. Transducers typically have a 0-1mAmps output connected to the remote terminal unit (RTU), often via the legacy System Operation Control Computer System (SOCCS) interface system, sometimes using scaling resistors. Each component and wire path are potential failure and error points, and more recently transmission facilities have experienced increased transients due to the presence of unshielded cables and grounding system performance issues.

New and upgraded metering will comply with specification CE-ES-2002 Part 51 – Realtime Metering, with 3-phase measurements, 0.3% accuracy instruments, and digital IEDs powered from station DC systems. SCADA enhancements will comply with Company and industry standards using similar IEDs, with a focus on more comprehensive and granular alarm and indication point assignments. All new and upgraded metering and SCADA points will be verified for functionality and accuracy at the station RTU and Energy Control Center level, which will also verify communication paths. New network and communication equipment may be needed to connect new/upgraded metering IEDs to the station RTU. New cables will comply with Company and industry standards for grounding and shielding of copper cables, with a preference to expand the fiber optic network for longer distances within the stations.

There are synergies with multiple Company programs in terms of engineering packages and outage planning.

Project Relationships (if applicable): This project has synergy with the following programs: High Voltage Breaker Replacements, Failed Station Equipment, Relay Modifications, Automation, RTU Upgrades, and Reinforced Grounding Grid.

3. Funding Detail

Historical Spend ($000):

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	2,298	775	924	1,147		962
O&M						
Retirement	53	24	16	11		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**$2,566**	**$3,182**	**$3,066**	**$3,066**	**$3,066**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	975	1,209	1,165	1,165	1,165
M&S	0	0	0	0	0
Contract Services	732	917	885	886	895
Other	0	0	0	0	0
Overheads	859	1,056	1,016	1,015	1,005
Subtotal	0	0	0	0	0
Total	**$2,566**	**$3,182**	**$3,066**	**$3,066**	**$3,066**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

1. Project / Program Summary

Type: ☐ Project ☐ Program	**Category:** ☐ Capital ☐ O&M
Work Plan Category: ☐ Regulatory Mandated ☒ Operationally Required ☐ Strategic	
Project/Program Title: Underground Secondary Reliability	
Project/Program Manager: Andrew Reid/Mark Riddle	**Project/Program Number (Level 1): 10031254, 10031241, 10031302, 10031340, 10031447, 10031929**
Status: ☐ Planning ☐ Design ☐ Engineering ☐ Construction ☒ Ongoing ☐ Other: ____________	
Estimated Start Date:	**Estimated Date in Service:**
A. Total Funding Request ($000) **Capital: 243,000** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

<u>Work Description</u>:

The Underground Secondary Reliability Program is an existing and ongoing program that proactively replaces and upgrades underground secondary equipment and facilities. This program reinforces secondary network infrastructure by replacing and upgrading underground structures, conduits, transformers and cable. The Underground Secondary Reliability Program addresses both system design and public safety through different subprograms and is structured to leverage sensor data and analytical tools that determine priority and corrective action. This program is optimized with related programs to find the most favorable solution to generate improvements in reliability and public safety while maintaining desired levels of efficiency and managing cost.

1. **System Design**

System Design focuses on work associated with maintaining the highly reliable network design basis. System design considerations include contingency, reinforcement, and proper equipment operation. Program units and schedule for System Design are shown in the table below.

Underground Secondary Reliability – System Design					
Type (Units)	**2021**	**2022**	**2023**	**2024**	**2025**
UG Conduit (Trench Feet)	7,900	8,500	9,000	9,500	9,500
UG Manhole Vault (Number)	5	10	15	15	15
UG Secondary Main Cable (Sections)	500	500	600	650	650
UG Service Box (Number)	20	30	30	30	30
UG Service Cable (Sections)	115	120	125	130	130
UG Service Conduit (Trench Feet)	1,500	1,800	2,000	2,200	2,200

2. Secondary Rebuild

Secondary Rebuild proactively replaces secondary equipment and mains in order to reduce the number of energized objects (streetlights, manhole covers, etc.), outages, and manhole events. The program's goal is to reduce the present five-year manhole events average by over 5% starting in 2022. To accomplish this goal, this program targets structures that have combinations of aluminum and 4/0 mains, experienced an Underground Secondary Event (UGSE) – smoke, fire or explosion, and use of wood or wood-fiber ducts. Replacements are separated into three groups based on the combination of these attributes:

1. Tier 1 replacements include structures with recent UGSEs, aluminum, 4/0 cable and wood(fiber) conduit
2. Tier 2 replacements include strictures with recent UGSEs, aluminum and 4/0 cable, but no wood(fiber) conduit
3. Tier 3 replacements include structures without recent UGSEs but that do contain aluminum or 4/0 cable and wood(fiber) conduits

Program units and schedule for Secondary Rebuild are shown in the table below.

	Underground Secondary Reliability – Secondary Rebuild				
Type (Units)	**2021**	**2022**	**2023**	**2024**	**2025**
UG Conduit (Trench Feet)	9,800	10,500	15,500	15,500	15,000
UG Secondary Main Cable (Sections)[1]	450	450	550	550	550

3. Secondary Service

Secondary Service Replacement program focuses on the replacement of service cables selected analytically based on performance or by inspection finding.

Program units and schedule for Secondary Service Replacement are shown in the table below.

1. Underground Secondary Reliability – Secondary Services					
Type (Units)	**2021**	**2022**	**2023**	**2024**	**2025**
UG Service Conduit (Trench Feet)	3,300	9,750	8,000	7,800	7,800
UG Service Cable (Sections)	265	880	875	870	870

4. Emergent Services

The Secondary Reliability Program will also include crab and main replacement work associated with hotspot findings from the enhanced inspection program.
Emergent Reliability includes work associated with new initiatives including enhanced inspection for non-visible defects and changes to the system design basis such as half element limiters.

Enhanced Inspection utilizes Infrared camera technology and current measurements to detect visibly hidden defects and prioritize their correction. Correction can range from the remaking of a single connection to the full replacement of cable sections and crabs depending on the condition of the cable and crabs in the structure.

Half-element limiter adds limiters to locations in the network that will isolate the smallest possible section of faulted equipment in the shortest time. These additional limiters will help minimize collateral damages and number of UGSE.

Program units and schedule for Emergent Reliability work are shown in the table below.

Underground Secondary Reliability – Emergent					
Type (Units)	**2021**	**2022**	**2023**	**2024**	**2025**
Half-Limiters crabs (each)	20	50	50	50	50
Non-visual Detection -VDC(Structures)					
▪ Cameras	30	30	30	30	30
▪ Cut & Rack	5	10	10	10	10
▪ UG Secondary main Cable (Sections)	50	50	50	50	50

Program units and schedule for Underground Secondary Reliability in total are shown in the table below.

Underground Secondary Reliability – Program Totals					
Replacements (Units)	**2021**	**2022**	**2023**	**2024**	**2025**
UG Mains Conduit (Trench Feet)	17,700	20,000	25,000	25,000	25,000
UG Manhole Vault (Number)	5	10	10	10	10
UG Secondary Main Cable (Sections)	1,000	1,000	1,250	1,250	1,250
UG Service Box (Number)	20	30	30	30	30
UG Service Cable (Sections)	380	800	1,120	1,125	1,130
UG Service Conduit (Trench Feet)	4,800	9,600	11,550	11,600	11,650
Half Limiters Crabs	20	50	50	50	50
Cut & Rack(structures)	20	20	20	20	20
IR Cameras	30	30	30	30	30

Justification Summary:
Damage to the secondary system is generally harder to identify compared to the primary system due to the redundancy of the secondary grid, magnitude of assets, and limited presence of remote monitoring equipment beyond the network transformer. As a result, many conditions are not found until they result in a customer outage, manhole event (smoke, fire, and explosion) or stray voltage condition. Moreover, the failure of a secondary cable may also result in collateral damage immediately by way of fire or explosion and in the future from the stresses created by short circuit currents. Since these conditions can lead to hazards to the public or prolonged outages, maintaining the safety and reliability of the secondary grid is a priority. Networks and structures will be targeted for proactive secondary mains and services replacement based, in part, on performance, build, and defect conditions. Additional treatments, such as limiters and structure fill will also be utilized to minimize risk.

In an effort to manage assets and failure risk proactively, the Secondary Rebuild and Service Replacement programs seek to make cable and connection replacements before a failure occur.
Analysis of the construction of structures that have experienced events involving property damage or injury shows approximately that 4/0 cable was present in 50% of cases, wood or wood-fiber duct in 30% and aluminum cable in

17% of events. The Secondary Rebuild Program will thus focus on structures having the greatest combinations of these attributes.

In an average year, more than 1,800 utility side sources of contact voltage are discovered and mitigated. These sources are discovered through existing programs that scan for contact voltages on street level publicly accessible metallic objects and through customer call-in reports. From these detections, compromised underground services account for approximately 50% of the sources to energized objects. The goal of Services Replacement program is to identify and replace these compromised services before they present a danger to the public or employees by inadvertently energizing street level metallic objects or metallic objects within the customer premises.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

The Corporate and Department Risk impacted by this program is the Low Voltage Distribution Equipment Failure. This risk is defined as a low voltage distribution cable failure injures the public or employees. The proactive removal and/or replacement of low performing secondary cable is the long-term strategy to mitigating this risk.

2. Supplemental Information

Alternatives

Alternative #1 **Run to failure**

Assets can continue to be run to failure with risk mitigation through other public safety programs such as stray and contact voltage testing, inspection, etc. vented covers installation, etc. While all of these contribute to risk mitigation, they are not long-term solution as there are still thousands of manhole events each year.

Risk of No Action

Risk 1

Any asset that is run to failure could result in personal injury, property damage or loss of reliability.

Risk 2

Failure to maintain minimum thresholds of performance could result in the company having to pay fines, or trigger Revenue Performance Mechanisms, or other Regulatory Actions.

Non-Financial Benefits

The primary non-financial benefit of this program is an improvement to public safety. With full program support, by 2025 the five-year manhole event average should be reduced by at least 5% or approximately 100 events per year, of which 4-8 would be significant manhole fires or explosions involving property damage or injury. During the first five years of the program, Tiers 1 and 2 would receive cable and connection replacements. All structures would receive a treatment including Latched Cover, monitoring/or vented cover.

Additionally, this program will contribute to a reduction in emergency response time, particularly during peak event periods (such as storms), since fewer emergency events will occur. It will also contribute to a reduction in troubleshooting time since defective equipment will be replaced before creating an energized object which can be time consuming to diagnose.

Finally, customer satisfaction will be improved by the increased reliability.

Summary of Financial Benefits and Costs (attach backup)

Every event avoided represents an emergency response not performed, an open main not created, and potential property damage and/or injury avoided. Thus, for the prospective 100 events avoided, an operations cost savings of $0.5M per year is expected. Energized objects take an average of eight man-hours to investigate and make safe. An estimated reduction of 100 energized objects per year would equate to approximately 800 man-hours or $80,000 saved in labor costs.

Additionally, the increased reliability and inspection rate that will result from this program will lower the Company's exposure to regulatory fines.

5. Conclusion

Project Risks and Mitigation Plan

Risk 1 Mitigation plan

The risk of cost overruns are a real possibility, the estimates to complete work and achieve project objectives were based on a historical duct replacement of 20-25% of the work to be executed and a further 20% on complimentary structure activities in nearby structures. Should these percentages be overcome, cost over runs may occur. To mitigate against costs overruns, a thorough tracking system will be enforced to ensure that the correct expenses are allocated to our project and implement a reduce work scope to match funds.

Risk 2 Mitigation plan

The company operates the electric system to achieve the highest levels of safety and reliability. To accomplish this, the company plans and organizes to the best of its ability but changing conditions result in reprioritization to meet the real-time needs of our customers. Such reprioritization is often driven by system emergencies that diminish capability. This can result in extended project timelines and prevent completion of proactive programs like this one. To mitigate that, the company is leveraging strategic planning and analytical tools to coordinate proactive secondary cable replacement with Open Mains (a reactive program) and other relevant work in any given structure. This can help mitigate the risk as well as drive improvements in operational efficiencies.

Technical Evaluation / Analysis

Compromised secondary main cable failure has the potential to inflict serious injury to employees and members of the public as well as to cause damage to property. Events of this nature have historically been viewed as predominately random. After analysis, these drivers are common to the greater percentage of these events. Preemptive action on this asset group will significantly reduce their probability to trigger a future occurrence.

Our findings reveal that those structures with a pre-event build of aluminum and/or 4/0 type cables experience UGSE's at a rate of up to four times that of 500 Circular Mils (MCM) cable, when normalized to their system population. Additional observations have revealed:

1. In instances where the aluminum and 4/0 traverse a wood and/or wood-fiber conduit, the public safety impact is greater as Carbon Monoxide gases are produced in greater quantities as both the cable and the conduit are consumables in the fire. The additional consumable also protracts the duration of the event.
2. It has been observed that approximately 20% of structures with an event in any given year will experience another event within the following five years. This rate of reoccurrence likely reflects that the stresses from one cable's failure can cause collateral damage to adjoining cables, leading to a repeat event.

Compromised secondary service cable (e.g. supplying streetlights & residences) accounts for approximately 50% of the energized object sources. The potential to inflict both serious injury to employees and members of the public is a real possibility. Historically, events of this nature have been viewed as predominately random. However, after a similar analysis, drivers for these events have also been determined.

For example, analysis has revealed that the rate of energized equipment (ENE) generation is higher in areas with lead mains and services. The rate of ENEs can be up to four times that of other mains and services cable when normalized to system populations. In winter periods, lead insulated cables can account for almost 45% of the publicly accessible electric shocks, even though the lead cable population is less than 15% on the system.

The half-limiter program will install limiters with approximately half the current pickup and clearing time of existing limiters. These crabs will be installed starting with midblock locations of appropriate loads. These limiters will a) increase sectionalizing, thus reducing collateral damage and potential outage, and b) improve clearing times thus, reducing stresses on the cables.

The AMI street and traffic lights Contact voltage detector. Will be mounted on the selected street and traffic lights around the city and environs and will report dangerous conditions. This effort is aimed at improving public safety.

Project Relationships (if applicable)

- Secondary Inspection Program: eight-year cycle (PSC Mandated)
- PILC Cable Removal Program
- Vented Cover Program
- Secondary Open Mains

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	**37,342**	**28,603**	**16,128**	**19,690**		**16,616**
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**21,000**	**25,483**	**25,752**	**29,714**	**30,690**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	3,869	4,695	4,745	5,475	4,655
M&S	3,100	3,762	3,802	4,387	4,531
Contract Services	3,212	3,898	3,939	4,545	4,694
Other	2,882	3,497	3,534	4,078	4,212
Overheads	6,273	7,612	7,692	8,875	9,167
Subtotal	**19,336**	**23,464**	**23,712**	**27,360**	**27,259**
Contingency**	1,664	2,019	2,040	2,354	3,431
Total	**21,000**	**25,483**	**25,752**	**29,714**	**30,690**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance	80	80	80	80	80
Capital Savings					
Capital Avoidance	500	500	500	500	500

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Unit Substation Modernization	
Project/Program Manager: Felipe Valverde	**Project/Program Number (Level 1):** 23492822
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date:	**Estimated Date In Service:**
A. Total Funding Request ($000) **Capital: $3,209** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period:** **(Years/months)**

Work Description:

This program funds Unit Substation Transformer enhancements through the installation of new Supervisory Control and Data Acquisition (SCADA) capable tap changer position indicators, electronic temperature gauges, Nitrogen pressure, temperature, and oil sensors. The program also funds their interconnection to the Company's Consolidated Distribution Management System (CDMS) to enable remote indication and control.

- Voltage regulation of the 4 kV system is provided by tap changers installed in unit substation transformers. To use the CDMS system to facilitate SCADA functions such as voltage reduction and to provide the capability of remotely de-loading transformers during a contingency, the use of remote tap changer control with accurate indication is necessary. Approximately 176 tap position indicators were installed previously. Under this program Con Edison plans to install tap changer position indicators at the remaining 15 stations at a rate of 3 installations per year.

- Unit Substations Transformers use a Nitrogen preservation system that allows for oil expansion and contraction. There are 239 transformers with about 1,000 oil-filled compartments at 15 Unit Subtations that have Oil Level and Nitrogen Pressure sensors that currently do not have any remote monitoring. Con Edison is planning to install the necessary SCADA equipment to bring the monitoring to the operators' displays. Con Edison will install and connect to CDMS the proposed sensors at a rate of 3 installations per year. Each installation will include all transformers located at a station.

- The existing transformer temperature gauges can provide inaccurate or unreliable temperature readings. Incorrect temperature readings could result in unit substation transformers operating beyond their temperature limits, resulting in loss of transformer life and increased risk of failure. The installation of 80 new temperature monitoring units was completed over the last eight years. There are approximately 55 locations left that require temperature monitoring units. Con Edison will install 11 new electronic temperature gauges a year.

Justification Summary:

Unit Substations transformers require accurate tap position detection and indication to effectively implement and monitor voltage reduction. The ability to execute voltage reduction increases the resiliency of the system. Voltage reduction is implemented during peak loads or contingencies to avoid overloading equipment, it allows operators to keep equipment in-service longer under such conditions avoiding customer outages. Voltage reduction also reduces the overall energy used by the system, reducing greenhouse gas (GHG) emissions and costs for customers. The addition of this component allows control center operators to be able to accurately monitor voltage reduction and enables remote adjustments through CDMS.

The Nitrogen system and the nitrogen-filled bottles require frequent visits for monitoring and bottle replenishment. The schedule-based visits may either be too late or too early for the nitrogen replacement. This may lead to establishing vacuum above the oil in the transformer. This, in turn, can lead to bubble formation in oil and premature transformer failure. If monitoring is provided remotely, the crew could be sent to replace the bottles as-needed and based on real conditions. Remote monitoring can also timely trigger CDMS alarms for maintenance of leaks detected in the preservation system.

Inaccurate temperature reading on Unit Substation transformers may result in unnecessary unit removal from service due to erroneous high temperature readings, producing unnecessary customer outages. Real-time archived temperature data provided by new monitoring units will allow for the implementation of dynamic ratings, which will help optimize the use of transformer capacity.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

This program aligns with long term goals to increase the use of analytic solutions and telemetry to provide data to inform real-time operational decisions and engineering analysis to move towards condition based maintenance and operational decisions. This removes the margins of safety necessary when working off theoretical models, and therefore allows for maximizing efficiency by providing the data to confidently deploy condition based maintenance strategies. It also allows for operating equipment to full capability as operators have feedback on key parameters giving insight into equipment conditions. This advancement in technology provides a platform on which future advancements will be built, as analytic models and applications mature, new insights will inform even more efficient and effective methods of operation and maintenance, all of which will help to meet the Company's long-term efficiency, reliability, and resiliency goals.

This program contributes to reduction in risk of customer outages due to equipment failure, which contributes to the overall mitigation of the Electric Ops Department risks related to Reliability Performance Mechanisms for reliability and major outages. The 4KV grid system is inherently reliable by design, and therefore maintaining the equipment in this system is vital to maintaining the reliability and resiliency of the system.

Unit substations are oil containing equipment, failure of such equipment could lead to oil draining to waterways. This program helps prevent equipment failure, which also mitigates this risk.

This program also enables voltage reduction capabilities, reducing GHG emissions and costs for customers, supporting efforts to meet the State's Climate Leadership and Community Protection Act (CLCPA) goals.

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection

The alternative to installing new tap changer position indicators to operate the system the same way it has been operating in the past, which is to send personnel to the substation to verify the tap position. This alternative causes a large delay between the time a decision is made to change a tap position and when the tap position is changed. Such delays may result in operational issues that damage equipment or interrupt customers.

Alternative 2 description and reason for rejection

The alternative to installing SCADA pressure and oil sensors is to increase frequency of inspection. This would increase operating costs, and abnormal conditions that occur between inspections may result in operational issues that damage equipment or interrupt customers.

Alternative 3 description and reason for rejection

The alternative to installing new electronic temperature gauges is to utilize the PT-Load software application which predicts peak transformer temperatures based on transformer data and historical load cycle and is used to determine transformer ratings. The weakness of this approach is that this software produces less accurate ratings than what can be achieved with more accurate data provided by new monitoring units.

Risk of No Action

Risk 1

Not installing transformer tap changer position indicators will prevent operators from correctly monitoring the voltage on the 4 kV grids. This has the potential to:

- Result in circulating current between stations which may overload equipment and require operational intervention to prevent damage which taxes resources during peak load periods
- Result in customer voltage outside specified limits
- Deny operators the ability to effectively implement voltage reduction during peak loads or contingencies. Voltage reduction is critical for stabilizing the system and preventing further failures during such times.

Risk 2

Lack of transformer remote nitrogen pressure and oil level monitoring could result in incorrect operator action, increased loss of transformer life, increased risk of failure and sub-optimal use of transformer capacity and consequently, unnecessary transformer replacements, increased chance of transformer failures, and environmental impact.

Risk 3

The continued use of inaccurate transformer temperature readings could result in incorrect operator action, increased loss of transformer life, increased risk of failure and sub-optimal use of transformer capacity and consequently, unnecessary transformer replacements, increased chance of transformer failures, and environmental impact.

Non-Financial Benefits

The implementation of this program will result in the more accurate operation of the 4 kV distribution systems, fewer customer outages, and will provide dynamic rating capability which will allow optimal use of transformer capacity.

Additional benefits from SCADA monitoring are identified through the monitoring essential Unit Substation transformer health data points in real-time. These new data points can be used for operations during normal and emergencies and optimize maintenance planning by reducing periodic visits though remote monitoring. In addition, the new units will provide local indication and storage of nitrogen pressure and oil levels as well as maximum temperature reached, which will allow field crews to utilize data for operations and scheduled maintenance.

Improved safety and reduced risk of oil spills (environmental impact).

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis (if required)
N/A

2. Major financial benefits

Costs associated with the replacement of a Unit Substation transformer failure is upwards of $1.5M during emergency and the environmental remediation of a potential 2,000+ gallons of oil in any given transformer can rapidly increases its estimate upon a moat failure.

3. Total cost
The implementation cost of this program is estimated at an average of $500k per year, for a total of $2,515k over the proposed 5-year program.

4. Basis for estimate
Historical unit costs from previous tap changer installation as well as the labor costs derived from the recent Unit Substation (USS)/Conservation Voltage Optimization (CVO) program are used for this estimate.

5. Conclusion

The investment benefits from this program improve the reliability and operation of Unit Station transformer while increasing operator remote monitoring through SCADA.

Costs associated with the replacement of a Unit Substation transformer failure is upwards of $1.5M during emergency and the environmental remediation of a potential 2,000+ gallons of oil in any given transformer can rapidly increase this cost upon a moat failure.

Project Risks and Mitigation Plan

Risk 1
Equipment unit-cost increase through program implementations

Mitigation plan
Proactive Procurement process to expand compatible equipment options

Risk 2
Unexpected labor force constrains due to competing higher priority programs

Mitigation plan
Proactive RFQ/Procurement process to attract and create contractor pool to aid in program implementation

Technical Evaluation / Analysis

The tap changer position indicator enables operators with the necessary remote monitoring to regulate the voltage on 4kV grids during normal and voltage reduction conditions. This eliminates circulating currents between stations which may overload Unit Substation transformers, and in turn preclude the operators from effectively stabilizing the system during system peak loads or contingencies

Real-time archived temperature data provided by new monitoring units will allow for the implementation of dynamic ratings, which will help optimize the use of transformer capacities over their lifetime.

Real-time monitoring of Nitrogen pressure, oil levels and their alarms can reduce the impact of events such as the Governor's Island incident, which resulted in a major oil spill. Almost a third of the main tank transformer oil (1,000 Gallons) managed to escape the moat through a crack and spilled into New York Harbor. The Company suffered heavy fines from several local, state and federal agencies and had to pay for the cleanup. The reason for the transformer leak was a tiny pinhole in the radiator – the result of corrosion in a salty and moist environment. An alarm about low oil level could have prevented such a large spill and limited the environmental impact from it. Due to very light load the transformer did not fail from the loss of oil in this case. However, for the oil-immersed transformers, the oil is the only heat removing medium. If the oil is removed, the winding of a transformer under normal load would overheat and fail.

Project Relationships (if applicable)

This program implementation will use a periodic review to identify potential overlapping work under the Unit Substation Transformer Replacement Program and the Unit Substation Relay SCADA Modernization to optimize scheduled resources, costs and outages.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital						**638**
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**638**	**638**	**638**	**638**	**657**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	73	73	73	73	74
M&S	0	0	0	0	0
Contract Services	513	513	513	513	528
Other	0	0	0	0	0
Overheads	52	52	52	52	54
Subtotal	**638**	**638**	**638**	**638**	**657**
Contingency**					
Total	**638**	**638**	**638**	**638**	**657**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☐ Project ☒ Program	**Category: ☒ Capital ☐ O&M**
Work Plan Category: ☐ Regulatory Mandated ☐ Operationally Required ☒ Strategic	
Project/Program Title: Unit Substation Transformer Replacement Program	
Project/Program Manager: Maksim Tsarenkov	**Project/Program Number (Level 1): 10028257**
Status: ☐ Planning ☐ Design ☐ Engineering ☐ Construction ☒ Ongoing ☐ Other: ___________	
Estimated Start Date: 2019	**Estimated Date In Service: Ongoing**
A. Total Funding Request ($000) **Capital: $21,159** **O&M:** **Retirement:**	**B.** **☐ 5-Year Gross Cost Savings ($000)** **☐ 5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

Replace the existing Unit Substation Transformers, a total of four (4) per year with new 10,500 KVA transformers. Each replacement is estimated at $1.3M including the cost of each transformer.

Justification Summary:

There are 239 4kV Unit Substation Transformers and 45 4kV High Tension Vaults in the Con Edison distribution system (total of 284 4kV transformers). They carry about 10% of the total load and play an important role in overall system reliability. Over the past 20 years, a third of these transformers were replaced with new larger banks to compensate for growing load under the Load Relief Program. However, since 2009 , there have been no proactive USS transformer. The USS transformers have only been replaced due to failures and considerations stated below. The Company analyzes the health of the Unit Substation (USS) transformers using a detailed model based on several key parameters. Further, the Company developed an Asset Class model which uses historical data to predict future failure rate based on replacement rate of the transformers. Based on this model, in order to maintain the current failure rate of under 1 transformer per year, 4 USS Transformers must be replaced, on average, every year. The USS Transformers to be replaced will be selected based on Health Index. The average age of USS transformers is now 35 years old, with approximately 100 of them over the age of 45, while the oldest units are currently 68 years old.

Below is the list of Unit Substation Transformers that are replaced as of 2021 and proposed for replacement in 2020-2025:

Year	Unit Substation	Manufacturer	KVA	Year Built
2020	Utica	GE	7000	1962
	Heathcote 23	MOLONEY	6250	1957
	Wolf's Lane 105	MOLONEY	5000	1956
	JFK Central Bank B	GE	10000	1959
2021	Tompkinsville	PENN	7000	1968
	Silver Lake # 1	PENN	6250	1958
	Canterbury	PENN	7000	1967
	Ferncliff	MOLONEY	6250	1956
2022	JFK Central Bank A	GE	10000	1959
	Hastings 9	W	6250	1953
	Primrose	GE	7000	1964
	Ralph Ave 1	W	6250	1961
2023	Lawrence Park	GE	6250	1955
	Green Knolls	GE	6250	1959
	Floral Park 2	PENN	7000	1968
	Mount Hope	MOLONEY	6250	1957
2024	Sherwood Park	W	6250	1955
	McLean 1	MOLONEY	6250	1960
	Valley Place	MOLONEY	6250	1960
	Naughton # 1	PENN-MCGRAW	10500	1967
2025	Oakwood	PENN	10500	1967
	Van Wart 92	GE	7000	1964
	Hunterbrook 1-28	W	3750	1954
	Woodlawn 75	W	6250	1961

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)
This program contributes to reduction in risk of customer outages due to equipment failure, which contributes to the overall mitigation of the Electric Ops Department risks related to Reliability Performance Mechanisms for reliability and major outages. The 4KV grid system is inherently reliable by design, and therefore maintaining the equipment in this system is vital to maintaining the reliability and resiliency of the system.

Unit substations are oil containing equipment, failure of such equipment could lead to oil draining to waterways. This program helps prevent equipment failure, which also mitigates this risk.

2. Supplemental Information

Alternatives

The alternative is to increase the number of spare transformers. This, however, carries extra cost of replacing the transformers under emergency and increased storage charges. In addition, a failed transformer creates a potential for public safety, equipment damage, and can potentially have environmental impacts.

Risk of No Action

Aging of equipment will eventually cause failures that may carry high environmental risks and jeopardize 4kV system reliability. The failure curve indicates that if left unaddressed the system will see more failures than manpower and budget can accommodate. System stability concerns may prohibit us from replacing much larger number of transformers at once.

Non-Financial Benefits

- Reliability.
- Increase in available capacity for future expansion.
- Reduced environmental impact, including total absence of PCBs in new transformers and reduction in the number of oil-filled compartments due-to new design spec.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)

2. Major financial benefits

3. Total cost
$1.3million/ Installation
4. Basis for estimate
Past and present costs of installations of 10,500 kVA USS transformers, escalation and contingency included.

5. Conclusion
See "Risk of No Action"

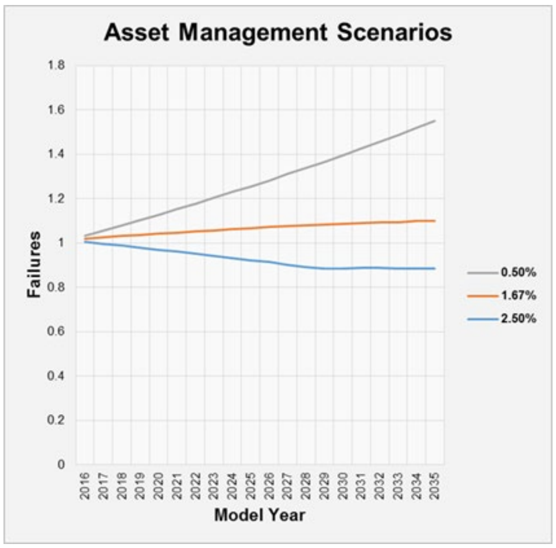
Project Risks and Mitigation Plan

Risk 1	Mitigation plan
Risk 2	Mitigation plan

Technical Evaluation / Analysis

The Company began using a model/matrix in 2016 to calculate a health index for its USS transformers. Based upon that model/matrix, units that have a score outside of the target are recommended for replacement. A USS transformer with a health index score above the goal has an increased risk of an in-service failure. The model/matrix uses the following factors in its health index calculation; Dissolved Gas in Oil Analysis (DGOA), furan test results, transformer loading, apparent corrosion, oil leaks, LTC functionality, environmental impact, proximity to public, and age. The Company plans to replace all USS transformers that have a score above the goal.

Asset Management has completed the asset class model for unit substation transformers. Based on that model, in order to maintain the current failure rate, 4 transformers need to be replaced every year. Replacement will be predicted by the asset health index.



Projection based on life-cycle model with three types of transformer, with oldest/worst transformers failing at .4% (1/239) per year, replacing with new transformers failing at 0.16% initially, and with 2.5% annual growth rate of failure rate, based on Con Edison experience in the last 15 years. Percentage replacements are as a percent of all 239 transformers, i.e., 1.67% = 4 transformers per year, including the one that might have failed.

Based on wide utility industry experience and analysis of transformer paper decomposition (ASTM D5837) there is a strong correlation between transformer's service age, its insulating paper decomposition, and its failure rate. Con Edison USS failure rate is currently around 1 transformer per year; however, if no replacements are made, as the fleet ages, the failure rate will increase. Failed transformers are invariably more expensive to replace under emergency condition, than planned replacement. Predicting far in advance exactly which transformer will fail and when is currently impossible. Yet it is understood that transformers with deteriorated insulating medium will fail with much greater probability than the same transformer with healthy insulation.

It is proposed to replace certain transformers based on a USS Transformer rating system based on parameters such as DGOA, Furan test results, transformer loading, apparent corrosion, oil leaks, LTC functionality, environmental impact, proximity to public, age. In order to estimate the number of transformers to be replaced every year, the following method is used: Considering furanic compounds (paper decomposition) per ASTM D5837 as the main parameter for the cut off age, it was found that the average transformer in the 4kV grid will reach the end of its operating life at approximately 70 years. This cut-off age shall not be treated as an absolute end of life, since all transformers age at different rates, but is used only as a guide for calculating the number of transformers needed to be replaced every year in order to avoid having too many of them past that age.

Project Relationships (if applicable)

Unit Substation PTO/Modernization

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital						5,950
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**5,434**	**3,902**	**3,902**	**3,902**	**4,019**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	989	710	710	710	731
M&S	2,074	1,489	1,489	1,489	1,534
Contract Services	1,093	785	785	785	809
Other	219	158	158	158	162
Overheads	1,059	760	760	760	783
Subtotal	5,434	3,902	3,902	3,902	4,019
Contingency**					
Total	**5,434**	**3,902**	**3,902**	**3,902**	**4,019**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Unit Substation (USS) Upgrade and Improvement	
Project/Program Manager: TBD	**Project/Program Number (Level 1):** 23545494
Status: ☒ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☐ **Ongoing** ☐ **Other: ___________**	
Estimated Start Date:	**Estimated Date In Service:**
A. Total Funding Request ($5,030) **Capital: $5,030** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This program will address corrective actions required to repair any deteriorated conditions that could lead to a potential safety, environmental or structural issues involving any of the 239 unit/multibank substations on our system. These deteriorated conditions include repairs to the transformer and switch gear pads, transformer moats and switchgear housing, station fencing and retaining walls, driveways, walkways, sidewalks, stairways, entrances (includes gates), station and security lighting. In addition to these civil improvements, there are both equipment and electrical items that if found defective will need replacement or upgrade.

Proposed equipment upgrades include the purchase and installation of transformer Maypole fall protection systems.

Justification Summary:

This program currently takes into account all 239 unit/multibank substations. Defects in these areas when left unaddressed areas can lead to safety concerns for our employees and the public, hinder operations causing delaying in the processing feeders and comprise reliability of the 4kv grids.

Certain types of repairs are repetitive and in cases can be cost effective when bundled with other defects in a programmatic approach.

Station lighting can be improved with newer energy efficient lighting systems to allow employees greater visibility. Unit substations are reviewed to ensure they meet Company security requirements and it is necessary to install additional perimeter security lighting systems.

Stations found to require repetitive repairs due to water leaks will be reviewed to determine the integrity of its roofing system. Those stations found with their integrity comprised will be a candidate for a new roofing system made by either the Carlisle or Kemper roofing systems.

Some of the Company’s transformer moats that are located in areas of poor drainage or high water are particularly susceptible to water flow-through or collection, which accelerates the breakdown of the concrete moat floor. The installation of spayed-on membranes represent a reasonable environmental investment in preventing moat soil remediation projects resulting from major releases or slow leaks.

New or upgraded systems including; on line monitoring, water sprinkler, cooling fans, and water taps for station use (water meter pit) are required to meet the operation needs of the station.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

The USS Upgrades and Improvement program supports the environmental safety and reliability of the 4kV Unit Substations by proactive upgrade and reinforcement of moats around the 4kV USS transformers to maintain the integrity of oil-catching moats that prevent environmental consequences of an oil leak at the USS. This minimizes the risk of environmental harm.

Also, in order to advance on future goals current facilities need to be maintained. This program ensures that the capital maintenance of the properties and environmental safety systems are in good working order. This prevents emergency clean-ups and repairs that would consume resources that could otherwise be dedicated to system expansion and enhancements.

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection

Address the repairs individually and under the current O&M program. The volume of repairs is projected to rise if a long term strategy is not followed.

Alternative 2 description and reason for rejection

Retire existing equipment and replace with a new unit substation. The costs, planning and logistics associated with replacement of unit substation represent an unreasonable plan since it focuses large investments to address small repairs while expediting the retirement of otherwise usable associated station components in addition to further delaying their repairs.

Risk of No Action

Risk 1

A deteriorated moat can have serious repercussions for the Company if they fail to contain oil. An oil spill to a waterway can result in substantial environmental harm, fines, and cleanup costs, consent order directives which may take years to fulfill, and damage to the Company’s public status and reputation as a good neighbor. Con Edison is also required by federal law to use more effective prevention and control technology as it becomes available.

Risk 2

Deteriorated conditions if left unaddressed can lead to safety concerns for Company employees, public and the environment.

Non-Financial Benefits

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)

2. Major financial benefits

3. Total cost

4. Basis for estimate

Historical unit cost for similar type projects in addition to spend information gathered during the "Evaluation of Coatings for Substation Moats" R&D pilot.

The R&D pilot delivered 7 moat coating installations at an average cost of ~ $6K per location plus labor support. The plan is to coat 24 locations year.

5. Conclusion

Station lightning, switchgear roofing and cooling system defects in need of repair or upgrade have the potential to become safety concerns for our employees and the public, hinder operations causing delaying in the processing feeders and comprise reliability of the 4kv grids

Installation of a durable material coating to defective or at risk moats reduces the need for periodic maintenance, reduces the risk of non-compliance with SPCC standards, and reduces the risk of oil entering the environment in the event of an incident at a station.

Based on this rationale we are recommending the implementation of this project

Project Risks and Mitigation Plan

1. Work Resource availability
2. Coating Material Manufacturing delays
3. Unforeseen inclement climate events will impact planned outages and overall schedule

Mitigation Plans

1. Identify shared resources and potential conflicts. Optimize schedule to make best of use of necessary resources
2. Place orders well in advance of work schedule and keep all necessary inventory on hand to avoid potential supply chain disruptions
3. Incorporate potential disruptions in the overall planning schedule and identify alternative outage dates should the planned outage dates be cancelled.

Technical Evaluation / Analysis

Each project will be designed and ruled by Property Records. Moat coating installations have been evaluated under the "Evaluation of Coatings for Substation Moats" pilot in 2019.

Project Relationships (if applicable)

3. Funding Detail

Historical Spend *(new program – N/A)*

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital						1,000
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	1,000	1,000	1,000	1,000	1,030
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	182	182	182	182	187
M&S	382	382	382	382	393
Contract Services	201	201	201	201	207
Other	40	40	40	40	42
Overheads	195	195	195	195	201
Subtotal	1,000	1,000	1,000	1,000	1,030
Contingency**					
Total	**1,000**	**1,000**	**1,000**	**1,000**	**1,030**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don’t occur today (e.g., anticipated short-term fixes/maintenance if capital isn’t deployed)

Central Operations / Substations
2023

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Upgrade Light and Power System Program	
Project/Program Manager: TBA	**Project/Program Number (Level 1):** 8ES3700/ 23287728
Status: ☒ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☐ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date: Ongoing	**Estimated Date in Service: Ongoing**
A. Total Funding Request ($000) **Capital: $4,000** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This program will re-configure light and power (L&P) systems at locations with two area substations (double stations). Each station at double stations should have L&P sources and systems that are fully independent of one another during contingency conditions. Some double stations, however, have AC load boards that are supplied by a common bus. This program will separate these types of buses, as well as diversifying L&P transformers from other station equipment such as capacitor bank breakers. The priority locations for this program are:

- W42nd Street
- W65th Street
- E63rd Street
- Corona
- W110th Street
- E40th Street
- Leonard Street
- Parkchester
- Bensonhurst
- Brownsville

Justification Summary:

All substations have critical sections of auxiliary equipment that are required to maintain system reliability. These critical components are supplied by station L&P. At various locations, 120/208V sources are connected to common bus. This configuration can lead to a loss of L&P for both stations (in a double station), have an adverse effect on network components and can make otherwise routine

switching operations overly complex. L&P are upgrades at select double stations are necessary to eliminate these factors.
In a double station, L&P components that are common to both stations are single points of failure. Most frequently, this single point of failure is common bus. This common bus can also cause cycling of redundant network protectors associated with each 208V secondary network that supplies L&P to each station. Over time there is high risk of damage to network protectors and AC load boards and associated network protectors during normal operation. The commonality can also lead to one source back-feeding the other under certain contingencies. Common bus configurations can also necessitate complex switching operations. To avoid a loss of power 120/208V AC power to the load board, complicated procedures are required during capacitor bank switching.

By upgrading L&P components and eliminating single points of failure, system reliability will be significantly increased. This will be accomplished through using strategic asset replacement and modification approaches. Combination of equipment replacement and modification will mitigate risk of high energy arc flash associated with normal operation. Additionally, this upgrade will improve the overall reliability of all dual area substations by decoupling operation of substation 120/208V auxiliary power system from operation of medium voltage capacitor banks. Lastly, these upgrades will eliminate risk of power pack feed between two associated secondary networks. Progressing with this asset management program will lead to an overall improvement of safety, asset protection, and operational/maintenance efficiency.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
This program impacts the Enterprise Risk "Loss of a Substation". The projects completed under this program will reduce the severity by making double station L&P systems independent. This will not only eliminate the risk of one L&P contingency affecting another station but will improve recovery times following a loss of AC.

2. Supplemental Information

Alternatives

1. Increase Operating Resources and Continue Use of Equipment Design with Low Reliability

   a. One of the alternatives would be to place associated network protectors in manual mode to avoid pumping of the network protectors and eliminate chance of back feeding power between associated secondary networks. This would require physical presence of operators at these area substations continuously increasing the time employees are required at these stations. Also, this alternative will not address the low reliability of auxiliary AC power system as same source circuit breaker is shared by medium voltage capacitor.

Risk of No Action

- Taking no action in this scenario would be leaving existing high priority substation equipment in place. If no action is taken system reliability will remain in compromised state.
- As switching operation of AC auxiliary power will remain complex, it will not reduce probability of Arc flash hazard, consequently, will not enhance human safety.

Non-Financial Benefits
1. This program will increase safety for all personnel working in ten area substations.
2. This program will increase the reliability of the entire Con Edison power system from transmission level and downstream.
3. This program will decrease the risk of damage to other major substation equipment.
4. This program will decrease the risk of arc flash incidents

Summary of Financial Benefits and Costs.
1. Cost-benefit analysis (if required) N/A

2. Major financial benefits
- Through the strategic replacement of auxiliary equipment there are multiple financial advantages that will be produced.
- These upgrades will prevent major equipment from being damaged under normal operations
- If a violent failure occurs due to back feed the potential exists for major assets to be damaged.
- More time and manpower would be used to resolve an unexpected outage or complete maintenance/testing related to that situation.

Upgrading of 120/208V AC load board and separating bus connections for light and power transformers and capacitor banks will provide long term cost reduction by better protecting high value assets, reducing environmental health and safety risks, and keeping customers lights on ensuring company revenue.

3. Total cost **$4,000**

4. Basis for Estimate: The funding level set for this program is based on our historic experience with projects of recent replacements. As it will address specific emergent projects that vary in scope, there will be expected variances between the funding level requested and the actual funding required, but, over time, this funding level is expected to be adequate to address our needs.

5. Conclusion: N/A

Project Risks and Mitigation Plan
Risk 1: Delays due resources support coordination.

Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Risk 2: Outage scheduling conflicts with other initiatives.

Mitigation: Outages to be coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs to avoid conflict with other program/ projects resulting in a more predictable budget and manageable outage scheduling.

Technical Evaluation / Analysis
As described above without the substation auxiliary equipment upgrade there are multiple layers of reliability that can be compromised to the overall system. After an overall technical assessment of the area substations system current equipment status, and from past failures that have occurred there is no question that this strategic replacement is necessary.

Project Relationships (if applicable)
The strategy that is going to be applied to this system will work in parallel with other projects and outages that are occurring. However, the initial priority will be to replace the most vulnerable assets reaching the end of operational lifespan.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	0	0	0	0		0
O&M						
Retirement	0	0	0	0		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**$0**	**$1,000**	**$1,000**	**$1,000**	**$1,000**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	0	330	330	330	330
M&S	0	62	62	62	62
Contract Services	0	249	249	249	252
Other	0	41	41	41	41
Overheads	0	318	318	318	315
Subtotal					
Total	**$0**	**$1,000**	**$1,000**	**$1,000**	**$1,000**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☒ **Strategic**	
Project/Program Title: USS Switchgear Flood Protection	
Project/Program Manager: Chris Rodriguez	**Project/Program Number (Level 1): 25776059**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☐ **Ongoing** ☐ **Other: ___________**	
Estimated Start Date:	**Estimated Date In Service:**
A. Total Funding Request ($000) **Capital: $42,330** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This program will upgrade unit substation pad-mounted switchgear with recloser switches by installing them on elevated platforms. A platform installation offers protection from anticipated torrential rainfall and flooding. Recloser switches are self-contained devices that can be replaced or repaired individually offering modular features traditional switchgear breakers lack.

The Company has targeted 26 unit substations that it considers vulnerable to flood damage for these upgrades. The program seeks to upgrade 6 substations per year at an approximate cost of $1.6M per unit station.

Justification Summary:

As a result of climate change, the Company expects increased impact from extreme weather events, coastal storms, and torrential rainfalls (such as that experienced during Hurricane Ida) that could result in the flooding of unit substations with the potential to significantly damage equipment and components such as circuit breakers, relays, Supervisory Control and Data Acquisition (SCADA) connected devices and associated local monitoring and control components. This damage could result in large area outages and risks cascading events, all of which will have an impact on overall system reliability.

The current unit substation switchgear was custom designed for operation under inclement weather but not for submergibility. The average age of unit station switchgear is approximately 52 years. None of the circuit breakers associated with these switchgear are currently being manufactured, requiring any repairs to be performed by third-party specialist vendors, introducing significant lead times and costly repairs when the equipment is damaged.

The upgrades included in this program are necessary to provide increased resiliency through the introduction of a combination of an elevated platform and modular reclosers as the basis for its design. The platform component will place critical components above anticipated flood levels while the reclosers compliment the station with more standard components. This eliminates dependency on legacy switchgear and the costs associated with third-party vendors required to maintain them. In addition, the upgrades will provide remote, secure access to digital data to prioritize system restoration while enhancing cybersecurity measures.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

Protecting USS switchgear from flooding aligns with the Company's Electric Long-Range Plan (ELRP) and Enterprise Risk Management (ERM) strategy by supporting system reliability, reducing safety risk to the public and employees associated with failing equipment, and minimizing the risk of regulatory penalties related to reliability.

2. Supplemental Information

Alternatives

1. Continue use of third-party vendor to perform repairs on damaged legacy switchgear. This alternative is costly due to dwindling availability of vendors who can perform these repairs. Vendor availability also affects the service restoration timeline and inherited system reliability gaps
2. Wait for the switchgear replacement program to upgrade the entire switchgear and introduce platform installation design. Current program duration is estimated to be 36 years at rate of 6 units per year. During this time, these unit stations would be exposed to the risks of inaction discussed before

Risk of No Action

1. Impact to reliability could lead to large customer outages and negative incentives from regulators
2. Increased safety risks to members of public and employees in proximity to unit substations
3. Exposure to extended outages which will impact system reliability and additional equipment damage
4. Lack of vendor availability could cause extended outages if volume of repairs exceeds vendor capability
5. Incremental loss of remote monitoring and control due to aforementioned legacy equipment failure

Non-Financial Benefits

1. Increased resiliency during coastal storms and torrential rainfall flooding
2. Reduced repair/replacement downtime due to modular design
3. Increased operation flexibility due to new protection features like single phase reclosing and down conductor detection.
4. Reduced maintenance requirements
5. Reduced number of vehicle rollouts to perform manual operations/monitoring lessens our carbon footprint contribution
6. Reduced number of emergency generator deployments lessens our carbon footprint contribution

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)

2. Major financial benefits

3. Total cost

4. Basis for estimate

5. Conclusion

This program supports system reliability and adaptation to climate change.

Project Risks and Mitigation Plan

1. Availability of resources to complete the required work
2. Equipment manufacturer delays

Mitigation Plans

1. Identify shared resources and potential conflicts. Optimize schedule to make best of use of necessary resources. Augment capability as needed through contractor forces.
2. Place orders well in advance of work schedule and keep all necessary inventory on hand to avoid potential supply chain disruptions
3. Incorporate potential disruptions in the overall planning schedule and identify alternative outage dates should the planned outage dates be cancelled.

Technical Evaluation / Analysis

N/A

Project Relationships (if applicable)

None

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital						
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	0	8,466	8,466	8,466	8,466
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor		2,836	2,836	2,836	2,836
M&S		1,865	1,865	1,865	1,865
Contract Services		775	775	775	775
Other		537	537	537	537
Overheads		2,453	2,453	2,453	2,453
Subtotal		**8,466**	**8,466**	**8,466**	**8,466**
Contingency**					
Total		**8,466**	**8,466**	**8,466**	**8,466**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Central Operations/ Substation Operations
2022

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: U-Type Bushing Replacement Program	
Project/Program Manager: Steven Bryan	**Project/Program Number (Level 1): 20704842.**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other: ___________**	
Estimated Start Date: N/A	**Estimated Date in Service: N/A**
A. Total Funding Request ($000) **Capital: $22,556** **O&M:** **Retirement: $3,292**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

A bushing is a device that brings out the transformer internal winding leads through an insulating tube for connection to the power system. Utility industry experts have identified transformer bushings that have design and manufacturing problems. The identified bushings are General Electric Type U, Haefely Trench Type COTA and OTA bushings and F&G (Felten & Guilleaume)/HSP Type OTF bushings. Failure of the bushings can lead to transformer failure, decreasing system reliability and availability of transformers on the transmission and sub-transmission systems.

Approximately thirty 345 kV bushings, two-hundred and forty 138 kV bushings, twenty-five 69 kV bushings, and ten 23 kV bushings have been identified for replacement and upgrade. As of 2021, approximately 156 bushings remain on the system to be replaced.

It is recommended that identified bushings be replaced and upgraded based on failure probability and system impact. The recommended priority is:

1. 138 kV and 345 kV shunt reactors
2. 345 kV transmission autotransformers
3. All phase angle regulators (PARs)
4. Other 138 kV and 345 kV auto-transformers
5. Two bank area substation transformers
6. Other area substation transformers

Justification Summary:

A major component of a power transformer is a bushing. General Electric Co. (GE) was a major supplier of bushings for all transformer manufacturers until the late 1980s. GE manufactured bushings with ratings from 15 kV through 800 kV and has served over 60% of the US market. One of the many types of bushings that GE supplied was the Type U bushing, a condenser-type design. The condenser-type design utilized a metal core tube with insulating paper and an electrically conductive foil or semi-conductive electrode wound around the core. The Type U design used alternate layers of plain Kraft paper and Kraft paper with conductive ink printed in a herring-bone pattern on the surface. In the late 1970s, users reported increases in the power factor of Type U bushings.

Teardown of failed and high-power factor bushings revealed the following problems:

1. Heavy loading of some transformers (e.g., generator step-up transformers and shunt reactors), generated a higher internal temperature than the temperature expected from conductor-generated heat. This higher temperature resulted in increased pressure in the gas space above the oil, leading some of the gas to become dissolved in the oil. Rapid temperature cycling resulted in gas bubble generation and a reduction of dielectric strength Insulation system degradation resulted in an increased power factor.

2. Over time, the conductive ink transferred from the printed-paper layers to the plain kraft paper layers. This bleeding of the conductive ink resulted in an increased power factor.

3. The terminal connection on the top of the bushing used a "flex-seal" system composed of a gasket, a seal nut, and a spring. If the cover bolts became loose over time, hot spots developed that compromised the gasket seal. Water would enter the bushing through the compromised gasket seal.

Type COTA bushings from Haefely Trench experienced unexpected failures in the middle of the last decade. Haefely Trench started manufacturing the Type COTA bushings in 1994. The Type COTA is also a condenser-type design. The failures occurred around the flange section of the bushing. The Type COTA bushing is shorter than bushings of the same rating manufactured by other manufacturers, which made it a good universal replacement. Because of the shorter dimension, the design must control the maximum and average voltage stresses in the Kraft paper insulation system.

Con Edison and other users started measuring the power factor of the Type COTA bushings and reported increased power factor measurements, which indicates degraded insulation. No definitive root cause was found for the bushing failures.

In addition, Type OTF bushings from Felten & Guilleaume (F&G)/HSP have experienced unexpected failures over the last two decades. The Type OTF bushing is also an oil-impregnated paper condenser-type design with a porcelain upper housing and an epoxy resin lower part. Many of these failures were catastrophic resulting in the explosion of the porcelain housing. Additional deteriorated bushings have been removed from service due to bushing electrical test results and dissolved gas-in-oil analysis that indicates a degradation of the bushing’s condition and concern over its reliable performance. No one definitive root cause was found for the bushing failures.

Bushings are subjected to high dielectric, thermal, and mechanical stresses, which makes them a critical component of a transformer. It has been well documented that the physical damage a failed bushing causes can lead to a damaged power transformer.

Upgrading bushings to the ABB design will result in a reliable transmission and sub-transmission system, a reliable and available transformer, and minimal transformer failures from bushing failures.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):

This program focuses to mitigate likelihood Substation Operations departmental risk of transformer failures from bushing failures by identifying bushings with design and/or manufacturing deficiencies to be replaced and upgraded based on failure probability and system impact, increasing system reliability and availability of transformers on the transmission and sub-transmission systems.

2. Supplemental Information

Alternatives
• **Alternatives**: Perform routine power factor testing on existing bushings that have a higher potential of failure. Bushings and/or a transformer could fail between periodic testing during the summer period, negatively impacting the reliability of the transmission system. In addition, this would also result in numerous additional outages for testing. Therefore, this alternative is not acceptable.

Risk of No Action
Waiting for bushings to fail and then replacing them can cause transformer failure. This alternative is not acceptable since failure of a bushing and/or a transformer during the summer period will negatively impact the reliability of the transmission system. In addition, replacing a transformer can cost $15 million to $40 million, which is significantly more than the cost of replacing the bushings.

Non-Financial Benefits
Upgrading bushings will result in a reliable transmission and sub-transmission system and minimize transformer failures from bushing failures.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis: N/A

2. Major financial benefits
Bushing failures have the potential to be catastrophic resulting in costly damages to transformers and lengthy outages on the system that could impact customers.

3. Total cost **$22,556**

4. Basis for estimate: The annual funding for this program is based on unit cost analysis of historic work that has been previously completed and is of a similar nature to the work planned is based on replacement of bushings on 10-11 transformers per year at a cost of $400K to $1M per transformer.
.
5. Conclusion: N/A

Project Risks and Mitigation Plan

Risk 1: Outage scheduling conflicts with other initiatives.

Mitigation: Outages to be coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs to avoid conflict with other program/ projects resulting in a more predictable budget and manageable outage scheduling.

Risk 2: Delays due resources support coordination.

Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Risk 3: **Lack of alignment between resources support and outages.**
Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction to avoid alignment conflicts with outages.

Technical Evaluation / Analysis:
Utility industry experience has shown that General Electric Type U, Haefely Trench Type COTA and F&G/HSP type OTF bushings have design and manufacturing problems that can lead to the catastrophic failure of the bushing. Industry bushing guides, such as IEEE and Doble Engineering, recommend that any GE Type U bushing having a C1 power factor which has increased to an absolute value of 1% or higher, or which exhibits a sudden, significant increase in power factor, though not yet exceeding the 1% maximum, should be considered in questionable condition. Similarly, investigation and evaluation of Trench COTA bushing failures indicate that they may be experiencing accelerated aging which can be assessed through the periodic measurement of bushing power factor and capacitance and compared against threshold values of 150% of nameplate power factor and an increase of more than 2.5% than the C1 capacitance value. Once the increase in the power factor is exhibited, it continues to increase rapidly.

Experience with Con Edison installed equipment has included the catastrophic failures of GE Type U bushings on Queensbridge Transformer TR3, Farragut Reactor R12, Corona Transformer TR8 and W50 St. Transformer TR2. In addition, measurements of bushing power factors on W50 St. Transformers TR1, TR3 and TR4, Fresh Kills Transformer TB1 and Leonard Street Transformer TR9 have picked up degraded bushings prior to their catastrophic failure. Con Edison's operating experience on Haefely Trench Type COTA bushings has included the catastrophic failure of a bushing in Corona Transformer TR1. Subsequent testing of the installed sister bushings in this transformer confirmed elevated bushing power factor and capacitance measurements. Experience with our installed equipment with F&G/HSP type OTF bushings has included the catastrophic bushing failures of PARs 3500 and 4500 at Ramapo Substation. The most recent failure of the F&G bushing at Ramapo that failed catastrophically resulted in the total failure of the phase angle regulator 3500.

Project Relationships (if applicable) N/A

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	2,999	3,852	6,125	3,801		1,334
O&M						
Retirement	106	170	1,636	1,246		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	2,736	5,600	5,100	4,400	4,720
O&M*					
Retirement	658	658	658	658	658

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	875	1,791	1,631	1,408	1,510
M&S	356	728	663	572	614
Contract Services	373	763	695	613	660
Other	251	529	483	404	443
Overheads	882	1,789	1,628	1,404	1,493
Subtotal					
Total	**$2,736**	**$5,600**	**$5,100**	**$4,400**	**$4,720**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Wainwright – Willowbrook Stepdown Transformer Installations	
Project/Program Manager: Glen Calabrese	**Project/Program Number (Level 1): 24817526**
Status: ☐ **Initiation** ☒ **Planning** ☒ **Execution** ☐ **On-going** ☐ ☐ **Other: ___________**	
Estimated Start Date:	**Estimated Date In Service:**
A. Total Funding Request ($000) **Capital: $20,000** **O&M:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period:** **(Years/months) (If applicable)**

Work Description:

Willowbrook Area substation supplies approximately 24,300 customers. The peak load emergency switching procedure requires deployment of (13) generators to supply the load above and beyond the backup switching capacity. Wainwright Area substation supplies approximately 24,900 customers. The peak load emergency switching procedure requires (7) generators to supply the load that exceeds the capability of the emergency ties.

This project objective is to eliminate the need for this mobile generation support as part of the emergency switching procedures. To do thirteen (13) 33kV / 13kV transformers along with associated switchgear and conductors will be installed, (8) in the Willowbrook load area and (5) in the Wainwright load area.

Justification Summary:

Willowbrook and Wainwright substations are classified as Sensitive Substations due to the fact that they operate in an N-1 design (only have two supplies). If one supply feeder or associated equipment is removed from service as scheduled work or as a result of an emergency condition, emergency switching procedures are required to re-establish supply to all affected customers. These plans do so using predetermined switching moves that gain supply from adjacent in-service feeders. However, at times of high system loads the capacity of these adjacent feeders is limited and cannot manage to supply all the customers. Portions of feeders are left out of the switching schemes and are to be supplied by mobile generation. During these scenarios, 3,849 customers fed from Wainwright and 4,938 customers fed from Willlowbrook stations need to be restored via generators and step-up transformers. Emergency generator deployment of this nature requires significant time and manpower. It will take approximately 8 hours to restore the customers via generation, assuming the generators are staged with all leads connected and technicians are standing by. Restoration will take longer if these best-case assumptions are incorrect. Once all step down transformer installations are completed, the restoration time will drop to 2 hours.

Emergency generators have a negative customer impact. The space required impedes traffic flow and reduces available automobile parking. When the generators are running, engine noise is undesirable to customers with homes near the installation location.

The stepdown transformer installations also will provide an additional source that can be utilized for emergency restoration during storms and other outage scenarios.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

Although the Wainwright and Willowbrook Area Substations do not feed secondary networks, they do feed a significant amount of customers. Successful completion of this project will reduce the exposure to customer outages associated with the catastrophic failure of either station as well as a second contingency in either station on the transmission feeders and transformers.

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection

Install six (6) express 13 kV underground feeder ties between Wainwright and Willowbrook substations. This would require the installation of additional bus sections and breaker positions in each station. The estimated cost of this alternative is $60M. It was rejected due to a cost higher than the selected option.

Alternative 2 description and reason for rejection

Install a distribution switching station in Fresh Kills Area Substation. This option would include emergency ties routed from Fresh Kills to Willowbrook substation and from Fresh Kills to Wainwright substation. It would also the require the installation of additional bus sections and breaker positions in Fresh Kills, Wainwright and Willowbrook substations. The estimated cost of this alternative is $121M. It was rejected due to a cost higher than the selected option.

Risk of No Action

Risk 1

Generator availability is a risk. If the total number of generators required are not available, then customers will remain out of service until they can be obtained or one of the feeds in Wainwright/Willowbrook is restored. There are 3,849 customers fed from Wainwright and 4,938 customers fed from Willlowbrook stations need to be restored via generators.

Risk 2

Step up transformer availability is a risk. If the total number of step up transformers required for the generators required are not available, then customers will remain out of service until they can be obtained or one of the feeds in Wainwright/Willowbrook is restored. There are 3,849 customers fed from Wainwright and 4,938 customers fed from Willlowbrook stations need to be restored via generators.

Non-Financial Benefits

- Project completion will improve customer satisfaction during Wainright and Willowbrook contingencies described in the Justification Summary. Emergency generators have a negative effect on customers. The space required inhibits traffic flow and reduces available vehicle parking. When the generators are running, engine noise is undesirable to customers with homes near the installation location.

- Project completion will improve our relationships with local elected officials. Reducing the risk of large outages and eliminating the need to deploy the equipment will improve customer satisfaction for their constituents.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)
This is a risk reduction program. The cost benefit analysis is not applicable.

2. Major financial benefits

3. Total cost
The total cost of this project is $20M.

4. Basis for estimate
The estimate was calculated by Staten Island Regional Engineering using the cost model used for all capital projects on Staten Island that require appropriations.

5. Conclusion
This project should be completed in order to eliminate the need for this mobile generation deployment for N-2 scenarios on the transmission feeders and area substation transformers in the Wainwright and Willowbrook Area Substations.

Project Risks and Mitigation Plan

Risk 1	Mitigation plan
Material and equipment availability is a risk to successful completion.	Material and equipment will be ordered with enough lead time to receive what is needed and avoid foreseeable delays.

Risk 2	Mitigation plan
There are multiple risks associated with the transformer vaults, including permits for street installations, potential for obstructions (other utilities, rock) in the selected locations, and soil stability (potential to need piles for stability) .	Public affairs will engage elected officials to bolster support for permit approval. Test pits and bore samples will be taken from each vault location prior to construction. If issues arise, the next lowest cost location in the area will be used.

Technical Evaluation / Analysis

Generators were required and deployed at both stations due emergency conditions experienced in 2019.
Project Relationships (if applicable)

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital						62
O&M						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	8,500	8,520	1,000	0	0
O&M*					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	2,399	2,404	252		
M&S	2,080	2,085	245		
Contract Services	1,786	1,790	210		
Other	(375)	(376)	(44)		
Overheads	2,610	2,617	337		
Total	**8,500**	**8,520**	**1,000**		

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Project Status:

- Initiation – New project, not authorized yet
- Planning – Project authorized, not started yet
- Executing – Project in-flight
- On-going – Annual program

Electric Operations
2023

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☐ **Capital** ☒ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Emergency Response	
Project/Program Manager:	**Project/Program Number (Level 1):**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other: ___________**	
Estimated Start Date: Ongoing	**Estimated Date In Service: Ongoing**
A. Total Funding Request ($000) **Capital:** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:
The Emergency Response program is comprised of the following individual work functions:

1) **Contingency** – This initiative provides a reserve of funds intended to offset unforeseen expenses that may arise because of system emergencies;

2) **Obstructed Ducts** – This program addresses several tasks associated with maintenance of blocked underground conduit. These tasks include:

   - Clearing duct obstructions with a rodding tool and flushing equipment;
   - Maintenance activities associated with clearing obstructed ducts carrying primary or secondary conductors, including the breaking and excavation of duct along with any associated backfilling and paving;
   - Clearing obstructed ducts for underground services and street lighting;

3) **Customer Investigations** – This budget is used to investigate service complaints on customers' premises, including the labor associated with "no lights" investigations which subsequently reveal the outage cause to be faulty customer equipment;

4) **Burnouts – URD** – This program accounts for the minor repair and remake of splices on primary, secondary, and service URD cables resulting from burnouts. Restoring customer premises

during emergency URD service repairs, along with any excavation and backfilling, is accounted for as well;

5) **Burnouts – Flush** – In order to provide a safe environment for our employees who work within underground structures, the cleaning of manholes, service boxes and vaults is necessary particularly when access is required with little advance notice. The most effective way to provide this support to emergency crews is to have flush truck resources and personnel ready when burnouts and other service outages occur. This program accounts for all activities associated with cleaning and flushing manholes and service boxes as a result of underground primary, secondary, or service burnouts/emergencies;

6) **Burnouts and Emergency Related** – This program is comprised of the following emergency maintenance activities:
   - Operation of switches or station equipment
   - Installation and removal of field grounds for fault readings
   - Grounding and identification of feeder phasing
   - Grounding and phase fault locating
   - Emergency repairs to overhead or underground street light services
   - Emergency overhead facilities repairs
   - Maintenance of primary or secondary cables resulting from burnouts
   - Repair of impending hazardous faults, or "D" faults, on feeders
   - Emergency repairs to overhead or underground services to resolve outage complaints from customers
   - High tension switch moves on customer premises from the District Operator
   - Maintenance of underground electric cables damaged by underground incidents;

7) **Burnouts or B Tickets – Overhead** – This initiative accounts for several maintenance activities associated with overhead burnouts. They are:
   - Maintenance of poles and fixtures during non-capital emergency work
   - Maintenance of overhead primary, secondary, or service conductors and devices during non-capital emergency work;

8) **Burnouts or B Tickets – Underground** – This initiative accounts for several maintenance activities associated with underground burnouts and potential faults. They are:
   - Maintenance activities associated with underground conduit during emergencies
   - Minor repairs, such as piece-outs or joint remakes, on primary feeders resulting from emergencies or OAs
   - Minor repairs, such as "re-crabbing" (joint remakes), on secondary mains resulting from emergencies
   - Corrective maintenance for potential impending faults, or "C" faults, on primary feeders
   - Service maintenance repairs, such as installing or removing temporary services, resulting from underground emergencies
   - Sealing ducts that enter customers' premises to prevent water leaks;

9) **Storm Reserve** – On occasion, the Company may experience significant damage to its electric overhead systems due to storms. The Public Service Commission (PSC) in its Order in case 08-E-0539 approved the establishment of a Storm Reserve which may be utilized in instances where

a storm meets certain criteria. The PSC recognizes three storm categories from least to most severe, numbered 1, 2, and 3. The storm reserve can be used for PSC Categories 2 or greater and for mobilization in advance of a storm anticipated to meet the criteria for a Category 2 or greater;

10) **Emergency Diesel Generators** – Mobile generators and their associated equipment provide support to the electric distribution & transmission systems and substations, steam, gas, and other facilities during emergency outages. They also assist in providing critical electric system support by de-loading in-service equipment that may be severely overloaded. This program addresses the maintenance and mobilization of Company owned mobile generators and the rental of vendor generators, transformers, cables, and the transportation of such equipment; and

11) **Overhead Storm Emergency** – This program accounts for several maintenance activities undertaken due to major overhead storm emergencies. They are:

- Maintenance of poles and fixtures
- Maintenance of primary, secondary, or service conductors and devices
- Company and/or contractor tree trimming, where the overhead system exists
- Labor and other non-field related expenses incurred in support of field activities during storm emergencies.

12) Storm Emergency Additional Vehicles for Mutual Assistance – This program accounts for the maintenance of vehicles designated for use by Mutual Assistance crews that are flown in in the event of a major storm. The availability of these vehicles extends the range from which we can draw support in the event of a major outage, and the speed with which we can mobilize such resources.

13) Emergency Response – OH Storm Contractor Retainers - In order for the Company to secure overhead resources for future storms, as well as increasing its overall storm preparedness, it is proactively securing retainers with overhead contractors. These retainers require the selected contractors to guarantee overhead line resources for Con Edison. In addition, the retainer requires the contractors to provide the Company the "First Right of Refusal" during times or storm events where other utilities could be looking to secure resources. This option provides the Company security by not jeopardizing the guaranteed resources allocated to Con Edison.

Justification Summary:
Emergency Management data predicts that the Northeast Region will experience an increase in severe storms in the future as a result of climate change. Currently, Category 1 and 2 hurricanes affect the region once every 19 years and major hurricanes, Category 3 or greater, affect the region once every 74 years.

In 2018, our overhead system experienced severe damage from Nor'easter's Quinn, Riley and Tobey. In addition to these larger named storms, we experienced a number of large unnamed storms that were also devastating, including the April windstorms experienced over April 14th to April 16th where wind gusts reached over 50 mph and a windstorm on May 15th where wind gusts were seen as high as 60 mph in the Bronx. More recently in August 2020, we experienced major storm Isaias which took the place as the 2nd largest storm in the Company's history. Recent history and climate change research indicates that the number of these severe weather events is increasing.

In recent years, obtaining overhead contractor resources for mutual assistance has become more challenging as other utilities also are in need of the same resources. The impact of not having contractor resources readily available for mutual assistance purposes became evident during the

March 2018 nor'easter storms (Riley/Quinn). One of the post-storm recommendations, was to find a better way to guarantee overhead FTE resources.

Further, in the cases of large severe weather events that impact the entire Northeast, mutual aid resources may not be available in the region, necessitating flying in mutual aid FTEs from other parts of the U.S. Owning and maintaining a number of overhead bucket trucks available for use of fly-in mutual aid crews allows the Company to respond to major storms with the level of resources needed to prepare as appropriate for significant system events.

Relationship to 5-Year and Long-Range Plans and Enterprise Risk Management Strategy

Overhead Storms are a major corporate risk at Con Edison. Improving the capabilities to respond to more frequent and sever major storms will reduce the impact those storms have on customers.

The Company's Electric Long Range Plan (ELRP) also includes a focus on lessening the impact of extreme weather on customers. The Emergency Response Program does just that.

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection

Alternative 2 description and reason for rejection

Alternative 3 description and reason for rejection

Risk of No Action

Risk 1

Failure to enter into an agreement with a contractor to secure overhead resources and have overhead bucket trucks on hand for their use for severe storms will hinder the Company's ability to provide additional and earlier access to worker resources; improve mutual aid response, proactively recruit contractors for faster response after severe storms, and secure access to bucket trucks for mutual aid crews as soon as they arrive. It will also hinder the Company's ability to prioritize roads for clearing and critical facilities; leading to less collaboration with municipalities to identify and prioritize critical facilities and roads for clearing. Finally, failure to implement such a program will weaken Con Edison's municipal liaison program due to lack of dedicated resources to give liaisons better information regarding crews and restoration.

Risk 2

Risk 3

Non-Financial Benefits
The benefits of this retainer and available overhead bucket trucks for their use are twofold. They help ensure supplemental resources for weather related events are available and they have the proper equipment to be effective. The retainer also provides Con Edison with greater transparency for when the overhead contractor resource pool begins to become depleted; thus allowing the Company to make more informed decisions when trying to secure these overhead resources.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis (if required)
N/A

2. Major financial benefits
N/A

3. Total cost
The OH Contractor Retainer is $6.5million/year starting in 2023, which is an increment of $4.54million over the 12 month normalized period ending September 30, 2021.

The Storm Emergency Additional Vehicles for Mutual Assistance is $2million annually starting in 2023 and is all incremental to the 12 month normalized period ending September 30, 2021.

4. Basis for estimate
Estimates are based on historical unit costs

5. Conclusion
Although difficult to quantify, the benefits of the program minimize the impact of major storms on customers, especially in the case of larger regional storms in which the availability of contractor FTEs would be otherwise limited and where FTEs are flown in.

Project Risks and Mitigation Plan
Evaluate and describe any risks that might extend the project timeline, prevent completion, or lead to cost overruns. Explain plan to minimize these risks.

Risk 1
Global Supply Chain delays continue to impact the ability to procure bucket trucks for Mutual Assistance Crews

Mitigation plan
The Company will work to procure as many trucks as is reasonable to do. Continued efforts to coordinate necessary resources and, if necessary, commit resources early to ensure the right resources are available to restore the system.

Risk 2	Mitigation plan
Technical Evaluation / Analysis	
Project Relationships (if applicable)	

3. Funding Detail

Historical Spend

	Actual 2017	**Actual 2018**	**Actual 2019**	**Actual 2020**	**Historic Year** (O&M only)	**Forecast 2021**
Capital						
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	**Request 2023**	**Request 2024**	**Request 2025**	**Request 2026**
Capital					
O&M*	**147,995**	**192,773**	**196,629**	**200,561**	**204,572**
Retirement					

Capital Request by Elements of Expense:

EOE	**2022**	**2023**	**2024**	**2025**	**2026**
Labor					
M&S					
Contract Services					
Other					
Overheads					
Subtotal					
Contingency**					
Total					

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2020	2021	2022	2023	2024	2025
O&M						
Capital						

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Business Unit / Division
Budget Year

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☐ **Capital** ☒ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Line Clearance/Vegetation Management Program	
Project/Program Manager:	**Project/Program Number (Level 1):**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date: Ongoing	**Estimated Completion Date: Ongoing**
A. Total Funding Request ($000) **Capital:** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

Con Edison's Line Clearance/Vegetation Management Program consists of the implementation of tree removal and trimming risk prevention and mitigation strategies designed to improve electric reliability to our customers. In addition, we actively promote and educate our customers on the importance of planting the right tree in the right place, to help reduce power outages. The necessary vegetation management work is conducted daily by 100 licensed tree-service contractors throughout the Company's service territory (Brooklyn, Queens, Staten Island, Bronx, and Westchester County), and the trees are assessed by professional foresters. The Company's vegetation management contractors are specially trained in preserving tree health and follow the International Society of Arboriculture (ISA), Tree Care Industry Association (TCIA) and American National Standards Institute (ANSI) tree maintenance standards. The following is a summary of our Line Clearance/Vegetation Management Program, the averages presented herein are based on 2018, 2019 and 2020 annual data analytics inclusive of work performed in Brooklyn, Queens, Staten Island, Bronx, and Westchester County.

- **Cycle Trimming:** Overhead distribution electrical lines are trimmed cyclically, 4kV & 13kV lines are trimmed on a 3-year cycle, and 27kV & 33kV lines are trimmed on a 2-year cycle. An average combined total of 1,400 miles are trimmed annually.

- **On Right of Way Tree Removals:** These removals are typically performed during the cycle trimming process, and are defined as dead, dying, or diseased trees located within our Right of Way, where failure could adversely affect the delivery of safe and reliable electricity to our customers. In NYC, these trees are predominantly under the jurisdiction of the NYC Parks Department. An average of 680 on Right of Way trees are removed annually.

- **<u>Tree Toppings:</u>** In New York City these requests are received by the NYC Parks Department exclusively via the NYC Parks Department computer application. In Westchester County these requests come in via various sources, typically via the local municipality. An average of 925 tree toppings are completed annually.

  Con Edison is currently in negotiations with the NYC Parks Department on the implementation of a Memorandum of Understanding (MOU). The MOU foundation is the replacement of the current tree topping process (canopy reduction) with a full tree removal (stump to remain), complete the work backlog (currently @ 511 trees), and establishes completion timeframes based on NYC Parks Department selected tree risk ratings that range from 7 to 60 days for new requests. Based on 2018, 2019 and 2020 annual data analytics inclusive of work performed in Brooklyn, Queens, Staten Island, and the Bronx we receive an average of 586 new requests annually. The estimated incremental increased operating cost impact associated with the MOU stipulations are: 1) 3-Year Rate Plan Recurring Additional Cost to Perform New Request Full Removals = $2.5 million dollars, 2) 3-Year Rate Plan Non-Recurring Cost to Eliminate the Backlog Performing Full Removals = $1.3 million dollars, totaling approximately $3.8 million dollars.

- **<u>Tree Related Customer Inquiry Investigations:</u>** The Con Edison vegetation management team receives and investigates customer tree related inquiries that come in via a myriad of sources. Including but not limited to: Agency/City requests, and various other customer requests, typically via the Con Edison tree trimming webpage email address. On average the Vegetation Management team investigates and resolves 5,914 customer inquiries annually.

- **<u>Hazardous Tree Removal Program:</u>** The program began in 2018 resultant from widespread tree related power outages caused by winter storms Riley and Quinn. Immediately following the storms, a tree care consultant was hired to conduct a study to determine the predominate types of tree failures that caused the power outages. The study results concluded that approximately 77% of the power outages were caused by off Right of Way privately owned trees, outside the typically maintained Right of Way corridor. As a result, Con Edison established the "Hazardous Tree Removal Program" focusing on the removal of off Right of Way dead, dying or diseased trees where failure is likely to occur, adversely affecting the electrical distribution system. The removal area focus is on increasing feeder reliability performance, and feeders supplying critical customers. In 2020 $1.5 million dollars was granted in support of this effort by the PSC under Case 19-E-0065. The below is a yearly breakdown of Hazardous Trees removed since the program began:

Hazardous Tree Removal Summary

	2018	2019	2020	1/1/2021 - 12/15/2021	Total
TOTAL	226	791	1,271	1,212	3,500

Additionally, Con Edison has been named a "Tree Line USA" utility by the Arbor Day Foundation for the past thirteen years. The award acknowledges Con Edison's national leadership in promoting the dual goals of providing safe, reliable electric service to our customers and abundant, healthy trees across the Company's service territory. Con Edison's efforts in meeting the annual Tree Line USA requirements, training Company workers in quality tree-care practices, and helping to educate customers to plant appropriate trees near power lines, demonstrate that trees and electrical utilities can co-exist for the benefit of communities and citizens.

With the expected increase in severity and frequency of storms as a result of climate change, Con Edison plans to increase funding for the Tree Trimming program in the rate years to further mitigate storm damage to the overhead system.

Justification Summary:

Con Edison is committed to providing safe and reliable electricity to our customers, an effective Line Clearance/Vegetation Management Program is vital to achieving this, as most electrical outages are caused by trees & limbs falling on overhead distribution lines. Trimming tree growth and maintaining minimum distances between electrical infrastructure and surrounding trees is critical, as untrimmed trees grow into distribution lines, cause customer outages, physical damage to the distribution system, and threaten public safely. Additionally, the removal of both on & off Right of Way dead, dying, and diseased trees helps ensure the safe and reliable operation of the electrical distribution system. An effective program also helps to efficiently manage overhead distribution system operation & maintenance expenses.

Relationship to 5-Year and Long-Range Plans and Enterprise Risk Management Strategy

The Electric Long Range Plan (ELRP) recognizes that weather is trending towards more frequent and severe events. As such, and key tenet of the plan is to make the system more resilient. This program is directly contributing to that improvement on the non-network system by mitigating potential impacts during extreme weather events.

The Company's Enterprise Risk Management (ERM) strategy considers operational risks that impact system reliability and identifies capital and O&M investments that mitigate those risks. The Company's Tree Trimming program does just that for the overhead system.

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection
An alternative to implementing a Line Clearance/Vegetation Management Program would be for the Company to incur an increased risk that overhead electrical infrastructure will become damaged by overgrown or dead, dying, or diseased trees during harsh weather, resulting in an increased likelihood of customer outages, vegetation related fires, and public safety incidents. The alternative would be detrimental, requiring the Company to conduct increased emergency repairs of damaged infrastructure, costing substantially more than implementing the Line Clearance/Vegetation Management Program. Moreover, conducting emergency repairs on damaged infrastructure would lower customer satisfaction due to increased power outages.

Alternative 2 description and reason for rejection

Alternative 3 description and reason for rejection

Risk of No Action

Risk 1:
The eradication of the Line Clearance/Vegetation Management Program would result in increased tree related power outages, poor SAIFI, CAIDI, and major storm response performance metrics. Poor performance in these categories can lead to financial penalties in the form of Reliability Performance Mechanisms. Electrical outages pose an unnecessary risk to those dependent on life support, compromise public safety and result in customer inconvenience. No action would increase the likelihood of fires from arcing electricity, and serious injuries or fatalities due to electrical contact. Additionally, there would be a substantial increase in system operation & maintenance expenses.

Risk 2

Risk 3

Non-Financial Benefits

The Company continues to increase communication with and educate customers on the importance of the Line Clearance/Vegetation Management Program. Timely and reliable communication of the program has helped enhance public program acceptance. Several avenues have been implemented to inform and are utilized to educate our customers, including posting policies and practices on Con Edison's website, YouTube, Facebook, and Twitter; sending out mailers and email notices; and leveraging informational door hangers before work is performed in an area. Environmentally, proper tree pruning, and the removal of dead, dying, and diseased trees helps to create a healthy, and viable urban forest.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)

2. Major financial benefits

3. Total cost

4. Basis for estimate

5. Conclusion

Project Risks and Mitigation Plan

Risk 1	Mitigation plan
Risk 2	Mitigation plan

Technical Evaluation / Analysis

Project Relationships (if applicable)

3. Funding Detail

Historical Spend

	Actual 2016	Actual 2017	Actual 2018	Actual 2019	Historic Year (O&M only)	Forecast 2020
Capital						
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital					
O&M*	**18,045**	**19,036**	**19,785**	**20,556**	**20,967**
Retirement					

Capital Request by Elements of Expense:

EOE	2021	2022	2023	2024	2025
Labor					
M&S					
Contract Services					
Other					
Overheads					
Subtotal					
Contingency**					
Total					

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Business Unit / Division
Budget Year

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☐ **Capital** ☒ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Safety Inspection Program	
Project/Program Manager: Maria Rodriguez	**Project/Program Number (Level 1):**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date: Ongoing	**Estimated Completion Date: Ongoing**
A. Total Funding Request ($000) **Capital:** **O&M: $206,450** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:
Con Edison proposed in its 2016 Electric Rate Filing 16-E-0060 a Safety Inspection Program (SIP) pilot that included current and infrared enhanced inspections of the Underground Network and Underground Residential Distribution (UG/URD) assets and the targeted mobile contact voltage scanning of areas with elevated energized object generation rates. Both the Enhanced Inspection and Targeted Mobile Scanning pilots have been successful in reducing manhole and electric shock events. The UG inspection program was revised under Case 04-M-0159 dated January 28, 2021.

1) **UG Asset Optimized SIP Inspection and URD Inspection** – This program funds the inspection of UG and URD distribution structures to identify conditions that can cause or lead to safety hazards or adverse effects on the system's performance. The Company has over 285,300 distribution manholes, service boxes, transformer vaults, and URD assets. Starting in 2021, the UG SIP program changed to inspections on assets that pose the highest risk to public safety and system reliability. This is now an established program. Assets are classified into three groups, High Priority (HP) group - consisting of five-year inspection; Medium Priority (MD) group – consisting of an eight-year inspection; and Low Priority (LP) group consisting of a ten-year inspection. URD structures remain on a five-year inspection cycle. Of the 285,300 UG and URD assets, 17,700 are URD structures. Of the 267,600 UG structures, 9,600 or 4% are HP; 136,000 or 50% are MP and 122,000 or 45% are LP.

   These inspections will continue to be performed by contractor and Con Edison crews, but they will be supplemented with new technologies. Technology like the Structure Observation System (SOS) platform that was first introduced in late 2016 and has since evolved and expanded to include even greater sensor capability. Assets equipped with SOS monitoring technology will have near continuous inspection. Another emergent technology is through cover inspection, which allows the operator to inspect the equipment in the structure without entering.

Con Edison is increasing funding for the UG program in the rate years to address "stopped inspections" for structures before the end of 2024, as directed by the February 2021 Order. "Stopped inspections" is the term used to describe structures where an inspection could not be performed either due to obstructions such as paved over, non-Company equipment or property, or those that could not be found. Increased costs are associated with the completion of backlogged repairs prior to the end of 2024.

In order to complete an UG/URD inspection, the equipment within that asset needs to be visible. The standard of visibility for an inspection will be line of sight to the equipment from five feet. Line of sight will not be considered obstructed where limited debris and or water is present on the equipment. The Company will clean structures ("flush") when debris prevents an inspection. While this language has been in place since 2021, the rate at which structures have needed to be flushed has not decreased, and continues to be a significant cost driver for the program.

2) These defects will either be repaired at the time of discovery or scheduled for repair according to the time frames specified by the revision to the New York State Public Service Commission Order Instituting Safety Standards adopted December 10, 2008 Case 04-M-0159. The UG Asset Optimized SIP Repair and URD Repairs will now include defects found through SOS monitor and through cover inspection as well as through regular inspections. A repair and prevention mechanism will also include the placement of structure fill bags into structures that will reduce the chance of a non-accessible defect resulting in an event.

3) **OH 5-Year Inspection** – This program funds the inspection of overhead distribution poles to identify conditions that can cause or lead to safety hazards or adverse effects on the system's performance. The Company will perform inspections of approximately 20% of these system assets in each year of the program. Each asset will be inspected at least once as part of the five-year inspection cycle. The workforce performing inspections consists of contractor and Con Edison inspection, maintenance, and construction crews.

4) **OH 5-year Repair** – This program funds the repair of defects identified during the OH 5-year inspections. Such defects may lead to safety hazards or have adverse effects on the system's performance. Defects found as a result of the inspections that are not repaired at the time of initial inspection will be scheduled and repaired according to the timeframes specified by the revision to the New York State Public Service Commission Order Instituting Safety Standards adopted December 10, 2008 Case 04-M-0159.

5) **Manual Contact Voltage Testing** – The Manual Contact Voltage Testing Program consists of the annual contact voltage testing of approximately 561,000 utility owned electric facilities and municipality owned street and traffic lights with a focus on improving public safety. The Program identifies possible insulation degradation and or bad connections that might be causing contact voltage on facilities so that crews can make repairs thereby enhancing overall system reliability. A full round of contact voltage testing must be completed by December 31st of each year.

6) **Mobile Contact Voltage Area Optimized (Vehicle Scans)** – This program covers the surveying of the underground electrical distribution system in the Con Edison service

territory for contact voltage utilizing mobile electric field detection. Contact voltages found are safe guarded until repair crews mitigate the contact voltage conditions. Upon detecting the presence of an electric field by the mobile detector, the testing contractor conducts a manual field investigation to locate the source of the electric field and mitigate if possible. If immediate repairs to mitigate the condition cannot be made by the contractor, the Con Edison Call Center is notified, the area cordoned off and safeguarded until repair crews respond to the location. Under the New York Public Service Commission (PSC) order Case 07-E-0523, Con Edison is mandated to complete twelve mobile contact voltage scans of the underground distribution system each rate year. In addition, under New York Public Service Commission (PSC) order Case 04-M-0159 Con Edison is mandated to conduct an annual mobile contact voltage detection survey of the underground electric distribution system in appropriate areas of cities with a population of at least 50,000. The 12 scans of NYC and 1 scan of Westchester cities with a population of 50,000 or more, are considered the annual cycle scan. In discussion during the rate case filing the PSC was in favor of the change from 12 system scans to 12 aggregate scans. This would allow for the optimization of the scanning program. The scan area optimization is projected to reduce the number of electric shocks as the time between detection and safeguarding for the substantial majority of energized objects is reduced. The Mobile Contact Voltage Detection Program has and will continue to make a significant contribution to improving public safety.

7) **Contact Voltage Testing Related Repairs** – Streetlights – This program works with the Manual and Mobile Contact Voltage Testing Programs. Contact voltage conditions discovered on municipality-owned streetlights or other street furniture are repaired under this program. Following a discovery, a crew works to identify the source of the contact voltage and will either make temporary or permanent repairs to mitigate the condition. Making repairs eliminates the contact voltage condition, which improves public safety, and corrects a defect on the system, which improves system reliability.

8) **Contact Voltage Testing Related Repairs – UG** – This program works with the Manual and Mobile Testing Programs. Contact voltage conditions discovered on publicly accessible objects (other than public streetlight or street furniture) are repaired under this program. Following a discovery, a crew works to identify the source of the contact voltage and will either make temporary or permanent repairs to mitigate the condition. Making repairs eliminates the contact voltage condition, which improves public safety, and corrects a defect on the system, which improves system reliability.

Justification Summary:
The Company is required to perform structure inspections and repairs pursuant to the PSC Safety Order(s) previously mentioned. The SIP UG Asset Optimized Inspection, URD Inspection and Repair are expected to reduce events by supporting other higher value initiatives. These initiatives include IR imaging and SOS monitoring, maintenance and repair. The Mobile Contact Voltage Area Optimized Pilot is also expected to reduce the number of electric shocks.

The increases in funding for the program are necessary to comply with the safety order and the "Order Granting in Part and Subject to Modifications Petition to Enhance Electric Safety Standards" January 28, 2021.

Relationship to 5-Year and Long-Range Plans and Enterprise Risk Management Strategy

This program seeks to identify potential defects and hazards. The Company investigates these conditions to determine if they are hazardous or could adversely impact system performance. The Company continues to seek ways to optimize this program, leveraging modern analytics and risk-based techniques to refine inspections, as well as techniques used to analyze findings. This is an important part of the risk mitigation strategy associated with the Enterprise Risk – Low Voltage Equipment Failure.

2. Supplemental Information

Alternatives

<u>Alternative 1 description and reason for rejection</u>

<u>Alternative 2 description and reason for rejection</u>

<u>Alternative 3 description and reason for rejection</u>

Risk of No Action
<u>Risk 1:</u>
UG/URD SIP Inspections and Repairs, defect repairs found continue to grow and the defect backlog continues to increase. Enhanced inspections and targeted scans would have to be curtailed and the benefits from these additional scans would not be realized.

<u>Risk 2</u>

<u>Risk 3</u>

Non-Financial Benefits
Examples:

The optimized scanning and inspections performed under this program improve both public safety and system reliability. Changes to the Inspection program will also have wide ranging public benefits from decreased traffic interruptions to noise associated with flushes.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis (if required)

2. Major financial benefits

3. Total cost

4. Basis for estimate
Incremental costs for the program in 2023 and 2024 are due to:

- Increased number of planned inspections prioritized for structures that weren't inspected in cycle 3, in accordance with PSC Order in response to Company petition to move to Asset Management approach to inspection prioritization.
- Higher than expected flush rate.
- High cost of "stopped inspections" – inspections that require additional labor to perform because they are obstructed, concealed, paved-over, or otherwise difficult to gain access to.

Costs nearly normalize 2025 but are slightly higher due to the need to complete any "stopped inspections" to meet the 100% target for high priority structures.

5. Conclusion

Project Risks and Mitigation Plan

Risk 1 — Mitigation plan

Risk 2 — Mitigation plan

Technical Evaluation / Analysis

Project Relationships (if applicable)

3. Funding Detail

<u>Total Request ($000)</u>:

Total Request by Year:

	Request 2022	**Request 2023**	**Request 2024**	**Request 2025**	**Request 2026**
Capital					
O&M*	**37,764**	**45,968**	**47,834**	**47,834**	**37,911**
Retirement					

*These figures do not match those in the revenue request in the initial filing. The revenue request will include these on update.

Exhibit_(EIOP-4)

T&D New Business and System Expansion

Schedule 1: T&D New Business and System Expansion Capital Program and Project Summary

Electric T&D *New Business & System Expansion*		**Year Total** Current Budget Total Dollars ($000)			
		RY1	**RY2**	**RY3**	**3 Yr. Total**
NEW BUSINESS					
Organization	**White Paper**				
Distribution	Light Duty Electric Vehicle Make-Ready Program	26,919	39,432	47,932	114,283
Distribution	Meter Installations	30,006	30,006	30,006	90,018
Distribution	New Business Capital Program	179,308	198,572	195,090	572,970
	New Business Sub-Total	**236,233**	**268,010**	**273,028**	**777,271**
SYSTEM EXPANSION					
Organization	**White Paper**				
Distribution	179th St Area Substation Reconstruction	488	-		488
Transmission	Amtrak PSA - OAK	5,000	5,000	-	10,000
Distribution	Brownsville Area Load Relief	35,264	26,000	27,000	88,264
Distribution	Crown Heights Network Split	-	-	12,482	12,482
Distribution	Ed Koch Queensboro Bridge 13kV Riser Replacement	-	750	1,600	2,350
Substations	Emergent Load Relief Program	1,100	1,100	1,100	3,300
Substations	Farragutt STATCOM	22,000	74,000	34,000	130,000
Substations	Gateway Park Area Station	30,000	20,000	200,000	250,000
Substations	Goethals Shunt Reactor R26	1,000	3,500	5,500	10,000
Substations	Jamaica Substation - Replace Limiting 27kV Bus Sections	2,000	2,000	2,000	6,000
Distribution	Network Transformer Relief	10,782	10,871	10,977	32,630
Substations	Newtown TR4 and 138kV Feeder 38Q05 from Vernon	10,000	33,000	33,000	76,000
Distribution	Non-Network Feeder Relief (Open Wire)	7,283	7,283	7,283	21,849
Distribution	Overhead Transformer Relief	2,299	2,299	2,299	6,897
Substations	Parkview TR5 and Feeder 38M85	-	30,000	72,000	102,000
Distribution	Primary Cable Crossing (B/W City Island, Riverdale, Croton River, and BQ Flushing)	21,500	11,600	2,500	35,600
Distribution	Primary Feeder Relief	10,444	10,444	10,444	31,332
Distribution	Secondary Mains Load Relief	7,064	7,064	7,064	21,192
Substations	Vinegar Hill Distribution Switching Station	33,000	-	-	33,000
Distribution	W42nd St No. 1 to Astor Transfer	2,000	2,000	-	4,000
Distribution	West Bronx/Randall's Island Reconfiguration Program	16,100	4,100	-	20,200
Distribution	Williamsburg Network Improvements	17,800	23,700	23,800	65,300
Distribution	Yorkville Crossings and Feeder Relief	16,000	10,500	3,000	29,500
	System Expansion Sub-Total	251,124	285,211	456,049	992,384
TOTAL ELECTRIC					
	New Business	**236,233**	**268,010**	**273,028**	**777,271**
	System Expansion	**251,124**	**285,211**	**456,049**	**992,384**
	Total New Business & System Expansion	**487,357**	**553,221**	**729,077**	**1,769,655**

Schedule 2: T&D New Business and System Expansion O&M Program Change Summary

Infrastructure Investment Panel				
O&M Program Changes				
EIOP - New Business and System Expansion				
($000)				
		RY1 Program Change	**RY2 Program Change**	**RY3 Program Change**
NEW BUSINESS				
Organization	**White Paper**			
Distribution	Meters and Customer Equipment Program	4,538	1,196	144
SYSTEM EXPANSION				
Transmission	Transmission Operations Capital Projects	3,915	3,915	3,915
Transmission	Transmission Planning Staffing Needs to Support Clean Energy Agenda	405	405	405
TOTAL ELECTRIC				
	New Business	**4,538**	**1,196**	**144**
	System Expansion	**4,320**	**4,320**	**4,320**
	Total New Business & System Expansion	**8,858**	**5,516**	**4,464**

Schedule 3:

T&D Capital and O&M White Papers

New Business and System Expansion

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☒ **Regulatory Mandated** ☐ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Light Duty Electric Vehicle Make-Ready Program	
Project/Program Manager: Joseph Lloyd	**Project/Program Number (Level 1): 23288072, 23291650, 23317524, 23319027**
Status: ☐ **Initiation** ☐ **Planning** ☒ **Execution** ☐ **On-going** ☐ ☐ **Other:** ___________	
Estimated Start Date: 7/16/2020	**Estimated Date In Service: 12/31/2025**
A. Total Funding Request: $184,405 **B. Capital: $184,405** **O&M: N/A** **Regulatory Asset:**	**C.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Regulatory Asset:**	**D. Investment Payback Period: N/A (Years/months) (If applicable)**

Work Description:

The Electric Vehicle Infrastructure Make-Ready Program ("Make-Ready Program" or "Program") will seek to incent make-ready infrastructure for new Level 2 (“L2”) and Direct Current Fast Charging ("DCFC") electric vehicle ("EV") charging stations for light-duty vehicles in the Company's service territory. The Order for this program, issued on July 16, 2020, authorized an approximately $290 million budget to support the installation of 18,539 L2 and 457 DCFC charging plugs in Con Edison’s service territory over the five-year Make-Ready Program. The Order also authorized other activities supporting the electrification of transportation, including the development of a Fleet Assessment Service.

Beyond providing incentives to participants installing charging stations, the program work includes program administration and management, business development and marketing, creation of an integrated IT platform to manage and track projects, enhancements to existing Company work management systems to streamline engineering reviews, development of program strategy, and support for electrification of Westchester transit depots.

Case 18-E-0138, “Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs”

As required by the New York Public Service Commission (“PSC”) Case stated above, the portion of the Make-Ready Program described in this white paper includes the utility-side capital costs associated with the program. This may include traditional distribution infrastructure that will be installed, owned, and operated by Con Edison, such as step-down transformers, overhead or underground service lines, and utility meters. These costs include the following categories:

- **EV New Business**: Utility electric infrastructure needed to connect and serve the load associated with new EV charger(s)
- **Utility-side Power Ready:** Any additional infrastructure that would have otherwise been paid by the Participant as Excess Distribution Facilities ("EDF"), contributions in aid of construction ("CIAC") and/or accommodation charges
- **Utility-side Future Proofing:** Any costs associated with installing additional infrastructure to accommodate additional plugs, parking spaces, or higher capacity equipment in the future

The projected utility-sided capital yearly expenditures are as follows:

Program Budget ($000)

Program	2022	2023	2024	2025	Total
EV New Business	$18,888	$20,623	$30,743	$37,674	$107,928
Utility-side Power Ready	$5,596	$5,829	$8,045	$9,498	$28,970
Utility-side Future Proofing	$448	$466	$644	$760	$2,318
Total	**$24,932**	**$26,919**	**$39,432**	**$47,932**	**$139,215**

The portion of the Make-Ready Program that includes program administration and management, business development and marketing, creation of an integrated IT platform to manage and track projects, enhancements to existing Company work management systems is described in the Customer Energy Solutions ("CES") Panel testimony and the white paper in the associated exhibit.

Justification Summary:

The PSC has recognized that EVs are a critical component to achieving the emission reductions called for in the State Energy Plan and the Climate Leadership and Community Protection Act ("CLCPA"). In particular, EV charging stations will serve as a key element to support EV adoption and enable the State to meet its CLCPA goals. This program supports the acceleration of EV charging station deployment and will drive down costs, reduce range anxiety, and speed the adoption of Zero Emission Vehicles.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

This work supports the Company's long-range plans for decarbonization by supporting the electrification of transportation in our service territory. This work is also related to a PSC Order, as described above. This program supports the achievement of PSC targets for electric vehicle charging stations and supports the achievement of the State's CLCPA goals.

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection
N/A: This Program is Required for compliance with a PSC order

<u>Alternative 2 description and reason for rejection</u>

<u>Alternative 3 description and reason for rejection</u>

Risk of No Action

<u>Risk 1</u>
N/A: This Program is Required for compliance with a PSC order

<u>Risk 2</u>

<u>Risk 3</u>

Non-Financial Benefits
N/A

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis (if required)
N/A

2. Major financial benefits
New capital spending and related earnings opportunities as described in the Order.

3. Total cost: $140M

4. Basis for estimate
Funding categories as authorized in the Order, and internal/external estimates of specific work elements.

5. Conclusion
This program meets a regulatory requirement and supports the State's achievement of CLCPA goals.

Project Risks and Mitigation Plan

Risk	Mitigation plan
Risk 1: Not meeting plug targets	Mitigation plan: Process improvements; IT portal; business dev.
Risk 2	Mitigation plan

Technical Evaluation / Analysis
N/A

Project Relationships (if applicable)
Light Duty Electric Vehicle Make-Ready Program under CES

3. Funding Detail

Historical Spend ($000)

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital						15,650
O&M						
Regulatory Asset						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	24,932	26,919	39,432	47,932	45,190
O&M*	N/A				
Regulatory Asset					

Capital/Regulatory Asset Request by Elements of Expense: N/A

EOE	2022	2023	2024	2025	2026
Labor	6,582	7,107	10,410	12,654	11,930
M&S	3,715	4,011	5,875	7,142	6,733
Contract Services	8,676	9,368	13,722	16,680	15,726
Other	(3,740)	(4,038)	(5,914)	(7,190)	(6,779)
Overheads	9,699	10,471	15,339	18,646	17,580
Total	**24,932**	**26,919**	**39,432**	**47,932**	**45,190**

Total Gross Cost Savings / Avoidance by Year: N/A

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year: N/A

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Project Status:

- Initiation – New project, not authorized yet
- Planning – Project authorized, not started yet
- Executing – Project in-flight
- On-going – Annual program

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☐ Project ☒ Program	**Category: ☒ Capital ☐ O&M**
Work Plan Category: ☒ Regulatory Mandated ☐ Operationally Required ☐ Strategic	
Project/Program Title: Meter Installations	
Project/Program Manager: Charles Feldman	**Project/Program Number (Level 1): 10029663, 10035740**
Status: ☐ Planning ☐ Design ☐ Engineering ☐ Construction ☒ Ongoing ☐ Other: ____________	
Estimated Start Date: 2021	**Estimated Date In Service:2025**
A. Total Funding Request ($000) **Capital: 150,930** **O&M:** **Retirement:**	**B.** **☐ 5-Year Gross Cost Savings ($000)** **☐ 5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This program provides for the installation of electric revenue meters and associated metering equipment for revenue collection as required by PSC regulations. The installation is to be handled by Electric Operations personnel and include electric meters and revenue grade instrument transformers. Meters are to be installed in new customer locations, in existing customer locations that were upgraded, and as replacements for mechanical meters which require more frequent testing.

Units per Year: Approximately 79,000 units that include electric meters and/or auxiliary metering appurtenances.

Mandatory: Approved electric revenue metering equipment as required in PSC No. 10 – Electricity, General Rule 6 and 16 NYCRR Part 92.

High-level schedule: This is an ongoing activity where the metering equipment is purchased based on customer requests and operational needs.

The replacement of failed meters and new business work will be done by Electric Operations and is not covered in the AMI project. The meters installed will be the same as those installed by the AMI project.

Justification Summary:
Meter Installation is necessary to provide service to customers. Electric meters are required by the New York State PSC for revenue collection.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

The purchase and installation of customer meters is fundamental to the core business. The AMI meters that are currently installed provide greater insight into real-time and historic energy use for customers and for Con Edison providing a platform for new programs and innovative operating procedures and policies. One example is the Customer Voltage Optimization program. Because the customer voltage is readily available, operators are able to reduce the voltage on feeders while ensuring all customers are getting adequate voltage. This reduces the energy consumed by the customers, which reduces their cost, and also reduces the generation needed to supply them. This provides an overall savings to the customer while also reducing the overall energy demand of the system. While this program itself does not implement strategies to mitigate the Enterprise Business Model Risk, it supports a platform upon which those programs will be built.

2. Supplemental Information

Alternatives

There are no acceptable alternatives to the use of PSC approved metering devices as specified in PSC 16 NYCRR Part 92 and PSC No. 10 – Electricity for electric rate paying customers. Meters provide the means to accurately record customer demand, implement time of day rates, demand response and energy efficiency programs and comply with regulatory metering programs such as reactive power. The last step in energizing new customers with electric service is to install the meter.

Risk of No Action

Without meters, new tariffs would have to be developed for flat rate billing which are not approved by the PSC at this time. In addition, service for many new customers would be delayed or recognized as unmetered.

Non-Financial Benefits

Metering a customer's energy usage provides an objective measure of the amount of energy used. This improves customer satisfaction by removing any doubt a customer might have about the accuracy of their bill. Electric meter data for customers is used to invoice customers for usage and will improve system planning for critical system upgrade engineering analysis.

Summary of Financial Benefits and Costs (attach backup)

Installation of electric meters provides an accurate means to record customer energy usage for revenue collection. In addition, meters provide a point of disconnection in the event of non-payment. Each year, the Revenue Protection Unit team uncovers approximately 3,000 cases of theft and irregular meter conditions.

Project Risks and Mitigation Plan

Risk 1
Supply chain issues with meters from only one source because of the AMI deployment using meters from a single manufacturer could result in delays in energizing new customers or supplying replacement meters when failures occur.

Mitigation Plan
To mitigate this risk, Meter Engineering will evaluate alternative products that are compatible with the AMI system to provide a competitive vendor environment toward reducing costs and assure that meters can be obtained in a timely manner.

Technical Evaluation / Analysis

Meters, Devices and Instrument Transformers are selected based on customer loads, engineering analysis of manufacturer's equipment relative to our service territory as well as previous performance of similar products. Included in the budget are add-ons to support time-of-use and interval data as well as remote communications.

Project Relationships (if applicable)

The Meter Installation program is directly tied to the Meter Purchase program. Con Edison needs to properly purchase and install new meters to bill customers and operate a safe and reliable network.

3. Funding Detail

Historical Spend (000s)

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	26,263	30,251	32,313	25,694		26,090
O&M						
Retirement	50	798	800			

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	30,006	30,006	30,006	30,006	30,906
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	18,246	18,246	18,246	18,246	18,793
M&S	1,464	1,464	1,464	1,464	1,508
Contract Services	290	290	290	290	299
Other					
Overheads	10,006	10,006	10,006	10,006	10,306
Subtotal	**30,006**	**30,006**	**30,006**	**30,006**	**30,906**
Contingency**					
Total	**30,006**	**30,006**	**30,006**	**30,006**	**30,906**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: New Business Capital	
Project/Program Manager: Joseph Lloyd	**Project/Program Number (Level 1): 10037542, 10037486, 21439917, 10037572, 10037475, 10037577, 10037519, 24543990, 23899431, 10030412, 10030414, 10030415, 10030416, 10030330, 10030332, 10030357, 10030358, 10030427, 10030428, 10030431, 10030361, 10030429, 10030359, 10030473, 10030475, 10032154, 10030552, 10030553, 10030554, 10030555**
Status: ☐ **Initiation** ☐ **Planning** ☐ **Execution** ☒ **On-going** ☐ ☐ **Other:** ___________	
Estimated Start Date: Various	**Estimated Date In Service: Various**
A. Total Funding Request ($931,303) **Capital:** $931,303 **O&M:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months) (If applicable)**

Work Description:

Based on the required Company facilities necessary to complete service installations for new business, the electric new business capital work is broken into two categories: Retail and Major Projects.

Under $100k Retail: To adequately supply proposed new customer loads, the Company must install or replace an existing overhead or underground service. For underground services, the Company installs or replaces an underground service cable in an existing service conduit or new service duct. For an overhead service, the Company extends a new service or replaces an existing service from our facilities to the customer's point of attachment.

Over $100K Projects Major Projects: To adequately supply proposed new customer loads, the Company must install service cable, primary and/or secondary cable in vacant conduit or newly installed conduit, or additional overhead (OH) primary/secondary spans/poles. Installation of transformers and manholes are required while manhole and service box enlargements may also be required.

Justification Summary:

Due to the impact of COVID in 2020, trends for retail and major projects were slightly lower than average. Over the next five years we expect the trends for retail and majors projects to increase steadily.

Also, as Local Law 97 is applied to large commercial and residential properties, an increase in conversions to all electric buildings will increase as well.

Relationship to 5-Year and Long-Range Plans and Enterprise Risk Management Strategy

Con Edison recognizes that climate is changing and considers that the floodplain will extend over time due to sea-level rise, and that temperature and rainfall amounts will also rise. As such facilities will be designed in accordance with standards for climate adaptation. Engineering will design systems in accordance with Climate Change Planning and Design Guideline Document & Corporate Instruction CI-610-4. The specific project will determine which climate change pathways ("the Pathways") and design elements to incorporate into the project for increased precipitation, temperature rise, and sea level rise. Note that each project and application will need to be reviewed and analyzed.

Examples

To maintain reliability and improve resiliency moving forward, designs and construction for new customers must account for rising sea levels and the associated extension of the floodplain. To address the impacts of rising sea levels, new installations use a projected floodplain of FEMA +5. Transformers, network protectors, and associated equipment in the floodplain must either consist of submersible equipment or be elevated above the plain.

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection

Given the fact that Con Edison has an obligation to serve new customers within the Company's service territory, there are few alternatives to consider regarding New Business Capital. However, the Company considers and reviews specific alternatives on each major project. Our Design Review initiative continues to vet various options and collaborate on the most cost-effective solution. In addition, we have recently completed a comprehensive review of our estimated demand factors resulting in an overall reduction in predicted peak demand. We also continue to incorporate new technologies into our design to help reduce capital spend. These technologies include the use of 18 Pt Terminal Housings & Submersible Bus Equipment. Lastly, Customer Engineering is working closely with the Distributed Engineering Department to develop specifications to incorporate customer sided distributed generation into our design criteria.

Alternative 2 description and reason for rejection

Alternative 3 description and reason for rejection

Risk of No Action

Risk 1
"No action" is not an option when it comes to capital spending associated with the connection of new customers. Our future revenue stream and compliance with New York Public Service Commission (PSC) regulations necessitates the connection of new customers to our system.

Risk 2

Risk 3

Non-Financial Benefits

To support customer satisfaction by ensuring regular communication with customers requesting new and additional energy supply. In addition, guaranteeing a safe, reliable, efficient, and timely installation of service.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis (if required)

2. Major financial benefits

3. Total cost

4. Basis for estimate
Historical costs.

5.

Project Risks and Mitigation Plan

Risk 1 Given new areas of development historical costs may be significantly less than new costs.

Mitigation plan
Costs in new areas will be evaluated closely and necessary adjustments will be made through the Capital Governance Process.

Technical Evaluation / Analysis

Each project in the new business program is ruled using diversification factor and load density factor methods. The lower value between the two methods will be used for the customer's new demand. Poly-Voltage Load Flow (PVL) is also used to access the customer's impact to the grid. The PVL software helps identify additional reinforcement work, if needed because of the new customer. Lastly, every year, all the upcoming new customer projects are verified by Customer Engineering and provided to the Commodity Forecasting department. It is used to provide a network peak forecast over the next 10 years.

Project Relationships (if applicable)

The new business program is a stand-alone program. However, there are instances where new business may impact load relief programs from Regional Engineering. In those cases, Customer Engineering and Regional Engineering will provide a cost beneficial solution which will address both customer needs and company requirements for load relief.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	**176,685**	**168,875**	**165,971**	**153,968**		**190,228**
O&M						
Regulatory Asset						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**164,299**	**179,308**	**198,572**	**195,090**	**194,034**
O&M*					
Regulatory Asset					

Capital/Regulatory Asset Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	41,080	44,832	49,649	48,778	48,514
M&S	25,653	27,996	31,004	30,460	30,296
Contract Services	52,837	57,664	63,859	62,739	62,400
Other	(17,909)	(19,945)	(21,645)	(21,265)	(21,150)
Overheads	62,638	68,360	75,704	74,377	73,974
Total	**164,299**	**179,308**	**198,572**	**195,090**	**194,034**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don’t occur today (e.g., anticipated short-term fixes/maintenance if capital isn’t deployed)

Project Status:

- Initiation – New project, not authorized yet
- Planning – Project authorized, not started yet
- Executing – Project in-flight
- On-going – Annual program

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: E. 179th St Substation Reconstruction Distribution Feeder Transfers	
Project/Program Manager: Travers Dennis	**Project/Program Number (Level 1):** 20593360
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date: Spring 2011	**Estimated Date In Service:** Fall 2023
A. Total Funding Request ($976) **Capital:** $976 **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:
Transfer existing distribution feeders in support of the upgrade and redesign of the bus within 179th Street area Substation (S/S). The feeders are being relocated from existing bus sections to the newly constructed bus sections as substation construction completes during the substation reconstruction project.

- 2016 - Install two manholes and conduit.
- 2017 - Install two manholes and conduit.
- 2018 - Install two manholes and conduit and relocate six feeders to two new bus sections.
- 2019 - Relocate four feeders to new bus section.
- 2020 - Relocate twelve feeders to three new bus sections and establish one new feeder.
- 2021 - Relocate four feeders to new bus sections and establish two new feeders.
- 2022-23 install new cable and transfer the distribution feeders from an existing switch positions to new positions

Justification Summary:
The E. 179th St Substation is the source of supply that feeds the Fordham Network in the Bronx. Con Edison began reconstruction of the substation in the spring of 2011, to modernize and make it more reliable. The plan is to reconstruct the existing substation and convert it into a double-syn bus design. The plan converts the transition of the area substation over a ten year period while the station remains in service. As each portion of the station is completed, Con Edison must transfer the distribution feeders from the existing switch positions and bus sections to the newly established switch positions. A manhole and conduit system will be built in 2019 to accommodate the transfer of the distribution feeders. The remaining work to install new cable and transfer the distribution feeders from an existing switch positions to the new positions
is planned for 2018, 2019, 2020, 2021, 2022 and 2023.

Relationship to 5-Year and Long-Range Plans and Enterprise Risk Management Strategy

- East 179th Street–Switchgear and Bus Replacement

- Basis for Estimate:
  Historical costs were applied after a review of the cable and splicing required and the inclusion of a projected 20% obstruction rate.

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection

- There are no alternatives to replacing aging substation equipment to improve reliability other than the continuation of the substation reconstruction project.

Alternative 2 description and reason for rejection

Alternative 3 description and reason for rejection

Risk of No Action

Risk 1

- The substation transformers will be overloaded.

Risk 2

Risk 3

Non-Financial Benefits

- Establish new feeders will be used to de-load feeders in the Fordham network to improve reliability and efficiency.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)

2. Major financial benefits

3. Total cost

4. Basis for estimate

5. Conclusion

Project Risks and Mitigation Plan

Risk 1 Mitigation plan

Risk 2 Mitigation plan

Technical Evaluation / Analysis

Project Relationships (if applicable)

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	375	776	295	1139		728
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**488**	**488**			
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	147	147			
M&S	86	86			
Contract Services	91	91			
Other					
Overheads	164	164			
Subtotal	**488**	**488**			
Contingency**					
Total	**488**	**488**			

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

Central Operations/STO
2022

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Amtrak PSA-OAK	
Project/Program Manager:	**Project/Program Number (Level 1): 24741479**
Status: ☒ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☐ **Ongoing** ☐ **Other: ___________**	
Estimated Start Date: 2022	**Estimated Date In Service:**
A. Total Funding Request ($000) **Capital: $15,000** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:
This project will establish new 138kV feeders from Mott Haven Substation to the new Metro North, Oak Substation. Amtrak/MTA is going to build a new substation in the east side of the Bronx along Bruckner expressway in order to upgrade its infrastructure. As a result, a new substation Oak Substation will be built. The station will be supplied by two 138kv feeders but under the rate tariff, these cables are considered service cables so won't be considered sub transmission feeders. There will a rebuild and replacement of the current Van Ness facility where a substation and train station will be built. MTA has to build these substations and add 3-4 miles of new track and refurbish three bridges, and four brand new train stations to be completed by 2025.

Con Edison will be building the service cables to their facility and is working together with MTA to engineer the path, from Mott Haven to an abandoned rail tunnel that runs east to west and at the end of the tunnel will be where this substation is. Con Edison's requirement is to build a few thousand feet of cable and two manholes in between.

Con Edison will be procuring the material and will install up to the property line to splice and terminate. One contractor will be doing all of the work between Amtrak, MTA and Con Edison so that the work is uniform. Con Edison will be responsible for maintaining up to the first manhole as the line of demarcation.

Con Edison is currently waiting on the bid which should be completed by the end of 2021.

Justification Summary:
MTA construction and development is funding an upgrade and infrastructure because Metro North will be running 125 trains a day on east side of the Bronx over Hellgate bridge into Penn Station. This

will shorten the commute for people in West Chester and the Bronx. In order to complete this work, Con Edison needs to supply 138kV cable that will act as service cable.
This project is a New Business project and ConEdison has an obligation to serve under the NYISO tariff section 4.6 related to high tension service. "High tension service may be designated by the Company for service when warranted by the magnitude or location of the load, or other physical conditions, or when it would result in the least cost to the Company".
This is a unique project in that all of the work will be done by one contractor.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):

2. Supplemental Information

Alternatives
ConEdison has an obligation to provide service per the NYISO tariff. Distribution looked at supplying the station with MV feeders.

Non-Financial Benefits
Click here to enter text.

Summary of Financial Benefits and Costs (attach backup)
N/A

Project Risks and Mitigation Plan

Technical Evaluation / Analysis

Project Relationships (if applicable)

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	N/A	N/A	N/A	N/A		N/A
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	5,000	5,000	5,000	0	0
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	160	160	160		
M&S	600	600	600		
Contract Services	3,120	3,120	3,120		
Other	840	840	840		
Overheads	280	280	280		
Total	5,000	5,000	5,000	0	0

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Brownsville Area Load Relief	
Project/Program Manager:	**Project/Program Number (Level 1): 25966356**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☐ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date:	**Estimated Date In Service:**
A. Total Funding Request ($113264) **Capital:** $113,264 **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

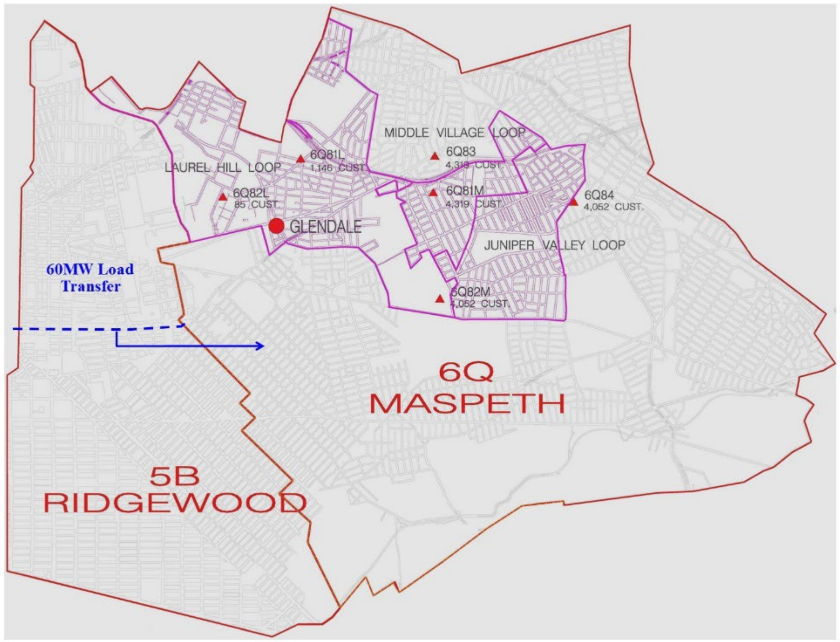
This program will focus on addressing the forecasted Brownsville sub-transmission feeders overloads. Prior to the new Gateway Park Area Station being established in 2028, the Company plans to implement several measures to address forecasted near-term load growth. These measures include (1) transferring 6MW of High Tension (HT) customer and autoloop loads to nearby stations/networks, (2) transferring 60MW of secondary network load from the Ridgewood network to the Maspeth network, (3) connecting 12MW of new Starrett City customer load to the Flatbush network, and (4) installation of 4kV Overhead and 120/208V Underground capacitor banks to improve system power factors.

Measure #1: The Company plans to transfer the Metropolitan Transportation Authority (MTA) transit rectifier station (HTV7051) from the Crown Heights (3B) to the Flatbush (4B) network. HTV7051 is a 2-feeder station with an estimated load of 2MW. The Company plans to install 150 feet of conduit and one section of primary cable to facilitate this transfer.

The Company also plans to transfer the MTA transit rectifier station (HTV2337) & Starr 4kV Autoloop from the Ridgewood (5B) to the Maspeth (6Q) network. HTV2337 and Starr Loop are supplied by the same two 5B feeders and have an estimated total load of 4MW. The Company plans to install 480 feet of conduit and 10 sections of primary cable to facilitate this transfer.

Measure #2: The Company plans a transfer of approximately 60MW from Brownsville #1 Substation to Glendale Substation. The northern portion of the Ridgewood (5B) network was selected as the most viable option to transfer the 60MW because of its geographic location. The design involves extending 12 network feeders from the Maspeth to the Ridgewood network. Fifteen feeders in the Ridgewood network will be split to accommodate the transfer.

To establish the new network the Company plans to install: 50,000 feet of conduit, 560 sections of primary cable, 140 structures, 8 network transformers, 3 shunt reactor, 50 switches, and 50 sections of secondary cable.



Measure #3: The Company will extend five 4B network feeders (Flatbush Network – Bensonhurst Substation) to connect 15MVA of load from Starrett City, a new customer. This involves approximately 20,000 feet of trenching on Flatlands Ave to install a new duct, 90 sections of primary cable, and 52 manhole structures.

Measure #4: Con Edison will install a number of capacitor banks in the area to provide approximately 20MVAr resulting in approximately 5 to 6MW of effective load relief. Types of capacitor banks will include 450kVAr switchable and Supervisory Control and Data Acquisition (SCADA) controlled capacitor banks, 90kVAr capacitor banks, and potentially 27kV pad mounted connected switchable capacitor banks.

Justification Summary:
The current forecast indicates significant load growth in the Brownsville area, driven by new residential and commercial business as well as increasing electric vehicle and electric heating load. Based on the current forecast, the Brownsville networks have projected loads that will cause the transmission feeders supplying the Brownsville load pocket (feeders: 38B01, 38B02, 38B03, 38B04 and 38B05) to experience overloads in the coming years. The addition of new Starrett City customers to the electric distribution system also adds significant additional load to the already constrained area. Due to ongoing load growth as well as forecast uncertainty in electric vehicle and electric heating adoption in the Brownsville Load Area load relief solutions need to be implemented prior to 2028.

							Gateway Planned Service Date ↓		Contingency Plan ↓	
	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Brownsville No. 1 & 2	776	800	819	828	834	840	847	860	889	902
Utility Sided Solutions (USS)	-11	-11	-11	-11	-12	-12	-12	-12	-12	-12
Customer Sided Solutions (CSS)	-1	-2	-3	-8	-18	-18	-18	-18	-18	-18
Net Load	764	787	805	809	804	810	817	830	859	872
MW deficiency @138 kV	7	-16	-34	-38	-33	-39	-46	-59	-88	-101
MW deficiency @143 kV	35	12	-6	-10	-5	-11	-18	-31	-60	-73

Justification for Measure #1: The 6MW in load transfers do not require any Station/Transmission work on the pick-up stations. The HTV/Loop transfers will not significantly affect the NRI of the pickup networks.

Justification for Measure #2: Glendale Substation, which supplies Maspeth, has the excess capacity to support the temporary load relief. This option is most cost beneficial because of Glendale Substation's proximity to the cut-line of the load transfer. The extent of conduit and cable installation would be minimized compared to load transfer to alternative substations such as Newtown or North Queens.

Justification for Measure #3: Starrett City, located in the heart of Brooklyn's East New York with 46 residential buildings, has been on electric self-generation for many decades. Partially due to the age of their onsite generation equipment, Starrett City has now requested to become a customer of Con Edison.

Starrett City's new load will connect to the Flatbush Network to avoid furthering the existing capacity constraints at Brownsville No. 2 substation and help circumvent system overloads.
With the multiple other Brooklyn Queens Demand Management efforts in place to relieve the already constrained capacity at the Brownsville No.2 substation, incorporating an addition 15MVA load to the substation is not an option.

Justification for Measure #4: The installation of numerous capacitor banks will provide an additional 5-6MW of load relief for the limiting 138kV feeders. In addition, the capacitor banks will also provide some load relief for the supplying 27kV feeders and will also benefit Conservation Voltage Optimization (CVO) efforts in the network as well.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

The Brownsville Area Load Relief Program will allow the continuous load growth in the network without overloading transmission and sub-transmission feeders that can cause equipment damage and service interruptions. In addition, the new capacitor banks installed as part of this program will improve system power factor. This program supports Electric Long-Range Plan goals for increased resiliency and sustained reliability while also helping to prevent a potential network shutdown, in alignment with the Company's Enterprise Risk Management Strategy.

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection

An alternative considered was to rely upon Customer Sided Solutions (CSS) such as energy efficiency programs to mitigate any future transmission capacity deficiencies. Energy efficiency programs can provide cost-beneficial solutions across multiple customer segments by accelerating load relief through energy efficient upgrades and may aid in the deferral of traditional solutions for multiple years. Based on the magnitude of load relief required to address the overload constraints in Brooklyn under a limited time frame, it has been assessed that an energy efficiency program is not a viable option. There is no known contingency plan other than to pursue the identified traditional solution should this alternative be pursued and prove unable to meet the projected deficits.

Alternative 2 description and reason for rejection

Also considered was a plan for a different, traditional solution to the transmission capacity deficiencies associated with Bensonhurst Substations# 1 and # 2 and Brownsville Substations # 1 and # 2. Installing cable cooling plants for the feeders that supply Bensonhurst would increase their capacities and address the deficiencies. This alternative would likely require land procurement for the cooling plants themselves and would only solve the feeder rating deficiency and would not provide any network reliability improvements to the subject networks. Should load growth continue to a point where equipment within either of the Bensonhurst and/or Brownsville substations reach its maximum capacity, additional work would be required.

Risk of No Action

An overload on the sub-transmission feeders supplying Brownsville #1 and #2 Substations is predicted to occur. Many of Con Edison's Brooklyn and Queens substations are near full capacity and do not offer the feasibility of load transfer. In the event the sub-transmission feeders overload, load shedding may be required during peak conditions.

Non-Financial Benefits

The benefit of the project are the relief of overloaded transmission feeders, which will ensure continued reliable service to the Brownsville load pocket. The project will also reduce the size of the Ridgewood network and the length of the Ridgewood distribution feeders. This will improve the reliability of the Ridgewood Network.

In addition, the switches used to facilitate the 60MW transfer from Ridgewood to Maspeth networks will remain in place to act as Substation Resiliency switches. These switches and associated cable will allow for faster restoration of power to customers in that load pocket in the event of an emergency affecting either the Glendale or Brownsville #1 Substations.

Summary of Financial Benefits and Costs (attach backup)

As discussed above, multiple alternatives were considered in-order to relieve the Brownsville load pocket and the selected option is the least expensive.

Project Risks and Mitigation Plan

Risk 1
The condition and status of the 14,000 feet of conduit previously installed in 2016 is such that It cannot be used for this project

Mitigation plan
Inspect the conduit and cable to ensure it is still capable of supporting the 60MW transfer.

Risk 2
Lanes for feeder extensions may not be available.

Mitigation plan
Survey and inspect the feeder extension routes.

Technical Evaluation / Analysis

In general, infrastructure adequacy is determined by comparing the infrastructure capability, in this case the transmission system supplying the Brownsville load pocket, against the net load to be served. The net load is determined from the gross forecasted customer demand less any load relief measures such as existing and forecasted energy efficiency or local distributed resources in the network.

Capability of the 138 kV transmission system is based on using nominal operating voltage of 138 kV and Summer Normal feeder rating. Based on the demand forecast and 138 kV feeder capabilities, the 138 kV sub-transmission feeders were deficient, with deficiencies continuing to grow and will require load relief. Some temporary operating measures including the use of 'special' feeder ratings and/or higher operating voltages can be utilized and will continue until permanent relief is obtained.

Project Relationships (if applicable)

Gateway Park Area Station project

3. Funding Detail

Historical Spend

	Actual 2016	Actual 2017	Actual 2018	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	1,708					
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital		35,264	26,000	27,000	25,000
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor		4,055	2900	3,105	2,878
M&S		7,582	5,590	5,805	5,371
Contract Services		7,546	5,564	5,778	5,354
Other		0	0	0	0
Overheads		10,191	7,514	7,803	7,230
Subtotal		**29,374**	**21,568**	**22,491**	**20,833**
Contingency**		5,980	4,432	4,509	4,167
Total		**35,264**	**26,000**	**27,000**	**25,000**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026	2027
O&M Savings						
O&M Avoidance						
Capital Savings						
Capital Avoidance						

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026	2027
O&M						
Capital						

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Crown Heights Network Split	
Project/Program Manager:	**Project/Program Number (Level 1): 25776060**
Status: ☒ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☐ **Ongoing** ☐ **Other: ___________**	
Estimated Start Date:	**Estimated Date In Service:**
A. Total Funding Request ($000) **Capital: $48,794** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

Con Edison is planning this project to deload Brownsville #1 Area Substation (BV1) and the supply transmission feeders by transferring 117 MWs of load from the Crown Heights (3B) network to the newly established Gateway Park Area Station (Gateway) by 2028 to avoid transmission feeder overloads in the Brownsville load area. Con Edison will accomplish this by creating a new network out of the southerly portion of the Crown Heights (3B) network south of President street. Con Edison would commence work would in 2025 and be completed by 2028.

The 3B Network is a 204 MW, 16 feeder network. Con Edison is planning to deload the transmission feeders to BV1 and Brownsville 2 (BV2) area stations, by splitting the 3B network into two separate load areas: 3B North and 3B South. 3B North will consist of 14 feeders and 87 MWs, and 3B South will consist of 16 feeders and 117 MWs. Con Edison split the secondary low voltage system along President Street and Carroll Street to separate the load pockets of 3B South and 3B North. Con Edison will reinforce the secondary system along the new cut line on both sides to allow both the 3B North and 3B South networks to operate independently. Con Edison will extend feeders from the newly established Gateway to pick up 3B South. 3B North will remain within the BV1 load area and will be isolated from the south side via switches on the primary and secondary isolation cuts on the secondary. These switches would also have a resiliency function making 3B North and 3B South transferable between Gateway and BV1. In addition, Con Edison will be using 1000 mcm cable from Gateway to the pick-up point of 3B South to allow for resiliency plans involving the pick-up of 3B North and portions of the Ridgewood (5B) network in the future. Con Edison will be upgrade cable from the pickup point to the area of the Brownsville area stations to 750 mcm or higher to ensure capacity for future resiliency plans and increase reliability. The units involved for the permanent transfer are included below.

Total Units to permanently transfer 3B south to Gateway:

- 60,700 feet of Conduit
- 207 sections of primary cable
- 636 sections of secondary cable
- 106 manholes and or Vaults
- 155 service boxes
- 5 new switches
- 16 transformers

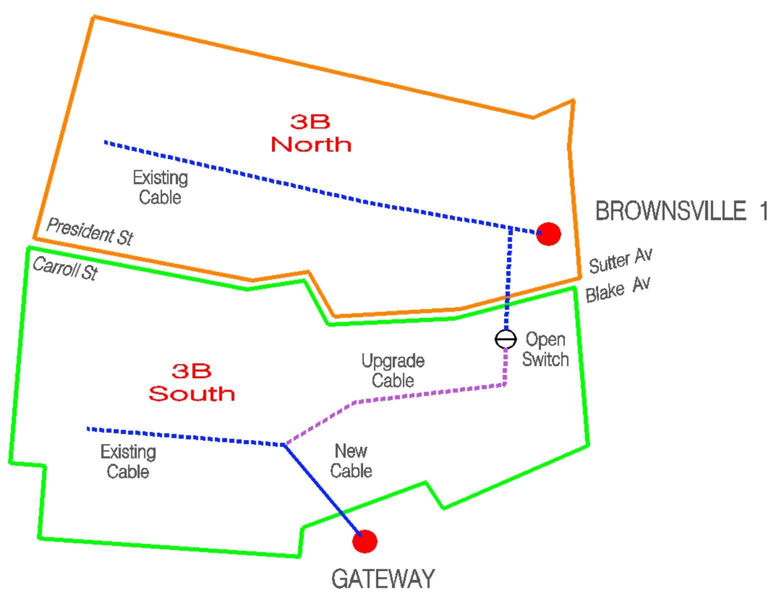
Additional units needed to make 3B North and 3B South transferrable for resiliency purposes:

- 86 sections of primary cable
- 9 manholes
- 9,690 feet of duct
- 12 Switches and associated structures

A prerequisite to this work is the establishment of Gateway which is a separate project. This station is a new indoor 27kV area substation that will be arranged in a double SYN bus configuration with five 138kV/27kV transformer banks. The station will be supplied from the 345kV Brooklyn Energy Hub. This station will allow for added resiliency to the network and additional transmission capacity to mitigate deficiencies in the Bensonhurst area stations and Brownsville load areas.

Substation Planning designs, and equipment procurement will begin in early 2023 for the Gateway project and construction is expected to begin in 2025. The in-service date of that project is May 2028.

The Gateway project also requires land procurement in an industrial manufacturing zoned area in Brooklyn. The land procurement process is expected to begin in 2022.



Justification Summary:
Provide an understanding of why the project/program should be done. ***Give a detailed description of the situation background and work to be completed.*** *If it is a primary driver for doing the work, include a discussion of the ERM addressed by the project or program. Be sure to include financial and non-financial benefits.*

The plan is to deload the Brownsville transmission feeders by splitting the Crown Heights (3B) network into two separate networks: 3B North will stay in BV1 and 3B South would be transferred to Gateway. This should provide about 117 MWs of load relief to the 138kV feeders feeding the Brownsville load pocket.

Based on the current forecast, the Brownsville electric distribution networks (Crown Heights-3B, Ridgewood-5B and Richmond Hill-9B) have projected loads that will cause the transmission feeders supplying the Brownsville load pocket (feeders: 38B01, 38B02, 38B03, 38B04 and 38B05) to exceed their capability by 2029. The capability of these feeders supplying BV1 and BV2 is 771 MWs and the load will match the capability by 2028. The transfer of 3B South to Gateway will alleviate the overloads on the 138kV feeders.

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Brownsville No. 1 & 2	786	786	791	795	790	792	795	797	799	822
Utility Sided Solutions (1)	-19	-19	-19	-20	-19	-19	-19	-20	-20	-20
CSS (1), (2)	-6	-6	-6	-6	-6	-6	-6	-6	-6	-6
Net Load	761	761	766	769	765	767	770	771	773	796
138 kV Feeder Capability (S.N. Rating = 847 Amperes)	771									

The Company has been successful in deploying a combination of traditional infrastructure and non-wires alternatives to defer the need for an area substation beyond the 10-year planning window. This alternative plan consists of non-traditional utility-side and customer-side solutions will provide load relief of about 26 MWs but will not be enough to avoid a forecasted overload of equipment by 2029. Variable inputs to the Company's annual demand forecasting and planning processes require the Company to pursue and construct Gateway in advance of its originally planned service date of 2032. In addition, Gateway will also offer the benefit to allow the company to deload the Bensonhurst load pocket if it becomes necessary.

The Gateway project will improve the reliability of networks by reducing the network sizes and will establish feasible resiliency options for various contingency events, which are not available with the existing distribution system design. The affected networks are: *(1)* Crown Heights (3B) network fed from BV1, *(2)* Ridgewood (5B) network fed from BV1, *(3)* Flatbush (4B) network fed from Bensonhurst 2 (BH2), and *(4)* Richmond Hill (9B) fed from BV2.

Crown Heights (3B) network (This Project): It will be split in two. This will greatly improve the reliability by breaking the load into smaller pockets fed by Gateway and BV1. There is a resiliency component since the two smaller load pockets are transferrable from one station to the other and vis versa.

Ridgewood (5B) network (Primary Feeder Reliability Program)**:** This network has the highest Network Reliability Index (NRI). With the construction of Gateway and the release of 3B South from BV1 3 feeder cubicles will be made available in BV1 allowing for new feeders to be introduced into the 5B network. Also, a portion of 5B south of Broadway can be permanently transferred to 3B North thereby further improving the NRI of Ridgewood. Resiliency can also improve if this load pocket out of Ridgewood is made transferable between Gateway and BV1.

Flatbush (4B) network (Primary Feeder Relief Program)**:** The Bensonhurst load pocket will need load relief in the future. 15 new feeders will be extended west from Gateway to pick up the south portion of the 4B network. The south portion consists of mostly non-network 4kV load with a total of 127 MWs and 15 feeders. 6 feeder cubicles would be released by this project in BH2 and can be used for new feeders in the 4B network and/or Brighton Beach (11B) networks. This would deload the Bensonhurst load pocket and improve the reliability of the networks fed by it. In addition, the new load pocket can be made transferrable between Gateway and BH2 to add an element of resiliency to the project.

Richmond Hill (9B) network (Primary Feeder Reliability Program): This network can be split into 2 portions: 9B North and 9B South. This will greatly improve the reliability by breaking the load into two smaller load pockets. The feeders from 3B South will be extended to and permanently pick up 9B South. This will reduce the load in the Brownsville load pocket and release 4 feeder cubicles in BV2 that can be used for new feeders in the 9B Network. In-addition 9B South can be made transferable between Gateway and BV2 to add an element of resiliency to the project.

Relationship to 5-Year and Long-Range Plans and Enterprise Risk Management Strategy
Explain how this project/program will help achieve goals in 5-year and long-range plans.
Explain how this project/program addresses risk mitigation activity. List specific departmental and/or corporate risk being impacted.

The operational measures and system improvements implemented with this project would be sufficient in addressing load growth across Company networks in central Brooklyn, and satisfy reliability, resiliency, safety, and compliance regulations.

By enabling load splits and smaller networks in the Brownsville and Bensonhurst load areas, this program will progressively increase the reliability of the associated networks in both the near and long term. It will help the company avoid public safety issues related to network failure, customer outages and significant damage to company equipment. Also, it will protect customers from any issues related to network shutdown.

Resiliency plans: this program will help during problems in the transmission and/or substation which limits the load capacity in the Bensonhurst and Brownsville substations. Once this project is complete, it will be more feasible to transfer out or partially restore the load coming out of Bensonhurst and Brownsville and help minimize the outage impact to customers.

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection

An alternative considered was to rely upon Customer Sided Solutions (CSS) such as energy efficiency programs to mitigate any future transmission capacity deficiencies. Energy efficiency programs can provide cost-beneficial solutions across multiple customer segments by accelerating load relief through energy efficient upgrades and may aid in the deferral of traditional solutions for multiple years. Based on the magnitude of load relief required to address the overload constraints in Brooklyn under a limited time frame, it has been assessed that an energy efficiency program is not a viable option. There is no known contingency plan other than to pursue the identified traditional solution should this alternative be pursued and prove unable to meet the projected deficits.

<u>Alternative 2 description and reason for rejection</u>

Also considered was a plan for a different, traditional solution to the transmission capacity deficiencies associated with Bensonhurst Substations# 1 and # 2 and Brownsville Substations # 1 and # 2. Installing cable cooling plants for the feeders that supply Bensonhurst would increase their capacities and address the deficiencies. This alternative would likely require land procurement for the cooling plants themselves and would only solve the feeder rating deficiency and would not provide any network reliability improvements to the subject networks. Should load growth continue to a point where equipment within either of the Bensonhurst and/or Brownsville substations reach its maximum capacity, additional work would be required.

<u>Alternative 3 description and reason for rejection</u>

Transferring the entire 3B network into Gateway would also alleviate the Transmission level overloads, but would only benefit a specific station and use up the capability of Gateway. Transferring the entire network would not improve the network reliability. By partially transferring the 3B's, it creates the opportunity to split other networks in the future and also to introduce resiliency plans by establishing transferable load pockets between the new station and existing stations.

Risk of No Action

Give the consequences, including enterprise risks that might arise by not doing the project/ program. Quantify the risks, if applicable.

<u>Risk 1</u>

An overload on the transmission feeders supplying Brownsville #1 and #2 Substations is predicted to occur. Many of Con Edison's BQ substations are near full capacity and do not offer the feasibility of load transfer. In the event the transmission feeders' overload, load shedding may be required during peak conditions. Thousands of customers will be out service if load shedding is used.

<u>Risk 2</u>

If this project is not pursued, the NRI of the Ridgewood network will be negatively impacted as continued growth without the ability to either split the network or increase feeders would result in an increasing NRI.

Additionally, should the construction of a new substation in Brooklyn be deemed necessary and no action has been pursued, there may not be sufficient time available to properly procure zoned land that would minimize costs. The Company faces the risk of procuring land for a new substation in an area that requires the exercise of eminent domain or at a distance that increases cost of construction due to increased transmission and distribution circuit mileage.

Non-Financial Benefits
Examples:
- *Increased safety, reliability, efficiency, or customer satisfaction*
- *Improved workflows and communication among departments*
- *Stronger relationships with community or with regulators*
- *Ensuring regulatory compliance*

This project will provide the necessary reliability and resiliency in an area of New York City that serves many critical loads and a densely populated area where many buildings have elevators and various equipment loads. Relief of overloaded transmission feeders will ensure continued reliable service to the Brownsville load pocket and will allow the station to maintain the area substation N-1 reliability design criteria for long term projected load growth in Brooklyn.

Splitting the load in Crown heights and establishing a new network improves the reliability and thus the network reliability index (NRI) of the 3B. This translates to lower customer outage costs and potentially avoids the high costs of a significant network or substation events. In addition, new feeder cubicles will be vacated in Brownsville 1 which can then be used to establish new feeders in Ridgewood. Ridgewood is ranked as the worst NRI network in the coned system in 2021 with an NRI of 0.979. Establishing new feeders is the most effective way to improve the NRI by decreasing load per feeder. In addition, it will be possible to transfer load out of the southern portion of the Ridgewood network into the new 3B north network. This will have additional positive reliability impact on the Ridgewood network.

Consequently, this project will allow the splitting of load out of the Bensonhurst load pocket providing load relief to the transmission feeders and increasing the reliability of the Flatbush network. Moreover, 6 new feeder cubicles will be vacated which can be used to increase the reliability of the networks fed from BH2.

The increased capacity brought on by Gateway offers the potential to minimize impact on customers during an area station event that limits station capacity. Resiliency options are not feasible in this load pocket without the use of rolling blackouts and mobile stations which take weeks to set up. By introducing new area station capacity and splitting current networks into smaller load areas, we will be able to handle loss of station capacity during emergencies while minimizing customer impact. If capacity at Brownsville, Bensonhurst or Gateway stations are compromised, load can be swapped between stations minimizing or eliminating the need for load shedding during an event. The design for network splits will account for resiliency by making accommodations for load swaps during emergencies.

Meeting New York's Climate Leadership Community Protection Act (CLCPA) goals will ultimately require the company to build system capacity for an anticipated increase in load growth. With electrification of the City, as the transition from a carbon economy progresses, the system will need the capacity in the affected networks to accommodate unprecedented load growth. Rapid load growth has the potential to leave the company in a difficult position to address all the relief and reliability challenges in the future.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)

To perform financial analysis on the project or program: Refer to Corporate Instruction 291-1 "Cost-Benefit Analysis (CBA) Guidelines" to determine cost avoidance or cost savings potential. Also, refer to "Estimating Cost Contingency" Guidelines and "Estimating Escalation Cost" Guidelines, both of which are available on the Project Management Society page on the Con Edison intranet site under the Project Manager's Toolkit menu. Attach data (e.g. estimates and quotes from vendors, model outputs) as needed.

2. Major financial benefits

Explain major benefits (e.g., revenue increase, cost avoidance) and demonstrate these benefits using financial metrics (e.g., net present value, internal rate of return, breakeven point, payback period) as calculated according to the CBA guidelines. If project/program results in cost savings identify the owning cost center (Organization) that will realize the savings and whether the savings are labor or non-labor. If non-labor include the expected FTE reduction and the baseline FTEs utilized for the assessment.

This project will enable the company to address transmission equipment overloads. Exceeding the capacity of the substation and transmission feeders could result in load shedding if contingencies occur during peak loading conditions. This would result in customer outages and increases the risk of equipment failure and adversely impacting the community served. The regulatory financial costs of load shedding customers and cost of replacing transmission/station equipment can be very costly to the company. This project will avoid those costs.

3. Total cost

State the total project/program implementation cost (which should match the detailed funding breakdown below), along with any on-going financial costs associated with the project/program. For software projects, segregate costs by each phase of development: feasibility, design, development, and production/implementation.

		Full Cost	
Discipline	**Name**	**Units**	**Tot $**
UG	120/208V Transformer	16	$245,000
UG	Secondary Mains	620	$19,712,000
UG	Street Ties (4 sets of 4-500)	16	$93,000
UG	3-2/0 EPR (splicing included)	16	$518,000
UG	3-750 EPR (splicing included)	74	$3,611,000
UG	3-1000 EPR (splicing included)	203	$18,240,000
UG	Switches (Upgrade)	8	$2,600,000
UG/CM	Switches (New)	9	$5,850,000
CM - Structure	V15-6	16	$1,639,000
CM - Structure	M11-6	99	$4,537,000
CM - Structure	Service Box	155	$2,080,000
CM - Conduit	Roadway Conduit	70,390	$42,951,000
Total		**$102,076,000**	

4. Basis for estimate

Explain the method used to create the estimate. Include all key assumptions.

Unit costing method was used. We estimated the number of required units of equipment and material and multiplied by a loaded unit cost that contains material, labor and overheads. The estimate is for the extension of new feeders from Gateway to pick up new 3B South load only and does not include the future costs associated with the additional project benefits described in this white paper.

5. Conclusion
Should the project be done at all? Does it make sense to spend additional dollars to continue the project? Justify.

Yes, this project is essential for the ability of the Brownsville and Bensonhurst load pocket to have capacity for future load growth and avoid transmission equipment overloads. Decarbonization and electrification of the city economy will further add to the load demands and without this project we will not be able to meet the new load growth. This project is necessary to enable Con Edison's Climate Change Implementation Plan. it will maintain the reliability and resiliency of its utility infrastructure in the face of climate change and its response to it. It will enable the company to address regulatory compliance items presented by the Climate Leadership community Protection Act (CLCPA).

Project Risks and Mitigation Plan
Evaluate and describe any risks that might extend the project timeline, prevent completion, or lead to cost overruns. Explain plan to minimize these risks.

Risk 1
Exact location of Gateway station is still uncertain. Major variations in its location will change the distribution circuit length and impact the cost estimate presented.

Mitigation plan
Work with real estate to find a suitable location with enough station outlets for distribution feeders.

Risk 2 s
Vicinity to above ground trains can make it difficult to find crossings/lanes for feeders.

Mitigation plan
Ensure via surveys that enough lanes are available for the feeder band runs. Obtain all permits ahead of time. Explore other options to go under any obstacles like trains.

Technical Evaluation / Analysis
Describe any specific studies or analysis related to the project such as: trend analysis, internal/external studies, social studies, and related KPI's (e.g. System Average Interruption Frequency Index (SAIFI) or Customer Average Interruption Duration Index (CAIDI)). Load forecasts, failure trends, etc., may also be presented in this section. However, these analyses are not available for all projects or programs.

Due to overload constraints identified for year 2028 on the 138kV sub-transmission system, a new area substation would be the only viable alternative for load relief. Con Edison is proposing a new 27kV indoor area substation, with five 138kV/27kV transformers and with a proposed in-service date of summer 2028. The split of the 3B network is complementary to the transmission/substation project and aims to transfer approximately 117 MW from the Brownsville 138KV transmission feeders to the Gateway Park area station.

In general, infrastructure adequacy is determined by comparing the infrastructure capability, in this case the transmission system supplying the Brownsville load pocket, against the net load to be served. The net load is determined from the gross forecasted customer demand less any load relief measures such as existing and forecasted energy efficiency or local distributed resources in the network.

The capability of the transmission system and the forecasted demand for the Brownsville load pocket includes consideration of customer sided and utility sided solution of 26 MWs. Capability of the 138 kV transmission system is based on using nominal operating voltage of 138 kV and Summer Normal feeder rating. Based on the demand forecast by 2028 and 138 kV feeder capabilities, the 138 kV transmission feeders were deficient, with deficiencies continuing to grow and will require load relief. Some temporary operating measures including the use of increased short term feeder ratings and/or higher operating voltages will be utilized until permanent relief is obtained.

Project Relationships (if applicable)

Explain whether this project/program will impact other projects/programs. Some projects must be done together due to outages, or one project may depend on another (e.g. Mohansic/Buchanan projects or movement of distribution work due to Substation service date change).

This project is sequential and complimentary to the establishment of the Gateway Park Area Station by 2028, a new indoor 27kV area substation that will be arranged in a double SYN bus configuration and with five 138/27kV transformer banks. The station will be supplied from the 345kV Brooklyn Energy Hub.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital						
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital				12,482	36,312
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor				469	3,792
M&S				1,395	7,722
Contract Services				4,365	6,715
Other				0	0
Overheads				3,372	9,704
Subtotal				9,601	27,932
Contingency**				2,880	8,380
Total				**12,482**	**36,312**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Ed Koch Queensboro Bridge 13kV Riser Replacement	
Project/Program Manager: TBD	**Project/Program Number (Level 1): 23441915**
Status: ☒ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☐ **Ongoing** ☐ **Other: ___________**	
Estimated Start Date: January 1st, 2024	**Estimated Date In Service: December 31st, 2028**
A. Total Funding Request ($000) **Capital: $3,998** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

The purpose of this project is to replace the 13kV distribution riser cables that route over the Ed Koch Queensboro Bridge, also known as the 59th Street Bridge that supplies electric power to Roosevelt Island. The existing riser cables consist of aerial paper cables supported by the bridge pier structures and on messenger wires above the North and South Outer Roadways (see Figure 1). There are a total of twelve riser cables that will be replaced, six on the Manhattan pier structure and six on the western Roosevelt Island pier structure.

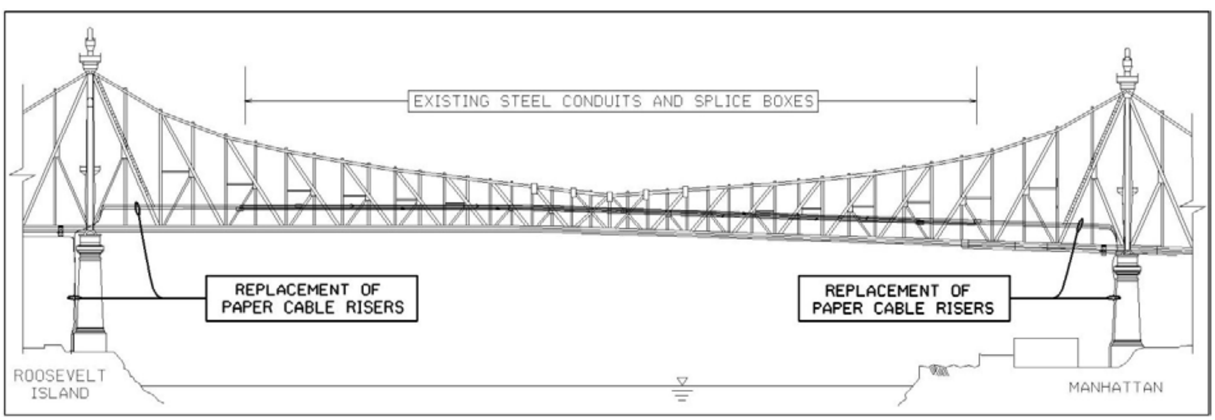
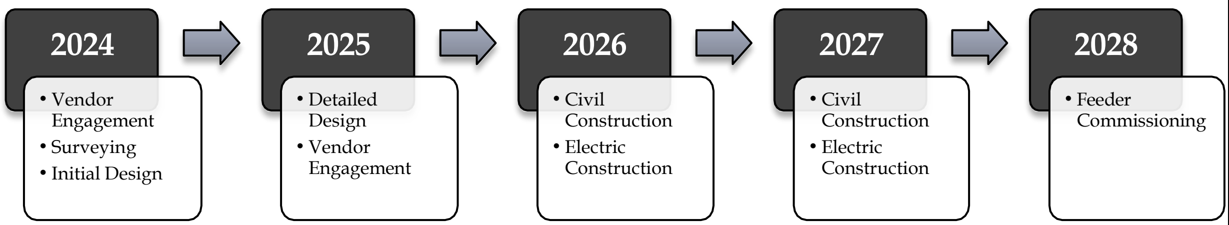


Figure 1: Ed Koch Queensboro Bridge North Elevation

High-level schedule:

Planning and design work on the distribution riser replacement will begin in 2024. Con Edison will retain engineering consulting services to complete initial and detailed designs for the riser replacement and cable pull setup. Based on the detailed design and construction bid-package, Con Edison will engage an external construction vendor and establish an agreement to complete this non-routine work, inclusive of installing all necessary supports and cables. Construction activities will begin in 2026 and last through 2027. Con Edison will perform any associated splicing work in parallel to allow proper construction sequencing to facilitate replacement work. The new risers will be completed and commissioned prior to the end of 2028 (see Figure 2).

Figure 2: High-Level Project Schedule



Note: This project has been subject to delays due to access issues related to ongoing NYCDOT projects. Such projects could cause further delays.

Justification Summary:

Since 2004, there have been fifteen failures and emergency repairs of the distribution cables on the bridge. With such a high rate of failure, the feeders presented public safety and electric reliability concerns. To address these concerns, from 2012 through 2017, Electric Operations designed and executed the '59th Street Bridge Crossing' project (Project No. Z13-06880-M) to upgrade the infrastructure supplying Roosevelt Island.

The project scope included the replacement of the existing messenger wires and aerial paper feeder cables on the main bridge spans with new conduit systems, consisting of structural steel support brackets, 5-inch steel conduits, and splice box enclosures. The new systems were equipped with 3-750 EPR-NL feeder cables. In addition, the project design included the installation of new armored cable risers on the bridge piers and the subsequent retirement of the existing risers.

During construction, the field conditions and the rigidity of the armored cables prevented them from being installed through the multiple bends of the bridge. Pulling calculations confirmed that the armored cable route was not constructible, and the armored cables would not be able to be manipulated into the route as provided in the design. Therefore, a revised concept was implemented which connected the newly installed conduit systems and associated EPR-NL cables on the bridge spans to the existing riser cables. The replacement of the risers was deferred to allow for a detailed review and redesign of the riser portion of the project.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

This project improves reliability and resiliency by replacing failure prone feeders on a crossing which are costly and time consuming to repair. This will contribute to reducing the risk of Network Shutdown, Major Outage, and Regulatory Risk associated with Reliability Performance Mechanisms.

Cable sizing will consider future load forecasts which incorporate any impacts of climate change and clean energy goals.

2. Supplemental Information

Alternatives

All System Expansion projects will be reviewed for Non-Wires Solution in accordance with the suitability criteria outlined in the DSP

Multiple alternative options were reviewed during the planning of the original '59th Street Bridge Crossing' project. These included, (i) placing the conduits under the bridge, (ii) replacing the existing messenger cable system like-in-kind, and (iii) exploring the possibility of feeding Roosevelt Island from a network from the Queens' distribution system using a directional boring method under the river.

Each alternative option was evaluated on a number of different factors including the likelihood of the plan being approved by the New York City Department of Transportation (NYCDOT), the expected cost, the degree of protection for the feeder cables, and general feasibility. While each option was viewed favorably in one or more of the factors, they also had significant disadvantages. The selected design of replacing the existing aerial messenger system with a new conduit system was favorable across all the factors.

This project, which will focus solely on the replacement of the twelve existing riser cables, will also be evaluated to ensure the most optimal solution is implemented. LiDAR and 3D modeling will be utilized to determine an ideal route from the top of the pier structure, through the bridge infrastructure, to above the outer roadways. Cable pull calculations will be a critical tool in the analysis of any proposed route. The calculations will have two main purposes, first, to ensure that the route does not exceed the physical limitations of the cable, and second, to help determine suitable means and methods for installation.

Risk of No Action

The existing risers are predominately comprised of older paper cables and have had fifteen failures and emergency repairs since 2004. There is a concern that these aged cables will begin failing at an increased rate, affecting the safety of pedestrians, cyclists, and vehicles, and jeopardizing the reliability of the electric service to Roosevelt Island. Cable failures may result in cascading feeder failures, which could result in a significant number of customers experiencing an extended outage. This problem will be exacerbated as the cables continue to age and become more prone to failure over time. In addition, the risers, due to their smaller cable size, limit the overall capacity of the feeders, constraining the future growth of Roosevelt Island.

Non-Financial Benefits

This project will help prevent a large customer outage on Roosevelt Island. In addition, removing the older paper cables and messenger wires above portions of the North and South Outer roadways will increase the resiliency of the system, improving the safety for pedestrians, cyclists, and vehicles on the bridge.

Summary of Financial Benefits and Costs

Proactively replacing the riser cables towards the end of their useful life allows for proper construction sequencing and ensuring an optimal plan is implemented rather than a "quick-fix." In addition, replacing the risers with larger cables will provide Roosevelt Island substantial electric capacity for its developing landscape.

Project Risks and Mitigation Plan

Risk 1 – Bridge Access – High
Mitigation plan – Coordinate the project start date to proceed after the conclusion of any bridge related projects. Monitor the ongoing status of the bridge related projects to adjust as necessary.

Risk 2 – Riser Routing – High
Mitigation plan – Perform surveying of bridge geometry. Detailed cable pull calculations coordinated with installation means and methods.

Technical Evaluation / Analysis

The Ed Koch Queensboro Bridge is under the jurisdiction of the NYCDOT Division of Bridges. The NYCDOT requires that any major work or modification to the bridge be performed by qualified engineering firms. As such, Con Edison will need to contract a third-party engineer who meets all the requirements of the NYCDOT. Due to the unique location of the work, many different variables will be taken into consideration during the design and planning phase. This includes, but is not limited to, work area access and egress, equipment access, marine rescue and emergency egress, allowable bridge member support loads, global and local roadway loading, roadway envelope limitations, expansion, deflection, and vibration concerns, future inspection and maintenance requirements, suitable staging locations, temporary structures and scaffolding, and temporary protection of existing facilities.

In addition, the area underneath the bridge, specifically between the anchor pier and adjacent pier structure in Manhattan and Roosevelt Island, falls under the jurisdiction of several city agencies. This includes the NYCDOT Office of Construction Mitigation and Coordination (OCMC), NYCDOT Division of Bridges, and the Roosevelt Island Operating Corporation (RIOC). Any major work scope requiring the erection of scaffolding to facilitate inspection or installation activities will require close coordination and communication between Company and Contractor representatives and the various city agencies responsible for providing construction and permit approvals.

Special consideration will be given to ensure all that proposed work activities can be safely performed within the expected stipulations for closures of the North and South Outer Roadways. Recent permits issued by the NYCDOT for full closures of the outer roadways have had very limited work hours, typically 9 p.m. to 5 a.m. nightly. The NYCDOT has also required the permit holder to operate a sizable shuttle bus service for pedestrians and bicyclists during any closure of the North Outer Roadway. The most recent permit required that the shuttle system be capable of transporting 80 passengers and 65 bicycles every 15 minutes from pick-up and drop-off points in both Manhattan and Queens.

The Company will review all System Expansion projects to determine the Non-Wires Candidates as part of the Distribution planning process. The Company will then provide information regarding these candidates and their progress on its website as well as via periodic NWS filings.

Project Relationships (if applicable)

N/A

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital			**4**	**2**		0
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital			**750**	**1,600**	**1,648**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor			-	-	-
M&S			53	124	128
Contract Services			374	877	903
Other			38	88	91
Overheads			285	510	526
Total			**750**	**1,600**	**1,648**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Central Operations / Substations
2022

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Emergent Load Relief Program	
Project/Program Manager: TBA	**Project/Program Number (Level 1):** 8ES3700/ 10035263
Status: ☒ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☐ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date: Ongoing	**Estimated Date in Service: Ongoing**
A. Total Funding Request ($000) **Capital: $4,400** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This program provides funding to cover any small-scale emergent load relief projects that may appear while updating ten-Year Load Relief Plans. Project types that typically are funded via this program include transformer cooling projects (both fan and water-cooling projects), bus cooling, capacitor bank installations, and bus upgrades.

Justification Summary:

While all known load relief projects that were developed in the Company's latest ten-Year Load Relief Plan are being requested as individual project lines in the Substation Operations Capital Budget, additional projects are required because of a new load forecast or post-summer analysis. In these cases, load relief measures and/or reliability work may be required to meet the forecasted demand for the following summer.

Since these projects are a result of post summer experience, they are not specifically included in the prior year's funding. This program line provides funding for projects of this type so that work can be done quickly, to have load relief measures in place prior to the next summer.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):

This program affects the Enterprise Risks loss of a substations and Equipment failures. The program reduces the likelihood of equipment failures events that can occur if fan and water-cooling equipment during summertime.

The expansion of this program to install and repair additional cooling equipment is a climate change adaptation initiative. Among other things, climate change is expected to produce an increased frequency of heat waves and pose a risk to transmission equipment, particularly equipment at outdoor/indoors substations. The absence of adequate cooling supply and protection increases the risk of equipment damage or destroy equipment, and this can lead to loss of substation and customer outages.

2. Supplemental Information

Alternatives
Alternatives are considered on per project basis. All load relief projects are vetted though a process to ensure that the best overall solution for any individual capacity shortfall is chosen. The projects that would eventually be chosen to be funded via this program would have been reviewed against various traditional (such as load transfers or equipment additions) and non-traditional (such as contracted energy efficiency) solutions. Typically, this program funds work that needs to be designed and constructed in 1 year or less.

Risk of No Action
Not performing the required load relief could result in load drop events if equipment was removed from service and station load limits were exceeded.

Non-Financial Benefits
This program aims to ensure reliable, uninterrupted service is provided to our customers, and that all area load growth is properly addressed.

Summary of Financial Benefits and Costs.

1. Cost-benefit analysis (if required) N/A

2. Major financial benefits
This program is expected to reduce the costs for ongoing maintenance issues caused by settlement on affected pieces of equipment.

3. Total cost **$4,440**

4. Basis for Estimate: The funding level set for this program is based on our historic experience with projects of this nature. As it will address specific emergent projects that vary in scope, there will be expected variances between the funding level requested and the actual funding required, but, over time, this funding level is expected to be adequate to address our needs.

5. Conclusion: N/A

Project Risks and Mitigation Plan
Risk 1: Delays due resources support coordination.

Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Risk 2: Outage scheduling conflicts with other initiatives.

Mitigation: Outages to be coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs to avoid conflict with other program/ projects resulting in a more predictable budget and manageable outage scheduling.

Technical Evaluation / Analysis Area Substation planning periodically evaluates each network projected peak loads for a ten-year period and compares those loads to the substation and transmission load pocket capacities. If any shortfalls are noted, potential methods for mitigating loads are developed, evaluated, and an overall best solution is chosen to mitigate this shortfall.
Project Relationships (if applicable) Load relief projects typically take priority over other work types, so any projects that create outage conflicts or constraints that could hinder load relief projects are usually cancelled or moved.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	0	0	0	0		0
O&M						
Retirement	0	0	0	0		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**$0**	**$1,100**	**$1,100**	**$1,100**	**$1,100**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	0	242	242	242	242
M&S	0	137	137	137	135
Contract Services	0	409	410	410	414
Other	0	0	0	0	0
Overheads	0	312	311	311	309
Subtotal					
Total	**$0**	**$1,100**	**$1,100**	**$1,100**	**$1,100**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations / System & Transmission Operations 2022

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Farragut STATCOM	
Project/Program Manager: Various	**Project/Program Number (Level 1): 25493381**
Status: ☒ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☐ **Ongoing** ☐ **Other: ___________**	
Estimated Start Date: January 2022	**Estimated Date In Service: May 2025**
A. Total Funding Request ($000) **Capital: $130,000** **O&M:** **Retirement: $7,000**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This project will establish a 425 MVA static synchronous compensator (STATCOM) at the Farragut 345kV Substation. To accommodate the installation of the STATCOM unit, Phase Angle Regulator TR12 and Shunt Reactor R12 are to be retired and removed. In addition, the currently out-of-service 345 kV transmission feeders B3402 (Farragut to Hudson in New Jersey) and C3403 (Farragut to Marion in New Jersey) are to be modified and reserved pending resolution of an ongoing dispute regarding the future of the feeders with Public Service Electric and Gas Company (PSE&G) (to which the feeders interconnect). The STATCOM is to be installed in the collective footprint of the removed equipment and the 345 kV feeder B44 will electrically remain to connect the device to the Farragut 345 kV Substation between breakers 1W, 10W and 11W.

Engineering and long lead equipment procurement will begin in 2022 for this project and construction is expected to begin in late 2022. The in-service date of this project is May 2025.

Justification Summary:

The necessity for new equipment installations on the Con Edison transmission system is identified through various long-range planning processes. These processes consider, among many aspects of long-range planning: forecasted demand, system topology, and available generation resources. Through various analyses, Fault-Induced Delayed Voltage Recovery (FIDVR) issues have been identified on the Con Edison 138 kV transmission system. Should large disturbances occur on the transmission system (post contingency), operationally required improvements are essential to ensure reliability criteria can be achieved or maintained. The installation of a STATCOM unit would provide dynamic voltage support that would address reliability needs driven by FIDVR issues. The FIDVR issues are caused by future load growth, the DEC NOx Emission Standard-driven gas turbine retirements, and the current unavailability of the B3402 and C3403 interregional transmission ties to New Jersey that PSE&G (to which these feeders interconnect) has declined to reconductor and restore and is the subject of ongoing litigation.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):

In efforts to protect the environment and reduce ozone pollution, the New York State Department of Environmental Conservation (DEC) adopted air emission regulations for simple cycle and regenerative combustion turbines during the ozone season. The primary goal of this regulation is to lower the allowable oxides of nitrogen (NOx) emissions from older peaking units during the ozone season, which is driving Company owned peaking units, gas turbines, and third party-owned generation towards replacement or retirement.

Projected future load growth along with the DEC NOx Emission Standard-driven peaking unit retirements (or unavailability of peaking units during the ozone season), and current transmission availabilities, will lead to deficits and system instabilities. The installation of a STATCOM unit would build in resiliency and provide dynamic voltage support that would address reliability needs driven by Fault-Induced Delayed Voltage Recovery (FIDVR) issues. The STATCOM will achieve greater grid stability during system disturbances by providing robust and controlled reactive power and reduce restoration time following a severe weather event.

The system improvements implemented with this project would be sufficient in managing FIDVR issues identified on the transmission system.

2. Supplemental Information

Alternatives

Fault-Induced Delayed Voltage Recovery (FIDVR) is driven by the lack of dynamic voltage support. The alternative solution is to either keep the “peaking units” operational, which is not a viable solution as DEC NOx Emission Standard would preclude the “peaking units” from being operational (i.e., violation of environmental regulations), or by development of replacement generation that would meet the new DEC NOx Emission Standard.

Risk of No Action

If this project is not pursued, there is a risk of Fault-Induced Delayed Voltage Recovery (FIDVR) issues with a possibility of extended impacts to the Company’s customer base (i.e., unacceptable/prolonged low voltage).

Non-Financial Benefits

This project will provide the necessary reliability and resilience in an area of New York City that serves many critical loads (e.g., airports, transportation hubs, and hospitals) in a densely populated area where many buildings have elevators and various equipment loads.

Summary of Financial Benefits and Costs

N/A

Technical Evaluation / Analysis

Along with projected demand growth and the retirement and/or unavailability of "peaking units" (i.e., Gas Turbines), Fault-Induced Delayed Voltage Recovery (FIDVR) issues will be present on the Con Edison transmission system. The installation of a STATCOM unit is the only viable alternative to provide dynamic voltage support to address FIDVR issues at this time.

Project Relationships (if applicable)

N/A

Basis for Estimate

This estimate is based on a conceptual scope of the project and on order of magnitude estimates.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	0	0	0	0		0
O&M						
Retirement	0	0	0	0		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	0	22,000	74,000	34,000	0
O&M*					
Retirement	5,000	2,000	0	0	0

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	0	2,113	8,495	3,407	0
M&S	0	4,480	22,360	9,900	0
Contract Services	0	12,500	31,819	15,620	0
Other	0	660	2,420	1,020	0
Overheads	0	2,247	8,906	4,053	0
Subtotal	0	22,000	74,000	34,000	0
Total	**0**	**$22,000**	**$74,000**	**$34,000**	**$0**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations / Substation Operations
2022

1. Project / Program Summary

Type: ☒ Project ☐ Program	**Category: ☒ Capital ☐ O&M**
Work Plan Category: ☐ Regulatory Mandated ☒ Operationally Required ☐ Strategic	
Project/Program Title: Gateway Park Area Station	
Project/Program Manager: Various	**Project/Program Number (Level 1): 25551794**
Status: ☒ Planning ☐ Design ☐ Engineering ☐ Construction ☐ Ongoing ☐ Other: ___________	
Estimated Start Date: January 2023	**Estimated Date In Service: May 2028**
A. Total Funding Request ($000) **Capital: $625,000** **O&M:** **Retirement:**	**B.** **☐ 5-Year Gross Cost Savings ($000)** **☐ 5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This project will establish the Gateway Park Area Station, a new indoor 27kV area substation that will be arranged in a double SYN bus configuration and with an initial build of three 138/27kV transformer banks (with provisions for expansion to five transformer banks). The station will be supplied from the 345kV Brooklyn Energy Hub, add resiliency to the network, and provide additional sub-transmission capacity to mitigate design capability deficiencies in the Bensonhurst and Brownsville load areas to meet projected load growth.

Engineering and long lead equipment procurement will begin in early 2023 for this project and construction is expected to begin in 2025. The in-service date of this project is May 2028.

This project also requires land procurement in an industrial manufacturing zoned area in southeastern Brooklyn. The land procurement process is expected to begin in 2022.

Justification Summary:

The Company has been successful in deploying a combination of traditional infrastructure construction and non-wires alternatives through the Brooklyn Queens Demand Management (BQDM) Program to defer the need to expand the Company's existing transmission system to supply and construct the new Gateway Park area substation beyond the ten-year planning window. However, variable inputs to the Company's annual demand forecasting and planning processes require the Company to pursue and construct the new Gateway Park area station in advance of its originally planned service date of 2032.

Future demand forecast iterations have identified design capability constraints on the Farragut to Brownsville 138kV sub-transmission system in the year 2028, prompting a reliability and resiliency plan to transfer loads from the Brownsville No.1 & No.2 and Bensonhurst No.1 & No.2 substations to the Gateway Park area station.

The Brownsville electric distribution networks (Crown Heights, Ridgewood and Richmond Hill) have projected loads that will cause the transmission feeders supplying the Brownsville load pocket to exceed their capability by 2029. The capability of these feeders supplying Brownsville No. 1 and Brownsville No. 2 is 771 MW, and the forecasted load will match the capability by 2028. By deloading Brownsville #1 Area Substation and the transmission supply feeders through the transfer of 117 MW of load from the Crown Heights network to the newly established Gateway Park Area Station by 2028 will alleviate the transmission feeder overloads in the Brownsville load area.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):

Extreme weather events such as coastal floods, intense precipitation and heat waves are gaining in frequency and severity as the planet continues to warm. Con Edison's electric infrastructure is vulnerable to climate-related threats as well as contributes to the growing risks. Along with sea level rise, severe storms have caused destruction on Company assets which have led to large and extensive power outages. Adapting to climate change in a timely manner and lessening the intensity of its effects through the reduction of greenhouse gas emissions aids in strengthens resiliency measures.

The Climate Leadership and Community Protection Act (CLCPA) has established greenhouse gas emission reduction limits associated with imported electricity and fossil fuels in New York State, as well as additional climate change goals to include 70% renewable electricity by 2030 and 100% zero emission electricity by 2040. The NYSDEC has coordinated with the NYISO to ensure that compliance with NOx emissions regulations and CLCPA policy objectives would not adversely affect grid reliability. In reviewing projected impacts driven by policy goals from the CLCPA, Con Edison has considered risk-based cost benefit analyses on how future projections of climate variability in the energy landscape will impact key assets and facilities, overall system operations, and emergency response capabilities.

Along with meeting NYS CLCPA clean energy goals, the Company anticipates expected increases in customer heating electrification. Load projections in the 2021 – 2030 Ten Year Load Relief Program indicate that the Brooklyn networks will encounter increasing overloads in ensuing years, with the Bensonhurst and/or Bronxville substations exceeding their station design capabilities. To address reliability design criteria and build in resiliency for various contingency events while complying with CLCPA requirements, the new Gateway Park Area Station will be placed into service by 2028. The new substation will be supplied by the Brooklyn Clean Energy Hub, enabling a renewable energy supply to access the load, as well as reduce dependency on local fossil fuel plants to maintain local reliability needs. This project will improve the reliability of networks by allowing for the reduction of network sizes and will establish feasible resiliency options for various contingency events, which are not available with the existing distribution system design.

By enabling load splits and smaller distribution networks in the Brownsville and Bensonhurst load areas, this program will progressively increase the reliability of the associated networks in both the near and long term. The program will alleviate issues in the transmission system which limits the load capacity in the Bensonhurst and Brownsville substation. Once the project is in service, it will be more feasible to transfer out or partially restore the load emanating out of Bensonhurst and Brownsville, minimizing the impact of outages to customers. It will help the Company avoid public safety issues related to network failures and significant damage to company equipment.

The operational measures and system improvements implemented with this project would be sufficient in addressing load growth across Company networks in central Brooklyn, and satisfy reliability, resiliency, safety, and compliance regulations.

2. Supplemental Information

Alternatives

The alternative solution is to transfer 60 MW from Brownsville No.1 (part of the Ridgewood network) to Glendale area substation. To accept this additional load, Glendale Substation would require significant capital reinforcement by installing a fifth transformer, a new 138 kV supply feeder (38Q05) from Vernon Substation and upgrading limiting sections of existing Feeders 38Q02, 38Q03 and 38Q04.

Another alternative considered was to rely upon Customer Sided Solutions (CSS) such as energy efficiency programs to mitigate any future sub-transmission capacity deficiencies. Energy efficiency programs can provide cost-beneficial solutions across multiple customer segments by accelerating load relief through little-to-no cost energy efficient upgrades and may aid in the deferral of traditional solutions for multiple years. Based on the magnitude of load relief required to address the overload constraints in Brooklyn under a limited time frame, it has been assessed that an energy efficiency program is not a viable option. There is no known contingency plan other than to pursue the identified traditional solution should this alternative be pursued and prove unable to meet the projected deficits.

Also considered was a plan for a different, traditional solution to the sub-transmission capacity deficiencies associated with Bensonhurst Substations No. 1 and No.2 and Brownsville Substations No. 1 and No. 2. Installing cable cooling plants for the feeders that supply Bensonhurst would increase their capacities and address the deficiencies. This alternative would likely require land procurement along the run of the feeders to construct the cooling plants themselves and would only solve the feeder rating deficiency. Another project would require execution should load growth continue to a point where equipment within either of the Bensonhurst and/or Brownsville substations reach its maximum capacity.

Risk of No Action

An overload on the transmission feeders supplying Brownsville #1 and #2 Substations is predicted to occur. Many of Con Edison's Brooklyn/Queens substations are near full capacity and do not offer the feasibility of load transfer. In the event the transmission feeders overload, load shedding may be required during peak conditions which would cause thousands of customers to encounter service outages.

Without pursuing the project, the Company networks will encounter the potential inability of maintaining reliable system power flow controls, system reliability and resiliency concerns and/or possible customer outages for an extended period during peak load conditions.

Additionally, should the construction of a new substation in Brooklyn be deemed necessary and no action has been pursued, there may not be sufficient time available to properly procure zoned land that would minimize costs. The Company faces the risk of procuring land for a new substation in an area that requires exercising eminent domain actions or at a distance that increases cost of construction due to increased transmission circuit mileage.

Non-Financial Benefits

This project will provide the necessary reliability and resiliency in an area of New York City that serves many critical loads (e.g., airports, transportation hubs, and hospitals) in a densely populated area where many buildings have elevators and various equipment loads. Relief of overloaded transmission feeders will ensure continued reliable service to the Brownsville load pocket and will allow the station to maintain the area substation N-1 reliability design criteria for long term projected load growth in Brooklyn.

The increased capacity brought on by Gateway offers the potential to minimize impact on customers during an area station event that limits station capacity. Resiliency options are not feasible in this load pocket without the use of rolling blackouts and mobile stations which requires a time-intensive set-up. By introducing new area station capacity and splitting current networks into smaller load areas, the Company will be able to handle loss of station capacity during emergencies and its impact on customers. If capacity at Brownsville, Bensonhurst or at the Gateway stations are compromised, load can be swapped between stations, minimizing, or eliminating the need for load shedding during an event.

Meeting New York's CLCPA goals will ultimately require the Company to build system capacity for an anticipated increase in load growth. With electrification of the City, as we move away from a carbon economy, we will require capacity in the affected networks to accommodate unprecedented load growth. Rapid load growth has the potential to leave the Company in a difficult position to address all the relief and reliability challenges in the near future.

Summary of Financial Benefits and Costs

N/A

Technical Evaluation / Analysis

Due to overload constraints identified for year 2028 on the 138kV sub-transmission system, a new area substation would be the only viable alternative for load relief. Con Edison is proposing a new 27kV indoor area substation, with five 138/27kV transformers and with a proposed in-service date of summer 2028. The project aims to transfer approximately 200MW from the Brownsville No.1 and No.2, and the Bensonhurst No.1 and No.2 substations to the Gateway Park area station.

Project Relationships (if applicable)

N/A

Basis for Estimate
This estimate is based on a conceptual scope of the project and on order of magnitude estimates.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	0	0	0	0		0
O&M						
Retirement	0	0	0	0		n/a

0

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	$0	$30,000	$20,000	$200,000	$375,000
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	0	595	609	14,710	12,211
M&S	0	4,160	7,930	42,000	95,000
Contract Services	0	23,000	8,000	120,000	220,000
Other	0	0	0	0	2,000
Overheads	0	2,245	3,461	23,290	45,789
Subtotal	0	0	0	0	0
Total	$0	$30,000	$20,000	$200,000	$375,000

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations / System & Transmission Operations
2022

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Goethals Shunt Reactor R26	
Project/Program Manager: Various	**Project/Program Number (Level 1): 25493386**
Status: ☒ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☐ **Ongoing** ☐ **Other: ___________**	
Estimated Start Date: January 2023	**Estimated Date In Service: May 2025**
A. Total Funding Request ($000) **Capital: $10,000** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This project will establish a new 345kV SF6 circuit switcher at the Goethals 345kV Substation. To accommodate this installation, the trifurcating joint in the nearby 345kV transmission manhole must be spliced, along with an extension of the 345 kV Feeder 26.

Engineering and long lead equipment procurement will begin in 2023 for this project and construction is expected to begin in early 2024. The in-service date of this project is May 2025.

Justification Summary:

The need for new equipment installations in the Con Edison system is identified through various long-range planning processes. These processes consider, among many aspects of long-rang planning: forecasted demand, system topology, and available generation resources. Through various analyses, Fault-Induced Delayed Voltage Recovery (FIDVR) issues have been identified on the Con Edison 138 kV transmission system. Should large disturbances occur on the transmission system - post contingency - operationally required improvements are essential to ensure reliability criteria can be achieved or maintained. The installation of the circuit switcher on the 345 kV Feeder 26 bus will provide static voltage support that would address reliability needs driven by FIDVR issues. The FIDVR issues are caused by future load growth as well as the DEC NOx Emission Standard-driven retirements and/or unavailability of "peaking units" (i.e., Gas Turbines).

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):

Extreme weather events such as coastal floods, intense precipitation and heat waves are gaining in frequency and severity as the planet continues to warm. Con Edison's electric infrastructure is vulnerable to climate-related threats as well as contributes to the growing risks. Along with sea level rise, severe storms have caused destruction on Company assets which have led to large and extensive power outages. Adapting to climate change in a timely manner and lessening the intensity of its effects through the reduction of greenhouse gas emissions strengthens resiliency measures.

In efforts to protect the environment and reduce ozone pollution, the New York State Department of Environmental Conservation (NYSDEC) has proposed air emission regulations for simple cycle and regenerative combustion turbines during the ozone season. The primary goal of this regulation is to lower the allowable oxides of nitrogen (NOx) emissions from older peaking units during the ozone season, which is driving Company owned peaking units, gas turbines, and third party-owned generation towards replacement or retirement. The reduced emissions would contribute to realizing New York's clean energy and climate agenda in the Climate Leadership and Community Protection Act (CLCPA), protect the stratospheric ozone layer and protect the health of New York State residents.

The CLCPA has established greenhouse gas emission reduction limits associated with imported electricity and fossil fuels in New York State, as well as additional climate change goals to include 70% renewable electricity by 2030 and 100% zero emission electricity by 2040. The NYSDEC has coordinated with the NYISO to ensure that compliance with NOx emissions regulations and CLCPA policy objectives would not adversely affect grid reliability. In reviewing projected impacts driven by DEC NOx limitations on generator emissions and by policy goals from the CLCPA, Con Edison has considered risk-based cost benefit analyses on how future projections of climate variability in the energy landscape will impact key assets and facilities, overall system operations, and emergency response capabilities.

Projected future load growth along with the DEC NOx Emission Standard-driven peaking unit retirements (or unavailability of peaking units during the ozone season) will lead to deficits and system instabilities. The installation of a circuit switcher on the 345 kV Feeder 26 bus at the Goethals Substation would build in resiliency and provide static voltage support that would address reliability needs driven by Fault-Induced Delayed Voltage Recovery (FIDVR) issues. The circuit switcher would allow for the interruption of power flow during abnormal system conditions (such as events due to severe weather).

The system improvements implemented with this project would help manage Fault-Induced Delayed Voltage Recovery (FIDVR) issues identified on the transmission system and satisfy reliability, resiliency, safety, and compliance regulations.

2. Supplemental Information

Alternatives

The alternative solution is to either keep the "peaking units" operational, which is not a viable solution as DEC NOx Emission Standard would preclude the "peaking units" from being operational (i.e., violation of environmental regulations), or by development of replacement generation that would meet the new DEC NOx Emission Standard.

Risk of No Action
If this project is not pursued, there is a risk of Fault-Induced Delayed Voltage Recovery (FIDVR) issues with a possibility of extended impacts to the Company's customer base (i.e., unacceptable/prolonged low voltage). In addition, the project ensures reliability criteria can be achieved or maintained.
Non-Financial Benefits
This project will provide the necessary reliability in an area of New York City that serves many critical loads (e.g., airports, transportation hubs, and hospitals) in a densely populated area where many buildings have elevators and various equipment loads.
Summary of Financial Benefits and Costs
N/A
Technical Evaluation / Analysis
Along with project demand growth and the retirement and/or unavailability of "peaking units" (i.e., Gas Turbines), Fault-Induced Delayed Voltage Recovery (FIDVR) issues will be present on the Con Edison transmission system. The addition of the new circuit switcher at Goethals allows for System Operations to operate the system with the major 345 kV Feeder 26 in service having the associated with 345 kV Feeder 26 shunt reactor R26 operated as out of service.
Project Relationships (if applicable)
N/A
Basis for Estimate
This estimate is based on a conceptual scope of the project and on order of magnitude estimates.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	0	0	0	0		0
O&M						
Retirement	0	0	0	0		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**0**	**$1,000**	**$3,500**	**$5,500**	**$0**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	0	290	1,010	1,194	0
M&S	0	0	0	0	0
Contract Services	0	410	1,444	2,805	0
Other	0	0	0	0	0
Overheads	0	300	1,046	1,501	0
Subtotal	0	0	0	0	0
Total	**0**	**$1,000**	**$3,500**	**$5,500**	**$0**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations / Substation Operations
2022

1. Project / Program Summary

Type: ☒ Project ☐ Program	**Category: ☒ Capital ☐ O&M**
Work Plan Category: ☐ Regulatory Mandated ☒ Operationally Required ☐ Strategic	
Project/Program Title: Jamaica Substation - Replace Limiting 27kV Bus Sections	
Project/Program Manager: Various	**Project/Program Number (Level 1):**
Estimated Start Date: January 2023	**Estimated Date In Service: May 2028**
A. Total Funding Request ($000) **Capital: 8,000** **O&M:** **Retirement:**	**B.** **☐ 5-Year Gross Cost Savings ($000)** **☐ 5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period:** **(Years/months)**

Work Description:

This project will replace the limiting 27kV bus sections at Jamaica Substation prior to the summer of 2028. The new bus sections will have a 300-hour summer rating of at least 3,000 amps. Engineering for this project will start in 2022. Due to the scope and difficulty of scheduling outages at Jamaica Substation, construction will need to begin in 2023 in order to complete the project by 2028.

Justification Summary:

The load projections for 2028 show that the 300-hour rating for the 27kV bus sections for Jamaica Substation will be exceeded. This means that under peak conditions, a contingency will would cause Jamaica Substation to be overloaded. The overloads under these conditions could trigger remedial actions such as voltage reduction or customer load shedding. The bus replacements done under this project will provide adequate ratings for Jamaica Substation to maintain single contingency design without remedial actions as described above.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):

This project helps mitigate the SSO enterprise risk Loss of a Substation. This project reduces the likelihood of loss of a substation by maintaining reliability standards for design contingency conditions.

As electrification progresses, the reliance on the electric transmission and distribution systems will increase. Maintaining reliability standards during design contingencies conditions will have increased significance.

2. Supplemental Information

Alternatives

An alternative to this project is to transfer load out of Jamaica Substation – either to an existing nearby station or to a new substation. However, the load transfer solutions have been rejected because they are more costly to execute. In addition, all system expansion projects will be reviewed for non-wires solutions (NWS) in accordance with the suitability criteria outlined in the Distributed System Platform (DSP).

Risk of No Action

If this project is not pursued, Jamaica may require remedial actions and/or customer outages during design contingencies.

Non-Financial Benefits

This project will provide the necessary reliability and resiliency in an area of New York City that serves many critical loads (e.g., airports, transportation hubs, and hospitals) in a densely populated area where many buildings have elevators and various equipment loads.

Summary of Financial Benefits and Costs

N/A

Technical Evaluation / Analysis

Project Relationships (if applicable)

N/A

Basis for Estimate

This estimate is based on previous projects of similar scope.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital						
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**$0**	**$2,000**	**$2,000**	**$2,000**	**$2,000**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor		500	500	500	500
M&S		400	400	400	400
Contract Services		120	120	120	120
Other		450	450	450	450
Overheads		530	530	530	530
Total	**$0**	**$2,000**	**$2,000**	**$2,000**	**$2,000**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Network Transformer Relief	
Project/Program Manager: Stephen Pupek	**Project/Program Number (Level 1):** 10031163 , 10031171, 10031205, 10031275, 10031385
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date: Ongoing	**Estimated Date In Service:** Ongoing
A. Total Funding Request ($000) **Capital:** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This program funds the installation costs associated with providing relief to network transformers whose projected load and operating temperatures exceed their rating. Con Edison engineering specification EO-5314 governs the prioritization effort.

Network transformers step down primary distribution supply voltages to customer-level voltages. Transformers and associated network protectors have loading limits as described in Con Edison engineering specification EO-2002: Loading Limits for Network Transformers and Associated Protectors. The network transformer load relief program funds projects that relieve projected overloads.

Figure 1: Network Transformer and Protector

Relief projects include the following:
- Replacing an existing transformer with a new transformer of the same design, but with a slightly higher rating
- Replacing an existing transformer with a larger transformer with a significantly higher rating (may require vault enlargement)
- Establishing a new vault and installing a new transformer to reduce the loading on the nearby transformers

Justification Summary:

A 1961 Public Service Commission order adopted the PSC staff's recommendation for a second contingency design of the low voltage networks in certain areas. In order to increase the reliability of the secondary distribution networks and meet second contingency design requirements in those areas, it is necessary to have in place network transformers (which supply the secondary distribution networks) that can be loaded within design limits – during both normal and contingency conditions. The objective of this program is to have network transformer loading meet the design specified in EO-2002: Loading Limits for Network Transformers and Associated Protectors. Relieving network transformers that are projected to operate above their normal and contingency ratings will maintain feeder stability, resulting in reliable service during peak summer conditions.

Currently, transformer relief undertaken for network transformers follows a one-year electric distribution planning cycle. When the summer load forecast projects overloads of either cable or equipment, the one-year planning cycle targets network or radial feeder and network transformer projects to be completed prior to the summer that the load is expected to overload the system.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

While this program targets transformers that are overloaded, and this condition is not the primary cause of transformer ruptures, one of the outcomes of this program is the replacement of vintage transformers that do not have the rupture preventing features that are incorporated in the design of new transformers. So, while it is not directly addressing the mitigation of the risk of transformer failure, it does contribute to the mitigation of that risk.

From a long-term planning perspective, whenever a transformer is identified for replacement, the designers consider not only the current loading, but the projected loading ensuring to install a transformer that will be adequate for forecasted load conditions. To the extent that the Company forecasting considers the impacts of climate change and clean energy goals, these will also be addressed with new transformer installations.

2. Supplemental Information

Alternatives

<u>Alternative 1 description and reason for rejection</u>
Distribution Engineering and Con Edison's 3G group developed an innovative alternative for network transformer load relief. This alternative involves strategically disconnecting underground cable to shift load between transformers. By adding a low voltage switch to disconnect the secondary cable and shift demand, the projected loading for a transformer can be reduced.

Alternative 2 description and reason for rejection

As a result of the New York State Reforming Electric Vision (REV) and the availability of Distributed Energy Resources (DERs) on the system, network transformer relief is moving to a multi-year electric distribution planning cycle. The multi-year electric distribution planning cycle references using operational methods if feasible to solve overloads and defer completing reinforcement projects that would solve the overload of either cable or equipment. Examples of operational measures include use of emergency primary feeder switching, installation of generators, demand reduction or monitoring of and cooling when necessary for network transformers. By deferring these reinforcement projects for one year, there is a greater possibility that a renewable energy source, DERs or other non-wires solution may come in to service and solve the overload condition and eliminate the need for the project. CECONY's Chief Engineer, Regional Engineering, reviews all reinforcement projects and determines whether projects can be deferred for an additional year through the use of operational measures.

Risk of No Action

Risk 1

Transformers that operate at or over their design temperature for extended periods of time are susceptible to degradation of their internal components (e.g., insulation). This degradation can lead to a decrease in the transformer's service life and increase in the risk of premature failure. In an extreme event, a transformer failure can cause additional failures in the network, and a network shutdown.

Risk 2

Con Edison's network transformers are installed in underground vaults and manholes in public areas. When a network transformer fails, the transformer may rupture, and oil may escape from the vault; this can result in public injury and/or property damage.

Risk 3

Transformer overloads compromise the reliability of the network. During summer months, sustained overload of a network transformer could ultimately lead to Con Edison performing load reduction actions and may even result in customer outages.

Non-Financial Benefits

Network transformer load relief reduces the risk of customer outages and network transformer failures by improving system reliability and public safety.

Replacing older overloaded transformers with higher capacity transformers also has the added benefit of the newer, safer transformer designs that are now in use (e.g., high fault energy tanks). The high fault energy tanks are able to withstand higher internal pressures, thus minimizing the risk of tank ruptures because of internal electrical faults. When the design pressure is exceeded, the tanks will rupture at the bottom of the transformer cooling panels. This effectively prevents heated fluid or fire from being ejected through the structure gratings and onto the streets, reducing the risks of public injury and/or property damage.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)

2. Major financial benefits

Network transformer load relief prioritization is assigned according to Con Edison Electric Operations Procedure EOP-5314: Electric Operations—Engineering and Design: ED-1 Budget Prioritization. The criteria used to determine the priorities include: projected loading, age of transformer, network reliability index, availability of pressure, temperature and oil sensors on transformer, and load relief options (replacement versus new vault).

3. Total cost

4. Basis for estimate

The basis for the estimates used for this program is the historic transformer installation unit cost as well as the projected volume by region.

5. Conclusion

Project Risks and Mitigation Plan

Risk 1	Mitigation plan
Risk 2	Mitigation plan

Technical Evaluation / Analysis

Regional Engineering groups conduct a load study annually after the peak load period. The most recent load flow models are used. Increases in demand due to load growth, actual load cycles experienced during the peak and potential reduction in demand due to demand side management initiatives are factored into each model. A list of potentially overloaded transformers is generated for normal and contingency scenarios. Regional engineering evaluates different options to relieve the key transformers, as identified through the prioritization process. These options include:

- Making secondary reinforcement or changing primary feeders
- Replacing an older unit with a new transformer with higher ratings
- Replacing the transformer with a larger transformer with greater capacity
- Installing a new transformer with associated structure and secondary connections

Regional Engineering proceeds with the most cost-effective option. These units are addressed prior to the next peak loading period unless operational measures are available.

The Company will review all System Expansion projects to determine the Non-Wires Candidates as part of the Distribution planning process. The Company will then provide information regarding these candidates and their progress on its website as well as via periodic NWS filings.

Project Relationships (if applicable)

Transformer Purchase
Secondary Reinforcement
Vault Modernization
Primary Feeder Reliability

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	**8,499**	**10,475**	**10,748**	**10,363**		7,228
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**10,112**	**10,782**	**10,871**	**10,977**	**11,306**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	2,272	2,422	2,442	2,466	2,540
M&S	1,753	1,869	1,885	1,903	1,960
Contract Services	1,953	2,082	2,100	2,120	2,184
Other	1,098	1,170	1,180	1,192	1,227
Overheads	3,037	3,238	3,264	3,296	3,395
Subtotal	**10,112**	**10,782**	**10,871**	**10,977**	**11,306**
Contingency**					
Total	**10,112**	**10,782**	**10,871**	**10,977**	**11,306**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don’t occur today (e.g., anticipated short-term fixes/maintenance if capital isn’t deployed)

Central Operations / Substation Operations
2022

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Newtown TR4 and 138kV Feeder 38Q05 from Vernon	
Project/Program Manager: Various	**Project/Program Number (Level 1):**
Status: ☒ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☐ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date: January 2026	**Estimated Date In Service: May 2028**
A. Total Funding Request ($000) **Capital: $120,000** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This project will establish a fourth 138kV supply feeder (38Q05) from the Vernon 138kV Substation to the Newtown 27kV Substation and a fourth 138/27kV transformer at the Newtown Substation. If there is a future load relief need, 38Q05 can be t-tapped and extended to Glendale Substation to provide a fifth supply and associated 138/27kV transformer there. This project may require the use of gas insulated substation (GIS) equipment at Vernon Substation.

Engineering and long lead equipment procurement will begin in 2022 for this project and construction is expected to begin in 2023. The in-service date of this project is May 2027.

Justification Summary:

Forecasted load projections in the 2022 – 2031 Ten Year Load Relief Program indicate that the Newtown 27kV area station will exceed its station capability in 2029. The sub-transmission feeders that supply Brownsville Substations Nos 1 and 2 are projected to exceed their capacity ratings by 2028, at which time Gateway Substation is planned to be in service. If load forecasts increase in subsequent years and the Brownsville sub-transmission feeder ratings are exceed prior to 2028, the Company must have a contingency plan to de-load Brownsville Nos 1 and 2. The Newtown project is being accelerated from 2029 to 2027 to facilitate a load transfer from Brownsville to Glendale as a contingency measure. To provide load relief and address the inherent network load growth, it is recommended to add station capacity to the Newtown area station that would accommodate a large load transfer from Brownsville to the Glendale area station in Queens, NY.

In addition to load relief measures at the Newtown substation, it is necessary to increase the capability of the Vernon-Newtown/Glendale 138kV feeders as well as the station capacity at the Glendale substation. To achieve this, a 138kV Vernon-Newtown/Glendale feeder (38Q05), will be established and supplied from the Vernon 138kV East ring bus. The new 138kV feeder will supply a new fourth transformer at Newtown. New duct banks will be installed in the entirety of the route from the Vernon substation to both the Newtown and Glendale substations. Cable will be installed in the portion of the route between Vernon and Newtown.

This project will provide load relief in the Vernon to Newtown/Glendale load areas, and is determined to be a sensible approach in anticipation of expected increases in customer transportation and building electrification, new business load growth and the Company's clean energy commitment to meet NYS CLCPA goals. This project also provides a stop gap solution to the construction of the Gateway area substation.

Relationship to 5-Year and Long-Range Plans and Enterprise Risk Management Strategy

The operational measures and system improvements implemented with this project would be sufficient in managing overload constraints within the system and satisfy reliability, resiliency, safety, and compliance regulations.

2. Supplemental Information

Alternatives

Alternate options considered include operation of 138kV feeders at higher voltages (143kV to 145kV) to increase feeder capabilities, a load transfer to Water Street substation or a load transfer to Bensonhurst No. 2 substation along with the establishment of a fifth transformer. However, these alternatives are short-term solutions and will encounter station capacity or 138kV feeder overloads in 2031. Additionally, operating 138kV feeders at higher voltages will cause stress on the feeders over extended time periods.

Also considered is the installation of cable cooling plants for the feeders that supply Brownsville No.1 and No. 2, which would increase their capacities and mitigate the deficiencies. This alternative would likely require land procurement for the cooling plants themselves and would only solve the feeder rating deficiency; if load growth continued to a point where other equipment within either Brownsville substation was at its maximum capacity, another project would require implementation.

Another alternative is to provide non-wires solutions to defer any traditional infrastructure project to beyond 2040. All system expansion projects will be reviewed for NWS in accordance with the suitability criteria outlined in the Distributed System Platform (DSP). However, future demand forecasts are subject to change based on actual peak summer load conditions as well as economic trends and are likely to present significant challenges in achieving required customer side load reductions to provide adequate solutions in the face of rapid network load growth. Changes in future forecasts and planning may result in the advancement of addressing system overloads.

Risk of No Action

If this project is not pursued, there is a high risk of overloading the substation equipment during peak load conditions. Exceeding the rated capacity of the substation could result in load shedding if contingencies occur during peak loading conditions resulting in customer outages, increasing the risk of equipment failure, and adversely impacting the community served, as well as encountering the potential inability of maintaining reliable system power flow controls, system reliability and resiliency concerns.

Non-Financial Benefits

This project will provide the necessary load relief in addressing forecasted network load growth, which will ensure the continuity of reliable service in the areas served by the Vernon, Newtown and Glendale substations.

Summary of Financial Benefits and Costs

N/A

Technical Evaluation / Analysis

Forecasted overloads will increase in subsequent years as network load continues to grow. The growth in the areas served by the Vernon, Newtown and Glendale substations is mostly due to an increased growth in customer and new business electrification. To accommodate the forecasted load under required design contingencies, new 138/27kV transformers are required at the Newtown and Glendale substations, and a new 138kV supply feeder is required at the Vernon substation.

Project Relationships (if applicable)

N/A

Basis for Estimate

This estimate is based on a conceptual scope of the project and on order of magnitude estimates.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital						
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**$1,000**	**$10,000**	**$33,000**	**$33,000**	**$33,000**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	$74	$737	$2,433	$2,433	$2,433
M&S	$258	$2,578	$8,509	$8,509	$8,509
Contract Services	$88	$875	$2,888	$2,888	$2,888
Other	$345	$3,452	$11,391	$11,391	$11,391
Overheads	$236	$2,358	$7,780	$7,780	$7,780
Total	**$1,000**	**$10,000**	**$33,000**	**$33,000**	**$33,000**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☐ Project ☒ Program	**Category: ☒ Capital ☐ O&M**
Work Plan Category: ☐ Regulatory Mandated ☒ Operationally Required ☐ Strategic	
Project/Program Title: Non-Network Feeder Relief (Open Wire)	
Project/Program Manager:	**Project/Program Number (Level 1): 10031928, 10031999, 10032052, 10032082, 10032128**
Status: ☐ Planning ☐ Design ☐ Engineering ☐ Construction ☒ Ongoing ☐ Other: ___________	
Estimated Start Date: Ongoing	**Estimated Date In Service: Ongoing**
A. Total Funding Request ($33,133) **Capital: 33,133** **O&M:** **Retirement:**	**B.** **☐ 5-Year Gross Cost Savings ($000)** **☐ 5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:
The goal of this program is to provide relief for non-network feeders that are projected to operate at greater than 100% of their normal (all equipment in service) ratings and 100% of their contingency rating (N-1). Relief projects include replacing overloaded cable with higher rated cable, transferring load from one feeder to another feeder, or establishing new feeders. Each year the Company plans to replace approximately 170 poles, 340 spans of overhead wire, 4000 feet of conduit, 8 primary risers, 20 air switches, and 32 sections of underground cable. The program will address the projected overloads in priority order. The Company's goal is to annually relieve all high priority feeder overloads prior to the start of summer.

In order to address overload conditions of non-network feeders, a number of methods may be implemented. The first method involves replacing existing cable with cable of greater capacity. A second method involves rearranging feeders to transfer load. This includes dropping off portions of a feeder to adjacent feeders that have the capacity for the additional load. A third method is to create new 4 kV feeders or step-down feeders as per *EO-2091 'System Design for Relief of 4 kV Load Areas using 2500 kVA Step-Down Transformers'*. The method chosen for each specific overload scenario is determined using engineering cost-benefit analysis.

Justification Summary:
As system load grows, individual feeders may exceed their design limits. This includes load growth driven by the electrification of transportation and heating as well as summer peak loads increasing due to rising temperatures as a result of climate change. Feeder peak loads and calculated feeder ratings are used to determine if a feeder needs reinforcement. The process for rating a feeder is specified in *EO-2048 'Determination of Distribution Feeder Ratings 60 Cycle Systems'*. If the projected feeder load for the "in-service year" is greater than the feeder rating for that year, then reinforcement of the feeder is required. According to *EO-2072 'Method Of Planning Reinforcement Of Network and Radial Feeders Operating at 13, 27*

& 33 kV', when an overload is determined, plans for eliminating the overload must provide a reasonable margin to cover three years (the next in-service year and two years into the future). Reinforcement plans generally call for eliminating small size cables, establishing new feeders, or transferring load by rearranging feeders. With an increase in wire and equipment size, existing poles and fixtures may not have the capability to support additional weight and may require replacement as well. In some cases, our feeders have reached full capacity with all other relief options having been exhausted and the only way to de-load is to create a new feeder.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)
This program aligns with the System Expansion section of the Company's Electric Long-Range Plan as it identifies and implements investments required for the electric system to meet growing demand. This program also provides additional System Average Interruption Frequency Index (SAIFI) improvement benefits through conductor upgrades. Replacing lower rated conductors reduces customer outage risk that is associated with higher feeder loadings.

2. Supplemental Information

Alternatives
Continue to operate under current conditions and risk failure of overhead wires which can cause accelerated failures and potential customer outages.

Risk of No Action
All System Expansion projects will be reviewed for Non-Wires Solutions (NWS) in accordance with the suitability criteria outlined in the Distributed System Implementation Plan (DSIP).

The overloaded overhead wires can possibly fail and cause outages if not addressed proactively by the Company.

If we exceed the number of allowable times the use of emergency ampacity occurs we will be forced to load shed. Use of emergency ampacity occurs when a cable is loaded above its normal 24 hour contingency rating without exceeding its temperature limitations. As per EO-6041 'Standard Ampacity Ratings For 4 KV Primary And Low Voltage Secondary Mains Cables Installed Overhead And In Riser Pipes', emergency ratings "are applicable for an average, over several years, of one period of not more than thirty six hours per year, but for a total of not more than three periods in any twelve consecutive months".

Non-Financial Benefits
Non-network feeder relief reduces the risk of non-network feeder failures. This minimizes potential safety risks, reduces customer outages and improves the overall reliability and resiliency of the overhead system.

Summary of Financial Benefits and Costs (attach backup)
Non-network feeder reinforcement increases the reliability of the feeder and reduces potential feeder outages. As a result, potential regulatory penalties associated with SAIFI and Customer Average Interruption Duration Index (CAIDI) can be minimized.

<u>Basis for Estimate</u>:
The estimate is based on historic unit costs prorated to account for increasing costs over the next five years.

Project Risks and Mitigation Plan	
Risk 1	Mitigation plan
Risk 2	Mitigation plan

Technical Evaluation / Analysis
The following Con Edison specifications are used when evaluating feeder loading and relief requirements:

- EO-2048 Determination of Distribution Feeder Ratings 60 Cycle Systems
- EO-2072 Method of Planning Reinforcement of Network and Radial Feeders Operating at 13, 27 & 33 kV
- EO-6041 Standard Ampacity Ratings for 4 kV Primary and Low Voltage Secondary Mains Cables Installed Overhead and in Riser Pipes

The Company will review all System Expansion projects to determine the Non-Wires Candidates as part of the Distribution planning process. The Company will then provide information regarding these candidates and their progress on its website as well as via periodic NWS filings.

Project Relationships (if applicable)

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	**3,810**	**3,153**	**2,513**	**3,939**		10,606
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**3,783**	**7,283**	**7,283**	**7,283**	**7,501**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	714	1,375	1,375	1,375	1,416
M&S	475	915	915	915	943
Contract Services	1,644	3,164	3,164	3,164	3,259
Other	24	46	46	46	48
Overheads	926	1,783	1,783	1,783	1,836
Subtotal	**3,783**	**7,283**	**7,283**	**7,283**	**7,501**
Contingency**					
Total	**3,783**	**7,283**	**7,283**	**7,283**	**7,501**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Overhead Transformer Relief	
Project/Program Manager: Various	**Project/Program Number (Level 1):** 10031259, 10035711, 10035821, 10035834, 10035565
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date: Ongoing	**Estimated Date In Service: Ongoing**
A. Total Funding Request ($000) **Capital: $11,564** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This program addresses overhead transformer overloads. Overhead transformers are field inspected and those determined to be overloaded, are replaced prior to the summer and heat events that pose the greatest potential for units to trip. The anticipated number of transformer replacement per region is shown below:

- Units per Year:
  Staten Island-25 units
  Brooklyn/Queens- 30 units
  Bronx/Westchester-80 units.

Justification Summary:

Overhead transformers are operated according to specification EO-2000. Our current process identifies potentially overloaded transformers before the peak summer period, and designs jobs to relieve those transformers. The goal of this program is to reduce the potential number of overhead transformer trips that result in customer outages and to protect our transformers from damage caused by overheating. An additional benefit to this load relief is the available capacity the new transformers provide that supports neighboring circuits in the event of a loss of a transformer and the need to supply customers on a temporary basis. In addition to loading studies done on overhead transformers, an annual review of all customer outages with a Completely Self Protected (CSP) transformer trip or customer complaints of an overhead transformer oil leak is completed. If the root cause is determined to be an overloaded/overheated transformer, the transformer is added to the list of overhead transformers requiring relief/replacement.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

From both an Enterprise Risk Management program and Long Range Planning perspective this program address core work. Failure to perform the work in this program will result in transformer failures and customer outages, impacting reliability and resiliency. Load forecasts incorporate needs dictated by climate change and clean energy policies. This forms the basis for the studies to determine which transformers must be replaced with those of greater capacity. In this way, this program also contributes to the long range plans.

2. Supplemental Information

Alternatives

Alternative 1
All System Expansion projects will be reviewed for Non-Wires Solutions in accordance with the suitability criteria outlined in the DSP

First alternative is to institute customer demand reduction for any identified overloaded transformer. Customer participation would be critical for this alternative to be successful in helping to avoid future CSP trips or overheating/overloading conditions.

Alternative 2

A second alternative would be to operate the equipment until failure. When a failure occurred, customer outages would also occur. Customer restoration times would be dependent upon the number of these events occurring simultaneously and the availability of the troubleshooter work force to respond.

Neither alternative provides a sound solution for addressing overloaded transformer equipment. In one case action would be required only from a very specific number of customers downstream of the overloaded transformer. In the second case, a number of coincident transformer failures during peak loading conditions would lead to extended outages to customers as restoration times would be impacted by crew availability.

Risk of No Action

Risk 1
When overloaded, transformers overheat. This presents a greater potential for oil leaks to develop, damaging equipment and creating an environmental concern. Operating these transformers until failure will have a negative impact on customer reliability and satisfaction, and greatly increase the likelihood of customer outages.

Non-Financial Benefits

This program reduces a potential safety risk to the public, lowers the number of oil spills into the environment, has a positive impact on customer satisfaction, reduces customer outage frequency, and improves the reliability of the overhead secondary system.

Summary of Financial Benefits and Costs (attach backup)
N/A

Project Risks and Mitigation Plan

Risk 1 Mitigation plan

Risk 2 Mitigation plan

Technical Evaluation / Analysis
Many of our overhead transformers are Completely Self Protected (CSP) meaning that when they are initially overloaded, they will automatically trip. This is referred to as a 'CSP' trip. When crews respond, they can reset these units or set to Emergency/Lock-in position.

We are currently using a computer application called Load Aggregator. This program combines our secondary mapping data and our customer service information billing data to proactively identify and prioritize transformers that have the greatest potential to trip, based upon customer summer load readings.

The CSP trip feature is advantageous to our system because it protects transformers from overheating damage. When a CSP trip occurs, it takes the transformer out of service and any customers connected to it lose electric service.

The Company will review all System Expansion projects to determine the Non-Wires Candidates as part of the Distribution planning process. The Company will then provide information regarding these candidates and their progress on its website as well as via periodic NWS filings.

Project Relationships (if applicable)
Transformer Purchase

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	**1,951**	**1,613**	**2,108**	**3,087**		**2,267**
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**2,299**	**2,299**	**2,299**	**2,299**	**2,368**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	710	710	710	710	731
M&S	139	139	139	139	143
Contract Services	769	769	769	769	792
Other	33	33	33	33	34
Overheads	648	648	648	648	667
Subtotal	**2,299**	**2,299**	**2,299**	**2,299**	**2,368**
Contingency**					
Total	**2,299**	**2,299**	**2,299**	**2,299**	**2,368**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Central Operations / Substation Operations
2022

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Parkview TR5 and Feeder 38M85	
Project/Program Manager: Various	**Project/Program Number (Level 1): 25493385**
Status: ☒ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☐ **Ongoing** ☐ **Other: ___________**	
Estimated Start Date: January 2024	**Estimated Date In Service: May 2027**
A. Total Funding Request ($000) **Capital: $202,000** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period:** **(Years/months)**

Work Description:

This project will establish 138kV supply feeder 38M85 from the Mott Haven 345kV Substation to the Parkview 13kV Substation and includes the installation of a fifth 138/13kV transformer at Parkview and a fifth 345/138kV transformer at the Mott Haven 345kV Substation.

Engineering and long lead equipment procurement will begin in 2024 for this project and construction is expected to begin in 2025. The in-service date of this project is May 2027.

Justification Summary:

Forecasted loads for the Parkview 13kV Substation are expected to exceed the station's design capability by the summer of 2027. Load projections in the 2021 – 2030 Ten Year Load Relief Program indicate that the station's capability will be exceeded by 6 MW (103%) with overloads increasing as the load continues to grow in ensuing years. To add capacity at Parkview Substation and to increase capability, it is recommended that a fifth 138/13kV transformer be installed at Parkview along with a new 138kV supply feeder from the Mott Haven 345kV Substation. A fifth 345/138kV transformer at Mott Haven will also be required to provide the supply to Parkview. The rapid load growth in the network over the next few years is primarily driven by the expansion of the MTA's 2nd Avenue Subway line with associated economic activity in the area expected to continue. This project adds 73MW of capability to Parkview Substation, and is determined to be a sensible approach in anticipation of expected increased customer heating electrification and the Company's clean energy commitment to meet NYS CLCPA goals.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):

The operational measures and system improvements implemented with this project would be sufficient in managing overload constraints within the system and satisfy reliability, resiliency, safety, and compliance regulations.

2. Supplemental Information

Alternatives

The alternative solution considered is a 30MW load transfer from Parkview to West 110th Street No. 1. Although this load transfer is feasible and allows for load relief through 2040 based on the current forecast, there are various factors including significant costs and time constraints to rely on this option. Furthermore, should the load forecast increase for Parkview and/or West 110th Street Stations No. 1 & 2, the fifth transformer and 138kV feeder will still be operationally required at Parkview. The transferring of more load to networks which are themselves experiencing inherent growth tends to compromise that network's reliability and is a less desirable option.

In addition, all system expansion projects will be reviewed for non-wires solutions (NWS) in accordance with the suitability criteria outlined in the Distributed System Platform (DSP). However, future demand forecasts are subject to change based on actual peak summer load conditions as well as economic trends and are likely to present significant challenges in achieving required customer side load reductions to provide adequate solutions in the face of rapid network load growth. Changes in future forecasts and planning may result in the advancement of addressing system overloads.

Risk of No Action

If this project is not pursued, there is a high risk of overloading the substation equipment during peak load conditions. Exceeding the rated capacity of the substation could result in load shedding if contingencies occur during peak loading conditions resulting in customer outages, increasing the risk of equipment failure, and adversely impacting the community served, as well as encountering the potential inability of maintaining reliable system power flow controls, system reliability and resiliency concerns.

Non-Financial Benefits

This project will provide the necessary load relief for overloaded feeders and equipment, which will ensure the continuity of reliable service in the areas served by the Parkview Substation.

Summary of Financial Benefits and Costs

N/A

Technical Evaluation / Analysis

Forecasted loads for Parkview in 2027 are approximately 180MW, which exceed the station's 174MW capability by 6MW or 3%. The overloads will increase in subsequent years as network load continues to grow. The growth in the Triboro Network load supplied by Parkview Substation is mostly due to expansion of the MTA's 2nd Avenue Subway line. To accommodate the forecasted load under a design N-2 contingency, a new 138/13kV transformer and new 138kV supply feeder are required at the Parkview Substation, along with a new 345/138kV transformer at the Mott Haven 345 transmission station.

Project Relationships (if applicable)

N/A

Basis for Estimate

This estimate is based on a conceptual scope of the project and on order of magnitude estimates.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	0	0	0	0		0
O&M						
Retirement	0	0	0	0		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital		$0	$30,000	$72,000	$100,000
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	0	0	7,086	17,200	23,526
M&S	0	0	6,600	15,440	21,000
Contract Services	0	0	11,400	27,360	39,000
Other	0	0	0	0	0
Overheads	0	0	4,914	12,000	16,474
Subtotal					
Total	**0**	**$0**	**$30,000**	**$72,000**	**$100,000**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Primary Cable Crossing **(B/W City Island, Riverdale, Croton River, and B/Q Flushing)**	
Project/Program Manager: Frantz St. Phar & Zhao Feng (Jeffrey) Mah	**Project/Program Number (Level 1): 10033749, 10035564**
Status: ☒ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date: Sept 2021	**Estimated Date In Service: 2051**
A. Total Funding Request ($48,100) **Capital:** $48,100 **O&M:** N/A **Retirement:** N/A	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** N/A **Capital:** N/A	**D. Investment Payback Period: N/A (Years/months)**

Work Description:

This program will reinforce cable crossings in several locations in Queens, Bronx, and Westchester that will require primary cable re-routing and reinforcement which includes new construction in areas with difficult to access and critical bottleneck crossings such as rivers, highways, bridges, and tunnels.

- Regional Engineering and Project Management will be planning these crossings in detail with measurements of required materials, obtaining permits from the city when required, creating a cost estimate of each crossing project broken down into detail, and managing and seeing the project through to completion.

- These crossing locations are a critical part of the primary electrical distribution; they connect the secondary electric networks to their source Area Substations.

A description of the work proposed for the Flushing Network follows:
The Flushing load pocket is located two miles from the Corona No. 1 substation and the feeders cross various geographical obstructions. Two of the five crossings run over the Grand Central Parkway, one runs over the Horace Harding Expressway, and the other two crossings run on bridges over the Flushing River. The Flushing Network's load is forecasted to increase substantially; all Flushing primary feeders will need to carry more load. To make this network more reliable, additional installation of duct will be required to maintain the electrical system in case of any unforeseen feeder faults or damage.

Based on loading and availability of spare ducts, we plan on doing reliability work on the following five crossings in the next five years (one crossing per year) in this order of priority:

1) **Roosevelt Avenue & Flushing Creek River:**

This crossing has only one system of 4 aerial feeders located on the south side of the overpass and runs along the #7 subway line of the Metropolitan Transportation Authority (MTA).

Proposal:
The anticipated work for this project includes installing 4 aerial cables on the north side of the crossing. This also includes 2 risers, 3 new manholes, and 300 feet of underground conduit. The total cost of this crossing project will include outside engineering consulting and construction contractor costs.

The projected cost for this project is **$1.8 M**.

2) **Roosevelt Ave. and Grand Central Parkway**

This crossing has 2 systems, a northern system and a southern system, with 4 feeders each and various locations of spare conduits. To increase the reliability of the system, installation of spare conduits on the north and south system will be done.

Proposal:
The anticipated work required for this project includes 800 feet of conduit in two systems installed under the structure and 11 sections of underground primary cable, 7 spans of overhead primary cable, and 100 feet of conduit. Costs will include outside engineering consulting.

The projected cost for this project is **$2.0 M**

3) **Horace Harding Expwy (Long Island Expwy) and the College Point Boulevard:**

This crossing has two systems, a northern system with 4 feeders and a southern system with 4 feeders. Neither system has any spare conduit. To increase the reliability of the system, installation of spare conduits on the north and south system will be installed via directional drilling if feasible.

Proposal:
The anticipated work for this project includes a total of 1197 feet of conduit in two systems installed under the overpass structure. Costs will include outside engineering consulting.

The projected cost for this project is **$3.6 M**.

4) **44th Avenue & Grand Central Parkway**

This crossing has two systems, a northern system with 4 feeders and a southern system with 4 feeders. There are 5 spare conduits of 4” Conduit. To increase reliability of the system 8 additional 5” spare conduits will be installed to be able to install larger primary cable of 3-750 EPR.

Proposal:
The anticipated work for this project includes a total of 2,548 feet of conduit in two systems installed under Grand Central Parkway. Costs will include outside engineering consulting.

The projected cost for this project is **$4.7 M**.

5) Grand Central Parkway & Northern Blvd

This crossing has two systems, a northern system with 2 feeders and a southern system with 3 feeders. Neither one of these systems have spare conduits. To increase reliability of the system, installation of spare conduits will be done based upon design chosen.

Proposal:
The anticipated work for this project includes a total of 1,049 feet of conduit in two systems installed under the overpass structure. Costs will include outside engineering consulting.

The projected cost for this project is **$2.5 M**.

A description of the work proposed for the Riverdale Network, City Island and Croton River Crossings are as follows:

1) Harlem River Crossing

Currently there are twelve feeders in the Riverdale Network that originate in Manhattan's Sherman Creek Substation and feed the Riverdale area in the Bronx. Eight feeders are still in need of replacement. These eight feeders (1X23, 1X24, 1X25, 1X26, 1X27, 1X28, 1X29, 1X30) supply approximately 67 % of the Riverdale network as well as the Riverdale Auto loop. For the Riverdale Network, the existing submarine cable crossings for eight 13 kV feeders will be replaced via two new crossings. River crossings for four of the 12 Riverdale network feeders have already been relocated into the M29 tunnel. A feasibility study was completed, and a consultant hired to perform soil borings and geotechnical baseline reports as well as design plans and a profile of the river crossings.

Based on the feasibility studies, the micro-tunneling option will be used due to the landing accuracy and space requirements compared to directional boring. The two crossings will be split worked as 2 projects in parallel: Phase 1 or Southern Crossing: Manhattan 204th and 9th Ave to Bronx Deegan Manholes and Phase 2 or Northern Crossing: Manhattan 208th St and 9TH Ave to Bronx Cable House (Exterior St.). Each crossing will have a total of 12 ducts, 4 occupied, 4 live end capped, and 4 spares. The Southern crossing will require permanent

The projected additional cost for this project is **$35.5M**

2) City Island Crossing

City Island is supplied by four 4kV feeders originating from three different networks (Washington Street, Cedar Street, and Southeast Bronx) to allow for increased reliability on the island. Two of the feeders, 7207 and 5361 enter the island via submarine cable on the seabed of the Hutchinson River, adjacent to the Pelham Bridge drawbridge. The cable on the seabed is vintage aerial cable associated with the two feeders installed over 40 years ago. Previous inspections have found that the cable has exceeded its useful life and should be replaced. The proposed solutions include replacing the cable with a newer submarine cable, directional boring under the Hutchinson River, or the complete elimination of the crossing. A feasibility study will need to be performed to identify the most cost-effective option among directional boring, submarine cables or conversion to 13 kV (which would eliminate the need for this crossing). Costs will include outside engineering consultation for a feasibility study, a geotechnical study, a final design plan if necessary, and installation.

The projected cost for this project is **$3.8 M**

3) Croton River Crossing

For the village of Croton-on-Hudson, the existing submarine cable crossings for feeders 6W62 and 6W69 under the Croton River will be replaced. The project will install conduits under the Croton River and retire the old submarine cables. The RFP for the feasibility study was completed and an engineering contractor has been selected and is developing a horizontal directional drilling plan. Six 5" conduits will be installed via horizontal directional boring and new 750 circular mil (MCM) EPR cable will be installed in these conduits. Costs for two feeders include outside engineering consulting

The projected cost for this project is **$3.7 M**

Justification Summary:

Crossings in Flushing Queens (5)

The cable crossing of our primary electric cables is part of the Resiliency Project to avoid potential emergency situations. Revamping these crossings is critical because these areas are not easy to access during an emergency. During an emergency, the field crew may sometimes need to get quick and easy access to these crossing areas to remedy the feeder fault. Without this crossing project being completed, there may be substantial delay in field crews being able to replace faulted cable. This may cause some low voltage issues or even customer power outages. This planned work of the crossings would include replacing outdated infrastructure so to increase reliability on the electrical system. These crossing jobs will not only beneficial during emergencies, but updating and strengthening these crossings also increases network reliability in general (ERM).

Harlem River Crossing

The cables supporting seven of the eight remaining Riverdale crossings were installed in 1913 and 1946. The eighth feeder was replaced in 1982 in an emergency by laying two sets of cable directly on the riverbed. Over the years, due to subsequent failures, the remaining spares have been used such that each feeder has only one spare with no means to readily install replacements. The age and the location of the existing crossing cable makes these cables prime candidates for failure with no means to replace them.

City Island Crossing

For City Island in the Bronx, the cable on feeders 5361 and 7207 that supply City Island in the Bronx is of an older vintage that was installed in 1975. This cable was inspected in the past and was found to be beyond its useful life. A failure of any of these cables would result in extensive voltage and load support issues on the City Island loops, and potentially lengthy customer interruptions. Repair times for these feeders will also be long as they will require cable in lengths beyond normal standards, special permits, and equipment not normally used by the Company.

Croton River Crossing

In the case of the Croton River crossing, there are two 13 kV feeders that supply approximately 4,500 customers. They both contain sections of 3-conductor 800Kcmil submarine cable. Over the years, all spare cable ducts that existed in this crossing have failed and are unusable. If another failure should occur, there will be no way to restore the feeder to service. This would severely jeopardize electric service to the 4,500 customers.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)
There are several critical crossing projects that need to be addressed, but because there are so many, they need to be prioritized and planned to be completed over a period of 5 years or more. The reason for spreading the projects over 5 year is due to budget constraints and feasibility of work. As previously described, due to their importance on the system these crossings must be included in the risk mitigation plans of Con Edison. Specifically, the emergency response crew can work seamlessly avoiding the risk of possible low voltage or customer outages. Additional risks identified as part of Enterprise Risk Management Strategy addressed by these projects include Network Shutdown, Regulatory Penalties (System Average Interruption Frequency Index) SAIFI, Customer Average Interruption Duration Index) CAIDI, and Major Outage Reliability Performance Mechanisms (RPMs). For 2021, the crossing at Roosevelt & Flushing Creek River is the next crossing to be completed. It is one of the many crossings that need to be done over the 5-year long-range planning.

The Electric Long-Range Plan includes goals for increased resiliency and sustained reliability. These projects will install facilities that allow for significantly faster emergency response as well as ensuring reliability through the replacement of cable which is at end of life.

2. Supplemental Information

Alternatives:

Alternative 1 description and reason for rejection: An alternative would be to not update and install new infrastructure; to leave it how it is existing now. The currently existing crossings do provide the required primary electric cables to feed the networks. In the event of a fault condition, emergency response crews will take longer to make cable repairs due to the outdated infrastructure. This delay, in effect, may cause customer outages.

Risk of No Action

Risk 1: In the event of a fault condition or any event whereby the crossing locations need to be accessed by emergency response crews, the repairs on the outage would take substantially longer, which may cause low voltage issues or customer outages.

Non-Financial Benefits

- Improved reliability of the electrical system
- Decreased possible outage time to customers
- Increased safety of the field members on emergency
- Ensuring regulatory compliance

Summary of Financial Benefits and Costs

1. Cost-benefit analysis
Relieving overloaded primary feeders in the crossings mentioned above will increase network reliability and reduce the risk of network shut down. Costs associated with network shutdowns such as restoration costs, and regulator penalties ($10 million penalty per network shutdown) are minimized. For some of the crossings, additional spare conduits will be installed as it is most cost effective to install sets of four or eight conduits at a time. This will minimize future costs associated

with future feeders in the area and minimize restoration cost associated with a feeder failure in a crossing.

2. Major financial benefits
The biggest financial benefit is the avoidance of customer outage, an unplanned emergency responses are very costly. The average cost of restoration of damaged feeders is $200k or more.

3. Total cost
The total cost for the crossing being planned for 2021 is estimated at $1.8M. The total cost over 5 years of all crossings, including B/Q and B/W will be about $62M for 9 different projects.

4. Basis for estimate
Each Crossing plan is very different as already explained. For each crossing project the cost estimate was based off the number of electric cable sections and the footage of conduit required. The final estimate is found using the appropriation cost estimate calculation, which contains a cost per unit, then adding a contingency rate to the total for the unknown.

5. Conclusion
This is a long-term program that includes many different crossing locations and instances that need to be addressed and remedied. These are critical points in the system that must be updated for maintenance every few years to keep the system reliable.

Project Risks and Mitigation Plan

Risk 1: Obtaining Permits — Mitigation plan: Start the process as early as possible
Risk 2: Unexpected soil contamination — Mitigation plan: Start the process as early as possible
Risk 3: Obtaining easements — Mitigation plan: Start the process as early as possible
Risk 4: Feasibility studies — Mitigation plan: Start the process as early as possible
Risk 5: Construction projects interfering with crossing route — Mitigation plan: Start the process as early as possible

Technical Evaluation / Analysis
The study to determine the order of priority for the seven different crossing locations, Poly-Voltage Loadflow (PVL) was used to find the highest loaded feeder sections on all of the crossings and which crossings have the highest impact on the network. Visual Contingency Analysis Program (VCAP) network map was used for feeder crossing location and diversity within the network and Substation. Contingency Analysis Program (CAP) was used to find the greatest customer impact upon feeder failure for each crossing location.

Project Relationships (if applicable)

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	3,149	1,058	405	890		262
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	7,800	21,500	11,600	2,500	4,700
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	1,314	3,622	1,954	421	792
M&S	1,431	3,944	2,128	459	862
Contract Services	2,766	7,624	4,114	887	1,667
Other					
Overheads	2,289	6,310	3,404	733	1,379
Subtotal	**7,800**	**21,500**	**11,600**	**2,500**	**4,700**
Contingency**					
Total	**7,800**	**21,500**	**11,600**	**2,500**	**4,700**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Primary Feeder Relief	
Project/Program Manager: Stephen Pupek	**Project/Program Number (Level 1): 10031922, 10031996, 10032078, 10032120, 10032202**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☒ **Other:**	
Estimated Start Date: Ongoing	**Estimated Date In Service: Ongoing**
A. Total Funding Request ($46533) **Capital: $46,533** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This program funds reinforcement (load relief) work on primary distribution feeders that have been projected to operate above their thermal ratings during the summer peak load period. This applies to both normal/continuous (all equipment in service) and contingency/emergency (up to two network/load-area feeders out of service) conditions. Reinforcement projects may include cable replacement, transferring load between feeders, balancing load on a given feeder, bifurcating an existing feeder, and establishing new feeders.
The primary feeder relief program is focused on proactively reinforcing distribution feeders that are projected to be overloaded during the upcoming summer peak periods.

Each year the distribution system is evaluated for load relief to determine specific system reinforcement needs based on the Area Substation and Sub-Transmission Feeder Ten-Year Load Relief program. These studies incorporate recent summer peak load data with location-specific information about customer growth and projected demand forecasts. They also factor in any new construction expected to be in-service that year. The primary feeder relief plan is then developed after every network's primary feeder capacity has been reviewed, based upon both the previous summer's loading and the upcoming summer forecasted load. This review occurs annually.

- **Mandatory:**
  Con Edison specifies that all feeders operate at, or below, 100 percent of their thermal rating. This is maintained by relieving all cable sections that are operating above 100 percent of rating.

  Operating specification EO-2072 illustrates how to determine the need for network feeder reinforcement, and plan and schedule reinforcement work for completion as required. The sections of this specification relating to load information, such as load readings and load growth, apply to all types of distribution feeders.

- **High-level schedule:**
  Primary feeder relief is conducted on an annual basis. Each fall the feeders are modeled using the Poly Voltage Load Flow (PVL) program, which is updated to include the prior summer's peak load data. All feeders with projected overloads have projects designed to ensure the feeder operates below its maximum capacity. All these projects are scheduled and completed prior to May 31 of the following year.

Justification Summary:

Per our specifications, distribution feeders must operate within their design thermal capabilities for both normal/continuous and contingency/emergency operation. Primary Feeder Relief ensures that the feeders are operating within their thermal capabilities.

Primary Feeder Relief is an annual relief program to maintain and ensure capacity on all primary distribution feeders. Adequate feeder capacity ensures the reliability of both the Company's primary and secondary distribution systems and provides our customers with highly reliable service.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

The Primary Feeder Relief Program blends the Company's Poly Voltage Load Flow (PVL) modeling with forecasted load growth. The forecasting group has identified an expected upward trend in load growth to accommodate electric vehicle (EV) charging as well as the anticipated electrification of heating being driven in part by the New York State Climate Leadership and Community Protection Act (CLCPA).

The PVL modeling factors in not only customer load but also distributive generation (DG) installations. Leveraging updated DG data for load flow modeling adds an additional dimension to help identify where load relief is going to be required.

This program is directly tied to the ERM for avoiding Network Shutdowns. Failure to address overloaded sections of cable will lead to eventual failure. If multiple sections of cable fail during high load periods within the same time period, the result could be full feeder failures cascading into a full network shutdown.

2. Supplemental Information

Alternatives

<u>Alternative 1 description and reason for rejection</u>
Voltage reduction during heat events has proven to be effective in avoiding system failures. As equipment continues to age the specification (EOP-5022) governing voltage reduction could be updated to reduce voltage more preemptively on circuits to avoid failures. This is not ideal as it will lead to power quality issues for some customers using voltage sensitive equipment.

Alternative 2 description and reason for rejection

During high load events, we have load shedding programs in place that provide guidance on dropping customers from the grid in order to preserve the operational integrity of the system. An alternative could be to institute aggressive load shedding / rolling blackout programs to preserve the system integrity and avoid equipment failure. This alternative is not desirable because it will result in poor customer experiences and have a negative impact on the SAIFI and CAIDI metrics

Risk of No Action

Taking no action would allow feeders to operate above their thermal ratings for extended periods of time. This could compromise the integrity of the primary cable insulation and make primary feeders more prone to failure.

If this relief project is not acted on, Operations will need to increase the use of extreme mitigation measures such as more aggressive load shedding and voltage reductions during peak loading times. This will be necessary in order to mitigate the added risks of cascading events that could result in a full network shutdown that would require extensive restoration efforts.

Non-Financial Benefits

- Primary feeder reinforcement often targets the removal of overloaded PILC cable from the system.
- The PILC cable contains lead and dielectric oil that could contaminate the environment.
- The removal of PILC cable sections and their associated stop-joints also enhances network reliability as measured through the NRI (Network Reliability Index).

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)

2. Major financial benefits

Primary feeder reinforcement increases network reliability and reduces the risk of a network shutdown. The risk of a network shutdown and the associated costs, including restoration costs and PSC's network shutdown penalty, are significantly reduced through the Primary Feeder Reinforcement program.

3. Total cost

4. Basis for estimate

The method used to determine the cost estimate was based on historical costs of performing similar work.

5. Conclusion

Primary feeders are evaluated annually for normal and emergency capacity using the Company's Poly Voltage Load Flow Program (PVL).

The Company will review all System Expansion projects to determine the Non-Wires Candidates as part of the Distribution planning process. The Company will then provide information regarding these candidates and their progress on its website as well as via periodic NWS filings.

Project Risks and Mitigation Plan	
Risk 1 Distribution feeders can operate beyond their thermal ratings	Mitigation plan Primary Feeder Relief
Risk 2 network shutdown and the associated costs, including restoration costs and PSC's network shutdown penalty	Mitigation plan Primary Feeder Relief

Technical Evaluation / Analysis

Primary feeders are evaluated annually for normal and emergency capacity using the Company's Poly Voltage Load Flow Program (PVL).
The Company will review all System Expansion projects to determine the Non-Wires Candidates as part of the Distribution planning process. The Company will then provide information regarding these candidates and their progress on its website as well as via periodic NWS filings.

Project Relationships (if applicable)

Primary Feeder Reliability

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	2,713	2,065	3,216	6,195		1,935
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	4,444	10,444	10,444	10,444	10,757
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	1,078	2,533	2,533	2,533	2,609
M&S	720	1,691	1,691	1,691	1,742
Contract Services	879	2,066	2,066	2,066	2,128
Other	353	831	831	831	856
Overheads	1,414	3,323	3,323	3,323	3,422
Subtotal	**4,444**	**10,444**	**10,444**	**10,444**	**10,757**
Contingency**					
Total	**4,444**	**10,444**	**10,444**	**10,444**	**10,757**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

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**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Secondary Mains Load Relief	
Project/Program Manager: Stephen Pupek	**Project/Program Number (Level 1):** 10031926
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date: Ongoing	**Estimated Date In Service:** Ongoing
A. Total Funding Request ($35532) **Capital: $35,532** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This program funds work as per Company guidelines on secondary mains whose loading is projected to exceed loading capability based on the forecasted system electric load growth and customer expectations including emergency response. Secondary mains replacements are prioritized based primarily on loading, voltage issues, past performance, age, conductor size and conductor type. Additional analysis factored into the prioritization of reinforcement projects includes impact to system performance including System Average Interruption Duration Index (SAIDI) and Customer Average Interruption Duration Index (CAIDI) and Network Reliability Index (NRI).

High-level schedule:

Secondary Mains Load Relief is conducted on an annual basis. Each fall, the secondary network grid is modeled using the Poly Voltage Load Flow (PVL) program, which is updated to include the prior summer's peak load data. All overloaded secondary mains not addressed by another load relief program have projects designed to ensure the mains operate below their maximum capacity. All these projects are scheduled and completed prior to May 31 of the following year.

Justification Summary:

The Con Edison electric distribution system is designed to operate safely and reliably under the 1st (non-network) and/or 2nd Contingency (network) standards in each of the respective regions without system component failure. These Company design standards require annual studies of electric network distribution system models that would enable identification of locations to be considered an overload or undervoltage. As per the operation guideline EOP-5314: ED-1 BUDGET PRIORITIZATION for the secondary low voltage distribution network grid of cables, load relief work on underground AC low-voltage mains and services should be initiated for reported overloads that are greater than or equal 125% of that set of mains' or services' first or second contingency thermal ampacity rating as per EO-6039: Standard Ampacity Ratings For 600 Volt Ac Underground Service Cables In Ducts, And Service Take-Offs form Multi-Bank Transformer Installations and EO-6040: Standard Ampacity Ratings for 600 Volt AC Mains Cables Installed Underground in Ducts as stated in Bulletin B-207. This percentage is based on results from the Low-Voltage Cable Thermal Capability project and helps operations and planning prioritize work. An additional benefit from this program, along with other secondary reliability programs, is to reduce the risk of stray voltage caused by defective cable, manhole events, and customer outages as well.

Relief projects include replacing the overloaded secondary cable sections with a new secondary cable of higher rating, installing additional secondary cable sections in order to decrease the load on the sections to a level where it is no longer overloaded, and to install transformers in order to take load off of the secondary grid and mains. Existing vacant secondary ducts would be utilized for the installation of additional secondary cable sections if available. In certain cases, additional structures may be installed or existing ones enlarged to accommodate the additional secondary cable. Secondary ducts will also be installed when insufficient vacant exist.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

The secondary network is a critical component of the network system. Load transfers through the secondary system dynamically providing continuous service in the event of failures of secondary or primary equipment. This design has provided system reliability that is second to none. Long term projections show even more dependence on electricity, and with greater demand, and expectations for improved resiliency. Demand forecasts are the basis for analysis, and since demand forecasts will account for demands related to the electrification of heat and transportation, this program will scale to meet those needs. While the secondary grid is very reliable, it is also very costly requiring more cable (and materials) per MegaWatt than the primary system. Further, because there is more cable it is more costly and difficult to maintain. Finally, it is difficult to monitor, and low voltage cable failures represent a key risk to reliability and public safety. For all these reasons the Company is evaluating long term solutions to leverage modern capabilities to transfer load and isolate faults on the primary system, reducing the need for the secondary grid, and providing a more resilient system which is more cost effective to maintain, and delivers energy more efficiently providing a less expensive and more environmentally friendly solution for our customers and the communities we serve.

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection

Expand other relief programs such as transformer load relief to install new transformers in the network allowing for more load distribution. This alternative is resource heavy where installing a transformer costs more than installing a section of cable.

Risk of No Action

Taking no action poses significant safety and reliability concerns. Secondary mains that operate at or over their design temperature for extended periods of time are susceptible to degradation as per their manufacturer specification. This can lead to premature failure or stray voltage, creating an additional burden on the connecting secondary mains and nearby transformers. The failure of the secondary section can lead to smoking manholes, manhole fires, manhole explosions, secondary burnouts, carbon monoxide (CO) events, and customer outages.

Manpower constraints are created when responding to these outages, especially during winter storms as well as peak summer load periods. In addition, other secondary cables are subject to higher loads, which can impact their expected life when overloaded secondary cables do fail.

Non-Financial Benefits

The program is crucial to enhancing the safety, reliability, and strength of the secondary voltage grid by reinforcing overloaded areas and preventing secondary cable failures. This work would also mitigate public and employee safety risks.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis (if required)

2. Major financial benefits

3. Total cost

For network secondary work, the analysis of all Con Edison system networks may yield results to reinforce certain areas of the grid. Targeted and proactive replacement of overloaded mains would reduce the possibility of manhole events, and the need to replace all mains that enter and exit the structure. Proactive main replacement costs are approximately $33,000 for a single main. With an average of eight mains in a structure, replacement of mains after a catastrophic event is estimated to cost $264,000.

4. Basis for estimate

Historical unit cost data.

5. Conclusion

Project Risks and Mitigation Plan

Risk 1 Energy demand increases lead to significantly more overloaded sections of secondary.
Mitigation plan

Should demand increase faster than the forecasted pace based on increased demands associated, for instance, with electrification of heating and transportation, the Company will adjust the overall strategy to address these demands, including additional investment in secondary relief and acceleration of plans to migrate from system reliance on the secondary grid.

Technical Evaluation / Analysis

As per Company specifications EOP-5303: SECONDARY DISTRIBUTION SYSTEM ANALYSIS, EOP-5319: PREPARATION FOR REINFORCEMENT PROJECTS OF PRIMARY AND SECONDARY SYSTEMS, and EOP-5314, Engineering teams throughout the Regions will use the Company's load flow (PVL) program to determine which secondary mains, if necessary, may need to be relieved. Customer billing data and network distribution transformer data is used to estimate peak demand at each service point. The network connectivity model with secondary, primary, and substation connections would provide an accurate representation of the network's components and related attributes and electric characteristics. PVL would be used to compute the flow on each secondary main for all possible contingencies of the primary feeders supplying the network, and provide reports of any overloads. Relieving secondary mains that are projected to be at and above 125% of the normal rating and contingency ratings will ensure the safety and reliability of the secondary network grid as per Company requirements.

The Company will review all System Expansion projects to determine the Non-Wires Candidates as part of the Distribution planning process. The Company will then provide information regarding these candidates and their progress on its website as well as via periodic NWS filings.

Project Relationships (if applicable)

Underground Secondary Reliability; Secondary Open Mains, Transformer Load Relief

3. Funding Detail

Historical Spend

EOE	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Labor	1,007	48	112	902		1347
M&S	568	9	39	378		564
Contract Services	1,362	19	85	968		1445
Other	11	0	1	1		2
Overheads	1,492	36	111	1,143		1706
Total	**4,440**	**111**	**467**	**3,392**		**2,730**

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**7,064**	**7,064**	**7,064**	**7,064**	**7,276**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	1,948	1,948	1,948	1,948	2,007
M&S	781	781	781	781	804
Contract Services	1,966	1,966	1,966	1,966	2,025
Other	5	5	5	5	5
Overheads	2,364	2,364	2,364	2,364	2,435
Total	**7,064**	**7,064**	**7,064**	**7,064**	**7,276**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Central Operations/ Substation Operations
2022

1. Project / Program Summary

Type: ☒ Project ☐ Program	**Category: ☒ Capital ☐ O&M**
Work Plan Category: ☐ Regulatory Mandated ☒ Operationally Required ☐ Strategic	
Project/Program Title: Vinegar Hill Distribution Switching Station (VHDSS)	
Project/Program Manager: Sara Gherman	**Project/Program Number (Level 1): . PR.23291581**
Status: ☐ Planning ☐ Design ☒ Engineering ☒ Construction ☒ Ongoing ☐ Other: ___________	
Estimated Start Date: 1/1/2020	**Estimated Date in Service: 12/31/2023**
A. Total Funding Request ($000) **Capital: $96,260** **O&M:**	**B.** **☐ 5-Year Gross Cost Savings ($000)** **☐ 5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This project will install a distribution switching with two 138/27kV transformers (supplied from 138kV Hudson Ave East Transmission station) creating an additional supply source for both Plymouth and Water St. substations before the summer of 2022. The additional supply source is created through a 27kV bus extension at Plymouth St. and Water St. supplied from a ring bus connecting the two 138/27kV transformers. The two new transformers supplied from Hudson Ave East will increase Plymouth St. capability from 373 MW to 502 MW and Water St stations capability from 373 MW to 509 MW. This project was formerly called the Hudson Avenue DSS.

Justification Summary:

The 2019 ten-year Load Relief Program (LRP) forecast Water St substation to develop a capability shortfall in 2022. Traditionally, these shortfalls would be addressed by adding transformer cooling at Plymouth St., Water St, Farragut Station, and by uprating Plymouth St. sub transmission feeders. Plymouth St. substation is also projected to develop a shortfall.

The VHDSS will provide additional capability to Plymouth St. and Water St stations eliminating the transformer cooling projects, the sub transmission feeder upgrades and the need for expanding Gowanus Station and the new Nevins Substation. The VHDSS will provide the capacity needed and is the least cost option to meet the projected shortfall in 2022 that will continue to increase in subsequent years. This project will provide additional station capacity and is expected to serve the station's capability needs beyond 2038.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):

This project affects the Substation Operations risk Loss of a Substation. The installation of the VHDSS not only provides additional capacity to Plymouth and Water Street Substation, it also provides flexibility in switching operations for both substations. This project reduces the likelihood of the loss of a substation by providing this flexible switching capacity.

2. Supplemental Information

Alternatives

One alternative would be to install transformer cooling on all area stations (Water St and Plymouth St) transformers and uprate the sub transmission Plymouth St. feeders by 2022. In addition, expand Gowanus transmission station and establish the new Nevins Area station by 2025. However, all the above projects are expected to be a costlier option due to the amount of work that would be required to establish a new area station.

Risk of No Action
If no action is taken, there would be a potential risk of losing customers due to the higher network load as compared with the station capability

Non-Financial Benefits
Ensures continued and uninterrupted service to our customers. Maintains Con Edison's system reliability.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis: N/A

2. Major financial benefits
Primary benefit of undertaking this program is improved reliability.

3. Total cost **$96,260**

4. Basis for estimate Future expenditures are based on an Order of Magnitude Estimate

5. Conclusion: N/A

Project Risks and Mitigation Plan
Risk 1: **Outage scheduling conflicts with other initiatives.**
Mitigation: Outages to be coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs to avoid conflict with other program/ projects resulting in a more predictable budget and manageable outage scheduling.

Risk 2: Delays due resources support coordination.
Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Technical Evaluation / Analysis: Based on Area Station Planning's load flow and forecast analyses, Plymouth St. and Water St Substation are projected to develop a 2 MW capability shortfall in 2022 that increases in subsequent years. If left unaddressed the shortfall would be 19 MW at Plymouth St. and 50MW by 2024. The new Vinegar Hill DSS will provide additional capacity to support the load increase in that area and the stations capability will be 502 MW at Water St. and 509MW at Plymouth St. station. This new DSS installation at Hudson Ave will provide the least cost option to meet the station projected loads through 2038 and beyond.

Project Relationships (if applicable) There are no associated projects with the new Vinegar Hill Distribution Switching Station project.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	0	0	125	31,760		69,734
O&M						
Retirement	0	0	0	141		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**$63,260**	**$33,000**	$0	$0	$0
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	19,647	10,319			
M&S	12,652	6,490			
Contract Services	17,452	6,570			
Other					
Overheads	13,509	9,621			
Subtotal					
Total	**$63,260**	**$33,000**	$0	$0	$0

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: W 42 No. 1 to Astor Transfer	
Project/Program Manager: Libin Mao	**Project/Program Number (Level 1):** 23244647
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☒ **Construction** ☐ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date: 8/30/2020	**Estimated Date In Service: 5/1/2024**
A. Total Funding Request ($10,100) **Capital: 10,100** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

Con Edison will transfer 55 MW of load from W.42nd St. No. 1 Substation to Astor Substation to avoid overloading the W.42nd St. No. 1 Substation that supplies the Pennsylvania network (16M) in Manhattan prior to the summer of 2024. Con Edison will accomplish this by transferring the installations in the Hudson East Yard area from W 42nd St. No. 1 Substation to Astor Substation to create a new network (47M) via 8 new feeders emanated from the vacant cubicle positions at Astor Substation.

The boundaries of the new network will be W.33rd St to the North and W.30th St. to the south; 10th Avenue to the East and 11th Avenue to the West. There is no secondary main reinforcement required since the new network consists of high tension service and 460V service only.

The completion of this work will result in the West 42nd Street No. 1 Substation having a loading of 223 MW versus a capability of 263 MW (85%), and Astor Substation having a loading of 154MW versus a capability of 179MW (86%) for the summer of 2024.

The work scope includes installing 9,600 trench feet of conduit, 107 sections of primary cable, 141 primary splices, 6 underground switches, 21 structures, protective relays, and start-up-shut-down connection.

Work on the W.42nd St No. 1 to Astor transfer began in the early part of 2020 (field surveys, engineering, and some sub-surface construction) and will last through the second half of 2023 with the intermesh and clean-up taking place prior to the summer of 2024.

Justification Summary:
Based on an analysis of the area substations and sub-transmission feeders in the W.49th Street load pocket, Con Edison projects the W.42nd Street No. 1 Substation will exceed its capability by the summer of 2024. As reported in the "2020-2029 Area Substation and Sub-transmission Feeder Ten-Year Load Relief Program", the Pennsylvania network will reach 278 MW by the summer of 2024, which exceeds the 263 MW capability of the W.42nd Street No. 1 Substation by 15 MW (106%).

The main driver of this project is the significant new business load growth in the Pennsylvania Network. Some of these customers include Hudson Rail Yards, Brookfield Properties, Javits Center expansion, Moynihan Station and several skyscrapers along the newly constructed Hudson Blvd. It is also expected that the No. 7 Subway Line extension to W.34th St and 11th Ave will play a significant role in attracting new tenants to this neighborhood.

This project will result in West 42nd Street No. 1 Substation operating within its capability and maintaining capacity for future load growth, but also relieve the feeder breaker capability in order to supply the new business growth at the Hudson West Yard.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

2. Supplemental Information

Alternatives
The alternate solution to relieving W 42nd Street No. 1 substation and the feeder breaker capability for the Hudson West Yard pickup would be transferring multiple smaller portions of the Pennsylvania network to the existing adjacent networks. However, the total cost for an alternate plan involving two or more load transfers would exceed $35M.

NWS (non-wire solution) portfolio to defer the project is deemed not feasible.

Risk of No Action
The Company is at risk of shutting down an electric distribution network (relatively low risk) or experience an extended outage for a significant number of customers (low to moderate risk) or the risk of a prolonged loss of an area substation at W. 42nd Street No. 1 (relatively low risk). The 10 year load forecast projects that W. 42nd Street No. 1 will be overloaded by 31 MW in the year 2029 if this transfer is not performed.

Non-Financial Benefits
The project helps prevent the potential for a large customer outage, network outage, or area substation outage in midtown Manhattan.

Summary of Financial Benefits and Costs (attach backup)
Transferring load out of Pennsylvania network improves the NRI (and thus the reliability) of the network and also improves the reliability at W. 42nd Street No. 1 area substation by de-loading the substation. This translates to lowered customer outage costs, and, potentially avoids the high costs of a significant network or substation event. The reliability of the existing Herald Square network will not be affected by the new network.

Project Risks and Mitigation Plan

Risk 1
Civil construction falls behind schedule
Mitigation plan
Construction Management reprioritizes resources

Risk 2
Cable installation falls behind schedule
Mitigation plan
Electric Construction implements modified shifts

Technical Evaluation / Analysis

The Company is at risk of shutting down an electric distribution network (relatively low risk) or experience an extended outage for a significant number of customers (low to moderate risk) or the risk of a prolonged loss of an area substation at W. 42nd Street No. 1 (relatively low risk). The 10 year load forecast projects that W. 42nd Street No. 1 will be overloaded by 31 MW in the year 2029 if this transfer is not performed.

The completion of this work will result in the West 42nd Street No. 1 substation having a loading of 223 MW versus a capability of 263 MW (85%), and Astor Substation having a loading of 154MW versus a capability of 179MW (86%) for the summer of 2024. By the summer of 2029, the loading will be 239MW in W 42 No. 1 substation and 154MW in Astor substation.

The table below shows the loading and rating of the feeders for the new network. Note that the Hudson East Yard Co-gen is included.

	Normal Load (A)	Normal Rating (A)	Emergency Load (A)	Emergency Rating (A)
47M96	231	587	399	877
47M39	420	454	644	705
47M40	463	498	673	716
47M41	338	455	545	737
47M42	390	474	582	716
47M43	389	474	596	715
47M44	358	455	569	716
47M95	228	587	397	877

The table below shows the loading and rating of the recently established Pennsylvania feeders after the Hudson West Yard is fully realized.

	Normal Load (A)	Normal Rating (A)	Emergency Load (A)	Emergency Rating (A)
16M65	411	455	643	745
16M86	398	455	622	753
16M85	465	524	742	748
16M87	475	524	754	774
16M78	462	524	739	752
16M88	480	524	758	773

Project Relationships (if applicable)
N/A

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital				**1,498**		**4,637**
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**6,100**	**2,000**	**2,000**		
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	16	5	5		
M&S	1,105	362	362		
Contract Services	3,028	993	993		
Other					
Overheads	1,951	640	640		
Total	**6,100**	**2,000**	**2,000**		

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

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Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: West Bronx/Randall's Island Reconfiguration Program	
Project/Program Manager: Travers Dennis	**Project/Program Number (Level 1): 24817761**
Status: ☐ **Planning** ☒ **Design** ☐ **Engineering** ☐ **Construction** ☐ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date: June 2021	**Estimated Date In Service: December 2024**
A. Total Funding Request ($000) **Capital: 43,298** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

The West Bronx (2X) network (NW) consists of 24-13kV distribution feeders which emanate from the Bruckner Substation in the Bronx. Over the past 5 years, the network has realized steady load growth. As a result, 21 of the 24 feeders have exceeded 95% of the normal capacity ratings. Due to the geographical location of the station, adjacent to the Hell Gate substation on one side and bordered by the East River on the other, there are limited paths for feeders exiting the station. As a result, cables close to the substation show significant drops in cable ratings due to duct occupancy. These overloads were addressed in the 2020 load relief season. Load for the West Bronx is projected to continue to grow in the next 10 years. As a result of the constant load growth, we recommend extending four feeders from the Randall's Island (14M) network and two feeders from the West Bronx (2X) to transfer load from the West Bronx (2X) network. To allow for separate processing of load from both networks, adding two Underground Interrupters per 14M feeder will be required.

- *2021- Survey routes for the installation of manholes and conduit.*
- *2022 - Install new manholes and conduit*
- *2022 - Install new cable.*
- *2023 - Install new manholes and conduit.*
- *2023 - Install new cable.*
- *2024 - Install new cable.*
- *2024 – Install UG Interrupters*

Justification Summary:

Looking ahead at the 10-year load forecast, the load continues to grow by 1 to 2 MW per year, and it is predicted that the network load will be at 240 MW by year 2030. Therefore, most of the distribution feeders within the West Bronx (2X) network will be above the normal ratings. As a result, 35 MW will be transferred to two feeders within the West Bronx (2X) network and four feeders from the Randall's

Island (14M) network. Both Randall's Island (14M) network and West Bronx (2X) network originate from the Bruckner substation. Therefore, the recommendation was made to extend feeders 2X38 and 2X39 within the West Bronx Network and extend four 14M feeders from the Randall's network. The feeders would extend and reach load pockets within the West Bronx (2X) network and transfer 35 MW of load.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

The West Bronx load transfer will allow the continuous load growth in the network without overloading the distributions feeders that can cause equipment damage and service interruptions. This project supports Electric Long-Range Plan goals for increased resiliency and sustained reliability. In addition, the new interrupter switches and sectionalizing devices installed as part of this project are part of a more resilient design that could help prevent a network shutdown, in alignment with the Company's Enterprise Risk Management Strategy.

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection

- An alternative is to establish four new feeders at the Mott Haven Substation and extend them in the West Bronx network to reach HTVs, ISO's and SPOT's. This plan would be more expensive and would not allow for the load transfer of network load along the route to reach the targeted load pockets

Alternative 2 description and reason for rejection

Alternative 3 description and reason for rejection

Risk of No Action

Risk 1

Risk of no action will result in limited capacity in the network and will not allow room for future load growth.

Risk 2

Looking ahead at the 10-year load forecast, in year 2023, it is predicted that the network will be at 230 MW. A PVL study conducted for summer 2023 shows 4 overloaded feeders (2X23, 2X24, 2X25, and 2X28) between 101% and 103% of their normal rating. Based on the latest 10-year forecast, the load continues to grow by 1 to 2 MW per year and it is predicted the network load will be at 240 MW by year 2030.

Risk 3

Non-Financial Benefits

This project will significantly increase reliability in the 2X network by extending 6 feeders that will de-load the existing heavily loaded West Bronx feeders. In addition, this will create capacity in the network that will allow for future load growth and improve customer satisfaction. The additional feeders will provide a more distributed and balanced supply to the network and more balanced feeder loading during normal conditions when all feeders are in service. The increased number of feeders available during contingencies will also mitigate the potential for cascading feeder failures associated with high feeder loading due to shifting load following a feeder open auto (OA). Extending the six feeders increases the network reliability and reduces the risk of a network shut down. Costs associated with a network shutdown such as restoration costs, and regulatory penalties are minimized. In addition, NRI reliability sectionalizing devices will be installed to isolate a section of the feeders to provide additional NRI reliability benefit to the network. The main purpose of installing these devices is to isolate a section of the feeder on the load side of the device by opening and isolating faulted portions and then restoring the rest of the feeder back in service either for emergencies or scheduled work.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)

2. Major financial benefits

3. Total cost

4. Basis for estimate

5. Conclusion

Project Risks and Mitigation Plan

Risk 1	Mitigation plan
Risk 2	Mitigation plan

Technical Evaluation / Analysis

Project Relationships (if applicable)

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital						221
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	23,100	16,100	4,100	0	0
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	564	395	101		
M&S	1,846	1,286	327		
Contract Services	14,464	10,080	2,566		
Other	28	20	6		
Overheads	6,198	4,320	1,100		
Subtotal	**23,100**	**16,100**	**4,100**		
Contingency**					
Total	**23,100**	**16,100**	**4,100**		

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

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Cost Avoidance: Reductions in anticipated future costs that don’t occur today (e.g., anticipated short-term fixes/maintenance if capital isn’t deployed)

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Williamsburg Network Improvements	
Project/Program Manager: Ramze Muntasser	**Project/Program Number (Level 1): 25529161**
Status: ☒ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☐ **Ongoing** ☐ **Other: ___________**	
Estimated Start Date: 2022	**Estimated Date In Service: 2029**
A. Total Funding Request ($000) **Capital: $79,000** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

To improve the reliability and resiliency of The Williamsburg Network, reduce the average load per feeder and accommodate future load growth, the company proposes the following:

Establish eight new feeders out of Water Street Substation in four feeder bands towards the goal of creating two smaller load areas out of the Williamsburg Network. The separation line between the two load areas is Flushing Avenue. The load pocket north of Flushing Avenue will consist of sixteen feeders and 189 MWs, the south load pocket will consist of twelve feeders and 125 MW. Eight new cubicles in Water Street Substation are being established under the work being done to establish the new Vinegar Hill Distribution Switching Station (VHDSS). The distribution work consists of running four bands of two feeders using 750 mcm cable or higher rated cable. One band will be extended every year to split the load between the south and northern portions. The conduit for the cable being extended will be constructed prior to extending the feeder bands. After the eight new feeders are established, the next three to four years will be spent on rebalancing the load to create two independent secondary load pockets. Construction will start in fall of 2022 with the conduit installation for the first band. In year two, band 1 cable will be installed and construction of conduit for band 2 will begin. In year three construction of conduit for band 2 will be completed, band 2 cable and band 3 duct will be installed. In year 4, band 3 cable and band 4 duct will be installed. In year 5, cable for band 4 will be installed.

In summary, the creation of the four new bands will take up to five years. The next three years will involve rebalancing the feeders and creating two independent load pockets: one north of Flushing Ave and one south of Flushing Ave. The program would be completed by 2029 based on this plan. The cost of the four new feeder bands is estimated at $72 Million and the cost of the rebalancing of the network an additional $30 Million.

The creation of four bands and eight new feeders including the extension of the new feeders into the load pick up points involves the installation of (*Figure 1* below):

- 109 sections of 3-500 primary cable
- 325 sections of 3-1000 primary cable
- 84 structures
- 54,500 feet of primary duct.

The feeder load rebalancing after the new bands are created and extended to the load pick point involve (*Figure 2* below):

- 8 new transformers
- 50 sets of secondary mains
- 8 sets of street transformer ties
- 166 sections of 3-500 primary sections
- 8 new v15-6 vaults
- 30 new M14 manholes
- 31,700 feet of primary conduit.

Figure 1 - Establish New Feeders

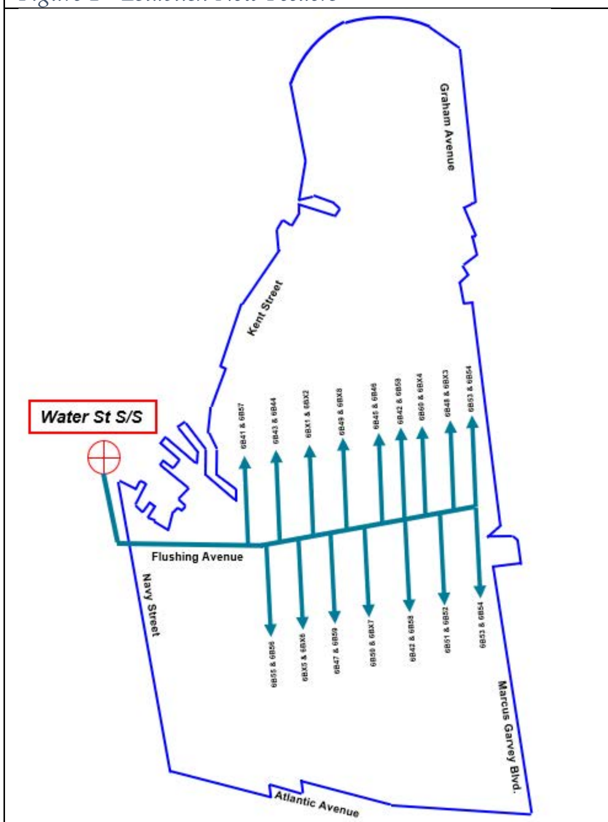
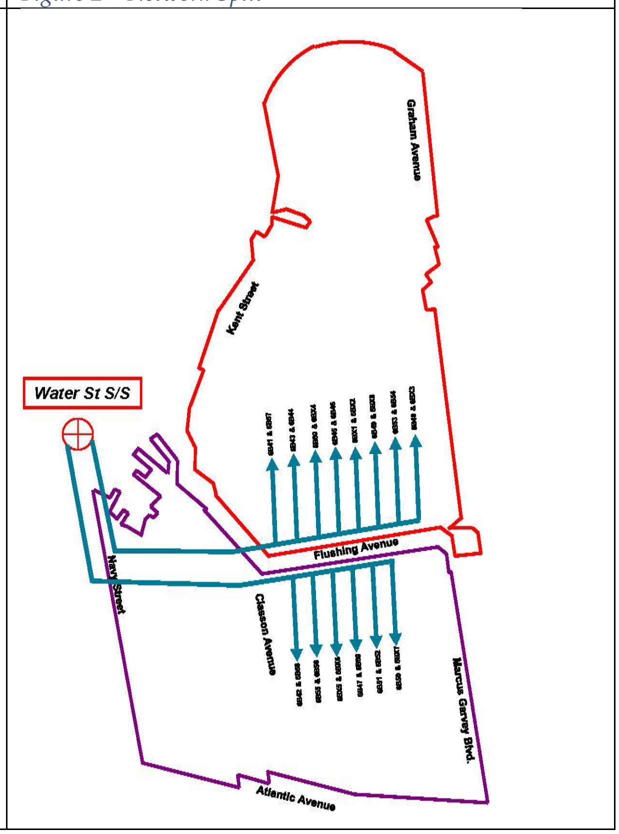


Figure 2 – Network Split



Justification Summary:

The Williamsburg network is a 314 MW network supplied by 20 feeders with a NRI (Network Reliability Index) of 0.819. The network has sixteen feeders above 90% of the normal rating and ten feeders above 90% of their emergency rating with very limited options for load relief to accommodate load growth. Upgrades of cable and conduit are the only alternative to keep feeders from overloading.

Although the cable upgrades will alleviate cable overloads, it will not have a significant impact to the reliability of the network.

The best solution to improve the load relief outlook and network reliability index is to introduce eight new feeders, and four feeder bands. These additional feeders are critical to supplying the expected load growth and to drive the NRI (Network Reliability Index) lower.
The new feeders will allow us to reduce load per feeder, split the load and reduce the size of the network by breaking the network into two distinct secondary load pockets. It will also reduce feeder's contribution to NRI and target and eliminate the three feeders conflict manholes also known as critical manholes. A Critical Manhole is an existing manhole location, identified by PVL simulation or Regional Engineering, which contains three or more feeders that can cause overloads, customer outages, or can have significant impact to a large area, load pocket, or network. A challenging aspect of this network that is not easy to solve and affects the reliability negatively is that there are 136 three (or more) feeder conflict manholes. A population of the conflict manholes are also critical manholes whose failure would cause catastrophic issues in the distribution system.

The Williamsburg network has consistently ranked high in the NRI reliability ranking over the last few years. NRI is a statistical unit of measure of a network's reliability with an upper limit of 1 or greater to indicate that a network is deemed to be considered less reliable. Within the current ten year forecast, the NRI for Williamsburg is projected to go over the upper limit of one. Although projects were conducted to improve the reliability of the network, the NRI of the Williamsburg Network is expected to increase in the future unless a major program is undertaken to reduce it. The NRI is expected to increase due to the current design of the network and the expected increase load growth and the need for feeders to continue to operate on the upper ranges of its design capacity. In addition, climate change and electrification of the transportation and heating sector will add another level of uncertainty to the forecasting of the network load and NRI ranking. The following standard ways to improve the NRI have already been implemented or are not available: removal of high failure rate (thermally sensitive) components, deload highly loaded feeders via new feeders or balancing of load, increase feeder rating and install sectionalizing switches.

The Williamsburg network has gone from a peak load of 254 MW in 2014 to 314 MW in 2021, which is a 60 MW load increase, equivalent to a 24 % load increase in the past seven years or 3.5% average increase per year. The load is forecasted to increase to 375 MW in 2030. Sixteen of the twenty primary distribution feeders are running at over 90% on base and ten feeders are running over 90% of the emergency rating. Feeders running close to the ratings are a factor in the NRI of the network because of the large loads that have to be transferred to nearby feeders when a feeder fails. Moreover, by 2028, we estimate that there will 560 sections overloaded. After adjustments, we estimate about that about 315 sections will require load relief at a cost of $56 Million to upgrade cable and conduit to handle the increased load per feeder. This number can vary depend on load growth and any load shift in the network. Climate change will impact the severity and length of heat waves in the future and worsen the NRI and number of highly loaded and overloaded sections. The most feasibly way to address the underlying problems of this network is to establish new feeders and shift load from those highly loaded feeders onto the new feeders.

There were previous long-range plans to address the issues in Williamsburg. The original plan was to build Nevins Street Substation. This would have alleviated distribution issues by freeing up cubicles at Water Street that could have been used for the Williamsburg network. Associated with Nevins Street S/S was the transfer of the Prospect Park network out of Water Street S/S to free up ten distribution feeder cubicle positions. With the Vinegar Hill DSS construction replacing the need for Nevins Street Substation, eight new cubicles were installed which will allows eight new feeders in the 6B network.

These eight new feeders will benefit the Williamsburg network from a load relief as well as a reliability and resiliency (NRI) perspective.

Installing eight new feeders in Williamsburg will lower load per feeder and lower the NRI. The plan is to introduce a band (two feeders) every year and then rebalance the load among all feeders in the next three to four years. The cost will be spread over seven to eight years to get incremental NRI improvements. The number of feeders will increase from 20 to 28. The network will be split into two load pockets by Flushing Avenue. The northern load pocket will contain sixteen feeders (189 MWs) and the southern load pocket will contain twelve feeders (125 MW). Estimated NRI improvements will be significant with NRI expected to be less than 0.249 in both the southern and northern potion. Moreover, the improvements will be incremental and once the feeder bands are introduced, the NRI will improve every year work is completed. The total cost will be $72 Mill for the four new feeder bands and another $30 Mill for rebalancing the load in the network. An additional benefit of this project is that it uses an Automatic Transfer Switch (ATS) concept to support load during an open auto using alternate new feeders where there is additional capacity since they are built with 750 MCM cable or higher rated cable. This system is currently in the design phase and can be implemented in tandem with the establishment of the new feeders using the new 27kV Eaton interrupters.

Overall, the proposed work will deload existing feeders and minimize the risk of cascading feeder failures. In addition, it will prepare this network to be resilient in the face of climate change and load growth from electrification and developer expansion in this area of Brooklyn. Instead of solving overloads by upgrading cable with minimal reliability improvements, this program will solve future primary overloads while greatly increasing the reliability and resiliency of the network by introducing eight new feeders. Moreover, the improvements from this program are progressive as each band is completed which will allow for improvements in reliability and resiliency both the near and long term and load relief of two to four feeders. Traditional reliability and load relief projects will not be effective in material improvements in reliability or resiliency and present a high risk to the safe and reliable operation this network. The proposed program in this white paper will solve both relief and reliability of the network in its current state and increase resiliency to prepare the system for the future of climate change and electrification.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

As discussed elsewhere in this paper, the main challenges to the Williamsburg network are the consistently higher corporate NRI rankings and the highly loaded feeders with an increasing load forecast. The most economical and feasible solution is to introduce eight new feeders which will solve all those concerns with the network. The plan proposed in this paper are synergistic and complementary to the Climate Change Implementation Plan proposed in December 2020 by the Company. The Plan explains how the Company will incorporate climate change projections for heat, precipitation, and sea level rise from the 2019 Climate Change Vulnerability Study into its operations to mitigate climate change risks to its assets and operations. The reliability, resiliency and load relief work proposed in this paper are complementary and a necessary step to manage the climate risk imposed by global warming. The NRI of the network is expected to go over 1.0 by 2030 accounting for the higher temperature days with heat waves lasting longer. As part of the study, the Company will integrate climate risk management into its governance structure, and review seven operational areas for opportunities to incorporate climate change information.

Three of these seven operational areas will be clearly helped by establishing new feeders and are necessary to get ready for climate change: load forecasting, load relief planning and reliability planning for the distribution system. The changes in the assumptions for these three operational areas necessitated by the rising heat and duration of future heat waves which will greatly compound and worsen the reliability of the network past acceptable limits with very few avenues for addressing the underlying condition. Also, due to the large number of sections within the 90% rating, prohibitively expensive load relief cable and conduit upgrades will be required to just maintain the NRI at current levels. The work described in this white paper would avoid all these risks. A further risk of no action is that the system will not meet the reliability and resiliency performance due to climate change and load growth, along with related more frequent and longer heat events.

The following is a summary of the anticipated changes to the planning process caused by climate change that will be detrimental to The Williamsburg network and to the ability of the network to remain viable without introducing new feeders. The establishment of new feeders will allow the Williamsburg Network to handle safely the changes imposed by climate change and the new assumptions to the planning process.

Load Forecasting
Con Edison has integrated an increase in peak TV of 1 degree in 2030 (87 TV) and 2 degrees in 2040 (88 TV) into its electric system peak load forecast. This will further increase need for load relief and decreased reliability without introducing the new feeders.

Load relief Planning
Con Edison will incorporate climate change-driven increases in load and deratings due to increased temperatures and TV in the 10- and 20-year load relief plans. There are hundreds of sections within the 90% rating, this will increase the number further and necessitate the introduction of new feeders.

Reliability Planning
Con Edison will use climate change-adjusted load forecasts, any projected changes in asset ratings, and projected increases in TV and heatwaves (frequency and duration) in its Network Reliability Index modeling. This network will go over 1.0 NRI with no long-term feasible solution unless we introduce new feeders.

An added benefit to the work proposed in this white paper is that, as New York State continues its efforts to reduce greenhouse gas emissions, further electrification of the economy will challenge the secondary distribution system. Introducing new feeders will allow better distribution of the load per feeder and transformers. New transformers will be introduced in the network which will help balance the load amongst multiple transformers.

Risk management. By virtue of ranking in the top three positions in the NRI for company over the last few years and with no expectations of being able to reduce this number meaningfully, the Williamsburg network is more susceptible to network shutdown relative to most networks in the system. This is despite different projects that have been conducted to try to improve the reliability of this network. The consequences would be severe for the company and the public. Public safety, disruption of public transportation, sever damage to company equipment and customer outages would be the immediate consequences. PSC penalties, reputational damage, increased regulatory scrutiny and severe financial impact would be the consequences in the longer timeframe. The severity of the consequences makes it more imperative that we address all underlying issues with the establishment of new feeders and balancing the network feeders and eliminating critical manholes.

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection

The main alternative considered was to do the traditional network split. All the work would have to be completed ahead of time (four to five years) before split occurs. This means that the reliability benefits wouldn't be available until after all work is completed. The current plan will allow for incremental and progressive improvements instead of waiting four to five years. In addition, the proposed plan would allow for more resiliency alternatives where the feeders that feed north and south separately can be used to support each other in case of contingencies since they will be built with 750 MCM cable or higher rated cable with significantly higher capacity than 500 MCM cable.

Alternative 2 description and reason for rejection

Originally, the company had plans to use the establishment of the new Nevin Station to make new feeder cubicles available to Water Street. Associated with Nevins Street S/S was the transferring of the Prospect Park network out of Water Street S/S to free up ten distribution feeder cubicle positions and feeder runs already in the street that could have been used to introduce new feeders into Williamsburg at a more economical way. The Vinegar Hill DSS project has moved the establishment of Nevins Street Substation out of the current 20-year forecast. The Williamsburg network is currently only supplied by 20 feeders. The existing configuration of Water Street Substation does not allow for installing dual breakers which would have increased the number of feeders supplying the Williamsburg network. The establishment of Nevins has been postponed because the new VHDSS offers cost savings of $450 Million and eliminated the need to build a new station and eliminated the need of loads transfers from other networks.

Risk of No Action

Risk 1

Network shutdown due to feeder cascading. This network has consistently ranked high in the NRI ranking and forecasted to exceed 1.0 by the end of the 10-year load forecast. This can happen sooner if the load growth returns to the same patterns as before covid. All standard ways to improve reliability like thermally sensitive component replacement, introduce new feeders (not available cubicles), deload highly loaded feeders by load balancing are not feasible or will have no significant impact. Due to this NRI ranking, this network is susceptible to shut down by feeder cascading of nearby related feeders. The fact that there are ten feeders within their 90% emergency rating increases the load shift and increases the chances of feeder cascading. Loss of feeders cause large load shifts to nearby feeders which can then start the feeder cascading effect and potential network shut down. This is compounded during contingencies beyond design where large amounts of load would be picked up by nearby feeders that are already close to the emergency rating on second contingency. The waterfront around Kent Ave which has become a popular place for developers to build skyscrapers is a very susceptible area because there is no support on the west side of the load pocket being a river.

<u>Risk 2</u>

Feeder overloads. There are sixteen feeders within 90% of their normal rating and ten within their emergency rating. With time, as load grows, the need for load relief will increase year over year and remain high for the foreseeable future. This is an expensive process with no significant improvements in the NRI relative to the cost. It is estimated that by 2028, we will need to resolve around 315 sections overloaded which will require upgrades involving higher rated cable and in most cases conduit since the overloaded cable is 500 mcm cable. Upgrading to 750 mcm or higher rated cable will require trenching to install new ducts. The number of feeder overloads will keep increasing as load grows.

There is an additional related risk caused by the low margins between the feeder loads and their rating. If there is unexpected load growth or load shifting within the network, it can cause feeder overloads that may require de-loading or load shedding plans if there is no time to solve the deload before the summer peak. These overloads will also increase the NRI going into the summer if they are not resolved.

Also, because the low margin between the emergency rating and emergency load, there is a high risk that feeders will exceed emergency ratings during contingencies beyond design during peak heat in the summer. This will increase the chances of feeder cascading and network shutdown.

All these risks will be eliminated under the plan proposed in this white paper by introducing new feeders and rebalancing the load among feeders.

<u>Risk 3</u>

Under the current state, the 6B network has a high number of three feeder conflicts. Under our program, we will eliminate the critical manholes in the Williamsburg Network. Catastrophic failure of these structures would cause issues in the distribution system. Among other effects, overloads, customer outages, or can have significant impact to a large area, load pocket, or network.

Non-Financial Benefits

Resiliency plans: this program will help during problems in the transmission and/or substation which limits the load capacity in Water Street substation which supplies this network. Once this subject program is complete, it will be more feasible to transfer out or partially restore the load coming out of Water Street. It will help minimize the impact on customers.

Customers will be satisfied with much less construction in the long term because the large number of overloads expected in the current design would be resolved with this program in an orderly planned manner over several years. Otherwise, hundreds of sections will require load relief and excavation over the next decade in different areas of this part of Brooklyn.

By decreasing the probability of a network shutdown, this program will progressively increase the reliability and resiliency of the network in the long term. It will help the Company avoid public safety issues related to network failure, customer outages and significant damage to company equipment. Also, it will shield the company from any reputational issues related to network shutdown.

Less customer disruption. This program will also help reduce outages because less stress on the feeders and eliminate all major load relief projects.

With electrification of the City, and the transition from a carbon economy, this network will need capacity to accommodate unprecedented load growth. More transformers will be needed as more load gets added to the secondary grid. Rapid load growth has the potential to overwhelm the capacity of the company to address all the relief and reliability challenges in the not too far future.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)

2. Major financial benefits

The main financial benefit of this work is cost avoidance. Because of the low margins between the feeder rating and feeder load the network will require an increasingly growing budget over the next decade to address feeder overloads. The standard way available to resolve the overload is to install new duct and replace the overloaded section. This is an expensive proposition. There are 315 sections at a minimum that will require upgrading by 2028 with a cost of close to $56 Million. This of course can fluctuate if the load forecast changes more than expected since there are hundreds of sections close to their emergency rating. The implications are that over the next decade the load relief projects can run in the tens of millions. An uptick in the load forecast, for example caused by the electrification of cars and heating, can increase this number dramatically. The number of sections with loads close to their rating is estimated to be close to 560 by 2028. That will require a replacement value of $60 to $80 Million if load increases significantly or if you expand the time when the analysis is conducted. In addition, the effect on the NRI index wouldn't be significant relative to the amount spent since we are only increasing the rating of the cable and are not fixing other inherent problems in the network. The work proposed in this paper will resolve all the over loaded sections in a planned matter and is projected to decrease the NRI by 75% based on a study conducted in 2019

Another cost savings is that the much lower load per feeder gained by introducing new ones will reduce the stress on the feeders during summer contingencies. Avoidance of penalties related to potential network shutdown implied in the high NRI number is another benefit of this program.

3. Total cost

		Full Cost	
Discipline	**Name**	**Units**	**Tot $**
UG	120/208V Transformer	8	$ 123,000
UG	Secondary Mains	50	$ 794,000
UG	Street Ties (4 sets of 4-500)	8	$ 47,000
UG	3-500 EPR (splicing included)	275	$ 10,642,000
UG	3-750 EPR (splicing included)	1	$ 49,000
UG	3-1000 EPR (splicing included)	325	$ 29,203,000
CM - Structure	V15-6	8	$ 820,000
CM - Structure	M14	114	$ 7,720,000
CM - Conduit	Roadway Conduit	86255	$ 52,632,000
			$ 102,030,000

4. Basis for estimate

Unit costing method was used as follows: The number of required units of equipment and material and multiplied by a loaded unit cost that contains material, labor and overheads.

5. Conclusion

This project is highly recommended and will bring great benefits to the Company and rate payers. This project will help the Company accomplish two goals. Reduces the amount of future load relief and greatly reduces the NRI index which indicates the susceptibility of network failure relative to other networks in the system. Also, it will help us with the future electrification of the economy because of the conversion to electric vehicles and heating.

The NRI index has remained high despite all attempts to reduce the number over the last few years. This is due to the concentration of load and the large load per feeder. Load growth which is expected to continue will add to the problem every year. As load increases, it will be exceedingly expensive and difficult to address overloads and improve the reliability index of the network. The only way available is to reduce the load per feeder and reduce the size of the load area. By introducing four feeder bands (eight feeders), we will be able to break the network into two smaller secondary load pockets and at the same time reduce the loading on the equipment both normally and during emergencies. An additional benefit is also the elimination of manholes with multiple feeder conflicts, this has an impact on the NRI too. Some of these manholes are considered critical and their failure could result in equipment overloads and customer interruptions. Introducing the new feeders and balancing the load is the most cost-effective way to alleviate all the problems of this network. In addition to the financial costs, there are other consequences to the company. Investing this money will decrease the likelihood of a network shutdown and all the consequences involved in that type of event: public safety, reputational damage, PSC penalties, customer outages, damage to the grid and equipment, etc.

Project Risks and Mitigation Plan

Risk 1
Congestion in main run and feeder outlets when looking for new duct lanes

Mitigation plan
Survey ahead and if it is no lane available, then have plans to use existing lanes with additional protection as per company specs (common trench and physical protection between systems).

Risk 2
Restricted access to street (Flushing Ave)
Mitigation plan
Identify all the restrictions, modify the phases of the plan and obtain necessary permits ahead of time.

Technical Evaluation / Analysis

The picture below shows how ten out of the twenty feeders in the network are within 90% of the emergency rating. This affects reliability and increases the financial cost of relieving the overloads since most of them require trenching to install new duct and cable. The low margins between the feeder load and rating are also the driver for the high NRI ranking. The NRI for the last three years along with the rankings are: 2019 (NRI = .793, Rank#3), 2020 (NRI = .87, Rank#1), 2021 (NRI = .819, Rank#3). Over the years all the PILC cable has been replaced in the network and a couple of recent projects cross banding a mid-network band into the waterfront to pick up multibanks and other reliability projects have helped keep the NRI number under 1. All the most feasible options to address the NRI have already been taken.

FDR	Normal Load (A)	Emergency Load (A)	Normal Rating (A)	Emergency Rating (A)	June 30 Peak Load (A)	Normal % Rating	Emergency % Rating
6B41	376	566	390	580	370	96	98
6B42	383	552	390	575	360	98	96
6B43	393	596	410	605	388	96	99
6B44	356	540	390	595	314	91	91
6B45	372	523	375	585	428	99	89
6B46	366	513	390	585	411	94	88
6B47	390	537	400	590	387	98	91
6B48	341	481	355	545	336	96	88
6B49	293	404	355	580	328	83	70
6B50	257	364	355	520	289	72	70
6B51	416	551	445	615	396	93	90
6B52	396	542	415	575	471	95	94
6B53	407	546	410	620	422	99	88
6B54	327	480	340	545	383	96	88
6B55	225	320	310	420	205	73	76
6B56	386	501	395	590	402	98	85
6B57	423	627	435	635	404	97	99
6B58	391	555	415	610	365	94	91
6B59	117	177	340	630	138	34	28
6B60	288	381	305	405	262	94	94

The table below illustrates the number of sections that are approaching and exceeding the emergency rating. As load grows, past 2028, the number of OL sections will continue to increase beyond the 315 sections listed. Introducing new feeders is the most cost-effective way to solve the problem.

Forecast Year	MW from 10 Year Forecast	Total OL's – No CYMCAP	Total OL's – after CYMCAP
2020	328	322	12
2023	349	436	114
2028	370	560	315

Project Relationships (if applicable)

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital						
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**7,069**	**17,795**	**23,745**	**23,809**	**9,870**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	866	2,172	2,892	2,8904	805
M&S	1,134	2,844	3,786	3,802	1,054
Contract Services	1,787	4,480	5,965	5,990	1,661
Other	51	127	169	170	47
Overheads	1,623	4,070	5,418	5,441	1,509
Subtotal	**5,462**	**13,692**	**18,231**	**18,308**	**5,077**
Contingency**	**1,638**	**4,107**	**5,469**	**5,492**	**1,523**
Total	**7,100**	**17,800**	**23,700**	**23,800**	**6,600**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2023	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Yorkville Crossings and Feeder Relief	
Project/Program Manager: Rintu Mathew	**Project/Program Number (Level 1): 21479860**
Status: ☐ **Planning** ☒ **Design** ☐ **Engineering** ☐ **Construction** ☐ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date: January 1st, 2017	**Estimated Date In Service: December 31st, 2025**
A. Total Funding Request ($000) **Capital: 32,000** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period:** **(Years/months)**

Work Description:

To maintain the reliability of the Yorkville network, new underwater crossings beneath the Harlem River between Manhattan and the Bronx will be established and the existing 13 kV primary feeders will be diversified.

The Yorkville network, located in Manhattan, is supplied from twenty-nine (29) 13 kV distribution feeders that originate from the Hell Gate Area Substation located in the Bronx. The boundaries of the Yorkville network are 110th Street to the north, 77th Street to the south, 5th Avenue to the west, and the East River to the east (see Figure 1).

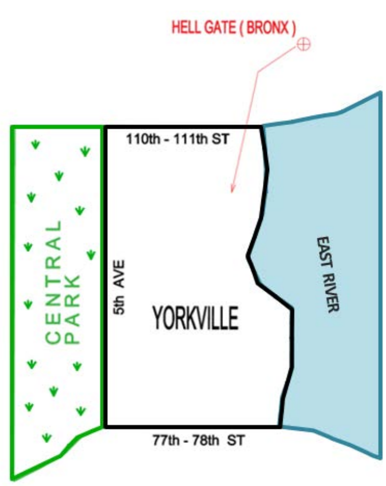


Figure 1: Existing Boundaries of the Yorkville Network in Manhattan, New York

The distribution feeders reach Manhattan via six (6) active underwater crossings. Four (4) of these crossings span across the Harlem River near the Willis Avenue and Third Avenue Bridges, known as Crossings Nos. 80, 81, 83, and 84 (see Figure 2). These crossings contain twenty-three (23) of the twenty-nine (29) feeders that supply the Yorkville network.

The fifth and sixth crossings route the distribution feeders via Randall's Island, known as Crossings Nos. 82 and 85. These crossings contain the remaining six (6) primary feeders that supply the Yorkville network as well as the distribution feeders that supply the Randall's Island network.

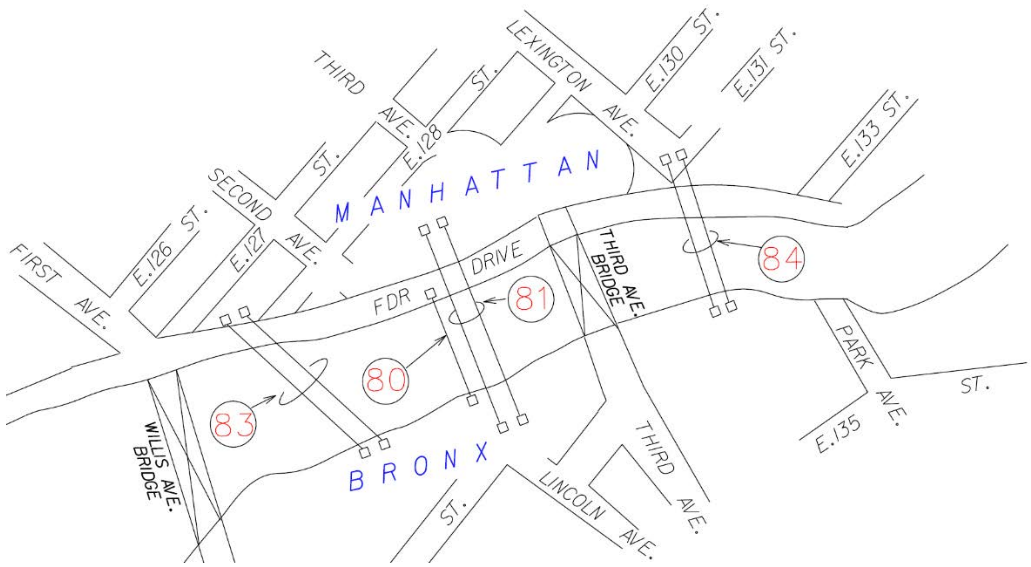


Figure 2: Underwater Crossings between Manhattan and the Bronx (Labeled Crossing Nos. 80, 81, 83, and 84)

The new underwater crossings will be comprised of a bundle of seven (7) 6-5/8" High Density Polyethylene (HDPE) conduits, similar to the composition of the existing crossings. The new crossings will be constructed under the base of the river by means of horizontal directional drilling (HDD) with a profile dependent on the exact geological and subsurface conditions. New terminal manholes and new outlet systems will be constructed on either side of the Harlem River so that the new crossings can interconnect with the existing distribution system. Each of the conduits will be equipped with 3-750 kcmil EPR-NL primary feeder cables.

An estimate of the units required for this project is shown in Table 1.

Table 1: Estimated Units Breakdown

Description	Quantity	Unit of Measure
Conduit (Street work)	6,000	Trench Feet
Primary Cable	110	Sections
Manhole Structures	8	Each
Underwater Crossings	2	Each

High-level schedule:

Planning and design work on the New Harlem River Crossings began in 2017 and will continue through 2021. Con Edison has retained engineering consulting services to complete a detailed design of the underwater crossings and cable pull setup. Based on this detailed design, Con Edison will engage a construction vendor and establish an agreement to complete this non-routine work, inclusive of building the crossings and pulling the cables. Construction activities for the crossings will begin in late 2022 and last through 2023. Conjunctional Con Edison construction work on the outlet systems and distribution feeder rearrangement will be in tandem with the vendor work. The new systems will be completed and commissioned prior year end 2025 (see Figure 3).

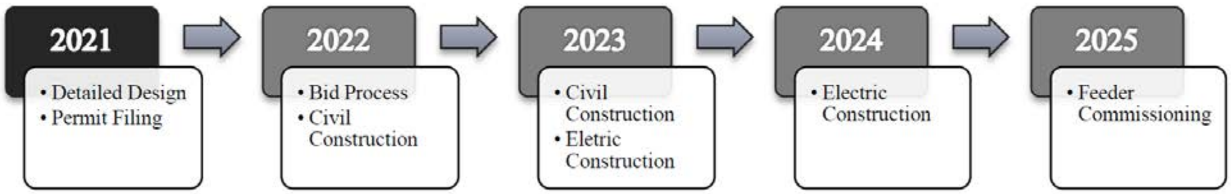


Figure 1: High-Level Project Schedule

Justification Summary:

The four (4) underwater crossings that span between Manhattan and the Bronx all have high duct occupancy and few remaining spare conduits as shown in Table 2. These spare conduits are critical in maintaining the reliability of the Yorkville network for both accommodating future load growth and for cable replacements due to failures. Many of the feeders are already double-legged (i.e., one feeder with two legs from the same station circuit breaker), with each leg having their own conduit, to support the high load of the Yorkville network.

Table 2: Underwater Crossings Showing Duct Occupancy and Spares

Crossing 80	Crossing 81-North	Crossing 83-North	Crossing 84-North
48" Aband. Gas Main	*7-6" Conduits*	*4-6" Conduits*	*7-6" Conduits*
3M43L	3M45	3M53	3M47
3M43M	3M51L	3M56L	3M61L
3M49L	3M54	3M56M	3M61M
3M49M	3M57	SPARE	3M64
Obstructed	3M65		Fiber Optic
Obstructed	3M69		SPARE
	Obstructed		SPARE

Crossing 81-South	Crossing 83-South	Crossing 84-South
7-6" Conduits	*7-6" Conduits*	*7-6" Conduits*
3M41L	3M52L	3M40L
3M41M	3M52M	3M40M
3M50L	3M58L	3M55
3M50M	3M58M	3M66L
3M51M	3M60L	3M66M
3M67	3M60M	3M68
Obstructed	SPARE	SPARE

The susceptibility of having such few spare crossings was recently highlighted by a City of New York Department of Transportation (NYCDOT) project in which the Harlem River Drive roadway was being reconstructed. As part of such project, the NYCDOT was driving piles for the pier supports of the new roadway within feet of the existing underwater crossings. In response to the NYCDOT activities, and the potential risk of damage to the crossings, Con Edison preemptively developed plans that, in the case of an emergency, would reroute and restore the impacted distribution feeders to service. It was evident that with such few spare conduits, restoring the network to normal operation would pose an immense challenge.

The greatest concern revolves around the crossings between the Willis Avenue and Third Avenue Bridges, Crossing Nos. 80, 81, and 83. Crossing Nos. 80, 81-North, and 81-South currently have no spare conduits and Crossing No. 83 has two (2) spare conduits. These crossings contain sixteen (16) feeders composed of twenty-five (25) feeder legs. With the complete loss of any of these crossings, there are not adequate spares to reroute the distribution feeders and place them back in service without significant temporary reroutes.

In addition to the lack of spare conduits, the majority of the distribution feeders that supply the Yorkville network are heavily-loaded. Based on the 2021-2030 Network Area Forecast, by year 2030, (i) approximately 60%, or seventeen (17) of twenty-nine (29), of the distribution feeders will operate at or above 90% of their normal rating, and (ii) more than 40%, or twelve (12) of twenty-nine (29), of the feeders will operate at above 95% of their normal rating as shown in Table 3.

Table 3: Projected Yorkville Load – Ten Year Look Ahead (Summer 2030)

- Loading ≥ 90%   - Loading ≥ 95%

Feeder	Normal Load (%)	Emergency Load (%)	Breaker Emergency (Amps)
03M40	**95**	75	821
03M41	78	73	831
03M42	77	84	627
03M43	**96**	**94**	918
03M44	**99**	86	997
03M45	73	57	434
03M46	82	76	562
03M47	**94**	74	521
03M48	**97**	81	550
03M49	84	77	773
03M50	85	79	860
03M51	**95**	**91**	1082
03M52	**92**	78	461
03M53	**99**	87	503
03M54	**100**	**92**	589
03M55	**98**	**99**	548
03M56	**100**	**91**	688
03M57	**97**	**92**	560
03M58	87	79	724
03M60	**93**	**93**	778
03M61	**91**	75	531
03M62	88	80	555
03M63	**100**	85	1100
03M64	**90**	75	536
03M65	84	71	436
03M66	85	66	764
03M67	86	79	474
03M68	**99**	**98**	553
03M69	86	66	476

The distribution feeder ratings of these heavily-loaded feeders are thermally limited due to high duct occupancy caused by subsurface congestion. In general, the limiting cable sections are those located in and around the crossings, the majority of which are 3-750 EPR-NL cable. In these situations, basketing these cable sections is not a feasible solution as it will increase the duct occupancy on all the adjacent feeders and will exacerbate the issue.

Increasing the feeder diversity, via new underwater crossings, which is equivalent to increasing the average number of related feeders in the network, is the most effective tool in reducing the feeder pick-up under second contingency conditions.

In addition, under emergency conditions, distribution feeders 03M51 and 03M63 are approaching the station breaker limit of 1200 Amperes, with 1082 and 1100 Amperes, respectively. This project will create capacity in adjacent feeder bands in order to de-load these heavily-loaded distribution feeders.

Relationship to 5-Year and Long-Range Plans and Enterprise Risk Management Strategy

Electric Long-Range Plan (ELRP): In order to meet the challenges posed by climate change, the Company plans to increase the resiliency of the system while maintaining reliability. Cable crossings in particular take a significant amount of planning and work to complete, and as such resiliency planning dictates the need for excess capacity for existing feeders as well as the availability of spare ducts for emergency feeder installation.

Enterprise Risk Management (ERM): Enterprise risk – Network Shutdown; Department Risk – Regulatory Penalties

2. Supplemental Information

Alternatives

Traditional Utility Alternatives:

The design of the Yorkville network, with the supply (Hell Gate Area Substation) located in the Bronx, and the load on the island of Manhattan, presents inherent restrictions in resolving this particular reliability concern. All the distribution feeders that supply the Yorkville network reach Manhattan via underwater crossings and, as such, there are limited options for resolving a lack of spare conduits.

The alternative to creating new underwater crossings would be to reduce the loading of the feeders in the existing crossings. By reducing the overall load on the crossings, the load can be consolidated onto fewer cables, making room for spare conduits. To reduce the load, a network load transfer to an adjacent network would need to be performed. As the Yorkville network is geographically bounded by Central Park to the west and the East River to the east (see prior Figure 1), there are limited nearby networks to which to transfer the load. The only destinations would be the Lenox network located to the south or the Triboro network located to the north. The East 75th Street Area Substation that supplies the Lenox network has minimal spare capacity and it would not be able to absorb a network transfer from the Yorkville network. The Parkview Area Substation that supplies the Triboro network also has minimal spare capacity and it would not be able to absorb a network transfer from the Yorkville network.

A long-term plan would be to establish a new Area Substation in the Upper East Side of Manhattan. By establishing a new area substation, a portion of the Yorkville network could be transferred to the new station, reducing the load on the crossing. Although it is a possible solution, establishing a new area substation is not a financially feasible option when compared to the creation of new underwater crossings.

Non-Wires Solutions:

As reducing the load on the distribution feeders of the Yorkville network may allow for the consolidation of cables in the crossings, the Company should consider utilizing Non-Wires Solution (NWS) as a potential load relief solution.

The Company should screen this project to determine if it is suitable for an NWS. If the project meets the screening criteria, the Company should construct a preliminary portfolio of NWS based on the Integrated Demand Side Management (IDSM) model, which identifies what Distributed Energy Resources (DERs) could be feasibly implemented in the area of need. The Company should pursue a comprehensive customer engagement strategy that involves community groups, the City of New York, non-government organizations, and market partners.

The NWS portfolio is to be evaluated using a Societal Cost Test, an economic test of costs and benefits. If the results indicate the portfolio of DER is cost-effective, the procurement process for DER should begin to determine actual costs.

> *Note: Even if the analysis indicates the DER solution is the most cost-effective, a traditional utility solution will be developed as the backstop if implementation issues arise or if subsequent analysis indicates the DER portfolio is not the most cost-effective.*

Risk of No Action

If no action is taken, cable or crossing failures may result in cascading feeder failures requiring the shutdown of the Yorkville network (relatively low risk) or a significant number of customers may experience an extended outage (low to moderate risk).

Non-Financial Benefits

This project would help prevent the negative publicity of a large customer outage on the Upper East Side of Manhattan.

Summary of Financial Benefits and Costs

Creating new underwater crossings and diversifying the distribution feeders will reduce the congestion of the existing crossings. Reducing the congestion of the crossings improves the Network Reliability Index value (NRI), and thus the reliability, of the Yorkville network. In addition, having spare conduits under the river allows for the quick replacement due to cable failures. Without spare conduits, the failure of individual cable sections, or the loss of an entire crossing, would increase the Yorkville network's susceptibility to a shutdown.

Project Risks and Mitigation Plan

Risk 1 – Harlem River Yards Land Acquisition Issue – High
Mitigation plan – Perform land appraisal. Enter negotiations early.

Risk 2 – Pile Tip elevations are deeper than expected on the Manhattan side – Low
Mitigation plan – Perform Non-Destructive Testing program.

Risk 3 – Frac-Out – Low
Mitigation plan – Develop a Frac-Out Contingency Plan. Include in Environmental, Health, & Safety Design Analysis 11.03. Coordinate with Contractor eHASP.

Technical Evaluation / Analysis

Poly Voltage Load flow (PVL) and Network Reliability Index (NRI) considerations will be utilized to determine the best solution.

Project Relationships (if applicable)
N/A

3. Funding Detail

Historical Spend ($000):

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital		**338**	**903**	**267**		296
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**2,500**	**16,000**	**10,500**	**3,000**	
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	106	679	446	127	
M&S	34	217	143	41	
Contract Services	1,867	11,946	7,839	2,240	
Other	7	45	30	8	
Overheads	486	3,112	2,043	584	
Total	**2,500**	**16,000**	**10,500**	**3,000**	

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Electric Operations / DE
Budget Year

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☐ **Capital** ☒ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Meters and Customer Equipment Program	
Project/Program Manager: N/A	**Project/Program Number (Level 1):**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date: Ongoing	**Estimated Completion Date: Ongoing**
A. Total Funding Request ($000) **Capital:** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:
The **Meters and Other Customer Equipment** program category is comprised of the following individual program initiatives:

1. <u>**Customer Requests**</u> – This program is used for a number of different expenses/work activities precipitated by customer requests. Below is a description of some of these expenses/work activities:
   - Miscellaneous distribution expenses, such as work associated with overhead load investigations
   - Customer installation expenses, such as high-tension vault work
   - FCC related activities, such as investigating radio and TV complaints in overhead or network systems
   - Power quality investigations
   - Other work on customer premises, such as remediation of residential load study equipment
   - Temporary electric service to customers for new building construction;

2. <u>**Meter and Customer Work**</u> – A clearing account used to track several activities associated with meter and customer premises work. The related charges accounted for in this program are:
   - Overhead transformer installations
   - Underground transformer installations
   - URD transformer installations
   - Transformer installation credits for operating overhead or underground lines;

3. **Meter and Test** – This program includes a variety of tasks pertaining to the inspection and testing of meters on the customer's premises. These tasks include:
   - Testing standard in service meters as required by New York Public Service Commission ("PSC") regulations
   - Removing and/or replacing meters
   - Performing customer special inspections on unique meter models
   - Performing customer premises load studies
   - Maintaining meters
   - Reading meters and downloading interval data
   - Remotely reading meters
   - Verification and troubleshooting of metering communications systems
   - Installation of communications network optimization equipment and supporting infrastructure
   - Installation and maintenance of solar and generator interface equipment that resides in customer meter pans
   - Assistance to the PSC to perform field testing of Meters and Instrument Transformers in response to customer complaints relative to billing
   - Annual testing and maintenance of ISO meters at points of generation and interties between utilities;

4. **Disconnect or Reconnect Meters** – As implied in the program name, this program accounts for the work associated with disconnecting and/or reconnecting meters.

Justification Summary:
Since Con Edison's Advanced Metering Infrastructure ("AMI") deployment is complete, the Company is establishing meter maintenance and test cycles. A maintenance and testing program is necessary to ensure that we are able to provide the best service to our customers. To do so, we must test our meters from time to time as mandated by the PSC to ensure functionality and accuracy and that there are no problems with the equipment. The only way to ensure that we are providing adequate service is to inspect and maintain our equipment periodically to make sure that it is operating as designed.

Meter Installation is necessary to provide service to customers. Electric meters are required by the PSC for revenue collection.

Relationship to 5-Year and Long-Range Plans and Enterprise Risk Management Strategy

The purchase and installation of customer meters is fundamental to the core business. The AMI meters that are currently installed provide greater insight into real-time and historic energy use for customers and for Con Edison, providing a platform for new programs and innovative operating procedures and policies. One example is the Customer Voltage Optimization program. Because the customer voltage is readily available, operators are able to reduce the voltage on feeders while ensuring all customers are getting adequate voltage. This reduces the energy consumed by the customers, which reduces their cost, and also reduces the generation needed to supply them. This provides an overall savings to the customer while also reducing the overall energy demand of the system. While this program itself does not implement strategies to mitigate the Enterprise Business Model Risk, it supports a platform upon which those programs will be built.

AMI data also enables analysis that wasn't previously possible. One example is the AMI Data Open Neutral analysis, which improves public safety by using AMI data to detect open neutral conditions at customer premises. This advances the Company's goal to improve public safety.

2. Supplemental Information

Alternatives
Briefly describe reasonable alternatives and reason for rejection (e.g., costs, timing, etc.).

Alternative 1 description and reason for rejection
There are no acceptable alternatives to the use of PSC approved metering devices as specified in PSC 16 NYCRR Part 92 and PSC No. 10 – Electricity for electric rate paying customers. Meters provide the means to accurately record customer demand, implement time of day rates, demand response and energy efficiency programs and comply with regulatory metering programs such as reactive power.

Alternative 2 description and reason for rejection

Alternative 3 description and reason for rejection

Risk of No Action

Risk 1:
Without meters, new tariffs would have to be developed for flat rate billing which are not approved by the PSC at this time.

Risk 2

Risk 3

Non-Financial Benefits
Examples:
- *Increased safety, reliability, efficiency, or customer satisfaction*
- *Improved workflows and communication among departments*
- *Stronger relationships with community or with regulators*
- *Ensuring regulatory compliance*

Metering a customer's energy usage provides an objective measure of the amount of energy used. This improves customer satisfaction by removing any doubt a customer might have about the accuracy of their bill. Electric meter data for customers is used to invoice customers for usage and will improve system planning for critical system upgrade engineering analysis.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis (if required)

2. Major financial benefits

3. Total cost

4. Basis for estimate
Expenditures in RYE2016 are projected to be $1.3 million greater than the historic year due to a revision to accounting procedures. The accounting procedure revision resulted in credits formally assigned to Electric Operations to be reassigned to an "Other Operating Revenues" account. The

absence of these credits applied to the first three months of the historic year effectively increasing costs for Electric Operations. But because the accounting procedure change is permanent, the absence of credits will apply to all four quarters of the first rate resulting in greater costs than those incurred during the historic year.

5. Conclusion

Project Risks and Mitigation Plan

Risk 1
Supply chain issues with meters from only one source because of the AMI deployment using meters from a single manufacturer could result in delays in supplying replacement meters when failures occur.

Mitigation plan
To mitigate this risk, Meter Engineering will evaluate alternative products that are compatible with the AMI system to provide a competitive vendor environment toward reducing costs and assure that meters can be obtained in a timely manner.

Risk 2

Mitigation plan

Technical Evaluation / Analysis
Describe any specific studies or analysis related to the project such as: trend analysis, internal/external studies, social studies, and related KPI's (e.g. System Average Interruption Frequency Index (SAIFI) or Customer Average Interruption Duration Index (CAIDI)). Load forecasts, failure trends, etc., may also be presented in this section. However, these analyses are not available for all projects or programs.

Meters, Devices and Instrument Transformers are selected based on customer loads, engineering analysis of manufacturer's equipment relative to our service territory as well as previous performance of similar products.

Project Relationships (if applicable)

3. Funding Detail

Historical Spend

	Actual 2016	**Actual 2017**	**Actual 2018**	**Actual 2019**	**Historic Year** (O&M only)	**Forecast 2020**
Capital						
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital					
O&M*	**5,116**	**7,088**	**8,426**	**8,739**	**8,914**
Retirement					

Capital Request by Elements of Expense:

EOE	2021	2022	2023	2024	2025
Labor					
M&S					
Contract Services					
Other					
Overheads					
Subtotal					
Contingency**					
Total					

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
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4. Definitions

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Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

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Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Central Operations / Transmission Operations
2022 - 2026

1. Project / Program Summary

Type: ☐ Project ☒ Program	**Category: ☐ Capital ☒ O&M/CLEARING**
Work Plan Category: ☐ Regulatory Mandated ☒ Operationally Required ☐ Strategic	
Project/Program Title: Transmission Operations Capital Projects	
Project/Program Manager: Various	**Project/Program Number (Level 1):**
Status: ☒ Planning ☐ Design ☐ Engineering ☐ Construction ☐ Ongoing ☐ Other: ___________	
Estimated Start Date: January 2023	**Estimated Date In Service: On-going**
A. Total Funding Request ($000) **Capital: $3,245** **O&M/CLEARING: $15,660** **Retirement:**	**B.** **☐ 5-Year Gross Cost Savings ($000)** **☐ 5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M/CLEARING:** **Capital:**	**D. Investment Payback Period:** **(Years/months)**

Work Description:

Transmission Operations is responsible for the planning and implementation of all activities for the successful construction, testing and energization of major projects and programs in Transmission capital portfolio. This will be increased significantly by several projects slated to serve the expanded territory.

The Brooklyn Clean Energy Hub (BCEH), a new 345kV transmission substation that will create Points of Interconnection (POI) for large scale renewable resources, such as Offshore Wind Generation (OSW). The transmission station will also include five 345/138kV transformer banks that will provide supply to existing substations (Trade Center and Seaport Nos. 1 and 2) and future area substations. This project will require demolition of retired facilities and the construction portion will be completed over two phases.

This project will utilize the (retired) Hudson Avenue Generating Station property in the Vinegar Hill neighborhood of Brooklyn. The initial construction phase shall include the design and construction of a double ring bus substation with twenty 345kV circuit breakers, 14 feeder positions and four 345/138kV transformer banks. Establishing the transmission station will include intercepting three existing 345kV feeders (61, 62 and 63) between the Farragut and Rainey 345kV Substations and diverting them into the Brooklyn Clean Energy Hub. The 345kV transmission feeders B47 and 48 are currently connected to Farragut Substation (from E13th Street) and the first phase of this project will also include re-routing the feeders to the BCEH.

The second construction phase of this project will include adding two more feeder positions (POIs for OSW) and a fifth 345/138kV transformer. and re-routing the Seaport and Trade Center supply feeders to the BCEH. Additionally, the Seaport/Trade Center loads that are currently supplied by the Farragut 345 kV Substation will be reconnected and supplied by the Brooklyn Energy Hub. The BCEH will also be capable of supplying additional 5 bank area substations.

The Gateway Park Area Station, a new indoor 27kV area substation that will be arranged in a double SYN bus configuration and with an initial build of three 138/27kV transformer banks (with provisions for expansion to five transformer banks). The station will be supplied from the 345kV Brooklyn Energy Hub, add resiliency to the network, and provide additional sub-transmission capacity to mitigate design capability deficiencies in the Bensonhurst and Brownsville load areas to meet projected load growth.

The Parkview TR5 and Feeder 38M85 project will establish a 138kV supply feeder 38M85 from the Mott Haven 345kV Substation to the Parkview 13kV Substation and includes the installation of a fifth 138/13kV transformer at Parkview and a fifth 345/138kV transformer at the Mott Haven 345kV Substation.

To facilitate the construction of these projects Transmission Operations will require an increase in staffing to support the future expansion of the transmission system:

Additional staffing requirements are needed to facilitate site preparation, construction of underground facilities, welding activities, cable pulling of both pipe and solid dielectric 345kV cable, associated splicing activities and testing. This requires ten (10) Splicers, twelve (12) Mechanics and two (2) Welders. Management oversite of these positions includes one (1) Planner, three (3) Supervisors and two (2) CCI. Associated vehicles include eleven (11) box trucks, two (2) welding trucks, and six (6) Management vehicles.

Justification Summary:

In 2019, New York State passed the nation-leading Climate Leadership and Community Protection Act (CLCPA). CLCPA's targets are among the most rigorous of any major economy in the world and include goals of 70% renewable energy by 2030 with 100% emanating from zero-emission electricity by 2040. To achieve the ambitious goals set by the CLCPA requires a transformation in the way power is generated, interconnected, and utilized by customers.
One of the CLCPA requirements is to interconnect 9,000 MW of Offshore Wind (OSW) by 2035. With the physical location of OSW sites' proximities to shore and due to the nature of high injection from OSW installations, the OSW must be connected to the downstate region. Moreover, OSW must be connected to the high capacity 345 kV bulk power system in order to be fully deliverable. The Brooklyn Clean Energy Hub will address these concerns and will create POIs for up to 6,000 MW (4,500MW at BCEH and 1,500MW at Farragut) of OSW that will be deliverable to New York State customers through the existing 345 kV bulk power system.

Additionally, the increasing frequency and severity of extreme weather conditions have the potential to affect the integrity of energy infrastructure, prompting the need to add greater resiliency and reliability to the network. To enhance the resiliency of the energy grid, existing 345kV feeders B47 and 48 will be diverted to the Brooklyn Clean Energy Hub from the Farragut 345 kV Substation. To diversify supply to the area stations, the existing Seaport/Trade Center Area Stations, which are currently supplied by the Farragut 345 kV Substation, will be reconnected and supplied by the Brooklyn Clean Energy Hub. The Brooklyn Clean Energy Hub will also become the supply source for the new 27kV Gateway Area Station. The latter actions will address NERC CIP-014 Physical Security concerns with the current design of the Farragut 345 kV substation.

The Company has been successful in deploying a combination of traditional infrastructure construction and non-wires alternatives through the Brooklyn Queens Demand Management (BQDM) Program to defer the need to expand the Company's existing transmission system to supply and construct the new Gateway Park area substation beyond the 10-year planning window. However, variable inputs to the Company's annual demand forecasting and planning processes require the Company to pursue and construct the new Gateway Park area station in advance of its originally planned service date of 2032.

Future demand forecast iterations have identified design capability constraints on the Farragut to Brownsville 138kV sub-transmission system in the year 2028, prompting a reliability and resiliency plan to transfer loads from the Brownsville No.1 & No.2 and Bensonhurst No.1 & No.2 substations to the Gateway Park area station.

The Brownsville electric distribution networks (Crown Heights, Ridgewood and Richmond Hill) have projected loads that will cause the transmission feeders supplying the Brownsville load pocket to exceed their capability by 2029. The capability of these feeders supplying Brownsville No. 1 and Brownsville No. 2 is 771 MW, and the forecasted load will match the capability by 2028. By de-loading Brownsville #1 Area Substation and the transmission supply feeders through the transfer of 117 MW of load from the Crown Heights network to the newly established Gateway Park Area Station by 2028 will alleviate the transmission feeder overloads in the Brownsville load area.

Forecasted loads for the Parkview 13kV Substation are expected to exceed the station's design capability by the summer of 2027. Load projections in the 2021 – 2030 Ten Year Load Relief Program indicate that the station's capability will be exceeded by 6 MW (103%) with overloads increasing as the load continues to grow in ensuing years. To add capacity at Parkview Substation and to increase capability, it is recommended that a fifth 138/13kV transformer be installed at Parkview along with a new 138kV supply feeder from the Mott Haven 345kV Substation. A fifth 345/138kV transformer at Mott Haven will also be required to provide the supply to Parkview. The rapid load growth in the network over the next few years is primarily driven by the expansion of the MTA's 2nd Avenue Subway line with associated economic activity in the area expected to continue. This project adds 73MW of capability to Parkview Substation, and is determined to be a sensible approach in anticipation of expected increased customer heating electrification and the Company's clean energy commitment to meet NYS CLCPA goals.

Transmission Operations will support the installation, testing and commissioning of these new feeders as well completing all the new terminations, cable relocations, cable testing and substation related installations.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):

Extreme weather events such as coastal floods, intense precipitation and heat waves are gaining in frequency and severity as the planet continues to warm. Con Edison's electric infrastructure is vulnerable to climate-related threats as well as contributes to the growing risks. Along with sea level rise, severe storms have caused destruction on Company assets which have led to large and extensive power outages. Adapting to climate change in a timely manner and lessening the intensity of its effects through the reduction of greenhouse gas emissions aids in strengthens resiliency measures.

The Climate Leadership and Community Protection Act (CLCPA) has established greenhouse gas emission reduction limits associated with imported electricity and fossil fuels in New York State, as well as additional climate change goals to include 70% renewable electricity by 2030 and 100% zero emission electricity by 2040. The NYSDEC has coordinated with the NYISO to ensure that compliance with NOx emissions regulations and CLCPA policy objectives would not adversely affect grid reliability. In reviewing projected impacts driven by policy goals from the CLCPA, Con Edison has considered risk-based cost benefit analyses on how future projections of climate variability in the energy landscape will impact key assets and facilities, overall system operations, and emergency response capabilities.

Along with meeting NYS CLCPA clean energy goals, the Company anticipates expected increases in customer heating electrification. Load projections in the 2021 – 2030 Ten Year Load Relief Program indicate that the Brooklyn networks will encounter increasing overloads in ensuing years, with the Bensonhurst and/or Bronxville substations exceeding their station design capabilities. To address reliability design criteria and build in resiliency for various contingency events while complying with CLCPA requirements, the new Gateway Park Area Station will be placed into service by 2028. The new substation will be supplied by the Brooklyn Clean Energy Hub, enabling a renewable energy supply to access the load, as well as reduce dependency on local fossil fuel plants to maintain local reliability needs. This project will improve the reliability of networks by allowing for the reduction of network sizes and will establish feasible resiliency options for various contingency events, which are not available with the existing distribution system design.

By enabling load splits and smaller distribution networks in the Brownsville and Bensonhurst load areas, this program will progressively increase the reliability of the associated networks in both the near and long term. The program will alleviate issues in the transmission system which limits the load capacity in the Bensonhurst and Brownsville substation. Once the project is in service, it will be more feasible to transfer out or partially restore the load emanating out of Bensonhurst and Brownsville, minimizing the impact of outages to customers. It will help the Company avoid public safety issues related to network failures and significant damage to company equipment.

The operational measures and system improvements implemented with this project would be sufficient in addressing load growth across Company networks in central Brooklyn, and satisfy reliability, resiliency, safety, and compliance regulations.

2. Supplemental Information

Alternatives

The alternative is to engage a contractor workforce to do the electric feeder related work. This would be challenging due to the fact that qualified extra high voltage underground mechanics, splicers and welders take years to train and they are not readily available in the marketplace. This emerging work coupled with the maintenance of the existing feeders will present a challenge for the company to support both sets of feeders.

Risk of No Action

These projects will get started and there will not be any resources from transmission operations to support it. This will result in these projects potentially getting delayed or failing to be implemented. This will be a tremendous waste of money and resources and it will result in future feeder failures. Other feeders will overload and load shedding may be required during peak conditions which would cause thousands of customers to encounter service outages for a long period of time.

Without pursuing the project, the Company networks will encounter the potential inability of maintaining reliable system power flow controls, system reliability and resiliency concerns and/or possible customer outages for an extended period during peak load conditions.

Non-Financial Benefits

These projects (The Brooklyn Energy Hub, Gateway Park Substations, Parkview Substation) will provide the necessary reliability and resiliency in an area of New York City that serves many critical loads (e.g., airports, transportation hubs, and hospitals) in a densely populated area where many buildings have elevators and various equipment loads. Relief of overloaded transmission feeders will ensure continued reliable service to the Brownsville load pocket and will allow the station to maintain the area substation N-1 reliability design criteria for long term projected load growth in Brooklyn.

The increased capacity brought on by Gateway offers the potential to minimize impact on customers during an area station event that limits station capacity. Resiliency options are not feasible in this load pocket without the use of rolling blackouts and mobile stations which requires a time-intensive set-up. By introducing new area station capacity and splitting current networks into smaller load areas, the Company will be able to handle loss of station capacity during emergencies and its impact on customers. If capacity at Brownsville, Bensonhurst or at the Gateway stations are compromised, load can be swapped between stations, minimizing or eliminating the need for load shedding during an event.

Meeting New York's CLCPA goals will ultimately require the Company to build system capacity for an anticipated increase in load growth. With electrification of the City, as we move away from a carbon economy, we will require capacity in the affected networks to accommodate unprecedented load growth. Rapid load growth has the potential to leave the Company in a difficult position to address all the relief and reliability challenges in the near future.

Summary of Financial Benefits and Costs

N/A

Technical Evaluation / Analysis

Due to overload constraints identified for year 2028, a new 345kV substation and reinforcing the 138kV sub-transmission system, building new area substations would be the only viable alternative for load relief. Con Edison is proposing increasing the Transmissions Operations technical team to support these new electric transmission feeder installations and relocations

Project Relationships (if applicable)

N/A

Basis for Estimate

This estimate is based on a conceptual scope of the project and on order of magnitude estimates.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	0	0	0	0		0
O&M						
Retirement	0	0	0	0		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital		$ 3,245			
O&M/CLEARING		$ 3,915	$3,915	$3,915	$3,915
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	0	0	0	0	0
M&S	0	0	0	0	0
Contract Services	0	0	0	0	0
Other	0	$ 3,245	0	0	0
Overheads	0	0	0	0	0
Subtotal	0	0	0	0	0
Total	**$0**	**$ 3,245**	**$0**	**$0**	**$0**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M/CLEARING		**$ 3,915**	**$3,915**	**$3,915**	**$3,915**
Capital					

Central Operations/System & Transmission Operation
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☐ **Capital** ☒ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Transmission Planning Staffing Needs to Support Clean Energy Agenda	
Project/Program Manager: Deidre Altobell	**Project/Program Number (Level 1):**
Status: ☐ **Initiation** ☐ **Planning** ☐ **Execution** ☒ **On-going** ☐ ☐ **Other:** ____________	
Estimated Start Date: 01/1/2023	**Estimated Date In Service:**
A. Total Funding Request ($000) **Capital:** **O&M: $1,620**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months) (If applicable)**

Work Description:
The timely achievement of New York's clean energy and environmental requirements, established through NYS Climate Leadership and Community Protection Act (CLCPA), will require innovative, multi-value electric system investment planning and execution. Significant and continued expansion of the local transmission and distribution systems will be necessary to achieve CLCPA clean energy targets in a cost-effective manner. Moreover, PSC September 9, 2021 Order calls for the establishment of a new coordinated statewide grid planning process that will increase the level and extent of studies, supporting documentation, working group processes and stakeholder engagement activities.

The three (3) new positions and their respective modeling tools will support the planned transition from a fossil driven power system to that of an intermittent inverter-based power system on both a long-range and a short-range basis.

<u>Major Responsibilities:</u>

- Implement requirements of the CLCPA into Con Edison's Transmission Master Plan.
- Study and recommend system upgrades needed for Offshore Wind (OSW), Energy Storage Systems, Solar, HVDC transmission, PPTN projects, and other new clean technologies that may arise.
- Coordinate, review and perform interconnection studies for generation and transmission projects including offshore wind, energy storage, solar, HVDC transmission, PPTN, and other new clean energy technologies.
- Analyze the transmission security of the Bulk Electric System (BES) for announced mothball or retirement of fossil generation facilities.

- Analyze the transmission security (planning and operations) of the future system that will be comprised primarily of intermittent resources connected through inverter-based interconnections.

On a day-to-day basis:

- Evaluate BES thermal and voltage response under prescribed design conditions
- Conduct stability studies to determine BES ability to remain stable for various contingency scenarios
- Determine breaker fault clearing duties and identifies required breaker upgrades
- Support the development of specialized studies such as the System Restoration Plan (SRP), the Underfrequency Load Sheading Program (UFLS), or Critical Clearing Time (CCT).

Justification Summary:
Con Edison responsibilities related to NERC, NPCC, NYSRC and Con Edison Standards, Directories and Reliability Rules continue to grow along with the volume of interconnection studies and support work under NYISO's FERC tariff, necessitating three Full Time Employee (FTE) staffing additions and associated modeling tools to the System Performance and Interconnection Sections to perform and document the required analysis. Moreover, with the on-going expansion of the electric transmission infrastructure necessary to meet the New York State clean energy and climate goals set by the Climate Leadership and Community Protection Act (CLCPA) and the required establishment of coordinated statewide grid planning (PSC September 9, 2021 Order), the level and extent of studies, supporting documentation, working group and stakeholder engagement activities will markedly increase.

Relationship to 5-Year and Long-Range Plans and Enterprise Risk Management Strategy
Additional staffing and associated modeling tools are necessary to perform activities and analysis that identify necessary infrastructure changes to meet the Company's and our customers' clean energy objectives in a safe and reliable manner.

2. Supplemental Information

Alternatives
None. These studies require highly specialized analytical tools and skills that leverage institutional knowledge of the local system that only resides at Con Edison.

Risk of No Action
The risk of no action is reduced effectiveness and possible omission of required reliability analysis necessary to maintain compliance with applicable NERC, NPCC, NYSRC and Con Edison Standards, Directories and Reliability Rules as well as delay in the implementation of the CLCPA targets/requirements.

Non-Financial Benefits
System reliability is maintained and/or enhanced. Strategies for multi-value system improvements are selected based on the best metrics.

Summary of Financial Benefits and Costs (attach backup)
Avoidance of penalties for work deferred beyond regulatory deadlines.

Project Risks and Mitigation Plan

Technical Evaluation / Analysis. Transmission Planning Engineers require significant time and experience to become familiar with the unique aspects of the Con Edison transmission system. They also require considerable time and experience to learn the functionality of the computer modeling applications and to gauge the accuracy of their results. These ongoing and critical responsibilities cannot be cost-effectively assigned to contractors on a short-term basis.
Project Relationships (if applicable) None

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital						
O&M	0	0	0	0	0	0
Regulatory Asset						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital					
O&M*		405	405	405	405
Regulatory Asset					

Capital/Regulatory Asset Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor		375	375	375	375
M&S					
Contract Services					
Other		30	30	30	30
Overheads					
Total		**405**	**405**	**405**	**405**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Exhibit_(EIOP-5)

T&D Climate Leadership Community Protection Act (CLCPA)

Schedule 1: T&D CLCPA Capital Program and Project Summary

Electric T&D *CLCPA System Expansion*		**Year Total**			
		Current Budget			
		Total Dollars ($000)			
		RY1	**RY2**	**RY3**	**3 Yr. Total**
CLCPA SYSTEM EXPANSION					
Organization	**White Paper**				
Transmission	Goethals to Foxhills - New 138kV Feeder	148,069	148,401	35,051	331,521
Transmission	Gowanus to Greenwood - New 138kV Feeder	50,000	39,000	6,000	95,000
Transmission	Rainey to Corona II - New 138kV Feeder	53,900	-	-	53,900
TOTAL ELECTRIC					
	Total CLCPA System Expansion	**251,969**	**187,401**	**41,051**	**480,421**

Schedule 2:

T&D Capital White Papers

CLCPA

Central Operations / System & Transmission Operations
2022-2026

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Goethals to Fox Hills – New 138kV Feeder	
Project/Program Manager: Various	**Project/Program Number (Level 1): 25362452**
Status: ☐ **Initiation** ☒ **Planning** ☐ **Execution** ☐ **On-going** ☐ ☐ **Other:** ___________	
Estimated Start Date: January 2021	**Estimated Date In Service: May 2025**
A. Total Funding Request ($000) **Capital: $384,000** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This project will establish a transmission tie between the Goethals 345 kV substation and the Fox Hills 138 kV substation via a new Phase Angle Regulator (PAR)-controlled 138 kV solid dielectric feeder. The route for the underground feeder will be approximately 8 miles and will be installed via a trench and conduit system. The connections for a new transmission feeder will require new bus sections in both the Goethals and Fox Hills substations. The new bus section at Goethals Substation will require the addition of 345 kV circuit breakers, a 345 kV to 138 kV auto-transformer, relay protection and a termination stand for the new feeder. A 138 kV Phase Angle Regulator (PAR) will also be installed in series with the line at the Goethals Substation, for the purpose of regulating the power transfer across the line under all conditions within rated limits. The bus section at Fox Hills Substation will require the addition of 138 kV circuit breakers, relay protection and a terminal stand for the new feeder.

Engineering and long lead equipment procurement will begin in 2021 for this project and construction is expected to begin in 2022. The in-service date of this project is May 2025.

Justification Summary:

The need for new tie lines between transmission stations in the Con Edison system is identified through various long-range planning processes. These processes consider forecasted demand, equipment ratings, modelled power-flow characteristics, and available generation capacity. The necessity for a transmission tie between Gowanus and Greenwood Substations was identified through the 2020 Reliability Needs Assessment (RNA) process. Changes in various environmental regulations that impact generators in New York State, as well as goals for the reduction of greenhouse gases are significant drivers in the need for this project.

In efforts to protect the environment and reduce ozone pollution, the New York State Department of Environmental Conservation (NYSDEC) has proposed air emission regulations for simple cycle and regenerative combustion turbines during the ozone season. The primary goal of this regulation is to lower the allowable oxides of nitrogen (NOx) emissions from older peaking units during the ozone season, which is driving Company owned peaking units, gas turbines, and third party-owned generation towards replacement or retirement. The reduced emissions would contribute to realizing New York's clean energy and climate agenda in the Climate Leadership and Community Protection Act (CLCPA), protect the stratospheric ozone layer and protect the health of New York State residents.

The CLCPA has established greenhouse gas emission reduction limits associated with imported electricity and fossil fuels in New York State, as well as additional climate change goals to include 70% renewable electricity by 2030 and 100% zero emission electricity by 2040. The NYSDEC has coordinated with the NYISO to ensure that compliance with NOx emissions regulations and CLCPA policy objectives would not adversely affect grid reliability. In reviewing projected impacts driven by DEC NOx limitations on generator emissions and by policy goals from the CLCPA, NYISO's 2020 Reliability Needs Assessment (RNA) has considered forecasts of peak power demand, planned upgrades to the transmission system, and generation modifications through 2030.

The 2020 RNA has identified system deficiencies on the Greenwood/Fox Hills 138kV Transmission Load Area (TLA) which impede the delivery of renewables that are exacerbated by local peaking units and generator emissions. The RNA has also observed thermal overloads and voltage violations on the Greenwood/Fox Hills 138kV TLA boundary feeders. The Greenwood/Fox Hills 138kV TLA is designed for first contingency and is anticipated to not meet this reliability criteria for the forecasted peak summer load in 2025.

Operationally required improvements are essential for the Greenwood/Fox Hills 138kV TLA to meet reliability criteria. To address the reliability design criteria deficiency prior to the summer of 2025, as well as comply with CLCPA and DEC NOx emissions standards, a Goethals to Fox Hills 138kV Phase Angle Regulator (PAR)-controlled feeder shall be installed and placed in service by 2025. The new feeder will address load pocket deficiencies, alleviate bottled resources connected to Staten Island's 345kV and 138kV system, as well as enable loads to be served by renewable energy.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
The operational measures and system improvements implemented with this project would be sufficient to satisfy reliability, safety, and compliance regulations, manage constraints that limit renewable energy delivery within the system and address the forecasted peak summer load in 2025.

2. Supplemental Information

Alternatives

General strategies that may be considered for addressing a TLA deficiency include: Load transfers between adjacent networks, new generation, or non-wires solutions. Below is a discussion of alternatives as they pertain to the deficiencies addressed by this project.

Alternative 1
Load Transfer – This strategy would involve transferring load from the affected areas into adjacent networks that are supplied from different TLAs. In this scenario, the adjacent networks or the adjacent TLA do not have sufficient excess capacity to absorb the deficiencies.

Alternative 2
Non-Wires Solutions/Energy Efficiency Measures – Customer-sided solutions may aid in the deferral of traditional solutions for multiple years through the implementation of energy efficiency programs. Energy efficiency programs can provide cost-beneficial solutions across multiple customer segments by accelerating load relief through little-to-no cost energy efficient upgrades. Based on the magnitude of load relief required to address the TLA deficiency under a limited time frame, it has been assessed that an energy efficiency program is not a feasible option to address the reliability needs identified in the RNA. There is no known contingency plan other than to pursue the identified traditional solution should this alternative be pursued and prove unable to meet the projected deficits.

Alternative 3
Non-Wires Solutions/Energy Storage – Energy storage can provide support to the distribution system, integrate intermittent renewable resources, lower emissions, and provide load relief for targeted areas. Battery storage was considered to address load relief needs however, given the abrupt implementation timeframe, the limited capacity of 2MW/10.5MWh does not provide sufficient capacity to address the large deficiency of 3,571 MWh (14 hours) for a peak day in 2025 and is not deemed a viable alternative.

Risk of No Action

If this project is not pursued, there would be no improvement to the reliability of the Greenwood/Fox Hills TLA. Furthermore, the risk of no action is that a contingency at peak load, in the year 2025, would result in load shedding at the stations served by Greenwood and Fox Hills, as well as fall out of compliance with DEC NOx regulations and CLCPA goals.

Non-Financial Benefits

This project will provide the necessary reliability in an area of New York City that serves many critical loads (e.g., airports, transportation hubs, and hospitals) in a densely populated area where many buildings have elevators and various equipment loads. The project will also achieve environmental policy objectives and comply with related NYSDEC requirements in the CLCPA.

Summary of Financial Benefits and Costs

N/A

Technical Evaluation / Analysis

Based on the required capacity increase for the Greenwood/Fox Hills 138kV TLA and to address the first contingency design deficiency, a transmission upgrade would be the only viable alternative for the support of the TLAs. Con Edison is proposing a new 345/138kV Phase Angle Regulator (PAR)-controlled feeder between Con Edison's Goethals and Fox Hills substations, with a proposed in-service date of summer 2025. The feeder will be approximately 9 miles long and will be equipped with a 345/138kV transformer and a PAR that will respectively have ratings consistent with Con Edison

design specifications. The new 138kV feeder between the Goethals 345kV and Fox Hills 138kV substations will have a nominal capacity of approximately 300 MW, enabling 300 MW of renewable energy supply to access the load, address local transmission area bottlenecks, as well as reduce dependency on local fossil fuel power plants to maintain local reliability needs.
Project Relationships (if applicable) N/A
Basis for Estimate This estimate is based on a conceptual scope of the project and on order of magnitude estimates.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital						380
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	52,500	148,000	148,400	35,000	-
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	3,731	3,671	3,072	1,579	
M&S	19,058	49,859	50,076	1,664	
Contract Services	21,863	93,804	94,212	31,702	
Other	7,848	667	1,039	55	
Total	**52,500**	**148,000**	**148,400**	**35,000**	**0**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations / System & Transmission Operations
2022-2026

1. Project / Program Summary

Type: ☒ Project ☐ Program	**Category: ☒ Capital ☐ O&M**
Work Plan Category: ☐ Regulatory Mandated ☒ Operationally Required ☐ Strategic	
Project/Program Title: Gowanus to Greenwood – New 138kV Feeder	
Project/Program Manager: Various	**Project/Program Number (Level 1): 25362448**
Status: ☐ Initiation ☒ Planning ☐ Execution ☐ On-going ☐ ☐ Other: ____________	
Estimated Start Date: January 2021	**Estimated Date In Service: May 2025**
A. Total Funding Request ($000) **Capital: $119,000** **O&M:** **Retirement:**	**B.** **☐ 5-Year Gross Cost Savings ($000)** **☐ 5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period:** **(Years/months)**

Work Description:

This project will establish a third transmission tie between the Gowanus 345kV substation and the Greenwood 138kV substation via a new Phase Angle Regulator (PAR)-controlled 138kV solid dielectric feeder. The route for the underground feeder will be approximately 1 mile and will be installed via a trench and conduit system. The connections for a new transmission feeder will require new bus sections in both the Gowanus and Greenwood Substations. The new bus section at Gowanus Substation will require the addition of 345kV circuit breakers, a 345kV to 138kV auto-transformer, relay protection and a termination stand for the new feeder. A 138kV PAR will also be installed in series with the line at the Gowanus Substation, for the purpose of regulating the power transfer across the line under all conditions within rated limits. The bus section at Greenwood Substation will require the addition of 138kV circuit breakers, relay protection and a terminal stand for the new feeder.

Engineering and long lead equipment procurement will begin in 2021 for this project and construction is expected to begin in 2022. The in-service date of this project is May 2025.

Justification Summary:

The need for new tie lines between transmission stations in the Con Edison system is identified through various long-range planning processes. These processes consider forecasted demand, equipment ratings, modelled power-flow characteristics, and available generation capacity. The necessity for a transmission tie between Gowanus and Greenwood Substations was identified through the 2020 Reliability Needs Assessment (RNA) process. Changes in various environmental regulations that impact generators in New York State, as well as goals for the reduction of greenhouse gases are significant drivers in the need for this project.

In efforts to protect the environment and reduce ozone pollution, the New York State Department of Environmental Conservation (NYSDEC) has proposed air emission regulations for simple cycle and regenerative combustion turbines during the ozone season. The primary goal of this regulation is to lower the allowable oxides of nitrogen (NOx) emissions from older peaking units during the ozone season, which is driving Company owned peaking units, gas turbines, and third party-owned generation towards replacement or retirement. The reduced emissions would contribute to realizing New York's clean energy and climate agenda in the Climate Leadership and Community Protection Act (CLCPA), protect the stratospheric ozone layer and protect the health of New York State residents.

The CLCPA has established greenhouse gas emission reduction limits associated with imported electricity and fossil fuels in New York State, as well as additional climate change goals to include 70% renewable electricity by 2030 and 100% zero emission electricity by 2040. The NYSDEC has coordinated with the NYISO to ensure that compliance with NOx emissions regulations and CLCPA policy objectives would not adversely affect grid reliability. In reviewing projected impacts driven by DEC NOx limitations on generator emissions and by policy goals from the CLCPA, NYISO's 2020 Reliability Needs Assessment (RNA) has considered forecasts of peak power demand, planned upgrades to the transmission system, and generation modifications through 2030.

The 2020 RNA has identified system deficiencies on the Greenwood/Fox Hills 138kV Transmission Load Area (TLA) which impede the delivery of renewables that are exacerbated by local peaking units and generator emissions. The RNA has also observed thermal overloads and voltage violations on the Greenwood/Fox Hills 138kV TLA boundary feeders. The Greenwood/Fox Hills 138kV TLA is designed for first contingency and is anticipated to not meet this reliability criteria for the forecasted peak summer load in 2025.

Operationally required improvements are essential for the Greenwood/Fox Hills 138kV TLA to meet reliability criteria. To address the reliability design criteria deficiency prior to the summer of 2025, as well as comply with CLCPA and DEC NOx emissions standards, a Gowanus to Greenwood 138kV Phase Angle Regulator (PAR)-controlled feeder shall be installed and placed in service by 2025. The new feeder will address load pocket deficiencies and reliability concerns intensified by the scheduled retirement of the Gowanus Gas Turbine Barges, provide increased capacity to the Greenwood 138kV Transmission Load Area (TLA), as well as enable loads to be served by renewable energy.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):

The operational measures and system improvements implemented with this project would be sufficient to satisfy reliability, safety, and compliance regulations, manage constraints that limit renewable energy delivery within the system and address the forecasted peak summer load in 2025.

2. Supplemental Information

Alternatives

General strategies that may be considered for addressing a TLA deficiency include: Load transfers between adjacent networks, new generation, or non-wires solutions. Below is a discussion of alternatives as they pertain to the deficiencies addressed by this project.

Alternative 1
Load Transfer – This strategy would involve transferring load from the affected areas into adjacent networks that are supplied from different TLAs. In this scenario, the adjacent networks or the adjacent TLA do not have sufficient excess capacity to absorb the deficiencies.

Alternative 2
Non-Wires Solutions/Energy Efficiency Measures – Customer-sided solutions may aid in the deferral of traditional solutions for multiple years through the implementation of energy efficiency programs. Energy efficiency programs can provide cost-beneficial solutions across multiple customer segments by accelerating load relief through little-to-no cost energy efficient upgrades. Based on the magnitude of load relief required to address the TLA deficiency under a limited time frame, it has been assessed that an energy efficiency program is not a feasible option to address the reliability needs identified in the RNA. There is no known contingency plan other than to pursue the identified traditional solution should this alternative be pursued and prove unable to meet the projected deficits.

Alternative 3
Non-Wires Solutions/Energy Storage – Energy storage can provide support to the distribution system, integrate intermittent renewable resources, lower emissions, and provide load relief for targeted areas. Battery storage was considered to address load relief needs however, given the abrupt implementation timeframe, the limited capacity of 2MW/10.5MWh does not provide sufficient capacity to address the large deficiency of 3,571 MWh (14 hours) for a peak day in 2025 and is not deemed a viable alternative.

Risk of No Action

If this project is not pursued, there would be no improvement to the reliability of the Greenwood/Fox Hills TLA. Furthermore, the risk of no action is that a contingency at peak load, in the year 2025, would result in load shedding at the stations served by Greenwood and Fox Hills, as well as fall out of compliance with DEC NOx regulations and CLCPA goals.

Non-Financial Benefits

This project will provide the necessary reliability in an area of New York City that serves many critical loads (e.g., airports, transportation hubs, and hospitals) in a densely populated area where many buildings have elevators and various equipment loads. The project will also achieve environmental policy objectives and comply with related NYSDEC requirements in the CLCPA.

Summary of Financial Benefits and Costs

N/A

Technical Evaluation / Analysis

Based on the required capacity increase for the Greenwood/Fox Hills 138kV TLA and to address the first contingency design deficiency, a transmission upgrade would be the only viable alternative for the support of the TLAs. Con Edison is proposing a new 345/138kV Phase Angle Regulator (PAR)-controlled feeder between Con Edison's Gowanus and Greenwood substations, with a proposed in-service date of summer 2025. The feeder will be approximately 1.5 miles long and will be equipped with a 345/138kV transformer and a PAR that will respectively have ratings consistent with Con

Edison design specifications. The new 138kV feeder between the Gowanus 345kV and Greenwood 138kV substations will have a nominal capacity of approximately 300 MW, enabling 300 MW of renewable energy supply to access the load, as well as reduce dependency on local fossil fuel power plants to maintain local reliability needs.

Project Relationships (if applicable)

N/A

Basis for Estimate

This estimate is based on a conceptual scope of the project and on order of magnitude estimates.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	N/A	N/A	N/A	N/A		500
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	24,000	50,000	39,000	6,000	0
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	3,692	4,452	3,943	0	
M&S	9,110	18,230	10,140	0	
Contract Services	8,729	23,865	24,560	5,622	
Other	2,468	3,453	3,57	378	
Total	**24,000**	**50,000**	**3,943**	**6000**	**0**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations / System & Transmission Operations
2022-2026

1. Project / Program Summary

Type: ☒ Project ☐ Program	**Category: ☒ Capital ☐ O&M**
Work Plan Category: ☐ Regulatory Mandated ☒ Operationally Required ☐ Strategic	
Project/Program Title: Rainey to Corona II – New 138kV Feeder	
Project/Program Manager: Various	**Project/Program Number (Level 1): 25239431**
Status: ☐ Initiation ☒ Planning ☐ Execution ☐ On-going ☐ ☐ Other: ___________	
Estimated Start Date: January 2021	**Estimated Date In Service: May 2023**
A. Total Funding Request ($000) **Capital: $246,400** **O&M:** **Retirement:**	**B.** **☐ 5-Year Gross Cost Savings ($000)** **☐ 5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This project will establish a second transmission tie between the Rainey 345kV substation and the Corona 138kV substation via a new Phase Angle Regulator (PAR)-controlled 138kV solid dielectric feeder. The route for the underground feeder will be approximately 6 miles and will be installed via a trench and conduit system. The connections for a new transmission feeder will require new bus sections in both the Rainey and Corona Substations. The new bus section at Rainey Substation will require the addition of 345kV circuit breakers, a 345kV to 138kV auto-transformer, relay protection and a termination stand for the new feeder. A 138kV PAR will also be installed in series with the line at the Rainey Substation, for the purpose of regulating the power transfer across the line under all conditions within rated limits. The bus section at Corona Substation will require the addition of 138kV circuit breakers, relay protection and a terminal stand for the new feeder.

Engineering and long lead equipment procurement will begin in 2021 for this project and construction is expected to begin in early 2022. The in-service date of this project is May 2023.

Justification Summary:

The need for new tie lines between transmission stations in the Con Edison system is identified through various long-range planning processes. These processes consider forecasted demand, equipment ratings, modelled power-flow characteristics, and available generation capacity. The necessity for a second transmission tie between Rainey and Corona Substations was identified through the 2020 Reliability Needs Assessment (RNA) process. Changes in various environmental regulations that impact generators in New York State, as well as goals for the reduction of greenhouse gases are significant drivers in the need for this project.

In efforts to protect the environment and reduce ozone pollution, the New York State Department of Environmental Conservation (NYSDEC) has proposed air emission regulations for simple cycle and regenerative combustion turbines during the ozone season. The primary goal of this regulation is to lower the allowable oxides of nitrogen (NOx) emissions from older peaking units during the ozone season, which is driving Company owned peaking units, gas turbines, and third party-owned generation towards replacement or retirement. The reduced emissions would contribute to realizing New York's clean energy and climate agenda in the Climate Leadership and Community Protection Act (CLCPA), protect the stratospheric ozone layer and protect the health of New York State residents.

The CLCPA has established greenhouse gas emission reduction limits associated with imported electricity and fossil fuels in New York State, as well as additional climate change goals to include 70% renewable electricity by 2030 and 100% zero emission electricity by 2040. The NYSDEC has coordinated with the NYISO to ensure that compliance with NOx emissions regulations and CLCPA policy objectives would not adversely affect grid reliability. In reviewing projected impacts driven by DEC NOx limitations on generator emissions and by policy goals from the CLCPA, NYISO's 2020 Reliability Needs Assessment (RNA) has considered forecasts of peak power demand, planned upgrades to the transmission system, and generation modifications through 2030.

The 2020 RNA has identified system deficiencies on the Astoria East/Corona 138kV Transmission Load Area (TLA) which impede the delivery of renewables that are exacerbated by local peaking units and generator emissions. The RNA has also observed thermal overloads on the Astoria East/Corona 138kV TLA boundary feeders. The Astoria East/Corona 138kV TLA is designed for second contingency (N-1-1-0) and is anticipated to not meet this reliability criteria for the forecasted peak summer load in 2023.

Operationally required improvements are essential for the Astoria East/Corona 138kV TLA to meet reliability criteria. To address the reliability design criteria deficiency prior to the summer of 2023, as well as comply with CLCPA and DEC NOx emissions standards, a 2nd Rainey to Corona 138kV Phase Angle Regulator (PAR)-controlled feeder shall be installed and placed in service by 2023. The new feeder will enable renewable energy supply to access the load, as well as reduce dependency on local fossil fuel plants to maintain local reliability needs.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
The operational measures and system improvements implemented with this project would be sufficient to satisfy reliability, safety, and compliance regulations, manage constraints that limit renewable energy delivery within the system and address the forecasted peak summer load in 2023.

2. Supplemental Information

Alternatives
General strategies that may be considered for addressing a TLA deficiency include: Load transfers between adjacent networks, new generation, or non-wires solutions. Below is a discussion of alternatives as they pertain to the deficiencies addressed by this project.

<u>Alternative 1</u>
Load Transfer – This strategy would involve transferring load from the affected areas into adjacent networks that are supplied from different TLAs. In this scenario, the adjacent networks or the adjacent

TLA do not have sufficient excess capacity to absorb the deficiencies. The adjacent networks not fed from the same TLA are Maspeth, Sunnyside, Borden and Richmond Hill. The adjacent TLA is the Jamaica/Corona TLA, which overlaps the Astoria East/Corona TLA and does not have sufficient capacity to absorb the deficiency.

<u>Alternative 2</u>
Non-Wires Solutions/Energy Efficiency Measures – Customer-sided solutions may aid in the deferral of traditional solutions for multiple years through the implementation of energy efficiency programs. Energy efficiency programs can provide cost-beneficial solutions across multiple customer segments by accelerating load relief through little-to-no cost energy efficient upgrades. Based on the magnitude of load relief required to address the TLA deficiency under a limited time frame, it has been assessed that an energy efficiency program is not a feasible option to address the reliability needs identified in the RNA. There is no known contingency plan other than to pursue the identified traditional solution should this alternative be pursued and prove unable to meet the projected deficits.

<u>Alternative 3</u>
Non-Wires Solutions/Energy Storage – Energy storage can provide support to the distribution system, integrate intermittent renewable resources, lower emissions, and provide load relief for targeted areas. Battery storage was considered to address load relief needs however, given the abrupt implementation timeframe, the limited capacity of 2MW/10.5MWh does not provide sufficient capacity to address the large deficiency of 659 MWh (10 hours) for a peak day in 2023 and is not deemed a viable alternative.

Risk of No Action

If this project is not pursued, there would be no improvement to the reliability of the Astoria East/Corona TLA. Furthermore, the risk of no action is that a contingency at peak load, in the year 2023, would result in load shedding at the stations served by Astoria East, Corona and/or Jamaica as well as fall out of compliance with DEC NOx regulations and CLCPA goals.

Non-Financial Benefits

This project will provide the necessary reliability in an area of New York City that serves many critical loads (e.g., airports, transportation hubs, and hospitals) in a densely populated area where many buildings have elevators and various equipment loads. The project will also achieve environmental policy objectives and comply with related NYSDEC requirements in the CLCPA.

Summary of Financial Benefits and Costs

N/A

Technical Evaluation / Analysis

Based on the required capacity increase for the Astoria East/Corona 138kV TLA and to address the N-1-1-0 design deficiency, a transmission upgrade would be the only viable alternative for the support of the TLAs. Con Edison is proposing a new 345/138kV Phase Angle Regulator (PAR)-controlled feeder between Con Edison's Rainey and Corona substation, with a proposed in-service date of summer 2023. The feeder will be approximately 7 miles long, and will be equipped with a 345/138kV transformer and a PAR that will respectively have the same ratings as the transformer, PAR, and feeder as the recently installed 1st Rainey to Corona 138kV feeder (placed in-service in 2019). The new 138kV feeder between the Rainey 345kV and Corona 138kV Substations will have a nominal capacity of approximately 300 MW, enabling 300 MW of renewable energy supply to access the load, as well as reducing dependency on local fossil fuel power plants to maintain local reliability needs.

Project Relationships (if applicable)

N/A

Basis for Estimate

This estimate is based on a conceptual scope of the project and on order of magnitude estimates.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital		57,368	28,712	261		20,230
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	192,500	53,900			
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	2,138	1,392			
M&S	39,694	28,586			
Contract Services	149,652	22,738			
Other	1,016	1,184			
Total	**192,500**	**53,900**			

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Exhibit_(EIOP-6)

T&D Replacement

Schedule 1: T&D Replacement Capital Program and Project Summary

Electric T&D *Replacement*		**Year Total**			
		Current Budget			
		Total Dollars ($000)			
		RY1	**RY2**	**RY3**	**3 Yr. Total**
REPLACEMENT					
Organization	**White Paper**				
Substations	Failed Substation Equipment Other than Transformers	11,500	11,500	11,500	34,500
Substations	Failed Substation Transformer Program	46,500	46,500	46,500	139,500
Substations	Hellgate Dock Refurbishment	15,600	-	-	15,600
Distribution	Overhead Emergency Response	61,546	72,179	74,027	207,752
Distribution	Primary Cable Replacement (OAs, FOTs, C&D Fault)	98,715	101,882	101,882	302,480
Distribution	Secondary Open Mains	128,706	140,841	141,960	411,507
Distribution	Service Replacements (Temporary Services and Bridges)	68,515	72,428	72,428	213,371
Distribution	Streetlights (Including Conduit)	27,235	27,235	27,235	81,705
Distribution	Targeted Direct Buried Cable Replacement	14,000	14,000	14,000	42,000
Distribution	Telecom - Underground Facilities	274	-	-	274
Distribution	Transformer Installation	51,229	51,229	51,229	153,688
Transmission	Transmission Feeder Failures	15,000	15,000	15,000	45,000
Transmission	Transmission Feeder Failures - Other	3,000	3,000	3,000	9,000
TOTAL ELECTRIC					
	Total Replacement	**541,821**	**555,794**	**558,762**	**1,656,377**

Schedule 2:

T&D Capital White Papers

Replacement

Central Operations/ Substation Operations
2022

1. Project / Program Summary

Type: ☐ Project ☒ Program.	**Category: ☒ Capital ☐ O&M**
Work Plan Category: ☐ Regulatory Mandated ☒ Operationally Required ☐ Strategic	
Project/Program Title: Failed Substation Equipment Other Than Transformers	
Project/Program Manager: Seda Steck	**Project/Program Number (Level 1): PR.2ES7700/10030241**
Status: ☐ Planning ☐ Design ☐ Engineering ☐ Construction ☒ Ongoing ☐ Other: ___________	
Estimated Start Date :N/A	**Estimated Date in Service: N/A**
A. Total Funding Request ($000) **Capital: $56,500** **O&M:** **Retirement: $13,000**	**B.** **☐ 5-Year Gross Cost Savings ($000)** **☐ 5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This program replaces substation equipment that has failed (excluding power transformers). Some of the equipment that has been replaced in the past under this program includes breakers, diesel generators, Direct Current ("DC") system components, coupling capacitor potential devices (CCPDs) and disconnect switches.

Justification Summary:

This program is necessary to fund the restoration of equipment that has failed in service and is necessary in maintaining system design configurations. Some of the equipment that has been replaced in the past under this program includes breakers, diesel generators, DC system components, Relays, Cap banks, Pumps, Controls, CCPDs and disconnect switches, among others.

The DC system in a substation is critical in control and protection and it must have adequate supply and back-up power. When a DC system component fails, it must be replaced so that relays, control systems and other DC loads can operate per design. Diesel generators provide emergency power to stations loads – including DC systems. When a diesel generator component fails, it must be replaced to provide a reliable emergency source of power to station loads.

Devices such as CCPDs and disconnect switches are important components in the reliable operation of substations. CCPDs provide important system parameter information for metering and protection systems. Disconnect switches provide isolation (visible break) for equipment that is out of service.

Given the variation in the type of equipment and cost associated with replacements, the funding for this program is based on historical failure averages.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
This program mitigates the Substation Operations Departmental Risk of likelihood of Equipment Failures by addressing unanticipated substation equipment failures and/or perform capitalized repairs on various pieces of equipment to maintain our high levels of system reliability. This program also minimizes the likelihood of the operational risk of loss of a Substation.

2. Supplemental Information

Alternatives
The only alternative is to not provide funding for potential failures. This is not recommended as it would necessitate the required replacement of failed equipment to be funded by diverting funds from other projects which would cause delays and increase the overall cost of these projects. These funding delays would lead to decreased system reliability and longer outage durations.

Risk of No Action
Taking no action is not recommended as it would lead to decreased system reliability and longer outage durations. It would also necessitate the required replacement of failed equipment to be funded by diverting funds from other projects, causing potential delays, and increasing the overall cost of making such repairs.

Non-Financial Benefits
This program helps avoid impacts to related projects, improves planning, and enables a more efficient use of capital dollars. Since this program provides funding that can be drawn on when a failure occurs, it reduces the need to constantly re-prioritize and deal/defer in flight work to provide funding when a failure occurs. This program also helps maintain our reliability levels, as it replaces failed equipment and allows our station design standards to be met.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis: N/A

2. Major financial benefits
Primary benefit of undertaking this program is improved reliability.

3. Total cost **$56,500**

4. Basis for estimate: The annual funding for this program is based on historical averages of $11.5M per year.

5. Conclusion: N/A

Project Risks and Mitigation Plan

Risk 1: **Outage scheduling conflicts with other initiatives.**

Mitigation: Outages to be coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs to avoid conflict with other program/ projects resulting in a more predictable budget and manageable outage scheduling.

Risk 2: Delays due resources support coordination.

Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Technical Evaluation / Analysis: N/A
Project Relationships (if applicable) All projects funded under this program are a result of equipment failure (excluding transformers) in substations.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	10,212	25,423	13,867	7,396		10,071
O&M						
Retirement	1,571	3,327	3,353	1,646		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	10,000	11,500	11,500	11,500	12,000
O&M*					
Retirement	2,600	2,600	2,600	2,600	2,600

Capital Request by Elements of Expense:

EOE	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Labor	3,050	3,557	3,622	3,626	3,789
M&S	2,030	2,300	2,415	2,415	2,520
Contract Services	1,399	1,610	1,746	1,744	1,845
Other	300	345	0	0	0
Overheads	3,221	3,688	3,717	3,715	3,845
Subtotal					
Total	**$10,000**	**$11,500**	**$11,500**	**$11,500**	**$12,000**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations/ Substation Operations
2022

1. Project / Program Summary

Type: ☐ Project ☒ Program	**Category: ☒ Capital ☐ O&M**
Work Plan Category: ☐ Regulatory Mandated ☒ Operationally Required ☐ Strategic	
Project/Program Title: Failed Substation Transformer Program	
Project/Program Manager: TBA	**Project/Program Number (Level 1): PR.2ES7600 / 10030240**
Status: ☐ Planning ☐ Design ☐ Engineering ☐ Construction ☒ Ongoing ☐ Other: ___________	
Estimated Start Date: N/A	**Estimated Date in Service/A**
A. Total Funding Request ($000) **Capital: $209,500** **O&M:** **Retirement: $12,500**	**B.** **☐ 5-Year Gross Cost Savings ($000)** **☐ 5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This ongoing program provides funding for the restoration work required to replace transformers in Area and Transmission Substations on an emergency basis. Con Edison maintains an inventory of various voltage and mega volt-amp rating (MVA) classes, which can be used in the event of a failure. In virtually all cases, a like-in-kind replacement unit is available for use as a permanent replacement for a failed unit. These units are transported to the facility where they are required and installed. A replacement unit is then purchased and put back into the spare transformer inventory.

Justification Summary:

Power transformers in substations are critical components of the transmission and distribution systems. The Company has a separate program to proactively replace transformers before they fail. Despite the strategy in place to identify units for proactive replacement, some transformers fail in service and must be replaced on an emergency basis in order to maintain reliability.

This program covers the cost of replacing three failed transformers (transformers, phase angle regulators and reactors) per year. The historical average number of failures per year from 2011 to 2020 was used as a basis for the program. To quickly restore system capacity and reliability to pre-failure levels, spare transformers are maintained for most types of units in the system. The projects done under this program typically draw upon spare transformer inventory in order to restore the system as quickly as possible and provide the procurement of a replacement. The spare units are purchased and kept on hand due to the long lead-time required for delivery of a new transformer. The spare units are pre-tested and partially assembled to reduce the time required for replacement of a failed unit.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):

This program affects the controllability of the operations risk of Loss of a Substation. If a transformer fails in service during high load periods, depending on the location, the failure of the next substation component could result in the loss of the station or an inability to carry load.

<u>Climate Change and Resiliency:</u> The increasing frequency of heat events projected in the Company's Climate Pathway may accelerate the effective aging of power transformers. This accelerated aging may result in an increase in transformer failure rates. The Company intends to increase the number of proactive transformer replacements to counter this potential trend, but the criticality of this program will only increase with more extreme weather invents.

2. Supplemental Information

Alternatives There is no alternative to replacing a failed transformer.
Risk of No Action The risk of no action can jeopardize the reliability of the distribution and transmission System. If multiple failures were to occur during a high load period or while other critical facilities are out of service, load shedding and large-scale customer outages can result.
Non-Financial Benefits This program aims to provide reliable, uninterrupted service to our customers. By maintaining an inventory of system spares, work on replacing a failed unit can begin immediately, rather than waiting for a replacement unit to be located and purchased
Summary of Financial Benefits and Costs (attach backup) 1. Cost-benefit analysis: N/A 2. Major financial benefits Primary benefit of undertaking this program is improved reliability. 3. Total cost $**209,500** 4. Basis for estimate: This funding level has been set based on our recent actual replacement costs and assumes 3 failures/year at a $15.5 M per transformer. 5. Conclusion: N/A
Project Risks and Mitigation Plan **Risk 1: Outage scheduling conflicts with other initiatives.** **Mitigation:** Outages to be coordinated with the Sequencing Group at System Operations to potentially incorporate other project/programs to avoid conflict with other program/ projects resulting in a more predictable budget and manageable outage scheduling. **Risk 2: Lack of alignment between resources support and outages.** **Mitigation:** Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction to avoid alignment conflicts with outages.
Technical Evaluation / Analysis: N/A
Project Relationships (if applicable) N/A

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	41,539	29,345	56,464	43,166		51,394
O&M						
Retirement	8,013	-1,900	-160	2,471		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	30,000	46,500	46,500	46,500	40,000
O&M*					
Retirement	2,500	2,500	2,500	2,500	2,500

Capital Request by Elements of Expense:

EOE	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Labor	5,700	8,835	8,995	8,996	7,796
M&S	11,700	18,135	17,941	17,949	15,440
Contract Services	3,794	5,970	5,970	5,970	5,135
Other					
Overheads	8,806	13,560	13,594	13,586	11,628
Subtotal					
Total	**$30,000**	**$46,500**	**$46,500**	**$46,500**	**$40,000**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations/ Substation Operations
2022

1. Project / Program Summary

Type: ☒ **Project** ☐ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Hellgate Dock Refurbishment	
Project/Program Manager: John Mazzani	**Project/Program Number (Level 1):. PR.22100425**
Status: ☒ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☐ **Ongoing** ☐ **Other: ___________**	
Estimated Start Date :1/1/2021	**Estimated Date in Service: 12/31/2022**
A. Total Funding Request ($000) **Capital: $ 18,000** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

The Hellgate wharf is located along the north shore of the East River between East 132nd and East 134th Streets in the Bronx, NY. The wharf supports the Electric Operations' flush truck facility for wastewater barges and Substation Operations'("SSO") heavy lift area for transformer delivery barges.

The wharf structure spans approximately 500 feet and varies in width from 30 to 70 feet. The wharf was constructed on 31 foot long by 6-foot-wide reinforced concrete walls, which are spaced at approximately 30 feet-3 inches on center and founded on rock. Concrete encased steel I-Beams span between the concrete walls and a reinforced concrete deck spans between the beams. Directly inland is a retired concrete discharge tunnel. The wharf and tunnel structures were originally part of the now removed Hell Gate power plant.

The project scope of work is based on a review and analysis of the waterfront from an inspection report compiled by McLaren Engineering in 2016. In the heavy lift area, the concrete encased beams exhibit some form of corrosion, spalling, or cracking. Currently all ten pier walls within this vicinity have signs of severe deterioration including exposed reinforcements, missing concrete covers on caissons, and overall concrete spalling and erosion. There is also evidence of steel rebar corrosion at some walls and supports. Portions of the area are in poor condition with reduced load capacity, which restricts the use of the wharf to lighter loads in these areas.

The Flush Truck Facility portion of the wharf is approximately 150 feet in length and exhibits similar deficiencies to those reported in the heavy lift area. This section of the wharf consists of three large bays. There is significant degradation to all decking and missing sections in the northern most bay; the concrete gravity walls have loss of concrete section with exposed corroded steel reinforcing; and the concrete encasement on the deck support beams has failed at many locations, which has led to section loss in the steel beams. Most of the area is unsafe for personnel access and the load rating is restricted to pedestrian loads. The mooring hardware and fenders are also missing in this portion of the wharf. Work in the Electric Operations' area will be performed under a separate project (PN 27306-16).

The SSO work will involve the reinforcing of the tunnel ceiling where sinkholes are present and extending the high capacity loading area deck to allow the use of longer multi-axle trailers for offloading transformers. It also includes re-establishing a mooring and fendering system for barges. Specific repairs and installations are:

- Remove and properly dispose of all debris and brick overlaying portions of the Heavy Lift Area.
- Repair the encased steel girders along the bulkhead in order to adequately support a new concrete slab.
- Wrap four steel pipe piles in jacketing in order to prevent further corrosion.
- Water blasts the steel beams at the former platform to remove moderate corrosion and reapply protective epoxy coating.
- Properly clean and prepare deteriorated areas of concrete and apply a bonding agent and repair mortar.
- Repair voids at the concrete bearing soffits where the deck steel beams rest.
- Seal the 24 foot long crack on the Heavy Load Area.
- Install a structural slab in two areas over the discharge tunnel's partially collapsed ceiling and restore paving once complete.
- Extend the heavy lift area east and west by installing a new two-way slab over the existing one designed to span the entire length between each pier wall independently of the encased steel beams. The beams shall be repaired to handle the increased loading.
- Install a new fender system secured to the face of the dock since current fenders are damaged or nonexistent. The system shall be designed according to maximum calculated energies associated with routine berthing maneuvers for the largest barges to dock at the wharf. Install a new bollard on the extended portion of the Heavy Lift Area. Fill existing steel bollards with concrete as recommended by the manufacturer. Clean and recoat them in order to prevent future corrosion. Patch spalls or other localized pockets from impact damage using conventional concrete placement at the eastern faces of the walls supporting the wharf, which will receive fenders.
- Install a permanent fence, railing, or other form of protection along the water's edge.
- The Electric Distribution Work will involve remediation of the concrete spalls and steel corrosion on the existing concrete gravity walls; plugging a sinkhole adjacent to the concrete bulkhead; removal of the existing decking, debris and concrete encased beams; installation of new steel beams and a concrete deck; and installation of a new fender system and mooring hardware.

Justification Summary:
The refurbishment of the Hellgate wharf will allow for the long term offloading of effluent from the Flush Truck Facility; and heavy equipment, such as transformers, in a safe and efficient manner from the SSO portion of the wharf. The expansion of the heavy lift area will allow more flexibility in positioning existing multi-axle trailers and allow the use of longer transport vehicles in the future. The restoration of the fendering and mooring systems will provide a safer means of barge docking along with flexibility in vessel types and positioning. Materials will be chosen that suit the harsh marine environment and the design will meet all applicable codes and standards. The project will benefit the Company by reducing the likelihood of injuries and establishing a more reliable offloading facility.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
N/A

2. Supplemental Information

Alternatives
One alternative is to restore the wharf back to its previous condition and not extend the unloading area. Although this would reduce the project cost and address structural deterioration, it would restrict the present and future use of the wharf to barges and trailers that can maneuver and fit into the limited space. This would slow the offloading and delivery process and limit the choice of vessels and trailers, possibly impacting outage durations and electric reliability.

Risk of No Action
SSO:
If the wharf is not refurbished, it will continue to deteriorate and there is a risk that additional unsafe conditions and eventual collapse will occur. In addition to increasing the risk of employee injuries, not doing the project will jeopardize the use of the facility for offloading transformers which will impact the reliability of our electric system, especially during unplanned outages.

ELECTRIC OPERATIONS – FLUSH TRUCK FACILITY:
No action will result in operations continuing to use "work arounds" to accomplish the task of offloading effluent to the barges. The barges will continue to be moored in the heavy lift area and long hoses, that present a safety concern, will need to be run from the flush pit to the barges.

Non-Financial Benefits
SSO:
In addition to an improvement in personal safety and offloading efficiency, the refurbishment of the Hellgate wharf will improve electric system reliability by allowing for an efficient delivery and transport of critical equipment. Potential navigation hazards created by deteriorating structures falling into the river will also be eliminated.

ELECTRIC OPERATIONS – FLUSH TRUCK FACILITY:
The availability of a new wharf adjacent to the Flush Truck Facility will provide a safer work area and improve the efficiency of the effluent offloading operation; as well as eliminating the potential for navigation hazards due to falling debris from the deteriorated wharf structure.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis: N/A

2. Major financial benefits
Primary benefit of undertaking this program is improved reliability.

3. Total cost **$18,000,**

4. Basis for estimate: Engineering Estimate

5. Conclusion: N/A

Project Risks and Mitigation Plan **Risk 1: Lack of alignment between resources support and outages.** Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction to avoid alignment conflicts.
Technical Evaluation / Analysis McLaren Engineering conducted a routine Waterfront Inspection of the Hellgate substation and surrounding area. The waterfront consists of a wharf structure and discharge tunnels from the former Hellgate generating station. The inspection report includes a structural analysis of the existing structures and mooring system and recommendations to restore them back to their intended function for receiving barges and delivery trailers.
Project Relationships (if applicable) Planned and Emergency transformer replacements.

3. Funding Detail

Historical Spend

	Actual 2017	**Actual 2018**	**Actual 2019**	**Actual 2020**	**Historic Year** (O&M only)	**Forecast 2021**
Capital	0	0	0	0		79
O&M						
Retirement	0	0	0	0		n/a

Total Request ($000):

Total Request by Year:

	Request 2022	**Request 2023**	**Request 2024**	**Request 2025**	**Request 2026**
Capital	**2,400**	**15,600**			**0**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	**2022**	**2023**	**2024**	**2025**	**2026**
Labor	216	1,404	0	0	0
M&S	408	2,652	0	0	0
Contract Services	1,197	7,798	0	0	0
Other	0	0	0	0	0
Overheads	579	3,746	0	0	0
Subtotal					
Total	**$2,400**	**$15,600**	**0**	**0**	**0**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M	715				
Capital					

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☐ Project ☒ Program	**Category:** ☒ Capital ☐ O&M
Work Plan Category: ☐ Regulatory Mandated ☒ Operationally Required ☐ Strategic	
Project/Program Title: Overhead Emergency Response	
Project/Program Manager: Not Applied	**Project/Program Number (Level 1): 10029401, 10079329, 23442193, 23442194, 23442195, 23442199, 23442201**
Status: ☐ Planning ☐ Design ☐ Engineering ☐ Construction ☒ Ongoing ☐ Other: ___________	
Estimated Start Date:	**Estimated Date In Service:**
A. Total Funding Request ($000) **Capital: $342,000** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:
This program provides funding for high-priority emergency work to replace non-network overhead and Underground Residential Distribution (URD) infrastructure and associated equipment after failure or when imminent failure is identified as a result of diagnostic testing such as infrared, ultrasonic, or visual inspection. Such equipment includes cable, URD, overhead transformers, and open-wire along with associated structures and accessories. The projected annual number of units is listed below. Actual units repaired will depend on a number of factors including weather and the amount of infrastructure and equipment identified for repair/replacement through inspections and testing in a given year.

Item	**Units Per Year**
Overhead transformers	350
Poles, Towers & Fixtures:	840
OH Primary Sections:	900
OH Secondary Sections:	1,300
OH Services:	650
OH Street Lights Spans:	1,100
OH Aerial Cable Sections:	350

Justification Summary:
Failed equipment or equipment identified as being in danger of imminent failure must be replaced. Equipment failures often cause customer interruptions. The restoration of those customers and normalization of the system typically involves replacement of failed equipment. Climate change increases the stress on existing infrastructure and equipment and thus increases the need for replacement.

Equipment identified as being in danger of imminent failure presents both a reliability and safety risk. It generally must be addressed by replacement.

This program supports the objective of meeting New York Public Service Commission (PSC) reliability performance goals System Average Interruption Frequency Index (SAIFI) and Customer Average Interruption Duration Index (CAIDI).

Relationship to 5-Year and Long-Range Plans and Enterprise Risk Management Strategy

The Overhead Emergency Response Program aligns with the Company's Electric Long-Range Plan (ELRP) and Enterprise Risk Management (ERM) strategy by supporting system reliability, reducing safety risk to the public and employees associated with failing equipment, and minimizing the risk of regulatory penalties related to reliability. The Overhead Emergency Response Program does just that.

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection

One alternative to emergency response replacement of non-network equipment failures is to delay replacement and schedule the repair work at some future time. This alternative would be only slightly less costly in some cases. In addition, at times, it would result in customers remaining out of service for extended periods of time or leave the system in an abnormal, vulnerable configuration without backup sources of supply.

Risk of No Action

Risk 1
No action on this program would result in customers remaining out of service for extended periods of time and the system remaining in an abnormal, vulnerable configuration without backup sources of supply.

Risk 2
There will be an increase in public safety risk for equipment identified in imminent danger of failure if no action is taken.

Risk 3
There is a reliability risk for both failing and failed equipment as the system would be in a vulnerable configuration until restored.

Non-Financial Benefits
This program helps mitigate public safety risk including hazards by repairing downed wires and poles damaged by trees. In addition, this program reduces the environmental impact associated with leaking and/or damaged transformers and other equipment.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis (if required)

2. Major financial benefits

3. Total cost

4. Basis for estimate

5. Conclusion

The PSC sets reliability performance standards (SAIFI and CAIDI) that the Company must meet. Reliability performance not meeting threshold targets may expose the Company to as much as $10 million in penalties ("Radial SAIFI" and "Radial CAIDI") under the current rate agreement. Addressing failing and failed equipment will reduce the potential that the Company will incur financial penalties due to non-compliance with reliability standards.

Project Risks and Mitigation Plan

Risk 1 Mitigation plan
Inventory required for emergency replacement is unavailable.
Purchasing uses historical usage to maintain adequate inventory.

Technical Evaluation / Analysis

See justification section.

Project Relationships (if applicable)

N/A

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	42,878	68,144	48,809	90,737		64,592
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**58,000**	**61,546**	**72,179**	**74,027**	**76,248**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	24,102	25,236	29,596	30,353	31,264
M&S	3,252	3,849	4,514	4,629	4,768
Contract Services	13,099	13,949	16,359	16,778	17,281
Other	-484	-495	-581	-596	-614
Overheads	18,031	19,008	22,292	22,863	23,549
Subtotal	**58,000**	**61,546**	**72,179**	**74,027**	**76,248**
Contingency**					
Total	**58,000**	**61,546**	**72,179**	**74,027**	**76,248**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Primary Cable Replacement (OAs, FOTs, C&D Fault)	
Project/Program Manager: Various	**Project/Program Number (Level 1): 23442204, 23442210, 23442212, 23442213, 23442218, 23442219**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date:	**Estimated Date In Service:**
A. Total Funding Request ($000) **Capital:** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:
This program provides the funding for emergency repair work on underground primary distribution feeders. The emergency repairs can include cable installation, splicing, and new conduit installation. These repairs are required under the following conditions:

- Component Failure (cables, splices, or terminations) which result in an in-service open auto (OA)
- Component Failures identified by post maintenance serviceability testing (High-Voltage Withstand/ Hipot, Ammeter-Clear) which result in a fail-on-test (FOT)
- Component Failures (cables, splices, or terminations) which result in an OA following a restoration attempt, or Cut-In Open Auto (CIOA)
- Severely degraded components which are classified as "C" or "D" faults per EO-1184

Units per Year:
Number of applicable feeder component repairs based on five-year historical average:

- OA, 845
- FOT, 210
- C&D Faults 534
- **Total** **1,589**

High-level schedule and synopsis:
The expectation is to repair approximately 1,600 primary feeder components each year due to component failure or a seriously degraded condition. In anticipation of increased feeder loads, all cable failures on the main runs of distribution feeders will be upsized to the largest cable the conduit can accommodate. As such, there may be an increase in the obstruction rate of primary

conduits which currently ranges between 10-30% by region. Additionally, the unit cost for conduit installation has increased (the 3-year average is approximately 24% higher than the 5-year average due to increasing contract costs).

	Units (5 year Avg.)	Unit Cost (3 year Avg.)	Unit Cost (5-year Avg.)
Conduit (Trench Feet)	34,500	$644	$520

Justification Summary:

Primary feeders are the backbone of our electric distribution system. While they are reliable, component replacements are regularly required due to a failure or a serious degraded condition. Due to the criticality of maintaining primary feeders in service, we maintain a zero backlog of open primary feeders. The requested funding will keep the system at a zero backlog.

A post-maintenance High-Voltage Withstand/Hipot test is required before a primary distribution feeder returns to service following most outages, per Con Edison specification EO-4019. This test ensures the integrity of the work performed during the outage and ferrets out any additional undiscovered component faults that could lead to an in-service failure when the feeder is re-energized (CIOA, Cut-In-Open Auto). These CIOAs have caused significant over voltage conditions on other associated network feeders and can result in the failure of another feeder supplying the same network.

Feeder components that are found in a seriously degraded condition are typically replaced before failure. These degraded components are classified as either a “C” or a “D” fault, per Con Edison specification EO-1184. This program corrects “C” and “D” fault conditions, which enhances the safety and reliability of the distribution system.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

Timely component repairs and restoration of distribution feeders to service reduces the probability of having cascading feeder failures leading to a network shutdown. A network shutdown is a distribution ERM. Additionally, the reliability performance mechanism in the current rate agreement provides for up to $25 million in RPM adjustments for a single major outage to a network.

Maintaining distribution feeders in service will become increasingly important in the future due to forecasted upward trends in load growth to accommodate electric vehicle (EV) charging as well as the anticipated electrification of heating being driven in part by the New York State Climate Leadership and Community Protection Act (CLCPA).

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection

There are no long-term alternatives other than addressing component failures when they occur on primary distribution feeders. Delaying the required replacements would negatively affect the reliability of our distribution

Alternative 2 description and reason for rejection

Alternative 3 description and reason for rejection

Risk of No Action

Risk 1

Feeder component failures and the time it takes to restore the failed feeder directly impact distribution system reliability and reliable customer service. Loss of multiple feeders in the same network results in a network contingency, which, during high load conditions, can cause low voltage conditions, cascading component failures, customer outages and possibly a network shut down. Taking no action will have a significant impact on network reliability and customer service.

Risk 2

There will be an increase in public safety risk for equipment identified in imminent danger of failure if no action is taken.

Risk 3

There is a reliability risk for both failing and failed equipment as the system would be in a vulnerable configuration until restored.

Non-Financial Benefits

The repair of "C" and "D" fault conditions provides significant Environment Health & safety (EH&S) to Con Edison employees and the general public by eliminating potential hazards from our underground distribution system. Over the past five years, nearly 2,700 degraded components were removed from the distribution system.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)

2. Major financial benefits

3. Total cost

4. Basis for estimate

Historical unit costs.

5. Conclusion

Project Risks and Mitigation Plan

Risk 1 — Mitigation plan

Material Availability — Engineering to work with Supply Chain to establish a cohesive plan to align with vendor lead times and stay engaged with vendors to ensure that lead times are maintained and if shortages are encountered, plan is adjusted as needed.

Risk 2 — Mitigation plan

Increasing Conduit Obstruction Rate
Engineering will continue to monitor the obstruction rate and work with Construction Management to ensure adequate resources are available and reprioritize other conduit installs to address emergent conduit installation needs.

Technical Evaluation / Analysis

Project Relationships (if applicable)

N/A

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Actual 2021
Capital	96,205	105,469	100,486	95,823		116,908
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**93,000**	**98,715**	**101,882**	**101,882**	**104,939**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2021	2022	2023	2024	2025
Labor	29,218	31,013	32,008	32,008	32,615
M&S	12,972	13,769	14,210	14,210	14,149
Contract Services	14,850	15,763	16,269	16,269	16,140
Other	4,669	4,956	5,115	5,115	5,888
Overheads	31,292	33,215	34,280	34,280	36,148
Subtotal	**93,000**	**98,715**	**101,882**	**101,882**	**104,939**
Contingency**					
Total	**93,000**	**98,715**	**101,882**	**101,882**	**104,939**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Secondary Open Mains	
Project/Program Manager: Various	**Project/Program Number (Level 1):** 10029180, 10029257, 10029402, 10029500, 10029640, 10029660, 10037568
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date: Ongoing	**Estimated Date In Service:** Ongoing
A. Total Funding Request ($000) **Capital:** $679,415 **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

The Secondary Open Mains Program is designed to evaluate and prioritize the remediation of secondary cable that has failed in the network system. To facilitate the evaluation, analytic tools have been developed that utilize load flow and operational data to simulate the impact of the failed mains on the system. The primary tools being used to support this program are: Poly Voltage Load flow (PVL), ARM Work Management and Asset Management Prioritization platform (AMPPs). The analytics are architected to periodically re-assess the system conditions factoring in peripheral conditions including other open main restorations and failures.

Specification EO-10308 establishes a uniform methodology for the prioritization or retirement of open mains. The prioritization methodology uses multiple variables with the aim of enhancing the safety and reliability of the secondary grid. In addition, the prioritization algorithms consider other work that can be bundled to the open main such as the need for a safety inspection.
The specifications aided by the analytics tool applies a consistent approach to categorizing the open mains into one of 6 buckets of work. These priorities are as follows:

Rapid: Needs to be worked immediately due to customer outage

Priority 1 and Priority 2: The highest probability of an event and most substantial consequences including equipment damage, loss of power, low voltage, overloads, and service interruption to critical customers. The distinction between the two is the overall customer impact.

Priority 3 and Priority 4: Open mains that are causing Radial conditions and do not contain overloads. The key difference between these two priorities is that priority 4 does not contain any overloads.

Priority 5: Open Mains that do not meet any of the above criteria and need to be reviewed by engineering to determine if they are candidates for retirement.

The program is setup for engineering to have a one stop dashboard to review and action the open mains as needed with a focus on transparency and uniform governance of the data.

Justification Summary:

Secondary open mains can result in local overloads within a network by shifting the flow of current from nearby in service transformer(s) while increasing load flow from more remote transformers and cables. Overloaded secondary cable sections, whether created by open mains or load increases, require replacement and/or reinforcement to mitigate low voltage conditions, manhole events, equipment coordination problems, and damage due to thermal overload. The company is taking proactive steps to analyze all open mains, determine the impact on the system and adjacent cables to avoid causing any loss of life in those cables while the target cable is out of service. This is done using the Priorities previously mentioned and assigning them to each open main and then using them in the assignment of which cables and associated conduits are replaced.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

The company recently developed the AMPPs tool to automatically prioritize work according to the priorities described above. This tool helps ensure that the regions are consistently working jobs that have the greatest impact on the distribution system. A major benefit to this new tool is that it allows engineering to have visibility into overlapping programs and activities. This visibility allows for efficient bundling of work thus maximizing productive time at each facility. The inclusion of load flow and operational data in the decision-making processes promotes a resilient distribution system that will help maintain system performance during weather events caused by climate change.

2. Supplemental Information

Alternatives

Alternative 1:
The alternative to implementing the Open Mains program is to cascade cable overloads when they occur. However, this is likely to result in equipment damage and therefore, lower service reliability would be realized.

Alternative 2:
Non-customer outage work managed as "first in first out" targeting the oldest open mains and working through the list. The risk of taking this approach is system impacts will only be recognized when an outage occurs. This will negatively impact customers with more outages and will result in increased unit costing for repairs.

Alternative 3:
Replace all open mains as soon as they occur. Construction groups balance resources between different programs and to direct the regions to relace all open mains will result in resources not being available for other work such as secondary reliability

Risk of No Action

Inaction will significantly impact customer service reliability, which includes extended restoration times and power quality issues. The process of studying each open main and assigning a priority helps ensure that cable is replaced or reinforced to ensure network stability and the ability to meet loading requirements.

Non-Financial Benefits

Con Edison's network customers experience the most reliable electric service in the country. Compared to the New York State (excluding Con Edison) average customer interruption rate of over 1000 interruptions per 1000 customers, the Company's network average customer interruption rate in 2020 was approximately 86 per 1000 customers. Thus, the service reliability of network customers is 11 times better than the NY State average. This program is required to ensure that the Company can continue to provide exceptional service to its customers.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)

2. Major financial benefits

3. Total cost

4. Basis for estimate

Estimate is calculated based upon historical data with 1% increase attributed to cable aging.

5. Conclusion

Project Risks and Mitigation Plan

Risk 1

An increase frequency in weather events lead to more salt distribution in the winter and longer and more frequent heat waves in summer leading to an increase in rate of failure.

Mitigation plan

The Company evaluates system performance annually to develop plans for restoration of open mains before each summer period. This process will continue, and if need be additional funds will be allocated to this program to ensure the system is ready to meet peak demands. Further, other programs, such as the Secondary Reliability Program, target the most failure prone cable which will mitigate this risk.

Technical Evaluation / Analysis

Secondary open mains are often caused by mechanical damage and chemical breakdown of the cable insulation from aging, movement, and improper load distribution. This insulation damage can result in arcing and eventually a fault leading to an open main(s). Secondary failures often occur in the winter when salt is distributed to melt the snow and to a lesser extent, in the summer from higher precipitation and loads. Cable replacement and reinforcement is critical to maintaining continuity of service to our network customers and preventing further equipment damage. This program will continue to address any and all capital reinforcements and replacements required to prevent cable failure or overload.

Open Mains	2019	2020	2021	2022
Received	4,251	3,616	5,112	4,620
Repaired	3,617	3,675	3,620	3,620

Project Relationships (if applicable)

Secondary Mains Load Relief

Underground Secondary Reliability

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	161,330	155,831	133,138	123,823		142,395
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	121,689	128,706	140,841	141,960	146,219
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	30,905	32,687	35,769	36,053	37,135
M&S	15,592	16,491	18,045	18,189	18,734
Contract Services	18,785	19,868	21,741	21,914	22,571
Other	16,766	17,733	19,405	19,559	20,146
Overheads	39,641	41,927	45,880	46,245	47,632
Subtotal	**121,689**	**128,706**	**140,841**	**141,960**	**146,219**
Contingency**					
Total	**121,689**	**128,706**	**140,841**	**141,960**	**146,219**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Service Replacements (Temporary Services and Bridges)	
Project/Program Manager: Various	**Project/Program Number (Level 1): 23442480, 23442485, 23442487, 23442491, 23442496, 23442497**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date:	**Estimated Date In Service:**
A. Total Funding Request ($000) **Capital: $355,972** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This program provides funding to remove the temporary service connection and perform a permanent service repair. However, if the existing conduit is unusable due to obstructions or size constraints, the repair will also require the installation of a new service conduit. When a customer has no electric service, or partial service, Con Edison attempts to make a permanent repair, unusable equipment (e.g., conduits) and/or field conditions preventing access to the cable(s) may require the installation of a temporary service. Examples of issues preventing immediate permanent repair include alternate side of the street parking which prevents access to the source structure, construction blocking the structure, obstructed service conduits, and conduits being too small for the new service cable. Permitting requirements associated with some repairs also result in the need for temporary service. The Company is obligated to replace a temporary service with a permanent repair within 90 days of the temporary service installation.

The years 2019 - 2021 had winters and tropical storms that impacted the system resulting in a high number of weather related customer electric service outages from damaged electric service wires. In 2020, the backlog grew and the volume of incoming and completed were impacted by the COVID-19 Pandemic. The addition of resources will help reduce this backlog.

The table below describes the Temporary Services repair plan with additional units to reduce the total number of on-hand temporary services.

Temporary Services	Year-End Projections - Cable Units With Conduits								
	2018	2019	2020	2021	2022	2023	2024	2025	2026
Starting Backlog	4,075	5,047	6,376	7,904	10,604	11,559	12,459	12,959	13,459
Projected Incoming	7,656	6,798	5,083	8,000	8,000	8,000	8,000	8,000	8,000
Total Completion	5,875	7,300	3,555	5,300	7,045	7,100	7,500	7,500	7,700
Backlog	5,856	6,376	7,904	10,604	11,559	12,459	12,959	13,459	13,759

Justification Summary:

This program is mandated by the New York Department of Public Service Commission (PSC).

The final connection between the distribution system and customers is via service cables and associated conduit. These facilities provide customers with the electric power they require for their homes and businesses. Over time these services fail based on a number of factors (age, weather, load, etc.) When the failed service's replacement must be deferred or is unsuccessful, due to local field conditions, a temporary service is established to return the customer to service. Temporary repairs occur either by installation of a bridge on the electric service (where the damaged service leg is cut clear and remaining customer electric load is jumped to the remaining service leg) or a shunt is installed (a temporary cable installed above the ground). The Company is obligated to replace a temporary service with a permanent repair within 90 days of the temporary service installation.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

The replacement of temporary services aligns with the Company's Electric Long-Range Plan (ELRP) and Enterprise Risk Management (ERM) strategy by supporting system reliability, reducing safety risk to the public and employees associated with failing equipment, and minimizing the risk of regulatory penalties related to reliability.

2. Supplemental Information

Alternatives

<u>Alternative 1 description and reason for rejection</u>

The alternative to installing a temporary service would be to utilize an alternate power supply that could include a portable generator, or a battery/inverter set. The reliability of these alternate supplies is not as consistent as a temporary service and could subject the customer to further interruptions and thereby reduce customer service and experience through this service replacement. Portable generators which burn fossil fuels are less efficient and less environmentally friendly.

Alternative 2 description and reason for rejection

Alternative 3 description and reason for rejection

Risk of No Action

Risk 1

Temporary services left in-service for more than 90 days incur financial penalties based on regulatory mandates. Service shunts require periodic inspections and maintenance, especially those located in high traffic areas. These actions are to safeguard the integrity of shunt protection and are an operating expense.

Risk 2

A further risk of no action is that temporary service backlogs will grow and further strain the distribution system resources. These strains can affect the long term reliability and resiliency of the system by increasing likelihood of customer outages due to climate change and load growth, along with related more frequent and longer storms or heat events.

Risk 3

Non-Financial Benefits

The permanent repair of temporary services enhances public safety by removing service shunts. These shunts present both a potential tripping hazard and a hazard from having live electrical cable on the ground within reach of the public. Addressing these shunts timely ensures compliance with regulatory mandates and fosters positive customer relationships.

Additionally, restoring permanent service will reduce the impact of repeated customer interruptions.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)

2. Major financial benefits

3. Total cost

4. Basis for estimate
The cost estimates are based on tracking all open and closed conditions for shunts and bridges by Work Request. These status outline pending backlog levels and annual projections. All closed conditions for shunts and bridges and their associated spending is tracked monthly to develop a unit cost.

Unit Cost - Capital	Shunts	Bridges	Blended Rate
2017	$9,182	$2,980	$12,162
2018	$7,517	$3,851	$11,367
2019	$8,451	$3,875	$12,327
2020	$7,370	$3,711	$11,082
2021	$5,794	$2,929	$8,723

5. Conclusion
This program meets a regulatory requirement and supports system reliability.

Project Risks and Mitigation Plan

Risk 1 Mitigation plan
The obstruction rate for underground service conduit increases, resulting in durations to complete and increased conduit expenses. The company can further employ the strategy of digging and clearing obstructed conduits, where possible, to help manage external Construction Contractor expenses.

Risk 2 Mitigation plan

Technical Evaluation / Analysis

Project Relationships (if applicable)

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	**66,744**	**74,523**	**70,872**	**52,687**		69,571
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	68,000	68,515	72,428	72,428	74,601
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	20,332	20,486	21,656	21,656	22,306
M&S	2,516	2,535	2,680	2,680	2,760
Contract Services	13,532	13,634	14,413	14,413	14,845
Other	9,112	9,181	9,705	9,705	9,996
Overheads	22,508	22,679	23,974	23,974	24,694
Subtotal	**68,000**	**68,515**	**72,428**	**72,428**	**74,601**
Contingency**					
Total	**68,000**	**68,515**	**72,428**	**72,428**	**74,601**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital	70,000	68,000	72,428	72,428	74,601

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☒ **Regulatory Mandated** ☐ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Streetlights (Including Conduit)	
Project/Program Manager: George Jensen	**Project/Program Number (Level 1): 23442223, 23442241, 23442324, 23442328, 23442329, 23442467**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other: ___________**	
Estimated Start Date: On-going	**Estimated Date In Service: On-going**
A. Total Funding Request ($000) **Capital: $134,992** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This program addresses the replacement of secondary cable that provides service to Street Lights and associated conduit. Streetlights have become an increasingly important role in public safety for the New York City Department of Transportation (NYCDOT) and Westchester Municipalities. The City and Municipalities who maintain these lights, patrol and collect field complaints from the public to determine which lights are not working. The lights are then tested to determine whether the City/Municipalities or Con Edison has the responsibility for making such repairs.

Justification Summary:

This program is mandated by the New York Public Service Commission (PSC). The Company is obligated to repair 90% of all incoming no current streetlights in 90 days during the winter period and 80% of all incoming no current streetlights in 45 days during the summer period.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

The Street Lights program addresses risk to public and employee safety as well as enterprise risk associated with New York State regulatory penalties.

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection

No practical alternative other than allowing the streetlights to remain in their current condition. This places the Public & the Company at risk & unfavorable media attention. This can result in the customer (DOT) remaining out of service for an extended period.

Alternative 2 description and reason for rejection

Alternative 3 description and reason for rejection

Risk of No Action

Risk 1

Streetlight failures need to be identified and permanently repaired as they are a vital part of keeping public areas safe. Con Edison has an obligation to public safety and to address any Con Edison owned equipment problems associated with streetlights as they are identified by the City and Municipalities. We plan to continue to make timely, permanent repairs to our streetlight infrastructure as a commitment to public safety. This ensures that streetlights stay energized and new cable installations lessen the possibility of stray voltage conditions.

Risk 2

The NYCDOT in cooperation with the Mayor's Office continues to expand on various safe intersection street initiatives that can have an adverse effect on Consolidated Edison if we cannot provide adequate assistance. The Company prefers to make initial installations permanent rather temporary. This avoids unnecessary follow up work & reduces duplication efforts. This also can increase outage durations.

Risk 3

Non-Financial Benefits

Benefits include continued and improved public safety, increased service reliability, improved customer satisfaction, and improved relationships with Community Boards and the Public Service Commission (PSC). Additionally, supporting & actively engaging with the city in its roll of growing its infrastructure.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)

2. Major financial benefits

3. Total cost

4. Basis for estimate

5. Conclusion

Project Risks and Mitigation Plan

Risk 1
Streetlights act as a safety conduit for our communities that we serve. Some City programs, i.e., Safe intersections, Curbside Dining & Alternate Side of the Street Parking can impact or extend timeline completion or unfavorably create a backlog of work. Generally, the above obstacles can incur unforeseen escalated cost in making permanent streetlight repairs.

Risk 2
As the City grows its initiatives, it also adds risk to the Company as we do & have experienced storms & the like to our infrastructure. Additional attachments & equipment can extend timelines in restoration efforts.

Technical Evaluation / Analysis

Project Relationships (if applicable)

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	**31,463**	**36,901**	**28,885**	**21,733**		25,133
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**27,235**	**27,235**	**27,235**	**27,235**	**28,052**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	206
Labor	1,470	1,470	1,470	1,470	1,514
M&S	991	991	991	991	1,021
Contract Services	14,984	14,984	14,984	14,984	15,433
Other	660	660	660	660	680
Overheads	9,130	9,130	9,130	9,130	9,404
Subtotal	**27,235**	**27,235**	**27,235**	**27,235**	**28,052**
Contingency**					
Total	**27,235**	**27,235**	**27,235**	**27,235**	**28,052**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Targeted Direct Buried Cable Replacement	
Project/Program Manager: Not Applied	**Project/Program Number (Level 1): 10032067, 10032143**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date:	**Estimated Date In Service:**
A. Total Funding Request ($000) **Capital: 62,420** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This program funds the replacement of primary and secondary Direct Buried Cable (DBC) with a higher quality jacketed cable installed in conduit to improve the reliability of the supply to Underground Residential Distribution (URD) customers. URD subdivisions with high fault activity and cable sections that have reached end of life are targeted to have section DBC URD sections replaced. The projected annual number of units is listed below. Actual units repaired will depend on a number of factors including weather, and the amount of cable failures that occur in a given year.

Item	Units
UG Conduit	11,367
Primary URD Sections	131
Secondary URD Sections	24
Urd Transformer	28
UG SVC Cable Sections	23
UG Service Structure	16

Justification Summary:

On average, it takes longer to locate and repair a fault when it occurs on direct buried cable than it does to repair a fault that occurs on the same cable installed in a conduit. When a direct buried cable fault is located, it must be excavated and exposed. The damaged cable or splice needs to be removed, and a new short "insert" needs to installed and spliced. The remaining portion of the existing direct buried section is left in place and may fault again in the future. Conversely, when a cable fault is located in a section of conduit, the entire section is replaced with new cable. The new section is much less likely to fail again in the near future compared to a direct buried section that is decades old. Generally, no excavation is needed.

Undertaking a more aggressive Targeted URD replacement program for both primary/secondary sections and services will reduce the number of DBC outages on the URD system (SAIFI) and also will reduce annual repair expenses.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection

One alternative is URD cable rejuvenation. This program is being explored in areas without high fault activity in Westchester and Staten Island. While this program may be valuable, it will not remedy areas where cable has repeatedly faulted due to the number of buried splices and condition of the cable.

Alternative 2 description and reason for rejection
Another alternative is convert underground residential distribution to overhead distribution. This may be a lower cost option, however local agencies generally prohibit installation of poles in existing underground areas.

Risk of No Action

Risk 1
Continued customer interruptions due to URD cable failure.

Risk 2
Higher emergency expense for URD repairs.

Risk 3
Leaving failing cable in place may lead to multiple outages for the same customers resulting in an increase in complaints and frustration.

Non-Financial Benefits

Improved system performance by reducing the amount of customer interruptions. This will increase overall reliability, resulting in a reduction in System Average Interruption Frequency Index.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis (if required)

2. Major financial benefits

3. Total cost

4. Basis for estimate
Cost is based on the planned units as described in the work scope.

5. Conclusion

The PSC sets reliability performance standards (SAIFI and CAIDI) that the Company must meet. Reliability performance not meeting threshold targets may expose the Company to as much as $10 million in penalties ("Radial SAIFI" and "Radial CAIDI") under the current rate agreement. Addressing failing and failed equipment will reduce the potential that the Company will incur financial penalties due to non-compliance with reliability standards.

Project Risks and Mitigation Plan

Risk 1 Mitigation plan

Risk 2 Mitigation plan

Technical Evaluation / Analysis

See justification section.

Project Relationships (if applicable)

N/A

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	**5,727**	**3,157**	**938**	**5,096**		7,064
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**6,000**	**14,000**	**14,000**	**14,000**	**14,420**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	957	2,235	2,235	2,235	2,302
M&S	668	1,559	1,559	1,559	1,606
Contract Services	2,415	5,635	5,635	5,635	5,804
Other	10	23	23	23	24
Overheads	1,950	4,548	4,548	4,548	4,685
Subtotal	**6,000**	**14,000**	**14,000**	**14,000**	**14,420**
Contingency**					
Total	**6,000**	**14,000**	**14,000**	**14,000**	**14,420**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Energy Services / Telecom
2022

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☒ **Regulatory Mandated** ☐ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Telecom – Underground Facilities	
Project/Program Manager: Sean Waldron	**Project/Program Number (Level 1): 10034417**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other: ___________**	
Estimated Start Date:	**Estimated Date In Service:**
A. Total Funding Request ($000) **Capital: $548** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:
Pursuant to the Public Service Commission's (PSC's) "Order Adopting Policy Statement on Pole Attachments (issued and effective August 6, 2004) (Case 03-M-0432), Con Edison installs and maintains underground conduits for use by Telecommunication Companies. The Telecommunication Companies are allowed to install, operate, and maintain their fiber optic cables in the Company's underground facilities under the Telecom Act of 1996. In accordance with the Company's Rider X tariff, Telecommunication Companies are charged a rental rate that allows Con Edison to recover ongoing capital charges incurred when new conduits are installed for telecommunication purposes. All rental rates and associated construction charges are clearly defined in the Rider X tariff document, which is reviewed and filed with the PSC by Con Edison's Rate Engineering group on an annual basis.

Justification Summary:
In order to support the cost of construction of new telecommunication routes when there is no capacity in the Company's existing facilities, and also the cost for relocation of Company facilities as a result of proposed Public Improvement projects throughout the Company's service territory, it is imperative that the Company forecasts and allocates Capital funding for this program. There are many factors that impact these annual forecasts, and actual costs may vary considerably from year to year. The forecasted capital funds are estimated charges derived from construction tasks to install new conduit and to relocate existing telecom facilities that are in interference with Public Improvement work. In addition, the Company seeks information from Telecommunication customers to assist with the identification of such costs. Associated costs for the projects consist of relocation of duct banks, manholes, and telecom splice boxes.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)
This program supports telecommunication infrastructure builds within the service territory, as directed by PSC order and per Electric tariff (Rider X)

2. Supplemental Information

Alternatives

There are very rarely alternatives to relocation due to Public Improvement projects. One exception is situations where the City gives the Company the option of paying for redesign or relocation of the City's facilities rather than relocating Con Edison facilities due to interference with a Public Improvement project. This usually happens in cases where it would cost more to relocate the Con Edison facilities than to redesign or relocate the Public Improvement project, in which case the City gives the Company the option to pay for that Public Improvement project redesign or relocation.

Alternatives for conduit installations are also few, job specific, and are only rejected by Electric Ops after a review of the work package. Removal of retired cables is one such alternative but is only available if:

- The proposed section for conduit installation has one or more retired electrical feeder(s);
- Regional Engineering has confirmed no future use; and
- After the retired cables have been removed there are at least two spare conduits.

Con Edison cannot allow Telecommunication Companies to use the last available conduit. Dig to Clear is another conduit installation alternative, though is only an option when the conduit in question is obstructed. The viability of this approach is dependent on the length of the obstruction, and if the obstruction is greater than 20 feet, the Dig to Clear method becomes cost prohibitive.

Risk of No Action

This program is required to comply with NYPSC Case 03-M-0432.

Non-Financial Benefits

Not Applicable

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)

2. Major financial benefits

3. Total cost

4. Basis for estimate

Estimates are based on data provided by the Telecommunication Companies. The Telecommunications Companies determine the average number of jobs they anticipate initiating per year for five years. Con Edison, in turn, estimates the average cost per foot for conduit installations and the average structure to structure length. This data is used along with factors related to Public Improvement relocation costs to forecast program costs. Due to the PSC's mandate to install four conduits (two for Telecommunications Companies and two for Con Edison), this forecast only accounts for the telecommunications portion (50%) of the construction cost when conduit installation is required.

5. Conclusion This program supports telecommunication infrastructure builds within the service territory, as directed by PSC order and per Electric tariff (Rider X).
Project Risks and Mitigation Plan Risk 1 — More than anticipated requests for build. Mitigation plan — We sought feedback from our telecom customers and industry personnel to discuss their projections for any future build.
Technical Evaluation / Analysis N/A
Project Relationships (if applicable) N/A

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital						**$0**
O&M						**$0**
Retirement						**$0**

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**$274**	**$274**	**$0**	**$0**	**$0**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	$14	$14	$0	$0	$0
M&S					
Contract Services	$187	$187	$0	$0	$0
Other	$17	$17	$0	$0	$0
Overheads	$56	$56	$0	$0	$0
Subtotal	**$274**	**$274**	**$0**	**$0**	**$0**
Contingency**					
Total	**$274**	**$274**	**$0**	**$0**	**$0**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Transformer Installation	
Project/Program Manager: Various	**Project/Program Number (Level 1): 23442502, 23442508, 23442513, 23442514, 23442516**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date: Ongoing	**Estimated Date In Service:** Ongoing
A. Total Funding Request ($000) **Capital:$** 244,475 **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

Due to public safety concerns, we have instituted various programs to identify equipment that could potentially fail**.** The Company's transformer inspection program includes both remote monitoring and physical inspections. Remote monitoring equipment installed on transformers provides real time pressure and temperature readings. Where remote monitoring is not installed, time based physical inspections are completed including dissolved gas in oil analysis. This approach provides a more comprehensive review of our underground transformers. Replacing failed transformer units and those that require replacement as a result of defects found during inspection is a critical function for ensuring the integrity of the network system. As a result of this increased monitoring, we have experienced an increased number of units needing replacement in order to maintain our system reliability.

This program is to replace electrical distribution equipment (primarily underground network transformers and their associated network protector, cable, conduit, and structures) that is found to be defective. These defective equipment replacements account for approximately 55% of transformer installations (the remaining 45% include load relief and new business). These components are identified for removal based on equipment condition determined from visual inspection, dissolved gas in oil analysis, and remote sensors which report pressure, temperature and oil level. Removal prioritization is based on risk of failure. Transformers with confirmed low levels of oil or with oil or pressure leaks are given the highest priority for removal from service.

Analyses of Pressure, Temperature and Oil sensor data have dramatically reduced the number of in service transformer failures, there were 147 failures in 2005 and in the last 5 years the average failure rate is 21 transformers per year. These reductions are directly correlated with the results of our failure mitigation programs. In the last 5 years, we have preemptively removed approximately 885 units that exhibited symptoms to potentially fail in-service through the use of engineering programs in addition to field removals.

Justification Summary:
Replacing failed transformer units and those that require replacement as a result of defects found during inspection is a critical function for ensuring public safety and system reliability. Public safety has already been improved by the installation of pressure, temperature, and oil level sensors which provide information to our remote monitoring system. These installations have resulted in reductions in transformer ruptures by allowing us to identify defective transformers and remove them from service prior to failure.

The reliability of the network system is dependent on the integrity of our network transformers. Transformer failures can contribute to the loss of multiple feeders in the same network, particularly during periods of high load which can result in local area voltage problems and customer outages.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

Part of the Company's long term strategy to adapt to climate change includes implementing a FEMA +5 flood rating to all of our underground structures. This will result in more equipment being submersible, which can lead to higher installation costs in the future.

The Risk Management sub-section of the Electric Long-Range Plan (ELRP) states that part of its minimization of risk to employee and public safety is "proactive replacement of high-risk components" and the use of "data and analytics to prioritize our response to any potential problems revealed". The Transformer Installation program does just that for the network transformers, combined with the network design criteria which builds in redundancy in network transformers, allowing two to fail without loss of load on peak day.

In addition, this program supports other aspects of Enterprise Risk Management as cited in the Risk Management sub-section of the ELRP, including:

- Resiliency and Reliability (achieved through the redundancy built into the secondary network design and maintained through replacement of failure-prone network transformers)
- Climate Change Vulnerability (again, achieved through network redundancy and contingent design)
- Critical Infrastructure Reliability (with service to critical infrastructure built into the impact of network transformer failure)

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection
There is no practical alternative to replacing failed distribution transformers as they are required to maintain electric service to our customers. The alternative to replacing transformers identified as defective with the potential to fail is to continue to operate the equipment and risk a catastrophic failure. This alternative would jeopardize public safety and system reliability and is not viable.

Risk of No Action

Risk 1
Failing to replace transformers would jeopardize public safety and system reliability.

Non-Financial Benefits
Transformer replacements improve public safety and system reliability by removing defective transformer. In addition to reducing equipment failures, the number of unplanned feeder outages is also reduced, since every transformer failure results in de-energization of the entire feeder that supplies it.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis (if required)
N/A

2. Major financial benefits
N/A

3. Total cost

4. Basis for estimate
The basis for the cost estimates is the historical program unit cost for transformer installation.
The unit cost is provided below

2017	2018	2019	2020	2021 YTD
16,334	21,928	25,645	37,493	39,411

5. Conclusion

Project Risks and Mitigation Plan

Risk 1	Mitigation plan
Equipment not available for installation	Maintain vendor diversity for applicable equipment

Technical Evaluation / Analysis
Defective transformers are classified as "Banks Off" when they are no longer supplying the electrical secondary grid but before they are replaced. Some Banks Off require complete equipment replacement, while others may involve a repair to either the transformer or network protector. The following table summarizes the historical banks off numbers.

Year	2014	2015	2016	2017	2018	2019	2020
Open	1229	2477	2320	1982	2011	1813	1841
Closed	1142	2652	2408	2104	1751	1921	1911
Pending	832	657	569	447	707	599	529

Project Relationships (if applicable)
Transformer Purchase Program – The Transformer purchase program provides the funding for the purchase of the transformer installed under this program.

3. Funding Detail

Historical Spend

EOE	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Total	**34,081**	**40,370**	**37,314**	**48,545**		**32,058**

Total Request ($000):

Total Request by Year:

EOE	Budget 2022	Request 2023	Request 2024	Request 2025	Request 2026
Labor	12,540	16,906	16,906	16,906	17,420
M&S	9,880	13,320	13,320	13,320	13,725
Contract Services	4,180	5,635	5,635	5,635	5,807
Other	-1,900	-2,561	-2,561	-2,561	-2,639
Overheads	13,300	17,930	17,930	17,930	18,476
Total	38,000	51,229	51,229	51,229	52,788

Capital Request by Elements of Expense:

EOE	2021	2022	2023	2024	2025
Labor					
M&S					
Contract Services					
Other					
Overheads					
Subtotal					
Contingency**					
Total					

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Central Operations/STO
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Transmission Feeder Failures	
Project/Program Manager: Mark Bauer	**Project/Program Number (Level 1):** 22679436
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date:	**Estimated Date In Service:**
A. Total Funding Request ($000) **Capital:** 70,000 **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:
The Transmission Feeder Failures Program provides funds for the repair of underground transmission feeders when the repair scope of work, as determined by Transmission Engineering, requires a complete cable section replacement between manhole structures and splicing of new joints.

Justification Summary:

The Transmission Feeder Failures Program establishes capital funding to address major transmission repairs. While funding for some transmission feeder repairs is provided in the O&M program, the cost of extensive replacements requiring the installation of a new cable section and joints are covered through this capital program.

For a high-pressure pipe-type cable transmission feeder, a complete cable section replacement would be recommended based on a technical evaluation performed by Transmission Engineering. This takes into consideration the following:

1) Evaluation to determine if external contaminants entered the dielectric fluid system caused by a water main/water service leak which over time can cause a cable failure.
2) Evaluation of operational history of the cable section (multiple failures in section) and original cable manufacturer.
3) Physical inspection of the fault and companion conductors for evidence of thermal- mechanical damage or other observed abnormalities that will likely result in subsequent failures in the section if not addressed.

The continuation of this program will maintain underground Transmission System reliability.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
This program is related to the likelihood corporate risk of loss of a substation. It is imperative that issues on failed feeders are addressed in order to ensure the resiliency of the grid.

2. Supplemental Information

Alternatives
The alternative to a cable section replacement is to remove the localized area of damaged cable and install a short section of cable and two buried joints at the fault location. If this alternative is exercised and water and/or other contaminants have entered the pipe, the integrity of the dielectric fluid system has been compromised and subsequent failures may occur due to contamination of the dielectric fluid system and paper insulating tapes of the cable. With regards to thermal-mechanical damage, or other abnormalities observed during inspection of the fault, the alternative again exists to remove only the damaged cable and install two buried joints and a short section of cable. There is the possibility that similar damage on the cable may exist within other areas of cable section not readily seen at the localized repair location. A subsequent failure may then occur in the same cable section at a later date. For example, a failure occurred in July 2014 on 345kV Feeder 71 between manhole structures M7369 and M7368 located in Yonkers. The cable fault was inspected by engineering representatives and the repair scope was to replace the cable section between the manhole structures. While the cable was being removed from the pipe, engineering representatives on location observed cable insulation damage approximately 250 feet away from the original fault location, which would have resulted in a future failure.

Risk of No Action
The risk of no action is an adverse impact on Transmission System reliability. If multiple failures were to occur during a high load period or while other critical facilities are out of service, load shedding and large-scale customer outages can result. Emergency mobilization and fault locating costs are also avoided by addressing the reliability issues proactively. Removing the suspect configurations and enhancing feeder reliability also helps avoid significant job cancellation costs for working groups throughout the Company due to the effects on scheduled transmission facility work when a transmission feeder fails.

Non-Financial Benefits
The availability of transmission and sub-transmission feeders is an important part of maintaining the reliability of the transmission system. This program will provide the funding to facilitate the quickest possible return to service for transmission feeders that have failed and/or require a cable section replacement.

Summary of Financial Benefits and Costs (attach backup) Analysis was done on this program to show that there are on average 3-4 failures per year costing between $3-5M and that on average, $15M a year was spent in the previous six years. Therefore, in order to address these failures, the budget was increased to accommodate.
Project Risks and Mitigation Plan
Technical Evaluation / Analysis
Project Relationships (if applicable)

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	**$22,665**	**$22,541**	**$10,421**	**$13,217**		16,900
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**10,000**	**15,000**	**15,000**	**15,000**	**15,000**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	2,412	3,260	3,260	3,260	3,260
M&S	1,308	1,800	1,800	1,800	1,800
Contract Services	2,808	4,832	4,832	4,832	4,832
Other	467	783	787	790	822
Overheads	3,005	4,325	4,321	4,318	4,286
Total	**10,000**	**15,000**	**15,000**	**15,000**	**15,000**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations/STO
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Transmission Feeder Failures - Other	
Project/Program Manager: Various	**Project/Program Number (Level 1):** 21556402
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date:	**Estimated Date In Service:**
A. Total Funding Request ($000) **Capital: 13,000** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:
The Transmission Failures – Other Program provides funds for the replacement of failed equipment associated with transmission feeders. The work scope of this program will include, but is not limited to, the replacement of failed cable terminations, riser cable sections or other transmission feeder equipment located inside substations.

Justification Summary:

The Transmission Failures - Other Program establishes capital funding to address transmission feeder equipment replacements inside a substation. While funding for some transmission feeder repairs is provided in the O&M program, the cost of repairs requiring the complete replacement of a new cable termination or riser cable section are covered through this capital program.

For transmission feeders, pothead replacement would be recommended based on a technical evaluation performed by Transmission Engineering. Potential conditions necessitating replacement includes the following:

- Physical inspection showing any visible damage to the cable insulation, stress cone, or cable shielding inside the pothead including broken or missing tapes, ridges or insulation distortion, or electrical discharges.
- Dielectric fluid or material analysis showing contamination such as high moisture content or reduced insulation strength.
- Broken or ruptured porcelain or riser pipes leading to a dielectric fluid leak that cannot be repaired.

The continuation of this program will help maintain underground Transmission System reliability. The scope and funding for this program was previously carried under the "Failed Equipment Program" for Substation Operations.

.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
This program is related to the likelihood of loss of a substation which is a corporate goal. It is imperative that failed equipment be replace in order to keep the grid resilient.

2. Supplemental Information

Alternatives
The alternative to replacing failed cable terminations and associated equipment is to repair them. For some types, spare components are no longer available requiring replacement with new style terminations. Additionally, higher electrical stresses in the terminations make them more vulnerable to failure if damage within the insulation is not visible during repairs.

Risk of No Action
The risk of no action can jeopardize the reliability of the Transmission System. If multiple failures were to occur during a high load period or while other critical facilities are out of service, load shedding and large-scale customer outages can result. Emergency mobilization and fault locating costs are also avoided by addressing the reliability issues proactively. Removing the suspect configurations and enhancing feeder reliability also helps avoid significant job cancellation costs for working groups throughout the Company due to the far-reaching effects on scheduled transmission facility work when a transmission pothead fails.

Non-Financial Benefits
Transmission feeder components in substations, such as cable terminations or auxiliary pressurization sources, make up essential elements of feeder availability. In order to maintain reliability, failed components must be replaced so that feeders can be restored as quickly as possible. This program will facilitate the restoration of transmission feeders following failures of components that are inside substations.

Summary of Financial Benefits and Costs (attach backup)
Historically, on average this program usually accounts for one single phase pothead replacement, however, in 2020, this program needed to accommodate a 3ph pothead replacement. Therefore, the budget is being increased to $3M in order to accommodate a 3ph replacement should it be required.

Project Risks and Mitigation Plan

Technical Evaluation / Analysis

Project Relationships (if applicable)

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	**253**	**0**	**0**	**3,072**		**1,000**
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**1,000**	**3,000**	**3,000**	**3,000**	**3,000**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	260	680	680	680	680
M&S	60	400	400	400	400
Contract Services	100	920	920	920	920
Other	279	102	103	103	110
Overheads	301	898	897	897	890
Total	**1,000**	**3,000**	**3,000**	**3,000**	**3,000**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Exhibit_(EIOP-7)

T&D Equipment Purchase

Schedule 1: T&D Equipment Purchase Capital Program and Project Summary

Electric T&D *Equipment Purchase*		**Year Total** **Current Budget** **Total Dollars ($000)**			
		RY1	**RY2**	**RY3**	**3 Yr. Total**
EQUIPMENT PURCHASE					
Organization	**White Paper**				
Distribution	Equipment Purchase	10,000	20,000	20,000	50,000
Distribution	Transformer Purchase	136,000	139,600	139,600	415,200
TOTAL ELECTRIC					
	Total Equipment Purchase	**146,000**	**159,600**	**159,600**	**465,200**

Schedule 2:

T&D Capital White Papers

Equipment Purchase

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☒ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Equipment Purchase	
Project/Program Manager: Charles Feldman	**Project/Program Number (Level 1):10029273**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☐ **Ongoing** ☐ **Other: ___________**	
Estimated Start Date:	**Estimated Date In Service:**
A. Total Funding Request ($80600) **Capital: 80,600** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:
Provides for the purchase of electric revenue meters and associated metering equipment for revenue collection as required by New York Public Service Commission (PSC) regulations. The purchases include electric meters and associated metering equipment such as revenue grade instrument transformers.

Units per Year: Approximately 167,000 electric meters and associated metering equipment are required.

Mandatory: Approved electric revenue metering equipment is required by PSC regulations.

High-level schedule: This is an ongoing activity where the metering equipment is purchased based on requests and expected needs.

Justification Summary:
This is required to support new businesses and customer upgrades.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

The Risk Management sub-section of the Electric Long Range Plan (ELRP) states that part of its minimization of risk to employee and public safety is "proactive replacement of high-risk components" and the use of "data and analytics to prioritize our response to any potential problems revealed." The Meter Purchases program supports the programs that directly address those needs.

2. Supplemental Information

Alternatives

Alternatives:
There are no acceptable alternatives to the use of PSC approved metering devices as specified in PSC Part 92 for billing customers.

Meters provide the means to accurately record customer demand, implement time of day rates, demand response and energy efficiency programs and comply with regulatory metering programs such as reactive power. The last step in bringing new customers on line with electric service is to install the meter. Without meters, many new customers would be delayed or tied in unmetered. New tariffs would have to be developed to support flat rate un-metered billing.

Risk of No Action
Without meters and the existing tariffs in place, customer usage would need to be estimated which is not reliable and subject to dispute.

Non-Financial Benefits

The analysis of advanced metering infrastructure (AMI) meter customers voltage and phase angle information to detect possible open neutrals, monitoring CPU temperature to detect "hot socket" conditions that are due to faulty/lose meter pan connections that creates dangerous heat conditions are non-financial benefits that are related to safety and customer satisfaction.

Load shedding using the service switch contained in the meters will support energy efficiency and energy conservation initiatives.

Utilizing the AMI communications network to transmit outage information for individual customers improves the workflow for emergency crews to monitor restoration efforts and report the results in a timely and accurate manner.

Magnetic tampering and meter inversion detection will provide information to monitor and better control tampering activity and ensure to minimize of lost revenue from theft of services.

Outage detection of customer with Life Sustaining Equipment (LSE) can be detected more efficiently and reliably.

Detection of unfiled contractor activity on the utility side of the service by monitoring last gasp outage messages enhances customer and utility worker safety.

Use of the AMI meter mesh communications network to transmit natural gas detection with provide early detection of customer/utility gas leaks.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis (if required)

2. Major financial benefits

3. Total cost

4. Basis for estimate

5. Conclusion
Project Risks and Mitigation Plan Risk 1: Long lead times and production shortages due to manufacturer material issues could delay procurement. Delayed procurement of meters will delay initiation of service to new customer or require they be tied in without a meter and estimated bills be generated. Mitigation plan: Alternative vendors should be solicited and PSC approval requested. Risk 2: As new vendors and products are introduced, prices will be higher because of the limited initial purchase quantities. Mitigation plan: Engage purchasing department to solicit competitive bidding
Technical Evaluation / Analysis
Project Relationships (if applicable)

3. Funding Detail

Historical Spend (000s)

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	8,289	3471	8,207	6,979		4,425
O&M						
Retirement	540	509	313			

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	$10,000	$10,000	$20,000	$20,000	$20,600
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	2,500	2,500	2,500	2,500	2,500
M&S	6,200	6,196	14,891	14,892	15,413
Contract Services					
Other					
Overheads	1,300	1,304	2,609	2,608	2,687
Subtotal	10,000	10,000	20,000	20,000	20,600
Contingency**					
Total	**10,000**	**10,000**	**20,000**	**20,000**	**20,600**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Transformer Purchase	
Project/Program Manager: Various	**Project/Program Number (Level 1):** 10029255, 10036032
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date: Ongoing	**Estimated Date In Service:** Ongoing
A. Total Funding Request ($000) **Capital: $668,688** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:

This program will fund distribution system equipment purchases under the ED2 capital budget used to purchase new and reconditioned capital electrical distribution equipment. This equipment includes underground network transformers, overhead transformers, padmount transformers (including mini-pads), capacitor banks, emergency generators, and network protectors to support distribution system relief, reliability, emergency, and load growth programs.

This funding is needed to provide Electric Operations Construction and Energy Services with electrical distribution equipment in order to complete active and planned burnout, new business, and system relief and reinforcement projects. Additional details are provided in the related white papers for transformer installation and load relief capital installations.

We will continue to institute and expand the various failure mitigation programs to identify the electrical distribution equipment on our system for which removal is most urgent. These programs are designed to proactively inspect our field equipment, replace equipment that exhibits warning signs of potential failure, ensure public safety, and maintain system reliability.

Analyses of Pressure Temperature Oil sensor data have dramatically reduced the number of in service transformer failures, there were 147 failures in 2005 and in the last 5 years the average failure rate is 21 transformers per year. These reductions are directly correlated with the results of our failure mitigation programs. In the last 5 years, we have preemptively removed approximately 885 units that exhibited symptoms to potentially fail in-service through the use of engineering programs in addition to field removals.

Additionally, Con Edison has been working with network transformer vendors to develop dry type submersible underground distribution transformers. The advantage of such units is that they do not contain dielectric fluid so there are no concerns with leaks or fire. These are potentially desirable features for locations with high pedestrian traffic and indoor installations. Prototypes have been reviewed and a limited population is undergoing field trial.

Justification Summary:

Without the required funding, we would be unable to purchase electrical distribution equipment as needed. Lack of installed transformer capacity in the same network especially during high load periods can result in system degradation and reliability issues including local area voltage problems and customer outages. In addition to impacting the distribution system reliability and customer service, there is a significant public safety concern if we are unable to proactively replace defective transformers in a timely manner.

The distribution equipment sourced and installed must be reliable and resilient to the rapidly changing requirements. The driving impact for such changes include climate, regulatory and demand due to electrification of transportation and heating. There will be an increase in the installation of submersible equipment due to increasing flooding concerns. Additionally, an increase in the quantity of network transformers with fixed tap changer is required in support of CVO, one of our Clean Energy initiatives. This equipment increases the baseline unit cost by approximately 7%

Our construction contracts include commodity price increases/ reductions at set contract intervals. The current and sustained impact on raw materials has resulted in consecutive contract price increases during the Pandemic. The impact in 2021 ranged between a 5 – 9% cost increase.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

Through the Company's Enterprise Risk Management (ERM) program, Con Edison manages an array of risks, including those associated with system reliability and employee and public safety. The ERM program considers operational risks and identifies capital and O&M investments that prevent, detect, and respond to such risks. Distribution transformers that are in need of replacement due to failure, system expansion, or risk reduction need to have the material on hand to ensure network reliability and timely restoration.

The Risk Management sub-section of the Electric Long-Range Plan (ELRP) goes on to state that part of its minimization of risk to employee and public safety is "proactive replacement of high-risk components" and the use of "data and analytics to prioritize our response to any potential problems revealed". The Transformer Purchases program materially supports the programs that directly address those needs. In addition, in-service tank ruptures are monitored as an Enterprise risk.

This program directly contributes to the mitigation of that risk by funding the procurement of the latest distribution transformers and related equipment.
In addition, this program supports other aspects of Enterprise Risk Management as cited in the Risk Management sub-section of the ELRP, including:

- Resiliency and Reliability (achieved through the redundancy built into the secondary network design, and maintained through replacement of failure-prone components, including transformers)
- Climate Change Vulnerability (again, achieved through network redundancy and contingent design)
- Critical Infrastructure Reliability (with service to critical infrastructure built into the impact of component failure)

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection
Distribution Equipment is required to maintain electric service to our customers and system reliability. Therefore, there is no viable alternative to purchasing transformers at this time.

Alternative 2 description and reason for rejection

Alternative 3 description and reason for rejection

Risk of No Action

Risk 1
Reduction in funding could impact availability of equipment for emergency replacement, new business work, or load relief. This would adversely impact system safety and reliability.

Risk 2

Non-Financial Benefits
Transformer replacements improve public safety and system reliability by removing defective transformer. In addition to reducing equipment failures, the number of unplanned feeder outages is also reduced, since every transformer failure results in de-energization of the entire feeder that supplies it.

Replacing old, degraded equipment (particularly equipment at elevated risk of failure) reduces the probability and frequency of equipment failures. This improves reliability by reducing the number of feeders that trip out (open). In addition, the ability to replace equipment reduces the risk of violent failure, which decreases the risks of injury to the public and to property.

The Company has made substantial progress and continues to work to establish additional suppliers for our major distribution equipment to promote competition and supplier diversity. The increased competition helps to reduce equipment costs, while the increased supplier diversity expands sourcing options and equipment availability. In addition to the diversification of vendors, Distribution Engineering has worked to develop quality metrics to track each vendor's product quality and on-time-delivery performance. These metrics have been incorporated into Purchasing's distribution equipment bid process.

The Company also continues to recondition equipment removed from service. These efforts help to reduce raw materials entering the waste stream and contribute to lower the total cost of equipment purchases for the company. This augments Clean Energy initiatives by extending life of existing materials and reducing waste.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis (if required)
N/A

2. Major financial benefits
N/A

3. Total cost

4. Basis for estimate
The basis for the cost estimates is the historical program unit cost for transformer installation.

- Summary of Financial Benefits (if applicable) and Costs: The approximate allocation of the ED2 budget is as follows:
    - Underground Network Transformers: 45%
    - Network Protectors: 35%
    - Non-Network (Overhead / Padmount) Transformers: 10%
    - Other (Shunt Reactors, Capacitors, etc.): 10%

There has been a recent increase in transformer and network protector purchases to support storm response and resiliency initiatives, including upgrading of network protectors to submersible designs and replacement of non-submersible 125/216V network transformers and protectors with submersible equipment.

5. Conclusion

This funding is needed to provide Electric Operations with electrical distribution equipment with which to achieve both planned and emergent transformer and related equipment installations.

Project Risks and Mitigation Plan
Risk 1
Manufacturing or Supply Chain disruptions could impact the procurement costs and the availability of equipment for purchase. With increasing lead times, the Company may need to increase orders as well as the on-hand quantities of distribution equipment.

Mitigation plan

To mitigate this risk, the Company's Engineering and Supply Chain representatives forecast and coordinate regular purchases to sustain on-hand inventory as well as pursue diversity across multiple suppliers. In addition, he Company actively pursues supplier diversity and competitively bids the equipment purchase contracts.

Risk 2 Mitigation plan

Technical Evaluation / Analysis

The purchasing process incorporates a forecasting model to predict the need for transformers based on historical usage. This model is run on a monthly basis for the purchase of equipment used to maintain electric service and maintain system reliability. The model includes variables such as historical usage, forecasted usage, current inventory levels, equipment on-order, and lead times. The orders are generally optimized to minimize cost while ensuring high levels of equipment availability. In addition, data analysis and trending is conducted on usage, inventory levels, and other supply chain parameters to help reduce costs and guide program spend in an effective and optimal manner.

Project Relationships (if applicable)
Transformer Installation Program – The Transformer purchase program provides the funding for the equipment installed under this program.

3. Funding Detail

Historical Spend

EOE	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	**104,968**	**97,857**	**96,792**	**121,536**		**92,058**
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

EOE	Budget 2022	Request 2023	Request 2024	Request 2025	Request 2026
Labor	3,896	4,760	4,886	4,886	5,022
M&S	99,597	123,080	126,198	126,198	129,857
Contract Services	1,693	2,040	2,234	2,234	2,152
Other	205	272	279	279	287
Overheads	4,608	5,848	6,003	6,003	6,171
Total	**$110,000**	**$136,000**	**$139,600**	**$139,600**	**$143,488**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M
**Please refer to the Corporate Contingency Guidelines

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Total Contingency: Total contingency expense according to the Corporate Contingency Guidelines

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Exhibit_(EIOP-9)

T&D Environmental

Schedule 1: T&D Environmental Capital Program and Project Summary

Electric T&D *Environmental*		**Year Total**			
		Current Budget			
		Total Dollars ($000)			
		RY1	**RY2**	**RY3**	**3 Yr. Total**
ENVIRONMENTAL					
Organization	**White Paper**				
Transmission	Environmental Enhancements	933	933	933	2,799
Transmission	Mobile Program for Transmission Feeder Leak Detection	300	300	300	900
Distribution	Oil Minders	1,700	1,700	1,700	5,100
Transmission	Pipe Enhancement Program	28,000	29,250	29,750	87,000
Substations	Substation EH&S Risk Mitigation Program	15,532	14,000	14,000	43,532
Transmission	Underground Transmission Structure Modernization	5,400	5,400	5,400	16,200
TOTAL ELECTRIC					
	Total Environmental	**51,865**	**51,583**	**52,083**	**155,531**

Schedule 2:

T&D Capital White Papers

Environmental

Central Operations/STO
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Environmental Enhancements	
Project/Program Manager: Various	**Project/Program Number (Level 1):** 22679434
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date:	**Estimated Date In Service:**
A. Total Funding Request ($000) **Capital: $4,665** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:
This program will cover the installation of cathodic protection rectifiers along select High Pressure, Fluid Filled Feeders to supplement existing pipe cathodic protection. The work may include the installation of conduit, power supply connections and the installation of anodes. This program will target approximately four feeder group installations per year. Previously this program also covered the upgrade of leak warning system components in the dielectric pressurization facilities in Substations. The funding and scope for that portion of the program was transferred to Substation Operations.

In addition, Con Edison plans to extend the application of this technology to the Transmission System. The technology will utilize a complement of both existing and new sensors selected and optimized for the transmission system. The Con Edison Structure Observation Systems (SOS) - Transmission – deployment will include visible and infrared imaging as well as sensors for oil detection. Deployment will include visible and infrared imaging as well as sensors for oil detection and cathodic voltage of the pipe.

<u>Structure Observation System</u>
The SOS transmission system monitors will send the environmental data they collect from transmission manholes over a secure cellular wireless network to facilitate leak detection, leak locating and inspection and monitoring and alarming of cathodic protection levels.

<u>Fluid Filled Underground Transmission Feeders</u>
Fluid filled underground transmission feeders utilize dielectric oil for cooling and insulation. When a fluid filled transmission feeders' pipe or joint becomes compromised, leaks may result. These leaks on medium and high-pressure fluid filled cables (MPFF) and (HPFF) pose a significant risk to system capacity, reliability and environmental integrity.

This program will support the procurement, installation and commissioning of approximately 50 monitors per year through 2025.

Justification:

Buried sections of pipe type cables are cathodically protected to prevent corrosion that can result in dielectric fluid leaks. Cathodic protection systems are comprised of a rectifier that applies direct current (DC) current to the pipe surface, a protective coating to minimize the required current and Isolator Surge Protectors (ISP) to provide DC isolation between the pipe and substation ground mats. If the coating deteriorates and its resistance decreases, the amount of current required for effective cathodic protection needs to increase often by the replacement of existing rectifiers or the installation of new ones. In accordance with Company Procedure G-6202, Procedure for Maintaining Cathodic Protection on Electric Underground Transmission Feeders, Corrosion Control performs an annual cathodic protection survey on each electric transmission pipe-type feeder to determine if system deterioration of the pipe coating has occurred. Gas Corrosion evaluates and makes recommendations if additional cathodic protection is required. Gas Corrosion has identified areas that either need rectifier additions or rectifier replacements. These rectifiers are a critical component in protecting feeder pipes from corrosion, thereby reducing the risk of dielectric fluid leaks.

Underground transmission feeders may run hundreds of feet between manholes with large sections of the feeder located under layers of soil, steel and or cement. A leak is typically first identified through the monitoring and analyzing of oil storage tank levels at each end of the feeder. Significantly, a leak may not result in any oil being visible from the surface. For example, a compromised pipe type leak, between manholes, would fill voids in the earth followed by the free space in the adjoining manholes.

Once a leak is suspected, there are two mechanisms for locating the potential leak. The first mechanism is the physical inspection of each structure for oil and the second the mobile scanning for Perfluorocarbon tracers (PFT) in the atmosphere. For physical inspection, the process is dependent on structure access, safe setup and entry, and the structure's environmental state. For PFT detection, a mechanic will drive a vehicle along the feeder route while another technician will analyze a chromatograph for changes in PFT level. While these mechanisms are effective, the execution of each is resource intensive.

In approximately half of the feeder leak events, the source of the leak is within a manhole. Moreover, the frequency of leaks among feeders is not uniform, each feeder has a different rate and risk of leaking.

Installing smart transmission manhole sensors applies this knowledge in an asset management-based plan. Feeders and their associated structures are selected and scheduled for monitoring installation based on leak performance.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):

This effort is part of Con Edison's LRP for Grid Modernization. The subject program embraces the LRP by helping to keep these feeders in service more effectively and efficiently through the latest technologies.

The ERM for Substance Release received a score of 288 and for Transmission Lines a score of 96. This programs directly contributes to the reduction in risk for substance release (oil) and, in severe cases, the risk of transmission line removal due to substantial loss in fluid.

2. Supplemental Information

Alternatives
There are no applicable alternatives.

Risk of No Action
The alternative to this program is not adding rectifiers to the cathodic protection systems of these select feeder locations and to allow for a reduced protection condition. Over time, this course of action will increase the risk of pipe corrosion and may result in dielectric fluid leaks to the environment. Dielectric fluid leaks not only have an adverse impact on the environment but they can affect feeder reliability.

Non-Financial Benefits
This program will reduce the likelihood of dielectric fluid leaks which can improve environmental performance and feeder availability.

Summary of Financial Benefits and Costs (attach backup)
The funding is based on a historical average of $150k per feeder group and four feeder groups planned per year.

Project Risks and Mitigation Plan

Technical Evaluation / Analysis

Project Relationships (if applicable)

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	328	217	180	630		223
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	933	933	933	933	933
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	85	85	85	85	85
M&S	408	408	408	408	408
Contract Services	150	150	150	150	150
Other	47	47	47	47	47
Overheads	243	243	243	243	243
Total	**933**	**933**	**933**	**933**	**933**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

Central Operations/STO
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Mobile Program for Transmission Feeder Leak Detection	
Project/Program Manager: Stanley Lewis	**Project/Program Number (Level 1):** 24807228
Status: ☒ **Planning** ☐ **Design** ☒ **Engineering** ☐ **Construction** ☐ **Ongoing** ☐ **Other: ____________**	
Estimated Start Date: 2020	**Estimated Date In Service: 2021-2025**
A. Total Funding Request ($000) **Capital: 1,500** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($1,057)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M: $1,057** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period:** **(Years/months)**

Work Description:

The Mobile Program for Transmission Feeder Leak Detection supports the procurement of highly specialized vehicles for the detection and location of dielectric fluid leaks.

Fluid filled underground transmission feeders utilize dielectric oil for cooling and insulation. When a fluid filled transmission feeders' pipe or joint becomes compromised, leaks may result. These leaks on medium and high-pressure fluid filled cables (MPFF) and (HPFF) pose a significant risk to system capacity, reliability, and environmental integrity.

Underground transmission feeders may run hundreds of feet between manholes with large sections of the feeder located under layers of soil, steel and/or cement. A leak is typically first identified through the monitoring and analyzing of oil storage tank levels at each end of the feeder. Significantly, a leak may not result in any oil being visible from the surface. For example, a compromised pipe type leak, between manholes, would fill voids in the earth followed by the free space in the adjoining manholes.

To facilitate the expeditious location of leaks a unique chemical tracer is added to the feeder dielectric fluid. The chemical is known as Perfluorocarbon Tracer (PFT). PFT is highly evaporative such that it will naturally tend towards the surface and atmosphere. In contrast, dielectric oil would only reach the surface if there were a subsurface pressure in excess of gravity. In addition to being highly evaporative, PFT, as a tracer, is very unique. This quality, of being unique in the atmosphere, means that when the PFT reaches the surface - at levels in the parts per quadrillion (PPQ) - it can be reliably detected by very sensitive instrumentation.

The instrumentation used to detect PFT is a combination of a concentrator and gas chromatograph (GC). The concentrator periodically samples the atmosphere and through a process of highly selective filtration, concentrates, if at all present, the samples PFT component. The processed sample is then passed to a GC which both identifies and quantifies the amount of PFT present. The equipment operator will then analyze the GC data for ambient and transient levels of PFT. When the operator sees a transient(s) several multiples the magnitude of the ambient, they have reason to believe a leak is in the vicinity of where the sample(s) were taken.

As the length of a transmission feeder may run over ten miles, the instrumentation to detect leaks must be made mobile. In order to make the instrumentation mobile, a commercial truck must be customized to securely and safely house not only the instruments; but also the many ancillary components and equipment. A few examples of such vehicle customization and ancillary components include firewalls for gas storage, routing of sampling lines from the instrument to the outside, and a generator and or inverter to supply power to the instruments.

After a vehicle and the associated instrumentation are procured and assembled, there is a period of commissioning. The commissioning is essential to transform the vehicle and instrumentation into a reliable and repeatable system for any immediate call to service. The commissioning can be viewed as a hybrid of performance measures and calibration both in vitro and in situ. In the case of in situ, the performance and calibration are schedule dependent with leak activity.

The Mobile Program for Transmission Leak Detection will support the scheduled development, replacement, and commissioning of such vehicles. The program shall also advance the art to the extent new efficiencies can be found and effectiveness increased. From 2021 through 2024 one new leak detection vehicle will be created per year with a five-year life expectancy.

Justification Summary:
The timely detection of transmission feeder leaks is not optional. A leak can result in a feeder being removed from service - off on emergency - or in a worst-case scenario automatically being removed from service following a fault. The removal of any transmission feeder from service may reduce system capacity and operational contingency. A leak also means that dielectric fluid is being lost to the environment, the longer a leak takes to find and correct the greater the scope of loss and cleanup.

This program recognizes the criticality of leak detection and ensures that the equipment is operational when called on, capable to address multiple concurrent leaks, and of the latest design basis to advance detection and correction. Moreover, while an instrument in a lab may have a service life of 10+ years, an instrument mounted to a vehicle navigating the streets of NYC that is subject to constant shock and vibration will be a fraction of that.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
This program is related to the departmental goal of a transmission event. Leak detection is imperative for reducing the duration and severity of an environmental event, and ensures the feeder is in service as intended.

2. Supplemental Information

Alternatives
In the alternative, transmission feeder leaks can be managed by looking for the visible presence of oil at the surface and within manholes. Essentially, as time passes, sufficient oil will have been released to force some amount to the surface and or an adjoining manhole where it can be observed.

Risk of No Action A leak on the transmission system that is not timely located can result in the feeder being removed from service and greater loss of fluid to the environment. This would be a risk to system reliability, capacity, and environmental integrity.
Non-Financial Benefits The integrity of our environment matters to Con Edison. Anything we can do to minimize the loss of dielectric fluid is a positive step towards being better caretakers.
Summary of Financial Benefits and Costs (attach backup) - Leak detection is not a discretionary task - Reduced vehicle maintenance estimated at $20k year savings - Reduced vehicle resources estimated at $50k year savings - Resource dedicated to commissioning of system at $165k
Project Risks and Mitigation Plan None
Technical Evaluation / Analysis Transmission leak detection and location by PFT has been used successfully for over ten years. The tracer, as discussed earlier, is a very unique compound allowing the gas chromatograph to readily fingerprint and identify the presence and magnitude of PFT. The majority of the instrumentation and ancillary components are commercial off the shelf.
Project Relationships (if applicable) Transmission leak detection findings contribute to the optimized selection of pipes and or joints for replacement including under the following capital programs - Pipe Enhancement Program - Transmission Feeder Failures - Partial Replacement of Feeders M51 and M52 In terms of the LRP, while electric volume is modestly trending down, the feeders supplying NYC will remain essential to satisfying demand and to do so reliably. Moreover, the LRP also looks at Operational Excellence by advancing new technologies. The subject program embraces the LRP by helping to keep these feeders in service more effectively and efficiently through the latest technologies.

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	**n/a**	**n/a**	**n/a**	**n/a**		**300**
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**300**	**300**	**300**	**300**	**300**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2021	2022	2023	2024	2025
Labor	22	22	22	22	22
M&S	190	190	190	190	190
Contract Services	-	-	-	-	-
Other	7	8	8	8	8
Overheads	81	80	80	80	80
Total	**300**	**300**	**300**	**300**	**300**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings	**117**	**235**	**235**	**235**	**235**
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

Electric Operations / DE
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Oil Minders	
Project/Program Manager: Jane Shin (John Roumeliotis)	**Project/Program Number (Level 1): 10031931, 10032005, 10032088, 10032130, 10032210**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date: Ongoing	**Estimated Date In Service:** Ongoing
A. Total Funding Request ($000) **Capital:** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:
This program provides funding for the installation of oil minders in underground network transformer vaults. The Oil Minder program was developed to prevent the pumped discharge of dielectric fluid from network transformers into the sewer system. An oil minder senses oil in water and disables the associated sump pump operation to prevent the discharge of oil. The oil minder control system registers an alarm in the local control room through the Remote Monitoring System (RMS) whenever the oil minder operates. This remote warning signal facilitates early detection and cleanup of leaking dielectric fluid. The oil minder also sends an alarm signal to control room for non-operation of sump pump.

The Company forecasts a rate of 75-100 new oil minder installations per year. At time of oil minder installation, any defective sump pumps will be replaced as well.

Justification Summary:
This program complies with a 1997 a commitment made by the Company to the New York State Department of Environmental Conservation (DEC) to address dielectric fluid leakage from underground transformers. The oil minder program has been effective at intercepting oil before it enters the sewer system.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)
Oil minders are a control to prevent accidental spills of transformer oil into the environment. They are one part of our comprehensive program to prevent damage to the environment and comply with all environmental regulations.

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection
An alternative would be to operate vaults without pumps and allow water to collect. Such a design would require the use of submersible equipment in all transformer vaults and would be significantly more costly than using ventilated equipment with a sump pump.

Alternative 2 description and reason for rejection
Install oil-less equipment in vaults. Dry type transformers would be bigger in footprint compared to oil filled transformers. For the vaults in scope of this project, this solution would require vault modification and be expensive. Therefore, this solution is not recommended at this time.

Risk of No Action

Risk 1
Without the presence of oil minders, there is a substantial risk of releasing oil into the sewer system.

Risk 2

Risk 3

Non-Financial Benefits
Oil released in a transformer vault is an indicator of transformer failure. The oil minder and alarm provide early indication of transformer failure and allow operators to investigate the problem prior to failure. This ability to intervene has implications to system reliability, quality of service, public safety and environmental impact.

Summary of Financial Benefits and Costs (attach backup)
Reducing the water levels in our vaults reduces rust and corrosion of the transformers and network protector switches and increases service life.

1. Cost-benefit analysis (if required)

2. Major financial benefits
.
3. Total cost

4. Basis for estimate

Historical unit costs

5. Conclusion

Project Risks and Mitigation Plan

Risk 1
Currently is only one approved vendor for this product.

Mitigation plan

Any changes to vendor lead time or supply chain constraints will be monitored by The Company

Technical Evaluation / Analysis
The oil minder has undergone several durability changes to improve their capability to withstand the conditions of underground transformer vaults. A power sensor device was added to send an RMS signal to notify operators of a power failure to the oil minder and sump pump. The power sensing feature helps prevent damage to the equipment. The oil minder is being upgraded to have continuous pump performance data for monitoring and troubleshooting purpose.

Project Relationships (if applicable)
None

3. Funding Detail

Historical Spend

EOE	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Labor	1345	930	798	789		
M&S	1636	3045	3128	3,011		
A/P	405	8	254	8		
Other	(2,110)	(3,579)	(4,584)	(3,575)		
Overheads	1451	1411	1,374	1,255		
Total	**2,727**	**1,815**	**970**	**1,488**		**1,288**

Total Request ($000):

Total Request by Year:

EOE	Budget 2022	Request 2023	Request 2024	Request 2025	Request 2026
Labor	1,001	1,001	1,001	1,001	1,001
M&S	3,654	3,654	3,654	3,654	3,654
A/P	108	108	108	108	108
Other	(4,670)	(4,670)	(4,670)	(4,670)	(4,670)
Overheads	1,607	1,607	1,607	1,607	1,607
Total	**1,700**	**1,700**	**1,700**	**1,700**	**1,700**

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	1,001	1,001	1,001	1,001	1,001
M&S	3,654	3,654	3,654	3,654	3,654
Contract Services	108	108	108	108	108
Other	(4,670)	(4,670)	(4,670)	(4,670)	(4,670)
Overheads	1,607	1,607	1,607	1,607	1,607
Subtotal	**1,700**	**1,700**	**1,700**	**1,700**	**1,700**
Contingency**					
Total	**1,700**	**1,700**	**1,700**	**1,700**	**1,700**

Total Gross Cost Savings / Avoidance by Year:

	2021	2022	2023	2024	2025
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2021	2022	2023	2024	2025
O&M					
Capital					

Central Operations/STO
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Pipe Enhancement Program	
Project/Program Manager: Mark Bauer	**Project/Program Number (Level 1):** 22679502
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date:	**Estimated Date In Service:**
A. Total Funding Request ($000) **Capital: 143,312** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:
The Pipe Enhancement Program is a proactive program to reduce dielectric fluid leaks and increase the availability of transmission facilities. This program focuses on addressing areas of corrosion on the pipe-type transmission feeder system and involves the large-scale installation of welded barrels to encase heavily corroded areas and the installation of new coating, along with the associated required excavation, coating removal, inspection, and backfill/restoration tasks As described below, for suspect areas of feeder pipe, this program will provide increased reliability, extend the life of existing pipe-type feeder facilities, and prevent or reduce the likelihood of the release of dielectric fluid from the pipe-type feeder system to the environment.

Suspect areas of feeder pipe are identified based on leak history data, field observations of pipe/coating conditions during maintenance work, repair rate of adjacent sections and the section's proximity to waterways.

Large areas of disbonded coating (where the existing coal tar coating is not necessarily missing but may be cracked and poorly adhered to the exterior surface of the pipe) have been identified as a significant issue for certain critical pipe-type feeders. Large areas of disbonded coating allows moisture to migrate onto the pipe surface beneath the coating. In addition, large areas of disbonded coating shields the flow of cathodic protection current, preventing it from reaching the surface of the pipe. As a result, severe corrosion can occur beneath the coating, causing significant pipe wall loss and dielectric fluid leaks.

<u>Current Status</u>: The Pipe Enhancement Program is an on-going annual program. Work packages appropriated under this program to date have focused on suspect areas of Feeders M51, M52 since they contribute the highest percentage of dielectric fluid lost to the environment of any feeders on the Con Edison Transmission System. The Company will focus a large majority of this program's funding in 2022-2023 on addressing the portion of M51 and M52 that have shown leaks in recent years. Unless

funding for replacement of these feeders is approved, the bulk of this program (approximately 78%) will be utilized for addressing pipe enhancement on these feeders methodically. In order to allow for work on other feeders, additional footage will ramp up between 2022 and 2024.

Based on the continued findings of the completed, ongoing, and planned Pipe Enhancement Program work packages, the Close Interval Survey results, and visual inspection of the pipe coating through Keyhole Excavations, additional locations to perform Pipe Enhancement Program will be prioritized.

Justification Summary:
This Pipe Enhancement Program will result in a reduction of the number of leaks. By addressing corrosion issues before the pipe leaks occur, Con Edison will be able to reduce the amount of dielectric fluid that is lost to the environment and the associated costs for leak emergency response and remediation. The program also reduces the probability that the feeder will need to be removed from service or fail due to an oil leak caused by corrosion on the pipe.
Dielectric fluid leaks can result in feeders being removed from service if the leak rate exceeds the flow rate capability of the pressurization pumps. If a leaking feeder was left in service and operating pressure could not be maintained, failure of the cable system can result, requiring an extended outage to complete repairs. In addition, even if pressure can be maintained, a feeder with a large leak may be forced out of service in order to clamp and repair the leak if the release of fluid cannot be adequately controlled during the repair process. These issues can have detrimental effects on overall system reliability, especially during high load periods.

If large areas of disbonded coating or significant corrosion results in significant wall loss over large portions of a feeder, a pattern of repeated, large volume leaks can be anticipated. At some point, these leaks will greatly diminish feeder reliability and effectively limit the feeder's useful life. To proactively prevent this condition, the Pipe Enhancement Program addresses large-scale coating problems to eliminate future corrosion, as well as restores pipe wall thickness in already deteriorated areas. This is accomplished by encapsulating large areas of wall loss with a new layer of pipe welded over the original pipe, over its full circumference (if needed), and coating that surface with a new protective coating system. More recently, a new technology has been tested and applied called Carbon Fiber Wrap (CFW,) which is a refurbishment method where several layers of a carbon fiber fabric saturated with epoxy are overlapped on the existing deteriorated pipe to form a composite shell. In effect, the corroded pipe is "replaced" without removing the old pipe, which of course could not be done without affecting the energized feeder cables inside. The composite wrapping becomes the new pressure boundary layer in place of the original steel pipe. While this method is significantly more costly than the conventional method of refurbishment using individual welded steel reinforcement patches or sleeves, this method is now being utilized where longer continuous lengths of pipe are severely deteriorated and where the conventional refurbishment method is not logistically favorable. The CFW method is expected to greatly extend the lifecycle for some of the feeder pipe areas that were the most difficult to address using the conventional method.

Mitigation of the release of dielectric fluid to the environment is a critical component of the Company's efforts to achieve environmental excellence. The Company sets an annual goal to minimize the volume of dielectric fluid released to the environment from the pipe-type feeder system and tracks the actual volume against this goal each month. The Pipe Enhancement Program will help to establish a trend of significantly reducing the dielectric fluid volume loss to the environment as the most suspect large sections of pipe on the Transmission System are proactively addressed.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
This project reduces the likelihood of release of Dielectric Fluid Loss which is a Corporate Risk. With Off Shore Wind integration, M51 and M52 will become even more critical in moving power around the state. These circuits are critical to the clean energy future so ensuring these feeders are available and not undergoing constant leak repair is imperative.

2. Supplemental Information

Alternatives

- One option would be to not do any pipe enhancement on these specific suspect areas that have been identified and just address leaks as they occur. Last year alone, ConEdison spent over $10M in leak repairs. Not addressing these areas could mean these sections and adjacent sections continue to deteriorate.
- Another option would be feeder replacement. Though this can be extensive and costly. One instance where it may be beneficial is for large feeders where there have been repeated leaks. One example of this would be replacement of M51 and M52. Currently there is a project proposed to replace these two feeders due to extensive and repeated leak history. Replacement of these feeders would free up funding for pipe enhancement work on other feeders that would benefit from proactive remediation. While this is an option that is being pursued, pipe enhancement on these feeders is necessary in the interim to curtail the leaks that are occurring.
- Although the Research and Development (R&D) Department has conducted benchmarking of other companies, and Con Edison continues to participate in EPRI and NACE studies, to date the Company has found no other proactive alternatives available to address the large-scale corrosion issues on transmission feeder pipes described above. R&D continues to pursue initiatives related to pinpointing specific areas of large-scale disbonded coating, but at this time no viable alternative exists to effectively address corrosion due to large-scale disbonded coating other than large-scale refurbishment of the pipe through the Pipe Enhancement Program.

Risk of No Action
Not addressing sections of deteriorated pipe will, over time, result in increased loss of dielectric fluid to the environment due to feeder pipe leaks and increased spending in the area of feeder emergencies. In addition, if the loss of dielectric fluid is severe enough, feeders may have to be removed from service while leaks are located and repaired.

Non-Financial Benefits
As described above, protection of the environment, increased reliability, and extension of the life of the pipe-type feeder system in connection with these suspect areas of feeder pipe are all significant non-financial benefits. In addition, building better key external stakeholder relationships with organizations such as the DEP, DEC, and PSC is another major non-financial benefit.

Summary of Financial Benefits and Costs (attach backup)
The basis for the funding levels is based on $6,500 per trench foot average unit cost.

Project Risks and Mitigation Plan

Technical Evaluation / Analysis
As discussed above, among other things, large areas of disbonded coating (where the existing coal tar coating is not necessarily missing but may be cracked and poorly adhered to the exterior surface of the pipe) have been identified as a significant issue for certain critical pipe-type feeders. Large areas of disbonded coating allow moisture to migrate onto the pipe surface beneath the coating. In addition, large areas of disbonded coating shields the flow of cathodic protection current, preventing it from reaching the surface of the pipe. As a result, severe corrosion can occur beneath the coating, causing significant pipe wall loss and dielectric fluid leaks. Further, studies have shown that paper-insulated pipe-type transmission cable has an exceptionally long life if proper pressurization is consistently maintained. Pressure excursions due to repeated, significant leaks may also impact cable life. The duration a cable is in service at pressures below the minimum specified operating pressure will adversely affect the useful life of the cable once the voltage stresses exceed the capability of the insulating system to withstand them. As pressure on a pipe-type feeder system decreases, the insulating capability of the system decreases and ionization (and eventual electrical breakdown) of the paper insulation can result. Even if a specific leak incident does not result in immediate failure of the cable, the long-term effective life of the cable may be reduced.
Project Relationships (if applicable)

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	**38,196**	**41,445**	**39,961**	**27,626**	**N/A**	**29,994**
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**26,162**	**28,000**	**29,250**	**29,750**	**30,150**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	2,900	3,950	3,950	3,950	3,950
M&S	480	440	480	480	480
Contract Services	12,700	16,450	16,450	16,500	16,500
Other	3,839	224	1,189	1,546	1,916
Overheads	6,243	6,936	7,181	7,274	7,304
Total	**26,162**	**28,000**	**29,250**	**29,750**	**30,150**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations / Substations
2022

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☒ **Regulatory Mandated** ☐ **Operationally Required** ☐ **Strategic**	
Project/Program Title: Substation EH&S Risk Mitigation Program.	
Project/Program Manager: John McCoy	**Project/Program Number (Level 1): 2ES8900 / 10030253**
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date:	**Estimated Date in Service:**
A. Total Funding Request ($000) **Capital: $67,933** **O&M:** **Retirement: $19,336**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description:
The Substation EH&S Risk Mitigation Program (the "Program") consists of operational enhancements and structural improvements to currently approximately 50 Company substations, such as modifications to secondary containment structures around oil-filled equipment, installation of unit containment and oil/water separator (OWS) systems, and site drainage upgrades.

These projects are required to help manage and mitigate the risks of potentially significant oil releases to the environment from certain substation equipment, and address applicable regulatory requirements, through the installation of measures that reduce the likelihood of releases from occurring or reaching the environment. Most of the work is completed or planned in conjunction with the required 5-year review of the applicable secondary Spill Prevention, Control and Countermeasure (SPCC) plans. As part of this program, the Company will also be transitioning from site containment to unit containment for oil-containing large power transformers, phase angle regulators and reactors. Thereafter, the Company will evaluate other oil-containing equipment in its substations in a further effort to reduce the risk of oil leaving a substation and getting into the environment and waterways.

Justification Summary:
The Program is needed to establish unit containment of oil-containing large power transformers, phase angle regulators and reactors in Company substations and to undertake other substation modifications that will help mitigate risks to water bodies and natural resources from the inadvertent release of oil due to equipment failure, accidents or other operational disruptions. Effective risk management is critical to ensuring good environmental stewardship and the health and safety of the public and our employees. Equipment in substations is evaluated for potential environmental impacts, particularly an uncontrolled oil release to the environment and waterways, during normal and abnormal conditions. As part of this Program, installation of and modifications to substations' containment and drainage

systems to manage the water discharges and runoff as well as potential oil releases are being implemented as needed to mitigate the risks identified during these evaluations.

The Program fulfills the requirements of federal SPCC regulations (40 CFR 112). These regulations provide minimum standards for providing secondary containment for oil-filled equipment and bulk storage tanks. Where secondary containment is employed, 40 CFR 112.7(c) states that "[t]he entire containment system, including walls and floor, must be capable of containing oil and must be constructed so that any discharge from a primary containment system, such as a tank, will not escape the containment system before cleanup occurs."

EPA recognizes both site containment and unit containment as acceptable methods of secondary containment. The bulk of the EH&S Risk Mitigation enhancements involve, where practicable, the addition of moats to major oil-filled equipment at substations. In the aftermath of the May 2017 Farragut Substation transformer failure and oil spill to the East River, Con Edison concluded that unit containment would be more effective to meet the requirements of 40 CFR 112.7(c) because fill material underlying the Company's substations could not be determined to have the requisite impermeability to contain all oil from major oil-filled equipment.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
This Program addresses the SSO departmental risk of potential noncompliance with regulatory requirements and oil releases to the environment and waterways that could result in substantial expenditures for environmental cleanups, civil penalties and natural resource damages.

The release of oil into the environment and waterways is prohibited by Section 173 of the Navigation Law unless the discharge is in compliance with a federal or state permit. Section 17-0501.1 of the Environmental Conservation Law (ECL) states: "It shall be unlawful for any person, directly or indirectly, to throw, drain, run or otherwise discharge into such waters organic or inorganic matter that shall cause or contribute to a condition in contravention of the standards adopted by the department pursuant to section 17-0301." The ground and surface water standard for oil set forth in 6 NYCRR § 703.2 is no "visible oil film nor globules of grease." Federal regulations contain a similar standard for oil discharges. See 40 CFR 110.3(b) ("[c]ause a film or sheen upon or discoloration of the surface of the water…").

2. Supplemental Information

Alternatives
The installation of unit containment and other associated enhancements is nearing completion and is expected to continue in 2023. The balance of the work under this Program will be the result of independent third-party reviews of the Company's SPCC plans at various Company substations. These reviews evaluate if there are spill risks that may not be adequately addressed and could impact the environment and waterways at each individual substation. Each issue raised as part of the reviews is then addressed. Cost-effective alternatives for each issue are evaluated during the design and engineering of each of the specific projects. Solutions such as berms, moats, oil water separators, etc. are all evaluated for effectiveness, and then the most cost-effective options are chosen for each specific project associated with each substation.

Risk of No Action

Absent funding for these projects, the Company will lack the resources to manage and reduce the risks associated with potential impacts to the environment, waterways and the health and safety of the public and employees. In addition, many of these projects are needed to maintain compliance with federal SPCC regulatory requirements.

Non-Financial Benefits

- These projects help reduce the risk of oil leaving substation property or reaching the environment and waterways, reducing potential impacts to the environment and natural resources/waterways.
- Promotes regulatory compliance.
- Fosters stronger relationships with communities and regulators by mitigating potential environmental risks.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)
N/A

2. Major financial benefits
This program addresses regulatory requirements and helps mitigate the risk of substantial expenditures for environmental cleanups, civil penalties and natural resource damages due to inadvertent releases of oil into the environment and waterways.
3. Total cost **$67,933**

4. Basis for estimate
Near term work is based on Engineering estimates. Outer term work is based on the cost of similar types of work done in the past. As this is an ongoing program, work scopes are generally similar in nature. Future funding requests assume all known regulatory required work will be completed by 2026.

Project Risks and Mitigation Plan
Risk 1: Delays due to resources support coordination.

Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction and outages to avoid performance delays alignment conflicts.

Risk 2: Lack of alignment between resources support and outages.

Mitigation: Anticipate, schedule and pre-plan with resource requirements such as engineering, labor, and construction to avoid alignment conflicts with outages.

Technical Evaluation / Analysis
N/A

Project Relationships (if applicable)
N/A

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	4,206	21,344	35,710	69,751		82,806
O&M						
Retirement	365	4,471	5,168	16,029		27,757

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	11,401	15,532	14,000	14,000	13,000
O&M*					
Retirement	6,000	3,334	3,334	3,334	3,334

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	1,701	2,336	2,108	2,109	1,975
M&S					
Contract Services	6,841	9,319	8,400	8,400	7,800
Other					
Overheads	2,860	3,877	3,492	3,491	3,225
Subtotal					
Total	**$11,401**	**$15,532**	**$14,000**	**$14,000**	**$13,000**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

Central Operations/STO
2022-2026

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M**
Work Plan Category: ☐ **Regulatory Mandated** ☐ **Operationally Required** ☒ **Strategic**	
Project/Program Title: Underground Transmission Structure Modernization	
Project/Program Manager: Vernon Schaefer	**Project/Program Number (Level 1):** 22661748
Status: ☐ **Planning** ☐ **Design** ☐ **Engineering** ☐ **Construction** ☒ **Ongoing** ☐ **Other:** ___________	
Estimated Start Date:	**Estimated Date In Service:**
A. Total Funding Request ($000) **Capital: 21,200** **O&M:** **Retirement:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months)**

Work Description

The Modernization Program for Con Edison's Electric Transmission Feeder Structures is a proactive program that started in 2018 to mitigate concerns regarding transmission structures (manholes) that have been identified as requiring major/non-routine upgrades. These structures contain Transmission Feeder splices along with auxiliary piping and valves. Structural deficiencies (especially at the end walls where the feeder pipes enter the manhole) as well as water entry due to structural issues, jeopardize the integrity of the feeder pipes and lead to dielectric fluid leaks each year. The upgrade entails rebuild of the end walls of the structures, involving rebar, concrete, and masonry components, as well as installation of new feeder pipe penetration sleeves and improved penetration seals, along with the associated required excavation, waterproofing, inspection, application of permanent corrosion repairs to the feeder pipes, new pipe coating, structure cover, and chimney upgrade (that will reduce water impingement on the feeder pipes) and backfill/restoration tasks. Other deficiencies with the structure will be addressed with a new spray on epoxy coating that will seal the inside of the entire structure after the end wall repair. This will provide a waterproof seal from the floor of the manhole to the manhole casting, preventing ground water from infiltrating and causing corrosion of the feeder pipes. In addition, the waterproofing of the floor of the manhole will prevent dielectric fluid from entering the environment (eliminating reportable spills to the New York State DEC). Furthermore, new oil minder devices will be installed to alert Transmission Operations of any water or oil that enters the structure. The program will provide increased reliability and extend the useful life of the existing structures and the feeders by making the assets within the structures more efficient and provide for greater long-term durability.

Justification Summary:

Attention to the deficiencies identified during the Con Edison inspection program will address defects in the structure end wall(s) as well as any deficiencies found on the existing feeder pipes that penetrate the structure end wall.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
This program is related to reducing the likelihood of the departmental goal of reducing oil leaks, which will ensure the feeders are more robust and available as needed.

2. Supplemental Information

Alternatives
No other alternatives have been identified.

Risk of No Action
Not addressing locations with structural or feeder pipe deficiencies will over time cause dielectric fluid leaks from the compromised feeder pipes, possibly leading to environmental impact, and increased spending due to emergency leak response to the leak and system reliability issues caused by forced feeder outages

Non-Financial Benefits
Increase reliability of the Underground Transmission System, extension of the useful life of both the feeder and structure. Eliminate risk of possible environmental contamination from a feeder leak.

Summary of Financial Benefits and Costs (attach backup)
The cost for 2018 going forward is based on the cost of reconstructing an end wall on a planned basis opposed to an emergency basis (after a leak has occurred): Excavation of one end wall, inspection and repair of the steel feeder pipe and reconstruction of the end wall is approximately $900K per manhole. Average Dielectric fluid leak search and remediation is approximately $300,000 direct cost. The basis for the budget is based on completing six manholes per year starting in 2023.

Project Risks and Mitigation Plan

Technical Evaluation / Analysis

Project Relationships (if applicable)
Structural work must be coordinated between Transmission Operations Construction Department, Substation Operations and System Operations

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital	N/A	0	0	1,936		2,126
O&M						
Retirement						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**2,000**	**5,400**	**5,400**	**5,400**	**3,000**
O&M*					
Retirement					

Capital Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	520	520	520	520	700
M&S	76	1,038	1,038	1,200	400
Contract Services	760	2,460	2,460	2,160	1,000
Other	53	61	62	173	22
Overheads	591	1,321	1,320	1,347	878
Total	**2,000**	**5,400**	**5,400**	**5,400**	**3,000**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

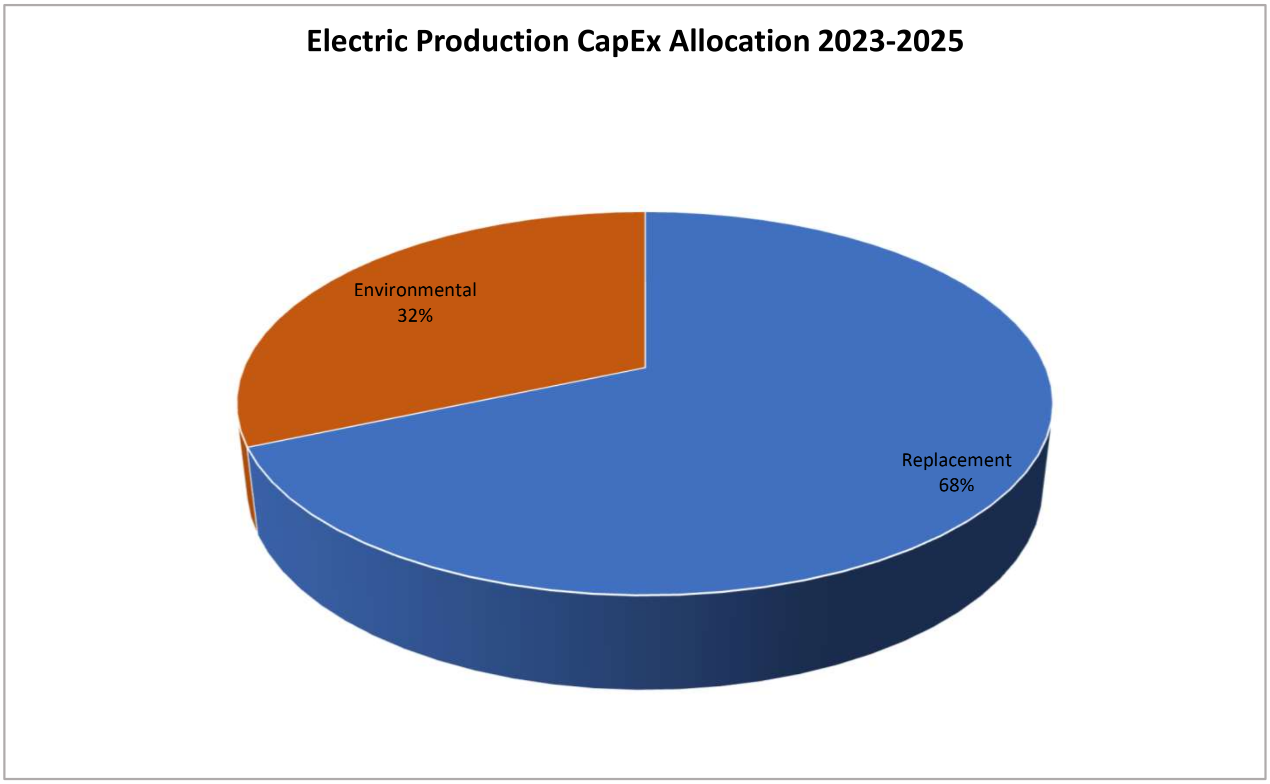
Exhibit_(EIOP-10)

Electric Production

Schedule 1: EP Capital Program and Project Summary

Electric Production		**Year Total**			
		Current Budget			
		Total Dollars ($000)			
		RY1	**RY2**	**RY3**	**3 Yr. Total**
REPLACEMENT					
Organization	**White Paper**				
Electric Production	East River Balance of Plant Equipment Projects	400	1,000	2,500	3,900
Electric Production	East River Civil & Structural Projects	2,055	-	2,000	4,055
Electric Production	East River Instrumentation & Control Replacement Projects	1,850	-	-	1,850
Electric Production	East River Major Equipment Replacement Projects	350	16,000	6,000	22,350
Electric Production	East River Power Distribution Replacement Projects	4,750	1,000	9,000	14,750
	Replacement Sub-Total	**9,405**	**18,000**	**19,500**	**46,905**
ENVIRONMENTAL					
Organization	**White Paper**				
Electric Production	59th Street Environmental	500	-	-	500
Electric Production	74th Street Environmental	500	500	100	1,100
Electric Production	East River Environmental	16,000	4,000	-	20,000
	Environmental Sub-Total	**17,000**	**4,500**	**100**	**21,599**
TOTAL ELECTRIC PRODUCTION					
	Replacement	**9,405**	**18,000**	**19,500**	**46,905**
	Environmental	**17,000**	**4,500**	**100**	**21,599**
	Total Electric Production	**26,405**	**22,500**	**19,600**	**68,505**

Schedule 2: EP Capital Allocation Categories



Schedule 3: T&D Risk Reduction O&M Program Change Summary

Infrastructure Investment Panel
O&M Program Changes
($000)

		RY1 Program Change	RY2 Program Change	RY3 Program Change
Organization	**Program Change**			
	East River Units 6/7 Major Overhauls	3,873	-	-
TOTAL ELECTRIC				
	Grant Total	**3,873**	**-**	**-**

Schedule 4:

EP Capital White Papers

Replacement

Central Operations / Steam Operations
2022

1. Project / Program Summary

Type: ☐ Project ☒ Program	**Category: ☒ Capital ☐ O&M ☐ Regulatory Asset**
Work Plan Category: ☐ Regulatory Mandated ☒ Operationally Required ☐ Strategic	
Project/Program Title: East River Balance of Plant Replacement Projects - EP	
Project/Program Manager: O'Hagan	**Project/Program Number (Level 1): 24610724**
Status: ☐ Initiation ☐ Planning ☐ Execution ☒ On-going ☐ ☐ Other: ___________	
Estimated Start Date:	**Estimated Date In Service:**
A. Total Funding Request ($000) **Capital: 6,300** **O&M:**	**B.** **☐ 5-Year Gross Cost Savings ($000)** **☐ 5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months) (If applicable)**

Work Description:
This program consists of projects that will replace balance of plant equipment that has failed, is performing poorly or is at or near obsolescence. Balance of plant equipment consists of all auxiliary mechanical equipment required to produce steam or electricity other than major equipment. This includes water treatment systems, cooling water systems, tanks, etc. The projects that are funded by this program are located at the East River Generating Station.

Justification Summary:

This program selects and prioritizes projects that proactively improve the reliability and/or safety of electricity production at East River Units 60, 70 and East River Station. The mitigation of risks associated with the operation of equipment that is directly used to produce steam improves overall system reliability. Descriptions of sample projects and associated justifications are listed below:

27235-16 ER Unit 6 Bowser Replacement

This project will replace existing components of the Unit 6 Lube Oil system with modern units. This includes controls and other appurtenances of the Bowser-type filtration components. The Lube Oil System supplies lubrication to the bearings on the high-pressure and low-pressure turbines and their associated generators and is used in the turbine unit protection system. To maintain lube oil cleanliness, a Bowser brand filtration unit helps recondition the lube oil used in the system. The existing unit 6 Bowser oil conditioning system is obsolete and is reaching the end of its useful life. Replacing this component will help ensure the availability and reliability of the oil system.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):

- This program directly reduces department risks associated with ensuring adequate production
- Select projects within this program marginally improve unit efficiencies

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection
Each project in program is operationally required, failure to complete projects may result in failure of a component that could result in plant shut down. The sole alternative to these selective projects for the existing units is to retire them and repower.

Risk of No Action

Risk 1
If no action is taken, there is risk of unnecessary maintenance due to poor equipment performance and will decrease the dependability and/or availability of a facility or an operation. This could lead to loss of production and subsequent failure to meet customer demand.

Non-Financial Benefits

Improved reliability

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis (if required)
N/A

2. Major financial benefits
This project has a minor contribution to improving the efficiency of the units, thus lowering fuel consumption and subsequent emissions.

3. Total cost
$6.3 million

4. Basis for estimate
The program's funding request is based on the engineering estimates for the constituent projects currently in progress.

5. Conclusion

Project Risks and Mitigation Plan

Technical Evaluation / Analysis

Project Relationships (if applicable)

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital						**75**
O&M						
Regulatory Asset						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**400**	**400**	**1,000**	**2,500**	**2,000**
O&M*					
Regulatory Asset					

Capital/Regulatory Asset Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	185	190	50	150	75
M&S	50	50		150	179
Contract Services	19	13	436	1,600	1,330
Other				58	
Overheads	146	146	214	543	416
Total	**400**	**400**	**1,000**	**2,500**	**2,000**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Project Status:

- Initiation – New project, not authorized yet
- Planning – Project authorized, not started yet
- Executing – Project in-flight
- On-going – Annual program

Central Operations / Steam Operations
2022

1. Project / Program Summary

Type: ☐ Project ☒ Program	**Category: ☒ Capital ☐ O&M ☐ Regulatory Asset**
Work Plan Category: ☐ Regulatory Mandated ☒ Operationally Required ☐ Strategic	
Project/Program Title: East River Civil & Structural Projects - EP	
Project/Program Manager: O'Hagan	**Project/Program Number (Level 1): 24611128**
Status: ☐ Initiation ☐ Planning ☐ Execution ☒ On-going ☐ ☐ Other: ___________	
Estimated Start Date: N/A	**Estimated Date In Service: N/A**
A. Total Funding Request ($000) **Capital: 7,830** **O&M:**	**B.** **☐ 5-Year Gross Cost Savings ($000)** **☐ 5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months) (If applicable)**

Work Description:
This program consists of major repairs and improvements to electric production facilities. Projects in this program upgrade, replace, or install new civil and structural equipment to improve plant operations and safety.

Justification Summary:

Descriptions of sample projects and associated justifications are listed below:

30293-20 ER 2020 Boiler House Roofing Replacement

This project will replace the existing roofing membrane and repoint parapet walls of the East River Boiler House roof. Additionally, large areas where concrete has been damaged due to the failed roof will be repaired. The roof has leaks and is at the end of its service life. Persistent leaks have begun to cause deterioration of the concrete deck beneath. A replacement is warranted to restore the roofing and to protect the structural components beneath.

24159-10 Access Platforms - EP

This project will install permanent steel access platforms and/or stairs and ladders at 14 individual locations within the Station. This project will improve operator access to equipment and to remove temporary structures constructed of combustible materials from the East River Generating Station.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):

These projects are CORE investment to ensure safety and reliability. They reduce fire hazards, falling hazards, and leaks within the station.

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection
Continue to operate with the existing equipment, exposing risk to employee safety, environmental releases, and property damage. The roof replacement project is operationally required, failure to complete projects may result in cessation of production.

Risk of No Action

Risk 1
If no action is taken, there is risk of continued unnecessary maintenance due to poor equipment performance and will decrease the dependability and/or availability of a facility or an operation.

Risk 2
Employee safety including the risk of loss of life

Risk 3
Environmental release

Non-Financial Benefits

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis (if required)

2. Major financial benefits

3. Total cost
$7.83 million

4. Basis for estimate
The program's funding request is based on the engineering estimates for the constituent projects currently in progress.

5. Conclusion

Project Risks and Mitigation Plan

Technical Evaluation / Analysis

Project Relationships (if applicable)

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital						**1,605**
O&M						
Regulatory Asset						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**1,775**	**2,055**		**2,000**	**2,000**
O&M*					
Regulatory Asset					

Capital/Regulatory Asset Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	160	80		100	100
M&S					
Contract Services	1,200	1,515		1,473	1,475
Other	8	29			
Overheads	407	431		427	425
Total	**1,775**	**2,055**		**2,000**	**2,000**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Project Status:

- Initiation – New project, not authorized yet
- Planning – Project authorized, not started yet
- Executing – Project in-flight
- On-going – Annual program

Central Operations / Steam Operations
2022

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: East River Instrumentation & Control Replacement Projects - EP	
Project/Program Manager: O'Hagan	**Project/Program Number (Level 1): 24611138**
Status: ☐ **Initiation** ☐ **Planning** ☐ **Execution** ☒ **On-going** ☐ ☐ **Other:** ___________	
Estimated Start Date: N/A	**Estimated Date In Service: N/A**
A. Total Funding Request ($000) **Capital: 4,390** **O&M:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months) (If applicable)**

Work Description:
This program consists of projects that will replace instrumentation and control equipment that has failed, is performing poorly or is at or near obsolescence within the stations. Instrumentation and control equipment consists of low voltage and control wiring, hardware, and software specific to the operation of plant systems. The projects that are funded by this program are located at the East River Generating Station.

Justification Summary:

Descriptions of sample projects and associated justifications are listed below:

30342-20 East River Gas Veranda Block Valve Leak-By & Controls Improvement

This project will install new double block and bleed isolation arrangement on the East River Gas Veranda. In addition, new weather-proof isolation valves are being installed to replace valves RMO60, RMO70, and V-365. This project is justified for safety, reliability, and environmental factors. The double block and bleed isolation arrangement would ensure a positive gas tight seal for both gas meter change out and proper hold offs on the boiler gas system from the Gas Veranda. The addition of a mini-flow regulator arrangement in parallel to both Main 60 & 70's 1st and 2nd cut main gas regulators would allow for better boiler control at low load on gas, start-up, and transition from full gas to full oil. This would prevent operating in manual which increases the risk of operator error. Making this change maintains automatic operation will minimize operator intervention. In addition, this project eliminates leak prone equipment which reduces GHG emissions.

30313-20 ER Dock PLC and Wireless System Upgrade Project

This project will replace programable logic controllers and ethernet modules, unreliable 1492-FPK2

Fuse Modules, Phoenix Ethernet Radios, and Solar Controllers on the Wireless Repeater Stations, which are located on the East River Generating Station Dock. Additionally, a GPS Time Clock and antenna will be installed to meet the latest control system standards. The listed equipment are obsolete and are at the end of their useful life. These control systems support Electric Production for both East River Unit 60 and East River Unit 70.

30197-19 East River Unit 70 DCS Upgrade

This project will upgrade the existing Emerson Ovation Distributed Control System (DCS) software to the latest revision offered by Emerson. The DCS system is used to control machinery in the plant. Existing database, graphics, and logic will be integrated into the new control system. Included in this upgrade will be eleven new computers using the latest Windows Operating System software. Network Switches in the DCS will also be replaced with currently supported hardware. The installed DCS controllers will be upgraded to OCR3000 Controllers, along with new power supplies, supplied by Emerson. All existing Input-Output (IO) hardware in the DCS will remain intact and will interface to the new Controllers. Upgrading the DCS to the latest offering from Emerson is a cost-effective method to keep the system secure and up to date.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):

- This program improves reliability and safety, and reduces fugitive emissions of greenhouse gases at the station

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection
There are no proposed alternatives for this program.

Risk of No Action

Risk 1
If no action is taken, there is risk of continued unnecessary maintenance due to poor equipment performance and will decrease the dependability and/or availability of a facility or an operation.

Risk 2
Fugitive methane emissions.

Non-Financial Benefits

- Improved reliability
- Improved safety
- Fewer methane emissions

Summary of Financial Benefits and Costs (attach backup) 1. Cost-benefit analysis (if required) 2. Major financial benefits 3. Total cost $4.39 Million 4. Basis for estimate The program's funding request is based on the engineering estimates for the constituent projects currently in progress. 5. Conclusion
Project Risks and Mitigation Plan
Technical Evaluation / Analysis
Project Relationships (if applicable)

3. Funding Detail

Historical Spend

	Actual 2017	**Actual 2018**	**Actual 2019**	**Actual 2020**	**Historic Year** (O&M only)	**Forecast 2021**
Capital						640
O&M						
Regulatory Asset						

Total Request ($000):

Total Request by Year:

	Request 2022	**Request 2023**	**Request 2024**	**Request 2025**	**Request 2026**
Capital	**1,540**	**1,850**			**1,000**
O&M*					
Regulatory Asset					

Capital/Regulatory Asset Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	80	120			60
M&S	60	80			20
Contract Services	1,040	1,130			689
Other	28	115			15
Overheads	332	405			216
Total	**1,540**	**1,850**			**1,000**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Project Status:

- Initiation – New project, not authorized yet
- Planning – Project authorized, not started yet
- Executing – Project in-flight
- On-going – Annual program

Central Operations / Steam Operations
2022

1. Project / Program Summary

Type: ☐ Project ☒ Program	**Category: ☒ Capital ☐ O&M ☐ Regulatory Asset**
Work Plan Category: ☐ Regulatory Mandated ☒ Operationally Required ☐ Strategic	
Project/Program Title: East River Major Equipment Replacement Projects - EP	
Project/Program Manager: O'Hagan	**Project/Program Number (Level 1): 24611154**
Status: ☒ Initiation ☐ Planning ☐ Execution ☐ On-going ☐ ☐ Other: ___________	
Estimated Start Date: N/A	**Estimated Date In Service: N/A**
A. Total Funding Request ($000) **Capital: 42,850** **O&M:**	**B.** **☐ 5-Year Gross Cost Savings ($000)** **☐ 5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months) (If applicable)**

Work Description:
This program consists of projects that will replace major equipment that has failed, is performing poorly or is at or near obsolescence. Major equipment consists of equipment that is directly used to produce steam or electricity. This includes generators and equipment contained within the boiler island including forced and induced draft fans, air preheaters, and combustion equipment. The projects that are funded by this program are located at the East River Generating Station.

Justification Summary:

Descriptions of sample projects and associated justifications are listed below:

25553-13 ER 70 Rear Wall BRILC

This project will replace brick, refractory, insulation, lagging and casing (BRILC) on the rear wall of East River Unit 70. This project will be completed as part of the major overhaul of this unit. This unit is a cold-casing design boiler where the casing is supported independently from the pressure parts. Due to its design, internal movement has led to the deterioration of the brick work and insulation. This has been exacerbated by bowing of the waterwall tubes out of plane allowing hot flue gases to enter the brick, refractory, insulation, lagging, and casing (BRILC) area causing it to deteriorate and fail. The failure of the BRILC has led to hot spots in excess of 900 degrees and is a safety concern where contact with the casing is possible.

24653-12 ER 70 Rear Wall Hopper Slope

This project will replace 183, 3 inch, SA210 tubing, within the Rear Furnace Wall Terminal Tube Assemblies of East River`s Unit 70. This replacement will require the removal and subsequent installation of Rear Furnace Wall tubing which forms the rear lower slope and the rear wall riser sections of the radiant furnace. The replacement will be from the lower header to elevation 57` approximately 2` below the upper hopper slope bend. East River 70 was originally equipped with tubing at the terminus of the rear radiant furnace wall which connects it to the Rear Wall Inlet Header and the Rear Steam Drum. These tubing areas have several features which leave them susceptible to long-acting failure mechanisms such as out of service corrosion, aligned pitting at or near bottom of tubes, fatigue indications at the neutral axis of bends. Failure of these tubes would force the unit out of operation.

25521-13 ER 70 Reheater & Superheater

The project will replace the East River Unit 70 Boiler Reheater Elements. The reheater section consists of three banks, each with 182 tube rows of 2" diameter tubing which are known as the elements. Additionally, new reheater support attachments, casing and refractory will be installed. As part of this work, gas seals around the main reheat and reheat bypass sections will be enhanced by redesigning the refractory and brick supports and convection rear wall/ reheat wall corner seals. This project requires an outage. This project is part of the East River Unit 70 overhaul which will ensure that the unit can continue to operate safely and reliably.

30723-21 ER 70 Furnace Upper Waterwall and Headers

This project will replace the upper waterwall and headers as part of the Unit 70. The waterwall and headers are constructed of tubing which allows heat transfer from the fuel to boiler water for the generation of steam. This project is part of the East River Unit 70 overhaul which will ensure that the unit can continue to operate safely and reliably.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):

- Loss of Significant Production

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection
Each project in this program is operationally required, failure to complete projects may result in cessation of production.

Risk of No Action

Risk 1
If no action is taken, there is risk of continued maintenance due to poor equipment performance and will decrease the dependability and/or availability of a facility or an operation.

Non-Financial Benefits

Summary of Financial Benefits and Costs (attach backup) 1. Cost-benefit analysis (if required) 2. Major financial benefits 3. Total cost $42.85 Million 4. Basis for estimate The program's funding request is based on the engineering estimates for the constituent projects currently in progress. 5. Conclusion	
Project Risks and Mitigation Plan Risk 1 Risk 2	 Mitigation plan Mitigation plan
Technical Evaluation / Analysis	
Project Relationships (if applicable)	

3. Funding Detail

Historical Spend

	Actual 2017	**Actual 2018**	**Actual 2019**	**Actual 2020**	**Historic Year** (O&M only)	**Forecast 2021**
Capital						
O&M						
Regulatory Asset						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**10,500**	**350**	**16,000**	**6,000**	**10,000**
O&M*					
Regulatory Asset					

Capital/Regulatory Asset Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor	265		200	180	600
M&S	990	247	600	160	200
Contract Services	6,855		11,848	4,410	6,899
Other	230	35	150	12	142
Overheads	2,160	69	478	1,238	2,159
Total	**10,500**	**350**	**16,000**	**6,000**	**10,000**

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Project Status:

- Initiation – New project, not authorized yet
- Planning – Project authorized, not started yet
- Executing – Project in-flight
- On-going – Annual program

Central Operations / Steam Operations
2022

1. Project / Program Summary

Type: ☐ Project ☒ Program	**Category: ☒ Capital ☐ O&M ☐ Regulatory Asset**
Work Plan Category: ☐ Regulatory Mandated ☒ Operationally Required ☐ Strategic	
Project/Program Title: East River Power Distribution Replacement Projects - EP	
Project/Program Manager: O'Hagan	**Project/Program Number (Level 1): 24611271**
Status: ☒ Initiation ☐ Planning ☐ Execution ☐ On-going ☐ ☐ Other: ___________	
Estimated Start Date: N/A	**Estimated Date In Service: N/A**
A. Total Funding Request ($000) **Capital: 21,190** **O&M:**	**B.** **☐ 5-Year Gross Cost Savings ($000)** **☐ 5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months) (If applicable)**

Work Description:
This program consists of projects that will replace power distribution equipment that has failed, is performing poorly or is at or near obsolescence. Power distribution equipment consists of all high-voltage equipment within the station including, unit substations, step-up transformers, and uninterrupted power supplies. Projects funded by this program are located at East River Generating Station.

Justification Summary:

Descriptions of sample projects and associated justifications are listed below:

26234-15 Battery Replacements - ER 6 & 7

This project will replace five batteries for ER 6 & 7 in 2023. These batteries are ER-6ED-125-BAT-1, ER-6ED-125-BAT-2, ER-7ED-125-BAT-3, ER-7ED-125-BAT-4 and ER-67ED-125-BAT-LA2. The first four batteries listed are Vented Lead Acid Battery (VLA), whereas the fifth is a Valve Regulated Lead Acid (VRLA). Con Edison specification CE-ES-1034 requires that VLAs be replaced every 15 years to ensure safety and operability. VRLAs have a five-year replacement frequency per Con Edison specification CE-ES-1061.

23091-08 60 ME Substation Switchgear Replacement - ER 6

This project will replace existing Unit Substation 60ME with a 480V distribution panel. The unit substation consists of a transformer and switchgear. The loads supplied from the 480V switchgear will be transferred to the new distribution panel and the failed Unit Substation 60ME removed. The transformer portion of the unit substation failed and was deemed beyond repair. The loads supplied by this unit were transferred to other unit substations as a temporary measure.

23090-08 72 Circulator Switchgear Upgrade - ER 7

This project will retrofit the existing switchgear for 72 Circulating Water Unit Substation. The switchgear will be retrofitted with new breakers, relays and a control compartment. The switchgears are operating beyond their design lives. It is difficult to find parts for repair. This affects the reliability and availability of the Unit 7 operation. Secondary power distribution panel and control panel for the Circulating Water Pump is in poor condition. Remote control, metering and monitoring capabilities are not adequately available. The protective relays are nearly obsolete and not easily available. Their reliability is a concern due to the increased maintenance and test issues.

23089-08 71 Circulator Switchgear Upgrade - ER 7

This project will retrofit in place the existing switchgear for 71 Circulating Water Unit Substation. The switchgear will be retrofitted with new breakers, relays and a control compartment. The switchgears are operating beyond their design lives. It is difficult to find parts for repair. This affects the reliability and availability of the Unit 7 operation. Secondary power distribution panel and control panel for the Circulating Water Pump is in poor condition. Modern capabilities such as remote control, metering and monitoring capabilities are not presently available. Additionally, the protective relays are nearly obsolete and not readily available in the market.

23085-08 60 FDW Unit Substation Replacement - ER 6

This project will replace existing Unit Substation 60 FDW. Unit substations consist of a transformer and associated switchgear, as well as associated monitoring and control systems. The unit substations are operating beyond their design lives. It is difficult to find parts for repair. This affects the reliability and availability of the Unit 6 operation. Modern capabilities such as remote control, metering and monitoring capabilities are not presently available. Additionally, the protective relays are nearly obsolete and not readily available in the market.

23084-08 60 FDE Unit Substation Replacement - ER 6

This project will replace existing Unit Substation 60 FDE with new equipment (transformer and switchgear). The unit substations are operating beyond their design lives. It is difficult to find parts for repair. This affects the reliability and availability of the Unit 6 operation. Modern capabilities such as remote control, metering and monitoring capabilities are not presently available. Additionally, the protective relays are nearly obsolete and not readily available in the market.

21747-05 61 & 62 Circulator MOV Controls and 6CP Switchgear Upgrade - ER 6

This project will remove failed transformer 5CP and replace the existing unit substation 6CP with new transformer and switchgear. In addition, the project will upgrade the motor operator valve (MOV) controls associated with the 61 and 62 Circulator Pumps. 208V distribution panel, incoming power cable and 480V feeder cable to CPs. A Unit 6 outage will be required. The switchgears are operating beyond their design lives. It is difficult to find parts for repair. This affects the reliability and availability of the Unit 6 operation. Secondary power distribution panel and control panel for unit 6 Circulating Water Pumps are in poor condition. Remote control, metering and monitoring capabilities are not presently available. The protective relays are nearly obsolete and not easily available.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection
Each project in program is operationally required, failure to complete projects may result in cessation of production.

Risk of No Action

Risk 1
If no action is taken, there is risk of continued unnecessary maintenance due to poor equipment performance and will decrease the dependability and/or availability of a facility or an operation.

Non-Financial Benefits

- Improved reliability
- Ease of maintenance
- Easier access to replacement parts in the open market

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)

2. Major financial benefits

3. Total cost

$21.19 million

4. Basis for estimate
The program's funding request is based on the engineering estimates for the constituent projects currently in progress.

5. Conclusion

Project Risks and Mitigation Plan

Risk 1	Mitigation plan

Risk 2	Mitigation plan
Technical Evaluation / Analysis	
Project Relationships (if applicable)	

3. Funding Detail

Historical Spend

	Actual 2017	**Actual 2018**	**Actual 2019**	**Actual 2020**	**Historic Year** (O&M only)	**Forecast 2021**
Capital						
O&M						
Regulatory Asset						

Total Request ($000):

Total Request by Year:

	Request 2022	**Request 2023**	**Request 2024**	**Request 2025**	**Request 2026**
Capital	**1,440**	**4,750**	**1,000**	**9,000**	**5,000**
O&M*					
Regulatory Asset					

Capital/Regulatory Asset Request by Elements of Expense:

EOE	**2022**	**2023**	**2024**	**2025**	**2026**
Labor		300	38	300	120
M&S	1,157	1,260	600	1,100	250
Contract Services		2,150	100	5,600	3,600
Other		3	53	133	14
Overheads	283	1,037	209	266	149
Total	**1,440**	**4,750**	**1,000**	**9,000**	**5,000**

Total Gross Cost Savings / Avoidance by Year:

	2022	**2023**	**2024**	**2025**	**2026**
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Project Status:

- Initiation – New project, not authorized yet
- Planning – Project authorized, not started yet
- Executing – Project in-flight
- On-going – Annual program

Schedule 5:

EP Capital White Papers

Environmental

Central Operations / Steam Operations
2022

1. Project / Program Summary

Type: ☐ Project ☒ Program	**Category: ☒ Capital ☐ O&M ☐ Regulatory Asset**
Work Plan Category: ☒ Regulatory Mandated ☐ Operationally Required ☐ Strategic	
Project/Program Title: 59th Street Environmental - EP	
Project/Program Manager: O'Hagan	**Project/Program Number (Level 1): 25395260**
Status: ☒ Initiation ☐ Planning ☐ Execution ☒ On-going ☐ ☐ Other: ___________	
Estimated Start Date: N/A	**Estimated Date In Service: N/A**
A. Total Funding Request ($000) **Capital: 500** **O&M:**	**B.** **☐ 5-Year Gross Cost Savings ($000)** **☐ 5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months) (If applicable)**

Work Description:
This program consists of projects that will replace balance of plant equipment at East River Generating Station that has failed, is performing poorly or is at or near obsolescence. Balance of plant equipment consists of all auxiliary mechanical equipment required to produce steam or electricity other than major equipment. This includes water treatment systems, cooling water systems, tanks, etc.

Justification Summary:

Descriptions of a sample project and associated justification is listed below:

30096-19 W59 No. 2 Oil Conversion - 59th St. EP

This project will install new piping to tie the fuel oil supply and return for gas turbines to the boiler fuel oil storage tanks. Two existing kerosene storage tanks located inside the station will be retired. Testing and tuning support to commission the gas turbines on No. 2 oil will be included in this project. Completion of this project will provide cost savings due to the consolidation of multiple liquid fuels systems. Existing kerosene tanks will be retired and demolished reducing operations and maintenance effort.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
Explain how this project/program addresses risk mitigation activity.
The move to a common fuel and eliminating the station tanks reduces the risk of oil release to waterway and fuel oil spills associated with deliveries and station equipment. This project frees up space within the plant for potential future uses.

2. Supplemental Information

Alternatives
Alternative 1 description and reason for rejection
The status quo does not mitigate the risk of oil leaks or oil releases to the waterway.

Alternative 2 description and reason for rejection

Alternative 3 description and reason for rejection

Risk of No Action

Risk 1
The status quo does not mitigate the risk of oil leaks or oil releases to the waterway.

Risk 2

Risk 3

Non-Financial Benefits

This program reduces the risk of oil release to waterway and fuel oil spills associated with deliveries and station equipment.
This program frees up space within the station for future uses.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)

2. Major financial benefits

3. Total cost
$0.5 million

4. Basis for estimate
The program's funding request is based on the engineering estimates for the constituent projects currently in progress.

5. Conclusion
A switch to a common fuel reduces the cost of fuel oil transportation and storage.

Project Risks and Mitigation Plan	
Risk 1	Mitigation plan
Risk 2	Mitigation plan
Technical Evaluation / Analysis	
Project Relationships (if applicable)	

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital						
O&M						
Regulatory Asset						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital		500			
O&M*					
Regulatory Asset					

Capital/Regulatory Asset Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor		5			
M&S		5			
Contract Services		385			
Other		5			
Overheads		100			
Total		**500**			

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Project Status:

- Initiation – New project, not authorized yet
- Planning – Project authorized, not started yet
- Executing – Project in-flight
- On-going – Annual program

Central Operations / Steam Operations
2022

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☒ **Regulatory Mandated** ☐ **Operationally Required** ☐ **Strategic**	
Project/Program Title: 74th Street Environmental - EP	
Project/Program Manager: Manzino	**Project/Program Number (Level 1): 24611136**
Status: ☒ **Initiation** ☐ **Planning** ☐ **Execution** ☐ **On-going** ☐ ☐ **Other: ___________**	
Estimated Start Date: N/A	**Estimated Date In Service: N/A**
A. Total Funding Request ($000) **Capital: 1,100** **O&M:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months) (If applicable)**

Work Description:

This program consists of projects that are intended to enhance environmental performance, reduce environmental impact, or to comply with regulatory requirements. The projects that are funded by this program are located at the 74th Street Generating Station, 60th Street Generating Station, or the Hudson Ave Generating Station.

Justification Summary:

30097-19 E74 No. 2 Oil Conversion - 74th St. EP

This project will install piping to tie the fuel oil supply and return for gas turbines (GTs) to the boiler fuel oil storage tanks. Four kerosene storage tanks located inside the station will be retired. This project will also include testing and tuning support to commission the GTs on No. 2 oil. Completion of this project will provide cost savings due to the consolidation of multiple liquid fuels systems. Existing kerosene tanks will be retired and demolished reducing operations and maintenance effort.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation)

The move to a common fuel and eliminating the station tanks reduces the risk of oil releases to waterways and fuel oil spills associated with deliveries and station equipment. This project frees up space within the plant for potential future use with energy storage or other carbon reduction technologies.

2. Supplemental Information

Alternatives

Alternative 1 description and reason for rejection
There is no alternative, not doing this work would lead to the risk of oil leaks or oil releases to the waterway.

Risk of No Action

Risk 1
The status quo does not mitigate the risk of oil leaks or oil releases to the waterway.

Risk 2
Not performing this work would not free up space for future uses.

Non-Financial Benefits
This program reduces the risk of oil release to waterway and fuel oil spills associated with deliveries and station equipment.
This program frees up space within the station for future uses.

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis (if required)

2. Major financial benefits

3. Total cost
$1.1 million

4. Basis for estimate
The program's funding request is based on the engineering estimates for the constituent projects currently in progress.

5. Conclusion
A switch to a common fuel reduces the cost of fuel oil transportation and storage.

Project Risks and Mitigation Plan

Risk 1

Risk 2

Technical Evaluation / Analysis

Project Relationships (if applicable)

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital						
O&M						
Regulatory Asset						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital		**500**	**500**	**100**	
O&M*					
Regulatory Asset					

Capital/Regulatory Asset Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor		70	70	15	
M&S		30	30		
Contract Services		250	250	25	
Other		27	27	27	
Overheads		123	123	25	
Total		**500**	**500**	**100**	

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Project Status:

- Initiation – New project, not authorized yet
- Planning – Project authorized, not started yet
- Executing – Project in-flight
- On-going – Annual program

Central Operations / Steam Operations
2022

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☒ **Capital** ☐ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☒ **Regulatory Mandated** ☐ **Operationally Required** ☐ **Strategic**	
Project/Program Title: East River Environmental - EP	
Project/Program Manager: O'Hagan	**Project/Program Number (Level 1): 24611129**
Status: ☐ **Initiation** ☐ **Planning** ☐ **Execution** ☒ **On-going** ☐ ☐ **Other: ___________**	
Estimated Start Date: N/A	**Estimated Date In Service: N/A**
A. Total Funding Request ($000) **Capital: 31,500** **O&M:**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months) (If applicable)**

Work Description:

This program consists of projects that are intended to enhance environmental performance, reduce environmental impact, or to comply with regulatory requirements. The projects that are funded by this program are located at the East River Generating Station.

Justification Summary:

Descriptions of a sample project and associated justification is listed below:

28282-19 ER No. 2 Oil Conversion - East River

This project will convert backup fuel oil systems at the East River Plant from #4 fuel oil to #2 fuel oil. This requires replacement of the components for the existing #4 fuel oil back up system, including oil gun/tip replacements, replacement of fuel oil pumps, fuel oil tank coating, and fire protection system upgrades. In addition, two new unit substations will be installed. The #4 fuel oil heaters will also be removed, as they are not required for #2 fuel oil. The generating units are interruptible gas customers and use liquid fuel as a backup for reliability and economics. The current liquid fuel, #4 oil, will not be allowed after December 31, 2024 due to NYCDEP regulation. Converting to #2 oil allows the boilers to maintain a liquid fuel back up. In addition, converting Tank 1 from kerosene to #2 oil will make the whole station a single liquid which increases the redundancy of fuel supply and better supports tank inspection and repair periods. Converting Tank 3 to a transfer tank allows the installation of a unit substation to upgrade power supplies to the fire suppression system and modernizes the oil pump power supplies. The fire suppression system replacement is necessary because it is under-designed for the hazards introduced by the new fuel; some parts are obsolete; and it uses fluorinated foam concentrate which can no longer be sold in New York.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):
The move to lighter distillate backup fuel reduces overall emissions of the facility. In addition, this project frees up space within the plant for potential future use with energy storage or other carbon reduction technologies.

2. Supplemental Information

Alternatives
Alternative 1 description and reason for rejection
The ongoing project in this program is to comply with municipal regulations. Not complying would risks fines and/or loss of production.

Risk of No Action

Risk 1
The ongoing project in this program is to comply with municipal regulations. Not complying would risks fines and/or loss of production.

Risk 2

Risk 3

Non-Financial Benefits

- This project has a minor impact in reducing carbon emissions
- Regulatory compliance
- Lower environmental footprint (Lower NOx emissions, Lower GHG emission, elimination of fluorinated foam concentrate)
- Lower risk of oil release (elimination of fuel oil heaters, fuel oil tank coatings)
- Greater flexibility and more freed up space for future uses within the plant

Summary of Financial Benefits and Costs (attach backup)
1. Cost-benefit analysis (if required)
N/A

2. Major financial benefits

3. Total cost
$31.5 million

4. Basis for estimate
The program's funding request is based on the engineering estimates for the constituent projects currently in progress.

5. Conclusion This project is required to comply with municipal law.
Project Risks and Mitigation Plan Risk 1 Mitigation plan Risk 2 Mitigation plan
Technical Evaluation / Analysis
Project Relationships (if applicable)

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital						1,636
O&M						
Regulatory Asset						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital	**11,500**	**16,000**	**4,000**		
O&M*					
Regulatory Asset					

Capital/Regulatory Asset Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor					
M&S					
Contract Services	9,238	12,867	3,217		
Other	2300				
Overheads	2,260	3,132	783		
Total	**11,500**	**16,000**	**4,000**		

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

*If whitepaper is supporting a capital project/program this refers to implementation O&M

4. Definitions

Total Funding Request: All funding requested for program or project over program/project lifecycle or for on-going programs the five-year requested amount, including all capital, O&M, retirement.

Cost Savings: Reductions in costs that are currently being incurred (e.g., reduced annual maintenance cost relative to today)

Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Project Status:

- Initiation – New project, not authorized yet
- Planning – Project authorized, not started yet
- Executing – Project in-flight
- On-going – Annual program

Schedule 6:

EP O&M White Papers

Steam Operations / East River Station
2022

1. Project / Program Summary

Type: ☐ **Project** ☒ **Program**	**Category:** ☐ **Capital** ☒ **O&M** ☐ **Regulatory Asset**
Work Plan Category: ☐ **Regulatory Mandated** ☒ **Operationally Required** ☐ **Strategic**	
Project/Program Title: East River Units 6/7 Major Overhauls	
Project/Program Manager:	**Project/Program Number (Level 1):**
Status: ☐ **Initiation** ☒ **Planning** ☐ **Execution** ☐ **On-going** ☐ ☐ **Other: ___________**	
Estimated Start Date: January 1, 2022	**Estimated Date In Service: Ongoing**
A. Total Funding Request ($000) **Capital:** **O&M: $19,365**	**B.** ☐ **5-Year Gross Cost Savings ($000)** ☐ **5-Year Gross Cost Avoidance ($000)** **O&M:** **Capital:**
C. 5-Year Ongoing Maintenance Expense ($000) **O&M:** **Capital:**	**D. Investment Payback Period: (Years/months) (If applicable)**

Work Description:

The steam turbines and generators of East River Unit No. 6 are overhauled on a 50,000 +/- operating hour frequency. This interval between overhauls is an OEM recommendation and industry standard. The next overhauls for Unit No. 6 are scheduled in 2022 when the Low-Pressure Turbine will be opened and inspected and 2023 when the High-Pressure Turbine, and the HP and LP generators will be overhauled. Because of its seasonal operation in electric mode, the steam turbine generator components of East River Unit No. 7 will not reach the 50,000-hour criteria in the typical 6 – 8-year period that the components of Unit No. 6 achieve. As a result, the overhauls of the Unit No. 7 components are scheduled on a nine-to-twelve-year basis. The overhauls for Unit No. 7 are scheduled as follows, 2024 High-Pressure Turbine and HP/LP generators, 2025 Low Pressure Turbine and 2026 Intermediate Pressure Turbine. The degradation of a steam turbine is not typically detected through performance evaluations nor is a limited inspection such as a borescope examination representative. Opening the steam turbine to remove, inspect and repair its components is required to ensure its continued reliable operation.

Justification Summary:

The ER Unit 6 Low Pressure Turbine was overhauled last in 2014. During the 2014 overhaul, significant wear to the main stop valve and stages 9 and 10 of the rotating blades was observed. The turbine has approximately 44,000 service hours and is estimated it will have 50,000 hours in fall 2022. NDE testing of the rotor bore, shaft and blades will be performed during the 2022 overhaul.

The ER Unit 6 High Pressure Turbine and its generators currently have approximately 36,000 service hours and it is estimated they will have 44,000 hours in fall 2023. These components were overhauled last in 2016. During the 2016 outage the first stage of rotating blades were replaced, and the shop teardown and inspection of the turbine rotor revealed significantly pitted surfaces of the rotor. Erosion of the first stage buckets and nozzle block has been a recurring issue and was noted and addressed in the 1993 and 2000 outages. The extraction valve housings and seats are reaching the end of their useful life and require a major refurbishment during the 2023 overhaul. NDE testing of the rotor bore, shaft and blades will be performed during the 2023 overhaul.

The ER Unit 7 HP turbine was overhauled last in 2012. During the 2012 overhaul, all turbine stage radial seals were replaced, the labyrinth glands and dummy piston rings were repaired, and the nozzle block was repaired. NDE testing of the rotor bore, shaft and blades did not reveal significant findings. During the 2024 overhaul, the scope will include replacement of the first six turbine rotating and stationary blade rows including the Curtis stage. NDE testing of the rotor bore, shaft and blades will be performed during the 2024 overhaul.

The ER Unit 7 Low Pressure turbine consists of two turbines "A" and "B" on the same shaft. Both were overhauled in 2005 and a limited inspection was conducted of the "A" turbine in 2018. The rotors of both turbines were "bottle-bored" sometime ago, probably in the early 1980's. Bottle boring is a process whereby the internal bore of the shaft is machined to remove indications found through nondestructive examination. While no significant indications were noted in the 2018 LPA inspection, the turbine overhaul scope in 2025 will include re-examination of these bores. NDE testing of the rotor bore, shaft and blades will be performed during the 2025 overhaul.

The ER7 Intermediate Turbine was last overhauled in 2015. Significant pitting of the turbine rotor was noted during the 2015 overhaul. NDE testing of the rotor bore, shaft and blades will be performed during the 2026 overhaul.

Relationship to Broader Company Plans and Initiatives (e.g. Long-Range Plans, CLCPA Initiatives, Risk Mitigation):

Con Edison recognizes that the East River steam turbine generating assets are integral parts of the System for the foreseeable future. Conducting major overhauls at pre-determined overhauls increases their reliability and minimizes the risk that the assets will be unavailable because of emergent and unforeseen repairs.

2. Supplemental Information

Alternatives

The alternative to overhauling the steam turbine generator components to the prescribed plan is to defer the overhauls for several years. This option is not recommended because of the risk of an in-service failure, more extensive repairs, and escalating costs in future years.

Risk of No Action

Risk 1
In-service failure resulting in loss of steam and electric generation.

Risk 2
Higher repair costs because of increased wear and escalation.

Non-Financial Benefits

Overhaul of the steam turbine generators on a prescribed schedule helps maintain reliability of these assets to Con Edison's steam and electric systems.

Summary of Financial Benefits and Costs (attach backup)

1. Cost-benefit analysis (if required)

2. Major financial benefits

3. Total cost

The total program cost is estimated at $19.4M for the period 2022 – 2026.

4. Basis for estimate

The base scope of work for the overhauls of the East River steam turbine generators is consistent, i.e., the machinery is opened, disassembled inspected and non-destructively tested. Estimates for future years are based on previous expenditures that are escalated for future years.

5. Conclusion

Project Risks and Mitigation Plan

Risk 1	Mitigation plan
Risk 2	Mitigation plan

Technical Evaluation / Analysis

The steam turbine generators are monitored continuously while in service and performance evaluations are completed on a frequent basis. Many aspects of the degradation in a steam turbine generator cannot be determined through performance evaluations and thus require overhauls to determine the health and required repairs for continued operation.

Project Relationships (if applicable)

3. Funding Detail

Historical Spend

	Actual 2017	Actual 2018	Actual 2019	Actual 2020	Historic Year (O&M only)	Forecast 2021
Capital						
O&M	0	0	0	0	0	0
Regulatory Asset						

Total Request ($000):

Total Request by Year:

	Request 2022	Request 2023	Request 2024	Request 2025	Request 2026
Capital					
O&M*	3,873	3,873	3,873	3,873	3,873
Regulatory Asset					

Capital/Regulatory Asset Request by Elements of Expense:

EOE	2022	2023	2024	2025	2026
Labor					
M&S					
Contract Services					
Other					
Overheads					
Total					

Total Gross Cost Savings / Avoidance by Year:

	2022	2023	2024	2025	2026
O&M Savings					
O&M Avoidance					
Capital Savings					
Capital Avoidance					

Total Ongoing Maintenance Expense by Year:

	2022	2023	2024	2025	2026
O&M					
Capital					

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Cost Avoidance: Reductions in anticipated future costs that don't occur today (e.g., anticipated short-term fixes/maintenance if capital isn't deployed)

Project Status:

- Initiation – New project, not authorized yet
- Planning – Project authorized, not started yet
- Executing – Project in-flight
- On-going – Annual program