Niagara Mohawk Power Corporation
d/b/a National Grid

PROCEEDING ON MOTION OF THE COMMISSION AS TO THE RATES, CHARGES, RULES AND REGULATIONS OF NIAGARA MOHAWK POWER CORPORATION FOR ELECTRIC AND GAS SERVICE

Testimony and Exhibits of:

Electric Infrastructure and Operations Panel
Exhibits (EIOP-1) through (EIOP-6)

Book 10 1 of 5

April 28, 2017

Submitted to:
New York State Public Service Commission
Case 17-E-____
Case 17-G-____

Submitted by:
Niagara Mohawk Power Corporation

nationalgrid

Testimony of
EIOP

Before the Public Service Commission

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID

Direct Testimony

of

Electric Infrastructure and Operations Panel

Dated: April 28, 2017

Table of Contents

I. Introduction and Qualifications

Q. Please introduce the members of the Infrastructure and Operations Panel.

A. The Panel consists of Keith P. McAfee, Christopher Kelly, Allen C. Chieco, Peter F. Altenburger, and Robert D. Sheridan.

Q. Mr. McAfee, please state your name and business address.

A. My name is Keith P. McAfee. My business address is 1125 Broadway, Albany, New York 12204.

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

A. I am employed by Niagara Mohawk Power Corporation d/b/a National Grid ("Niagara Mohawk" or "Company") as Vice President, New York Electric. I am responsible for operations, construction, and maintenance, including emergency response and storm restoration, of the electric system in Niagara Mohawk's electric service territory. My functions include overhead and underground service, substations, protection and telecom, distribution design, inspections, and work planning. In this role, I oversee approximately 1,700 direct and indirect reports.

Q. Please describe your educational background and business experience.

A. I graduated from Clarkson University with a Bachelor of Science in Electrical Engineering. I received a Master of Business Administration from New Hampshire College in Manchester, New Hampshire. I am a licensed Professional Engineer in New York State. I also completed the 18-month Power Technologies Inc. (now Siemens Inc.) Distribution System Engineering course.

I joined National Grid in 1992 as an Account Manager in Buffalo, New York. In 1994, I became Technical Services Manager in Albany, New York. In 1999, I became Regional Manager for the Northeast Region in Glens Falls, New York. In 2002, I was appointed Director of Customer Operations for the Eastern Division of New York and in 2007 was named Vice President of Operations, Eastern Division of New York. In 2011, I took on my present position of Vice President, New York Electric.

Prior to Niagara Mohawk, I was employed by Central Hudson Gas and Electric from 1985 through 1987 as an Associate Engineer. Between 1987 and 1991, I held various operations management and engineering positions for the Public Service Company of New Hampshire in Manchester and Nashua, New Hampshire.

I also serve as Chairman of the Electric Edison Institute Distribution Executive Committee, and am on the Engineering Advisory Board at Clarkson University.

Q. Have you previously testified before the Commission?

A. Yes. Most recently, I provided pre-filed testimony in Case 12-E-0201, Niagara Mohawk's 2012 electric rate case proceeding (the "2012 Electric Rate Case").

Q. Mr. Kelly, please state your name and business address.

A. My name is Christopher Kelly. My business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

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

A. I am employed by National Grid USA Service Company, Inc. ("National Grid Service Company" or "Service Company"), a subsidiary of National Grid USA ("National Grid"), as Senior Vice President of Electric Process and Engineering, responsible for the overall asset strategy, investment portfolio planning, engineering, and major project construction for National Grid's electric operating companies, including Niagara Mohawk.

Q. Please describe your business experience and educational background.

A. I have served for over 28 years in the utility and telecommunication industries. Prior to taking on my current role, I served as Vice President of Electric Systems Engineering, Manager of Substation Engineering and Design, Director of Project Management, Protection/Meter Engineering, and Utility of the Future. Prior to joining the electric utility industry, I worked for the Department of Defense in its telecommunication sector specializing in point to point communications and encryption.

I graduated from Rutgers University's Electrical Engineering program (B.S.E.E.), and have a Master of Business Administration from Worcester Polytechnic Institute. I also am a registered Professional Engineer in the Commonwealth of Massachusetts.

Q. Mr. Chieco, please state your name and business address.

A. My name is Allen C. Chieco. My business address is 1125 Broadway, Albany, New York 12204.

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

A. I am employed by National Grid Service Company, and serve as Ombudsman Distributed Generation, New York Electric. In this role, I serve as a liaison between the Company and distributed energy resource ("DER") developers and customers regarding distributed generation projects. Additionally, I work to implement improvements to the Company's performance in this area, consistent with the State's objective of greater solar and DER penetration on the distribution system.

Q. Please describe your educational background and business experience.

A. I graduated from Clarkson University with a Bachelor of Science in Electrical Engineering and received a Master of Business Administration from Rensselaer Polytechnic Institute. I joined Niagara Mohawk in 1985 and have held numerous roles of increasing responsibility, which have included Manager, Electric and Gas Operations in the Eastern Division; Director, Distribution Engineering Services for all of National Grid's U.S. service territory; Director, Network Strategy, New York Electric; New York System Storm Director; and Director, Distribution Planning and Asset Management New York Electric.

Q. Have you previously testified before the Commission?

A. Yes. Most recently, I provided pre-filed testimony in the 2012 Electric Rate Case.

Q. Mr. Altenburger, please state your name and business address.

A. My name is Peter F. Altenburger. My business address is 1125 Broadway, Albany, New York 12204.

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

A. I am employed by Niagara Mohawk and was recently appointed (effective April 1, 2017) Director, Distribution Overhead and Underground Lines – NY East, responsible for the in-house workforce that constructs, operates, and maintains the distribution and sub-transmission system in Niagara Mohawk's Eastern Division.

Q. Please describe your educational background and business experience.

A. I received a Bachelor of Engineering in Electrical Engineering from Manhattan College in 1986 and a Master of Science in Electrical Engineering from Rensselaer Polytechnic Institute in 1990. Before my current position, I served as the Director, Transmission Planning and Asset

Management – NY since 2013, responsible for identifying transmission line and substation capacity, reliability, and asset condition needs and the subsequent development of the transmission capital plan and maintenance programs. Prior to that position, I served in a number of managerial roles including Transmission Asset Management, Manager of the Reliability Enhancement Program, and Distribution Asset Management. Prior to these managerial roles, I served as an individual contributor in a number of electrical engineering positions and as a supervisor in the relay department responsible for the installation and maintenance of protective relay systems on the distribution and transmission system. Prior to working for Niagara Mohawk, I served as an electrical engineer in the High Voltage (230-500KV) station engineering department at Pacific Gas and Electric and a transmission line engineer with Long Island Lighting Company.

Q. Mr. Sheridan, please state your name and business address.

A. My name is Robert D. Sheridan. My business address is 40 Sylvan Road, Waltham, MA 02451.

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

A. I am employed by National Grid Service Company. My role is Director, New Energy Solutions responsible for the development of electric grid modernization plans and demonstration scale projects in New York, Massachusetts, and Rhode Island. A primary responsibility of mine has been the development of the Company's Distributed System Implementation Plans and participation in numerous working groups associated with the Commission's Reforming the Energy Vision ("REV") proceeding.

Q. Please describe your educational background and business experience.

A. I received a Bachelor of Science in Electrical Engineering degree from the University of South Florida and a Master of Business Administration from Bentley College. I am a licensed Professional Engineer in the Commonwealth of Massachusetts.

I joined National Grid in 1988 as an Associate Engineer in the Distribution Engineering department of Massachusetts Electric Company. In 1995, I became a District Engineering Manager for the Massachusetts Electric Company and took on a similar role for the Narragansett Electric Company in 1998. In 2002, I was appointed to the position of Vice

President of Distribution Planning and Engineering for National Grid's New England jurisdictions. In 2008, I took on the role of Director, Distribution Asset Management for both the New York and New England jurisdictions, and in 2013, I became Director, Utility of the Future and worked on National Grid's grid modernization plans in Massachusetts and then the REV proceeding in New York.

Prior to National Grid, I was employed by General Dynamics Electric Boat Division as an engineer in Groton, Connecticut from 1987-1988.

Q. Have you previously testified before a regulatory commission?

A. Yes. I have testified before the Massachusetts Department of Public Utilities, the Rhode Island Public Utilities Commission and the New Hampshire Public Utilities Commission on various topics related to engineering, operations, and capital investment issues. This is my first time testifying before the New York Public Service Commission ("Commission").

II. <u>Purpose of Testimony</u>

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

A. The purpose of the Panel's testimony is to present the Company's plans for electric system capital investment and operations and maintenance ("O&M") activities and to describe the primary drivers affecting the investment and operations plans. The Panel describes: (1) historic capital spending for the period from fiscal year 2012 ("FY12") through FY16, (2) estimated capital spending results for FY17, and (3) planned capital spending for FY18 through FY22. The Rate Year is FY19 (*i.e.*, the 12 months ending March 31, 2019). Data Year 1 is FY20 (*i.e.*, the 12 months ending March 31, 2020). Data Year 2 is FY21 (*i.e.*, the 12 months ending March 31, 2021). FY20 and FY21 are collectively referred to as the "Data Years." This information is summarized in Exhibit __ (EIOP-2).

With respect to capital investments, the Panel's testimony provides a detailed description of the electric infrastructure investment plan for the period FY18 – FY22, and a comparison of prior capital investment amounts. The Panel also describes the Company's methodology to develop its investment plans, prioritize its budget and annual work plan, and execute that work plan. The capital plan presented in the Company's filing reflects the investments necessary to modernize the electric system to accommodate an increasing amount of DER and establish the framework needed to support an animated, multilateral energy marketplace that will ultimately deliver greater value and benefits for customers. Key investments in this regard are in the area of advanced metering infrastructure ("AMI"), and the Company's investment plan includes costs for AMI implementation. The Company's AMI implementation plan is described in the direct testimony of the Company's AMI Panel.

Like the rest of the economy, the electric system relies increasingly on advanced communications and information technologies. The Panel's testimony describes several communication and information systems investments being made by or on behalf of the Company necessary to support AMI and other grid modernization efforts. The capital plan presented by the Panel includes investment to begin the transition of the Company's street light system to state-of-the-art light emitting diode ("LED") technology. The Panel also describes an improved process to integrate non-wires alternatives ("NWA") into system planning to promote more cost-effective and environmentally sustainable solutions for addressing system needs. The Panel also presents plans for other capital investments essential to running the business, including facilities and properties, fleet assets, and investments to support the inventory management/investment recovery functions.

With respect to O&M activities, the Panel's testimony summarizes the Company's ordinary O&M activities and costs, and describes, in detail, a number of programs the Company proposes to implement in the Rate Year, the costs of which are not fully reflected in the 12 months ended December 31, 2016 ("Historic Test Year"). These programs represent incremental, known and measureable changes from Historic Test Year expense, and include, among other things, a focused program to address the Emerald Ash Borer ("EAB") infestation, increased expenditures to paint towers and station assets to prolong their useful lives, and a program to enhance the Company's geographic information system ("GIS") to support the integration of DER in system planning and operations. In addition, the Panel describes incremental resource requirements needed to implement the Company's work plan as well as address succession planning considerations.

The Panel also reports on the Company's performance with respect to electric reliability and other performance metrics. Finally, the Panel describes its participation in research, development, and demonstration programs and the costs associated with those programs.

Q. Are you sponsoring any exhibits as part of your testimony?

A. Yes. In connection with this testimony, the Panel is sponsoring the following exhibits, which were prepared by one or more members of the Panel or under their supervision and direction:

i. Exhibit __ (EIOP-1): Summary of planned capital investment by system (transmission, sub-transmission, distribution), April 1, 2017 – March 31, 2022 (FY18 – FY22);

ii. Exhibit __ (EIOP-2): Summary of actual and planned transmission and distribution ("T&D") infrastructure investment by system, FY12 – FY22;

iii. Exhibit __ (EIOP-3): Summary of planned investment for electric and common capital plant and cost of removal, January - March 2017 – FY22;

iv. Exhibit __ (EIOP-4): Comparison of annual actual and budgeted investment levels, FY12 – December 31, 2016;

v. Exhibit __ (EIOP-5): Transmission capital investment plan, FY18 – FY22;

vi. Exhibit __ (EIOP-6): Details of significant transmission capital investment plan projects and programs, FY18 – FY22;

vii. Exhibit __ (EIOP-7): Sub-transmission capital investment plan, FY18 – FY22;

viii. Exhibit __ (EIOP-8): Details of significant sub-transmission capital investment plan projects and programs, FY18 – FY22;

ix. Exhibit __ (EIOP-9): Distribution capital investment plan, FY18 – FY22;

x. Exhibit __ (EIOP-10): Details of significant distribution capital investment plan projects and programs, FY18 – FY22;

xi. Exhibit __ (EIOP-11): Common capital investment plan, FY18 – FY22;

xii. Exhibit __ (EIOP-12): Summary of known and measureable O&M program cost changes from the Historic Test Year to Rate Year;

xiii. Exhibit __ (EIOP-13): Incremental labor adjustments;

xiv. Exhibit __ (EIOP-14): NWA project opportunities list;

xv. Exhibit __ (EIOP-15): Research, Development & Demonstration spending plan, CY16 – CY20.

The Panel also includes the following workpapers: the Company's Annual Transmission and Distribution Capital Investment Plan, dated January 31, 2017 ("5-Year CIP"); the Initial Distributed System Implementation Plan, dated June 30, 2016 ("DSIP"); and the Report on the Condition of Physical Elements of Transmission and Distribution Systems, dated

October 1, 2016 ("Asset Condition Report"), all of which are presented in Exhibit __ (EIOP-16).

Q. Please explain the objectives of the infrastructure investment and operations plans presented in this filing.

A. The Company's electric infrastructure and operations plans are developed to meet its obligation to provide customers with safe, reliable, and adequate service at reasonable costs, and to do so in an environmentally sound manner. The Company's electric service territory encompasses approximately 25,000 square miles in more than 450 cities and towns, and serves approximately 1.6 million customers. In addition to building infrastructure to meet new customer needs, the Company's investment plan also addresses the needs of the existing infrastructure. The Company's system is comprised of over 6,000 circuit miles of transmission lines, more than 300 transmission substations, over 4,800 circuit miles of sub-transmission lines, over 525 distribution substations, more than 700 large power transformers, 36,000 circuit miles of primary on over 1.2 million distribution poles supplying over 400,000 line transformers, and many more assets.

A significant number of assets have been in service for 70 years or more, and exhibit conditions consistent with their age. In many cases, such equipment can no longer be effectively maintained because of obsolescence. Attention to these assets is essential to continued reliable operation of the system.

The Company's plans also identify capital and O&M spending designed to meet state and federal regulatory requirements for the electric system, to address load growth/migration, to fund investments necessary to accommodate new public policy initiatives, and also to move towards a more distributed system platform as described in the Company's DSIP filing.

In summary, the Company's overall objective is to develop cost-effective investment and operations plans that meet the needs of customers, maintain the integrity of the system, and continue the transition to a more advanced, resilient, and efficient electric system.

III. Capital Investment Plan

A. Introduction

Q. Please describe the Company's capital investment plan.

A. The Company is continually evaluating its system requirements relating to capacity, reliability, customer and public needs, asset condition, and other factors. The Company prepares and submits to Department of Public Service Staff ("Staff") a number of periodic reports that address the infrastructure condition, planned investments, and actual capital investment performance. These reports include the Company's 5-Year CIP and Asset Condition Report. The most recent submission of each of these reports is included in the Panel's workpapers, Exhibit __ (EIOP-16).

The 5-Year CIP covers the period FY18 – FY22, and describes the Company's capital investment plan by system (*i.e.*, transmission, sub-transmission, and distribution), as well as by spending rationale (*i.e.*, customer requests/public requirements, damage/failure, asset condition, system capacity, reliability, communication/control systems, DER-electric system access, and non-infrastructure). Although the 5-Year CIP provides the starting point for the Company's capital investment plan, the plan presented in this case differs in certain aspects from the 5-Year CIP.

Q. How do the 5-Year CIP and the plan in this filing differ?

A. In preparing the investment plan presented in this case, the Company carefully considered how best to implement the electric system and market modernization objectives exemplified by the Commission's REV initiative, while recognizing the need to effectively balance transitional cost impacts to customers. As a result, the plan presented here reflects some changes to the projects and programs in the 5-Year CIP as well as changes in implementation schedules.

In addition, the capital investment plan presented herein includes certain investments, such as capital investments in IS assets, buildings and facilities, operations support (including fleet, aviation), inventory management and investment recovery functions, that are not covered by the 5-Year CIP.

Q. Please summarize the Company's DSIP.

A. The DSIP filed on June 30, 2016 marked the starting point of the Company's evolution as a Distributed System Platform ("DSP") provider. The contents of the initial DSIP were intended to:

- Inform customers and stakeholders as to the Company's existing capabilities and the compatibility of its T&D system with respect to the REV objectives and the functionalities of a DSP;
- Provide information to stakeholders that may facilitate the integration of increasing levels of DER; and

- Present a roadmap and five-year plan of potential investments to enhance the Company's DSP capabilities.

The initial DSIP addresses the development of the Company's DSP capabilities in four focus areas: DSP Development; Advanced Metering; Grid Modernization; and Cybersecurity and Privacy.

Q. How are the DSIP recommendations represented in this filing?

A. The DSIP recommendations impact almost every functional area within the Company. Potential investments presented in the DSIP have been integrated into the implementation plans of each business function and elements of the DSIP recommendations are found throughout this filing. Below, the Panel summarizes this integration and provides a guide as to where more information is provided on the various DSIP elements in this filing.

DSP Development

- <u>Interconnection On-Line Application Portal:</u> The development of this IS application is discussed in our Panel's testimony, and rent expense costs are supported in the exhibits to the direct testimony of the Information Services ("IS") Panel.

- Integrated Planning: This category covers a number of initiatives including Load and DER Forecasting, Hosting Capacity Analysis, and NWA assessments. Investments necessary to enhance integrated planning include increased resources (both internal staffing and contractors), as well as the procurement of data to support more advanced forecasting. The incremental resource needs are discussed in our Panel's testimony and the data procurement is presented in the exhibits to the direct testimony of the IS Panel.
- System Data Portal: The need for additional staff to support the maintenance and enhancement of the Company's System Data Portal available to DER providers is discussed in this Panel's testimony.
- Customer Energy Management Platforms: A number of customer enabling projects are supported in the direct testimony of the Electric Customer Panel.
- DER Management System ("DERMS") / DSP Platform: The Company is evaluating platform technologies as part of a REV demonstration project discussed in the direct testimony of the Electric Customer Panel. No additional projects are proposed at this time and the DSIP indicated the Company would evaluate DERMS later as DER penetrations increase and technologies develop.

Advanced Metering

- A detailed discussion of the Company's AMI business plan and deployment schedule is presented in the direct testimony of the AMI Panel.

Grid Modernization

- <u>Foundational IS:</u> The DSIP discussed the need for foundational enhancements to National Grid's information technology systems and processes to support the increasingly digital environment. The direct testimony of the IS Panel includes plans to develop service bus architecture, cloud computing and data lakes, as well an advanced analytics platform.
- <u>DMS / DSCADA:</u> Enhancing the capability of control center operators is critical to managing the increasingly complex distribution system. The deployment of a distribution management system ("DMS") and dedicated distribution Supervisory Control and Data Acquisition ("SCADA") is discussed in this Panel's testimony, and associated costs are presented in the exhibits to the direct testimony of the IS Panel.
- <u>Plant Information Historian:</u> To maintain the increasing volume of operational data captured through SCADA and DMS, storage

capabilities need to be expanded and additional data mining capabilities developed. The historian enhancement project is presented in the direct testimony of the IS Panel.

- Telecommunications: The expansion of telecommunications capabilities to monitor and control distributed devices requires the installation of additional telecommunications assets to the Company's substations and along its distribution feeders. Projects for these field assets are presented in this Panel's testimony. In addition to the field assets, back office information systems need to be enhanced to manage the communication systems the data generated from them. Associated telecommunications projects are presented in the direct testimony of the IS Panel.
- Remote Terminal Units ("RTU"): A number of RTU projects, which enable remote monitoring and control of T&D substations, are presented in this Panel's testimony.
- Distribution Automation: Projects to install distribution sensors and to implement Volt-Var Optimization/Conservation Voltage Reduction ("VVO/CVR") and automated circuit restoration are presented in this Panel's testimony.
- GIS Data Enhancement: The accurate modeling of the distribution system is central to many of the Company's DSP enabling initiatives

including DMS, load and DER forecasting, hosting capacity analysis, and the automation of interconnection applications. An effort to enhance and expand the data maintained in the Company's GIS system is presented in this Panel's testimony.

- Training: The necessary training for each initiative is included in the cost and schedule for that initiative. A stand-alone training program, although included in the DSIP roadmap, is not a part of this filing.
- Integrated Network Operating Center ("INOC"): The DSIP discussed the long term need for an INOC to coordinate and manage the operations of the expanding telecommunications systems associated with the DSP. This is still the Company's vision, however, the Company does not plan to develop an INOC within the horizon of the Rate Year and Data Years and therefore it is not included in this filing.
- Field Force Enablement: The initiative discussed in the DSIP for field force enablement is not progressing at this time and is not included in this filing.

Cyber Security

- A broad cyber security program is presented in the direct testimony of the IS Panel.

Q. What is the Company's proposed electric capital investment for the Rate Year?

A. In the Rate Year, the Company plans to invest approximately $554.2 million in its electric transmission, sub-transmission, and distribution infrastructure. This amount includes investments in traditional infrastructure to provide for the continued reliability of the transmission and distribution system, as well as to provide service to new and expanding customers. The plan also includes investments to accommodate the expansion of broadband across the state, the transition of the Company's street light system to LED technology, and the increased deployment of electric system monitoring, control and communications technology. The capital plan also includes spending for the Company's AMI program, which is described in the direct testimony of the AMI Panel.

In addition to direct capital investment in the electric system, the Company also will be procuring a substantial amount of IS services to operate and maintain the system, and implement REV objectives. These IS services are beyond the Company's traditional IS services, and include increased investments for cyber and physical security, system modernization, and investments to facilitate customer access to system information and the development of a more distributed energy system. The vast majority of IS investments are made by the Service Company and are charged to Niagara Mohawk in the form of "rent expense." Although they are not direct capital investments by Niagara Mohawk, many of the IS investments included in this rate case are necessary to support the Company's capital investments. Accordingly, the Panel addresses relevant IS investments that are needed to support the safe and reliable operation of the electric delivery system, as well as IS investments necessary to enable more advanced, distributed grid functionality. Additional support for IS projects and programs is provided in the direct testimony of the IS Panel.

The Company also plans to make capital investments of approximately $13.5 million per year in facilities and properties. These investments are needed for the continued provision of safe and adequate service to customers, and are important to the Company's infrastructure and operating plans going forward.

The total level of planned electric and common capital investment is set forth in Exhibit __ (EIOP-3).

B. Electric Infrastructure Capital Investment Plan

Q. Please describe how the Company's electric infrastructure capital investment plan is presented.

A. The Company's investment plan is presented by delivery system level (*i.e.*, transmission, sub-transmission, and distribution), and by spending rationale within each delivery system level. The spending rationales describe the primary drivers for the investments. The eight spending rationales are: (1) Customer Requests/Public Requirements; (2) Damage/Failure; (3) System Capacity; (4) Reliability; (5) Asset Condition; (6) Communications/Control Systems; (7) Distributed Energy Resources (DER)-Electric System Access; and (8) Non-infrastructure.

Q. Please describe what capital expenditures are included in the Customer Requests/Public Requirements spending rationale.

A. Customer Requests/Public Requirements work includes capital expenditures required for the Company to meet customer requests for service and requests or requirements from public entities. Such items include new business requests (residential and commercial), new metering installations, outdoor lighting, third-party attachments, land rights, municipal relocations, generator interconnections (not DER), and other requirements, including municipal and customer interconnections.

Q. Please describe what capital expenditures are included in the Damage/Failure spending rationale.

A. This category includes capital work required to replace failed or damaged equipment and to restore the electric system to its original configuration and capability following equipment damage or failure. Damage may be caused by storms, vehicle accidents, vandalism or unanticipated deterioration, among other causes.

Q. Please describe what capital expenditures are included in the System Capacity spending rationale.

A. System Capacity projects are required to upgrade the capability of the T&D delivery system to provide adequate stability, thermal loading, and voltage performance under existing and anticipated system conditions.

Q. Please describe what capital expenditures are included in the Reliability spending rationale.

A. Reliability projects are required to improve power quality, reliability and resiliency performance. Examples of investments in this rationale include investments to meet North American Electric Reliability Corporation ("NERC") requirements, bring substations to Northeast Power Coordinating Council, Inc. ("NPCC") design, protection and operation standards, comply with New York State Reliability Council rules, and to address reliability issues identified as a result of system studies. These types of investments were previously listed under the System Capacity and Performance rationale, which has been segmented to present the two drivers, capacity and reliability, separately.

Q. Please describe what capital expenditures are included in the Asset Condition spending rationale.

A. Asset Condition work includes capital work required to reduce the risk and consequences of unplanned failures of transmission, sub-transmission and distribution assets. The Company conducts an annual asset health assessment that includes analyses of each major asset class and asset system. The assessments focus on identification of specific susceptibilities (failure modes) and the development of alternatives to avoid such failure modes.

Q. Please describe what capital expenditures are included in the Communications/Control Systems spending rationale.

A. Communication/Control Systems projects are required for monitoring and controlling the distribution system, and include such things as installing EMS/RTU and advanced metering communications.

Q. Please describe what capital expenditures are included in the DER-Electric System Access spending rationale.

A. DER-Electric System Access projects are investments required to enable the Company to support implementation of items such as distributed generation ("DG") interconnections, NWA, microgrids, storage, and other similar initiatives.

Q. Please describe what capital expenditures are included in the Non-infrastructure spending rationale.

A. The Non-infrastructure category of investment is for capital expenditures that are not directly associated with the distribution or transmission of energy, but are necessary to run the electric system. In this category are items, such as tools and general plant, that are required to operate the network. Examples of such investments include spending for truck-to-truck radio systems and test equipment.

Q. Please identify how the $554.2 million planned Rate Year infrastructure investment is distributed among the delivery system levels and spending rationales.

A. The $554.2 million planned investment in electric system infrastructure in the Rate Year breaks down as follows:

- Transmission--$206 million,
- Sub-transmission--$37.2 million, and
- Distribution--$311 million.

Approximately 32.6 percent ($180.8 million) of the total planned spend across the electric delivery system is considered mandatory work in the Customer Requests/Public Requirements and Damage/Failure spending rationales; 15.5 percent ($86.02 million) is in the System Capacity spending rationale; 8.4 percent ($46.77 million) is in the Reliability spending rationale; 40.7 percent ($225.81 million) is driven primarily by Asset Condition issues; 1.6 percent ($8.70 million) is in the Communications/Control Systems spending rationale; 0.7 percent ($3.61 million) is in the DER-Electric System Access spending rationale; and the remaining 0.5 percent ($2.55 million) is Non-Infrastructure related.

Q. How does the proposed investment level compare to historic levels?

A. Exhibit __ (EIOP-2) shows the Company's annual actual and planned electric infrastructure capital expenditure levels for transmission, sub-transmission, distribution, and total for FY12 – FY22.

Q. How do the Company's annual historic investment levels compare to corresponding budgeted levels for those years?

A. That information is included in Exhibit __ (EIOP-4).

1. Transmission System Investment

Q. Please summarize the Company's planned transmission system capital investment for the Rate Year.

A. In the Rate Year, the Company plans to invest $206 million in its transmission infrastructure. This transmission investment is comprised of the following:

- Damage/Failure: $7.3 million
- System Capacity: $64.2 million
- Reliability: $ 13.1 million
- Asset Condition: $119.8 million
- Communications/Control Systems: $1.7 million

Exhibit __ (EIOP-5) details the Company's transmission investment plan by spending rationale, by program within each spending rationale, and by project within each program for FY18 – FY22.

Q. What information is presented in Exhibit __ (EIOP-6)?

A. In Exhibit __ (EIOP-6), the Company provides additional information for significant transmission projects within the plan, including:

- Project or Program name
- Capital funding number
- Spending rationale
- Project or Program description
- Project or Program justification
- Customer benefits discussion
- Alternatives discussion
- Reference to other supporting information (*e.g.*, studies, sanction papers, *et cetera*)
- Estimated costs and cost breakdown (at the applicable estimating accuracy level)
- Schedule

Q. What are some of the major transmission projects or programs included in the Company's infrastructure investment plan?

A. Significant transmission projects reflected in the Company's plan include:

- The Gardenville-Dunkirk 141-142 Northern Phase Rebuild involves rebuilding the Gardenville-Dunkirk 141 (T1260) and Gardenville-Dunkirk 142 (T1270) 115 kV transmission circuits between the Gardenville and North Angola Stations. The project will address asset condition and potential safety issues of the lines, as well as relieve thermal overload during periods of high power imports from Ontario and low loads in Western New York ($85.8M, FY18 – 22).

- The Pannell-Geneva 4 4A T1860 ACR project is necessary to continue to provide reliable 115kV network service with Rochester Gas and Electric Corporation ("RG&E") and New York State Electric and Gas Corporation ("NYSEG"). National Grid owns the line connecting RG&E's Pannell station and NYSEG's Border City (Geneva) station. The project will replace the entire length of line conductor due to recent LineCore conductor testing results of the neighboring Mortimer-Pannell 24 115kV line, which is the same vintage and conductor type, and which shows zinc loss due to corrosion. The project also includes addition of shield wire, as well as adding permanent access roads to upland areas ($41.2M, FY18 – 22).
- Huntley-Lockport #36 (T1440) & #37(T1450) will address broken conductor strand issues found in the 556.5 kcm AAC "Dahlia" conductor adjacent to compression splices following numerous failures in 2015 and 2016. The project includes replacing conductor and shield wire for 8.6 miles ($16.7M, FY18 – 22).

- Lockport-Batavia 112 (T1510) 115 kV transmission circuit. Conductor and shield wire testing in 2015 determined that all ACSR conductor and shield wire can remain in service. However, 17.5 miles of the 428 AAC conductor will be replaced because the calculated breaking strength was as much as 14 percent below the rated breaking strength. Reconductoring also is appropriate because this is a non-standard conductor and it is difficult to obtain spare parts (conductor and splices) in the event of a failure. The project also includes replacement of several tower and wood pole structures based upon an engineering field evaluation ($49.9M, FY18 – 22).
- The Lasher Road substation project will add a new 115 kV switching station that will relieve exposure to potential post-contingency thermal overloads on the 115kV system in the Northeast Region. The project will provide capacity for growth in the Northeast Region and Luther Forest and mitigate adverse effects on reliability associated with potential generation retirements, which are presently a concern in the Northeast Region. The project also will allow for the retirement of the Randall Road 34.5-13.2kV station, as well as for the retirement of certain sub-transmission lines ($18M, FY18 – 22).

- The Gardenville rebuild project will address a history of poor performance primarily due to asset condition issues. The project includes construction of a new 115kV breaker and a half substation at the Gardenville substation site, including connections to the 230-115kV transformers, the re-routing of existing incoming transmission lines to reduce the potential for multiple interruptions for a single event. Gardenville substation is an important station in the Western Division, supplying approximately 750MVA of load to distribution stations via seventeen (17) 115kV circuits, and a rebuild is necessary to ensure continued reliable service to customers ($31.8M, FY18 – 22).

Detailed information about these projects is included in Exhibit __ (EIOP-6), as well as in Chapter II of the Company's 5-Year CIP in Exhibit __ (EIOP-16).

2. Sub-Transmission System Investment

Q. Please summarize the Company's planned sub-transmission system capital investment in the Rate Year.

A. In the Rate Year, the Company plans to invest $37.2 million in its sub-transmission infrastructure. This annual sub-transmission investment amount is comprised of the following:

- Customer Requests/Public Requirements: $2.1 million
- Damage/Failure: $4.2 million
- System Capacity: $2.3 million
- Reliability: $4.3 million
- Asset Condition: $24.4 million

Exhibit __ (EIOP-7) details the Company's sub-transmission investment plan by spending rationale, by program within each spending rationale, and by project within each program for FY18 – FY22.

Q. What information is presented in Exhibit __ (EIOP-8)?

A. In Exhibit __ (EIOP-8), the Company provides additional information regarding significant sub-transmission projects within the plan, including:

- Project or Program name
- Capital funding number
- Spending rationale
- Project or Program description
- Project or Program justification
- Customer benefits discussion
- Alternatives discussion

- Reference to other supporting information (*e.g.*, studies, sanction papers, *et cetera*)
- Estimated costs and cost breakdown (at the applicable estimating accuracy level)
- Schedule

Q. What are some of the major sub-transmission projects or programs included in the Company's infrastructure investment plan?

A. Significant sub-transmission projects reflected in the Company's plan include:

- The West Portland-Sherman 867 34.5 kV is a 23.1-mile long sub-transmission line targeted for refurbishment to address potential safety and reliability concerns due to deteriorated assets. The line consists of single wood pole structures, and steel structures in single circuit configuration located in the towns of West Portland, Ripley and Sherman south of Dunkirk, New York. The scope includes the replacement of 11.38 miles of small non-standard copper conductor and 227 new structures with additional work on other structures some of which are in designated wetlands ($3.6M, FY18 – 22).

- The Old Forge-Racquette Lake 22 46 kV sub-transmission line is part of a 60-mile long radial line that runs from Boonville-Racquette Lake on National Grid's 46 kV system and is targeted for partial refurbishment to address safety and reliability issues from deteriorated assets and tree concerns. Engineering inspection has identified deteriorated structures and a large number of splices on the 2/0 copper conductors, which have contributed to the poor performance of this line. The scope includes refurbishing six miles of line utilizing insulated conductor in light of the significant tree line adjacent to the circuit in this area ($5.9M, FY18 – FY22).
- The Trenton-Whitesboro 25-46 kV sub-transmission line is 24 miles long and is targeted for refurbishment to address potential safety and reliability concerns due to deteriorated assets north of the Marcy State Hospital Tap. The scope includes replacement of 26 structures on the main line and 20 additional structures on the Marcy State Hospital Tap. In addition, 43 steel towers with damage or deterioration need to be addressed, the shield wire will be tested for structural integrity, and deteriorated post insulators will be replaced due to cracking and tracking ($3.9M, FY18 – FY22).

Detailed information about these projects is included in Exhibit __ (EIOP-8), as well as in Chapter III of the Company's 5-Year CIP included in Exhibit __ (EIOP-16).

3. Distribution System Investment

Q. Please summarize the Company's planned distribution system capital investment in the Rate Year.

A. In the Rate Year, the Company plans to invest $311 million in its distribution infrastructure. This annual distribution investment amount is comprised of the following:

- Customer Requests/Public Requirements: $119.7 million
- Damage/Failure: $47.6 million
- System Capacity: $19.5 million
- Reliability: $29.4 million
- Asset Condition: $81.7 million
- Communications/Control Systems: $7 million
- DER-Electric System Access: $3.6 million
- Non-Infrastructure: $2.5 million

Exhibit __ (EIOP-9) details the Company's distribution investment plan by spending rationale, by program within each spending rationale, and by project within each program for FY18 – FY22.

Q. What information is presented in Exhibit __ (EIOP-10)?

A. In Exhibit __ (EIOP-10), the Company provides additional information regarding significant distribution projects within the plan, including:

- Project or Program name
- Capital funding number
- Spending rationale
- Project or Program description
- Project or Program justification
- Customer benefits discussion
- Alternatives discussion
- Reference to other supporting information (*e.g.*, studies, sanction papers, *et cetera*)
- Estimated costs and cost breakdown (at the applicable estimating accuracy level)
- Schedule

Q. What are some of the major distribution projects or programs included in the Company's infrastructure investment plan?

A. Significant distribution projects reflected in the Company's plan include:

- The Buffalo Station 59 rebuild project includes substation, distribution line and sub-transmission line elements. The primary drivers for this project relate to potential safety, reliability and maintenance concerns of the existing equipment and the ability to serve load. The existing equipment at this indoor substation has a potential risk of failure due to its condition. In addition, the equipment is obsolete, which makes repairs and acquisition of spare parts difficult. The combined substation, distribution and sub-transmission line projects resolve the safety and reliability issues inherent in this 1930s vintage substation by rebuilding Buffalo Substation 59 adjacent to the existing substation. Station 59 serves the Larkin District in the City of Buffalo, which currently has several large commercial customers with new services and anticipates adding several others. Large commercial customers require capacity that exceeds what is normally available on a 4.16 kV feeder ($5.5 million; FY18 – FY22).

- The Van Dyke project calls for a new substation to serve new load needs in the area as well as address some existing asset condition issues. The scope of the project includes two 24/32/40MVA, 115/13.2kV LTC transformers, two six-position metal-clad switchgear units, and two 3.6MVAR station capacitor banks. Line taps of the Bethlehem-New Scotland #4 115kV transmission line will be extended to serve the station, six distribution feeder getaways will be constructed in an underground duct bank and approximately 14 miles of overhead distribution will be re-conductored or converted to 13.2kV operation. All load from Juniper and Delmar substations will be transferred to the new Van Dyke substation feeders and those former stations retired. New relaying equipment also will be installed at Bethlehem and Patroon substations to replace the relaying being retired at Delmar substation ($22.2 million; FY18 – FY22).

- The Sodeman Road substation will add needed capacity to the Northeast Region. The project will include a 15/20/25MVA, 115/13.2kV LTC transformer, four-feeder position metal-clad switchgear, and a 3.6MVAR station capacitor bank. Line taps off the adjacent 115kV transmission line will be extended approximately 400 feet to serve the station, four distribution feeder getaways will be constructed in an underground duct bank and approximately 6 miles of overhead distribution will be reconductored or converted to 13.2kV operation, along with the reconfiguration of the area feeders. The Sodeman Road project will enable retirement of the 34.5kV Rock City Falls Substation and approximately 3.5 miles of 34.5kV supply line, and will also allow the 144 mile long Brook Road 36955 feeder, which has a history as a worst performing feeder, to be split into two to reduce customer exposure to interruptions in the future. Strengthened feeder ties with existing neighboring 13.2kV distribution stations in the area (Ballston and Brook Road) will reduce the amount of unserved load during transformer/feeder outages ($14.7 million, FY18 – FY22).

- The VVO/CVR program involves deployment of voltage control devices, such as capacitors and voltage regulators, in an intelligently controlled and coordinated manner to optimize performance of the distribution system. The program will reduce customer load and energy use, and help lower overall costs. VVO/CVR installations are being implemented as part of the Company's Clifton Park REV Demonstration Project, and the program proposed here would deploy VVO/CVR technology to approximately 100 additional distribution circuits from 37 substations over the period FY19 – FY22 ($23.4 million, FY19 – FY22). The benefit-cost analysis for this program is included in Exhibit __ (ECP-1) to the Electric Customer Panel's direct testimony.

- The Advanced Distribution Automation, also known as Fault Location Isolation and Service Restoration (“FLISR”), is a control scheme that uses telecommunications and advanced control of key switching devices to improve reliability and facilitate operations and maintenance. The control schemes will enable an automated response to system contingencies to minimize customer interruptions and expedite system reconfiguration and service restoration. The remote monitoring and control capabilities will enable system operators to more efficiently and effectively manage operations. To enable these capabilities, select manual switches and feeder ties will be upgraded to automated switches and integrated with the Company’s SCADA system and future DMS ($18.8 million, FY20 – FY22).
- The Substation Communications Expansion project upgrades and expands the Company’s communications network connecting substations with Control Center and corporate information systems. The program will provide new public or private communications capability to select substations that currently have no operations communication capability. This program will also provide enabling telecommunications capabilities which support multiple projects and initiatives ($16.7 million, FY18 – FY22).

- The Company's Distribution Line Sensors/Monitors program will deploy overhead line sensors throughout the Company's distribution system, typically where RTUs are not available in the distribution substation. The sensors and monitors are capable of providing near real-time measurements of system performance to enable better management of the electric delivery system. The more granular loading and voltage information made available from these sensors and monitors will support improved distribution system planning, hosting capacity analyses, and NWA consideration and provide system operators improved situational awareness. ($12 million, FY19 – FY22).
- The Company is proposing to increase its investment in RTUs to add remote monitoring and control to substations currently without that capability, and to support deployment of a DMS and distribution SCADA system in the Control Center. RTUs are located in substations and communicate information about substation equipment status and operational values (*i.e.*, volts, amperes, watts, VARs, *et cetera*) with the Company's Energy Management System ("EMS"). Timely and accurate communication of such information reduces response times to, and impacts of, operating excursions and abnormal conditions. RTUs

enable improved situational awareness to control center operators and remote operation and control of select field equipment to improve reliability and increase safety ($32.8 million, FY18 – FY22).

- The $3V_0$ program provides for the addition of substation upgrades to facilitate the deployment of distributed generation resources. The $3V_0$ program will deploy protection equipment that will make the upgraded substations "DG ready" and reduce financial impediments to DER implementation ($9 million, FY19 – FY21). The Electric Customer Panel discusses a Platform Service Revenue proposal in connection with this program, and projected revenues are reflected in Exhibit __ (E-RDP-2), Schedule 4, Page 10 of 10.
- The Company's planned broadband investment is intended to support implementation of Governor Cuomo's New NY Broadband Program. The New NY Broadband Program's goal is to ensure that nearly every New Yorker has access to broadband services (defined as high-speed internet and advanced telecommunication services) by the end of 2018. The New NY Broadband Program will invest up to $500 million in State grant funding to support statewide broadband investment, with a dollar for dollar match being provided by telecommunications and

internet service providers. Additionally, in conjunction with its merger with Time Warner Cable, Charter Communications agreed to a four-year plan to provide broadband service to approximately 145,000 households and businesses in Upstate New York beginning in 2016. A large number of the customers that will be affected by the New NY Broadband Program and Charter's broadband expansion are in the Company's service territory. These broadband initiatives will require certain make ready work on Company facilities to accommodate broadband expansion, including survey, design and other construction work. Although the majority of Company costs associated with the make ready work will be fully reimbursed by the telecommunications providers, the Company has determined that in a small percentage of cases, existing facilities may not be in compliance with applicable clearance standards and may require pole replacement or other investment to accommodate the requested attachment. In those cases, such work is not recoverable from the telecommunications providers, and the cost is included in the Company's investment plan.

Given the size and scope of the broadband expansion, the Company has forecast capital investment of $8.05 million associated with these initiatives to accommodate broadband expansion ($4.28 million in FY18, $2.56 million in the Rate Year, and $1.21 million in Data Year 1). The forecast is based on the Company's review of projected areas and facilities likely to be affected within its service territory. Actual estimates will be developed upon receipt of pole attachment requests with specific locations for survey and assessment of work requirements. These costs have been included in the Company's capital plan, and are reflected in Exhibit __ (EIOP-1). Increased third-party attachment revenues associated with the broadband expansion initiative are included as offsets to the Company's revenue requirement and are reflected in Exhibit __ (E-RDP-2), Schedule 3.

Detailed information about many of these projects and programs is included in Exhibit __ (EIOP-10), as well as in Chapter IV of the Company's 5-Year CIP included in Exhibit __ (EIOP-16).

Q. Does the Company's capital investment plan include costs associated with the REV demonstration projects Niagara Mohawk is implementing?

A. Yes. As authorized by the Commission in its February 26, 2015 Order in Case 14-M-0101, Niagara Mohawk has deferred the revenue requirement impacts from its authorized REV demonstration projects until this rate plan filing. Treatment of the deferral balance is discussed by the Revenue Requirements Panel. Any going forward capital and O&M costs that are not reflected in the deferral amounts are included in the revenue requirements.

Q. Does the Company describe the REV demonstration projects in this case?

A. Yes, the demonstration projects are described in detail in the testimony of the Company's Electric Customer Panel.

C. <u>Information Services</u>

Q. Do the Company's electric system capital investment and O&M plans rely on any significant new IS investments?

A. Yes. The Company's investment and operating plans presented in this case rely on several IS investments. Some of the IS investments are intended primarily to facilitate certain specific electric infrastructure or O&M initiatives, such as control center system enhancements, improved DG interconnectability, and system hosting capacity analyses. Some of these IS investments primarily, or exclusively, benefit Niagara Mohawk and are allocated directly to the Company, or may be direct capital investment by the Company. Other IS investments may benefit other National Grid operating companies, in which case the investments are typically made by the Service Company, with costs allocated to the benefitted operating companies (including Niagara Mohawk) pursuant to an annual rent expense. IS investments that primarily support the Company's electric delivery infrastructure and operations are addressed in this testimony, as well as in the direct testimony of the IS Panel.

Q. Please describe the SCADA and DMS plans for the Control Center.

A. To be able to safely and reliably manage a more complex distribution system with higher penetrations of DER and increased numbers of advanced distribution assets, the Company plans to deploy a dedicated distribution SCADA system and a DMS for Control Center operators. The primary role of the SCADA system is to collect data from intelligent electronic devices on the distribution network for use by operators and the DMS, and transmit commands, settings, and other operational functions from operators and/or the DMS to the intelligent electronic devices. The DMS consists of engineering-focused applications that can either assess and advise in the operation of the distribution network, or automatically monitor and control devices on the distribution network. DMS applications utilize the as-operated network model in the DMS, as well as monitoring data from the intelligent electronic devices throughout the distribution network and substations. Expanding the number of SCADA points is necessary to accommodate the growing number of devices, both utility and customer/DER, that can be monitored and controlled. In addition to expanding the distribution SCADA points, the Company plans to separate the transmission and distribution SCADA environments to improve security. The DMS applications will allow system operators to produce loadflow simulations of as-is and forecast system configurations to identify potential issues, evaluate restoration switching alternatives and support enhanced distribution system automation. The SCADA and DMS investments will be undertaken by National Grid Service Company. The costs for these projects are reflected in Exhibit __ (RRP-11), Workpapers to RRP-3, Schedule 9, Workpapers 3, 6 and 9. Associated Company projects in this case are planned to enable the SCADA and DMS deployments, including the expansion of RTUs discussed earlier, and the GIS Data Enhancement program discussed later in this testimony.

Q. What other IS investments are presented in the Company's plan?

A. The Company's electric system operations rely on several other IS investments that are being made by the Service Company, and for which the Company will be assessed annual rent expense. One significant IS project aimed at advancing DER penetration goals is the DG Interconnection Online Application Portal.

Q. Please describe the DG Interconnection Online Application Portal project.

A. The DG Interconnection Online Application Portal ("DG IOAP") will simplify and automate the process for customers and developers applying for an interconnection to the Company's distribution system. The application will be rolled out in phases to provide the capabilities described in the *New York Interconnection Online Application Functional Requirements* document provided to the Company by Staff in September 2016.

Q. What is the timing of the project?

A. The DG IOAP project will be implemented in phases. For DG applications less than 5MW, Phase 1 of the DG IOAP is anticipated to deliver quantitative and qualitative benefits to customers and the Company. The DG IOAP is expected to reduce application review and approval lead times, and provide customers with immediate access to project status, including meter set dates. Customers will also have ability to make online payments. Many of these features will be in place by May 2017 while full functionality, in line with Electric Power Research Institute ("EPRI") specifications, will be available by October 1, 2017.

In future phases, the Company expects to further improve application processing lead times through automation of technical screenings. Implementation of these future phases will be more challenging than Phase 1 due to the need to integrate a number of existing systems, including the Customer Information System ("CIS"), Work Management System ("WMS"), and GIS, as well as information from the Company's on-going Hosting Capacity Analysis. The Company continues to work through the Interconnections Technical Working Group to finalize the desired technical screens to be automated, and an internal project team is developing the detailed scope and schedules for the next phase of deliverables. A conceptual estimate for the future phases is presented in the exhibits to the direct testimony of the IS Panel.

Q. Are costs of the DG IOAP reflected in the Company's filing?

A. Yes. The capital costs for the Phase 1 deliverables are reflected in Exhibit __ (ISP-3) to the direct testimony of the IS Panel. The estimated costs for future phases of the DG IOAP are presented in the IS projects exhibits. Estimates for the future phases have a three-year cumulative (FY19-FY21) project cost of $19.13 million, which consists of $14.84 million of capital expense and $4.3 million of operation and maintenance expense. The DG IOAP will be a shared asset owned by the Service Company, and a portion of the revenue requirements related to the DG IOAP will be allocated to the Company. The Company's rent expense forecast for the project is $0.735 million in Data Year 1 and $3.329 million in Data Year 2, as shown in Exhibit __ (RRP-11), Workpapers to Exhibit __ (RRP-3), Schedule 9, Workpapers 6 and 9. The operations and maintenance expense for the DG IOAP in the Data Years is included in Exhibit ___ (RRP-3), Schedule 27.

Q. Is National Grid making other operations-related IS investments that are reflected in this rate case?

A. Yes. National Grid is making several foundational IS investments necessary to enable Niagara Mohawk and other National Grid companies to continue to operate safely, securely and efficiently. These investments include cyber security, Cloud Computing and Data Lake, Information Management and Advanced Analytics, Enterprise Service Bus (ESB) Architecture and Application Programming Interface (API) Integration Services, PI Historian, and Load and DER Forecasting. These initiatives, and their associated costs, are supported by the testimony of the IS Panel.

D. Capital Plan Budgeting

Q. Please describe the development of the Company's capital plan.

A. The Company's capital plan is developed to achieve the objectives of delivering safe and reliable service. Projects are categorized by the spending rationales, and proposed spending includes the latest cost estimates for in-progress projects as well as initial estimates for newly proposed projects. Expected deviations from historic trends, volume and cost of work are also considered.

All mandatory projects known at the time are included in the plan. Once the budget level has been established for the mandatory work, projects in the other spending rationales are reviewed for inclusion in the plan. The decision to include a project in the plan is based on several factors including, but not limited to, whether the project is new or in-progress, risk score, and resource availability.

Once developed, the plan is reviewed with the President of the New York jurisdiction and the Finance organization. The New York President reviews the overall customer, service quality and financial impacts of the investment plan as part of the business planning process and may request changes to the level or combination of investments.

A corporate plan is then presented to the National Grid plc Executive Committee. The capital portfolio is subsequently presented to the National Grid plc Board of Directors for review and approval. The budget amount is approved on the basis that it meets the business objectives set for that year. The result of the budgeting process is the approval of the capital spending plan for the budget year.

Q. Are there additional approvals needed before a project or program in the annual capital plan can proceed?

A. Yes. Aside from the capital planning and budgeting process, specific approval must be obtained for any project or programs within the five-year capital plan to proceed. Approval is obtained through a delegation of authority process. All projects and programs greater than $8 million are reviewed for approval by the U.S. Sanctioning Committee ("USSC"), a committee established by the National Grid USA Board of Directors for this purpose. Projects or programs estimated at greater than $25 million are reviewed and approved by the Senior Executive Sanctioning Committee ("SESC"). Other projects and programs from $1 million to $8 million are approved by the Senior Vice President of Electric Process and Engineering and are considered by the USSC through that committee's consent agenda process. Projects less than $1 million are approved through a supervisory hierarchy based on certain established delegated authority thresholds.

Q. Please explain the difference between the DOA review and approval (sanctioning) process and the approved five-year capital plan used to forecast the Rate Year and Data Years.

A. The timing of the sanctioning process is not aligned with the capital planning process used to forecast the Rate Year and Data Years. The Company develops a long term investment plan that is used as the basis for the forecast for the Rate Year, Data Year 1, and Data Year 2 proposals. Sanctioning, however, generally takes place on an on-going basis, with most projects and programs sanctioned just prior to the fiscal year for which the investment is planned. For example, FY19 capital projects and programs generally will be sanctioned in early 2018. Thus, the Company's currently sanctioned or partially sanctioned projects do not yet represent the full capital forecast proposed in the Rate Year and Data Years.

Q. How does the Company's plan provide for unbudgeted or "emergent" projects?

A. The Company includes certain reserve line items in its investment plan, by budget class or spending rationale, to allocate funds for unanticipated projects. Historic trends are used to develop the appropriate reserve levels. As the specific project details become available, emergent projects are added to the plan with funding drawn from the reserve funds. The majority of emergent projects are the result of in-year occurrences in mandatory project categories such as damaged or failed equipment, customer or generator requirements or regulatory mandates. Reserve funds are also established for high priority risk score projects that may arise during the year in response to unforeseen system reliability or loading concerns. The Company tracks and manages budgetary reserves and emergent projects as part of its investment planning and spending management processes.

E. <u>NWAs</u>

Q. Please describe the Company's approach to incorporating NWAs into electric system planning.

A. The Company continues to increase its attention and focus on NWAs and how to effectively integrate them into system planning. On March 1, 2017, the Company, along with the State's other investor-owned utilities, submitted its NWA suitability criteria matrix to the Commission. The matrix describes three criteria (project type, timeline, and cost) to be considered when assessing whether a potential project would be a good candidate for an NWA solution. On considering the NWA suitability criteria, the Commission directed the utilities—including the Company—to file additional information and revised matrices within 60 days of the Commission's March 9, 2017 order that describes how the suitability criteria will be applied as a standard procedure in the development of project justifications, and to identify the projects in each utility's five-year capital plan that meet the suitability criteria and when NWA solicitations would likely be issued for those projects. The Company is working with the State's other utilities on this supplemental information to be submitted in May 2017.

Q. Has the Company identified any particular projects or locations that may present good opportunities for NWAs?

A. Yes. As described in Exhibit 5 of the Company's 5-Year CIP, included in Exhibit__ (EIOP-16), the Company has issued a request for proposal ("RFP") that solicits NWAs to address a system need identified in the area of Baldwinsville, New York. The 5-Year CIP also identifies over 20 other areas/projects that have passed an initial review and will be further evaluated for viable NWA solution options. The Company also applied its recently revised NWA suitability criteria to all of the projects in its five-year capital plan and has identified additional projects for which it will pursue NWA opportunities. A current listing of NWA opportunity areas the Company is evaluating is set forth in Exhibit__ (EIOP-14). The Company also will be posting such information in the future on its System Data Portal to provide greater transparency and information regarding potential non-wires alternative opportunities.

Q. How are the costs of NWAs reflected in the Company's capital investment and O&M plans?

A. NWA costs include on-going evaluation and solicitation costs, as well as actual NWA project implementation and management costs. The base evaluation and solicitation costs presented in this case include costs for four incremental full-time equivalent (“FTE”) resources, as well as incremental external vendor costs to support the increased level of NWA activities. These resource needs are discussed below in the Panel’s testimony on O&M expenses.

Regarding actual NWA project implementation and management costs, upon identifying a viable NWA project, the Company will make a filing with the Commission that describes the project, indicates the investments the Company intends to defer and/or avoid, and proposes a cost recovery mechanism. Because the Company is unable to determine at this time the nature of particular NWAs that might be proposed, there are no NWA project costs in the case and the Company is not proposing a specific NWA project cost recovery proposal at this time. As experience with non-wires alternatives increases, the Company anticipates that cost recovery frameworks for such measures will become more standardized and efficient to implement.

Q. How will the Company determine if a proposed NWA is beneficial compared with a traditional capital investment solution?

A. The Company proposes to follow the same NWA evaluation structure the Commission approved for Consolidated Edison Company of New York, Inc. (“Con Edison”) in Case 15-E-0229 in an Order dated January 25, 2017. Under that framework, the Company would perform a benefit cost analysis (“BCA”) of the NWA using the Benefit Cost Analysis Handbook (“BCA Handbook”) adopted in Case 16-M-0412, and compare the present value of the NWA solution benefits with the present value of the traditional capital investment solution. The difference in the present values of the BCA for the NWA and traditional solution would represent the initial net benefits for the NWA project.

Q. Would the Company modify the BCA methodology compared to what is reflected in the BCA Handbook?

A. Yes. Consistent with the direction the Commission provided Con Edison in the January 25, 2017 order, the Company would take into account local factors, such as local community and environmental justice considerations, as well as values associated with reduced carbon dioxide emissions.

Q. What incentive will the Company have to pursue a NWA rather than favoring traditional capital investments?

A. Similar to what the Commission approved for Con Edison, the Company proposes to implement a net benefits sharing mechanism whereby the Company will be authorized to retain a percentage of the initially determined net benefits calculated for an NWA. This sharing of benefits would continue for as long as the NWA project allows the traditional wires solution to be deferred, and could increase if it turns out that the actual net benefits exceed the initial calculation of benefits. Conversely, if actual benefits are less than initially calculated, the Company's share of net benefits would be commensurately reduced. The Company proposes that it would file a specific NWA cost recovery and incentive proposal once a specific NWA solution is identified.

F. <u>Delivering the Capital Investment Plan</u>

Q. Upon completion of the budget and work plan, how does the Company deliver this plan?

A. After the budget and subsequent preliminary work plans are developed, work plan review sessions are held with teams from operations, resource planning, project management and engineering planners to ensure the plan is appropriate and all resource concerns are addressed. Resource planning then utilizes any updated location based resource information gained to further optimize delivery of the plan and identifies where outsourcing is necessary to address resource capacity gaps.

Following this resource review, the final work plans are shared with those organizations responsible for execution of the plan prior to the start of the fiscal year to facilitate the scheduling of contractor resources and ordering of materials, tools and any specialized construction equipment. The overall delivery of the plan is then managed by the resource planning organization.

Q. How does the work move through engineering planning and design to construction?

A. The Company uses Primavera P6 project management software, which provides a view to all projects in the overall investment plan and target in-service dates, and enables the Company to properly prioritize the design workload. In effect, design is receiving the project scope information and in-service dates from engineering planning, which will drive the design process prioritization.

Q. Describe the resources the Company uses to implement the capital plan.

A. A sizeable workforce is needed to construct and maintain electric facilities and to appropriately respond to emergency situations across the service territory. The Company uses in-house staff supported by contractors to effectively meet this need. This model allows proper coverage of the service territory for emergency response, day-to-day customer work, required maintenance activities, as well as some capital projects by in-house personnel. The use of contractors to supplement the workforce provides the ability to manage the capital work plan where needed as efficiently as possible. In addition, the contracted work force is available to supplement in-house personnel during emergency restoration activities.

Q. Are all construction and maintenance work activities in the investment plan completed with internal labor?

A. No. As discussed above, a portion of the workplan is completed with external resources. This work is typically accomplished under a Company's Contractor of Choice ("COC") arrangement, which is based on negotiated unit-based agreements or by lump sum bids. The COC framework is essentially the same model as the Company's previous Distribution Alliance Contractor model.

Q. Who are the Company's COCs?

A. Harlan Electric Company and D&D Power are the Company's COCs for distribution and sub-transmission work. However, the current COC arrangements expire in May 2018, and at this time the Company has not determined whether it will seek to rebid those agreements.

G. <u>In-Service Dates</u>

Q. What is the effect of the in-service date of a project on the Company's revenue requirements?

A. The in-service date of a project determines when a project is reflected in the Company's rate base for depreciation purposes.

Q. Please explain how the Company determines the in-service dates for planned electric capital spending.

A. First, the Company's objective is to establish in-service dates that accurately reflect the estimated actual in-service date. The ability to accurately estimate in-service dates for large projects that are already underway and near completion is obviously greater than for projects that have not commenced and are further out in time. Larger projects are also often subject to licensing and permitting requirements, which can increase complexity and often lead to changes in scope and implementation delays.

It is also difficult to predict the in-service dates of smaller projects, which may be more prone to schedule shifts for operational efficiency or other reasons, or programs comprised of recurring projects that are put in service throughout the year. Therefore, in developing the in-service dates reflected in this case, the Company estimates actual in-service dates for very large projects (*i.e.*, those with estimated costs greater than $10 million). For the remaining programs and projects, the Company developed closing rules pursuant to accounting closing processes applicable to the type of project or program. Thus, amounts for construction work in progress ("CWIP") and capital expenditure cash flows forecast from CWIP were estimated to go into service in the month following the applicable period under the closing rule. The relevant closing rule periods were determined based on a historical analysis of CWIP and plant closings, along with considering the future capital project mix. Sample closing periods used by the Company include: transmission substations and distribution substations—12 months; transmission lines—eight months; distribution lines—five months; general plant—three months; street lighting—two months; meters and line transformers—one month. For example, assuming a projected expenditure of $100,000 in January for a distribution line capital project, the expenditure would be deemed closed to plant in service in the month following the closing rule period, or June.

H. <u>Cost of Removal</u>

Q. Does the Company's revenue requirement in this case include cost of removal ("COR") associated with the capital investment plan?

A. Yes. In addition to the capital costs discussed above, there is a level of COR required to implement the Company's infrastructure investment plan. As reflected in Exhibit __ (EIOP-3), the Company forecasts COR of approximately $21.0 million for January – March 2017, $58.1 million in FY18, $73.8 million in FY19, $64.0 million in FY20, $73.6 million in FY21, and $70.8 million in FY22.

Q. What types of activities are associated with COR?

A. The Company defines removal as any work on an existing capital asset that results in the asset being removed from the asset inventory, whether or not a different asset is subsequently added in its place. This type of work would include, but is not limited to, all the activities associated with disconnection, removal and disposal of capital units of property such as circuit breakers and transformers; disconnection, removal and disposal of secondary items of equipment such as relays and control equipment; removal and/or demolition of foundations; disconnection, removal and disposal of insulator strings; removal of wood poles or steel structures; and disconnection and removal of conductor and shield wire.

Q. Please explain the basis for the forecast COR amounts.

A. COR is dependent on the nature of the project. New construction projects with limited impact on existing facilities typically have no, or relatively low, COR forecasts. Conversely, projects that involve replacement of substantial portions of existing facilities would have relatively high COR forecasts. In addition, the type of work affects COR; for example, line projects typically have higher COR than substation projects. Some projects, such as the removal of de-energized lines that have been determined to be of no future beneficial use, are COR-only projects. Thus, the COR in the investment plan will vary depending on the nature and amount of work in the plan. The COR in this filing is based on the forecast removal associated with the specific projects included in the plan.

Q. How does the forecast COR compare to historic COR levels?

A. Comparison of historic and forecast COR as a percentage of capital investment levels is provided in Revenue Requirements Panel Exhibit __ (RRP-11), Workpapers for Exhibit (RRP-7), Schedule 1, Workpapers 15 and 16. In general, historic and forecast COR percentages are fairly close. In those cases where forecast and historic COR percentages differ substantially, such differences are due to the different nature of the capital work (*e.g.*, new versus replacement, line versus substation, *et cetera*).

I. <u>Investments Not Reflected in Plan</u>

Q. Does the Company anticipate any investments that are not reflected in the capital plan?

A. Yes. Emergent issues, such as the effect of new regulatory standards, changes in generation resources, and other factors, will drive the need for investments that the Company is unable to anticipate or accurately estimate at this time.

Q. What is an example of new regulatory standards that may drive new investment needs?

A. Although not reflected in the capital investment plan, the Company anticipates that new standards adopted by NERC will drive significant capital investment over the next several years. For example, new Cyber Security standards will impact facilities that must comply with the critical infrastructure protection standards. The new critical infrastructure protection standards now require facilities that are critical in deriving Interconnection Reliability Operating Limits ("IROLs") that have Special Protection Schemes that could impact an IROL, or that have a high number of lines connected to the substation, to be included as a critical cyber asset. The nature, amount and timing of necessary investment will depend on what is required and the time allotted for compliance. It is therefore difficult to provide more detailed estimates until the new definitions and standards are approved.

Q. What impacts does the Company anticipate in response to changes in generation resources interconnected to the electric system?

A. In its March 15, 2013, Order approving the Joint Proposal in the 2012 Electric Rate Case, the Commission directed the Company to perform a study of the effect of potential generation retirements on the reliability of the Company's electric system. To comply with this directive, the Company joined with the state's other transmission-owning utilities and the New York State Independent System Operator ("NYISO") to perform a coordinated, statewide study of reliability effects of potential generator retirements. The study was completed in March 2016. The results of the study identified and evaluated system impacts, potential solutions and associated cost estimates under various retirement scenarios.

Q. Does the proposed capital plan include investments to address the potential reliability impacts identified by the study?

A. It is not feasible to plan for all the investments needed to address all the potential reliability impacts identified in the study. Rather, the Company has identified and included in its capital plan certain investments that would provide broad benefits based on potentially likely scenarios. The Company will continue to evaluate the system in connection with announced and potential generator retirements and develop plans for responding to such retirements in an effort to minimize costs and maintain reliability.

Q. Does the Company's capital investment plan include any capital investment costs for projects to address Public Policy Transmission Needs currently being considered by the Commission?

A. The capital plan in this case does not include any projects specifically aimed at addressing the Public Policy Transmission Needs ("PPTN") identified in connection with the Commission's AC Transmission Upgrades or Western NY PPTN proceedings. At this time, the NYISO is evaluating proposals submitted by market participants to determine the most efficient solutions to address the identified needs. The Company is committed to supporting New York's energy future and is participating in those PPTN proceedings. It is our understanding that costs associated with PPTN projects will be reflected in and recovered through the NYISO's open access transmission tariff ("OATT") and not as part of local utility tariffs.

Q. Does the Company's investment plan in this case include any local network upgrades that may be needed to implement the PPTN solutions?

A. No. Although the Company will likely need to implement certain non-bulk transmission system upgrades to accommodate one or more of the PPTN solutions that may ultimately be selected, the Commission's October 13, 2016, Order Addressing Public Policy Transmission Need in Western New York, in Case 14-E-0454, noted that the costs of such upgrades on the non-bulk transmission system ultimately would not be recovered through the Company's local tariff, and will likely be recovered through the NYISO's Open Access Transmission Tariff. Accordingly, the costs associated for implementing non-bulk system investment needed to enable the PPTN solution to proceed are not reflected in the capital plan presented in this case.

Q. Is Niagara Mohawk proposing recovery of any other costs related to the evaluation of public policy needs projects?

A. Yes. Prior to the initiation of the Commission's public policy proceedings and prior to the promulgation of FERC Order No. 1000, the Company undertook a variety of engineering evaluations to identify potential solutions to resolve the persistent congestion across the UPNY/SENY interface. The Company incurred approximately $4.6 million in incremental costs on such studies. The Company proposes to amortize and recover this amount from customers, over a period of three years, beginning with the Rate Year, as reflected in Exhibit __ (RRP-7), Schedule 2.

J. Facilities and Properties Capital Investment Plan

Q. Please describe the Company's facilities-related capital investments reflected in the electric and gas revenue requirements in the Rate Year and Data Years.

A. The level of planned capital investments for the electric and gas businesses in properties and facilities is approximately $13.5 million per year from the Rate Year through the Data Years as summarized in Exhibit __ (EIOP-11), Page 1 of 4. This level of annual capital investment is above recent historic levels, including the annualized capital investment level projected from the Historic Test Year to the start of the Rate Year. The need for the increased capital spend is driven by the extent of deferred investment, better intelligence on the conditions of our assets, and impacts of changing products and equipment.

Q, What are some of the specific investment areas driving the Company's investment needs?

A. The capital spend forecast for facilities and properties is comprised of work to address known issues at several of the Company's facilities. A significant portion of the planned capital investment (approximately $4 million for the Rate Year and each Data Year) relates to roof replacements. The Company's Facilities organization has conducted more comprehensive condition assessments of our building roofs, which has resulted in an improved, planned replacement approach. HVAC and boiler replacements and upgrades also account for significant portions of the planned spend. The Company's building infrastructure is aging, and in many cases investment has been deferred due to budgetary considerations.

Fire and life safety spending also has increased due to the need to replace antiquated fire detection/alarm systems, or install systems in facilities that currently do not have them.

The Company also plans to upgrade its control center operator consoles to more ergonomic consoles at the transmission and distribution control centers, and undertake several other building interior renovations that have been deferred for many years due to lack of funding.

The Company's bucket trucks for electric construction and maintenance also have increased in height and some no longer fit in the existing garages at our Operations facilities. There is additional need to house vehicles out of the elements during the winter months. Where feasible, garages are modified to allow the trucks to fit, or new structures are built. Many operation center yards also require paving replacement to ensure the safety of employees. Several of these projects had been deferred in the past.

A listing of the specific planned investments for the period FY18-FY22 is provided in Exhibit __ (EIOP-11), Page 1 of 4. The Company's historic capital investment levels relating to facilities and properties are shown in Exhibit __ (EIOP-4).

K. Operations Support, Investment Recovery, and Inventory Management Investment Plans

Q. Please describe the capital investment related to operations support, inventory management and investment recovery.

A. For the Rate Year, operations support plans annual capital expenditures of approximately $1.6 million for items such as new vehicle lifts, work at the North Albany facility on a track vehicle garage for Transmission Line

Services, new fuel tanks and tank relocations, a GPS for the Company's aircraft, and new lab and test equipment. The Company also projects annual capital expenditures of approximately $0.200 million in the inventory management and investment recovery areas. Because operations support and inventory management/investment recovery are common functions supporting both the gas and electric businesses, the revenue requirements associated with the capital investments in these areas are allocated according to the applicable electric/gas split, as described in the testimony of the Revenue Requirements Panel. The planned investment profiles for inventory management, investment recovery and operations support is shown in Exhibit __ (EIOP-11), Pages 2 and 3 of 4.

IV. <u>Incremental Operations and Maintenance Expenses</u>

Q. Please summarize the Panel's testimony regarding incremental costs of operating the electric system.

A. In addition to supporting the Company's infrastructure plan and other capital investments, the Panel addresses known and measureable changes between the Historic Test Year costs and the Rate Year costs to operate the electric delivery system, as well as the costs of new significant efforts the Company is undertaking in its capacity as a DSP provider. Among the O&M expense changes the Panel describes are:

- Increased costs for transmission tower painting
- Increased costs relating to sub-transmission steel tower painting, and sub-transmission footer inspection and repair
- Costs to implement a new station painting program
- Costs to address the NERC Level 1 alert related to high-voltage gas circuit breakers
- Increased vegetation management costs associated with proactively addressing the EAB infestation
- Increased elevated voltage testing expense related to a contractor rate increase
- Geographic Information System enhancement costs
- Increased Hosting Capacity Analysis costs
- Increased NWA Analysis costs

A summary of these changes is provided in Exhibit __ (EIOP-12).

In addition to supporting these changes, the Panel also describes the basis for incremental labor resource expense for the electric operations, engineering, asset management, and planning functions in the Company's

Rate Year and Data Years as compared to the end of the Historic Test Year.

A. Transmission Tower Painting Program

Q. Please describe the Company's transmission tower painting program and the planned incremental costs.

A. The Company has approximately 20,000 steel structures operating at 115kV or higher, with an average age of 65 years. The Company has adopted a tower painting initiative aimed in part at extending the life of mature steel transmission towers in Visual Category 4. A Visual Category 4 applies to structures that exhibit light pitting, some very light edge roughening, loss of the greater majority of coating and zinc layers, and that include a corroded surface that would dominate surface preparation. The painting program maintains the integrity of these existing steel towers, thereby promoting longer service lives, reliability and safety in a cost-effective manner. In addition, this strategy seeks to delay or prevent Visual Category 1, 2, and 3 structures from degrading into the Visual Category 4 condition or worse.

Q. How much is the Company proposing to spend on transmission tower painting?

A. The Company's Historic Test Year spend on transmission tower paining was approximately $2.397 million. The Company proposes to increase the level of spend to $4.443 million in the Rate Year – an increase of approximately $2.0 million over the Historic Test Year for this activity, as shown in Exhibit __ (EIOP-12).

Q. Why is the Company proposing to increase expenditures on this program?

A. The tower painting program was placed on hold for an extended period due to safety issues with contractors. Increased funding is needed to address higher costs related to updated safety procedures, which include the use of electrically-qualified contractor crews to apply grounds and act as safety observers. The incremental request proposed here will not bring the program to the preferred 20-year cycle as the ability to obtain outages under the new safety rules during summer months (*i.e.*, painting season) is very limited. The Transmission Innovation team, however, is investigating robot technologies that may allow the program to continue in a more efficient manner.

B. <u>Sub-transmission Maintenance Program</u>

Q. Please describe the changes in costs associated with the Company's sub-transmission maintenance programs.

A. The Company proposes to increase its level of spending on the sub-transmission steel tower painting and sub-transmission footer inspection and repair programs. These programs have been effective at identifying corrosion and structural concerns on existing sub-transmission towers, and addressing those concerns to cost-effectively extend the life and reliable performance of these assets.

Q. Please describe the sub-transmission steel tower painting program.

A. The sub-transmission steel tower painting program is similar to the transmission tower program and is aimed at extending the lives of mature steel sub-transmission towers. Structures are inspected for structural imperfections and for safety concerns. Any problem areas are structurally corrected. The painters then prepare the surface of the structure and apply a coating of the appropriate paint. The facilities to be addressed are identified through information obtained during foot patrols, engineering evaluations/walk-downs associated with capital projects and problem reporting. Many of the towers have an average age over 70 years. The tower painting program increases the integrity of these steel towers, thereby promoting longer service lives, reliability and safety in a cost effective manner.

Q. How much is the Company proposing to spend on the sub-transmission steel tower painting program?

A. The Company spent approximately $0.566 million in the Historic Test Year on the sub-transmission steel tower painting program, and plans to increase that amount by approximately $0.734 million in the Rate Year ($1.3 million total). The increased expenditures will enable the Company to achieve a desired 20-year paint cycle for sub-transmission towers. The proposed Rate Year expense is shown in Exhibit __ (EIOP-12).

Q. Please describe the sub-transmission footer inspection and repair program.

A. The Company has an ongoing sub-transmission footer inspection and repair program. On-site, below grade footer inspections are performed as a follow-up to aerial patrols to determine whether repairs or replacement is warranted. This effort will identify issues prior to failure to improve the reliability of the identified circuits, and reduce the potential for more costly capital investments as a result of failure.

Q. How much is the Company proposing to spend on the sub-transmission footer inspection and repair program?

A. The Company spent approximately $0.753 million in the Historic Test Year on the sub-transmission footer inspection and repair program, and plans to increase that amount by approximately $0.247 million in the Rate Year ($1.0 million total). The proposed funding level is expected to allow the Company to achieve a 20-year inspection and repair cycle for sub-transmission tower footers. The proposed Rate Year expense is shown in Exhibit __ (EIOP-12).

C. Station Painting Program

Q. Please describe the proposed Station Painting program.

A. Station Painting is a new program. The Company has a number of older stations (>50 years of age) that have bus-supporting structures that are still structurally sound, but are subject to deterioration from continued exposure to the elements. Similar to the tower painting programs, the station painting program is intended to protect the structures from exposure and cost-effectively extend the lives of these assets. In addition to treating bus-supporting structures, this program will address painting station metalclad assets and repairing metalclad roofs.

Q. What is the cost of the Station Painting program?

A. The Company plans to spend $0.800 million in the Rate Year on station painting, and increase that amount by inflation in the following years. The proposed expense for the Station Painting program is shown in Exhibit __ (EIOP-12).

D. <u>High Voltage Gas Circuit Breakers – NERC Level 1 Alert</u>

Q. Please describe the High Voltage Gas Circuit Breaker program.

A. In August 2013, NERC issued a Level 1 Alert Advisory on the Hitachi HVB 362kV HPI single break SF6 breakers. The NERC alert was the result of a 2010 manufacturer maintenance advisory about loose hardware with the potential for breaker nozzle failures. The Company has 53 breakers on its system that need to be addressed. The program is based on addressing seven breakers per year until completed, and is dependent on expected outage availability.

Q. What is the cost of the High Voltage Gas Circuit Breaker program?

A. The Company plans to spend $0.364 million in the Rate Year to address the breakers identified in the NERC Alert, and to increase that amount by inflation in the following years. The proposed expense for the High Voltage Gas Circuit Breaker program is shown in Exhibit __ (EIOP-12).

E. <u>Vegetation Management</u>

Q. Please generally describe the Company's vegetation management activities.

A. The Company implements a comprehensive vegetation management program that includes cycle trimming, hazard tree mitigation, and right-of-way floor maintenance elements. In the Historic Test Year, the Company's normalized spend was $62.3 million to implement its standard vegetation management program.

The Company manages its Vegetation Management program on a FY basis (April – March). FY spending aligns with the Company's rate allowances, management of expenses and monitoring of field work plans. Although increases in FY Vegetation Management program spending generally translates into increased calendar year spending, the difference between the calendar year and FY periods also contributes to fluctuations between calendar year and FY spending amounts.

Overall, the Company develops and manages a work plan to achieve a trim cycle of approximately 5.5 years for the Distribution system; however, the work plan does not necessarily result in level spending month-to-month or even year-to-year. The Company achieves the target average trim cycle even though the actual mileage maintained year-on-year may vary. These year-on-year variations may be due to several factors, including: actual costs and complexity for differing geographies (rural, suburban, metro), weather, needs of the transmission system, and other additional work which can fluctuate, such as specific targeted reliability needs and customer work. The Company's ability to proactively plan its Vegetation Management work, and the flexibility to adjust those plans to react to system needs, are vital to the Company's ability to achieve its safety and reliability objectives.

In FY15, the increase in vegetation management spend over the rate allowance set in the 2012 rate case ($54.6 million) was due in large part to increased costs in the vegetation management labor market. During 2014 contract negotiations, National Grid saw an overall increase of 19 percent in vegetation contractor costs. Because spending at the rate allowance level in light of the higher cost inputs would have substantially reduced the amount of vegetation management work the Company could perform, the Company increased overall spend on the transmission and distribution work plans by approximately $5 million.

In FY16, the Company continued the increased spending level on the transmission and distribution work plans to maintain reliable service for customers. The Company also took advantage of a milder than normal winter and improved contractor pricing (discussed below) to advance a portion of the FY17 planned maintenance into FY16. In total, the spending above the rate allowance was approximately $8.9 million.

The FY17 spending plan was developed to more closely align to the rate allowance, primarily supported by two key factors that tended to reduce FY17 costs: 1) the vegetation management contract was renewed and overall rates were reduced approximately seven percent from the prior contract; and 2) the Company's decision to advance work into FY16 reduced the FY17 work plan requirements (the FY17 work advanced into FY16 was performed at the lower FY17 contractor rate). Offsetting these two factors, the Company plans to increase FY17 spending to address the EAB issue, and by FY end will have spent approximately $2.5 million on EAB tree removal, which is the total forecast overspend above the rate allowance for FY17.

Q. Describe the normalizing adjustments mentioned above.

A. The Company made normalizing adjustments to remove approximately $6.3 million from the Historic Test Year costs of the distribution, sub-transmission and transmission vegetation management programs to arrive at a Rate Year revenue requirement of $65.352 million for the Company's base vegetation management programs.

Q. Describe the EAB program.

A. The Company is proposing to implement a multi-year, $10 million per year program to proactively address the threat presented by the EAB infestation. The EAB is an invasive species introduced to the United States from Asia. The EAB attacks ash trees and is expected to result in 100 percent mortality of all ash trees within the state. Based on a study commissioned by the Company, it is estimated that approximately one-third of ash trees in the utility forest will likely strike the Company's overhead lines, resulting in a significant increase in service interruptions. Left unmitigated, EAB-related tree failures will negatively impact customers and will result in the failure to meet reliability targets (CAIDI/SAIFI) for multiple years, and also represent a risk to public and employee safety.

Q. How does the Company plan to implement the EAB program?

A. The Company began implementing the EAB mitigation plan in January 2017. The Company has established a circuit prioritization methodology based on the known presence of EAB and reliability and/or safety impacts from potential tree strikes. The prioritization process also takes into account knowledge from field forces on areas where infestation is most pervasive. The Company has established separate accounting to track the costs incurred under this focused program. The program also includes a substantial customer outreach and communication component, including education about the spread of the EAB infestation and restrictions on the movement of cut wood. The proposed expense for the EAB program is shown in Exhibit __ (EIOP-12).

Q. Does the Company's filing include any deferral recoveries related to vegetation management?

A. Yes. To stay ahead of the most significant potential adverse reliability impacts from the EAB infestation, the Company initiated a proactive mitigation strategy beginning in January 2017. The annual cost of this proactive program is substantial at approximately $10 million; however, given the likely reliability impacts that could result if the Company deferred action pending receipt of program funding, the Company has chosen to commence implementation of the EAB mitigation program in

January 2017. It is the Company's position that such timing is in the best interest of customers. Because the amount being spent on the program is material, incremental to the Company's base vegetation management rate allowance, and the Company is not over-earning, the amount associated with the 2017 implementation of the EAB mitigation program should be eligible for deferral treatment.

In addition to deferral treatment of the 2017 initiation of the EAB program, the Company also deferred approximately $16.2 million associated with the FERC's FAC-003 transmission right-of-way clearance standards.

F. Increased Elevated Voltage Contractor Costs

Q. Please explain the increased elevated voltage contractor costs.

A. The Company performs annual elevated voltage testing of all Company and non-Company owned metallic streetlights and traffic signals and all publicly accessible Company-owned underground distribution facilities that are capable of conducting electricity. In addition, the Company conducts elevated voltage testing of its publicly accessible overhead distribution facilities, URD facilities, overhead and underground transmission structures, and substation fences that are capable of conducting electricity.

The primary vendor that provides elevated voltage testing services to the Company recently increased its labor rate, such that at the start of the Rate Year, elevated voltage testing expense is projected to be $0.427 million more than it was in the Historic Test Year. These incremental costs are shown in Exhibit __ (EIOP-12).

G. GIS Data Enhancements

Q. Please explain the Company's proposal regarding GIS Data Enhancements.

A. The GIS (Geographic Information System) Data Enhancements project will enhance the Company's Smallworld GIS and data to support the deployment of a Distribution Management System (DMS), more detailed hosting capacity analysis, the DG Interconnection On-Line Application Portal (DG IOAP) and other advanced analytics. Modern grid operations require increasing granularity, accuracy and timeliness of data to achieve the benefits associated with advanced functionality. GIS is the foundation upon which advanced analytical and control systems are built. The Company utilizes the GIS as its authoritative source for distribution asset information and network configuration. The Company will be incurring direct incremental expense for the GIS Data Enhancement project in the Rate Year and Data Years as shown in Exhibit __ (EIOP-12), and also will be receiving support from National Grid Service Company. The total expected incremental operations and maintenance expense associated with the GIS Data Enhancement project in the Rate Year and each of the Data Years is shown in Exhibit __ (RRP-3), Schedule 27.

H. Hosting Capacity Analysis

Q. Please describe the Hosting Capacity Analysis program.

A. The Company will evaluate the hosting capacity of each feeder on its distribution system and post the results via an interactive map on its System Data Portal. This effort will require the development of detailed feeder load flow models and an assessment of the impact of DER along the entire length of the feeder mainline. The range of hosting capacity for DER on each feeder will be presented both as a heat map as well as with tabular data in a pop up box available by clicking on the feeder location. The available hosting capacity on a feeder will change over time as DER is deployed and as feeder configurations change and therefore this analysis needs to be periodically refreshed. Also, the Company expects to continually evolve the level of detail and the granularity of its hosting capacity assessments as additional data and the capabilities of assessment tools improve. The Company will perform hosting capacity analyses on more than 2,000 feeders across its territory. The initial assessments on its 13.2kV feeders will be completed by October 1, 2017, with the remainder of the system completed by Summer 2018. Immediately following this initial assessment, the Company expects to begin a refresh of the assessments with the latest available data and tool sets. It is expected that the refresh cycle of these assessments will shorten as the models mature and the program will continue beyond the Rate and Data Years.

Q. How much incremental cost is the Company projecting for Hosting Capacity Analysis?

A. The Company proposes to hire two additional engineers in 2017 and two contracted resources in the Rate Year to perform the required modeling and feeder assessments. The estimated cost of the contracted resources is $0.40 million in the Rate Year and each Data Year. The costs of the contracted resources is shown in Exhibit __ (EIOP-12). The two additional FTEs are included below in the Panel's testimony regarding Labor and are reflected in Exhibit _ (EIOP-13).

I. NWA Analysis

Q. Please describe proposed cost changes in the Company's NWA program.

A. The Company will be spending $0.75 million incremental to the Historic Test Year in the Rate Year and each of the Data Years for contracted vendor resources to support increased NWA efforts. The costs of the contracted resources is shown in Exhibit __ (EIOP-12). The Company also will be hiring four incremental FTEs. The additional FTEs are included below in the Panel's testimony regarding Labor and are reflected in Exhibit _ (EIOP-13).

Q. What is the combined effect of the above-described O&M program changes on the Company's costs in the Rate Year?

A. The combined effect of these changes in the Rate Year is summarized in Exhibit __ (EIOP-12).

J. O&M Expense Related to Infrastructure Investment

Q. How did the Company calculate the annual incremental O&M expense related to capital?

A. To calculate the Rate Year incremental O&M expense it expects to incur to deliver the increased capital plan, the Company took a three-year average (FY14 – FY16) of the ratio of annual O&M costs to capital costs for electric transmission (segregated into lines and substations), sub-transmission, and distribution and applied the resulting percentages to the planned incremental capital investment to arrive at base incremental O&M expense related to capital of $11 million in the Rate Year and an additional $2 million in each of the Data Years (*i.e.*, $13 million in Data Year 1, and $15 million in Data Year 2). In addition, in light of the various incremental and new initiatives (*e.g.*, AMI implementation, grid modernization investments, *et cetera.*), the Company projects additional incremental O&M expense related to capital of approximately $7 million in the Rate Year, $13 million in Data Year 1, and $16 million in Data Year 2. The derivation of these amounts is shown in Exhibit __ (RRP-11), Workpapers for Exhibit __ (RRP-3), Schedule 27, Workpaper 1.

Q. Is there any specific incremental O&M project that stands out from the others?

A. Yes, the disassembly and removal of the Sanford Lake-Ticonderoga line. In 2008, National Grid initiated the purchase of a portion of a customer-owned 115kV transmission line, including real estate rights, from National Grid's Ticonderoga Station to a customer-owned Sanford Lake station that was used to support a mining operation. The intent was to construct a new

115kV line to connect an existing radial line that terminated at Niagara Mohawk's North Creek station, to the radial line connected to Niagara Mohawk's Ticonderoga station to create a loop and minimize the risk of extended customer interruptions (the 115kV line proceeding north from Ticonderoga would remain as a radial line). However, the Company has since determined that the need for the project did not justify the costs. Over time, the assets have continued to degrade and are creating a potential safety hazard to the public. Because the line was never placed in service, it was entered into the Company's property records as a land asset. As a land asset, removal costs for this portion of the line will be charged to the corresponding maintenance accounts, not capital accounts, to ensure proper accounting treatment. The costs associated with the disassembly and removal of the line are $2.4 million in the Rate Year, and $1.9 million in Data Year 1, as shown in Exhibit __ (RRP-3), Schedule 27, Workpaper 6, page 1 of 1, and are also reflected in Exhibit __ (EIOP-12).

Q. Do capital investments also offer an opportunity to reduce O&M expense?

A. Yes. In addition to incremental O&M expense related to incremental capital, the Company also estimated O&M expense reductions related to capital investment in the Rate Year and Data Years, which are reflected in the net incremental O&M expense associated with the proposed capital plan.

Q. Given the scope of the Company's capital investment, why are the O&M reductions not more significant?

A. O&M cost savings are limited because the planned capital investment affects a relatively small portion of the existing system. Even though the Company is making significant investments in its transmission and distribution facilities to maintain reliable service, those expenditures result in the replacement of a small percentage of circuit breakers, conductor miles, steel towers, and other such assets. The replacement of a small proportion of these assets makes no significant difference in the volume of routine maintenance activities such as visual and operational inspections, infrared surveys, and foot patrols. These activities are required whether an asset is new or old and, in the case of relay equipment, station batteries and diesel generators, maintenance intervals, often are mandated by NPCC or similar standards. For the same reason, while it is assumed that there will be a decrease in the amount of "found-on-inspection" and "follow-up" maintenance activities associated with new equipment, this decrease is relatively small given that the new equipment is a small percentage of total system assets, many of which are mature and require continuing maintenance.

In general, substantial O&M savings would be expected from capital or capital-related O&M spending only if the expenditures enable the Company to reduce the total number of personnel devoted to maintenance and repair of the electric system. The plan does not support such reductions.

K. <u>Annual Major Storm Recovery</u>

Q. Is the Company proposing any changes to the annual rate allowance related to major storms?

A. Yes. In the 2012 Electric Rate Case, the annual Major Storm Funding allowance was set at $29 million per year. This amount was based on a ten-year average of major storm costs at the time. Since that level was established, the annual average of major storm costs has reduced, such that the ten-year average of annual major storm costs is now closer to $23 million. Accordingly, the Company proposes to reduce its annual Major Storm Funding allowance from $29 million per year to $23 million per year. This is shown in Exhibit __ (RRP-11), Workpapers to RRP-3, Schedule 38, Workpaper 1, and also is reflected in Exhibit __ (EIOP-12).

Q. Is the Company proposing any other changes to the Major Storm Funding mechanism?

A. No, other than the proposed reduction in the annual funding level, the Company is not proposing any other changes to the mechanism.

V. <u>Labor</u>

Q. Does the Company propose any adjustments to its Historic Test Year labor costs to deliver its electric infrastructure investment and operations plan?

A. Yes. Based on the employee complement at the end of the Historic Test Year, the Company plans to increase staffing of the organization supporting electric infrastructure and operations by 189.5 FTE resources between now and the end of FY21. The planned increases are aimed at addressing increased capital investment requirements, significantly increased DER activity and DSP development, street lighting support, control center staffing needs, operations needs, succession planning, and workforce optimization. More information on the individual incremental positions and the timing of hires is provided in Exhibit __ (EIOP-13).

Q. Please summarize the Company's planned labor increases.

A. The Company proposes to add 24 FTEs through the Rate Year to support implementation of its increased capital investment plan. These positions include distribution and transmission engineers and planners, project and program managers, estimators, and several technical analysts. The Company plans to add 14 more FTEs (38 total) in this area through Data Year 2 to support capital plan implementation.

The Company also plans to add 31 FTEs through the Rate Year to support the increased number of complex DG interconnection activities. These positions include controls and integration engineers, additional map and records technicians, protection and telecoms engineers, distribution and substation engineers, and customer coordination staff. The Company plans to add two more FTEs (33 total) in this area through Data Year 2 to support DG interconnections.

The Company also plans to add 13.5 FTEs through the Rate Year to support the evolution of the Company’s DSP capabilities in support of a more animated and transactive energy market. These positions include additional protection, telecoms, and control and integration engineers, distribution engineers to support Hosting Capacity analyses, personnel to support the acquisition and development of advanced data analytics, maintain the Company's system data portal and similar resources, and several program managers to coordinate and support new initiatives such as dynamic load control, solar siting, energy efficiency programs, *et cetera.* The Company plans to add six more FTEs (18.5 total) in these areas through Data Year 2.

Q. Please describe the Company's plans to address succession planning and workforce optimization.

A. The Company has a significant cohort of employees nearing retirement at about the same time. Based on a workforce review, the Company determined that the level of anticipated retirements is well beyond normal attrition levels in some disciplines and/or geographic areas. Many of the positions held by these employees require substantial amounts of training and experience to be performed effectively. To avoid a potentially significant disruption that could result from a wave of retirements with inadequate backfill capacity, the Company plans to add 49 FTEs through the Rate Year. The Company plans to add 27 more (76 total) through Data Year 2 to address succession planning needs.

The Company's planned workforce optimization hires are intended to address existing staffing deficiencies and improve operations. For example, current workforce levels at the Company's transmission control center typically results in staffing only one operator on weekends and night shifts. Likewise, staffing at the Company's distribution control centers affects the ability of employees to take vacations and can result in limited coverage when there are vacancies. Similar staffing increases are needed to address increased workloads relating to NWAs work order controls, maps and records, vegetation management, energization coordination, and property services functions. The Company plans to add 24 FTEs through the Rate Year to address workforce optimization needs.

More information on the individual incremental positions and the timing of hires is provided in Exhibit __ (EIOP-13).

VI. Performance Metrics

Reliability Performance

Q. Please describe the Company's performance with respect to the electric service quality performance metrics established in the 2012 Rate Case.

A. The Company assesses reliability performance based on System Average Interruption Frequency Index ("SAIFI") and Customer Average Interruption Duration Index ("CAIDI"). Pursuant to the SAIFI metric, an average customer should experience no more than 1.13 interruptions per year (excluding certain specifically identified events). If the Company's SAIFI performance for the year exceeds 1.13 interruptions, the Company is subject to a $3 million negative revenue adjustment and if performance exceeds 1.19 interruptions, the Company is subject to an additional $3 million negative revenue adjustment. The total potential SAIFI-related negative revenue adjustment is therefore $6 million. In the Historic Test Year, the Company's SAIFI performance was 1.04 and thus no negative revenue adjustment was incurred.

Pursuant to the CAIDI metric, an average customer should not be without service for more than 2.05 hours per year. If the Company's CAIDI performance for the year exceeds 2.05 hours, the Company is subject to a $3 million negative revenue adjustment and, if performance exceeds 2.15 hours, the Company is subject to an additional $3 million negative revenue adjustment. The total potential CAIDI-related negative revenue adjustment is therefore $6 million. In the Historic Test Year, the

Company's CAIDI performance was 2.02 hours and thus no negative revenue adjustment was incurred.

Details of the Company's SAIFI and CAIDI performance for the Historic Test Year are included in the Annual Service Quality Assurance Program Report, which was filed March 29, 2017 in Case 12-E-0201, and in the Company's Annual Electric Reliability Report, which was filed with the Commission March 31, 2017 in Case 17-E-0164.

Q. Does the Company propose any changes regarding the reliability performance standards?

A. No. The Company believes the current reliability performance standards provide customers with adequate assurance of safe and reliable electric service. The current standards are challenging, while at the same time reasonably achievable, and adequately ensure the Company is providing safe and reliable service by measuring performance against fair targets based on historical data. Moreover, potential impacts from climate-change influenced weather volatility and effects of the invasive EAB infestation could challenge the Company's ability to cost-effectively achieve the reliability performance goals. Given these factors, at this time the Company does not recommend any changes to the reliability performance measures.

Standardized Interconnection Requirements

Q. Please describe the Company's performance with respect to standardized interconnection requirements.

The Company measures performance with respect to application processing and installation requirements relating to standardized interconnection requests for certain new distributed generators that are connected in parallel to the Company's distribution system.

One measure assesses the timely processing of certain sized DG applications. Failure by the Company to process at least ninety percent of the aggregate completed applications within the set timeframes subjects the Company to a negative revenue adjustment of $2 million. In the Historic Test Year, the Company processed 98.2 percent of completed applications within the required timeframes and thus no negative revenue adjustment was incurred.

The second measure assesses the timely installation of net meters for systems that qualify for the expedited application process. Failure to install at least ninety percent of net meters within ten business days also subjects the Company to a negative revenue adjustment of $2 million. In the Historic Test Year, the Company installed 96.7 percent of qualifying net meters within the required timeframe and thus no negative revenue adjustment was incurred.

Details of the Company's standardized interconnection requirements performance in the Historic Test Year are included in the Annual Service Quality Assurance Program Report for 2016.

Q. Does the Company propose any changes regarding these metrics?

A. Yes, the Company proposes to eliminate the application processing metric. The application processing metric has been in place since January 2011, when the provisions of the Company's 2010 rate case (Case 10-E-0050) went into effect. The metric is based on standards established in the July 2010 "New York State Standardized Interconnection Requirements and Application Process for New Distributed Generators 2MWor Less Connected in Parallel with Utility Distribution Systems." The July 2010 standards differ from the current regulatory standard in effect for application processing. For example, the July 2010 standards apply different processing timelines to different generator size ranges than under the currently effective State standards. As a result, the Company must comply with different standards depending on generator size.

In addition, since the 2010 rate case standard was made effective, the Company has consistently achieved the performance metric, and did so again in 2016. Therefore, the performance issues the Company admittedly had prior to 2010 are no longer a problem. Continuing to apply a potential negative revenue adjustment mechanism to the Company is unwarranted under the circumstances.

Finally, the Commission has recognized that creating positive incentives is effective at promoting desired, innovative behaviors and has directed the utilities to propose earning adjustment mechanisms ("EAM") relating to DG interconnection. That process is on-going, and the Company is participating in that effort. The direct testimony of the Electric Customer Panel describes the Company's proposed Interconnection EAM, which requires as a threshold condition that the interconnection timelines in the Standardized Interconnection Requirements be satisfied. The Company's position is that creating one or more positive EAMs for the utilities with respect to DG interconnection is more consistent with the framework created by REV than continuation of an outdated, singularly applied application processing metric.

Estimating

Q. Please describe the Company's performance with respect to the project estimating metric.

A. The estimating metric applies to distribution or sub-transmission capital projects completed between January 1 and December 31 of the year for each individual total project cost over $100,000. The metric was recently modified in the *Order Granting Incremental Cost Relief, in Part, and Authorizing the Issuance of Securities*, issued May 19, 2016, in Case 15-M-0744. The metric now consists of three tiers of potential negative revenue adjustment based on accuracy of project estimates to actual costs:

(a) if less than 80 percent, but at least 70 percent, of projects are within 10 percent of their respective cost estimate, there is a $1 million negative revenue adjustment.

(b) if less than 70 percent, but at least 60 percent, of projects are within 10 percent of their respective cost estimate, there is a $2 million negative revenue adjustment.

(c) if less than 60 percent of projects are within 10 percent of their respective cost estimate, there is a $4 million negative revenue adjustment.

There is no negative revenue adjustment if 80 percent or more of projects are within 10 percent of their respective cost estimate.

In the Historic Test Year, 229 projects met the criteria for inclusion in the estimating accuracy performance metric. Of those 229 projects, 99 projects (43.2 percent) were completed within a variance of plus or minus 10 percent, resulting in the Company incurring a $4 million negative revenue adjustment for 2016.

Q. What steps has the Company taken to improve its estimating accuracy?

A. Estimating performance was a major focus of the Management Audit and Niagara Mohawk is dedicated to improving its estimating accuracy and has implemented process and staffing changes to improve performance under this metric. The Company established the Estimating Center of Excellence, which is now called Electric Project Estimating. Electric Project Estimating includes a group of professional estimators with responsibility for developing estimates for substation, transmission line, and distribution line projects. The Company's estimators and various engineering departments use estimating software ("Success Enterprise") to produce estimates for larger and higher complexity projects. For Distribution line work, the Company uses the work management system, STORMS, as the basis for the initial estimates. An Estimating Procedures Team within Electric Project Estimating meets regularly to discuss system interface details and testing, to develop estimating units, and to create process and procedure documentation.

In addition, the Company has adapted its approval process for capital projects to identify the type of estimate being approved. Projects in their early conceptual or preliminary engineering stages do not have the detailed engineering completed to support development of a project or construction grade estimate. Only projects with complete final engineering are ready for a final engineering estimate as these projects have received a thorough review of all issues, including a constructability review with local personnel to special conditions such as digging conditions, special equipment needs, *et cetera*. Thus, the Company's goal is to produce project grade estimates once the designs have completed a constructability review following final engineering design, which also increases the accuracy of the Company's capital project estimates.

The enhanced focus and structure the Company has brought to the estimating process have resulted in several improvements and provided many insights. A centralized approach will drive consistency. The collaborative review with participation from all departments including field personnel ensures local knowledge of the projects is considered and included. The Company continues to learn as a result of the framework and processes established and the entire team is dedicated to improving the accuracy of estimates and creating tools and processes to enable that outcome.

Q. Does the Company propose any changes regarding the estimating metric?

A. Not in this filing. However, the Company is analyzing the estimating process and metrics to determine whether meaningful changes might be proposed that can lead to improved estimating accuracy and provide increased value to customers. Based on the results of its review, the Company intends to propose an alternative methodology and metric in the future.

<u>Inspections & Maintenance ("I&M")</u>

Q. Please describe the Company's performance with respect to the I&M metric.

A. The I&M metric provides for potential negative revenue adjustments based on the timeliness of addressing deficiencies identified as part of the Company's inspection program. Specifically, the Company is subject to a negative revenue adjustment of $1 million if it fails to repair at least 85 percent of Level II deficiencies (as defined in the Safety Orders in Case 04-M-0159 ("Safety Orders")) that have a repair due date in the respective calendar year within the time period allowed for such repairs under the Safety Orders (*i.e.*, one year). The Company is subject to an additional negative revenue adjustment of $1 million if it fails to repair at least 75 percent of Level III deficiencies (as defined in the Safety Orders) that have a repair due date in the respective calendar year within the time period allowed for such repairs under the Safety Orders (*i.e.*, three years). In 2016, the Company satisfied its I&M Program performance objectives, repairing 93.1 percent of Level II deficiencies and 92.2 percent of Level III deficiencies within the respective timeframes. The Company is not proposing any changes relative to the I&M performance objectives.

VII. <u>Research, Development and Demonstration Program</u>

Q. Please describe the Company's Research, Development and Demonstration Program ("RD&D") program.

A. The purpose of the Company's RD&D program is to drive innovation through the evaluation and eventual deployment of new technologies and processes to improve the efficiency of the Company's electric operations while meeting the challenges and future needs of providing safe, reliable service at reasonable cost. Through the program, the Company works collaboratively with other utilities to identify new beneficial technologies and processes that can be integrated into day-to-day operations. The objectives of the program are to promote developments that can (1) increase safety for employees and the public, (2) improve electric system reliability, (3) meet the challenges of climate change, and (4) reduce costs.

The Company invests in longer-term studies or higher risk topics where it is unlikely that manufacturers would invest on their own. The Company also seeks to collaborate with other parties to leverage its research investment.

Q. Provide an example of how the Company leverages its investment in RD&D.

A. The Company collaborates with industry organizations and participating utilities to identify areas of research responsive to ongoing or anticipated challenges. This collaboration of knowledge and funding allows individual utilities to gain knowledge at a fraction of the cost of pursuing the research singularly. The Company primarily collaborates with the Electric Power Research Institute ("EPRI") and the Centre for Energy Advancement through Technological Innovation ("CEATI").

Q. Is the Company proposing to increase its RD&D program funding?

A. Yes. The Company's revenue requirement reflects incremental recovery above the historic annual amount by $0.213 million in the Rate Year, and $0.221 million and $0.230 million in the Data Years, respectively. These incremental costs are shown in Exhibit __ (EIOP-12).

Q. Why is the Company proposing to increase cost recovery for RD&D initiatives?

A. By making incremental RD&D investments and maintaining a targeted portfolio to address specific challenges, the Company can focus its limited resources on those issues likely to result in a safer, more efficient and environmentally conscious approach to the delivery of electric energy.

The investments presented here seek to use RD&D to introduce products to the Company, improve processes and systems, and modernize work methods. The Company determines the projects it invests in by identifying where current and future challenges exist. The RD&D group then aligns those needs with technical organizations, such as EPRI and CEATI, that may already have ongoing studies addressing those challenges. Should empirical research be needed, the Company looks to universities or other entities capable of performing that research. A budget is then developed based on the costs associated with each project. This approach ensures that RD&D investment is targeted towards areas that will benefit from it.

Q. Does the Company describe the projects included in its RD&D program?

A. Yes. Exhibit __ (EIOP-15) identifies the projects included in the Company's RD&D portfolio, along with forecast annual funding during the Rate Year and Data Years. Further details on specific projects are included in the Company's Electric Research, Development, and Demonstration Plan, originally filed with the Commission on March 31, 2017, and revised on April 28, 2017.

Q. Does this conclude the Panel's testimony?

A. Yes, it does.

Exhibits of
EIOP

Index of Exhibits

Exhibit __ (EIOP-1)	Summary of Planned Capital Investment by System, April 1, 2017 – March 31, 2022
Exhibit __ (EIOP-2)	Summary of Actual and Planned T&D Infrastructure Investment by System, Fiscal Year 2012 – Fiscal Year 2022
Exhibit __ (EIOP-3)	Summary of Planned Investment for Electric and Common Capital Plant and Cost of Removal, January – March 2017 – Fiscal Year 2022
Exhibit __ (EIOP-4)	Comparison of Annual Actual and Budgeted Investment Levels, Fiscal Year 2012 – December 31, 2016
Exhibit __ (EIOP-5)	Transmission Capital Investment Plan, Fiscal Year 2018 – Fiscal Year 2022
Exhibit __ (EIOP-6)	Details of Significant Transmission Capital Investment Plan Projects and Programs, Fiscal Year 2018 – Fiscal Year 2022
Exhibit __ (EIOP-7)	Sub-Transmission Capital Investment Plan, Fiscal Year 2018 – Fiscal Year 2022
Exhibit __ (EIOP-8)	Details of Significant Sub-Transmission Capital Investment Plan Projects and Programs, Fiscal Year 2018 – Fiscal Year 2022
Exhibit __ (EIOP-9)	Distribution Capital Investment Plan, Fiscal Year 2018 – Fiscal Year 2022
Exhibit __ (EIOP-10)	Details of Significant Distribution Capital Investment Plan Projects and Programs, Fiscal Year 2018 – Fiscal Year 2022
Exhibit __ (EIOP-11)	Common Capital Investment Plan, Fiscal Year 2018 – Fiscal Year 2022

Index of Exhibits (continued)

Exhibit __ (EIOP-1)

Summary of Planned Capital Investment by System
April 1, 2017 – March 31, 2022

Summary of Planned Capital Investment by System
(Transmission, Sub-Transmission, Distribution)
April 1, 2017 - March 31, 2022 (FY18-22)

System	FY18	FY19	FY20	FY21	FY22
Transmission	190.2	206.0	210.0	222.0	230.0
Sub-Transmission	18.1	37.2	42.9	49.8	47.2
Distribution	283.5	311.0	340.5	410.5	450.9
Total	**491.7**	**554.2**	**593.4**	**682.3**	**728.1**

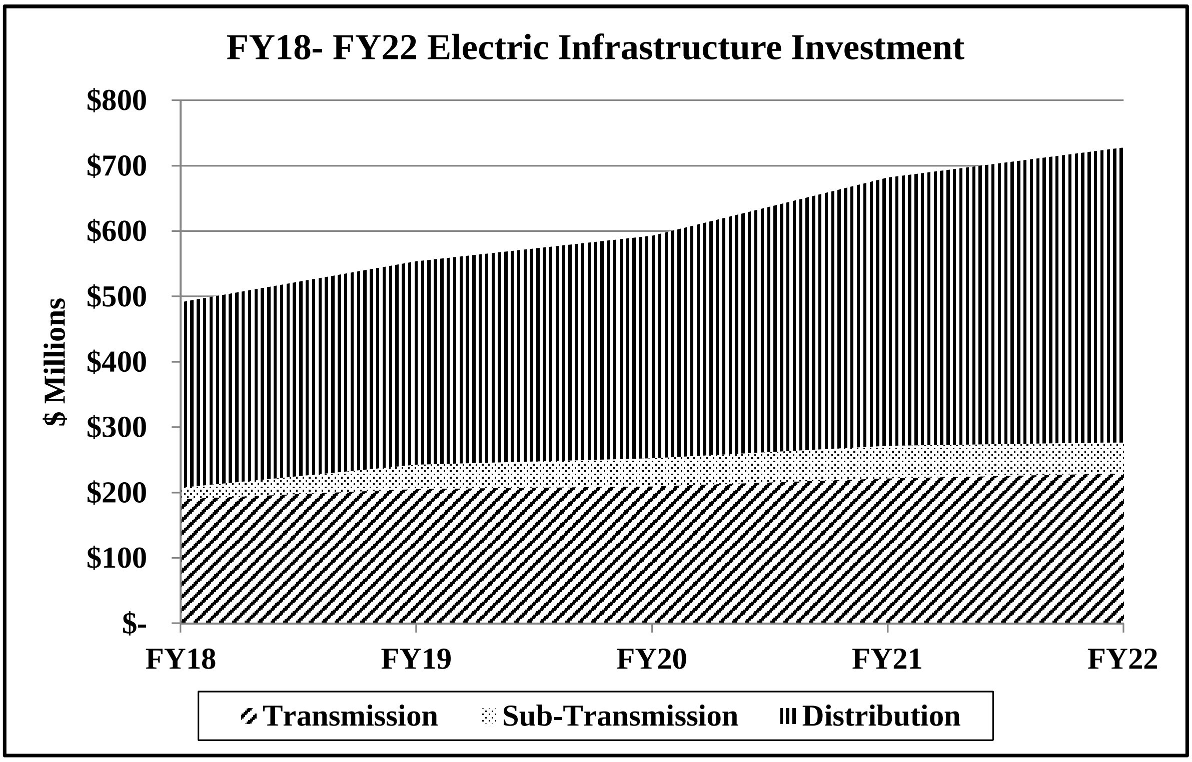

Exhibit __ (EIOP-2)

Summary of Actual and Planned T&D Infrastructure Investment by System
Fiscal Year 2012 – Fiscal Year 2022

Summary of Actual and Planned T & D Infrastructure Investment by System

	Actual					Est.	Planned				
System	**FY12**	**FY13**	**FY14**	**FY15**	**FY16**	**FY17**	**FY18**	**FY19**	**FY20**	**FY21**	**FY22**
Transmission	128.8	165.3	154.8	167.5	170.3	191.5	190.2	206.0	210.0	222.0	230.0
Sub-Transmission	61.5	33.0	36.5	28.8	27.0	21.3	18.1	37.2	42.9	49.8	47.2
Distribution	231.3	200.3	300.5	310.9	286.7	249.0	283.5	311.0	340.5	410.5	450.9
Total	**421.6**	**398.6**	**491.9**	**507.2**	**484.0**	**461.8**	**491.7**	**554.2**	**593.4**	**682.3**	**728.1**

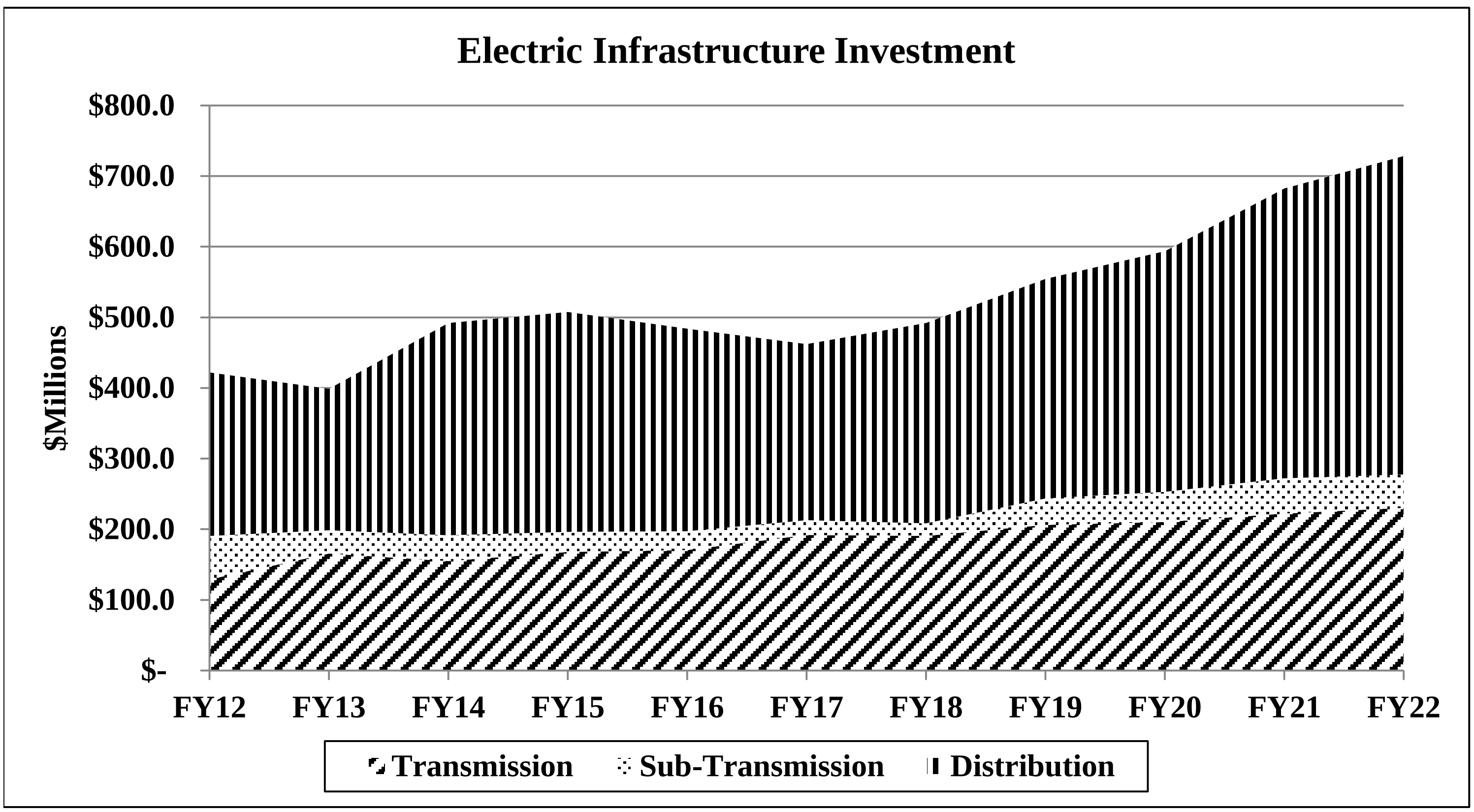

Exhibit__ (EIOP-3)

Exhibit __ (EIOP-3)

Summary of Planned Investment for Electric and Common Capital Plant and Cost of Removal
January – March 2017 – Fiscal Year 2022

NMPC Electric Rate Case
Summary of Planned Investment for Electric and Common Capital Plant and Cost of Removal
January - March FY17 - FY22
(000's)

CAPEX	FY17 Jan-Mar 17 Forecast	FY18	FY19	FY21	FY21	FY22
Electric Direct Capex						
Electric Direct - Distribution	89,714,136	283,490,681	310,984,463	340,459,558	410,453,899	450,897,940
Electric Direct - Transmission	56,197,155	190,165,000	206,000,000	210,000,000	222,000,000	230,000,000
Electric Direct - Sub-Transmission	12,184,214	18,064,252	37,238,528	42,932,655	49,836,898	47,228,386
Electric Direct Capex - Total	158,095,505	491,719,933	554,222,991	593,392,213	682,290,797	728,126,326
Allocated Capex (at 100%)						
Info Services - Electric	160,460	200,000	200,000	200,000	228,000	228,000
Property Services - Common	4,000,998	7,500,000	13,500,000	13,500,000	13,500,000	13,500,000
Operations Support - Common	64,000	512,000	3,162,857	1,481,429	1,481,429	1,481,429
Inventory Management/Investment Recovery - Common	-	230,000	166,667	166,667	166,667	166,667
Allocated Capex (at 100%) - Total	4,225,458	8,442,000	17,029,524	15,348,096	15,376,096	15,376,096

Cost of Removal	FY17 Jan-Mar 17 Forecast	FY18	FY19	FY21	FY21	FY22
Electric Direct Cost of Removal						
Electric Direct - Distribution	7,814,559	28,748,179	40,053,326	32,749,518	32,824,341	34,545,556
Electric Direct - Transmission	6,290,000	23,711,000	26,300,000	22,100,000	30,800,000	28,900,000
Electric Direct - Sub-Transmission	6,502,486	4,962,966	6,277,683	7,899,164	8,742,701	6,145,533
Electric Direct Cost of Removal - Total	20,607,045	57,422,145	72,631,009	62,748,682	72,367,042	69,591,089
Allocated Cost of Removal (at 100%)						
Info Services - Electric	-	-	-	-	-	-
Property Services - Common	360,090	675,000	1,215,000	1,215,000	1,215,000	1,215,000
Operations Support - Common	-	30,000	-	-	-	-
Inventory Management/Investment Recovery - Common	-	-	-	-	-	-
Allocated Cost of Removal (at 100%) - Total	360,090	705,000	1,215,000	1,215,000	1,215,000	1,215,000

Exhibit __ (EIOP-4)

Comparison of Annual Actual and Budgeted Investment Levels
Fiscal Year 2012 – December 31, 2016

Capital Expenditures
Actual and Budget
Historic 5 Years: FY12 - FY16
Historic Test Year: CY2016
Summary by Year
(In thousands)

	FY2012		FY2013		FY2014		FY2015		FY2016		Test Year CY 2016	
	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget HTY	Actual HTY
Distribution												
Asset Condition	31,692	31,998	27,644	22,860	30,000	35,987	63,805	82,637	67,257	79,465	61,883	63,344
Customer Requests/Public Requirements	-	-	-	-	-	-	85,454	108,392	85,488	96,627	100,307	94,626
Damage/Failure	22,304	25,678	21,670	18,481	22,440	38,144	23,106	34,917	27,739	45,089	49,521	40,306
Non-Infrastructure	4,462	2,769	4,444	1,948	4,160	3,183	3,232	5,367	2,957	1,858	3,099	2,269
Statutory/Regulatory	133,171	127,147	140,573	120,425	123,056	157,828	-	-	0	0	-	-
System Capacity & Performance	41,372	43,665	40,669	36,631	53,344	65,399	67,681	79,599	70,113	63,686	47,790	37,964
Total Distribution	**233,000**	**231,257**	**235,000**	**200,346**	**233,000**	**300,542**	**243,279**	**310,913**	**253,554**	**286,724**	**262,599**	**238,509**
Sub - T												
Asset Condition	24,221	17,208	15,674	13,792	17,050	15,955	24,144	19,556	18,992	18,585	11,046	12,092
Customer Requests/Public Requirements	-	-	-	-	-	-	1,982	2,708	1,597	1,724	7,299	(505)
Damage/Failure	3,235	3,529	4,037	2,865	3,300	3,738	2,757	3,286	3,422	4,852	4,745	5,406
Non-Infrastructure	-	199	166	(40)	-	49	145	-	-	11	-	33
Statutory/Regulatory	12,889	12,940	17,905	10,766	13,898	10,061	-	-	-	-	-	-
System Capacity & Performance	3,655	27,672	8,218	5,633	6,752	6,693	3,748	3,236	3,281	1,797	2,720	1,293
Total Sub T	**44,000**	**61,548**	**46,000**	**33,016**	**41,000**	**36,496**	**32,775**	**28,787**	**27,293**	**26,969**	**25,810**	**18,319**
Transmission												
Asset Condition	42,408	38,538	40,552	58,551	34,733	31,969	57,498	53,321	61,290	74,975	74,896	78,797
Customer Requests/Public Requirements	-	-	-	-	-	-	56	728	539	3,913	456	(98)
Damage/Failure	24,121	17,355	14,039	12,802	15,072	26,628	12,009	11,627	8,992	10,521	5,521	14,208
Non-Infrastructure	11,458	7,176	1,550	2,081	50	2,269	3,792	15,260	2,588	(7,994)	2,017	(4,229)
Statutory/Regulatory	44,398	50,459	63,773	69,029	74,233	67,673	-	-	-	-	-	-
System Capacity & Performance	9,616	15,273	22,336	22,809	28,190	26,303	102,947	86,597	93,427	88,875	95,806	83,219
Total Transmission	**132,000**	**128,802**	**142,250**	**165,273**	**152,279**	**154,843**	**176,300**	**167,533**	**166,835**	**170,290**	**178,696**	**171,898**
Total Electric	**409,000**	**421,607**	**423,250**	**398,634**	**426,279**	**491,880**	**452,354**	**507,233**	**447,681**	**483,982**	**467,106**	**428,726**
Common Capital	**26,404**	**14,698**	**19,918**	**14,493**	**17,688**	**17,531**	**11,377**	**18,164**	**8,246**	**7,829**	**10,211**	**7,006**

Exhibit__(EIOP-4)
Page 1 of 1

Exhibit __ (EIOP-5)

Transmission Capital Investment Plan
Fiscal Year 2018 – Fiscal Year 2022

Transmission Capital Investment Plan

Spending Rationale	Program	Project Name	Project #	FY18	FY19	FY20	FY21	FY22	Total
Asset Condition	Asset Condition I&M	NY Inspection Repairs - Capital	C026923	12,002,000	15,000,000	12,000,000	12,000,000	12,000,000	63,002,000
	Asset Condition I&M Total			12,002,000	15,000,000	12,000,000	12,000,000	12,000,000	63,002,000
	Component Fatigue/Deterioration	345kV Laminated Cross-arm-Placehold	C060365	2,426,000	3,000,000	3,000,000	3,000,000	3,000,000	14,426,000
		Access Road Packard-Hunt 115 kV	C076862	500,000	1,000,000	0	0	0	1,500,000
		Alabama-Telegraph 115 T1040 ACR.	C033014	300,000	4,600,000	0	0	0	4,900,000
		Alcoa Fence Replacement	C072207	55,000	0	0	0	0	55,000
		Alps relay replacement	C049296	118,000	0	0	0	0	118,000
		Amsterdam - Station Retirement	C076006	0	8,000	0	0	0	8,000
		AMT PIW/SERR - NIMO	C031545	250,000	250,000	250,000	250,000	250,000	1,250,000
		Ash St. 115-12kV TRF Asset replace	C076282	500,000	1,200,000	650,000	130,000	0	2,480,000
		Balmat - Repl liquid filled fuse	C076189	0	0	0	24,000	54,000	78,000
		Batavia - Obsolete Relays	C073587	0	43,000	65,000	0	0	108,000
		Batavia - Replace five OCBs	C075904	0	240,000	1,230,000	545,000	0	2,015,000
		Batavia-Golah 119 ACR	C060217	0	0	300,000	0	0	300,000
		BatteryRplStrategyCo36TxT	C033847	160,000	684,000	500,000	550,000	250,000	2,144,000
		Battle Hill - replace 3 OCBs	C049543	778,000	0	0	0	0	778,000
		Bethlehem Relay Replacem't Strategy	C049583	115,000	0	0	0	0	115,000
		Boonville Rebuild	C049903	0	0	50,000	300,000	2,500,000	2,850,000
		Boonville-Rome 3-4 T4060-T4040 ACR	C047795	75,000	0	0	0	0	75,000
		Border City-Elbridge #15/#5 ACR	C075723	0	300,000	1,000,000	3,000,000	0	4,300,000
		Br F-Taylorville 3-4 ACR	C024359	2,508,000	0	0	0	0	2,508,000
		Breaker T Repl Program 4-69kV NYC.	C049258	597,000	597,000	597,000	600,000	600,000	2,991,000
		Breaker T Repl Program 4-69kV NYE	C049257	598,000	598,000	598,000	600,000	600,000	2,994,000
		Breaker T Repl Program 4-69kV NYW	C049260	650,000	598,000	598,000	600,000	600,000	3,046,000
		Brockport Tap Refurbishment	C055531	0	0	0	100,000	350,000	450,000
		Carr St./E.Syracuse CO-Gen Relays	C049739	394,000	0	0	0	0	394,000
		Colton-BF 1-2 T3140-T3150 ACR	C036164	0	0	0	100,000	200,000	300,000
		Colton-Replace CBs and Disconnects	C029844	30,000	0	0	0	0	30,000
		Curtis St - Oil Breaker Replacement	C049584	349,000	0	0	0	0	349,000
		Dewitt - Remote End Work	C075822	54,000	0	0	0	0	54,000
		Dunkirk Rebuild	C005155	563,000	3,595,000	12,392,000	12,400,000	750,000	29,700,000

Exhibit__(EIOP-5)
Page 1 of 12

Transmission Capital Investment Plan

Spending Rationale	Program	Project Name	Project #	FY18	FY19	FY20	FY21	FY22	Total
		Dunkirk Substation Rebuild CH	C073999	100,000	400,000	2,000,000	0	0	2,500,000
		Dunkrk-Falc 161-162 T1090-T1100 ACR	C047831	0	0	100,000	200,000	200,000	500,000
		EASEMENT-RELOCATE S. DOW-POLAND 865	C072888	750,000	0	0	0	0	750,000
		East Norfolk - Repl liq filled fuse	C076188	0	0	0	24,000	54,000	78,000
		Edic/N Scotland-NG Assoc work-TOTS	C058064	400,000	0	0	0	0	400,000
		Edic: Protection Migration	C076214	0	600,000	1,100,000	500,000	0	2,200,000
		Elm St #2 TRF Asset Replacement	C069426	500,000	3,000,000	2,000,000	1,000,000	300,000	6,800,000
		Existing Control Bldg - Tran-NY	CNYT352	250,000	250,000	250,000	250,000	250,000	1,250,000
		Falconer Cap Bank BKR Asset Replace	C065468	470,000	0	0	0	0	470,000
		Feura Bush Relay Replacement	C049585	720,000	0	0	0	0	720,000
		Frontier 180 182 ACR/Recond	C027436	0	0	0	300,000	200,000	500,000
		Frontier 181 ACR/Recond	C060215	0	0	0	300,000	200,000	500,000
		Gard-Dun 141-142 N Phase Rebuild	C003389	2,225,000	8,685,000	22,790,000	28,440,000	23,642,000	85,782,000
		Gard-Dun 141-142 South Struct Repl	C077024	650,000	40,000	0	0	0	690,000
		Gardenville Rebuild	C005156	24,894,000	5,706,000	493,000	663,000	0	31,756,000
		Gardenville-Rebuild Line Relocation	C030084	6,314,000	7,210,000	4,589,000	0	0	18,113,000
		Gard-HH 151-152 T1950-T1280 S ACR	C027425	100,000	200,000	200,000	1,000,000	3,000,000	4,500,000
		GE Butyl Rubber VT Replacement	C049002	321,000	0	0	0	0	321,000
		Geres Lock Switch Replacements	C073446	4,000	0	0	0	0	4,000
		GOLAH RELAY & BREAKER PROGRAM REPL	C050920	0	55,000	490,000	957,000	0	1,502,000
		Greenbush Relay Replacement	C049587	330,000	0	0	0	0	330,000
		Greenbush-Stephentown #993 ACR	C060208	100,000	200,000	200,000	1,000,000	3,000,000	4,500,000
		G'ville/HH 152 Vange/J-hook Replace	C069689	500,000	0	0	0	0	500,000
		Homer Hill - Replace five OCBs	C075942	0	0	0	240,000	1,230,000	1,470,000
		Homer Hill - West Olean 156 ACR	C060218	0	0	300,000	0	0	300,000
		Homer Hill-Bennett 157 T1340 ACR	C027429	0	400,000	0	0	0	400,000

Exhibit__(EIOP-5)
Page 2 of 12

Transmission Capital Investment Plan

Spending Rationale	Program	Project Name	Project #	FY18	FY19	FY20	FY21	FY22	Total
		Hoosick - Replace Bank 1 & relays	C053132	0	100,000	3,000,000	3,400,000	200,000	6,700,000
		Huntley - Install Control Bldg	C067027	2,450,000	0	0	0	0	2,450,000
		Huntley-Gardenville 38/39 Rebuild	C075543	0	0	0	0	300,000	300,000
		Huntley-Lockport 36 37 ACR	C069538	300,000	10,000,000	6,300,000	100,000	0	16,700,000
		Independence Station relay Replace	C049598	55,000	524,000	0	0	0	579,000
		Inghams Phase Shifting Transformer	C047864	50,000	4,410,000	0	0	0	4,460,000
		Inghams Station - Assoc Line work	C060240	0	0	0	100,000	900,000	1,000,000
		Inghams Station Re-vitalization	C050917	0	50,000	173,000	700,000	4,450,000	5,373,000
		Inghams Station Revitalization CH	C074000	0	0	0	100,000	2,400,000	2,500,000
		Inghams-E. Springfield #7 ACR	C060209	0	0	100,000	200,000	200,000	500,000
		Kensington #4 & #5 TRF asset replac	C069429	0	0	250,000	2,500,000	2,250,000	5,000,000
		Leeds - Replace U Series Relays	C024663	88,000	0	0	0	0	88,000
		Leeds Station Service	C049900	48,000	0	0	0	0	48,000
		LightHH 115kV CH	C073996	0	0	100,000	2,400,000	0	2,500,000
		LightHH 115kV Yard Repl & cntrl hs.	C031662	5,000	25,000	300,000	1,800,000	11,579,000	13,709,000
		LightHH Trans Lines Reconnect	C073997	0	0	50,000	500,000	6,557,000	7,107,000
		Lockport 103-104 T1620-T1060 STR	C027432	0	0	0	300,000	200,000	500,000
		Lockport Sub Rebuild CH	C073991	0	0	0	100,000	2,400,000	2,500,000
		Lockport-Batavia 108 T1500 STR.	C027431	100,000	200,000	100,000	0	0	400,000
		Lockport-Batavia 112 T1510 ACR	C003422	100,000	300,000	2,500,000	12,000,000	35,000,000	49,900,000
		Lockport-Mortimer 111 T1530 ACR	C003417	500,000	0	0	0	0	500,000
		LockportSubstationRebuildCo36TxT	C035464	0	50,000	400,000	2,201,000	9,125,000	11,776,000
		Long Lane Relay Replacement	C049600	660,000	0	0	0	0	660,000
		Maplewood - Replace one OCB	C075867	0	0	210,000	284,000	0	494,000
		Maplewood-Norton-Replace Pilot Wire	C036006	80,000	0	0	0	0	80,000
		Marshville - replace R11 OCB	C049547	9,000	0	0	0	0	9,000
		Menands Cntrl Bldg & Relay Replcmt	C049601	187,000	1,417,000	3,070,000	3,388,000	2,148,000	10,210,000

Exhibit__(EIOP-5)
Page 3 of 12

Transmission Capital Investment Plan

Spending Rationale	Program	Project Name	Project #	FY18	FY19	FY20	FY21	FY22	Total
		Mohican - Replace Bank 1 and Relays	C053133	0	100,000	2,300,000	1,597,000	0	3,997,000
		Mortimer #3 Auto TRF Replace	C076283	125,000	675,000	2,763,000	0	0	3,563,000
		Mortimer-Golah #110 ACR	C060220	0	0	0	300,000	200,000	500,000
		Mortmr-Pannll 24-25 T1590-T1600 ACR	C047816	0	100,000	200,000	1,000,000	3,000,000	4,300,000
		New Scotland - Obsolete Rly Rpl LN3	C076344	338,000	0	0	0	0	338,000
		New Scotland - replace 345kV OCBs	C049553	19,000	0	0	0	0	19,000
		New Scotland 345kV&115kV Relay Repl	C047861	562,000	0	0	0	0	562,000
		New Walden #2 TRF asset replacement	C064192	950,000	0	0	0	0	950,000
		Niagara-Lockport 101/102 ET-Truss	C060216	650,000	0	0	0	0	650,000
		Northeast Region Switch Operation	C053604	4,000	0	0	0	0	4,000
		Norwood - Repl liquid filled fuse	C076187	0	0	0	48,000	108,000	156,000
		NY Priority OHL Tran Switch Repl	C076621	630,000	630,000	630,000	630,000	630,000	3,150,000
		Oneida Substation Rebuild	C034443	0	0	30,000	250,000	1,040,000	1,320,000
		Oswego - 115kV & 34.5kV - Rebuild	C043426	2,644,000	3,572,000	0	0	0	6,216,000
		Oswego: 115kV Control House	C061991	1,287,000	776,000	0	0	0	2,063,000
		Oswego: 345kV Asset Sep/Repl	C076218	50,000	700,000	2,150,000	0	0	2,900,000
		Oswego: 345kV Asset Sep/Repl CH	C076983	100,000	400,000	2,000,000	0	0	2,500,000
		Packard - Replace three OCBs	C075943	0	0	125,000	975,000	135,000	1,235,000
		Pannell-Geneva 4 Thruway Crossing	C069541	100,000	0	0	0	0	100,000
		Pannell-Geneva 4-4A T1860 ACR	C030889	200,000	1,000,000	4,000,000	18,000,000	18,000,000	41,200,000
		Porter-Watkins Rd 5 ACR	C060207	0	0	300,000	200,000	2,000,000	2,500,000
		Purchase Spare Transformers	C053135	4,660,000	8,007,000	5,796,000	0	0	18,463,000
		Quaker-Sleight Road #13 ACR	C060219	0	0	300,000	0	0	300,000
		Queensbury - replace OCBs	C049554	951,000	0	0	0	0	951,000
		Rebuild Huntley Station Asset Separ	C049902	4,619,000	16,000,000	12,000,000	4,000,000	0	36,619,000
		Ridge Substation - 34.5kV System Re	C046693	0	312,000	329,000	0	0	641,000
		Rotterdam 115kV SubRebuild(AIS)	C034850	46,000	300,000	6,727,000	19,931,000	24,910,000	51,914,000

Exhibit__(EIOP-5)
Page 4 of 12

Transmission Capital Investment Plan

Spending Rationale	Program	Project Name	Project #	FY18	FY19	FY20	FY21	FY22	Total
		Rotterdam-Bear Swamp E205 T5630 ACR	C047832	0	0	0	300,000	200,000	500,000
		S Oswego-Clay #4 T-334 Rebuild	C075544	0	0	0	0	300,000	300,000
		Schuyler - replace OCBs	C049562	300,000	667,000	0	0	0	967,000
		Schuyler Rd Repl 918 928 CirSws	C050799	2,000	0	0	0	0	2,000
		Scriba - Replace Insulators	C075962	0	135,000	63,000	0	0	198,000
		Scriba Relay Replacement	C049611	180,000	615,000	8,000	0	0	803,000
		Seneca #2 & #5 TRF asset Replace	C069427	0	250,000	2,500,000	2,250,000	200,000	5,200,000
		Seneca Reactor 71E asset replace	C065766	0	989,000	1,278,000	0	0	2,267,000
		Seneca Term Relay Replacement	C049613	530,000	0	0	0	0	530,000
		Seneca Terminal TB3 Replacement	C049744	656,000	0	0	0	0	656,000
		Sleight Rd-Auburn #3 ACR	C075566	0	0	0	0	300,000	300,000
		Southeast Batavia - Obsolete Relays	C073588	0	16,000	16,000	0	0	32,000
		Teall - Replace one OCBs	C075902	0	0	146,000	221,000	0	367,000
		Teall Ave - 115kV Foundation Repl	C076216	0	0	0	150,000	326,000	476,000
		Teall Ave. Transformer Replacement	C047865	837,000	0	0	0	0	837,000
		Telegraph Road TRF #2 Asset Replace	C069346	50,000	1,500,000	1,000,000	0	0	2,550,000
		Terminal Station Relocation	C076242	0	0	50,000	3,000,000	2,650,000	5,700,000
		Ticonderoga 2-3 T5810-T5830 ACR	C039521	300,000	1,400,000	7,000,000	7,000,000	1,100,000	16,800,000
		Ticonderoga-Sanford T6410R Removal	C032309	1,140,000	556,000	422,000	0	0	2,118,000
		Tuller Hill 115kV Tap Replacement	C065087	0	10,000	51,000	0	0	61,000
		Turner D Switch Replacements (36)	C052603	0	1,376,000	1,376,000	0	0	2,752,000
		Volney station Relay Replacement	C049626	180,000	446,000	8,000	0	0	634,000
		Walck RD Relay Replacement	C049628	199,000	0	0	0	0	199,000
		Whitehall - Replace three OCBs	C075885	0	140,000	970,000	151,000	0	1,261,000
		Wood Pole Mgmt Prgm (Osmose)	C011640	1,500,000	2,500,000	2,500,000	2,500,000	2,500,000	11,500,000
		Woodard - Replace three OCBs	C075903	0	110,000	895,000	96,000	0	1,101,000
		Woodard Relay Replacement	C047863	271,000	0	0	0	0	271,000
		Woodlawn Transformer Replacement	C051986	18,000	700,000	2,340,000	1,800,000	0	4,858,000

Exhibit__(EIOP-5)
Page 5 of 12

Transmission Capital Investment Plan

Spending Rationale	Program	Project Name	Project #	FY18	FY19	FY20	FY21	FY22	Total
		Yahnundasis - Mobile Disconnects	C049564	108,000	0	0	0	0	108,000
	Component Fatigue/Deterioration Total			78,486,000	104,517,000	132,568,000	151,545,000	176,538,000	643,654,000
	Failure Trend	Central Div Sta - Shielded Cable	C058003	0	196,000	206,000	206,000	0	608,000
		West Div - Shielded Cables	C058130	50,000	70,000	60,000	75,000	0	255,000
	Failure Trend Total			50,000	266,000	266,000	281,000	0	863,000
Asset Condition Total				90,538,000	119,783,000	144,834,000	163,826,000	188,538,000	707,519,000
Communications / Control Systems	EMS/SCADA	Program-Remote Terminal Unit (RTU)	C003772	400,000	0	0	0	0	400,000
		RTUs M9000 Protocol Upgrades	C069437	300,000	1,229,000	1,238,000	1,064,000	1,060,000	4,891,000
		VARIOUS STA - RANGE OF OPERATIONS	C032551	1,000	0	0	0	0	1,000
	EMS/SCADA Total			701,000	1,229,000	1,238,000	1,064,000	1,060,000	5,292,000
	Telecom	Upgrade Comm Equip Verizon Retireme	C069570	198,000	500,000	5,000,000	5,000,000	6,995,000	17,693,000
	Telecom Total			198,000	500,000	5,000,000	5,000,000	6,995,000	17,693,000
Communications / Control Systems Total				899,000	1,729,000	6,238,000	6,064,000	8,055,000	22,985,000
Customer Requests/Public Requirements	Customer Interconnections	Arkwright Wind - Line	CNYCS07	1,000,000	1,500,000	0	0	0	2,500,000
		Arkwright Wind - Line Reimb	CNYCS07R	(1,000,000)	(1,500,000)	0	0	0	(2,500,000)
		Arkwright Wind - Stations Reimb	CNYCS06R	(1,000,000)	(1,617,000)	0	0	0	(2,617,000)
		Arkwright Wind-Stations	CNYCS06	1,000,000	1,617,000	0	0	0	2,617,000
		Bethlehem Energy Center Uprate - Stations	CNYCS02	1,000,000	760,000	0	0	0	1,760,000
		Bethlehem Energy Center Uprate - Stations Reimb	CNYCS02R	(1,000,000)	(760,000)	0	0	0	(1,760,000)
		Bethlehem Energy Center Uprate-Line	CNYCS01	30,000	70,000	0	0	0	100,000
		Bethlehem Energy Center Uprate-Line Reimb	CNYCS01R	(30,000)	(70,000)	0	0	0	(100,000)
		Byrne Dairy Load Expansion	C052843	2,000	0	0	0	0	2,000
		Copenhagen Wind Loop In/Loop out	C076290	500,000	515,000	0	0	0	1,015,000
		Copenhagen Wind Project - Line Reimb	C076290R	(500,000)	(515,000)	0	0	0	(1,015,000)
		Copenhagen Wind Project - Stations	C076291	1,400,000	703,000	0	0	0	2,103,000
		Copenhagen Wind Project - Stations Reimb	C076291R	(1,400,000)	(703,000)	0	0	0	(2,103,000)
		DUN-FALC 161/162 - ATHENEX	C074805	4,200,000	0	0	0	0	4,200,000
		DUN-FALC 161/162 - ATHENEX Reimb	C074805R	(4,200,000)	0	0	0	0	(4,200,000)
		Edic-MVEdge Customer Connection	C066166	10,567,000	0	0	0	0	10,567,000

Exhibit__(EIOP-5)
Page 6 of 12

Transmission Capital Investment Plan

Spending Rationale	Program	Project Name	Project #	FY18	FY19	FY20	FY21	FY22	Total
		Edic-MVEdge Customer Connection Reimb	C066166R	(10,567,000)	0	0	0	0	(10,567,000)
		Erie Cogen-Stations	CNYCS05	670,000	350,000	0	0	0	1,020,000
		Erie Cogen-Stations Reimb	CNYCS05R	(670,000)	(350,000)	0	0	0	(1,020,000)
		Green Power Wind Project	C058099	1,218,000	138,000	0	0	0	1,356,000
		Green Power Wind Project Reimb	C058099R	(1,218,000)	(138,000)	0	0	0	(1,356,000)
		Green Pwr Wind Loop in/out	C058101	846,000	106,000	0	0	0	952,000
		Green Pwr Wind Loop in/out Reimb	C058101R	(846,000)	(106,000)	0	0	0	(952,000)
		Monroe County Mill Seat-TRAN	C067866	109,000	9,000	0	0	0	118,000
		Monroe Cty Mill Seat 3.2MW Exp Reimb	C067866R	(109,000)	(9,000)	0	0	0	(118,000)
		RG&E ROCH AREA RELIABILY PROJ(RARP)	C074886	128,000	0	0	0	0	128,000
		RG&E ROCH AREA RELIABILY PROJ(RARP) Reimb	C074886R	(128,000)	0	0	0	0	(128,000)
		Turning Stone 115kV Line Relocation	C069434	5,973,000	0	0	0	0	5,973,000
		Turning Stone 115kV Line Relocation Reimb	C069434R	(6,000,000)	0	0	0	0	(6,000,000)
	Customer Interconnections Total			(25,000)	0	0	0	0	(25,000)
	Request From External TO	Upgrade Mortimer Station	C064567	127,000	0	0	0	0	127,000
		Upgrade Mortimer Station - Reimb	C064567R	(359,000)	0	0	0	0	(359,000)
	Request From External TO Total			(232,000)	0	0	0	0	(232,000)
	Public Requirements	Rosa Road - GE #14 Line - Raising	C070889	130,000	0	0	0	0	130,000
		Rosa Road - GE #14 Line - Raising Reimb	C070889R	(130,000)	0	0	0	0	(130,000)
	Public Requirements Total			0	0	0	0	0	0
Customer Requests/Public Requirements Total				(257,000)	0	0	0	0	(257,000)
Damage/Failure	Damage/Failure	#4&#12 Porter-Valley/Valley-Fairfie	C060139	8,000	0	0	0	0	8,000
		Harper Station #40 TRF D/F	C075622	1,274,000	0	0	0	0	1,274,000
		Nile Sta D/F Sw 660 & 676 Replace	C074004	276,000	0	0	0	0	276,000
		North LeRoy TRF #1 Replacement	C056083	61,000	0	0	0	0	61,000
		OHL D-F Disconnect Switch Spares	C048159	300,000	0	0	0	0	300,000
		Storm Budgetary Blanket - NMPC	C003481	500,000	500,000	500,000	500,000	500,000	2,500,000
		Trans Station Failure Budget Blanke	C003792	1,700,000	1,700,000	1,700,000	1,700,000	1,700,000	8,500,000
		Trans Station Failure Reserve	C073870	3,000,000	4,600,000	4,600,000	4,600,000	4,600,000	21,400,000

Exhibit__(EIOP-5)
Page 7 of 12

Transmission Capital Investment Plan

Spending Rationale	Program	Project Name	Project #	FY18	FY19	FY20	FY21	FY22	Total
		TransLine D/F Budget Blanket	C003278	550,000	450,000	450,000	450,000	450,000	2,350,000
	Damage/Failure Total			7,669,000	7,250,000	7,250,000	7,250,000	7,250,000	36,669,000
Damage/Failure Total				7,669,000	7,250,000	7,250,000	7,250,000	7,250,000	36,669,000
DER - Electric System Access	Customer Interconnections	DG 8391 Town of Halfmoon 1.008MW	C074484	3,000	0	0	0	0	3,000
		DG 8391 Town of Halfmoon 1.008MW Reimb	C074484R	(3,000)	0	0	0	0	(3,000)
		DG NY 8156 INTERGROW GREENHOUSE RTU	C074523	7,000	0	0	0	0	7,000
		DG NY 8156 INTERGROW GREENHOUSE RTU Reimb	C074523R	(7,000)	0	0	0	0	(7,000)
		DG NY10482 MVCC PV DTT	C074827	13,000	0	0	0	0	13,000
		DG NY10482 MVCC PV DTT Reimb	C074827R	(13,000)	0	0	0	0	(13,000)
		DG NY-11143 Amsterdam EMS SCADA RTU	C074508	5,000	0	0	0	0	5,000
		DG NY-11143 Amsterdam EMS SCADA RTU Reimb	C074508R	(5,000)	0	0	0	0	(5,000)
		DG NY11222 SUNY SELKIRK (SE) DTT Reimb	C074784R	(468,000)	0	0	0	0	(468,000)
		DG NY11222 SUNY Selkirk(SE) Station	C074784	468,000	0	0	0	0	468,000
		DG NY11223 SUNY SELKIRK (NE) DTT Reimb	C074786R	(170,000)	0	0	0	0	(170,000)
		DG NY11223 SUNY Selkirk(NE) Station	C074786	170,000	0	0	0	0	170,000
		DG NY11257 SUNY Selkirk (C) Station	C074752	170,000	0	0	0	0	170,000
		DG NY11257 SUNY SELKIRK CENTER DTT Reimb	C074752R	(170,000)	0	0	0	0	(170,000)
		DG NY11258 SUNY SELKIRK (NW) DTT Reimb	C074763R	(170,000)	0	0	0	0	(170,000)
		DG NY11258 SUNY Selkirk(NW) Station	C074763	170,000	0	0	0	0	170,000
		DG NY12449 - 3I0 at Mohican Station	C076985	226,000	0	0	0	0	226,000
		DG NY12544 SENECA NATION WIND (RTU)	C074527	6,000	0	0	0	0	6,000
		DG NY12544 SENECA NATION WIND (RTU) Reimb	C074527R	(6,000)	0	0	0	0	(6,000)
		DG NY16088 SUNY Perth South RTU	C075006	46,000	0	0	0	0	46,000
		DG NY16088 SUNY Perth South RTU Reimb	C075006R	(46,000)	0	0	0	0	(46,000)
		DG NY5451 Skidmore 2MW PV RTU	C076964	9,000	0	0	0	0	9,000
			C076964R	(9,000)	0	0	0	0	(9,000)
		DG NY5529 Clarkson PV RTU	C076864	9,000	0	0	0	0	9,000
			C076864R	(9,000)	0	0	0	0	(9,000)

Exhibit__(EIOP-5)
Page 8 of 12

Transmission Capital Investment Plan

Spending Rationale	Program	Project Name	Project #	FY18	FY19	FY20	FY21	FY22	Total
		DG NY6856 Oneida County DPW RTU	C075702	3,000	0	0	0	0	3,000
		DG NY6856 Oneida County DPW RTU Reimb	C075702R	(3,000)	0	0	0	0	(3,000)
		HVCC 8.1 MW DG RTU	C068148	8,000	0	0	0	0	8,000
		HVCC 8.1 MW DG RTU Reimb	C068148R	(8,000)	0	0	0	0	(8,000)
		Tn of Whitehall - Millet A RTU	C072610	9,000	0	0	0	0	9,000
		Tn of Whitehall - Millet A RTU Reimb	C072610R	(9,000)	0	0	0	0	(9,000)
		Tn of Whitehall - Millet B RTU	C072611	6,000	0	0	0	0	6,000
		Tn of Whitehall - Millet B RTU Reimb	C072611R	(6,000)	0	0	0	0	(6,000)
	Customer Interconnections Total			226,000	0	0	0	0	226,000
DER - Electric System Access Total				226,000	0	0	0	0	226,000
Reliability	NERC/NPCC Standards	Conductor Clearance - NY Program	C048678	9,409,000	10,009,000	12,105,000	9,771,000	10,190,000	51,484,000
		Physical Security	C066246	855,000	0	0	0	0	855,000
			C073348	260,000	0	0	0	0	260,000
			C073349	0	0	86,000	962,000	0	1,048,000
			C073351	670,000	0	0	0	0	670,000
			C073352	0	62,000	806,000	0	0	868,000
			C073353	493,000	696,000	0	0	0	1,189,000
			C073354	477,000	681,000	0	0	0	1,158,000
			C073355	942,000	0	0	0	0	942,000
			C073356	722,000	0	0	0	0	722,000
			C073648	0	80,000	906,000	0	0	986,000
		230kV Substation – Upgrade Brks/Disc/PT's	C036866	350,000	1,000,000	1,259,000	15,550,000	6,185,000	24,344,000
	NERC/NPCC Standards Total			14,178,000	12,528,000	15,162,000	26,283,000	16,375,000	84,526,000
	Performance	Backup UG Pump Plant-Trinity Ln 5&9	C062469	0	250,000	1,847,000	100,000	0	2,197,000
		Hudson Station 087- Animal Fence	C059640	55,000	0	0	0	0	55,000
		Osprey Mitigation/Avian Protection	C076662	300,000	300,000	300,000	300,000	300,000	1,500,000
		Rensselaer Station - Animal Fence	C076522	55,000	0	0	0	0	55,000
	Performance Total			410,000	550,000	2,147,000	400,000	300,000	3,807,000
Reliability Total				14,588,000	13,078,000	17,309,000	26,683,000	16,675,000	88,333,000
System Capacity	Generator Retirements	New Elbridge - State St Line	C047298	185,000	0	0	0	0	185,000
		New Elbridge - State St Line Reimb	C047298R	(185,000)	0	0	0	0	(185,000)
		Reconductor #5 Elbridge - State ST	C047297	523,000	0	0	0	0	523,000
			C047297R	(523,000)	0	0	0	0	(523,000)
		Reconfigure Elbridge Sub	C047299	1,252,000	0	0	0	0	1,252,000
		Reconfigure Elbridge Sub Reimb	C047299R	(1,252,000)	0	0	0	0	(1,252,000)
	Generator Retirements Total			0	0	0	0	0	0

Exhibit__(EIOP-5)
Page 9 of 12

Transmission Capital Investment Plan

Spending Rationale	Program	Project Name	Project #	FY18	FY19	FY20	FY21	FY22	Total
	TO Led System Studies	Airco-Bffl Rvr147 Adv Metal Tap	C054711	720,000	182,000	0	0	0	902,000
		Albany-Greenbush 1&2 Reconductoring	C077034	100,000	4,000,000	0	0	0	4,100,000
		Batavia Second 115 kV Cap Bank	C031478	1,600,000	0	0	0	0	1,600,000
		Bethlehem sub relay upgrade line #6	C054267	0	0	0	0	196,000	196,000
		Central Breaker Upgrades - Ash	C043424	1,346,000	0	0	0	0	1,346,000
		Clay-Teall#10,Clay-Dewitt#3 Recond	C043995	28,404,000	8,125,000	0	0	0	36,529,000
		Collamer Crossing_115kV_Line_TAP	C070394	1,100,000	0	0	0	0	1,100,000
		Construct Five Mile Station	C024015	891,000	0	0	0	0	891,000
		E.Golah 2nd 115kV tap	C051829	0	0	0	70,000	1,000,000	1,070,000
		Eastover - Add 2nd Bank	C060247	1,120,000	0	0	0	0	1,120,000
		EDIC - 345-230kV TB2 RECONNECT	C044674	30,000	0	0	0	0	30,000
		Elbridge WoS Reactors	C069531	250,000	250,000	500,000	4,500,000	0	5,500,000
		Elm St Relief_Add 4th Xfer	C049594	1,995,000	48,000	0	0	0	2,043,000
		Gardenville-Erie 54-921 Reconductor	C060213	566,000	0	0	0	0	566,000
		GE-Geres Lock 8 T2240 Reconductor	C047835	0	4,426,000	5,164,000	0	0	9,590,000
		Golah Cap Bank Installation	C064868	785,000	806,000	0	0	0	1,591,000
		Golah Sub rebuild	C051831	0	0	55,000	490,000	957,000	1,502,000
		Grdvll-Bffl Rvr146 2nd Tap Ohio Sta	C054713	2,237,000	182,000	0	0	0	2,419,000
		Land - Lasher Rd Substation	C065886	250,000	0	0	0	0	250,000
		Land Rights/Acquisition - Tran-NY	CNYT350	225,000	225,000	225,000	225,000	225,000	1,125,000
		Land-Clay-Teall#10,Clay-Dewitt #3	C068288	491,000	0	0	0	0	491,000
		Lasher Rd Transmission Line	C043672	728,000	445,000	226,000	0	0	1,399,000
		Lasher Road Substation	C064726	6,000,000	8,000,000	2,500,000	0	0	16,500,000
		Lasher Road Substation - LAB	C064727	1,150,000	300,000	90,000	0	0	1,540,000
		Malone 2nd Bank_Tline	C059673	0	0	40,000	240,000	120,000	400,000
		Malone Metalclad&Transformer	C069306	0	0	0	165,000	1,974,000	2,139,000
		Maplewood #19/#31Reconductoring	C069466	38,000	754,000	4,524,000	4,524,000	0	9,840,000
		Menands #10/#15 Reconductoring	C068850	500,000	5,000,000	500,000	0	0	6,000,000
		Menands-Riverside #3 Sta Work	C060546	8,000	0	0	0	0	8,000
		Mohican Battenkill#15 Rebuild Recon	C034528	8,229,000	695,000	665,000	0	0	9,589,000

Exhibit__(EIOP-5)
Page 10 of 12

Transmission Capital Investment Plan

Spending Rationale	Program	Project Name	Project #	FY18	FY19	FY20	FY21	FY22	Total
		Mortimer line Re-Arrangement	C060248	50,000	570,000	500,000	0	0	1,120,000
		Mountain Station Relay Replacement	C049603	504,000	0	0	0	0	504,000
		NEW MAPLE AVE - LINE PORTION	C070395	0	122,000	527,000	0	0	649,000
		New Tonawanda Station - Line Taps	C053156	574,000	65,000	0	0	0	639,000
		New Watertown 115-13.2kV T - Line	C053155	0	0	0	84,000	0	84,000
		North Troy Brkr & Relay Repl	C069438	2,023,000	596,000	0	0	0	2,619,000
		Ohio Street new 115 - 34.5kV sub	C055263	4,685,000	5,219,000	0	0	0	9,904,000
		Packard 77/78 Series Reactors	C063627	286,000	0	0	0	0	286,000
		Patroon sub relay upgrade line #6	C054269	0	0	0	0	196,000	196,000
		Porter #3 / #7 Install Reactors	C060241	1,804,000	100,000	0	0	0	1,904,000
		Porter Reactors Trans Line Work	C073246	61,000	0	0	0	0	61,000
		Recond Cortland Clarks Corners	C053141	421,000	0	0	0	0	421,000
		Riverside-Reynolds Rd#4 Forbes Tap	C043592	0	0	0	73,000	2,493,000	2,566,000
		Rosa Rd add 115kV Cap Bank	C069467	0	60,000	1,900,000	0	0	1,960,000
		Rotterdam - Add Reactors LN19/20	C069548	200,000	2,360,000	100,000	0	0	2,660,000
		Rotterdam - Curry #11 recond	C060243	504,000	8,000,000	2,500,000	0	0	11,004,000
		Rotterdam Breaker Replacement	C049605	942,000	471,000	0	0	0	1,413,000
		Rotterdam-Reconfig Bus& add breaker	C060255	1,444,000	0	0	0	0	1,444,000
		Royal (New Harper) 115 kV line taps	C044594	0	0	28,000	629,000	338,000	995,000
		Royal (New Harper) TxT Substation	C044874	0	0	1,657,000	6,185,000	1,833,000	9,675,000
		Schaghticoke Control House	C062925	100,000	135,000	1,300,000	0	0	1,535,000
		Schaghticoke Switching Station	C060252	1,150,000	3,300,000	7,000,000	0	0	11,450,000
		Schaghticoke Tap Sw St - Line taps	C060253	142,000	207,000	630,000	0	0	979,000
		Schoharie substation reconfiguratio	C046494	0	915,000	938,000	0	0	1,853,000
		Sodeman Rd Install New taps	C043755	4,000	242,000	480,000	94,000	0	820,000
		Taps to 115 kV new Cicero Sub	C050939	0	100,000	370,000	120,000	0	590,000
		Ticonderoga- Inst Cap Bank, Rpl OCB	C060254	1,105,000	2,403,000	0	0	0	3,508,000
		TP Mortimer Second Bus tie	C050696	650,000	0	0	0	0	650,000

Exhibit__(EIOP-5)
Page 11 of 12

Transmission Capital Investment Plan

Spending Rationale	Program	Project Name	Project #	FY18	FY19	FY20	FY21	FY22	Total
		Trans Study Budgetary Blanket NY	C008376	150,000	150,000	150,000	150,000	150,000	750,000
		Van Dyke 115-13.2 Sub Taps	C044173	0	0	0	628,000	0	628,000
		W. Ashville sub 115kV ln 160 tap	C043832	17,000	876,000	31,000	0	0	924,000
		W. Ashville substation TxT	C043833	923,000	4,831,000	1,769,000	0	0	7,523,000
	TO Led System Studies Total			76,502,000	64,160,000	34,369,000	18,177,000	9,482,000	202,690,000
System Capacity Total				76,502,000	64,160,000	34,369,000	18,177,000	9,482,000	202,690,000
Grand Total				190,165,000	206,000,000	210,000,000	222,000,000	230,000,000	1,058,165,000

Exhibit__(EIOP-5)
Page 12 of 12

Exhibit __ (EIOP-6)

Details of Significant Transmission Capital Investment Plan Projects and Programs
Fiscal Year 2018 – Fiscal Year 2022

Project Title: NY Oil Circuit Replacements
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: X_ Comm: ___ Cust: ___ DER: ___ D/F: ____ Non Inf: ___
Reliability: ____ Syst. Cap: _____

Program Name: N/A

Funding numbers: C075867 – Maplewood
C075943 – Packard
C049562 – Schuyler
C075902 – Teall
C075903 – Woodard
C075904 – Batavia
C075885 – Whitehall
C050920 - Golah

Description:

These projects will replace oil circuit breakers ("OCB") in transmission substations throughout the service territory from FY19 to FY21 due to declining condition, obsolescence, and the need to reduce the likelihood of potential safety or environmental issues that could result from the failure of a large oil volume circuit breaker.

Project Justification:

The replacement of problematic, poor condition, large oil volume circuit breakers with modern SF_6 circuit breakers will improve reliability. The circuit breakers addressed in this Capital Investment Plan ("Plan") are obsolete, in a state requiring replacement, and have limited spare parts or manufacturer support.

There are 700 circuit breakers installed on the transmission system. Of these, 316 are large oil volume types. The majority of the OCBs addressed in this Plan were installed between 1948 and 1969. They are in poor condition or are the last remaining members of problematic breaker families. The remaining OCBs in these families are either planned for replacement as part of substation rebuild requirements or planning needs such as increased short circuit duty or load growth. Due to the deferral and re-phasing of planned investment, several of these projects have been postponed and a reassessment of replacement priorities is needed. There is an increasing trend of problems associated with the large oil volume circuit breaker population. Common problems include:

- Oil leaks, air leaks, bushing hot spots, high power factors and poor insulation.
- Failures of: pressure valves, hoses, gauges, motors, compressors, pulleys, o-rings, control cables, trip coils, close coils, lift rods and contacts.

The following circuit breaker types are ranked the highest priority for replacement;

Allis Chalmers Type BZO – The operating mechanisms in this family of breakers, manufactured in the 1950s through 1980s, are showing an increase in accumulator pump and O-ring failures. Design changes and changes in component manufacture over the years require different replacement parts for various vintages and these parts are difficult to obtain. Mechanism wear has resulted in reduced levels of reliability, increased maintenance costs and a number of failures.

Westinghouse GM – Test results from this family of breakers indicate contact timing problems and questionable insulation integrity.

General Electric Type FK – There have been problems with bushing oil leaks and lift rods issues due to moisture ingress with these circuit breakers. In addition, lead paint is prevalent in this family of breakers.

Due to the key function carried out by circuit breakers, particularly for fault clearance, they cannot be allowed to become unreliable, and should be replaced. The average age of the Company's OCBs is 45 years. Approximately four percent are greater than 60 years old and 30 percent of the total population is between 40 and 59 years old. The typical expected life for oil circuit breakers is 45 years.

<u>Customer Benefit:</u>

The planned replacement of circuit breakers reduces the likelihood of an in-service failure which can lead to long-term interruptions of components of the transmission system as well as significant customer interruptions. This circuit breaker replacement strategy promotes reliability of the transmission network in terms of CAIDI and SAIFI performance.

<u>Alternatives:</u>

- Do nothing: This option would have no initial cost, however, there will be indirect costs associated with increased maintenance levels. This option would involve no proactive replacement of equipment, only replacing when failure occurs. This option is unacceptable because leaving degraded circuit breakers in service puts the company and customers at risk of long-term interruptions of the transmission system and violent failures of this equipment have the potential to cause extensive damage to other equipment as well as a potential safety issue for Company employees. All circuit breakers should be replaced before the onset of significant unreliability.
- Refurbishment: This option would be to undertake a major refurbishment as opposed to replacement involving a disassembly of the majority of the circuit breaker components. These components would need to be refurbished back to original design tolerances. Also, replacement of any worn out or degraded parts would need to be acquired. Because of a lack of manufacturer support and inability to locate replacement parts this option is likely to be more costly. In addition, refurbishment may only provide a few years of additional life. Refurbishment is a one-off activity and cannot be repeated indefinitely, but

refurbishment may have limited application where it is not possible to replace the circuit breakers due to outage or other constraints.

- DER/NWA Alternative: The Company's Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company's evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

Studies/References:

Study Report Name (s): N/A
Sanction Paper No: TIC 1030
Strategy No: SG 158

Total Project Cost Breakdown: ($ thousands)

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	0	240	1,230	545	0	0	2,015
C075904	Batavia - Replace five OCBs	OpEx	0	0	0	0	0	0	0	0
		Removal	0	0	0	70	10	0	0	80
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	0	0	210	284	0	0	494
C075867	Maplewood - Replace one OCB	OpEx	0	0	0	0	0	0	0	0
		Removal	0	0	0	0	16	0	0	16
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	0	0	125	975	135	0	1,235
C075943	Packard - Replace three OCBs	OpEx	0	0	0	0	0	0	0	0
		Removal	0	0	0	0	40	0	0	40
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	30	300	667	0	0	0	0	998
C049562	Schuyler - replace OCBs	OpEx	0	0	7	0	0	0	0	7
		Removal	0	0	36	0	0	0	0	36
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	0	0	146	221	0	0	367
C075902	Teall - Replace one OCBs	OpEx	0	0	0	0	0	0	0	0
		Removal	0	0	0	0	8	0	0	8
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	0	110	895	96	0	0	1,101
C075903	Woodard - Replace three OCBs	OpEx	0	0	0	0	0	0	0	0
		Removal	0	0	0	32	0	0	0	32
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	0	140	970	151	0		1,261
C075885	Whitehall - Replace three OCBs	OpEx	0	0	0	0	0	0		0
		Removal	0	0	0	40	0	0		40
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	0	55	490	957	0	0	1,502
C050920	Golah Relay and Breaker Replacement	OpEx	0	0	29	29	56	0	0	115
		Removal	0	0	0	58	113	0	0	170
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment _X_ Conceptual ___ Planning _____ Project _____

Schedule:

Circuit breaker replacements are part of a revolving replacement program that continues through the term of this Plan (FY18-22) so the schedule will vary as the program progresses.

Begin Preliminary Engineering: N/A
Final Design Complete: N/A
Construction Start: N/A
In service date: N/A

Project Title: Substation Physical Security
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: ___ Comm: ___ Cust: ___ DER: ___ D/F: ____ Non Inf: ___
Reliability: _X_ Syst. Cap: _____

Program Name: Physical Security

Associated funding numbers: C066246, C073348, C073349, C073351, C073352, C073353, C073354, C073355, C073356, C073648

Description:

These projects deploy enhanced physical security measures at selected sites per NERC requirements in order to deter or detect unauthorized access.

Project Justification:

The implementation of the recently released North America Energy Reliability Council (NERC) document pertaining to select transmission substations will enhance the existing security above their current requirements. The Company fully recognizes and supports the need to ensure the highest levels of security at these locations.

A further review of substation physical security requirements will be undertaken to assess possible threats and determine whether even greater measures are warranted.

Customer Benefit:

Deterring and detecting unauthorized access to certain substations would result in avoided or reduced physical and personal injury to unauthorized third parties as well as Company personnel at the substations. It will also reduce the potential for service interruptions or equipment damage/loss due to vandalism or theft.

Alternatives:

- Do nothing: This would not establish an enhanced approach to implementing physical security systems at selected substations. It would not establish additional security to deter, detect, monitor and alarm security breaches and would leave National Grid at risk for theft or possible terrorist activities due to the lack of visible deterrence technologies an furthermore not meet the NERC requirements.
- Provide 24x7 security guards: This would offer very good deterrence and detection of intrusion; however, it comes with substantial cost. A number of guards for each location would have to incur background checks and be properly trained to work in an electric substation environment. Further, comfort facilities would have to be provided at each guarded substation. Guard effectiveness would have to be tested periodically to ensure compliance with our security requirements.

- Scale back on proposed security measures: This would yield a lower capex investment; however, it would not meet the intent of the level of security jointly recommended by the NERC documentation and the Company, therefore possibly leaving the Company at risk of litigation or damage to its substation assets.
- DER/NWA Alternative: The Company's Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company's evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

Studies/References:

Study Report Name (s): Multiples
Sanction Paper No: Multiples
Strategy No: N.A.

Total Project Cost Breakdown: ($ thousands)

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	206	855	0	0	0	0	0	1,061
C066246	Physical Security	OpEx	0	0	0	0	0	0	0	0
		Removal	9	45	0	0	0	0	0	54
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	15	260	0	0	0	0	0	275
C073348	Physical Security	OpEx	0	74	0	0	0	0	0	74
		Removal	0	37	0	0	0	0	0	37
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	0	0	86	962	0	0	1,048
C073349	Physical Security	OpEx	0	0	0	0	0	0	0	0
		Removal	0	0	0	0	40	0	0	40
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	30	670	0	0	0	0	0	700
C073351	Physical Security	OpEx	0	0	0	0	0	0	0	0
		Removal	0	0	0	0	0	0	0	0
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	0	62	806	0	0	0	868
C073352	Physical Security	OpEx	0	0	0	0	0	0	0	0
		Removal	0	0	0	34	0	0	0	34
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	30	493	696	0	0	0	0	1,219
C073353	Physical Security	OpEx	0	0	0	0	0	0	0	0
		Removal	0	0	0	0	0	0	0	0
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	30	477	681	0	0	0	0	1,188
C073354	Physical Security	OpEx	0	0	0	0	0	0	0	0
		Removal	0	0	0	0	0	0	0	0
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	30	942	0	0	0	0	0	972
C073355	Physical Security	OpEx	0	0	0	0	0	0	0	0
		Removal	0	0	0	0	0	0	0	0
		CIAC/Reimbursement	0	0	0	0	0	0	0	0
Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	25	722	0	0	0	0	0	747
C073356	Physical Security	OpEx	0	0	0	0	0	0	0	0
		Removal	0	0	0	0	0	0	0	0
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	0	80	906	0	0	0	986
C073648	Physical Security	OpEx	0	0	0	0	0	0	0	0
		Removal	0	0	0	0	0	0	0	0
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment _X_ Conceptual ___ Planning _____ Project ______

Schedule:

The physical security projects are part of the Capital Investment Plan (FY18-22) and will have varying schedules.

Begin Preliminary Engineering: N/A
Final Design Complete: N/A
Construction Start: N/A
In service date: N/A

Project Title: NY Transformer Replacements
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: X_ Comm: ___ Cust: ___ DER: ___ D/F: ____ Non Inf: ___
Reliability: ____ Syst. Cap: _____

Program Name: N/A

Funding numbers:

C047865 – Teall Ave
C049744 – Seneca Terminal #3
C069427 – Seneca #2 and #5
C069426 – Elm Street #2
C069429 – Kensington Terminal #4 and #5
C047864 - Inghams
C051986 – Woodlawn
C053132 – Hoosick
C053133 - Mohican
C076282 – Ash Street
C076283 – Mortimer #3
C069346 – Telegraph Road #2

Description:

Over the next five years, twelve (12) transformers will be replaced with new units. These transformers have anomalous DGA results, are in poor asset condition, or have a history of failure.

Project Justification:

National Grid's maintenance program includes performing Dissolved Gas Analysis (DGA) annually on transmission transformers. DGA is a cost effective condition assessment tool that detects abnormal characteristics within transformers which may indicate a developing fault. Analysis of this data is performed using the IEEE Standard C57.104.1991.

Customer Benefit:

The transformers scheduled for replacement are located in larger transmission stations. Prolonged outages due to an unplanned failure during summer months may jeopardize the supply to distribution stations, create voltage problems over a wider area, or require other operational measures to mitigate the impact to the system.

Alternatives:

- Do Nothing: This option would have no initial cost; however, there will be indirect costs associated with increased maintenance levels. This option is unacceptable because leaving degraded equipment in service puts the company and customers at risk of long-term interruptions of the transmission system.
- Refurbishment: This option would be to undertake a major refurbishment as opposed to replacement. Components would need to be refurbished back to original design tolerances and replacement of any worn-out or degraded parts would need to be acquired. In addition, refurbishment may only provide a few

years of additional life. Refurbishment was not considered as beneficial for the units in question due to their age.

- DER/NWA Alternative: The Company's Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company's evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

<u>Studies/References:</u>

Study Report Name (s): <u>N/A</u>
Sanction Paper No: <u>N/A</u>
Strategy No: <u>N/A</u>

<u>Total Project Cost Breakdown:</u> ($ thousands)

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	5,396	837	0	0	0	0	0	6,233
C047865	Teall Ave. Transformer Replacement	OpEx	24	0	0	0	0	0	0	24
		Removal	394	73	0	0	0	0	0	467
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	2,889	656	0	0	0	0	0	3,545
C049744	Seneca Terminal TB3 Replacement	OpEx	24	15	0	0	0	0	0	39
	Replacement	Removal	134	83	0	0	0	0	0	217
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	0	250	2,500	2,250	200	0	5,200
C069427	Seneca #2 & #5 TRF asset Replace	OpEx	0	0	0	0	0	0	0	0
		Removal	0	0	0	132	118	0	0	250
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	500	3,000	2,000	1,000	300	0	6,800
C069426	Elm St #2 TRF Asset Replacement	OpEx	0	0	0	0	0	0	0	0
		Removal	0	26	158	105	53	0	0	342
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	0	0	250	2,500	2,250	0	5,000
C069429	Kensington #4 & #5 TRF asset replac	OpEx	0	0	0	0	0	0	0	0
		Removal	0	0	0	0	132	118	0	250
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	253	50	4,410	0	0	0	0	4,713
C047864	Inghams Phase Shifting Transformer	OpEx	2	0	0	0	0	0	0	2
		Removal	0	0	0	0	0	0	0	0
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	206	18	700	2,340	1,800	0	0	5,064
C051986	Woodlawn Transformer Replacement	OpEx	0	0	16	52	40	0	0	108
		Removal	0	2	62	208	160	0	0	432
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	0	100	3,000	3,400	200	0	6,700
C053132	Hoosick - Replace Bank 1 & relays	OpEx	0	0	0	0	0	0	0	0
		Removal	0	0	0	158	179	0	0	337
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	0	100	2,300	1,597	0	0	3,997
C053133	Mohican - Replace Bank 1 and Relays	OpEx	0	0	0	24	17	0	0	41
		Removal	0	0	0	122	85	0	0	207
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	50	500	1,200	650	130	0	0	2,530
C076282	Ash St. 115-12kV TRF Asset replace	OpEx	0	0	0	2	0	0	0	2
		Removal	0	0	0	102	0	0	0	102
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	50	125	675	2,763	0	0	0	3,613
C076283	Mortimer #3 Auto Trf Replacement	OpEx	0	0	0	325	0	0	0	325
		Removal	0	0	0	163	0	0	0	163
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	50	1,500	1,000	0	0	0	2,550
C069346	Telegraph Road TRF #2 Asset Replace	OpEx	0	0	0	0	0	0	0	0
		Removal	0	0	79	53	0	0	0	132
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment _X_ Conceptual ___ Planning _____ Project _____

Schedule:

Transformer replacements are part of a revolving replacement program that continues through the term of this Plan (FY18-22) so the schedule will vary as the program progresses.

Begin Preliminary Engineering: N/A
Final Design Complete: N/A
Construction Start: N/A
In service date: N/A

C032252, C032253, C032261, C049257, C049258, C049260
Project/Program Title: Substation Circuit Breaker and Recloser Replacement Program_
T: _X_ SubT: __ D: _X_
Spending Rationale: A/C: _X_ Comm:___ Cust:___ DER:___ D/F: ____ Non Inf: ___
Reliability: ____ Syst. Cap: __ __

Program Name: Substation Breaker

Associated funding numbers: __ __

Description:

There are several circuit breaker families that are recommended for replacement due to maintenance or reliability concerns. A brief description of the circuit breaker family, the condition code and the issue is found in Table 1 along with a reference to the associated Substation Maintenance Standard (SMS), if available, covering the equipment replacement.

Table 1. Targeted Breaker Families

Mfr	Type	Avg. Age	Condition Code	Issue
Allis-Chalmers	OCB	58	3	obsolescence
Condit	OCB	70	3	obsolescence; increased maintenance
Federal Pacific	OCB	59	3	obsolescence; improper tripping
General Electric	AMCB	53	2 & 3	obsolescence; asbestos; arc-flash
General Electric	OCB	60	3	obsolescence; slow operation
General Electric	RC	43	3	obsolescence; in-service failures[1]
ITE	OCB	48	2 & 3	obsolescence
McGraw Edison	RC	26	3	obsolescence of current interchanger[2]
Westinghouse	AMCB	58	3	obsolescence

Project Funding Number C032252: This project funding number supports the replacement of circuit breakers and reclosers at distribution substations located in the New York East Division.

Project Funding Number C032253: This project funding number supports the replacement of circuit breakers and reclosers at distribution substations located in the New York Central Division.

Project Funding Number C032261: This project funding number supports the replacement of circuit breakers and reclosers at distribution substations located in the New York West Division.

[1] SMS 401.40.1
[2] SMS 401.41.1

Project Funding Number C049257: This project funding number supports the replacement of circuit breakers and reclosers at transmission substations located in the New York East Division.

Project Funding Number C049258: This project funding number supports the replacement of circuit breakers and reclosers at transmission substations located in the New York Central Division.

Project Funding Number C049260: This project funding number supports the replacement of circuit breakers and reclosers at transmission substations located in the New York West Division.

Project Justification:

Circuit breakers and reclosers play a vital role in the protection of critical assets in a substation. The inability of a circuit breaker or recloser to respond as designed can result in longer than expected interruptions and possible extensive damage to other substation equipment. Delaying the replacement of the targeted circuit breaker and recloser families will increase the likelihood of the particular issue associated with the family occurring.

The method for managing substation circuit breakers and reclosers consists of periodic maintenance and "replace on condition." This approach is being augmented by a replacement program targeting aged and unreliable circuit breaker families and units in poor condition. Aged units have been specifically identified for replacement because they are difficult to repair due to the lack of available spare parts. Likewise, unreliable units have been identified for replacement to maintain customer reliability.

Customer Benefit:

Replacing unreliable circuit breakers and reclosers will reduce the number of customer interruptions. Several of the targeted breaker families represent opportunities to reduce hazards associated with safety and the environment (*i.e.*, oil and asbestos).

Alternatives:

N/A

DER/NWA Alternative:

The Company's Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company's evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

Studies/References:

Study Report Name (s): N/A_______
Sanction Paper No: N/A_
Strategy No: DCIG0311P379_

Total Project Cost Breakdown: ($thousands)

				Current Planing Horizon						
Project Number	Project Estimate	Spend	Prior Years	FY18	FY19	FY20	FY21	FY22	FY23+	Total
C032252	NE ARP BREAKERS & RECLOSERS	CapEx	7,661	632	636	647	647	647	0	10,870
		OpEx	78	7	7	7	7	7	0	111
		Removal	267	12	12	12	12	13	0	328
		Total	8,006	650	654	666	666	667	0	11,309
C032253	NC ARP BREAKERS & RECLOSERS	CapEx	6,112	606	618	629	629	628	0	9,222
		OpEx	119	6	6	6	6	6	0	148
		Removal	181	12	12	12	12	13	0	243
		Total	6,412	624	636	647	647	647	0	9,613
C032261	NW ARP BREAKERS & RECLOSERS	CapEx	5,550	650	650	650	650	650	0	8,801
		OpEx	46	7	7	7	7	7	0	82
		Removal	131	13	13	13	13	13	0	194
		Total	5,727	670	670	670	670	670	0	9,077
C049257	Breaker T Repl Program 4-69kV NYE	CapEx	4,861	598	598	598	600	600	0	7,855
		OpEx	51	13	13	13	14	14	0	118
		Removal	253	61	61	61	61	61	0	556
		Total	5,165	672	672	672	674	674	0	8,529
C049258	Breaker T Repl Program 4-69kV NYC.	CapEx	900	597	597	597	600	600	0	3,891
		OpEx	25	13	13	13	14	14	0	92
		Removal	2	60	60	60	61	61	0	305
		Total	927	671	671	671	674	674	0	4,288
C049260	Breaker T Repl Program 4-69kV NYW	CapEx	3,290	650	598	598	600	600	0	6,336
		OpEx	145	15	13	13	14	14	0	213
		Removal	77	66	61	61	61	61	0	385
		Total	3,512	730	672	672	674	674	0	6,935
Total		CapEx	28,374	3,733	3,697	3,719	3,726	3,725	0	46,975
		OpEx	464	61	60	60	60	61	0	766
		Removal	911	223	218	218	219	221	0	2,010
		Total	29,749	4,017	3,975	3,998	4,006	4,007	0	49,750

Estimate Grade:
The Substation Circuit Breaker and Recloser Replacement Program is part of a multi-year replacement program detailed in the Capital Investment Plan (FY18-22), and the schedule may vary as the program progresses.

Begin Preliminary Engineering: N/A
Final Design Complete: N/A
Construction Start: N/A
In service date: N/A

Project Title: Damage-Failure Blanket/Reserve Programs
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: ___ Comm: ___ Cust: ___ DER: ___ D/F: _X_ Non Inf: ___
Reliability: ___ Syst. Cap: _____

Program Name: N/A

Associated funding numbers: C073870 – Trans Station Failure Reserve
C003792 – Trans Station Failure Budget Blanket
C003481 – Storm Budgetary Blanket
C003278 – Trans Line D/F Budget Blanket

Description:

The Company budgets for the replacement or repair of known damaged or failed ("D/F") station and line equipment required to restore the electric system to its original configuration and capability. FP# C073870 – Transmission Station Failure Reserve is a placeholder for future specific station projects greater than $100K and C003792 – Tran Station Failure Blanket is a blanket for smaller scope D/F work orders less than $100K.

When a station failure related issue with anticipated spend of greater than $100K in total cost (capex, opex plus removal) occurs in a given fiscal year, a specific project funding number is created and the Transmission Station Reserve forecast is reduced. For less complex station failure issues that are anticipated to be less than $100K in total cost, a work order is created under the Transmission Station Failure blanket funding number.

Likewise, for transmission lines, C003481 is for D/F projects associated with storms or severe weather while C003278 is for non-storm events. As blankets, both project funding numbers are meant for projects costing less than $100k where work orders are opened directly against the blanket funding number. However, if the Company believes a work order will exceed $100k then a separate project funding number will be created (following internal delegation of authority rules) and the respective blanket project's forecast reduced.

Project Justification:

The four reserve accounts above have amounts forecasted in the FY18 – FY22 Capital Investment Plan based on a three year average of actual spending levels in the period FY14 – FY16 as shown in the table below.

FP#	FP Name	(Actuals in $1,000) FY14	FY15	FY16	3 Yr Ave
C073870	Trans Station Failure Reserve*	$4,232	$4,522	$5,067	$4,607
C003792	Trans Station Failure Budget Blanket	$668	$1,718	$2,584	$1,656
C003481	Storm Budgetary Blanket - NMPC	$2,444	$228	$12	$895
C003278	TransLine D/F Budget Blanket	$591	$265	$787	$548

* History includes station failure projects greater than $100k that were budgeted under C003792, but will use C073870 going forward.

Customer Benefit:

Reserve programs with funding available to address short term D/F projects allows the Company to quickly return failed assets to service and minimize customer interruption durations.

Alternatives:

- Eliminate reserve and blanket programs for D/F projects: Without short-term reserve accounts available to address D/F events, the Company would have to go through its internal delegation of authority process each time a project is required to address a storm or D/F event. This would delay the approval of funds needed to restore service quickly to customers.
- DER/NWA alternative: The Company's Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company's evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

Studies/References:

Study Report Name (s): N/A
Sanction Paper No: N/A
Strategy No: N/A

Total Project Cost Breakdown: ($ thousands)

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	120	3,000	4,600	4,600	4,600	4,600	-	21,519
C073870	Trans Station Failure Reserve	OpEx	150	32	49	49	49	49	-	380
		Removal	479	194	297	297	297	297	-	1,860
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	16,480	1,700	1,700	1,700	1,700	1,700	-	24,981
C003792	Trans Station Failure Budget	OpEx	1,437	99	99	99	99	99	-	1,931
	Blanket	Removal	1,186	178	178	178	178	178	-	2,076
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	6,528	500	500	500	500	500	-	9,028
C003481	Storm Budgetary Blanket	OpEx	444	50	50	50	50	50	-	694
		Removal	680	100	100	100	100	100	-	1,180
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	5,164	550	450	450	450	450	-	7,513
C003278	Trans Line D/F Budget Blanket	OpEx	1,747	184	150	150	150	150	-	2,532
		Removal	613	61	50	50	50	50	-	875
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment _X_ Conceptual ___ Planning _____ Project ______

Schedule:

The projects created from these station and line reserve programs will each have their own individual schedules over the term of the capital plan.

Begin Preliminary Engineering: N/A
Final Design Complete: N/A
Construction Start: N/A
In service date: N/A

C003389
Project Title: Gardenville-Dunkirk 141-142 T1260-1270 Northern Phase Rebuild
T: X SubT: ___ D: ____
Spending Rationale: A/C: X D/F: ____ Non Inf: ___ S/R: ____ Syst. Cap: _____

Program Name: Overhead Line Refurbishment Program – Asset Condition

Associated funding numbers: N/A

Description:

This project involves rebuilding the Gardenville-Dunkirk 141 (T1260) and Gardenville-Dunkirk 142 (T1270) 115 kV transmission circuits between the Gardenville and North Angola Stations. The overhead line details follow:

Total Length: Approximately 20 miles
Conductor Types: Varies – 250 kcm CU, 400 kcm CU, 4/0 CU, 336 kcm ACSR, 636 kcm AAC, and 795 kcm ACSR.
Number of Steel Structures: 250 structures (of which are Ritter-Conley Flexible Towers with Z cross members)
Types of Structures: Double circuit, primarily steel (Z type flex), structures
Typical Installation Date: 1930s vintage

This project, also referred to as the northern phase, addresses asset condition and safety issues of these lines per the Overhead Line Refurbishment Strategy Paper SG080, as well as relieves thermal overload during periods of high power imports from Ontario and low loads in western NY.

The specific scope for this northern section rebuild, to be completed by FY22, will include:

- Rebuild both 141 and 142 lines in their entirety from the Gardenville station to the North Angola station with single-pole, double-circuit, davit arm steel structures.
- Reconductor with 795 ACSR Drake.
- Add OPGW in place of shield wire.
- Replace transmission line switches at the Angola and Lakeview switch structures.
- Upgrade access roads (primarily in upland areas).
- Where necessary widen ROW width to our 100’ standard for 115kV with targeted land purchases, easements or vegetation clearing rights.

This project is specifically limited to the northern phase. Refurbishment of the southern phase, from North Angola to Dunkirk (25 miles), will be addressed in a separate, associated project.

Project Justification:

The primary driver for this project is asset condition per the Overhead Line Refurbishment Strategy SG080. A full Article VII line rebuild project is proposed to address deteriorated assets, ensure the lines meet technical requirements of the National Electric Safety Code (NESC), and eliminate thermal overloads on the northern end of the lines during periods of high imports from Ontario and low load in western NY.

Customer Benefit:

Rebuilding this line is necessary to provide reliable service to approximately 20,000 customers served from eight distribution stations and a NYSEG owned station.

This overhead line refurbishment program promotes safety and reliability by addressing asset condition issues and allowing the transmission lines to meet the governing NESC by replacing deteriorating structures and line components that no longer structurally or electrically conform to the NESC.

Alternatives:

The following alternatives were also considered:

- Alternative 1: Targeted refurbishment to extend operational life of these circuits by 15-20 years including the replacement of only significantly deteriorated structures, replacement of insulators and fittings, tower painting and footer repairs, adding optical ground wire in place of shield wire, and adding access roads in upland areas. This alternative is not recommended due to the severely deteriorated condition of the steel structures. Also, without replacing the 4/0 Cu conductor with larger 795 ACSR Drake, loading concerns on the northern phase will not be addressed.
- System Reconfiguration: This alternative is not feasible as this transmission line is required to serve customers.
- REV Solutions: With thermal overloads occurring on the northern end of the 141 & 142 lines during periods of high power imports from Ontario and low load levels in western NY, reducing load in the area would only exacerbate this problem. Furthermore, a non-wires alternative would not address the safety concerns with the deteriorated steel structures that need to be replaced.

Studies/References:

Study Report Name (s): N/A
Sanction Paper No: USSC-13-118 v2
Strategy No: SG080 (Overhead Line Refurbishment Program)

Total Project Cost Breakdown: ($ thousands)

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	3,285	2,225	8,685	22,790	28,440	23,642	3,000	92,067
C003389	Gardenville - Dunkirk 141 142	OpEx	146	275	315	663	988	1,087	500	3,973
	N Phase Rebuild	Removal	13	0	0	3,048	10,073	2,446	0	15,579
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment ___ Conceptual _X_ Planning _____ Project ______

Schedule:

Begin Preliminary Engineering: October 2016
Final Design Complete: August 2018
Construction Start: August 2019
In service date: January 2022

C003422
Project Title: Lockport-Batavia 112, T1510 ACR
T: X SubT: ___ D: ____
Spending Rationale: A/C: X D/F: ____ Non Inf: ___ S/R: ____ Syst. Cap: _____

Program Name: Overhead Line Refurbishment Program – Asset Condition

Associated funding numbers: C027431 Lockport-Batavia 108 T1500 ACR

Description:

This project involves the Lockport-Batavia #112 (T1510) 115 kV transmission circuit. The overhead line details follow:

> **Total Length**: Approximately 34 miles
> **Conductor Types**: Varies - 250 kcm Copper 19-Strand, 795 kcm ACSR "Coot" 36/1, 336.4 kcm ACSR "Linnet" 26/7, 428 kcm AAC 19-Strand, and 636 kcm AAC "Orchid"
> **Total Number of Structures**: 369
> **Number of Wood Structure Units**: 156
> **Number of Steel Structure Units**: 213
> **Types of Structures**: Steel towers (178 of which are tri-leg towers) and wood pole structures (111 of which are single pole with davit arms).
> **Typical Installation Date:** 1930-1940s

The Lockport-Batavia #112 shares a double circuit with the Lockport-Batavia #108 for 3.5 miles near the Batavia station. Also, for 12.6 miles beginning at the Lockport station, both lines run parallel with and share the Lockport-Mortimer #111 right-of-way.

The budgeted scope of this life extension project includes replacement of all 178 steel tri-leg towers and 5% of the total number of wood structures that are in deteriorated condition; replacement of insulators and fittings; reconductoring 17.5 miles of 428 AAC conductor and replacement of associated shield wire; relocation of 4.6 miles of the line out of the Tonawanda Wildlife Management area; and building permanent access roads in upland areas.

The project is in Step 0 (conceptual engineering) undergoing scope development based upon engineering field assessment, input from Transmission Planning, and conductor testing.

Project Justification:

Based upon an engineering field evaluation, some tower and wood pole structure replacements are necessary along with some tower repairs due to deterioration.

Conductor and shield wire testing in 2015 determined that all ACSR conductor and shield wire can remain in service. However, 17.5 miles of the 428 AAC conductor is being recommended for replacement because the calculated breaking strength was as low as 14% below the rated breaking strength. Furthermore, being a non-standard conductor, it is difficult to obtain spare parts (conductor and splices) in the event of a failure.

4.6 miles of the line is located within the Tonawanda Wildlife Management area, which is predominantly a wetland area, making it very difficult for the Company to access for either maintenance or restoration efforts.

Customer Benefit:

Refurbishment of this line is necessary to provide reliable service to approximately 2,100 customers served by Oakfield Substation.

This overhead line refurbishment program promotes safety and reliability by addressing asset condition issues and allowing the transmission lines to meet the governing National Electrical Safety Code (NESC) under which they were built by replacing deteriorating structures and line components that no longer structurally or electrically conform to the NESC.

Alternatives:

The following alternatives are under consideration as part of the re-scoping process:

- Targeted Refurbishment: This alternative replaces deteriorated structures, replaces all steel tri-leg towers, replaces insulators and fittings, and improves grounding.
- Line Refurbishment: Includes same scope as targeted refurbishment above, plus reconductoring select section of the line with 795 ACSR.
- Line Refurbishment and Tonawanda Relocation: Includes same scope as targeted refurbishment above, plus relocating the 4.6 mile section of the line in the Tonawanda Wildlife Management area.
- Line Refurbishment, Tonawanda Relocation and Double Circuiting #112 and #108: Includes same scope as line refurbishment and Tonawanda Relocation above, plus double-circuiting the Lockport-Batavia #112 and #108 lines in the 12.6 mile shared corridor beginning outside the Lockport station.
- System Reconfiguration/Retire the Line: This alternative is not feasible as this transmission line is required to serve customers.
- REV Solutions: Cannot be implemented as these assets are still necessary to support the transmission system.

Studies/References:

Study Report Name (s): N/A
Sanction Paper No: N/A
Strategy No: SG080 (Overhead Line Refurbishment Program)

Total Project Cost Breakdown: ($ thousands)

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	206	100	300	2,500	12,000	35,000	48,000	98,106
C003422	Lockport - Batavia 112 ACR	OpEx	67	0	0	0	1,200	3,500	4,800	9,567
		Removal	0	0	0	0	2,400	7,000	14,000	23,400
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment _X_ Conceptual ______ Planning _____ Project ______

Schedule:

Begin Preliminary Engineering: March 2019
Final Design Complete: March 2021
Construction Start: August 2021
In service date: March 2023

C005155
Project Title: Dunkirk Rebuild
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: _X_ Comm: ___ Cust: ___ DER: ___ D/F: ____ Non Inf: ___
Reliability: ____ Syst. Cap: _____

Program Name: N/A

Associated funding numbers: C073999 Dunkirk Substation Rebuild Control House
C076185 Dunkirk Replace 34.5kV Relays (Sub-T Line)

Description:

The project scope includes the asset separation/replacement at Dunkirk Substation. The asset separation will include a new control house and equipment on the existing land within the Dunkirk substation to allow for National Grid owned equipment within the NRG owned Dunkirk power plant to be removed. The NRG Dunkirk power plant was mothballed on January 1st, 2016.

The replacement of 230kV, 115kV, and 34.5kV equipment creates a reliable and efficient cutover effort and replaces equipment in poor condition.

Project Justification:

The National Grid owned Dunkirk substation interconnects with the NRG owned Dunkirk Power Plant. The substation serves as an interconnection to the electrical grid at the 230, 115 and 34.5kV levels. The plant was originally constructed in the early 1950s by Niagara Mohawk as the owner of generation, transmission and sub-transmission assets. National Grid's major equipment includes four transformers: two (2) new 230/120/13.2kV 125MVA autotransformers and two (2) 115/34.5kV 41.7MVA transformers supplying four (4) 230kV transmission lines, five (5) 115kV transmission lines and two (2) 34.5kV sub-transmission lines as well as NRG's station service.

National Grid retains ownership of most of the 230kV, 115kV, and 34.5kV switch yard; however, the controls are located in the generation control room owned by NRG.

There are asset condition issues at the Dunkirk substation. The foundations are in poor condition in the 230kV and 34.5kV yards affecting the integrity of the structures. Some circuit breaker foundations are in very poor condition raising the possibility that an oil circuit breaker (OCB) could move during a severe fault leading to more damage and/or causing safety issues.

The five (5) 230kV OCBs are Westinghouse type GW design (1958 through 1961) and would be part of the OCB replacement program, if not for this project. The 230kV Westinghouse Type O bushings are a concern as the power factor and capacitance results are trending upwards.

The 230/120/13.2kV autotransformers differential relaying is in need of upgrading to address inadequate protection (presently there is no tertiary differential). The 230kV, 115kV and 34.5kV disconnects have become problematic from an operational standpoint. The 230kV bushing potential devices (BPDs) have become problematic due to poor condition and the remaining BPDs will likely have to be replaced in the near future. Fencing around the yard is not compliant with National Grid standards and requires repair at the base or a berm built up to restrict animal entrance.

The conduit system carrying control wires has degraded to the point that the integrity of the control wires has been compromised. Control wires inside the plant have also seen insulation degradation. In some cases, the wiring is so poor that troubleshooting abilities are limited for fear of handling control wires with degraded insulation. Grounds, alarms or breaker mis-operations happen more frequently during periods of heavy rain, indicating poor insulation below ground.

National Grid has recently replaced both 230-120-13.2kV 125MVA GE autotransformers with new ABB 230-120-13.2kV 125MVA autotransformers and all 115kV OCBs with new SF6 breakers, foundations and control cable.

The plant was originally constructed with generation, transmission and sub-transmission assets combined, including station service, battery, relaying, alarm/annunciation, control and communications. All troubleshooting, maintenance testing, equipment replacement and upgrades require excellent knowledge of the plant operation. NRG and National Grid must maintain good lines of communication and share updated prints to preserve operation continuance. The separation of assets would help avoid inadvertent trips to the generators and/or line breakers or any possible equipment failures.

There are parallel efforts underway to address these issues. In the short term, a project was approved to install a new cable trench in the 230kV yard in 2009 and was completed in the summer of 2010. Control cables deemed faulty can be replaced using these new facilities. Conceptual engineering has been completed for a new control house and completely separate assets rebuilt within the existing yard. Other equipment, such as disconnects and potential transformers, deemed to be in poor condition and/or problematic will be part of this project as well as installation of a second bus tie breaker.

Customer Benefit:

The planned replacement of this substation reduces the likelihood of an in-service failure which can lead to long-term interruptions of the transmission system as well as customer outages. It also serves to separate the assets between National Grid and NRG.

Alternatives:

The following alternatives were under consideration as part of the conceptual engineering Step 0 process:

- Do Nothing: This was rejected since the existing substation is a shared facility with NRG and would not allow for asset separation. Also, leaving the equipment this way would create additional maintenance issues and allow for the possibility of a larger spread resulting from a fault.
- DER/NWA Alternative: The Company's Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company's evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

Studies/References:

Study Report Name (s): Substation Conceptual Engineering for Dunkirk Asset Separation/Replacement.
Sanction Paper No: N/A
Strategy No: N/A

Total Project Cost Breakdown: ($ thousands)

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	38	563	3,595	12,392	12,400	750	0	29,738
C005155	Dunkirk Station Rebuild	OpEx	0	0	189	652	653	39	0	1,534
		Removal	0	0	0	0	0	0	0	0
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	100	400	2,000	0	0	0	2,500
C073999	Dunkirk Station Rebuild Control	OpEx	0	0	0	0	0	0	0	0
	House	Removal	0	0	0	0	0	0	0	0
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	0	0	0.100	0.200	0.425	0	0.725
C076185	Dunkirk - Asset Sep/Repl Sub T	OpEx	0	0	0	0	0	0.010	0	0.010
		Removal	0	0	0	0	0	0.040	0	0.040
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment ____ Conceptual _X_ Planning _____ Project ______

Schedule:

Begin Preliminary Engineering: July 2017
Final Design Complete: November 2018
Construction Start: January 2019
In Service Date: December 2021

C005156
Project Title: Gardenville Rebuild
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: _X_ Comm: ___ Cust: ___ DER: ___ D/F: ____ Non Inf: ___
Reliability: ____ Syst. Cap: _____

Program Name: N/A

Associated funding numbers: C030084 - Gardenville Rebuild Line Relocation

Description:

Project C005156 includes the construction of a new 115kV breaker and a half substation at the Gardenville substation site, including connections to the 230-115kV transformers. Project C030084 will re-route the existing incoming transmission lines to the new substation location.

Project Justification:

Gardenville has a history of poor performance primarily due to poor condition of assets. Examples include over-dutied 115kV breakers, control wiring that has been temporarily routed in above-grade cable trench due to reliability issues causing mis-operations, type BZO and GM 115kV breakers that have been identified as poor performers, 115kV disconnect switches that no longer operate properly, the supporting steel structures being in poor condition, and the control building housing all the protective relaying is over 80 years old. In addition, reconfiguring the bus to a breaker-and-a-half scheme allows all of the incoming transmission lines to be terminated to the station without any crossings, which are prevalent at the existing location, thereby minimizing the chance of multiple interruptions for a single event.

Given the number of issues that are present at the station a plan has been established to construct a new breaker-and-a-half station adjacent to the Old Gardenville substation. This plan will allow the existing station to remain in service while the new substation is being constructed.

Customer Benefit:

A rebuild is necessary to ensure continued reliable service to customers. Gardenville substation is an important station in the Western Division supplying approximately 750MVA of load to distribution stations via seventeen (17) 115kV circuits - eight (8) of which are radial, including two (2) terminal substations that serve downtown Buffalo.

Alternatives:

The following alternatives were considered as part of the conceptual engineering Step 0 process:

- Rebuild the Substation as a Straight Bus: While technically feasible and a lower cost option, the Company is pursuing the breaker-and-a-half option as it is the appropriate solution given the size and importance of the substation to the Western Division as described in the customer benefit section. In addition, while there are no current planning contingencies necessitating the need for breaker-and-a-half, this opportunity is the "last chance" to build the station in this configuration and will allow future expansion to meet the expanding needs of the area.
- Do Nothing: This option would involve no proactive replacement of assets and only replace them when failure occurs. This option would have no cost initially; however, it is not viable as it does not address the asset issues at the station, increasing the risk of equipment failures which could lead to extended customer outages.
- Replace Poorly Performing and Overdutied Assets, Add Three Capacitor Banks as well as Refurbish Structures/Foundations in Place: This option would repair existing problematic assets in place. Given outage unavailability, this work would not likely be possible without significant load outages. When completed, Gardenville substation would still be an eighty (80) year old station with a very poor configuration. Within twenty (20) years, the station would likely be in a state requiring complete rebuild.
- DER/NWA Alternative: The Company's Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company's evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

Studies/References:

Study Report Name (s):	Gardenville – New 115kV Station Technical Requirements Document
Sanction Paper No:	USSC-14-173
Strategy No:	SG 112

Total Project Cost Breakdown: ($ thousands)

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	38,660	24,894	5,706	493	663	0	0	70,416
C005156	Gardenville Rebuild	OpEx	203	2,310	1,851	5	7	0	0	4,375
		Removal	927	5,182	154	10	14	0	0	6,287
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	7,612	6,314	7,210	4,589	0	0	0	25,725
C030084	Gardenville Rebuild - Line	OpEx	203	294	0	0	0	0	0	496
	Relocation	Removal	524	734	0	0	0	0	0	1,258
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment ____ Conceptual ___ Planning _X_ Project ______

Schedule:

Begin Preliminary Engineering: August 2015
Final Design Complete: May 2017
Construction Start: November 2016
In service date: November 2018

(Final design completion is when all vendor drawings for wiring inside the control house are integrated into the final design package. Construction on the station itself will begin before the vendor drawings are integrated; hence the construction start date shown to be before the final design is complete.)

C011640
Project Title: Wood Pole Management Program
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: _X_ D/F: __ Non Inf: ___ S/R: ____ Syst. Cap: ____

Program Name: Wood Pole Management

Associated funding numbers: N/A

Description:

The wood pole management program includes the replacement of deteriorated wood poles identified by Osmose Utilities ("Osmose") during ground line inspections as being a 'Reject', 'Priority Reject', or 'Restorable Reject' (a Restorable Reject is a wood pole that is eligible for external reinforcement to restore its ground-line strength). The annual ground line inspections cover approximately 10% of the Company's transmission wood poles andwhere the remaining residual pole strength is calculated taking into account the presence of internal and external decay and provides additional treatment and insecticide if required.

This wood pole management program is in addition to the Company's Inspection and Maintenance program's ("I&M", C026923) five-year foot patrol which is required under the Commission's 2005 Safety Order in Case 04-M-0159.

Project Justification:

This program replaces deteriorated wood poles and structures, as needed, that no longer meet National Electrical Safety Code (NESC) requirements.

A wood pole identified as a "Reject" fails to meet code requirements for extreme design conditions when the pole has two-thirds, or less, of its original design strength. Priority Reject poles are those that fall below one-third of its original design strength and potentially can fail under conditions considered to be "normal" circumstances.

Customer Benefit:

The wood pole management program promotes safety and reliability by replacing Reject and Priority Reject wood structures that no longer structurally or electrically conform to the NESC before they fail in service.

Storm resiliency during severe weather events is the greatest concern for Reject poles and structures. Failures can hamper service restoration efforts, increase outage durations and raise public safety concerns.

Alternatives:

The following alternatives were considered:

- Only replace visual rotting wood structures in the I&M program, when a line is refurbished, or as pole failures occur: While the I&M program will identify deteriorated poles based on 'pole sounding' techniques, this program provides a more qualitative means of identifying deteriorated poles that may not be captured during sounding.
- REV solutions: Cannot be implemented as these assets are still necessary to support the transmission system.

Studies/References:

Study Report Name (s): N/A
Sanction Paper No: N/A
Strategy No: SG009 v2 Wood Pole Management Program

Total Project Cost Breakdown: ($ thousands)

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	22,234	1,500	2,500	2,500	2,500	2,500	-	33,734
C011640	Wood Pole Management	OpEx	2,213	150	250	250	250	250	-	3,363
		Removal	3,695	300	500	500	500	500	-	5,995
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment _X_ Conceptual ______ Planning ____ Project ______

The estimate grade depends upon each individual project work order and the level of engineering completed.

Schedule:

Wood pole replacements are part of a continuous wood pole replacement program that continues through the term of the Capital Investment Plan (FY18-22), therefore, the individual project schedules will vary as the program progresses.

Begin Preliminary Engineering: N/A
Final Design Complete: N/A
Construction Start: N/A
In service date: N/A

C026923
Project Title: NY Inspection Projects - Capital
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: _X_ D/F: __ Non Inf: ___ S/R: ____ Syst. Cap: _____

Program Name: NY Inspection Repairs

Associated funding numbers:

- TLine Annual Foot Patrol: E015471, E014152, E014153, E014154
- TLine Stray voltage: E014470, E014472, E014474, E014476
- TLine I&M Program: E014130

Description:

The goal of this program is to replace deteriorated, damaged or failed components on the transmission overhead line system identified during five-year foot patrol inspections. This follows standard industry practice and the Commission's 2005 Safety Order in Case 04-M-0159.

Project Justification:

The primary driver of this project is to meet the Company's regulatory obligations under the 2005 Safety Order. In addition, performing identified maintenance and capital repair work will benefit customers by enhancing the safety and reliability of transmission line assets and maintain the structural integrity of lines.

The project scope is limited to replacing assets identified from the inspection of transmission line assets specifically obtained by a) foot patrol visual inspections, b) helicopter patrol visual inspections, c) helicopter patrol infrared inspections, and d) stray voltage inspections.

Customer Benefit:

This program enhances public safety by addressing damaged or failed transmission overhead line components and in order to meet the governing National Electrical Safety Code under which they were built. Replacement of damaged and failed components identified during inspection also promotes reliable service performance.

Alternatives:

- Do nothing and replace assets when lines are refurbished or structure failures occur: Failure to carry out the Company's Inspection & Maintenance repair program would leave assets in place with potential to impact the level of reliability of the transmission system. Also, not having an Inspection &

Maintenance program would result in the Company not complying with the 2005 Safety Order.

- REV solutions: Cannot be implemented as these assets are still necessary to support the transmission system.

Studies/References:

Study Report Name (s): N/A
Sanction Paper No: N/A
Strategy No: N/A

Total Project Cost Breakdown: ($ thousands)

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	52,359	12,002	15,000	12,000	12,000	12,000	-	115,360
C026923	NY Inspection Repairs	OpEx	6,073	800	1,000	800	800	800	-	10,273
		Removal	14,972	3,200	4,000	3,200	3,200	3,200	-	31,772
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment ____ Conceptual _X_ Planning _____ Project ______

The estimate grade depends upon each individual project work order and the level of engineering completed.

Schedule:

This is an ongoing program that will run through the term of the Capital Investment Plan (FY18-22) so the individual project schedules will vary as the program progresses.

Begin Preliminary Engineering: N/A
Final Design Complete: N/A
Construction Start: N/A
In service date: N/A

C027425 Project Title: Gardenville – Homer Hill 151 152 ACR
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: _X_ D/F: ____ Non Inf: ___ S/R: ____ Syst. Cap: _____

Program Name: Overhead Line Refurbishment Program – Asset Condition

Associated funding numbers: C069689 Gardenville-Homer Hill 151/152 Vang/J-Hook Replacement

Description:

This project will address asset condition related issues on the 115kV Gardenville-Arcade #151 (T6440), Gardenville-Five Mile Rd #152 (T6830), and Arcade-Five Mile Rd #167 (T6850) from Structure #200 to the Five Mile Rd Station. The overhead line details follow:

Total Length: 37.65 miles (Str. 200 to Five Mile Sta)
Conductor Types: 336.4 kcm ACSR 30/7 "Oriole", 795 kcm ACSR 36/1 & 26/7 conductors, OHGW 2-3/8" HS 7-strand steel
Total Number of Structures: 346
Total Steel: 287
Total Wood: 59
Types of structures: Double circuit flex towers for tangents and double circuit square base towers for dead-ends
Installation Date: 1922 (oldest record in Power Plant)
Conductor Clearance: In process

The portion of these circuits from Gardenville to Structure #200 and from Five Mile Rd Station to Homer Hill were previously rebuilt. The budgeted scope of this asset condition refurbishment includes replacing all insulators and hardware, installing permanent access roads to upload areas, reconductoring and shield wire replacement the total length of the line, replacement/rehabilitation of 50% of steel structures and replacement of 50% of wood structures which are in deteriorated condition.

Project Justification:

On November 2, 2015 conductor dropped from the arm at Structure #447 on the 152 circuit due to a worn attachment plate (vang) between the steel arm and the top of the insulator.

As part of the associated Vang/J-hook project (C069689), an aerial comprehensive inspection has been scheduled for Spring 2017. Results from this aerial inspection will be used in connection with additional inspections to formulate a scope of refurbishment for the line as part of the conceptual engineering process.

Items deemed urgent based on the aerial inspection will be addressed under C069689 as soon as late FY17/early FY18. The Company anticipates additional vangs and other hardware items will require replacement. It is expected that the steel towers on this circuit will require extensive rehabilitation if they are to be re-used.

Transmission Line Engineering visually inspected the entire mainline of the Gardenville-Arcade 151, Gardenville-Homer Hill 152, and the Arcade-Homer Hill 167 115 kV transmission lines by foot in 2009 noting 427 conductor splices on the line (224 on #151 and 203 on #152).

If non-destructive (MIR-Innovations LineCore) and confirmatory destructive (coupon) conductor and shield wire testing indicate adequate remaining strength to remain in service, splice replacements will likely be needed (except the previously rebuilt section between Gardenville and structure #200 where all new 795 conductor was installed). In addition, many of the insulators appear to be original and are showing signs of degradation which may contribute to poor lightning performance. According to the Incident Data System (IDS) the 151/152/167 circuits had 19 events between 6/25/2012 and 6/27/2015.

Customer Benefit:

Refurbishment of this line is necessary to provide reliable service to customers served by National Grid and foreign-owned stations.

This overhead line refurbishment program promotes safety and reliability by addressing asset condition issues and allowing the transmission lines to meet the governing National Electrical Safety Code (NESC) under which they were built by replacing deteriorating structures and line components that no longer structurally or electrically conform to the NESC.

Alternatives:

The following alternatives will be considered as part of the conceptual engineering (Step 0) process:

- Targeted Refurbishment: This alternative replaces deteriorated structures, insulators and hardware, adds improved grounding, and targeted replacement of conductor and shield wire on the mainline and taps.
- Line Rebuild: If the conductor fails testing and it is deemed the steel structures are too deteriorated to remain in service, the line will need to be rebuilt except for the section between Gardenville and structure #200.
- System Reconfiguration: This alternative is not feasible as this transmission line is required to serve customers.
- REV Solutions: Cannot be implemented as these assets are still necessary to support the transmission system.

Studies/References:

Study Report Name (s): N/A
Sanction Paper No: N/A
Strategy No: SG080 (Overhead Line Refurbishment Program)

Total Project Cost Breakdown: ($ thousands)

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	52	100	200	200	1,000	3,000	21,500	26,052
C027425	Gardenville - Homer Hill 151 152	OpEx	0	0	0	0	0	300	2,300	2,600
	ACR	Removal	0	0	0	0	0	600	4,600	5,200
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment _X_ Conceptual ___ Planning _____ Project ______

Schedule:

Begin Preliminary Engineering: August 2018
Final Design Complete: November 2020
Construction Start: April 2021
In service date: May 2025

C030889
Project Title: Pannell-Geneva 4 4A T1860 ACR
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: _X_ D/F: ____ Non Inf: ___ S/R: ____ Syst. Cap: _____

Program Name: Overhead Line Refurbishment Program – Asset Condition

Associated funding numbers: C069541 Pannell-Geneva 4 4A Thruway Crossing

Description:

This project involves the Pannell-Geneva 4-4A (T1860) 115 kV "bussed" transmission circuits.

Total Length: Approximately 25 miles
Conductor Types: 795 kcm ACSR "Coot" and 336.4 kcm ACSR "Oriole"
Number of Wood Structure Units: 8
Number of Steel Structure Units: 265
Types of Structures: steel lattice towers, Blaw Knox dead-end towers, wood pole structures, flex towers, and steel pole.
Estimate Installation Date: 1900 to 1920s

The budgeted scope of this project is for the anticipated replacement of conductor the entire length of the line due to recent LineCore conductor testing results of the neighboring Mortimer-Pannell 24 115kV line, which is the same vintage and conductor type as this Pannell-Geneva 4 4A lines, showing Zinc loss due to corrosion. With few exceptions, there is currently no shield wire for either circuit, so it is assumed shield wire will be added the entire length of the line, as well. Adding permanent access roads to upland areas is also included in the scope.

Project Justification:

This line is necessary to provide reliable 115kV network service with RG&E and NYSE&G. National Grid owns this line connecting RG&E's Pannell station and NYSE&G's Border City (Geneva) station.

There are known asset condition issues on the line including conductor failures as recently as July 2015 with associated safety concerns.

Customer Benefit:

Refurbishment of this line is necessary to support the 115kV transmission network.

This project, part of the Overhead Line Refurbishment program, promotes safety and reliability by addressing asset condition issues and allowing the transmission lines to meet the governing National Electrical Safety Code (NESC) under which they were built by replacing deteriorating structures and line components that no longer structurally or electrically conform to the NESC.

Alternatives:

Alternatives under consideration as part of the scoping process:

- Reconductoring this Circuit using 795 ACSR: This option would convert the line into a single circuit instead of a bused circuit, however it may require 100% structure replacement if it is determined the existing structures cannot support the weight of the 795 ACSR.
- Reconductoring this Circuit using an Alternate Conductor Type: This will consider lighter conductors to try and salvage the existing towers.
- Rebuilding the Circuit with Wood Poles: If the structures are not able to be reused and must be replaced, single-circuit wood pole structures will be considered.
- System reconfiguration: This alternative is not feasible as this transmission line is required to connect RG&E and NYSE&G stations.
- REV solutions: Cannot be implemented as these assets are still necessary to support the transmission system.

Studies/References:

Study Report Name (s): N/A
Sanction Paper No: N/A
Strategy No: SG080 (Overhead Line Refurbishment Program)

Total Project Cost Breakdown: ($ millions)

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	175	200	1,000	4,000	18,000	18,000	2,000	43,375
C030889	Pannell-Geneva 4 4A ACR	OpEx	0	0	0	500	4,000	4,000	0	8,500
		Removal	0	0	0	800	3,600	3,600	0	8,000
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment __X__ Conceptual ____ Planning _____ Project ______

Schedule:

Begin Preliminary Engineering: November 2018
Final Design Complete: November 2020
Construction Start: January 2020
In service date: March 2022

C031662
Project Title: Lighthouse Hill 115kV Yard Replacement & Control House
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: _X_ Comm: ___ Cust: ___ DER: ___ D/F: ____ Non Inf: ___
Reliability: ____ Syst. Cap: _____

Program Name: Substation Relocation/Rebuild

Associated funding numbers: C073996 – Lighthouse Hill 115kV Control House
C073997 – Lighthouse Hill Transmission Lines Reconnect

Description:

A new Lighthouse Hill substation is proposed at a greenfield location to allow for the complete segregation of National Grid assets from the Brookfield owned power house while also eliminating the flood risk potential and replacing deteriorated Oil Circuit Breakers (OCB) and transformer assets. The new substation will be comprised of a 115kV transmission switching substation, 115-34.5kV substation, and 115-12kV distribution substation. This will also require transmission line relocations from the current substation to the new site approximately a half mile away.

Project Justification:

This facility is a significant switching substation with two (2) 115kV buses and five (5) transmission lines connecting to the substation allowing power to flow from the Oswego generating complex to the Watertown and Syracuse areas.

Significant issues at Lighthouse Hill include the deteriorated asset condition of oil circuit breakers (OCBs), and disconnects, station operated as a shared facility under a contractual agreement with Brookfield Power, and the risk of flooding at the site due to a failure of the dam.

The 115kV OCBs were identified for replacement in the Circuit Breaker Replacement Program. In addition, the disconnect switches are in very poor condition. Furthermore, seven (7) OCBs are located 200 feet from the Salmon River. In addition, the substation is located one mile upstream of the New York State Wildlife Fish Hatchery. A significant oil spill in the station would have an environmental impact. Flooding in the area occurred as recently as October 1, 2010 due to a major rain event.

The lack of direct access to the Brookfield owned power house at the Lighthouse Hill facility limits the Company's control over conditions of the battery and relay systems. The Company has controls on the first floor of the power house which is immediately adjacent and downstream of Brookfield's hydroelectric dam. An uncontrolled release from the dam could flood the control room area.

Customer Benefit:

The planned replacement of this substation reduces the likelihood of an in-service failure of deteriorated assets which can lead to long-term interruptions of the transmission system as well as customer outages. It also reduces the risk of contamination of the Salmon River due to the failure of an oil circuit breaker.

Alternatives:

The following alternatives are under consideration as part of the conceptual engineering Step 0 process:

- Asset Replacement/Separation on existing site: This is not recommended since it does not solve the issue of the shared 115kV yard with Brookfield. It also does not mitigate the flood risk identified for this site and would leave any new assets at the site vulnerable to a flood event.
- Asset Replacement: This is not recommend since it does not solve the shared asset issue with Brookfield or eliminate the flood risk potential.
- DER/NWA: The Company's Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company's evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

Studies/References:

Study Report Name (s): Substation Conceptual Engineering for LHH; and
TLS Conceptual Engineering for LHH
Sanction Paper No: N/A
Strategy No: N/A

Total Project Cost Breakdown: ($ thousands)

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	165	5	25	300	1,800	11,579	11,297	25,170
C031662	Lighthouse Hill Replace Yard &	OpEx	0	0	0	0	0	0	0	0
	Control House	Removal	0	0	0	0	0	872	278	1,150
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	0	0	100	2,400	0	0	2,500
C073996	Lighthouse Hill 115kV Control	OpEx	0	0	0	0	0	0	0	0
	House	Removal	0	0	0	0	0	0	0	0
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	0	0	50	500	6,557	2,083	9,190
C073997	Lighthouse Hill Transmission	OpEx	0	0	0	0	0	650	0	650
	Lines Reconnect	Removal	0	0	0	0	0	1,300	0	1,300
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment ____ Conceptual _X_ Planning _____ Project ______

Schedule:

Begin Preliminary Engineering:	June 2018
Final Design Complete:	November 2019
Construction Start:	January 2020
In Service Date:	March 2023

C032309
Project Title: Ticonderoga-Sanford Lake 4 Removal and Partial Refurbishment 115 kV
T: _X_ SubT: __ D: ____
Spending Rationale: A/C: _X_ D/F: ____ Non Inf: ___ S/R: ____ Syst. Cap: ____

Program Name: N/A

Associated funding numbers: N/A

Description:

The scope of this project includes the refurbishment of the Ticonderoga – Hague Road #4 115kV transmission line and the removal of the retired Ticonderoga – Sanford Lake #4 transmission line.

The refurbishment work includes the replacement of nine wood pole structures, the installation of one new termination structure, and the installation of a single guy/anchor on one structure. The removal work includes the removal of 256 wood pole structures, approximately 21.9 circuit miles of conductor, and 22 miles of shield wire.

Project Justification:

The primary drivers for this project are asset condition. The refurbishment portion will address deteriorated assets. The removal portion will address poor asset condition concerns on the Ticonderoga-Sanford Lake #4.

Customer Benefit:

This energized part of the line is needed to reliably serve customers and the refurbishment will improve its reliability. Removing the de-energized portion will eliminate a line, which is in poor condition, as well as the need to perform ongoing maintenance and repairs.

Alternatives:

Do nothing and allow routine inspections to identify damage-failure problems. This alternative is not recommended because the condition of these structures is poor and leaving these structures in place would not address the existing asset condition or the reliability concerns.

Studies/References:

Study Report Name(s): Conceptual Engineering Report T5820 Ticonderoga-Hague Road #4, 115 kV Asset Condition Refurbishment (ACR) November 2014
Strategy Paper No: USSC-12-048
Sanction Paper No: USSC-15-116 V2 1/31/2017

Total Project Cost Breakdown:

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	142	1,140	556	422	0	0	0	2,261
C032309	Ticonderoga-Sanford Removal	OpEx	417	1,343	1,896	1,440	0	0	0	5,096
		Removal	18	51	76	58	0	0	0	202
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment ___ Conceptual _X_ Planning _____ Project ______

Schedule:

Begin Conceptual Engineering: March 2012
Final Design Complete: July 2015
Construction Start: April 2018
In service date: March 2020

C033014
Project Title: Alabama-Telegraph 115 T1040 ACR.
T: X SubT: ___ D: ____
Spending Rationale: A/C: X D/F: ____ Non Inf: ___ S/R: ____ Syst. Cap: _____

Program Name: Overhead Line Refurbishment Program – Asset Condition

Associated funding numbers: N/A

Description:

The Alabama-Telegraph 115 (T1040) 115 kV transmission circuit connects to a switching station which connects to taps off of the Lockport-Mortimer 111 and Lockport-Batavia 107 lines. Overhead Line Details for the Alabama-Telegraph 115 (T1040) 115 line:

Total Length: 4.2 miles (T1040 only)
OHL Conductor: 4/0 ACSR 6/1 "Penguin"
Number of Structures: 44
Type of Structures: Wood pole
Typical Installation Date: 1930s or 1940s
Project Playbook Step: 0

The budgeted scope is a target structure refurbishment with the replacement of forty wood H-frame deteriorated structures, reconductoring 4.2 miles of 4/0 ACSR 6/1 Penguin conductor with 477 kcm ACSR 26/7 Hawk conductor, and the addition of two new shield wires. Deteriorated hardware and insulators will be replaced, as well. Conceptual engineering and scope development, based upon an engineering field assessment, input from Transmission Planning, and conductor testing, has been completed. The project will begin preliminary & final engineering in FY18 with construction targeted for FY19.

Project Justification:

This project resulted from condition concerns identified by field personnel who noted significant deterioration of the structures on this line.

The visual inspection of the Alabama–Telegraph #115 line by Transmission Engineering indicated most poles required replacement. They found, with the exception of two structures, the existing wood poles exhibited signs of weathering and some rotting, and many had insect infestations. At angle dead ends, leaning, curved poles were common. Most cross-arms had splitting, and were green from mold. The conductor was lab tested in 2013 and is not expected to last another ten years of service based on failed torsion and a declining level of Zinc which results in the conductor becoming more brittle over time.

Customer Benefit:

Refurbishment of this line is necessary to support a 34.5 kV network served by the Telegraph Road Substation.

This project, part of the Overhead Line Refurbishment program, promotes safety and reliability by addressing asset condition issues and allowing the transmission lines to meet the governing National Electrical Safety Code (NESC) under which they were built by replacing deteriorating structures and line components that no longer structurally or electrically conform to the NESC.

Alternatives:

The following alternatives were considered as part of the Step 0 process:

- Defer the Project: This alternative is not recommended long term as it was already determined in 2013 that the conductor has ten years or less of its service life remaining. Also, many of the wood structures are in poor condition and deferral may result in a structure failure.
- System Reconfiguration/Retire the Line: This alternative is not feasible, the transmission line is required to support a 34.5 kV network.
- REV Solutions: Cannot be implemented as these assets are still necessary to support the transmission system.

Studies/References:

Study Report Name (s): Conceptual Engineering Report dated April 2014
Sanction Paper No: USSC-15-250
Strategy No: SG080 (Overhead Line Refurbishment Program)

Total Project Cost Breakdown: ($ millions)

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	144	300	4,600	0	0	0	0	5,044
C033014	Alabama-Telegraph 115 ACR	OpEx	0	22	337	0	0	0	0	359
		Removal	0	44	673	0	0	0	0	717
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment ___ Conceptual __X__ Planning _____ Project ______

Schedule:

Begin Preliminary Engineering: April 2017
Final Design Complete: July 2018
Construction Start: October 2018
In service date: March 2019

C033847
Project Title: Battery Replacement Strategy Co. 36 TxT
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: _X_ Comm: ___ Cust: ___ DER: ___ D/F: ____ Non Inf: ___
Reliability: ____ Syst. Cap: _____

Program Name: Battery Replacement Program

Associated funding numbers: N/A

Description:

This annual program replaces battery systems in transmission substations throughout the service territory. Battery systems designated for replacement are typically selected when their age nears 20 years or testing indicates deteriorated capacity.

Substation Engineering will evaluate each battery system for adequacy to support the substation load. Control cables, conduits, safety switches, and battery chargers will also be analyzed and replaced where necessary.

Project Justification:

This project will reduce the possibility of an unavailable or inadequate continuous power source necessary for protection, monitoring and control of substations. Batteries close to end of life have a higher probability of not performing adequately when needed. Due to inherent battery system design there is no cost effective method to determine exactly when this will occur. A conservative assumption of 20 years, based on well founded industry data, is the most cost effective way to ensure that all battery systems on the network are adequate. A conservative approach is justified given that most transmission substations have a single battery system.

Customer Benefit:

Any battery system that does not perform adequately could result in equipment damage or extended interruptions to customers if protective devices such as relays and circuit breakers are not able to operate as designed to interrupt a fault.

Alternatives:

- Replace only battery systems showing visible deterioration: This option would replace battery systems at failure or only after displaying visible signs of deterioration. If this option is selected, the Company is exposed to an elevated risk of battery system failure and the associated safety and reliability and consequences.
- DER/NWA Alternative: The Company's Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company's evaluation, the

need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

Studies/References:

Study Report Name (s): N.A.
Sanction Paper No: AMIC 10020
Strategy No: SG 128

Total Project Cost Breakdown: ($ thousands)

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	2,277	160	684	500	550	250	-	4,420
C033847	Battery Replacement Program	OpEx	58	0	43	31	34	16	-	182
		Removal	141	0	128	94	103	47	-	513
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment ____ Conceptual __X__ Planning _____ Project ______

Schedule:

The battery replacements are part of a revolving replacement program that continues through the term of the Capital Investment Plan (FY18-22) so the schedule will vary as the program progresses.

C034850
Project Title: Rotterdam Substation Rebuild
T: _X_ SubT: _X_ D: ____
Spending Rationale: A/C: _X_ Comm: ___ Cust: ___ DER: ___ D/F: ____ Non Inf: ___
Reliability: ____ Syst. Cap: _____

Program Name: Substation Rebuild

Associated funding numbers: N/A

Description:

The scope of the project includes rebuild of the 230kV and 115kV yards. The driveway will be reworked to allow an efficient way to maneuver vehicles to construct and then maintain the substation. A new control house would be installed for the 230kV and the 115kV yards.

This is project covers the scope of the 115kV rebuild as it is anticipated that Energy Highway Initiative will address the rebuild of the 230kV station to 345kV operation.

Project Justification:

Rotterdam is a large substation with 230kV, 115kV, 69kV, 34.5kV, and 13.2kV sections spread out over multiple tiers on a hillside. The 230kV yard is on the highest tier and the main source for Schenectady, NY and the Northeast Region. The 230kV yard has had performance issues and one failure of a Federal Pacific Electric ("FPE") breaker. These breakers have horizontal rotational contacts inside their tank as compared to vertical lift contacts in newer style circuit breakers. FPE breakers are no longer manufactured and spare parts are not available. There are two spare SF6 gas circuit breakers stored at Rotterdam to replace the FPE breakers if one were to fail at this station.

Two of the three 230kV auto transformers (#7 & #8) are proposed for future replacement. This family of Westinghouse transformers has shown a higher than normal failure mode in the industry due to its design (specifically, due to T beam heating and static electrification). The internal design leads to "hot spots" in the transformer windings that generate hot metal gases that could lead to transformer failure.

Many of the 115kV breakers and disconnect switches are showing signs of degradation and have had issues in the past with equipment damage or not operating correctly. The concrete foundations supporting the breakers and structures, the differential, and voltage supply cabinets are all in poor condition and require repair or replacement. Some need attention now and others within the next 5 years.

A master plan for the site is in the developmental stages to address the sequence in which the station should be rebuilt and the retirement/movement of the 69kV & 34.5kV assets in the station with an emphasis on the overall station/system needs, stability, reliability, maintenance and future upgrade/system improvement possibilities.

There are many factors that will help determine the appropriate configuration of the 230kV yard in the future including potential alternatives related to National Grid's submittal in response to the Energy Highway Initiative.

Customer Benefit:

The planned replacement of the substation assets reduces the likelihood of an in-service failure, which can lead to long-term interruptions of the transmission system as well as customer outages.

Alternatives:

The following alternatives were under consideration as part of the conceptual engineering Step 0 process:

- Gas Insulated Station (GIS): The GIS option would be to rebuild the 230kV yard. This would then allow for the 115kV yard to be rebuilt in the next phase of the project. This also would serve as an alternative to the Master Plan pending the information and development of the Energy Highway decision/direction.
- Do Nothing: This is not recommended since this would mean leaving the assets in a deteriorated condition and would create additional maintenance issues and allow for the possibility of a larger spread resulting from a fault.
- DER/NWA: The Company's Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company's evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

Studies/References:

Study Report Name (s): Substation Engineering Report for Rotterdam Substation 115kV Rebuild
Sanction Paper No: N/A
Strategy No: N/A

Total Project Cost Breakdown: ($ thousands)

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
C034850	Rotterdam 115kV Substation Rebuild (AIS)	CapEx	0	46	300	6,727	19,931	24,910	1,000	52,913
		OpEx	18	0	0	72	212	265	0	567
		Removal	0	0	0	358	1,060	1,325	0	2,743
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment _X_ Conceptual ___ Planning _____ Project ______

Schedule:

Begin Preliminary Engineering:	July 2018
Final Design Complete:	May 2019
Construction Start:	November 2020
In Service Date:	April 2023

C035464
Project Title: Lockport Substation Rebuild
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: _X_ Comm: ___ Cust: ___ DER: ___ D/F: ____ Non Inf: ___
Reliability: ____ Syst. Cap: _____

Program Name: N/A

Associated funding numbers: C073991- Lockport Sub Rebuild Control House

Description:

The project scope includes the asset replacement of the 115kV and 12kV equipment at Lockport Substation. The assets will include Oil Circuit Breakers (OCBs), disconnect switches, potential transformers, a power transformer, steel structures, and foundations.

A new control house will be installed to ensure a suitable location is created to keep the relays and communication equipment protected.

Project Justification:

Lockport substation was originally part of the 25 cycle system dating back to the 1910s and is currently a major 115kV transmission substation with thirteen (13) 115kV transmission lines connected through the East and West bus sections. The overall condition of the station yard and control room is poor. Work is required on control cable duct banks, breaker operators, structure painting and concrete equipment foundations that are deteriorated significantly.

The original manhole and duct system for control cables is in degraded condition, which has caused control wire shorts, battery grounds and unwanted circuit breaker operations. Station maintenance crews are restricted in performing repairs due to the overall condition of the duct bank because single control cables cannot be replaced without adversely affecting adjacent control cables in the same ducts.

There are four (4) forty year old 115kV oil filled BZ0 breakers which have been identified in the New York OCB strategy for replacement.

Transformer #60 is a 115-12kV 7.5MVA transformer manufactured in 1941 which supplies Lockport's station service and Race Street Line 751 which is tied to the Race Street seasonal hydraulic unit. An alternate station service should be provided should TR #60 or station service fail.

The control room building is also in very poor condition and requires replacement. It is an oversized building with continued maintenance costs for the original roof and the intricate brickwork. It contains a 90 ton overhead crane in the old 25 cycle frequency changer portion of the building which is presently used only to store old cable. The control house roof was repaired in the 1990s and brick pointing was also done to limit deterioration within the last 5 years. The old 25 cycle control circuitry has been disconnected with the DC battery to eliminate potential source of battery ground problems.

Customer Benefit:

The planned replacement of the substation assets reduces the likelihood of an in-service failure due to deteriorated assets which can lead to long-term interruptions of the transmission system as well as customer outages.

Alternatives:

The following alternatives have been considered as part of the conceptual engineering Step 0 process:

- Gas Insulated Station (GIS): This is not recommended due to the complexity and cost. This proposal would be to modify the existing High-bay at the Lockport substation into a GIS style station to replace the assets.
- New land location: This is not recommended due to the complexity and cost. This proposal would be to relocate the substation to a greenfield site within a close proximity of the existing station, and replace the assets.
- Do Nothing: This is not recommended since this would mean leaving the equipment in a deteriorated condition and would create additional maintenance issues and allow for the possibility of a larger spread resulting from a fault.
- DER/NWA Alternative: The Company's Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company's evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

Studies/References:

Study Report Name (s): Substation Conceptual Engineering for Lockport Substation Rebuild
Sanction Paper No: N/A
Strategy No: N/A

Total Project Cost Breakdown: ($ thousands)

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	89	0	50	400	2,201	9,125	750	12,615
C035464	Lockport Station Rebuild	OpEx	0	0	0	0	0	0	0	0
		Removal	0	0	0	0	0	92	0	92
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	0	0	0	100	2,400	0	2,500
C073991	Lockport Station Control House	OpEx	0	0	0	0	0	0	0	0
		Removal	0	0	0	0	0	0	0	0
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment _X_ Conceptual __ Planning _____ Project ______

Schedule:

Begin Preliminary Engineering: July 2019
Final Design Complete: October 2021
Construction Start: November 2021
In Service Date: May 2022

C036866
Project Title: Porter 230kV – Replace Assets
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: ___ Comm: ___ Cust: ___ DER: ___ D/F: ____ Non Inf: ___
Reliability: _X_ Syst. Cap: _____

Program Name: N/A

Associated funding numbers: N/A

Description:

The project scope includes the asset replacement of deteriorated 230kV equipment at Porter Substation. This includes Oil Circuit Breakers (OCBs), disconnect switches, potential transformers, and power transformers.

The existing 230kV control house will be retrofitted to accommodate new protective relays and telecommunication equipment per IEC standard 61850.

Project Justification:

The 230kV portion of the Porter substation was designed and built in the late 1950's time-frame. The configuration of the 230kV yard is breaker-and-a-half with a total of seven (7) connections, five (5) transmission lines and two (2) 230-115kV power transformer connections.

There are existing assets that are original to the construction of the 230kV portion of Porter substation and these assets have deteriorated over their lifetime, they lack spare parts, and have little to no original equipment manufacturer (OEM) support.

The OCBs are in poor condition, have limited to no spare parts, no OEM support and are identified in the New York oil circuit breaker strategy as a breaker family requiring replacement.

The 230kV control house is in good condition and can be re-used to enclose the new protective relays and telecommunication equipment. The inside of the control house will be retrofitted to allow for the new assets installation while maintaining the existing equipment. The existing relays are in poor condition, have limited to no spare parts, are no longer supported by the OEM, and have been identified for replacement in the New York obsolete relay replacement program.

The 230kV auto transformers (#1 & #2) are proposed for future replacement. This family of Westinghouse transformers has shown a higher than normal failure mode in the industry due to its design (specifically, due to T beam heating and static electrification). The internal design leads to "hot spots" in the transformer windings that generate hot metal gases that could lead to transformer failure.

Customer Benefit:

The planned replacement of the substation assets reduces the likelihood of an in-service failure of deteriorated breakers or protective relays, which can lead to long-term interruptions of the transmission system as well as customer outages.

Alternatives:

Alternative considered as part of conceptual engineering include:

- Do Nothing: This is not recommended because it would mean leaving the equipment in a deteriorated condition and would create additional maintenance issues and allow for the possibility of a larger spread resulting from a fault.
- DER/NWA Alternative: The Company's Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company's evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

Studies/References:

Study Report Name (s): Substation Conceptual Engineering for Porter 230kV Asset Replacement
Sanction Paper No: USSC-15-291
Strategy No: N/A

Total Project Cost Breakdown: ($ thousands)

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	438	350	1,000	1,259	15,550	6,185	0	24,782
C036866	Porter 230kV Upgrade Brkrs/Dis	OpEx	0	0	0	0	0	0	0	0
		Removal	0	0	0	109	818	326	0	1,253
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment ____ Conceptual _X_ Planning _____ Project ______

Schedule:

Begin Preliminary Engineering: September 2018
Final Design Complete: June 2020
Construction Start: October 2020
In Service Date: December 2021

C039521
Project Title: Ticonderoga 2-3 T5810-T5830 ACR
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: _X_ D/F: ____ Non Inf: ___ S/R: ____ Syst. Cap: _____

Program Name: Overhead Line Refurbishment Program – Asset Condition

Associated funding numbers: N/A

Description:

This project will address remaining asset condition issues on the Ticonderoga-Whitehall #3 T5830 and Ticonderoga-Republic #2 T5810 115kV transmission lines. The following are details regarding the circuit:

Total Length: Approximately 42.2 miles total with approximately 19.7 miles on the T5810 and 22.5 miles on the T5830
Conductor Types: Ticonderoga-Republic 2: 336.4 kcmil ACSR 30/7 "Oriole" and 4/0 7-strand BSCU conductors. OHGW 1-7/16" EHS CW and 1-3/8" HS CW. Ticonderoga-Whitehall 3: 336.4 kcmil ACSR 30/7 "Oriole" conductor.
OHGW: 1-7/16" EHS CW
Total number of Structures: 350
Number of Wood Structure Units: 343 (original poles were Western Red Cedar)
Number of Steel Structure Units: 7
Types of Structures: Single circuit, primarily consisting of wood pole H-frame structures and steel lattice towers
Typical Installation Date: 1920-1930s
Last Osmose Inspection: 2016
Conductor Clearance: To be completed concurrently with ACR

The budgeted project scope for this refurbishment project includes:

Ticonderoga-Whitehall #3:

1. Replace approximately (36) wood structures due to pole top rot identified from reviewing oblique aerial photographs including structures identified by Osmose
2. Replace approximately (6) structures due to potential clearance issues
3. Replace and/or relocate Str. 447–453 on Mount Defiance including re-conductoring

Ticonderoga-Republic #2:

1. Replace approximately (61) wood structures due to pole top rot identified from reviewing oblique aerial photographs including structures identified by Osmose
2. Replace approximately (4) structures due to potential clearance issues

In addition, manufactured Osprey platforms will be installed at preselected locations to entice the birds to nest off the transmission structures.

Permanent access roads will be considered whenever possible to minimize the amount of temporary swamp mating used.

Project Justification:

The line was evaluated using the following resources to determine its component properties and develop the project scope:

- Wood pole ground line evaluation was performed by Osmose in 2016. Osmose performed pole inspection and treatment on all wood poles. As part of the Osmose inspection, Osmose determined whether a wood pole requires replacement based on an external and internal investigation.
- Aerial oblique photos were taken during the summer of 2016. The oblique photographs were used to visually evaluate the wood pole tops for decay, woodpecker activity, hardware issues, and overall general condition at the top of the poles.
- In 2016, a steel structure footer contractor evaluated and refurbished the legs on all seven (7) of the steel structures.
- Coupons (*i.e.*, steel samples) from the ACSR and BSCU conductor and overhead ground wire were lab tested to determine their existing tensile strength, brittleness, and the amount of residual zinc on the steel core within the ACSR is remaining.
- An aerial comprehensive inspection will be scheduled in FY18 to evaluate the connections and hardware on the seven (7) steel towers.

Customer Benefit:

Refurbishment of this radial transmission line is necessary to continue providing reliable service to approximately 10,000 customers (including International Paper) served by the Company's four (4) distribution stations. The northern line terminus for National Grid is the NYSEG Republic Station.

One element being considered in Step 0 is the structure replacement and re-conductoring the Mount Defiance section of the line, specifically between structure #447 and #453 (1.23 miles section located between Whitehall and Ticonderoga). This section of the line is not easily accessible and if a line failure were to occur in this area, customers from Ticonderoga north would be without electricity for a long duration.

Alternatives:

The following alternatives are under consideration as part of the project scoping process:

- System Reconfiguration: This alternative is not feasible for an asset condition type project as there are no other transmission circuits in the area.
- Do Nothing: This is not recommended as wood pole replacements are necessary to maintain reliability.
- REV Solutions: Cannot be implemented as these assets are still necessary to support the transmission system.

Studies/References:

Study Report Name (s): Conceptual Engineering Report Whitehall-Ticonderoga 3 and Ticonderoga-Republic #3 ACR
Sanction Paper No: N/A
Strategy No: SG080 (Overhead Line Refurbishment Program)

Total Project Cost Breakdown: ($ thousands)

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	66	300	1,400	7,000	7,000	1,100	0	16,866
C039521	Ticonderoga 2 3 ACR	OpEx	0	0	140	700	700	100	0	1,640
		Removal	0	0	280	1,400	1,400	200	0	3,280
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment _X_ Conceptual ___ Planning _____ Project ______

Schedule:

Begin Preliminary Engineering: October 2017
Final Design Complete: September 2019
Construction Start: February 2020
In service date: August 2021

C043426
Project Title: Oswego 115kV and 34.5kV Rebuild
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: _X_ Comm: ___ Cust: ___ DER: ___ D/F: ____ Non Inf: ___
Reliability: ____ Syst. Cap: _____

Program Name: N/A

Associated funding numbers: C061991 – Oswego 115kV Control House

Description:

The project scope includes replacement of the 115kV and 34.5kV equipment in poor condition, removal of obsolete equipment, and relocation of protective relays and control equipment from the NRG owned Oswego Steam Plant to a new control building with an “A” and “B” control room.

In addition, a new “A” and “B” cable path for the 115kV portion of the yard will be installed. The 34.5kV yard will only require one cable path.

Project Justification:

This facility is a 345kV, 115kV, and a 34.5kV substation that interconnects to the Oswego Steam Plant, and allows the flow from the Oswego Steam Plant to the Oswego area and the Syracuse area.

The 115kV substation includes assets in poor condition, has out-of-service equipment that has not been formally retired, and the bus sections have been cut and rerouted. The disconnect switches to the oil circuit breakers (OCBs) are original to the station and are the pin and cap design that has an industry recommendation for replacement. The electro-mechanical relays and battery for this yard and the 34.5kV yard are still inside the generation plant which limits the Company’s control and access to these assets.

The 34.5kV yard is the original to the 1940s plant 1&2 (retired decades ago). All equipment in the yard is of original vintage, obsolete, and in poor condition.

The lack of direct access to NRG’s control room within the Oswego Steam plant limits the Company’s control over the conditions for the battery and relay systems.

Customer Benefit:

The planned replacement of this substation reduces the likelihood of an in-service failure of deteriorated assets which can lead to long-term interruptions of the transmission system as well as customer outages.

Alternatives:

Alternatives considered in conceptual engineering include:

- Do Nothing: This is not recommended since the deteriorated equipment is already tagged as out of service and those that are not are of the same vintage as the out of service equipment. Leaving the equipment this way would create additional maintenance issues and allow for the possibility of a larger spread resulting from a fault.
- DER/NWA Alternative: The Company's Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company's evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

Studies/References:

Study Report Name (s): Substation Conceptual Engineering for Oswego 115kV and 34.5kV Asset Separation/Replacement
Sanction Paper No: USSC-12-190 v3
Strategy No: N/A

Total Project Cost Breakdown: ($ thousands)

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	875	2,644	3,572	0	0	0	0	7,091
C043426	Oswego 115kV & 34.5kV Station	OpEx	7	0	0	0	0	0	0	7
	Rebuild	Removal	4	130	188	0	0	0	0	323
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment ____ Conceptual _X_ Planning _____ Project ______

Schedule:
Begin Preliminary Engineering: January 2016
Final Design Complete: October 2017
Construction Start: February 2017
In Service Date: July 2018

C043833
Project Title: New West Ashville 115/34.5kV Substation
T: ___ SubT: _X_ D: ____
Spending Rationale: A/C: _X_ Comm: ___ Cust: ___ DER: ___ D/F: ____ Non Inf: ___
Reliability: ____ Syst. Cap: _X

Program Name: N/A

Associated funding numbers: C043833 – W. Ashville Substation (T-Sub)
C043832 – W. Ashville Sub 115kV Line 160 Tap (T-Line)
C048152 – W. Ashville Sub TxD Line 863 Tap (Sub-T Line)
C062505 – W. Ashville Substation Land (T-LAB)
C071466 – Replace Relays at Ashville Station (D-Sub)

Description

Construct a new single bank 115-34.5kV substation in Harmony, NY. The station will be tapped off the existing Dunkirk-Falconer 160 115kV and Sherman-Ashville 34.5kV 863 lines. The Article VII-certified Dunkirk-Falconer 160 line would extend a half-mile off its existing ROW and will loop in-and-out of the station. The Sherman-Ashville 863 line will also loop in-and-out of the station. The 34.5kV system operates as a closed network with sources at Dunkirk, Hartfield and South Dow Stations. This project will improve the pre and post contingency voltages for the substations along the Hartfield- South Dow 859, Hartfield-Ashville 854, Ashville-South Dow 864, and Sherman-Ashville 863 34.5kV lines.

Project Justification:

Several N-1 contingencies cause the 34.5kV system voltage to fall below the Company's post-contingency limit of 90% of system nominal. Opening the South Dow R440 breaker (line 864) or a bus outage at South Dow will result in the voltage at stations along lines 864 (Frewsburg, Busti,) and 859 (Elicott, Oakhill, Greenhurst) falling to 85%. The low voltages were found in the winter and summer peak seasons. Once the proposed project is completed, voltage performance of the system will be considered acceptable.

Customer Benefit:

This project will improve pre and post contingency voltages on the 34.5kV network. It will help residential and commercial customers maintain a voltage profile within acceptable limits during faults, thus providing better reliability overall. In addition, this project allows for 14MVA of capacity increase on the sub-transmission system.

Alternatives:

- Construction of a new 115 – 13.2kV Stedman Substation and 15 miles of feeder rebuilds and voltage conversions: This would also include the retirement of Panama 70, Stow 52 and Chautauqua 57 substations. This alternative is not recommended because it would only temporarily mitigate the 34.5kV concern and is more expensive than the recommended project scope to improve voltage performance of the system.

- Rebuild Ashville switching substation into a new 115 – 34.5kV substation: This new substation will be supplied by a new 1.5 mile single tap to the Dunkirk - Falconer 160

115kV line. This option is not recommended because the 115kV tap would run through a soon-to-be named federal wetland reserve or residential areas. The Ashville station also presents space constraints given the intended layout. Noise/EMF risks would have to be mitigated with close proximity of housing to the station. This option would also be more expensive than the recommended project scope.

- Build new substation near Cummins 160 Tap: This option was reviewed and deemed not able to satisfy planning criteria.

- Expand Baker St Substation with new a 34.5kV bay: This alternative would expand the existing Baker St substation (115kV - 13.2kV) to include a 115kV – 34.5kV bay, bus work, control house and associated 34.5kV feeders. While this option would most likely have removed this project from Article VII jurisdiction, Distribution Planning has earmarked the station for expansion in supporting the 13.2kV load in the area. Also, this solution would require over 8 miles of new 34.5kV rights and line construction, adding greatly to execution timelines and cost.

- Install one (1) 115/13.2kV 15/20/25MVA transformer and metal clad switchgear with four (4) active feeder positions at Two Mile Creek Rd: The option is not recommended because there are no 13kV ties available that could handle the full load of this substation.

- DER/NWA Alternative: The Company's Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company's evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.
.

Studies/References:

Study Report Name (s): Chautauqua South Relief
Sanction Paper No: USSC-13-134 v2
Strategy No: N/A

Total Project Cost Breakdown:

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	1,096	923	4,831	1,769	0	0	0	8,618
C043833	West Ashville Substation	OpEx	5	0	0	0	0	0	0	5
		Removal	-1	0	0	0	0	0	0	-1
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	64	17	876	31	0	0	0	988
C043832	West Ashville Sub 115kV Line	OpEx	1	0	56	0	0	0	0	57
	160 Tap (T-Line)	Removal	0	0	0	0	0	0	0	0
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	75	76	891	41	0	0	0	1,083
C048152	West Ashville Sub TxD Line	OpEx	0	0	0	0	0	0	0	0
	863 Tap (Sub-T Line)	Removal	0	0	0	0	0	0	0	0
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	69	0	0	0	0	0	0	69
C062505	West Ashville Substation Land	OpEx	0	0	0	0	0	0	0	0
	(T-LAB)	Removal	0	0	0	0	0	0	0	0
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	0	80	0	0	0	0	80
C071466	Replace Relays at Ashville	OpEx	0	0	0	0	0	0	0	0
	Station (D-Sub)	Removal	0	0	0	0	0	0	0	0
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment ___ Conceptual _X_ Planning _____ Project ____

Schedule:

Begin Preliminary Engineering: March 2016
Final Design Complete: February 2018
Construction Start: August 2018
In service date: August 2019

C043995
Project Title: Clay-Teall#10, Clay-Dewitt#3 Reconductoring
T: _X__ SubT: ___ D: ____
Spending Rationale: A/C: ___ Comm: ___ Cust: ___ DER: ___ D/F: ____ Non Inf: ___
Reliability: ____ Syst. Cap: __X___

Program Name: N/A

Associated funding numbers: N/A

Description:

This project removes the 4/0 copper in service on both circuits by reconductoring and rebuilding a significant portion of line #3 and all of line #10. Presently, lines #3 and #10 are co-located over a distance of approximately 13.1 miles before line #3 departs the shared right-of-way, eventually connecting to the DeWitt Substation.

Project Justification:

During the 2011 Central Division Area Study, the Clay – Teall #10 and Clay – Dewitt #3 lines were identified as being over their acceptable loading during contingencies including multi-element single contingencies (stuck-breaker contingency) and multiple outage contingencies (two parallel lines, one after another). At the time of that study, operational measures were identified and implemented to mitigate concerns with the single contingency issues – specifically, Bartell Road substation was moved to its alternate tap feed to reduce line loading on Clay – Teall #10, which was the heavier loaded line. This resulted in reduced post-contingency loading on the line and meant that all remaining issues were for N-1-1 (multiple element) contingencies. Additionally, this mitigation prevented either line from exceeding its short term emergency (STE) rating under contingency in the 2012 and 2016 case years. It was not until the 2021 case year (under projected load growth assumed in the study) that the STE ratings would be exceeded.

Further analysis of operational mitigation identified a number of short-term solutions that would be acceptable until such time as a permanent solution could be put in place. The permanent solutions were determined and projects were initiated.

In subsequent years of analysis of the Central Division system conditions had changed – including, but not limited, to the retirement of generation in the Syracuse and surrounding areas as well as changing patterns of flow through the system related to transfers between parts of the State. These changes have resulted in higher flows than previously identified in the initial study and have driven the need for the permanent solutions to be implemented. All of the analysis performed in the 2011 study was done with the best information available at the time which identified a need, but did not trigger a necessity to expedite work. As system conditions have changed in the past few years this work has become more critical for the reliability of the area.

Customer Benefit:

Reconductoring the limiting elements of the line will eliminate operational actions currently being used to mitigate contingency limits.

Alternatives:

- Re-routing lines alternative: Various line “re-configurations” were considered that would meet the capacity requirements and still serve existing substations/load. This alternative was dismissed due to greater system and environmental impacts.
- Underground 115kV line alternative: An underground routing alternative that followed the existing line corridor was considered along with two “dips” scenarios; where the line is placed underground for short lengths. While the path that follows the existing ROW meets the primary electrical requirements, the existing ROW crosses over several roadways, established wetlands, wetland buffer zones, and other sensitive resource areas. Additionally, cost to install the underground 115kV transmission lines historically are six to ten times more costly than overhead construction.
- DER/NWA Alternative: The Company’s Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company’s evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

Studies/References:

Study Report Name (s): N/A
Sanction Paper No: USSC-12-341
Strategy No: N/A

Total Project Cost Breakdown:

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	4,449	28,404	8,125	0	0	0	0	40,978
C043995	Clay-Teall #10 , Clay-Dewitt #3	OpEx	602	1,775	508	0	0	0	0	2,885
	Reconductoring	Removal	199	5,326	1,523	0	0	0	0	7,048
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment ____ Conceptual ______ Planning _____ Project X

Schedule:
Begin Preliminary Engineering: January 2014
Final Design Complete: September 2017
Construction Start: April 2018
In service date: March 2019

C044594, C044874, C046417, C045581, C045580, C045585, C045586, C045583, C045584

Project Title: Southern Niagara Falls Rebuild/Replacement
T: _X_ SubT: ___ D: _X
Spending Rationale: A/C: _X_ Comm: ___ Cust: ___ DER: ___ D/F: ____ Non Inf: ___
Reliability: ____ Syst. Cap: _____

Program Name: N/A

Associated funding numbers: N/A

Description:

Royal Ave Substation (C044594 and C044874): This project will construct a new, standard 115-13.2kV / 40MVA two transformer substation using metal-clad switchgear on National Grid property located north of the existing substation site. The secondary bus tie breaker will be operated as normally open. Feeder reactors will be installed to maintain the fault duty at the indoor substation within acceptable values. Installation of new equipment will occur on the adjacent lands such that the existing substation can remain in service during the construction of the new station. Upon completion of the installation, this project will begin to cutover new distribution 13.2kV feeders to the new equipment and will remove all of the existing outdoor electrical equipment. The transmission service connection will be relocated and will remain as a dual-tap configuration from the existing Dupont – Packard #183 & #184 115kV lines.

Stephenson Avenue Substation #85 (C046581 and C046580): This project will construct a new 13.2-4.8kV / 9.375MVA two transformer bank substation using metal-clad switchgear on National Grid property located within the existing substation fence. The secondary bus tie breaker will be operated as normally closed. The metal-clad switchgear will house both the incoming 13.2kV breakers for high-side bank protection as well as the 4.8kV feeder breakers for feeder protection. Installation of new equipment will occur on the substation property such that the existing substation can remain in service during the new substation construction. Upon completion of the installation, the 13.2kV and 4.8kV feeders will be cutover to the new equipment, the existing indoor electrical equipment will be removed, and the existing building will be demolished.

Eighth Street Substation #80 (C045585 and C045586): This project will construct a new 13.2-4.16kV / 5MVA one transformer bank substation using a Modular Integrated Transportable Substation (MITS) on National Grid property located north of the existing substation building. Installation of new equipment will occur on the substation property such that the substation can remain in service during the new construction phase. Upon completion of the installation the 13.2kV and 4.16kV feeders will be cutover to the new equipment, the existing indoor electrical equipment will be removed, and the existing building will be demolished.

Welch Avenue Substation #83 (C045583, C045584): This project will construct a new 13.2-4.16kV / 9.375MVA two transformer bank substation using metal-clad switchgear on National

Grid property located within the existing substation fence. The secondary bus tie breaker will be operated as normally closed. The metal-clad switchgear will house both the incoming 13.2kV breakers for high-side bank protection as well as the 4.16kV feeder breakers for feeder protection. Installation of new equipment will occur on the substation property such that the existing substation can remain in service during the new substation construction. Upon completion of the installation, the 13.2kV and 4.16kV feeders will be cutover to the new equipment, the existing indoor electrical equipment will be removed, and the existing building will be demolished.

Project Justification:

Asset condition is the primary driver on this project. Due to the high energy electrical discharge present in the Harper transformers and its failure history, plus the amount of overdutied equipment at the outdoor substations and their failure history, it is recommended to also install new outdoor substations and utilize adjacent land owned by the company.

Replacement of the substations as recommended in this project is consistent with National Grid's goal of improving safety and reliability for the following reasons:

- Due to the design and condition of these substations, there is a higher probability than normal for a human factors event. In addition, the condition of these substations creates a higher probability than normal for a failure to occur.
- Since control, protection, cabling, circuit breakers, and structure are obsolete; a failure of a single component in the substation may not be easily fixed. This situation will cause an extended outage and in many cases the component will have to be replaced.
- Most of the replacements covered by this project are at locations where there is a significant and immediate reliability risk should a failure occur. Under normal conditions, failure of a component could result in immediate and sustained customer outage until some type of a replacement is installed.
- Failure to replace these substations leaves National Grid open to the exposures identified above. At all indoor substations, a simple equipment failure could have a significant reliability impact.
- Executing this project will also improve operations by removing aging assets from at risk locations.
- This project addresses Asset Management’s goals by removing obsolete, aging and problematic assets from the system.
- Circuit outage availability is very limited. Unplanned outages can cause significant disruption to planned work and impact the availability and reliability of the distribution system and customers. Indoor substation equipment failures can result in increased loading on parallel units which may increase the risk of multiple failures.

Customer Benefit:

This recommended project includes the replacement of existing equipment with new and upgraded equipment and will deliver improved substations with all safety, operational and maintenance issues resolved. It also mitigates risks to reliability with an extended outage due to equipment failure. The recommended plan provides capacity to support economic development in the town of Niagara Falls and sets the stage for future infrastructure development for the area.

Alternatives:

- An indoor substation refurbishment similar to the Buffalo substation rebuilds: This also includes the installation of a New Harper substation; however, it was decided it unnecessary to keep and maintain the existing buildings. In addition, there is also enough space within the substation footprints to build new equipment without being in close proximity to energized equipment. Utilizing recent investment grade estimates from "Buffalo Style" substation rebuilds and the conceptual report for Harper substation this alternative is estimated at $28M.

- An indoor substation refurbishment by utilizing padmount distribution class equipment: This also includes the installation of a New Harper substation. The distribution class equipment does not conform to the Company's substation standards, particularly in terms of how it is controlled and how protective relaying is utilized to protect feeders and assets. Traditionally, a configuration of this kind would be considered a distribution center instead of a substation. As such, some level of risk in terms of schedule and cost would be assumed due to the non-standard nature of this equipment. This option is estimated at approximately $22M.

- An indoor substation refurbishment by retiring existing assets at Eighth Street #80, Welch Avenue #83 and Stephenson Avenue #85: This also includes the installation of a New Harper substation. This would require the voltage conversion of existing 4kV loads to 13.2kV. However, due to the boundaries mentioned in the background section and the added costs/time to rebuild and convert feeder mainlines to 13.2kV this option was rejected. In addition, lessons learned with efforts to rebuild the City of Niagara Falls to 13.2 kV from 4.16 kV and 4.8 kV in the 1990's indicate that it is a very slow and expensive process. Rebuilding the substations is more effective to deal with asset replacement issues in a timely fashion. This option is estimated at approximately $38M.

- An indoor substation refurbishment by replacing Harper substation and installing two (2) new Modular Integrated Transportable Substations (MITS) on property located within the existing Welch Avenue and Stephenson Avenue substation fences: The two MITS units would be broken into two separate skids, one for the high side protection and transformer and another for the regulators and reclosers. Installation of new equipment would occur on the adjacent station property such that the station can remain in service during the new construction phase. This alternative was hampered by a lack of vendor information to adequately determine if equipment may be protected. In addition, the MITS scheme is not capable of supporting a secondary bus tie. If a bus tie is added, a low side interrupting device would be required. Also, MITS units are better suited for applications involving a single bus section and fewer feeders such as the case with Eighth Street Substation #80. Due to the above concerns this option is not recommended and due to the protection issues mentioned no estimate is provided.

- Substation refurbishment project similar to the preferred alternative, but operates all of the substations with a normally open secondary bus tie scheme: This alternative does not require the use of feeder reactors at Harper Station. The arc flash analysis and mitigation program requires that estimates of the maximum available heat energy to which employees could be exposed to shall be determined and that control methods shall be implemented to mitigate exposure. With the implementation of a normally open secondary bus tie scheme, and the installation of feeder reactors at Harper, the maximum available heat energy to which employees are exposed to will be within 8 cal/cm^2. This option is estimated at approximately $24.1M.

- Defer or do nothing: This is not recommended because these concerns represent risk to National Grid assets, reliability, safety and customer service.

- DER/NWA Alternative: The Company's Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company's evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

Studies/References:

Study Report Name (s): N/A
Sanction Paper No: USSC-13-224
Strategy No: N/A

Estimate Grade:

Investment ____ Conceptual __X__ Planning _____ Project ______

Schedule:

Begin Preliminary Engineering: April 2023
Final Design Complete: December 2023
Construction Start: March 2024
In service date: December 2024

Total Project Cost Breakdown: ($ Millions)

					Current Planing Horizon						
Project Number	Project Type	Project Es	Spend	Prior Year	FY18	FY19	FY20	FY21	FY22	FY23+	Total
C044874	Royal Ave Substation TxT Sub	Est Lvl (e.g. +/- 25%)	CapEx	0.578	0.000	0.000	1.657	6.185	1.833	0.000	10.253
			OpEx	0.002	0.000	0.000	0.051	0.191	0.000	0.000	0.244
			Removal	0.000	0.000	0.000	0.000	0.000	0.019	0.000	0.019
			Total	0.581	0.000	0.000	1.708	6.376	1.852	0.000	10.517
C044594	Royal Ave Sub Transmission Line Tap	Est Lvl (e.g. +/- 25%)	CapEx	0.016	0.000	0.000	0.028	0.629	0.338	0.000	1.011
			OpEx	0.001	0.000	0.000	0.001	0.019	0.010	0.000	0.031
			Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			Total	0.017	0.000	0.000	0.029	0.648	0.348	0.000	1.042
C046581	Stephenson 85 - Indoor Substation Refurbishment - DSub	Est Lvl (e.g. +/- 25%)	CapEx	0.105	0.000	0.000	0.000	0.000	0.000	5.999	6.104
			OpEx	0.012	0.000	0.000	0.000	0.000	0.000	0.186	0.198
			Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			Total	0.117	0.000	0.000	0.000	0.000	0.000	6.185	6.302
C046580	Stephenson 85 - Indoor Substation Refurbishment - Dline	Est Lvl (e.g. +/- 25%)	CapEx	0.163	0.000	0.000	0.000	0.000	0.000	2.052	2.215
			OpEx	0.000	0.000	0.000	0.000	0.000	0.000	0.063	0.063
			Removal	0.001	0.000	0.000	0.000	0.000	0.000	0.000	0.001
			Total	0.164	0.000	0.000	0.000	0.000	0.000	2.115	2.279
C054046	Military Rd New F21052 - N Falls	Est Lvl (e.g. +/- 25%)	CapEx	0.027	0.000	0.000	0.000	0.000	0.893	0.000	0.920
			OpEx	0.000	0.000	0.000	0.000	0.000	0.028	0.000	0.028
			Removal	0.000	0.000	0.000	0.000	0.000	0.019	0.000	0.019
			Total	0.027	0.000	0.000	0.000	0.000	0.940	0.000	0.967
C046585	Eighth St 80 - Indoor Substation Refurbishment - Dsub	Est Lvl (e.g. +/- 25%)	CapEx	0.061	0.000	0.000	0.000	0.000	0.502	3.098	3.600
			OpEx	0.010	0.000	0.000	0.000	0.000	0.016	0.050	0.066
			Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			Total	0.071	0.000	0.000	0.000	0.000	0.518	3.148	3.666
C046586	Eighth St 80 - Indoor Substation Refurbishment - Dline	Est Lvl (e.g. +/- 25%)	CapEx	0.000	0.000	0.000	0.019	0.194	0.906	0.248	1.367
			OpEx	0.000	0.000	0.000	0.001	0.006	0.028	0.000	0.035
			Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			Total	0.000	0.000	0.000	0.020	0.200	0.934	0.248	1.402
C046583	Welch 83 Indoor Substation Refurbishment - Dsub	Est Lvl (e.g. +/- 25%)	CapEx	0.000	0.000	0.000	0.000	0.000	0.000	6.052	6.052
			OpEx	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			Total	0.000	0.000	0.000	0.000	0.000	0.000	6.052	6.052
C046584	Welch 83 Indoor Substation Refurbishment - Dline	Est Lvl (e.g. +/- 25%)	CapEx	0.000	0.000	0.000	0.000	0.020	1.392	0.000	1.412
			OpEx	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			Total	0.000	0.000	0.000	0.000	0.020	1.392	0.000	1.412
C046417	Royal Ave Substation - Dline	Est Lvl (e.g. +/- 25%)	CapEx	0.000	0.000	0.000	0.000	0.000	1.652		1.652
			OpEx	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			Total	0.000	0.000	0.000	0.000	0.000	1.652	0.000	1.652
C053426	S Niagara Falls Sub-T Line Remove	Est Lvl (e.g. +/- 25%)	CapEx	0.000	0.000	0.002	0.000	0.006	0.002	0.000	0.010
			OpEx	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			Removal	0.000	0.000	0.149	0.000	0.693	0.148	0.000	0.990
			Total	0.000	0.000	0.151	0.000	0.699	0.150	0.000	1.000
Total Project Sanction			CapEx	0.950	0.000	0.002	1.704	7.034	7.518	17.449	34.596
			OpEx	0.025	0.000	0.000	0.053	0.216	0.082	0.299	0.665
			Removal	0.001	0.000	0.149	0.000	0.693	0.186	0.000	1.029
			Total	0.977	0.000	0.151	1.757	7.943	7.786	17.748	36.291

C047816
Project Title: Mortimer-Pannell 24 25 [T1590 – T1600] Refurbishment
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: _X_ D/F: ____ Non Inf: ___ S/R: ____ Syst. Cap: _____

Program Name: Overhead Line Refurbishment Program – Asset Condition

Associated funding numbers: N/A

Description:

This project involves the Mortimer-Pannell 24 25 115 kV transmission lines.

Total Length: Approximately 15.7 miles
Conductor Types: 336.4 kcm ACSR "Oriole"
Number of Wood Structure Units: 78
Number of Steel Structure Units: 172
Types of Structures: steel lattice towers, Blaw Knox dead-end towers, wood pole structures, flex towers.
Estimated Installation Date: 1907 and 1940s

The budgeted scope for this project is for the anticipated replacement of conductor the entire length of the line due to recent LineCore conductor testing results of the Mortimer-Pannell 24 115kV line showing Zinc loss due to corrosion. With few exceptions, there is currently no shield wire for either circuit so it is assumed shield wire will be added the entire length of the line as well. Adding permanent access roads to upland areas is also included in the scope.

Project Justification:

This line is necessary to provide reliable 115kV network service to Rochester Gas & Electric (RG&E) Pannell station.

There are known asset condition issues on the line and over eighty (80) incidents reported in IDS since 1990, most of which are during summer months leading to the conclusion the lack of shield wire and insufficient grounding on the line leaves it vulnerable to lightning strikes.

Customer Benefit:

Refurbishment of this line is necessary to support the 115kV transmission network.

This project, part of the Overhead Line Refurbishment program, promotes safety and reliability by addressing asset condition issues and allowing the transmission lines to meet the governing National Electrical Safety Code (NESC) under which they were built by replacing deteriorating structures and line components that no longer structurally or electrically conform to the NESC.

Alternatives:

Alternatives that will be considered as part of conceptual engineering include:

- Reconductoring this Circuit using 795 kcm ACSR: This option may require 100% structure replacement if it is determined the existing structures cannot support the weight of the 795 kcm ACSR.
- Reconductoring this Circuit using an Alternate Conductor Type: If reconductoring is necessary, this will consider lighter conductors to try and salvage the existing towers.
- Rebuilding the Circuit with Wood Poles: If the structures are not able to be reused and must be replaced, single-circuit wood pole structures will be considered.
- System Reconfiguration: This alternative is not feasible as this transmission line is required to connect RG&E and NYSE&G stations.
- REV Solutions: Cannot be implemented as these assets are still necessary to support the transmission system.

Studies/References:

Study Report Name (s): N/A
Sanction Paper No: N/A
Strategy No: SG080 (Overhead Line Refurbishment Program)

Total Project Cost Breakdown: ($ millions)

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	113	0	100	200	1,000	3,000	23,000	27,413
C047816	Mortimer-Pannell 24 25 ACR	OpEx	0	0	0	0	0	300	2,400	2,700
		Removal	0	0	0	0	0	600	4,700	5,300
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment __X__ Conceptual ____ Planning _____ Project ______

Schedule:

Begin Preliminary Engineering: January 2020
Final Design Complete: January 2022
Construction Start: June 2022
In service date: December 2023

C047835
Project Title: GE-Geres Lock 8 Reconductor
T: _X__ SubT: ___ D: ____
Spending Rationale: A/C: _X__ Comm: ___ Cust: ___ DER: ___ D/F: ____ Non Inf: ___ Reliability: ____ Syst. Cap: _____

Program Name: N/A

Associated funding numbers: N/A

Description:

The GE-Geres Lock #8 line was identified in 2013 and 2014 Central Division Area Studies as being above its contingency operating limits due to 4/0 AWG 7 strand copper and 336.4 kcm ACSR 18/1 “Merlin” being limiting elements on the mainline. Due to generation retirements and projected load growth by 2017, the operational actions currently being used may no longer be capable of alleviating the contingency. In addition to reconductoring the line, minor condition issues identified in a May 2015 field inspection will be addressed.[1] Also, the 1-3/8” and 2-3/8” HS copperweld and steel shieldwire will be replaced with 3/8” EHS steel shield wire over the entire length of the line where 3/8” EHS shield wire does not currently exist.

Project Justification:

In 2014 the Clay-GE #15 115kV line, which is in series with the GE – Geres Lock #8, was reconductored because it was above its contingency condition operating limits.

Central division area studies in 2013 identified the GE-Geres Lock #8 115kV line also nearing its contingency operating limits due to 4/0 AWG 7 strand copper (6.3 miles) and 336.4 kcm ACSR 18/1 “Merlin” (.84 miles) being limiting elements on the mainline. However, there were still questions about generation retirements at the time so it was determined that a wait-and-see approach would be taken.

In 2014 the #8 line was re-analyzed and found to exceed limits during contingency. Due to generation retirements, along with load growth projections for 2017, the operational actions currently being utilized to mitigate the issue would no longer be capable of alleviating the contingency.

Customer Benefit:

Reconductoring the limiting elements of the line will eliminate operational actions currently being used to mitigate contingency limits.

[1] The .36 mile Solvay Village Tap (Matthews) and .48 mile Solvay Village Tap (Bridge) are not being reconductored as part of this project.

Alternatives:

While the overall goal of the project – to increase the capacity of the line by replacing the 4/0 Copper and 336.4 ACSR conductor – was consistent, there were a few alternatives discussed when determining the optimal way to accomplish that goal.

- Utilize the wire on the opposite side of the double-circuit tower to bus the conductor: This led to a significant reduction in line impedance, which caused a change of flow-pattern in the region resulting in additional overloads on other lines. A partial bussing was also considered, using only the section of the Woodard #28 34.5kV line that is slotted for de-energization. There was no significant difference between this alternative and the full-line bussing.
- Alternate conductor types including, but not limited to, 795 ACSR, 477 ACSR, and a variety of sizes of ACCR and ACSS conductor: Each of these conductor types has a different list of merits and detractions, none of which are perfect for the project needs. Analysis is still underway to determine if a least-cost, acceptably-effective conductor exists, preferable to the 297 ACCR conductor type. The final decision on which wire to use for the reconductoring, should it differ from the proposed 297 ACCR, will not change the overall project plan nor the requested sanctioning amount, though may impact the project cost.
- DER/NWA Alternative: The Company's Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company's evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

Studies/References:

Study Report Name (s): N/A
Sanction Paper No: USSC-16-194
Strategy No: N/A

Total Project Cost Breakdown:

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	107	0	4,426	5,164	0	0	0	9,697
C047835	GE-Geres Lock #8	OpEx	0	0	632	738	0	0	0	1,370
	Reconductoring	Removal	0	0	1,265	1,475	0	0	0	2,740
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment ____ Conceptual _X_ Planning _____ Project ______

Schedule:

Begin Preliminary Engineering:	June 2017
Final Design Complete:	July 2018
Construction Start:	October 2018
In service date:	July 2019

C048678 Project Title: Conductor Clearance – NY Program
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: ___ D/F: ____ Non Inf: ___ R: _X_ Syst. Cap: _____

Program Name: Conductor Clearance

Associated funding numbers: N/A

Description:

The Conductor Clearance program will increase the clearance of certain overhead conductors to address locations that may not meet standards prescribed by the National Electrical Safety Code ("NESC") under certain loading conditions. The need for greater clearances has been identified as a result of an ongoing Aerial Laser Survey (ALS), also known as LiDAR for Light Detection and Ranging, being conducted on the transmission system. Clearances are in the process of being measured with aerial surveys providing an accuracy, which was previously available by ground inspection only. The program will continue beyond FY22 to address conductor clearance issues for 115kV lines. This timeline assumes there will be no further directives from FERC similar to the October 7, 2010 NERC Alert (Recommendation to Industry: Consideration of Actual Field Conditions in Determination of Facility Ratings) that would prescribe a specific correction period.

To minimize the need for Part 102 filings, circuits within a common corridor are bundled together and undergo desktop reviews of ALS data to identify deficient spans that are labeled as a 'point of interest' (POI). POIs/spans that are confirmed in the field as not meeting current code requirements for conductor clearance, and where the line cannot be re-rated following analysis by Transmission Planning, will be addressed through a variety of construction methods (*i.e.*, re-grading, installation of floating dead-ends, re-framing, and, as a last resort, structure replacement.)

Project Justification:

This program assures that transmission lines meet the governing NESC under which they were constructed by addressing ground to conductor clearances in substandard spans. This follows standard industry practice and a Public Service Commission Order (Case 04-M-0159, effective January 5, 2005) that the Company shall adhere to the NESC. The NESC sets required conductor clearances of overhead lines from the ground and other ground based objects.

Customer Benefit:

While safety events caused by substandard clearance conductors are rare, their consequences can be serious and are difficult to quantify. Application of the NESC criteria provides a reasonable means to manage the issue and mitigate the risk from such events.

Alternatives:

Studies/References:
Study Report Name (s):___________
Sanction Paper No: ___________
Strategy No: SG163 (A-10 Predecessor Conductor Clearance Strategy to BES Program)

Total Project Cost Breakdown: ($ thousands)

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	25,598	9,409	10,009	12,105	9,771	10,190	-	77,082
C048678	Conductor Clearance - NY Progr	OpEx	2,571	1,038	1,087	1,278	1,124	1,082	-	8,180
		Removal	2,602	1,818	1,979	2,370	1,956	2,074	-	12,799
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment _X_ Conceptual ______ Planning _____ Project ______

Schedule:

This is an ongoing program that will run through the term of the Capital Investment Plan (FY18-22). The duration of individual projects will vary based on the number of POI encountered on a specific circuit. The company is maintaining near constant funding annually, which may result in the program being extended.

Begin Preliminary Engineering: N/A
Final Design Complete: N/A
Construction Start: N/A
In service date: N/A

C049601
Project Title: Menands Control Building & Relay Replacement
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: _X_ Comm: ___ Cust: ___ DER: ___ D/F: ____ Non Inf: ___
Reliability: ____ Syst. Cap: _____

Program Name: N/A

Associated funding numbers: N/A

Description:

The Menands substation control house and the station relay equipment were identified in the approved New York Relay Strategy Paper SG157 as being deteriorated assets and obsolete assets with no support from the original equipment manufacturer (OEM). The control house is 80 years old and along with the substation relays are being replaced due to asset condition.

New cables from all of the electrical equipment in the yard will be installed to the new control building. Installing new cables will allow for a quick cut over for the new installation and will minimalize outages. The old control building will be demolished as part of the Menands project

Project Justification:

Menands is a 115kV, 34.5k, 13.2kV, and 4.16kV transmission substation that ties the 115kV transmission system to the sub-transmission and distribution systems in the Albany area and a key substation for voltage support in the region.

The Protection and Telecom Operations personnel have identified several families of electromechanical and solid state relays that are no longer sustainable on the transmission system. Further, many of these relays suffer from lack of manufacturer support such that technical support and spare parts are no longer available. The targeted relays were selected based on family history, performance, field O&M experience and available manufacturer support.

The Menands control house was selected for replacement due to inadequate environment for microprocessor relays, and because the existing building is not of adequate size to accommodate the additional investment of panel work for the new protection and control equipment.

Customer Benefit:

The planned replacement of the substation assets reduces the likelihood of an in-service failure of relay protective systems which are essential to minimize the impact of a fault which can lead to long-term interruptions of the transmission system as well as customer outages.

Alternatives:

Alternatives considered in conceptual engineering include:

- Refurbish existing Control House and upgrade relays: This is not recommended since this would install new equipment in an existing building that would have a shorter life span then the newly installed assets, and does not allow for expansion.
- Do Nothing: This is not recommended since this would mean leaving the equipment in a deteriorated condition and would create additional maintenance issues and allow for the possibility of a larger spread resulting from a fault.
- DER/NWA Alternative: The Company's Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company's evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

Studies/References:

Study Report Name (s): Substation Conceptual Engineering for Menands Substation Control house and Relay Replacement
Sanction Paper No: USSC-14-194
Strategy No: SG-157

Total Project Cost Breakdown: ($ thousands)

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	305	187	1,417	3,070	3,388	2,148	0	10,515
C049601	Menands Cntrl Bldg & Relay Replcmt	OpEx	0	0	0	0	0	0	0	0
		Removal	0	0	0	0	216	137	0	354
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment ____ Conceptual _X_ Planning _____ Project ______

Schedule:

Begin Preliminary Engineering: June 2017
Final Design Complete: April 2019
Construction Start: October 2019
In Service Date: December 2021

C049902
Project Title: Rebuild Huntley Station
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: _X_ Comm: ___ Cust: ___ DER: ___ D/F: ____ Non Inf: ___
Reliability: ____ Syst. Cap: _____

Program Name: N/A

Associated funding numbers: C067027 – Huntley Install Control Building

Description:

The project scope includes the asset separation/replacement at Huntley station of National Grid owned assets from the NRG owned generating plant. In 2015, NRG announced the retirement of the Huntley generating station requiring the Company to relocate assets such as protective relays, controls and batteries to a new control house to be located in the switchyard.

Project Justification:

The generating plant and substation were built in the late 1930s and is a terminal point for eight (8) 115kV lines, four (4) 230kV lines, one (1) 230kV pipe type oil filled cable. A 230kV 91MVAR oil filled reactor used for overvoltage protection on the 230kV oil filled cable is also located in the 230kV switchyard.

There are also many asset condition issues at the Huntley substation. The 230kV and 115kV OCBs are either Westinghouse type GW design or General Electric type FK design, which are breaker families that have been identified in the OCB strategy for replacement.

The majority of the disconnect switches are in poor condition and have required extra maintenance over the past few years to have them repaired. Spare switches were recently procured to be on hand if replacements are needed.

Customer Benefit:

The planned replacement of this substation reduces the likelihood of an in-service failure of deteriorated assets, which can lead to long-term interruptions of the transmission system as well as customer outages. It also serves to separate the assets between National Grid and NRG.

Alternatives:

Alternatives considered in conceptual engineering include:

- Do Nothing: This is not recommended since the existing substation is a shared facility with NRG and would not allow for asset separation. Also, leaving the equipment this way would create additional maintenance issues and allow for the possibility of a larger spread resulting from a fault.
- DER/NWA Alternative: The Company's Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company's evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

Studies/References:

Study Report Name (s): Substation Conceptual Engineering for Huntley Asset Separation/Replacement.
Sanction Paper No: SESC-16-011
Strategy No: N/A

Total Project Cost Breakdown: ($ thousands)

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	1,266	4,619	16,000	12,000	4,000	0	0	37,885
C049902	Huntley Station Rebuild	OpEx	2	0	0	0	0	0	0	2
		Removal	456	243	842	632	211	0	0	2,384
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	49	2,450	0	0	0	0	0	2,499
C067027	Huntley Station Rebuild Control	OpEx	0	0	0	0	0	0	0	0
	House	Removal	0	0	0	0	0	0	0	0
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment ____ Conceptual _X_ Planning _____ Project ______

Schedule:

Begin Preliminary Engineering: June 2016
Final Design Complete: December 2018
Construction Start: April 2019
In Service Date: June 2020

C050917
Project Title: Inghams Station Re-vitalization
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: _X_ Comm: ___ Cust: ___ DER: ___ D/F: ____ Non Inf: ___
Reliability: ____ Syst. Cap: _____

Program Name: N/A

Associated funding numbers: C060240 – Inghams Station Associated Line Work
C074000 – Inghams Station Re-Vitalization Control House

Description:

The project scope includes the relocation of the Inghams 115/46/13.2kV substation to a new greenfield location in close proximity to the existing site, but above the 500-year flood zone. The existing phase angle regulator (PAR), which moderates the power flow on the local 115kV lines, will be replaced with a unit offering greater range which is planned to be purchased as a spare in advance of this project under a separate project (C047864 Inghams Phase Shifting Transformer). The existing unit will then be made available as a spare.

In addition, the relocation will provide for the separation of assets between the National Grid substation and the interconnected Brookfield hydro facility. Presently, National Grid has shared assets that reside in the Brookfield owned power house at the Inghams site.

Project Justification:

The Inghams substation connects the Brookfield owned power house to the local transmission and distribution electric system. The substation includes 115kV, 46kV, and 13.2kV equipment which is obsolete or has deteriorated.

Transmission Planning analysis has determined that a wider adjustment range is required beyond what the existing PAR can provide to maintain area power flow within the capability of the adjacent 115kV transmission lines.

The Inghams substation was flooded in 2006 and remains a flood concern. After the substation was repaired, a new stone wall approximately five (5) feet tall was constructed along the substation perimeter that is shared with the river boundary. However, the stone wall is a temporary measure which will limit the current flow of the river but will not keep the station from being flooded.

Customer Benefit:

The planned replacement of this substation reduces the likelihood of an in-service failure of deteriorated equipment, which can lead to long-term interruptions of the transmission system as well as customer outages. It also serves to separate the assets between National Grid and Brookfield.

Alternatives:

The following alternatives were considered in conceptual engineering:

- Do Nothing: This is not recommended since the existing substation is within a floodplain and has flooded in 2006. Also, leaving the equipment this way would create additional maintenance issues and allow for the possibility of a larger spread resulting from a fault.
- DER/NWA Alternative: The Company's Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company's evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

Studies/References:

Study Report Name (s): Substation Conceptual Engineering for Inghams New land location.
Sanction Paper No: N/A
Strategy No: N/A

Total Project Cost Breakdown: ($ thousands)

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	0	50	173	700	4,450	5,707	11,080
C050917	Inghams Station Revitalization	OpEx	0	0	0	0	0	0	0	0
		Removal	0	0	0	0	37	234	679	950
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	0	0	0	100	2,400	0	2500
C074000	Inghams Station Revitalization	OpEx	0	0	0	0	0	0	0	0
	Control House	Removal	0	0	0	0	0	0	0	0
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	0	0	0	100	900	2,272	3272
C060240	Inghams Station Associated Line	OpEx	0	0	0	0	0	129	0	129
	Work	Removal	0	0	0	0	0	257	313	570
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment ____ Conceptual _X_ Planning _____ Project ______

Schedule:

Begin Preliminary Engineering:	April 2019
Final Design Complete:	October 2021
Construction Start:	November 2021
In Service Date:	March 2023

C052603
Project Title: Turner D Switch Replacements
T: __X__ SubT: ___ D: ____
Spending Rationale: A/C: __X_ D/F: ____ Non Inf: ___ S/R: ____ Syst. Cap: _____

Program Name: N/A

Associated funding numbers: N/A

Description:

This project will replace Turner Electric Company (Turner) Type D sidebreak disconnect switches in the Company's transmission line system. This switch model has experienced reliability issues due to incomplete closure of the switch blades during. The blades on this type of switch are difficult to properly latch within the switch jaw and improper closure cannot be seen from the ground. If not properly latched, over time the blades of the switch can gradually work free from the jaw, resulting in poor contact and eventual failure.

Where possible, the Company has already replaced several Type D switches as part of completed overhead transmission line asset condition refurbishment (ACR) projects leaving the following switches still on the system:

- Firehouse – North Troy #15 SW1511 and SW1522
- LaFarge-Pleasant Valley #8 SW811 and SW822
- Mohican-Luther Forest #3 SW322
- New Scotland-Long Lane #7 SW711
- Menands-Riverside #3 SW311
- Mohican-Luther Forrest #3 SW311
- Huntley-Lockport #36 SW51 *
- Huntley-Lockport #27 SW52 *
- Feura Bush-North Catskill #2 SW211
- Dennison-Colton #4 SWX4-1 and SWX4-2
- Colton-Browns Falls #1 SW X1-1 *
- Coffeen-West Adams#2/Coffeen-LHH #5 SWX2L5
- Huntley-Praxair #46 SW 998

(* - project will be considered within the scope of an upcoming overhead line ACR.)

Project Justification:

The primary drivers for these switch replacement projects are safety and reliability. The potential failure of Turner D switches during service is a risk to employees and the public. It is not feasible to ensure that all phases of a switch are fully closed after each operation due to the variables of switch design, installation, and operation. Harsh weather, especially during winter months, poses the greatest threat to safe operation of

Turner D switches. High winds and icy conditions put strong mechanical forces on the switch arm. If the jaw is not correctly locked, the build-up of ice can push the blade out of the contact area, resulting in an arc failure.

Customer Benefit:

It has been determined that the Type D switch manufactured by Turner presents a potential safety and reliability risk due to its design and problems inherent in its operation. Improperly functioning line switches prevent the transmission system from being operated efficiently and, in some cases, not acceptable for emergency system operations.

Alternatives:

Given the safety and reliability concerns with the Turner D switches, alternatives to replacement are minimal. Constant adjustment of switches in the field would require multiple outages and have a high cost without solving the cause of the problem.

Studies/References:

Study Report Name (s): N/A
Sanction Paper No: N/A
Strategy No: USSC-13-335

Total Project Cost Breakdown: ($ millions)

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	0	1,376	1,376	0	0	0	2,752
C052603	Turner Type-D Switch	OpEx	0	0	86	86	0	0	0	172
	Replacement	Removal	0	0	258	258	0	0	0	516
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment X Conceptual ____ Planning _____ Project ______

Schedule: (This will result in individual projects each having their own schedules based on outage availabilities.)

Begin Preliminary Engineering: N/A
Final Design Complete: N/A
Construction Start: N/A
In service date: N/A

C053135
Project Title: Purchase System Spare Transformers
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: _X__ Comm: ___ Cust: ___ DER: ___ D/F: ____ Non Inf: ___ Reliability: _X_ Syst. Cap: _____

Program Name: N/A

Associated funding numbers: N/A

Description:

The Company is purchasing the following spare system transformers to maintain the transformer fleet for proper availability in the event of the loss of a transformer due to damage/failure:

- 345-230kV 332 MVA Auto
- 345-115kV 448 MVA Auto
- 115-13.8kV LTC 25 MVA
- 115-13.8kV LTC 40 MVA
- 115-34.5kV LTC 25 MVA
- 115-34.5kV LTC 40 MVA
- 240-24kV 100 MVA Auto

Project Justification:

Spare transformers are required to mitigate the risk of an extended loss of supply to transmission customers and distribution networks in the event of a failure. Long lead times to procure new transformers, typically nine months, make it necessary to have spare transformers available in case of transformer failure.

Customer Benefit:

The planned addition of the proposed system spares reduces the lead time to long term interruptions of the transmission system in the event of a failure to maintain overall system reliability.

Alternatives:

- Refurbishment of System Transformers: This option would refurbish as opposed to replace a transformer with abnormal dissolved gas analysis ("DGA") levels. This option is not recommended as components would need to be refurbished back to original design tolerances and replacement of any worn-out or degraded parts would need to be acquired. In addition, refurbishment may only provide a few years of additional life. Refurbishment is a one-off activity and cannot be repeated indefinitely, but refurbishment may have limited application where it is not possible to replace a transformer due to outage or other constraints.

- DER/NWA Alternative: The Company's Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company's evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

Studies/References:
Study Report Name (s): N/A
Sanction Paper No: N/A
Strategy No: N/A

Total Project Cost Breakdown:

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	4,660	8,007	5,796	0	0	0	18,463
C053135	Spare Transformers Purchase	OpEx	0	50	90	90	0	0	0	230
		Removal	0	0	0	0	0	0	0	0
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment _X_ Conceptual ______ Planning _____ Project ______

Schedule:

The spare transformers will be purchased on varying schedules between FY18 thru FY20.

Begin Preliminary Engineering: N/A
Final Design Complete: N/A
Construction Start: N/A
In Service Date: N/A

C055263
Project/Program Title: Ohio St 115 – 34.5kV Substation
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: ___ Comm: ___ Cust: ___ DER: ___ D/F: ____ Non Inf: ___
Reliability: ____ Syst. Cap: _X

Program Name: N/A

Associated funding numbers: C054713 Grdvll-Bffl Rvr146 2nd Tap Ohio Sta
C054711 Airco-Bffl Rvr147 Adv Metal Tap
C055304 OHIO ST STATION - SUBT LINES
C061387 Easement - Ohio St. Substation

Description:

C055263 – Ohio St. Sub 115 -34.5kV.
Construct a new 115-34.5kV Ohio Street substation with two (2) 115-34.5kV 30/40/50MVA LTC transformers and six (6) 34.5kV feeders supplied by 115kV lines 146 and 147. Run 0.5 miles of new cables north of Ohio St. Substation through the new Ohio St. 20 ways ducts.

C054713 – Gardenville-Buffalo River 146 2nd Tap to Ohio Street Substation.
Extend the 115kV Gardenville–Buffalo River Switch 146 line in the vicinity of the Buffalo River Switch Structure to the new Ohio Street Substation.

C054711 – Airco-Buffalo River 147 Advance Metal Tap to Ohio St. Substation. Construct an 115kV Airco-Buffalo River 147 Advance Metal Tap to the new Ohio St. Substation

C055304 – Ohio St. substation Sub-transmission lines.
Reconfigure the sub-transmission system. The new Ohio Street substation will serve six (6) 34.5kV lines as lines 611, 612, 613 cross the site and as such are easily reconfigured to six circuits.

C061387 - Easement - Ohio St. Substation.
Acquire a permanent easement for an access road to the new 115 – 34.5kV station.

Project Justification:

The drivers for this project are load growth and reliability. With the reconstruction of Ohio Street and the availability of construction-ready sites, several developers presently have projects planned from the Ohio Street crossing of the Buffalo River towards downtown Buffalo and new load is proposed for the NFTA site and Freezer Queen. Also, a Modular Integrated Transportable Substation (MITS), supplied from the 34.5kV system, will be installed at Buffalo Station 42 to eliminate the 23kV cable concerns due to their location in a flooded river tunnel and to provide some relief for Seneca Terminal Station.

The source of the 34.5kV system is Ridge Station 142. The 34.5kV lines 611, 612 and 613 that run toward the Buffalo River cross the Tifft Nature Reserve, exposing customers to frequent outages due to trees and animals.

Customer Benefit:

Meet anticipated load growth, mitigate contingency outage exposure, improve reliability and capacity on the sub-transmission.

Alternatives:

- Do Nothing: Due to the reconstruction of Ohio Street and the designation of construction-ready sites, several developers presently have projects in the Buffalo River area. The NFTA site and Freezer Queen are two existing customers looking to increase their load. Riverbend, on the other hand, is a new manufacturing site in the area. Accordingly, this option is not recommended due to load growth and reliability concerns in the area.

- DER/NWA Alternative: The Company’s Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company’s evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

Studies/References

Study Report Name (s): N/A
Sanction Paper No: USSC-15-008
Strategy No: N/A

Total Project Cost Breakdown:

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	98	2,237	182	0	0	0	0	2,516
C054713	Gardenville-Buffalo River Street	OpEx	9	320	52	0	0	0	0	381
	146 2nd Tap Ohio Station	Removal	17	639	26	0	0	0	0	682
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	82	720	182	0	0	0	0	984
C054711	Airco-Buffalo River 147 Advance	OpEx	4	206	26	0	0	0	0	236
	Metal Tap	Removal	8	103	52	0	0	0	0	163
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	2,347	4,685	5,219	0	0	0	0	12,250
C055263	Ohio Street New 115-13.2kV	OpEx	0	0	0	0	0	0	0	0
	Station	Removal	0	0	0	0	0	0	0	0
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	544	453	425	0	0	0	0	1,422
C055304	Ohio Street Substation SubT	OpEx	25	53	50	0	0	0	0	128
	Lines	Removal	5	27	25	0	0	0	0	57
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	19	0	0	0	0	0	0	19
C061387	Ohio Street Station Easement	OpEx	0	0	0	0	0	0	0	0
		Removal	0	0	0	0	0	0	0	0
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment ____ Conceptual __X__ Planning _____ Project ______

Schedule:

Begin Preliminary Engineering: April 2015
Final Design Complete: December 2017
Construction Start: February 2018
In service date: February 2019

C059671 and C076242
Project Title: Terminal Substation
T: _X_ SubT: __ D: _X
Spending Rationale: A/C: _X_ Comm: ___ Cust: ___ DER: ___ D/F: ____ Non Inf: ___
Reliability: ___ Syst. Cap: _____

Program Name: N/A

Associated funding numbers: N/A

Description:

Terminal Station is a 115kV/13.2kV two-bank distribution station constructed in 1962 with seven (7) distribution feeders and four (4) network feeders. All feeders derive from a Westinghouse metal-clad arranged in a breaker-and-a-half scheme. The project scope of work consists of replacing the existing TB2 with a new power transformer matching the rating and impedance of the existing TB3 (115/13.8kV, 40MVA with LTC), replacing the existing metal-clad with a new metal-clad matching the existing breaker-and-a-half configuration, replacing 115kV circuit breakers R60 and R70, replacing all fifteen (15) 115kV disconnect switches and MODs, and replacing the station service modular switchgear. The new metal-clad would be located in the currently vacant south-west corner of the station yard, adjacent to the existing metal-clad.

A flood barrier wall will also be constructed around the substation perimeter with top barrier two (2) feet above the 100 years flood plain.

Project Justification:

An asset condition report was completed in 2013 identifying numerous issues with the equipment at this station. In summary:

- The 115kV circuit breakers, R60 and R70, are 53 year old GE oil circuit breakers in which the sister tie breaker, R8105, was recently replaced on a damage/failure project due to swelling of the operating rods within the breaker. It is expected that R60 and R70 will have the same issues in the near future.
- All 15kV circuit breakers are roll-in Westinghouse type 15-DH-750E circuit breakers that have been targeted for replacement in the near future with a new and modern design.
- The metal-clad in which these circuit breakers reside is original and will begin to develop issues with the main bus and bus insulators.
- All 115kV disconnect switches and motor operated disconnects are original to the station and will become a maintenance issue in the near future.
- The station service modular switchgear is becoming obsolete due to the lack of availability of spare parts and should be replaced in 10-15 years.

It should also be noted that TB3 failed due to a shorted winding in 2008 and was subsequently replaced. TB2 is a sister unit to the failed TB3 and should also be replaced. Additional factors include environmental issues due to soil contamination and the current substation pad being approximately one (1) foot below 100 years flood elevation.

Customer Benefit:

This project would address existing asset condition related issues at the substation reducing the risk of potential failure resulting in interruptions to the 8,180 customers served by the station.

Alternatives:

- Rebuild Station with Metal-Clad Outside Existing Yard: the new metal-clad will be located east of the existing station just outside the existing station fence. This alternative would require station expansion on land currently owned by National Grid. This option is more expensive than the recommended project scope.

- Rebuild Station at the New Location: This consists of completely rebuilding the station at a new location south of the existing station on land currently owned by National Grid. This alternative would require transmission line extension to the new substation crossing potential recreational area the City of Utica is looking to redevelop as part of the Utica Harbor Point development, so permitting issues are expected. In addition, the City has reached out to the Company expressing their intent to build a baseball park at the same location planned to build a substation. This option is more expensive than the recommended project scope and has potential permitting issues.

- DER/NWA Alternative: The Company's Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company's evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

Studies/References:

Study Report Name (s):	N/A
Sanction Paper No:	N/A
Strategy No:	N/A

Total Project Cost Breakdown: ($ millions)

					Current Planning Horizon						
Project Number	Project Title	Project Estimate Level (%)	Spend ($M)	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23	Total
C076242	Terminal Substation	-25%/+50%	CapEx	0.000	0.000	0.000	0.050	3.000	2.650	5.143	10.843
			OpEx	0.000	0.000	0.000	0.050	0.000	0.100	0.000	0.150
			Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.023	0.023
			Total	0.000	0.000	0.000	0.100	3.000	2.750	5.166	11.016
C059671	Terminal Substation Feeder Getaway	-25%/+50%	CapEx	0.000	0.000	0.000	0.050	0.100	3.900	3.804	7.854
			OpEx	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			Total	0.000	0.000	0.000	0.050	0.100	3.900	3.804	7.854
Total Project Sanction			CapEx	0.000	0.000	0.000	0.100	3.100	6.550	8.947	18.697
			OpEx	0.000	0.000	0.000	0.050	0.000	0.100	0.000	0.150
			Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.023	0.023
			Total	0.000	0.000	0.000	0.150	3.100	6.650	8.970	18.870

Estimate Grade:

Investment ____ Conceptual _X_ Planning _____ Project ______

Schedule:

Begin Preliminary Engineering: April 2019
Final Design Complete: December 2020
Construction Start: March 2021
In service date: September 2022

C060208
Project Title: Greenbush-Stephentown 993 ACR
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: _X_ D/F: ____ Non Inf: ___ S/R: ____ Syst. Cap: _____

Program Name: Overhead Line Refurbishment Program - Asset Condition

Associated funding numbers: None

Description:

This project will address asset condition issues on the 115kV Greenbush-Stephentown #993 (T5190) transmission circuit. The following are details regarding the circuit:

Total Length: Approximately 19.56 miles
Conductor Types: 4/0 7-strand BSCU conductors, 2-span of 336.4 kcm ACSR
Total Number of Structures: 271
Number of Wood Structure Units: 271 (original poles were Western Red Cedar)
Number of Steel Structure Units: 0
Types of Structures: Single circuit wood pole H-frame structures, original with steel cross-arms
Oldest Installation Date: 1923
Last Osmose Inspection: 2011
Conductor Clearance: Completed

The budgeted project scope is for the replacing all insulators and hardware; installing permanent access roads in upland areas; replacing deteriorated wood structures (assumed to be 5% of the line's population): and replacing conductor and shield wire on sections of the line with a concentration of splices (assumed to be 5% of the length of the line). Conductor testing will be performed and further define the overall condition of the conductor.

Project Justification:

The 993 line dates back to the early 1920's with many of the structures being original. In 2016, the line was inspected by the Company's Inspection and Maintenance group which found four (4) level 2 and eighty-two (82) level 3 Code 511's for visual rotting. This follow up project is needed to address the remaining asset condition issues on this line.

The line has experienced nine (9) events from 5/21/2012 to 5/27/2015. Since 2010 there have been six (6) disturbances on the line with an "unknown" cause, which excludes any weather related causes. Also, the 993 line ranked #19 on the Worst Performing Feeder List for (2007-2011) with 80.315 weighted Transmission Performance Score (TPS).

Customer Benefit:

The 993 line suppliess NYSEG's Stephentown station. Rebuilding this line will improve reliability for the NYSEG customers served by this station and address potential safety concerns as this line crosses over roads, is adjacient to residential areas, and occupies agriculture lands.

Alternatives:

The following alternatives are under consideration as part of the conceptual engineering Step 0 process:

- Asset Condition Refurbishment: This alternative replaces deteriorated structures based on aerial oblique photographs where pole tops are inspected for rot, decay, and wood pecker infestation. Hardware, grounding, and conductor will all be evaluated to determine their condition.
- System Reconfiguration: Adjacent to the NYSEG Stephentown Station is the 345kV Alps-Berkshire #393. Tapping the 393 line for a NYSEG Station would have to be evaluated economically and from a commercial standpoint.
- REV Solutions: Cannot be implemented as these assets are still necessary to support the transmission system.

Studies/References:

Study Report Name (s): N/A
Sanction Paper No: N/A
Strategy No: SG080 (Overhead Line Refurbishment Program)

Total Project Cost Breakdown: ($ thousands)

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	100	200	200	1,000	3,000	9,200	13,700
C060208	Greenbush-Stephentown 993 ACR	OpEx	0	0	0	0	0	300	1,100	1,400
		Removal	0	0	0	0	0	600	1,600	2,200
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment __X__ Conceptual ____ Planning _____ Project ______

Schedule:

Begin Preliminary Engineering: April 2019
Final Design Complete: March 2021
Construction Start: August 2021
In service date: March 2023

C060243
Project Title: Rotterdam - Curry #11 Reconductor
T: X SubT: ___ D: ____
Spending Rationale: A/C: ___ Comm: ___ Cust: ___ DER: ___ D/F: ____ Non Inf: ___
Reliability: ____ Syst. Cap: _____

Associated funding numbers: N/A

Description:

Reconductor seven (7) miles of the Rotterdam–Curry Road #11 115kV circuit between Rotterdam and Curry Road Substations with 795 kcm ACSR 26/7 conductor.

Project Justification:

Reconductoring the seven (7) mile thermally limited section of the #11 line will relieve exposure to single contingency overloads which is a concern during summer operating seasons in 2016 and beyond.

Customer Benefit:

Relief by load shedding would require about 26MW of load to be shed for 2016 summer peak conditions. This represents the demand of approximately 15,000 residential customers.

Alternatives:

- Relieve thermal limits by tapping spare capacity on another line: There are no circuits near the Rotterdam – Curry #11 line with spare capacity that would enable relief via load transfers, so this is not an available option.
- Extend a new circuit from a nearby station not already fed by the loops which the Rotterdam – MECO #10 and MECO – Inghams #15 lines are part of (Rotterdam, Menands, or Albany; for instance): This would be more expensive and time-consuming compared with reconductoring Rotterdam – Curry #11.
- DER/NWA Alternative: The Company's Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company's evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

Studies/References:

Study Report Name (s): N/A
Sanction Paper No: USSC-16-189

Strategy No: N/A

Total Project Cost Breakdown:

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	60	504	8,000	2,500	0	0	0	11,063
C060243	Rotterdam-Curry #11 Recond	OpEx	0	72	1,143	357	0	0	0	1,572
		Removal	0	144	2,286	714	0	0	0	3,144
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment ____ Conceptual _X_ Planning _____ Project ______

Schedule:

Begin Preliminary Engineering: July 2017
Final Design Complete: September 2018
Construction Start: December 2018
In service date: December 2019

C060248
Project Title: Mortimer Line Re-Arrangement
T: X SubT: ___ D: ____
Spending Rationale: A/C: ___ Comm: ___ Cust: ___ DER: ___ D/F: ____ Non Inf: ___
Reliability: ____ Syst. Cap: X

Program Name: NA

Associated funding numbers: NA

Description:

This project involves the swap of the Lockport-Mortimer #113 and Lockport-Mortimer #114 115kV lines on the right-of-way at the transition from overhead to underground near structure #564 at the Rochester Pump Plant Station. The scope includes:

- Replacing double-circuit square base lattice suspension structure #564 with a double-circuit steel pole davit arm dead-end structure on a concrete caisson foundation.
- Installation of two steel 3-pole dead-end pull-out structures on concrete caisson foundations on the #114 line.
- Replacement of insulators and hardware at #113 and #114 line bus structures.
- Swapping the line protection communication channels to reflect the change in the line terminations.
- Re-commissioning the existing protection schemes for both #113 and #114 lines.

Project Justification:

The existing bus arrangement at the Mortimer station has the Lockport – Mortimer #111 and #113 lines on bus section 1 and the Lockport – Mortimer #114 line on bus section 2. For a fault on the #111 line or on Mortimer bus section 2, and a failure of the #111 line breaker (R194) to operate, line #111 would be taken out of service and line #113 would be open at Mortimer and closed at the Lockport station. A similar situation would result if the #113 line breaker (R124) were to fail following a line #113 or Mortimer bus section 2 fault. Both of these outages are an N-1 Breaker Failure or Stuck Breaker contingency.

These outages results in up to 75MW of load being supplied radial from the Lockport station, a distance of 50 miles. Due to the magnitude of load and the length of the radial circuit the voltage in the Brockport area drops to 85%, nearly a 15% drop from the pre-contingency value for the #111 line breaker failure and 90% and 11% drop for the #113 line breaker failure.

By swapping the #113 and #114 lines, a condition with the Brockport load served radial from Lockport can no longer be created by any N-1 contingencies.

Customer Benefit:

Preventing this condition from developing would eliminate the need to shed load in order to restore the voltage to an acceptable level.

Alternatives:

The following alternatives have been considered as part of the conceptual engineering Step 0 process:

- Swap the #113 and #114 lines at Mortimer station instead of out on the right-of-way near the Rochester Pump Station: This option was not recommended due to a $230,000 higher cost and concerns working in a very congested area at Mortimer.
- Add a second breaker in series with both R124 and R194 to prevent the breaker failure contingency from developing: This option was not considered further due to space concerns at Mortimer station and the expectation that the cost would be higher than swapping the line positions.
- DER/NWA Alternative: The Company's Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company's evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

Studies/References:

Study Report Name (s): 2015 Western Division Area Study Needs & Solutions Reports v0
Sanction Paper No: N/A
Strategy No: N/A

Total Project Cost Breakdown:

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	50	570	500	0	0	0	1,120
C060248	Mortimer Line Re-Arrangement	OpEx	0	0	81	71	0	0	0	153
		Removal	0	0	163	143	0	0	0	306
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment ____ Conceptual _X_ Planning _____ Project ______

Schedule:

Begin Preliminary Engineering: April 2018
Final Design Complete: May 2019
Construction Start: November 2019
In Service Date: March 2020

C060252
Project Title: Schaghticoke Switching Station
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: ___ Comm:___ Cust:___ DER:___ D/F: ____ Non Inf: ___
Reliability: ___ Syst. Cap: _X

Program Name: N/A

Associated funding numbers: C060253 – Schaghticoke Tap Switch Structure Line Taps
C062925 – Schaghticoke Control House
C067046 – Schaghticoke Land Purchase

Description:

This project is the addition of a new 115kV switching station where the supply lines for Luther Forest from the east are connected to the main 115kV double-circuit serving the Northeast Region.

Project Justification:

The Schaghticoke station will more evenly balance the flow of power from the Northeast Region's 115kV system to Luther Forest thereby providing capacity for growth in the Northeast Region and Luther Forest and also mitigate adverse effects on reliability associated with potential generation retirements which are presently a concern in the Northeast Region.

Customer Benefit:

The new station will provide increased capacity and reliability and decrease dependence on local generation in the Northeast Region benefitting tens of thousands of customers. Without this station, concerns will remain with the capacity to serve the growing demand in the region and reliance on generation within the region for adequate reliability.

Alternatives:

The following alternatives were considered:

- Reconductoring approximately 7.5 miles of the 115kV Luther Forest – Eastover Road #308 and Battenkill – Eastover Road #10 Lines between Tower 305 and Tower 355, with 1113kcmil ACSR "Finch" conductor, and coordinating this with a reconductoring by New York State Electric and Gas Corporation ("NYSEG") of a 4.2-mile portion of its section of the #308 line between Tower 305 and NYSEG's Mulberry Substation, with 1113kcmil ACSR "Finch" conductor. This alternative would also include the replacement of the existing shield wires with two 3/8" 7-strands EHS for National Grid's portion of the reconductoring with costs when available). This would be more costly and less effective than adding the new Schaghticoke switching station.

- DER/NWA Alternative: The Company's Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company's evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

Studies/References:

Study Report Name (s): N/A
Sanction Paper No: USSC-15-137
Strategy No: N/A

Total Project Cost Breakdown:

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	861	1,150	3,300	7,000	0	0	0	12,311
C060252	Schaghticoke Switching Station	OpEx	22	0	0	0	0	0	0	22
		Removal	2	0	0	0	0	0	0	2
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	15	100	135	1,300	0	0	0	1,550
C062925	Schaghticoke Control House	OpEx	0	0	0	0	0	0	0	0
		Removal	0	0	0	0	0	0	0	0
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	145	142	207	630	0	0	0	1,124
C060253	Schaghticoke Tap Switch Struc	OpEx	0	3	3	50	0	0	0	56
	Line Taps	Removal	0	7	6	110	0	0	0	123
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	246	0	0	0	0	0	0	246
C067046	Land Purchase -Schaghticoke	OpEx	0	0	0	0	0	0	0	0
	Station	Removal	0	0	0	0	0	0	0	0
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment ____ Conceptual ______ Planning _X_ Project ______

Schedule:

Begin Preliminary Eng.: Complete
Final Design Complete: August 2018
Construction Start: October 2018
In service date: March 2020

C060254
Project Title: Ticonderoga - Install Cap Bank Rpl OCB
T: X SubT: ___ D: ____
Spending Rationale: A/C: ___ Comm: ___ Cust: ___ DER: ___ D/F: ____ Non Inf: ___
Reliability: ____ Syst. Cap: X

Associated funding numbers: N/A

Description:

This project is to add two (2) 115kV 10.8 MVAR capacitor banks and associated equipment, a line circuit breaker for the Ticonderoga – Whitehall #3 line, and the replacement of an oil circuit breaker for the Ticonderoga – Hague Road #4 115kV line.

Project Justification:

The Ticonderoga area 115kV system is exposed to normal and post-contingency low voltage. For peak demand periods in 2021, pre-contingency voltage in this area is 91% and voltage for the most-limiting single contingency in the area is 85%. The addition of the proposed capacitor banks relieves concern with voltage performance vs. criteria in the Ticonderoga area.

Customer Benefit:

The Ticonderoga area 115kV system serves three (3) National Grid distribution substations, International Paper (IP) Ticonderoga, and approximately 13MW of NYSEG's distribution load via Barton Brook. The peak demand on this part of the 115kV system is approximately 54MW which includes about twenty thousand residential customers and IP Ticonderoga. The proposed capacitor addition resolves the aforementioned voltage-performance concerns for these customers.

Alternatives:

- Extending a source into the area for improved voltage support: This would be far more expensive in comparison to the reactive compensation, particularly in this area which is remote and served from a radial 115kV supply from Whitehall.
- DER/NWA Alternative: The Company's Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company's evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

Studies/References:

Study Report Name (s): N/A
Sanction Paper No: USSC-15-144
Strategy No: N/A

Total Project Cost Breakdown:

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	548	1,105	2,403	0	0	0	0	4,056
C060254	Ticonderoga Install Cap Bank &	OpEx	0	11	25	0	0	0	0	36
	Replace OCB	Removal	29	23	50	0	0	0	0	102
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment ____ Conceptual ______ Planning _X_ Project ______

Schedule:

Begin Preliminary Engineering: Complete
Final Design Complete: September 2017
Construction Start: April 2018
In service date: October 2018

C060365
Project Title: 345kV Laminated Cross Arm
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: _X_ D/F: __ Non Inf: ___ S/R: ____ Syst. Cap: _____

Program Name: 345kV Laminated Cross-Arms

Associated funding numbers: N/A

Description:

The D-1501-type 345kV structures built prior to 1975 will be aerially inspected to identify delaminating cross-arms and overstressed vee braces. The aerial inspection will be scheduled over a number of years with road crossing inspected initially followed by the remaining off-road structures. Those circuits with a history of delaminated cross-arms have been previously addressed.

Project Justification:

The New Scotland – Alps #2 T5450 345kV line has experienced two cross arm failures, one in 2012 and a second in 2014. Both were on tangent (NMPC Overhead Electric Transmission Standards D-1501-type) structures – a two-pole wood H-frame with two laminated wood cross-arms and wood vee braces. The root cause has been identified as delamination of the wood layers that make up the laminated cross arms used to support the suspension insulators. These specific laminated cross arms manufactured by Joslyn were used by Niagara Mohawk on all 345kV circuits prior to approximately 1975.

Several D1501 cross arm samples were obtained from structures that were being replaced on the T5450 New Scotland-Alps #2 line due to normal maintenance. These cross arms were destructively examined in the field by forcing a shear failure parallel to their laminations. Once split, the lamination was examined for glue adhesion quality. Concurrently, full sized cross arm samples were sent to the State University of New York College of Environmental Science and Forestry (SUNY-ESF) for laboratory analysis to measure their bending strength and compare them to their original design specifications. The results found the in-service cross arms were weaker than specifications.

Follow-up to the SUNY-ESF testing consisted of an aerial inspection program to identify deteriorated cross arms and overstressed vee braces in the field for D-1501 structures constructed prior to 1975.

Customer Benefit:

This program enhances public safety by replacing damaged or failed transmission overhead line components prior to failure. Replacing damaged or failed components on 345kV also enhance system reliability as these circuits are heavily loaded and when de-energized for maintenance, typically results in congestion costs and additional loading on other 345kV circuits.

Alternatives:

The following alternatives were considered:

- Replace the laminated cross arms as damage/failure work: This action is not recommended on the 345kV system because it potentially places the public at risk. In addition, a fault on the 345kV places stress on the other 345kV lines in the region and may cause de-rating of other 345kV lines when they are most needed.
- Rely on the visual I&M Program to detect delaminated cross arms: This action is not recommended as the delaminated cross arms are not easily detected from the ground.
- REV solutions: Cannot be implemented as these assets are still necessary to support the transmission system.

Studies/References:

Study Report Name (s): N/A
Sanction Paper No: N/A
Strategy No: N/A

Total Project Cost Breakdown: ($ thousands)

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	750	2,426	3,000	3,000	3,000	3,000	-	15,176
C060365	345kV Laminated Cross-Arm	OpEx	0	252	300	300	300	300	-	1,452
	Replacements	Removal	0	473	600	600	600	600	-	2,873
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment _X__ Conceptual ______ Planning ____ Project ______

Schedule:

The number of 345kV circuits inspected and the number of laminated cross arms replaced will vary based upon program funding. At some locations, the decision to replace the entire structure is most cost effective.

Begin Preliminary Engineering: N/A
Final Design Complete: N/A
Construction Start: N/A
In service date: N/A

C062469
Project Title: Backup UG Pumping Plant - Trinity
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: _X_ D/F: ____ Non Inf: ___ S/R: ____ Syst. Cap: _____

Program Name: N/A

Associated funding numbers: N/A

Description:

Trinity Substation is a distribution station serves downtown Albany networks and is supplied by four 115 kV pipe type cables; Riverside to Trinity #18 and #19 (two cables in a common trench) as well as Trinity to Albany Steam #5 and #9 (two cables in a common trench). This project will add a second pressurizing plant at the end of the Trinity-Albany Steam #5 and #9 underground cables at the Binghamton Street (Pearl Street) transition station for redundancy.

Project Justification:

The cable pressurizing plant at Trinity currently has a high level of internal redundancy including independent pumping ladders, partitioned reservoir, redundant AC station services, and a backup generator. However, in the event of a "common mode failure" affecting the entire pressurizing plant (fire for example), the pressure on all four cables would not be maintained which is a key element of the electrical insulation for the cables. During such an event, all four cables would have to be removed from service to prevent them from failing electrically and subsequently isolating Trinity Substation from its electrical supply.

Based on a review of the cable loadings and demands, the recommended alternative to improve reliability is to add a second pressurizing plant that would allow the Trinity-Albany Steam #5 and #9 underground cables to remain in service in the event of a failure at the Trinity pressurization plant. The Riverside substation could be supplied from the Menands-Riverside and Riverside-Reynolds Road circuits or a cross connection could be made at the Trinity substation to allow pressurization of all four cables.

Customer Benefit:

Customers will have a decreased reliability risk resulting from a "common mode failure" at the Trinity pressurization plant that could take the Riverside to Trinity #18 and #19, as well as the Trinity to Albany Steam #5 and #9, 115 kV cables out of service for an extended period of time. In the event of a common mode failure, Trinity Substation would not be able to serve customers connected to the downtown networks in the City of Albany. A planned resolution to a common mode failure would likely reduce the cost of unexpected repairs, expensive immediate restoration efforts, and offers the lowest lifetime cost approach for customers.

Alternatives:

The following alternatives were considered as part of conceptual engineering:

- Defer: This option would repair the existing equipment in the event of a failure. However, if additional changes are not made, a common mode failure at the existing Trinity pressurizing plant would result in a potential extended outage to a significant part of Albany. This option provides no protection against this common mode failure scenario and is therefore, not recommended.
- Install a second (back-up) pressurization plant at the Trinity Substation: There are two potential issues with this option. The first is that the Trinity substation is within a confined area. A major event causing the common mode failure may render both plants inoperable. The second is that the current layout of the substation yard may not allow adequate room and spacing for a second (back-up) pressurization plant. Therefore, this option was not recommended.
- Install a second (back-up) pressurizing plant at Riverside Substation: If a second pressurizing plant was installed for the Riverside-Trinity #18 and #19 circuits instead at Riverside Substation, it is expected that the current circuits feeding Riverside would not be able to handle the additional load of Trinity which is typically feed from Albany Steam through the Trinity to Albany Steam #5 and #9 cables.
- Install an independent transmission cable to Trinity: This option would install an additional underground cable to Trinity to provide a redundant service feed in the event of a Trinity pressurization plant failure. This option would be significantly more expensive than the recommend option and require significant permitting and siting efforts. Therefore, this option was not recommended.
- Re-cable one or more of the pipe-type cables with non-pipe cables: This option would replace one or more of the existing pressurized fluid filled pipe-type cables with a cable not requiring pressurized fluid. This option would be significantly more expensive than the recommended option, require long outage periods to replace, and may result in possible rating issues. Therefore, this option is not recommended.
- REV solutions: Cannot be implemented as assets are still necessary to support the transmission system.

Studies/References:

Study Report Name (s): N/A
Sanction Paper No: USSC-15-157
Strategy No: N/A

Total Project Cost Breakdown:

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	0	250	1,847	100	0	0	2,197
C062469	Backup UG Pump Plant - Trinity	OpEx	0	0	0	0	0	0	0	0
		Removal	0	0	0	0	3	0	0	3
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment ____ Conceptual _X_ Planning _____ Project ______

Schedule:

Begin Preliminary Engineering: October 2018
Final Design Complete: December 2019
Construction Start: January 2020
In service date: July 2020

C064726
Project Title: Lasher Road Substation
T: _X_ SubT: _X_ D: ___
Spending Rationale: A/C: _ Comm: ___ Cust: ___ DER: ___ D/F: ____ Non Inf: ___
Reliability: ___ Syst. Cap: _X

Program Name: N/A

Associated funding numbers: C064727 – Lasher Road Substation Land and Building
C043672 – Lasher Road Transmission Line
C065886 – Lasher Road Substation Land
CD00897 – Lasher Road Distribution Getaway
C068326 – Lasher Road 52 Feeder OH Phase 1
C068348 – Lasher Road Getaway Cable
C068327 – Lasher Road 53 Feeder OH Phase 1
C068346 – Lasher Road 53 Feeder OH Phase 2
C068347 – Lasher Road 53 Feeder OH Phase 3
C048968 – Balston-Randall-W. Milton 34.5kV Removal

Description:

This project is for the addition of a new 115kV switching station where the supply lines for Luther Forest from the west connect to the main 115kV north-south right-of-way serving the Northeast Region. The new station also includes the addition of a 115-13.2kV distribution transformer at the station with 13.2kV assets necessary to interconnect this with existing distribution system in the area, which will allow for the retirement of the Randall Rd 34.5-13.2kV station. The project will also allow for the retirement of sub-transmission lines between the Ballston Spa station that currently supplies Randall Rd station and provide a backup supply to the West Milton facility.

Project Justification:

This station will relieve exposure to potential post-contingency thermal overloads on the 115kV system in the Northeast Region by more evenly balancing the flow of power from the main north-south 115kV right-of way which supplies Luther Forest from the east.

This will also provide capacity for growth in the Northeast Region and Luther Forest and mitigate adverse effects on reliability associated with potential generation retirements which are presently a concern in the Northeast Region.

The Lasher Road station is needed to resolve the transmission concerns above, but it will also be used to supply a distribution transformer which will resolve concerns with the distribution and sub-transmission systems in the area. The Ballston, Swaggertown and Shore Road distribution substations have either outage exposure criteria violations or feeders that are approaching their summer normal ratings. Lasher Road station will alleviate those concerns by providing additional 13.2kV feeder ties between all three stations, plus it will absorb some of their load relieving the thermal overload concerns.

Further, there are asset concerns regarding the Ballston-Randall Road #9 line, which has approximately two (2) miles of deteriorated steel structures and is located in areas that are very difficult to access and maintain. The addition of the distribution transformer at Lasher Road will allow for the retirement of this line along with the associated West Milton tap. In all, approximately 10 miles of 34.5kV sub-transmission line will be retired.

Customer Benefit:

The need for a 115kV switching station and a new distribution station to serve local customers were combined to create efficiencies in design and amount of property needed to construct the project.

Resolution of concerns with exposure to post-contingency thermal overloading of the 115kV system in the Northeast Region increases capacity and reliability on the transmission and distribution system in the area as well as decreases dependence on local generation in the Northeast Region which benefits tens of thousands of customers.

Without this project, concerns will remain with transmission thermal performance in the Northeast Region, the capacity to serve growing demand from the transmission and distribution system in the region, asset condition of the distribution system in the area, and reliance on generation within the region for adequate reliability.

Alternatives:

The following alternatives considered are more costly and less effective:

- Reconductoring approximately 7.5 miles of the 115kV Luther Forest – Eastover Road #308 and Battenkill – Eastover Road #10 Lines between Tower 305 and Tower 355, with 1113kcmil ACSR "Finch" conductor, and coordinating this with a reconductoring by New York State Electric and Gas Corporation ("NYSEG") of a 4.2-mile portion of its section of the #308 line between Tower 305 and NYSEG's Mulberry Substation, with 1113kcmil ACSR "Finch" conductor. This alternative would also include the replacement of the existing shield wires with two 3/8" 7-strands EHS for National Grid's portion of the reconductoring.
- Addition of a new 115-13.2kV distribution station in the Ballston area: Together with infrastructure to interconnect this with the distribution system in the area, this would also be required to resolve distribution concerns above.
- DER/NWA Alternative: The Company's Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company's evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

Studies/References:

Study Report Name (s): Technical Scope Document – Lasher Rd New 115kV Station v2
Sanction Paper No: USSC-12-191 v2
Strategy No: N/A

Total Project Cost Breakdown:

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	1,840	6,000	8,000	2,500	0	0	0	18,340
C064726	Lasher Road Substation	OpEx	1	0	0	0	0	0	0	1
		Removal	0	0	0	0	0	0	0	0
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	40	1,150	300	90	0	0	0	1,580
C064727	Lasher Road Substation LAB	OpEx	0	0	0	0	0	0	0	0
		Removal	0	0	0	0	0	0	0	0
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	187	728	445	226	0	0	0	1,586
C043672	Lasher Road Transmission Line	OpEx	1	15	9	0	0	0	0	25
		Removal	0	8	5	0	0	0	0	12
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	104	250	0	0	0	0	0	354
C065886	Land - Lasher Road Substation	OpEx	0	0	0	0	0	0	0	0
		Removal	0	0	0	0	0	0	0	0
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	76	368	367	0	0	0	0	811
CD00897	Lasher Road - New Station	OpEx	16	41	0	0	0	0	0	57
	Distribution Getaway	Removal	16	45	0	0	0	0	0	61
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	315	492	315	0	0	0	1,122
C068326	Lasher Road - 52 Feeder OH	OpEx	0	37	58	37	0	0	0	132
	Phase 1	Removal	0	19	29	19	0	0	0	67
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	172	172	0	0	0	0	344
C068348	Lasher Road - Getaway Cable	OpEx	0	0	20	0	0	0	0	20
		Removal	0	0	10	0	0	0	0	10
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	0	0	985	0	0	0	985
C068327	Lasher Road - 53 Feeder OH	OpEx	0	0	0	116	0	0	0	116
	Phase 1	Removal	0	0	0	58	0	0	0	58
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	0	0	0	585	0	0	585
C068346	Lasher Road - 53 Feeder OH	OpEx	0	0	0	0	69	0	0	69
	Phase 2	Removal	0	0	0	0	34	0	0	34
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	0	0	0	0	1,600	0	1,600
C068347	Lasher Road - 53 Feeder OH	OpEx	0	0	0	0	0	188	0	188
	Phase 3	Removal	0	0	0	0	0	94	0	94
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	0	0	0	0	0	0	0
C048968	Balston-Randall-W. Milton 34.5kV	OpEx	0	0	0	0	0	0	0	0
	Removal	Removal	0	25	0	1,500	1,000	0	0	2,525
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment ____ Conceptual ___ Planning _X_ Project ______

Schedule:

Begin Preliminary Engineering:	October 2015
Final Design Complete:	September 2017
Construction Start:	October 2017
In-Service Date:	July 2019

C065766
Project Title: Seneca Terminal Reactor 71E Asset Replacement
T: __X_ SubT: ___ D: ____
Spending Rationale: A/C: _X__ Comm: ___ Cust: ___ DER: ___ D/F: ____ Non Inf: ___ Reliability: _X_ Syst. Cap: _____

Program Name: N/A

Associated funding numbers: N/A

Description:

Replace the #71E GE reactor at Seneca Station which has been identified by the Company's testing as being unreliable and following the same failure history symptoms as its sister unit, the #72E reactor damage/failure.

Project Justification:

The General Electric (GE) #72E reactor at Seneca Terminal Station failed in 2008 due to the reactor core grounds shorting out. GE stated in a letter their reactor design has an internal flaw in the reactor core grounds. The 72E reactor core limbs were rebuilt in 2008. This repaired the design flaw that lead to high temperature combustible gassing issues inside the reactor. These shunt reactors #71E & #72E are located approximately half-way between Elm Street and New Gardenville, functioning to absorb and counteract capacitive (leading) reactive power during lightly loaded conditions and to provide stability. Shunt reactors of this type are particularly effective in preventing overvoltage conditions on long underground transmission lines where there is an addition of large capacitance from line-to-ground built up during lightly loaded conditions.

Customer Benefit:

The pro-active replacement of a poor condition reactor that has a family history of failure with a new reactor will improve the station's reliability to supply load to customers.

Alternatives:

- Refurbishment: This option would be to undertake a major refurbishment of the reactor as opposed to replacement. This option is not recommended as components would need to be refurbished back to original design tolerances and replacement of any worn-out or degraded parts would need to be acquired. In addition, refurbishment may only provide a few years of additional life. Refurbishment is a one-off activity and cannot be repeated indefinitely, but refurbishment may have limited application where it is not possible to replace the transformer due to outage or other constraints.
- DER/NWA Alternative: The Company's Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and

potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company's evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

Studies/References:

Study Report Name (s): N/A
Sanction Paper No: N/A
Strategy No: N/A

Total Project Cost Breakdown:

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	91	0	989	1,278	0	0	0	2,357
C065766	Seneca Reactor 71E Replace	OpEx	0	0	31	40	0	0	0	72
		Removal	0	0	21	27	0	0	0	48
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment ___ Conceptual ______ Planning __X___ Project ______

Schedule:

Begin Preliminary Engineering: April 2019
Final Design Complete: August 2019
Construction Start: November 2019
In service date: March 2020

C068850 Project Title: Menands #10/#15 Reconductoring
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: ___ Comm: ___ Cust: ___ DER: ___ D/F: ____ Non Inf: ___
Reliability: ____ Syst. Cap: _X

Associated funding numbers: N/A

Description:

This project is for the reconductoring of 3.2 miles of the State Campus – Patroon - Menands #15 115kV circuit, between Menands station and structure #129A, and the reconductoring of 1.1 miles of the Wolf Road – Menands #10 115kV circuit between Menands station and structure #139.

Project Justification:

The Menands-State Campus-Patroon #15 and Wolf Road-Menands #10 115kV circuits are exposed to post-contingency overloading during summer peak conditions in 2016 and beyond for the opening of Albany Steam 115kV Breaker R7 or loss of Albany Steam 115kV Bus #1. This issue is exacerbated by the continued growth of the Center for Nanoscale Science and Engineering (CNSE), which must currently limit their projected growth until the project is completed. The proposed reconductoring will relieve the #10 and #15 lines from exposure to post-contingency overloading.

Customer Benefit:

Relieving the #10 line for the worst-case contingency would require approximately 18.5MW of load to be shed. Similarly, relieving the #15 line would require about 7MW of load to be shed for the worst-case single contingency.

The total load required to relieve the #10 and #15 for worst-case single contingencies in 2017 is therefore 25.5MW. This represents approximately 15,000 residential customers, which the proposed project would benefit directly.

Alternatives:

- Extending a new circuit from a station which is not already fed by #10 and #15 lines such as Rotterdam, Menands, or Alban: This would be more expensive and time-consuming compared with the recommended reinforcement.
- DER/NWA Alternative: The Company’s Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company’s evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

Studies/References:

Study Report Name (s): N/A
Sanction Paper No: USSC-15-282
Strategy No: N/A

Total Project Cost Breakdown:

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	50	500	5,000	500	0	0	0	6,050
C068850	Menands #10/#15 Reconduct	OpEx	0	71	714	71	0	0	0	857
		Removal	0	143	1,429	143	0	0	0	1,714
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment ____ Conceptual _X_ Planning _____ Project ______

Schedule:

Begin Preliminary Engineering: February 2017
Final Design Complete: January 2018
Construction Start: April 2018
In service date: August 2018

C069437
Project Title: M9000 Replacement
T: _X_ SubT: ___ D: _X__
Spending Rationale: A/C: ___ Comm: _X__ Cust: ___ DER: ___ D/F: ____ Non Inf: ___ Reliability: ____ Syst. Cap: _____

Program Name: N/A

Associated funding numbers: C069687 – M9000 Replacement (Distribution)

Description:

A new Energy Management System (EMS) has recently been installed for the control centers, which requires the upgrade of RTUs with M9000 protocol to DNP3 protocol. This is a utility best practice based upon NERC Recommendation 28 released in response to the August 2003 blackout requiring the use of, among other things, more modern time-synchronized data recorders. Many in-service RTUs do not satisfy this requirement and obsolete RTUs, which have communications 'patches' in place, will not work reliably with the new Energy Management Systems ("EMS").

Project Justification:

The RTUs are being replaced under this program for the following reasons:

- The target M9000 RTUs are at risk of not communicating as needed since this protocol is outdated and is presently patch-worked into the new DNP3 EMS system. The patch is a temporary fix until the M9000 protocol RTUs can be corrected to function reliably with the DNP3 protocol.
- The target M9000 RTUs and equipment are legacy systems and have limited support by the manufacturer. Replacement parts are either difficult to obtain or unavailable. Failure of an RTU may be un-repairable and require a complete unplanned replacement on short notice. This situation could occur when data from the failing RTU is most critical, such as during system events, resulting in reduced reliability performance.

Customer Benefit:

The new RTUs will provide more timely and reliable data than their predecessors. In the event of a system disturbance, accurate data received in a timely manner is a necessity in the customer restoration process. Data received from the RTUs will quickly identify key devices that have failed or have been affected by the event, will expedite isolation of the problem, and reduce the duration of the outage and in some cases avoid expansion of the outage to other system components.

Furthermore, if the M9000 RTUs are not replaced, they will not reliably communicate with the new EMS which would then prevent the required modern supervisory control and data acquisition of the transmission system from taking place. This type of functionality is required to meet the reliability needs of customers.

Alternatives:

- Do nothing: This would lead to reduced reliability because as existing RTUs fail their repair at some point will not be possible and the replacement would take a considerable amount of time.
- Postpone Installation for the M9000 RTUs: Any delay in this program upgrade/replacement will increase the likelihood of additional equipment failures in the future.
- DER/NWA Alternative: The Company's Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company's evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

Studies/References:

Study Report Name (s): Multiple Substation Engineering Reports
Sanction Paper No: N/A
Strategy No: N/A

Total Project Cost Breakdown: ($ thousands)

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	30	300	1,229	1,238	1,064	1,060	0	4,921
C069437	RTU M9000 Protocol Upgrades	OpEx	0	0	0	0	0	0	0	0
		Removal	0	0	38	38	33	33	0	142
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	876	1,263	1,629	1,299	1,281	0	6,348
C069687	RTU M9000 Protocol Upgrades	OpEx	0	0	0	0	0	0	0	0
		Removal	0	24	35	45	36	36	0	176
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment _X_ Conceptual ______ Planning _____ Project

Schedule:

The M9000 replacements are part of a revolving replacement program that continues through the term of the Capital Investment Plan (FY18-22) so the schedule will vary as the program progresses.

Begin Preliminary Engineering: N/A

Final Design Complete:	N/A
Construction Start:	N/A
In service date:	N/A

C069466 Project Title: Maplewood #19/#31Reconductoring
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: ___ Comm: ___ Cust: ___ DER: ___ D/F: ____ Non Inf: ___
Reliability: ___ Syst. Cap: _X

Associated funding numbers: N/A

Description:

This project is to reconductor 3.0 miles of double circuit 336.4 kcmil ACSR in the Maplewood-Menands #19 115kV and Maplewood-Reynolds Rd #31 115kV lines.

Project Justification:

The #19 and #31 circuits are exposed to post-contingency overloading during summer peak conditions beginning in 2017 and beyond. The proposed reconductoring will relieve these circuits from exposure to the most limiting N-1-1 scenarios.

Customer Benefit:

Relieving the #19 line for the worst-case N-1-1 contingency (which will occur in 2021) would require approximately 95MW of load to be shed. Relieving the #31 line for the worst-case N-1-1 contingency would require approximately 89MW of load to be shed from the same part of the transmission system.

The total load required to relieve the #19 and #31 lines for the worst-case N-1-1 scenarios in 2021 is 95MW. This represents approximately fifty six thousand residential customers which the proposed project would benefit directly.

Alternatives:

- Extending a new circuit from a station which is not already fed by the loops which the #19 and #31 are part of (Menands, or North Troy; for instance): This would be more expensive and time-consuming compared with the recommended reinforcement.
- DER/NWA Alternative: The Company's Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company's evaluation, the need addressed by this project satisfies the Suitability Criteria and will be evaluated for a potential NWA

Studies/References:

Study Report Name: 2015 Capital and Northeast Region Area Study (concerns verified and quantified with latest power-flow models above)
Sanction Paper No: N/A
Strategy No: N/A

Total Project Cost Breakdown:

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	38	754	4,524	4,524	0	0	9,840
C069466	Maplewood #19/#31 Reconduct	OpEx	0	0	107	646	645	0	0	1,398
		Removal	0	0	216	1,292	1,292	0	0	2,800
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment _X_ Conceptual ______ Planning _____ Project ______

Schedule:

Begin Preliminary Engineering: November 2019
Final Design Complete: September 2020
Construction Start: December 2020
In service date: March 2021

C069467
Project Title: Rosa Rd add 115kV Cap Bank
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: ___ Comm: ___ Cust: ___ DER: ___ D/F: ____ Non Inf: ___
Reliability: ___ Syst. Cap: _X

Associated funding numbers: N/A

Description:

This project installs a 115kV 54Mvar capacitor bank at Rosa Road Substation.

Project Justification:

The 115kV system between Rotterdam R16 and Maplewood R12 is exposed to post-contingency low voltage. For peak demand periods in 2021, voltage for the most-limiting single contingency in the area is 86%. The addition of the proposed capacitor bank relieves the concern with voltage performance vs. criteria in this area.

Customer Benefit:

The substations affected by post-contingency low voltage in this area by summer 2021 include Front St, Rosa Rd, GE R&D, Elnora, and Inman Rd. The total peak demand at these stations is approximately 120MW, which includes about 56,000 residential customers and GE Research and Development. The proposed capacitor addition resolves the aforementioned voltage-performance concerns for these customers.

Alternatives:

- Extending a new 115kV source into the area for improved voltage support: This was considered, but would be far more expensive in comparison to the recommended reactive compensation.
- DER/NWA Alternative: The Company's Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company's evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

Studies/References:

Study Report Name: 2015 Capital and Northeast Region Area Study (concerns verified and quantified with latest power-flow models above)
Sanction Paper No: N/A
Strategy No: N/A

Total Project Cost Breakdown:

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	0	60	1,900	0	0	0	1,960
C069467	Rosa Road Add 115kV Cap Bank	OpEx	0	0	0	0	0	0	0	0
		Removal	0	0	0	40	0	0	0	40
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment _X_ Conceptual ______ Planning _____ Project ______

Schedule:

Begin Preliminary Engineering: November 2018
Final Design Complete: April 2019
Construction Start: July 2019
In service date: March 2020

C069531
Project Title: Elbridge WoS Reactors
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: ___ Comm: ___ Cust: ___ DER: ___ D/F: ____ Non Inf: ___
Reliability: ____ Syst. Cap: _X

Program Name: N/A

Associated funding numbers: N/A

Description:

Install five (5) reactors at five stations on each of the lines extending west from Elbridge substation as well as on Woodard – Elbridge line #4.

Project Justification:

Transmission planning analyses indicate that generation changes in the western half of the state will result in significant constraints on facilities. Additional flow is expected from the Oswego region to compensate for these constraints and will overload the affected lines if the reactors are not installed.

Customer Benefit:

This project would allow the continued reliable operation of the system under the conditions reviewed in the contingency analyses.

Alternatives:

- Significant mileage of 115kV reconductoring (100+miles)
- An additional 345kV line between Clay and Pannell stations.
- DER/NWA Alternative: The Company's Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company's evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

Studies/References:

Study Report Name (s): N/A
Sanction Paper No: N/A
Strategy No: N/A

Total Project Cost Breakdown:

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
C069531	Elbridge WoS Reactors	CapEx	0	0	250	250	500	4,500	0	5,500
		OpEx	0	0	0	0	0	0	0	0
		Removal	0	0	0	0	0	0	0	0
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment _X_ Conceptual ______ Planning _____ Project ______

Schedule:

Begin Preliminary Engineering: May 2019
Final Design Complete: November 2020
Construction Start: April 2021
In service date: December 2021

C069538
Project Title: Huntley-Lockport #36 & #37 ACR
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: _X_ D/F: ____ Non Inf: ___ S/R: ____ Syst. Cap: _____

Program Name: Overhead Line Refurbishment Program - Asset Condition

Associated funding numbers: C074712 Damage/Failure Project in 2016

Description:

This project will address issues on the 115kV Huntley-Lockport #36 (T1440) and Huntley-Lockport #37 (T1450) transmission circuits. The overhead line details follow:

Total Length: The #36 and #37 lines are approximately 20.92 miles in length.
Conductor Types: 636 kcm AAC, 636 ACSR, 556.5 kcm AAC, 300 kcm BSCU, and 400 kcm BSCU
Total number of Structures: 268
Number of Wood Structure Units: 43
Number of Steel Structure Units: 225
Types of Structures: Double circuit, primarily consisting of steel flex towers for tangents and steel square bases for dead-ends
Earliest Asset Date: 1929
Conductor Clearance: Completed

This project was initiated to address broken strand issues found in the 556.5 kcm AAC "Dahlia" conductor adjacent to compression splices following numerous failures in 2015 and 2016. As a result of these failures, an aerial comprehensive inspection was undertaken in the summer of 2016 and the most urgent issues were corrected under Damage/Failure project C074712.

The budgeted project scope includes replacing 556.5 kcm AAC conductor and shield wire for 8.6 miles of the line to complement the damage/failure scope of project C074712.

Project Justification:

A refurbishment project is necessary based on the number of conductor failures adjacent to compression splices. Recent failures indicate the 556.5 kcm AAC conductor is failing due to fatigue at the leading edge of the conductor compression splices, believed to be triggered by stress concentrated at the neck of the splice, causing strands in the conductor to break. The C074712 damage/failure project only addressed the most urgent conditions. These circuits still have a large number of original compression splices remaining.

Customer Benefit:

Refurbishment is necessary to provide reliable service to approximately 40,000 customers served by distribution stations supplied by these lines.

This overhead line refurbishment program promotes safety and reliability by addressing asset condition issues and allowing the transmission lines to meet the governing National Electrical Safety Code (NESC) under which they were built by replacing deteriorating structures and line components that no longer structurally or electrically conform to the NESC.

Alternatives:

The following alternatives are under consideration as part of the conceptual engineering Step 0 process:

- Asset Condition Refurbishment with 8.6 miles of Re-conductoring: Replace the 556.5 kcm AAC, targeted structures and hardware.
- Replace Splices: Aerial comprehensive inspection identified the conductor with broken strands near the existing compression splices. Replace the balance of the splices. The drawback to this is for every splice that is removed, two new splices are installed.
- System Reconfiguration: This alternative may not be feasible for an asset condition type project. However, re-conductoring with ACSR or a hybrid conductor are potential options that will be explored to maintain or decrease weight on the tower arms.
- REV Solutions: Cannot be implemented as these assets are still necessary to supply the distribution stations supplied by the transmission lines.

Studies/References:

Study Report Name (s): N/A
Sanction Paper No: N/A
Strategy No: SG080 (Overhead Line Refurbishment Program)

Total Project Cost Breakdown: ($ thousands)

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	300	10,000	6,300	100	0		16,700
C069538	Huntley-Lockport 36 37 ACR	OpEx	0	0	1,000	630	0	0		1,630
		Removal	0	0	2,000	1,300	0	0		3,300
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment _X_ Conceptual ____ Planning _____ Project ______

Schedule:

Begin Preliminary Engineering:	August 2017
Final Design Complete:	March 2018
Construction Start:	July 2018
In service date:	March 2020

C069548
Project Title: Rotterdam - Add Reactors LN19/20
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: ___ Comm: ___ Cust: ___ DER: ___ D/F: ____ Non Inf: ___
Reliability: _X_ Syst. Cap: _X

Associated funding numbers: N/A

Description:

This project is to add 45mH reactors to the Rotterdam-Altamont #17 and Rotterdam-New Scotland #19 115kV lines.

Project Justification:

The addition of reactors will relieve exposure to overloads for single contingency and N-1-1 scenarios which affect the 115kV double-circuit path between Rotterdam and New Scotland formed by the Rotterdam-Altamont #17, Altamont-New Scotland #20, and Rotterdam-New Scotland #19 lines. This is a concern during summer operating seasons in 2017 and beyond.

Customer Benefit:

Relief by load shedding would require about 54MW of load to be shed for 2021 summer peak conditions. This represents the demand of approximately thirty two thousand residential customers.

Alternatives:

- Reconductor the #17, #19, and #20, by replacing 33.5 circuit miles of 4/0 Cu and 336.4 ACSR. The conductor to replace would include 16.8 miles of 4/0 Cu in the #19, 8.4 miles of 4/0 Cu and 336.4 ACSR in the #17, and 8.3 miles of 4/0 Cu and 336.4 ACSR in the #20: The cost of this alternative would be many times the cost of the proposed reactors.
- DER/NWA Alternative: The Company's Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company's evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

Studies/References:

Study Report Name: 2015 Capital and Northeast Region Area Study (concerns verified and quantified with latest power-flow models above)
Sanction Paper No: N/A

Strategy No: N/A

Total Project Cost Breakdown:

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	200	2,360	100	0	0	0	2,660
C069548	Rotterdam - Add Reactors Lines	OpEx	0	0	0	0	0	0	0	0
	19/20	Removal	0	0	68	0	0	0	0	68
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment ____ Conceptual _X__ Planning _____ Project ______

Schedule:

Begin Preliminary Engineering: March 2018
Final Design Complete: August 2018
Construction Start: December 2018
In service date: March 2019

C069570
Project Title: Upgrade Comm. Equip Verizon Retirement
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: ___ Comm: _X_ Cust: ___ DER: ___ D/F: ____ Non Inf: ___
Reliability: _X_ Syst. Cap: _____

Program Name: N/A

Associated funding numbers: N/A

Description:

This project is a placeholder for migrating analog leased communication circuits owned by Verizon to Verizon DS1 digital circuits and/or National Grid owned digital networks.

Project Justification:

Verizon will be phasing out analog leased communication circuits used by National Grid for the protection of its transmission lines. The Company has already seen increases in monthly recurring costs and a steady decline in circuit repair services from Verizon for analog circuits.

A solution proposed by Verizon to convert analog to their digital circuits does not meet all of the communications requirements outlined by National Grid's Protection Engineering. Furthermore, Verizon Fiber is not available everywhere, so at some Company substations we would not have access to Verizon Fiber, giving rise to the need for a Company-owned private/microwave network. Historically, Verizon customers are given about 18 to 24 months to migrate circuits after Verizon has announced their phase-out plans.

Customer Benefit:

Upgrade of analog leased communication circuits is necessary to maintain reliability across the system by providing high-speed relay protection typically used on bulk power. In addition, migrating to digital circuit technology will enhance disaster recovery abilities, allowing communication circuits to be restored and rerouted faster during outages.

Alternatives:

A Telecom Engineering Service Firm has been contracted to study long term options and recommend an implementation plan to National Grid. The study is expected to be completed in FY18.

Studies/References:

Study Report Name (s): N/A
Sanction Paper No: N/A
Strategy No: N/A

Total Project Cost Breakdown:

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	50	198	500	5,000	5,000	6,995	40,000	57,743
C069570	Upgrade Communications Equip	OpEx	0	0	0	0	0	0	0	0
	Due to Verizon Retirements	Removal	0	0	0	263	263	368	2,000	2,894
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment _X_ Conceptual ______ Planning _____ Project ______

Schedule:

Begin Preliminary Engineering: April 2017
Final Design Complete: April 2018
Construction Start: April 2019
In service date: December 2029

C075723
Project Title: Border City – Elbridge #15/#5 ACR
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: _X_ D/F: ____ Non Inf: ___ S/R: ____ Syst. Cap: _____

Program Name: Overhead Line Refurbishment Program - Asset Condition

Associated funding numbers: C030889 Pannell-Geneva (Border City) #4/#4A ACR
C047816 Mortimer-Pannell #24 #25 ACR

Description:

This asset condition project will address asset condition issues on the Border City-Elbridge #15 (T2260) 115kV line from the NYSEG Border City Tap to the NYSEG Auburn/State St Tap. The de-energized Mortimer-Solvay #5 69kV line, which shares the same double circuit transmission structures as the 15 line along this segment, will be removed. Because the segment from the NYSEG Auburn/State St. Tap to Elbridge is currently being rebuilt as part of the NYSEG Cayuga Article VII Reinforcement Project, no work is being proposed on this section.

The following are details regarding the circuit:

Total Length: 21.01 miles from the Border City Tap to the Auburn/State St. Tap. The Mortimer-Solvay #5 circuit is de-energized the entire length.
Conductor Types: 336.4 kcm ACSR 30/7 "Oriole"
Total number of structures: ~ 197 (between Border City-State St Tap)*
Types of Structures: Double circuit steel flex towers for tangents and double circuit steel square base towers for dead-ends
Installation Date: 1907 (earliest date in PowerPlant)
Conductor Clearance: To be performed concurrently with ACR

*The number of structures in the project is approximated because the property records information for this line dates back to when the line was referred to as Geneva–Geres Lock #15 Auburn.

The budgeted scope of this project includes the removal of existing conductor and hardware on the de-energized #5 line side of the towers, and re-conductoring the #15 line, including shield wire replacement for 21.01 circuit miles with a hybrid conductor so the existing towers can be reused. It is assumed that none of the wood structures and 5% of the steel towers will require replacement. New permanent access roads will be added to upland areas.

Project Justification:

A limited field inspection was performed by Transmission Asset Management (TAM) in 2016. The insulator attachments plates or vangs in these 1907 vintage towers may be elongating and in need of replacement as well as other hardware components. Concurrently, Transmission Planning is evaluating these circuits for potential re-conductoring based on potential generator retirement scenarios.

The Oriole conductor on this line is a similar vintage to conductor on the Mortimer-Pannell #24/#25 line, which was tested in October 2016, and found to have the zinc galvanizing bonded to the steel core almost completely eroded away.

According to the Company's Incident Data System ("IDS"), the Border City–Elbridge #15 line has had thirteen (13) outages between 4/26/2011 & 7/25/2016 with two (2) of them lock-outs.

Customer Benefit:

The #15 circuit serves National Grid's Elbridge station which ties with the Pannell-Geneva #4/#4A to transmit power cross-state. The #15 line serves two NYSEG stations - Border City and Hyatt Rd.

The #15 circuit is a key element in the west to east power flow of the 115kV transmission network.

Alternatives:

The following alternatives are under consideration as part of the Step 0 process:

- System Reconfiguration: This alternative is not feasible for an asset condition type project. However, if NYSEG and/or RGE were to construct their own cross-state lines the scope of this project could be reevaluated.
- REV solutions: The majority of the #15 circuit is contained within the NYSEG franchise area. It is possible that a NWA type project, if cited in the correct area, could reduce but not completely eliminate the scope of this project.

Studies/References:

Study Report Name (s): N/A
Sanction Paper No: N/A
Strategy No: SG080 (Overhead Line Refurbishment Program)

Total Project Cost Breakdown:

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	0	300	1,000	3,000	0	36,700	41,000
C075723	Border City-Elbridge #15/#5	OpEx	0	0	43	143	429	0	3,500	4,114
		Removal	0	0	86	286	857	0	7,000	8,229
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment __X__ Conceptual ___ Planning _____ Project ______

Schedule:

Begin Preliminary Engineering:	March 2019
Final Design Complete:	December 2020
Construction Start:	April 2023
In service date:	May 2025

C076214
Project Title: Edic: Protection Migration
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: _X_ Comm: ___ Cust: ___ DER: ___ D/F: ____ Non Inf: ___
Reliability: ____ Syst. Cap: _____

Program Name: N/A

Associated funding numbers: N/A

Description:

This project is for replacement of the remaining protection and control equipment inside the original control house to the new control house. This equipment would include the bus differential relays, line protection relays, transformer protection relays, and circuit breaker controls.

Project Justification:

The Edic substation is a 345kV breaker- and-a-half substation with three (3) transformers which are interconnected with the Porter substation. One (1) is a 345kV–230kV bank and two (2) are 345kV–115kV banks. There are six (6) transmission line connections.

A recent project at Edic substation was completed which included the installation of a new control building that, when originally designed, was prepared to handle the new protection and control equipment. This project also upgraded three (3) of the transmission lines' protection equipment with some additional work to upgrade the circuit breaker equipment as well. All of this new protection and control equipment is already in the new house.

The remaining protection and control equipment in the original control house is original to the construction of Edic substation, which is early 1960s vintage. The remaining relays have limited spare parts, and limited manufacturer support. There remains one transmission line "A" and "B" protection package that is part of the obsolete relay replacement strategy which, if not done under this project, would be done under the relay replacement program.

The replacement of the equipment will place the protection and control equipment within the new control house and allow the retirement of the last remaining secondary wiring originally installed at the substation.

Customer Benefit:

This program will improve the overall reliability of the relay protection system which is essential to minimize the impact of faults on the system. In addition, the replacement relays will have the capability of providing fault and operational data which is currently not available. This data can be used in the future when it comes to analyzing and improving the system as a whole. Both of these factors will promote reliable customer service.

Alternatives:

The following alternatives will be considered in conceptual engineering:

- Do Nothing: This is not recommended since it would leave deteriorated and poor conditioned assets operating. Also, the protection schemes would be interconnected between the new control building and the original control building.
- DER/NWA Alternative: The Company's Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company's evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

Studies/References:

Study Report Name (s): N/A
Sanction Paper No: N/A
Strategy No: N/A

Total Project Cost Breakdown: ($ thousands)

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	0	600	1,100	500	0	0	2,200
C076214	Edic Station Protection Migration	OpEx	0	0	0	0	0	0	0	0
		Removal	0	0	0	0	0	0	0	0
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment _X_ Conceptual ___ Planning _____ Project ______

Schedule:

Begin Preliminary Engineering: October 2018
Final Design Complete: August 2019
Construction Start: January 2020
In service date: July 2020

C076218
Project Title: Oswego - 345kV Asset Separation/Replacement
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: _X_ Comm: ___ Cust: ___ DER: ___ D/F: ____ Non Inf: ___
Reliability: ____ Syst. Cap: _____

Program Name: N/A

Associated funding numbers: C076983 – Oswego 345kV Asset Separation & Replacement Control House

Description:

The project scope includes the replacement of protection and control equipment from the NRG owned Oswego steam plant to a new 345kV control building with an "A" and "B" control room and installation of NERC requirements.

In addition, a new "A" and "B" cable path for the 345kV portion of the yard will be installed to connect the assets to the new control house.

Project Justification:

This facility is a 345kV, 115kV, and a 34.5kV substation that interconnects to the Oswego steam plant, which allows the flow from the Oswego steam plant to the Oswego area and the Syracuse area. Presently, there is an asset separation/replacement project for the 115kV and 34.5kV portion of the substation (C043426).

The 345kV substation control house is full to capacity and cannot accommodate additional equipment to complete an asset separation and/or the installation of the physical security requirements. The control house is approximately 40 years of age which is the anticipated life-span for a metal constructed building. In addition, a number of relays, controls, and telecommunications are still within the NRG owned steam plant including the remote terminal unit (RTU) for the 345kV yard must be relocated.

The lack of direct access to NRG's control room within the Oswego steam plant limits the Company's control over the conditions for the shared assets.

Customer Benefit:

The planned separation/replacement of these substation assets reduces the likelihood of an in-service failure, which can lead to long-term interruptions of the transmission system as well as customer outages.

Alternatives:

The following were considered as part of conceptual engineering:

- Do Nothing: This is not recommended since the National Grid assets would remain within the NRG owned steam plant and the installations of the NERC requirements would still require a new control house.
- DER/NWA: The Company's Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company's evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

Studies/References:

Study Report Name (s): Substation Conceptual Engineering for Oswego 345kV Asset Separation/Replacement
Sanction Paper No: TBD
Strategy No: N/A

Total Project Cost Breakdown: ($ thousands)

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	50	700	2,150	0	0	0	2,900
C076218	Oswego 345kV Asset Separation	OpEx	0	0	0	0	0	0	0	0
	and Replacement	Removal	0	0	50	275	0	0	0	325
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	100	400	2,000	0	0	0	2,500
C076983	Oswego 345kV Asset Separation	OpEx	0	0	0	0	0	0	0	0
	and Replacement Control House	Removal	0	0	0	0	0	0	0	0
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment ____ Conceptual _X_ Planning _____ Project ______

Schedule:

Begin Preliminary Engineering: June 2017
Final Design Complete: November 2018
Construction Start: January 2019
In Service Date: March 2020

C076621
Project Title: Priority OHL Transmission Switch Replacements
T: __X__ SubT: ___ D: ____
Spending Rationale: A/C: __X__ D/F: ____ Non Inf: ___ S/R: ____ Syst. Cap: _____

Program Name: Priority OHL Transmission Switch Replacements

Associated funding numbers: N/A

Description:

The Transmission Control Center (TCC) has advised of the operational importance of maintaining full load break capabilities with key switches. This program will address the replacement of switches that no longer operate as designed and are considered to be a priority by the TCC.

Project Justification:

The Transmission Control Center (TCC) has notified Asset Management of a number of overhead line switches which are operationally important for reliability that have been yellow-tagged as being inoperable or difficult to operate. Leaving tagged switches inoperable for long periods of time, or removing them, leaves the transmission system operationally less flexible. In some cases, this is not acceptable for emergency system operations.

The Company has formed a NY Transmission Line Priority Switch Replacement team which meets quarterly to discuss line switches on the system that have been experiencing operational issues and are a priority to the TCC. This switch replacement program is targeted for the replacement of three switches per year as required.

Customer Benefit:

Improperly functioning line switches prevent the transmission system from being operated efficiently and, in some cases, not acceptable for emergency system operations. Inoperable line switches may prevent the timely restoration of service to customers following a fault on the line.

Alternatives:

Given the safety and reliability concerns with inoperable transmission line switches, alternatives to replacement are minimal. Constant adjustment of switches in the field would require multiple outages at high cost without solving the cause of the problem.

Studies/References:

Study Report Name (s): N/A
Sanction Paper No: N/A
Strategy No: N/A

Total Project Cost Breakdown: ($ millions)

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	630	630	630	630	630	-	3,150
C076621	NY Priority OHL Tran Switch	OpEx	0	90	90	90	90	90	-	450
	Replacements	Removal	0	180	180	180	180	180	-	900
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment __X__ Conceptual ____ Planning _____ Project ______

Schedule: (This will result in individual projects each having their own schedules based on outage availabilities.)

Begin Preliminary Engineering: N/A
Final Design Complete: N/A
Construction Start: N/A
In service date: N/A

C076672
Project Title: Osprey Mitigation/Avian Protection
T: X SubT: ___ D: ____
Spending Rationale: A/C: __ D/F: __ S/R: X Syst. Cap: ___

Program Name: Osprey Mitigation/Avian Protection

Associated funding numbers: N/A

Description:

To lessen continued line interruptions on the Company's transmission network due to the growing population of Ospreys between the months of April and September, when they are active in New York State, an Osprey Mitigation/Avian Protection Program is being implemented to add nesting platforms either to existing structures or adjacent wood poles. This program will be in addition to including Osprey mitigation efforts in project scopes of transmission line refurbishment projects for lines in active Osprey regions.

Project Justification:

Ospreys are birds of prey that build large nests of sticks atop transmission structures that can reach 4-7 feet in diameter and similar height. The nests typically weigh four hundred pounds, although larger nests have been reported at up to seven hundred pounds. Interruptions can occur when the nests come into contact with energized conductor or the bird droppings cause an arc between phase conductors.

There are growing populations of Ospreys in the Adirondack, Central and Southwest regions of New York. The Company has addressed line outages caused by Ospreys on the Sleight-Auburn #3 115kV line by adding ten new platforms atop wood H-frame structures, which is a proven alternative for the Ospreys to nest on as long as that nesting site is the highest point in the area. The Ticonderoga-Whitehall #3 and Ticonderoga-Republic #2 115kV lines also had platforms added to address interruptions.

In the last two years, the Company has seen seventeen interruptions directly related to Osprey nests and many more trips listed in the Incident Data System without a direct correlation, but patrols suspected were Osprey related. Aerial patrols in the fall of 2016 found approximately 80 Osprey nests atop transmission structures in the West, Central and Eastern regions of the Company's service territory. Without further monitoring and mitigation efforts, interruptions caused by Osprey nests will continue to increase in frequency.

Customer Benefit:

With Osprey populations increasing in New York, the bird is no longer classified as "endangered", but still considered "of special concern" by the Department of

Environmental Conservation (DEC) and should be protected. An Osprey Mitigation Program will reduce the risk of avian related interruptions and improve system reliability.

Alternatives:

Alternatives to an Osprey Mitigation Program include:

Targeted Nest Removal: When a nest reaches a "danger" level it is immediately removed by the Company's Transmission Line Services personnel with permission from the DEC. However, there are DEC restrictions as to when Osprey nests can be moved/removed. Thus, a nest may be growing to, or already identified as, a "danger" nest, but not be able to be addressed before an interruption occurs. Without a mitigation program proactively installing nesting platforms or deterrents, it will be difficult to stay ahead of the growing number of danger nests.

Studies/References:

Study Report Name (s): N/A
Sanction Paper No: N/A
Strategy No: N/A

Total Project Cost Breakdown: ($ Thousands)

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	300	300	300	300	300	-	1,500
C076662	Osprey Mitigation - Avian	OpEx	0	30	30	30	30	30	-	150
	Protection	Removal	0	60	60	60	60	60	-	300
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment _X_ Conceptual ______ Planning _____ Project ______

Schedule: (This is an ongoing annual program that will result in individual projects each having their own schedules.)

Begin Preliminary Engineering: N/A
Final Design Complete: N/A
Construction Start: N/A
In service date: N/A

C077034
Project Title: Albany-Greenbush 1 2 Reconductoring
T: _X_ SubT: ___ D: ____
Spending Rationale: A/C: ___ Comm: ___ Cust: ___ DER: ___ D/F: ____ Non Inf: ___
Reliability: ___ Syst. Cap: _X

Associated funding numbers: N/A

Description:

This project is to reconductor three (3) miles of double-circuit 605 kcmil ACSR on the Albany-Greenbush #1 and #2 115kV lines with 795 kcmil ACCR conductor.

Project Justification:

The reconductoring is a required System Upgraded Facility (SUF) resulting from a generator interconnection: Bethlehem Energy Center (BEC) Uprate NYISO Interconnection Q403. Although the cost is typically BEC's responsibility per normal process, the Company is considering a $4M contribution to the project, approximately 50% of the cost of this SUF, because the SUF has the advantage of mitigating adverse effects associated with the potential retirement of a generator identified in the Generator Retirement Study.

Customer Benefit:

This reconductoring project supports both a planned uprate by BEC to 835MW and the potential retirement of a large generator in the Capital Region. BEC's output alone represents the residential peak demand of about 490,000 customers.

Alternatives:

- Building new circuits to relieve the #1/#2: This would be more costly and time consuming, if even feasible.
- DER/NWA Alternative: The Company's Non-Wires Alternative (NWA) Suitability Criteria considers the driver/spending rationale, timeframe, and potential costs to address a system need in determining whether that need can practicably be addressed with an NWA. Based on the Company's evaluation, the need addressed by this project does not satisfy one or more element of the Suitability Criteria and will not be evaluated for a potential NWA.

Studies/References:

Study Report Names: Class Year 15 Facilities Study-Part 1 (6/23/16), Generator Retirement Contingency Planning Analysis - Phase 2 (1/28/16)
Sanction Paper No: N/A

Strategy No: N/A

Total Project Cost Breakdown:

Number	Name	Spend	Prior Yrs	FY18	FY19	FY20	FY21	FY22	FY23+	Total
		CapEx	0	100	4,000	0	0	0	0	4,100
C077034	Albany-Greenbush 1 2	OpEx	0	0	400	0	0	0	0	400
	Reconductoring	Removal	0	0	800	0	0	0	0	800
		CIAC/Reimbursement	0	0	0	0	0	0	0	0

Estimate Grade:

Investment ____ Conceptual ______ Planning _____ Project _X

Schedule:

Begin Preliminary Engineering: August 2017
Final Design Complete: February 2018
Construction Start: April 2018
In service date: June 2018

(Note: schedule remains to be developed with BEC)