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:

Gas Infrastructure and Operations Panel

Book 8

April 28, 2017

Submitted to:
New York State Public Service Commission
Case 17-E-____
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Submitted by:
Niagara Mohawk Power Corporation

nationalgrid

Testimony of
GIOP

Before the Public Service Commission

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID

Direct Testimony

of

Gas Infrastructure and Operations Panel

Dated: April 28, 2017

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I. Introduction and Qualifications

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

A. The Panel consists of Ross W. Turrini, Johnny Johnston, John S. Stavrakas, and Keri Sweet Zavaglia.

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

A. My name is Ross W. Turrini. My business address is 25 Hub Drive, Melville, New York 11747.

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

A. I am employed by National Grid USA Service Company, Inc. ("Service Company"), a subsidiary of National Grid USA ("National Grid"), as the Senior Vice President for Gas Process and Engineering. I oversee approximately 2,735 employees and $6 billion of gas infrastructure assets serving over 3.6 million customers in New York, Massachusetts, and Rhode Island.

In New York, National Grid owns and operates three gas distribution companies that provide retail gas service to more than 2.4 million customers: Niagara Mohawk Power Corporation d/b/a National Grid ("Niagara Mohawk" or the "Company") serves areas of eastern and central New York, The Brooklyn Union Gas Company d/b/a National Grid NY ("KEDNY") serves Brooklyn, Staten Island and parts of Queens in New York City, and KeySpan Gas East Corporation d/b/a National Grid ("KEDLI") serves customers on Long Island and the Rockaway Peninsula in Queens. I am responsible for all aspects of the performance of National Grid's New York gas networks, including emergency/storm response, gas engineering, construction activities, and the operation and maintenance of gas transmission and distribution facilities.

Q. Please describe your educational background and business experience.

A. I received a Bachelor of Science in Civil Engineering from the United States Military Academy at West Point in 1985. I have worked for National Grid and its predecessor companies, the Long Island Lighting Company ("LILCO") and KeySpan Corporation ("KeySpan"), for 22 years in various roles in engineering, operations, and procurement. Prior to joining National Grid, I spent five years as an Officer in the United States Army Corps of Engineers and three years in engineering and construction roles at Brown & Root Services Corporation, an international engineering, procurement and construction company.

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

A. Yes. I submitted pre-filed testimony in Cases 16-G-0058 and 16-G-0059 (the "2016 KEDLI and KEDNY Rate Cases").

Q. Mr. Johnston, please state your full name and business address.

A. My name is Johnny Johnston. My business address is One MetroTech Center, Brooklyn, New York 11201.

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

A. I am employed by Service Company. Effective January 1, 2016, I was appointed Senior Vice President for National Grid's Gas Business Enablement ("GBE") Program. Immediately prior to serving in my current role, I served as the Vice President of Customer Meter Services where I oversaw more than 2,400 personnel supporting National Grid's electric and gas distribution businesses in the U.S. With respect to the New York gas business, I was responsible for all field service personnel who provide gas emergency response, meter related activities (including meter installation and removal) and field operations related to billing (including meter reading, bill investigations and collections). My responsibilities also included overseeing the gas dispatch centers.

Q. Please describe your educational background and professional experience.

A. I received a Master of Engineering Science from Oxford University in 2002 and a Master of Business Administration from Cranfield University in 2006. I have worked for National Grid for 19 years. I started in Network Design in National Grid's United Kingdom business before moving to Cleveland, Ohio to join GridAmerica LLC, a wholly owned subsidiary of National Grid, where I worked on transmission planning. I then moved to Salt Lake City, Utah to support a transmission project to deliver wind energy from Wyoming to California, before returning to the United Kingdom. Back in the United Kingdom, I worked in National Grid's Engineering Department and was responsible for Network Design, including renewable gas projects. I was then promoted to the Gas Distribution Executive Team to lead Customer Operations with responsibility for the gas call centers, resource planning, dispatch and mapping teams. I then became Chief of Staff for the global Chief Executive Officer before relocating to Brooklyn to lead Customer Meter Services.

Q. Have you previously testified before the Commission?

A. Yes. I submitted pre-filed testimony in the 2016 KEDLI and KEDNY Rate Cases.

Q. Mr. Stavrakas, please state your full name and business address.

A. My name is John S. Stavrakas. 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 Service Company as the Vice President for Gas Asset Management. I oversee approximately 95 employees and am responsible for asset management of gas infrastructure assets serving over 3.6 million customers in New York, Massachusetts, and Rhode Island. I am responsible for the asset management of National Grid's New York gas networks, including system planning, gas transmission engineering, pressure regulation and LNG engineering, and gas distribution engineering.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Engineering in Mechanical Engineering from the State University of New York in 1983. I have worked for National Grid and its predecessor companies (LILCO and KeySpan) for 30 years in various roles in engineering and operations. Prior to joining National Grid, I spent two years in the Operating Plants Division of Westinghouse Bettis Atomic Power

Laboratory. I currently hold Professional Engineering Licenses in the State of New York and Commonwealth of Massachusetts.

Q. Have you previously testified before the Commission?

A. Yes. In 2002, I testified on behalf of KeySpan in an Article X proceeding, Case 01-F-0761 (Spagnoli Road Energy Center). I also testified in other Article VII proceedings on behalf of LILCO prior to 2002.

Q. Ms. Zavaglia, please state your full name and business address.

A. My name is Keri Sweet Zavaglia. My business address is 300 Erie Boulevard West, Syracuse, New York 13202.

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

A. I am employed by Service Company as Vice President, New York Performance and Strategy. I am responsible for the performance management of the New York businesses (Niagara Mohawk, KEDNY, and KEDLI) and executing their business strategies.

Q. Please describe your educational background and experience.

A. In 1999, I received a Bachelor of Arts in Journalism, Public Relations and Advertising from Temple University. In 2002, I received a Juris Doctorate from the Temple University Beasley School of Law and then served as an Assistant District Attorney in Philadelphia, Pennsylvania. I have worked for National Grid for eleven years, primarily as an attorney in various roles in the New York Regulatory Legal Group. From January 2015 through March 2017, I served as the Acting Vice President of Gas Operations for Upstate New York, where I oversaw the approximately 300 employees responsible for maintenance, construction and damage prevention. In the beginning of 2016, I assumed my current role.

Q. Have you previously testified before the Commission?

A. Yes. I submitted pre-filed testimony in the 2016 KEDLI and KEDNY Rate Cases.

II. Purpose of Testimony

Q. What is the purpose of the Gas Infrastructure and Operations Panel's testimony?

A. The purpose of the Panel's testimony is to provide the Company's forecast of gas capital investments for the twelve-month period ending March 31, 2019 ("Rate Year") and the two subsequent twelve-month periods ending March 31, 2020 ("Data Year 1") and March 31, 2021 ("Data Year 2") (Data Year 1 and Data Year 2 are collectively referred to as the "Data Years"). The Panel discusses capital expenditures that will (i) increase the safety and reliability of the Company's gas network, (ii) modernize the Company's gas transmission and distribution infrastructure, and (iii) promote gas growth in a manner consistent with the Commission's policy objectives. The Panel will also discuss the Company's practices and policies for maximizing the efficiency of its capital construction program from planning and budgeting through the completion of construction.

The Panel's testimony provides an overview of the significant projects in the Company's gas capital plan, including retirement of leak prone pipe ("LPP"), a reinforcement project that will mitigate a significant system constraint and improve supply flexibility in the Albany area, and safety programs to address known system risks. The Panel's testimony also presents an overview of the Company's pipeline integrity and reliability programs that will improve the overall safety and reliability of the Company's gas system, and will also address recently enacted, as well as pending, pipeline safety regulations administered by the U.S. Department of Transportation ("DOT") Pipeline and Hazardous Materials Safety Administration ("PHMSA"). The Panel also discusses the Company's plans to expand gas service to customers through targeted capital investments.

Q. Does the Panel's testimony also address the Company's operations and maintenance ("O&M") programs?

A. Yes. In addition to capital investments in gas infrastructure, the Panel describes incremental labor (full time equivalent positions or "FTEs") and non-labor O&M expenses that the Company proposes in the Rate Year, the costs of which are not fully reflected in the twelve-month period beginning January 1, 2016 and ending December 31, 2016 ("Historic Test Year"). These expenses represent known and measureable changes from Historic Test Year expenses that are necessary to (i) improve system reliability, (ii) address new and emerging safety regulations, (iii) enhance customer service, and (iv) support the Company's capital investments. The Panel will also discuss the Company's staffing plan for the proposed new FTEs.

Q. Does the Panel address any other topics?

A. Yes. The Panel discusses the GBE Program, an initiative to develop and implement a comprehensive framework of new technology solutions and business process changes that will enhance gas safety, compliance, and customer service performance across National Grid's gas business. Among the core investments of the GBE Program are standardized asset and work management, scheduling, geographic information system ("GIS"), and field mobility solutions.

Q. Does the Panel sponsor any exhibits as part of its testimony?

A. Yes. The Panel sponsors the following exhibits that were prepared under its direction and supervision:

Exhibit __ (GIOP-1): Actual and Projected Capital Expenditures: Historic Test Year, fiscal year ("FY") 2018, Rate Year, Data Year 1, and Data Year 2

Exhibit __ (GIOP-2): Graph Comparing Actual and Projected Annual Investment Levels for FY 2014 – 2021, including the Historic Test Year

Exhibit __ (GIOP-3): Chart Summarizing Projected Leak Rates for LPP for Various Main Replacement Strategies

Exhibit __ (GIOP-4): Data Sheets for Significant Capital Programs. This exhibit includes summaries of the Company's significant capital projects/programs

Exhibit __ (GIOP-5): Incremental O&M Non-Labor Expenditures: Rate Year, Data Year 1, and Data Year 2

Exhibit __ (GIOP-6): Incremental Full Time Equivalent Positions by Function in the Rate Year, Data Year 1, and Data Year 2

Exhibit __ (GIOP-7) Hiring Plan for Incremental Full Time Equivalent Positions in the Rate Year, Data Year 1, and Data Year 2

Exhibit __ (GIOP-8): GBE Program High-Level Roadmap Showing Phased Implementation and Capabilities

Exhibit __ (GIOP-9): GBE Program Description of the Specific Projects, Capabilities, and Benefits that will go In-Service in the Rate and Data Years for Niagara Mohawk

Exhibit __ (GIOP-10): Incremental Operating Expenses for the GBE Program Allocable to Niagara Mohawk in the Rate Year and Data Years

Exhibit __ (GIOP-11): Additional Run the Business Costs to Niagara Mohawk to Support the GBE Program Post-Implementation

Exhibit __ (GIOP-12): Total U.S. Type I and Type II Savings Estimates (Capital and O&M) and Niagara Mohawk Allocated Type I Savings Estimates Identified in Connection with the GBE Program

The capital expenditures presented throughout the testimony and in the exhibits include cost of removal ("COR"), as applicable.

Q. How is the Panel's testimony organized?

A. The testimony is organized into the following sections:

- <u>Sections I and II</u> are introductory sections outlining the Panel's testimony.
- <u>Section III</u> provides an overview of the Company's capital investment and O&M program priorities and objectives, including the retirement of leak

prone mains and services and other key investments in reliability and pipeline safety. This discussion includes justification for the Company's gas capital and O&M expenditures for these programs and the public interest considerations served by their implementation.

- Section IV provides details on the Company's proposed capital investment program for the Rate Year and Data Years, including the Company's spending rationales, categories of capital investment, and specific work activities within each category.
- Section V describes the Company's O&M programs, including those targeted at current and emerging safety regulations and those necessary to carry-out the Company's proposed capital programs. Section V also describes O&M costs for damage prevention.
- Section VI describes the Company's investment in the GBE Program.

III. Capital and O&M Plan Objectives and Priorities

Q. Please describe the overall objective of the Company's infrastructure and operations plans.

A. The Company's gas infrastructure and operations plans are designed to provide safe and reliable gas delivery service to customers at reasonable costs. As shown on Exhibit __ (GIOP-2), over the last several years, the Company has increased investment to modernize and enhance the resiliency of its gas assets.

Significant capital investment over the next several years is required to ensure that the gas system continues to meet the demands of customers. The proposed plan includes capital and O&M spending to meet these needs and to satisfy state and federal regulatory requirements and goals, including retirement of LPP. In developing its capital and O&M plans, the Company balanced the need for spending to achieve safety, reliability, and service objectives with the need to manage costs and minimize impacts on customer rates.

Q. Why have the Company's capital expenditures increased over the last several years?

A. Several developments have required Niagara Mohawk and other natural gas distribution utilities to increase their annual capital expenditures. Notably, pipeline safety incidents, such as the tragic events in San Bruno, California, Allentown, Pennsylvania, and more recent incidents, including East Harlem, New York, have appropriately increased focus on pipeline safety and the need to carefully monitor and replace aging pipeline infrastructure. Recent weather events such as Superstorm Sandy, Hurricanes Irene and Lee, and the Polar

Vortex, and the expectation that similar events will continue to occur, require the Company to find ways to protect its facilities from severe weather.

Additionally, natural gas supplies are likely to be available to Niagara Mohawk and its customers now and for the foreseeable future at a significantly lower cost than the cost to develop alternative energy sources. To take advantage of the favorable gas supply dynamics, natural gas utilities are increasing their reliability and growth spending to offer the economic benefits of relatively inexpensive natural gas supplies to meet consumer demand.

The foregoing developments indicate that the Company must increase capital spending to modernize its gas transmission and distribution assets, increase the size and scope of its safety replacement and reliability programs, and sustain gas growth.

Q. How will the Company support this increased level of capital investment?

A. As the Company developed plans to modernize its gas assets, it also began to build and enhance its operations, engineering, resource planning, work management, and quality control organizations and capabilities to deliver increasing levels of capital investment.

The Company will further develop these capabilities in the Rate Year and Data Years by adding incremental labor resources to execute the capital plan and support the increased operations workload (discussed in Section V). The Company's efforts to develop its internal workforce are also discussed by the Human Resources Panel.

With regard to contractor resources, the Company has developed a procurement strategy that supports sustainable growth in qualified contractors to meet the work plan increases. To ensure adequate levels of qualified, skilled labor and the challenges around developing qualified contractors, the Company's resource plan includes the following elements:

- Establishing longer term contracts to enable contractors to plan and invest in hiring, training, facilities and equipment to meet the Company's construction needs.
- Providing greater work plan visibility to contractors on forecast crew requirements, which will enable them to develop the required capacity.
- Managing the work plan to limit seasonal variability to support a stable contractor workforce and promote worker retention.

The Company is working with contractors to develop new sources of skilled labor to build the workforce, including by recruiting prospective utility workers from community colleges, trade schools and veteran groups (as discussed in the Human Resources Panel's testimony).

Q. Does the Company require additional personnel in the Rate Year and Data Years to execute its capital and O&M programs?

A. Yes. The Company forecasts the need for an additional 78 FTE positions in the Rate Year and Data Years to support the additional capital investment, increasing O&M workload, and new programs discussed below. These FTEs include positions in customer meter services, engineering, project management, resource planning, instrumentation and regulation, damage prevention, and corrosion control. The cost of these FTEs will be charged to both capital and O&M programs based on the job function and nature of the work. Exhibit __ (GIOP-6) identifies the incremental FTE positions by function. Labor O&M associated with these FTEs is presented in the Revenue Requirements Panel's testimony and exhibits.

Q. How will the Company execute the hiring of these incremental FTEs?

A. The Company has developed a staffing plan that staggers hiring throughout the Rate Year and Data Years to support the forecast capital plan and O&M workload. This staffing plan is set forth in Exhibit __ (GIOP-7).

Q. Please describe some of the significant programs included in the capital plan.

A. As a whole, the capital plan represents the investments required to provide safe and reliable service to the Company's customers. Niagara Mohawk's marquee programs and projects include the following:

- Proactive Main and Service Replacement (LPP) Program
- Integrity Management Program ("IMP") and Integrity Verification Process ("IVP") Program
- Albany Loop Closure Project
- Pipeline 34 Replacement Project
- Transmission Services Removal Program
- Advanced Meter Infrastructure Program

These programs and projects are described in detail below and are included in Exhibit __ (GIOP-4). The Advanced Meter Infrastructure ("AMI") Program is described in the direct testimony of the AMI Panel.

A. <u>Proactive Main and Service Replacement (LPP) Program</u>

Q. What is the Company's proposal regarding its Proactive Main and Service (LPP) Replacement Program?

A. To reduce the risk of leaks and breaks, improve system performance and reliability, meet the Company's commitment to enhance customer satisfaction and reduce methane emissions, the Company has prioritized the retirement of older and higher-risk gas infrastructure – specifically, LPP and associated services that disproportionally contributes to leaks on Niagara Mohawk's system.

The existing plan, approved by the Commission in Case 15-M-0744, requires retirement of at least 98 total miles of LPP during calendar year ("CY") 2016 and CY 2017 (collectively). The Company's proposal is to (i) retire 50 miles of LPP per year on average for the Rate Year and Data Years and (ii) to begin retiring pre-1985 vintage Aldyl-A plastic mains and pre-1974 high-density polyethylene ("HDPE") services associated with its LPP inventory. Under the Company's proposal, all LPP will be eliminated by 2030, well ahead of the Commission's stated policy goal of full LPP retirement by CY 2035 (Case 15-G-0151).

Q. Please describe the inventory of LPP existing on the Company's system.

A. As of the end of CY 2016, the Company has approximately 675 miles of LPP in its remaining inventory comprised of: (i) unprotected (*i.e.*, non-cathodically protected) steel pipe whether bare or coated (ii) cast and wrought iron pipe, and (iii) Aldyl-A pre-1985 pipe. As would be expected, the Company has observed a significantly higher leak rate on its LPP inventory as compared to all other distribution facilities. While the current LPP inventory represents only eight percent of Niagara Mohawk's distribution system, LPP is responsible for 87 percent of leak repairs, excluding excavation damages. The current leak rate for all distribution piping is 0.07 leaks per mile, excluding damages from excavation. The current leak rate for LPP is 0.77 leaks per mile.

Q. Why is the Company proposing retirement of pre-1985 vintage Aldyl-A plastic mains and pre-1974 HDPE services associated with its LPP inventory?

A. Some early vintages of plastic pipe and services are known to have performance issues, including brittle cracking. Consistent with the KEDNY and KEDLI proactive LPP replacement programs, the Company proposes including pre-1985 vintage Aldyl-A plastic mains in the LPP inventory for the Proactive Main and Service Replacement Program. Additionally, since 2012, the Company has noted an increase in identified leaks occurring on pre-1974 HDPE services. Accordingly, these services should be removed in conjunction with the retirement of associated LPP. The Company's LPP replacement program proposal takes into account the addition of the pre-1985 Aldyl-A plastic mains and pre-1974 HDPE services in its commitment to eliminate all LPP from its system by 2030.

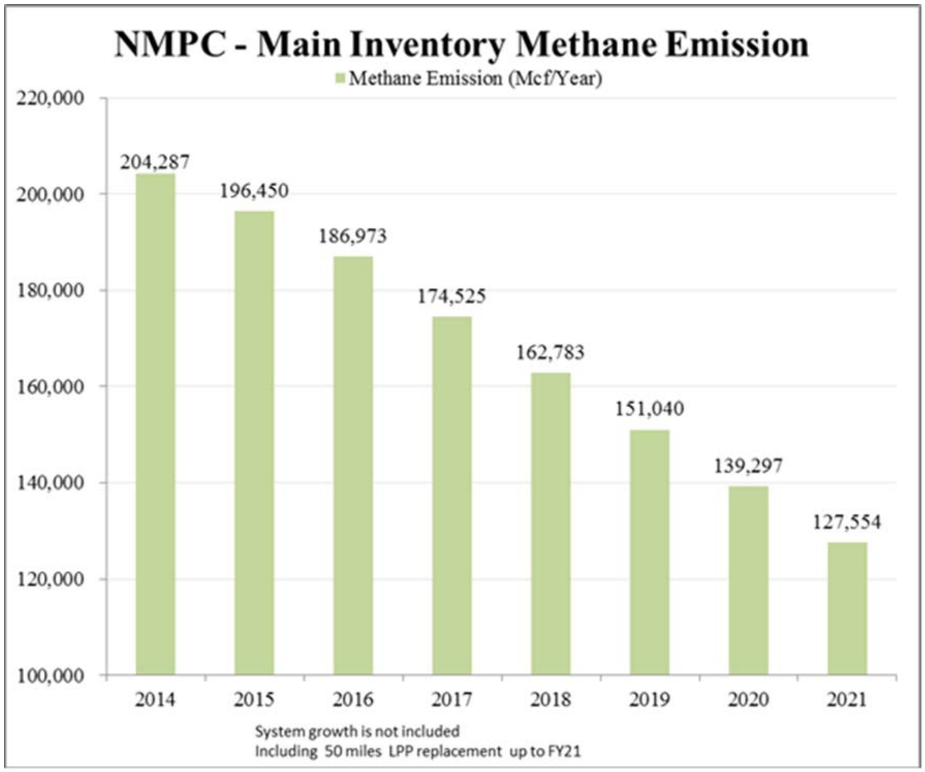
Q. How does the Company prioritize the retirement of main segments for the Proactive Main and Service Replacement Program?

A. Each year, the Company prioritizes retirement of LPP segments by using a risk ranking algorithm that is part of the Company's Distribution Integrity Management Plan ("DIMP") and the Company's Gas Operating Procedure for the Identification, Evaluation and Prioritization of Distribution Main Segments for Replacement (ENG04030). The Company's risk model calculates a relative risk score for each LPP segment based on specific performance data and localized incident probabilities and consequences, combined with calculated risk factors for the asset classes being evaluated. This risk-based algorithm, along with the Company's good engineering judgment, which takes all factors and risks into consideration in each case, form the foundation of the LPP retirement strategy.

Q. Is there an environmental benefit associated with the retirement of LPP?

A. Yes. Retirement of LPP reduces gas losses and fugitive emissions of methane. Table 1 provides a high-level estimate of potential methane emissions reductions over the next several years assuming the retirement of LPP pursuant to Niagara Mohawk's proposed program.

<u>Table 1</u>: Estimated Methane Emissions Reduction



In 2015, the Company changed its LPP retirement algorithm to include Type 3 leaks and service leaks, thereby enhancing the emissions reduction benefits of its Proactive Main and Service Replacement Program.

Q. Does the Company's Proactive Main and Service Replacement Program include projects to address low system pressure resulting from LPP retirements?

A. Yes. Beginning in the Rate Year, this program includes main work, such as installation of new main or replacement of non-leak prone distribution main, that is necessary to retire LPP. More than half of the remaining LPP inventory is located on the low pressure system, and LPP is often either a main feed to an area or is essential to maintaining minimum pressures on connected facilities. As the remaining LPP is retired or upgraded to medium pressure, low pressure pockets can occur on non-leak prone distribution main. The Company estimates that one mile per year of new main installation or non-leak prone main replacement will be necessary to enable LPP retirement.

Q. How does the Company address relocation of inside meters to outside in conjunction with the Proactive Main and Service Replacement Program?

A. In 2012, in the Company's last rate case filing (Case 12-G-0202), the Company agreed to establish a policy for relocating inside gas meters in conjunction with regular work activities performed inside customer premises pursuant to which the Company committed to relocating additional inside meters subject to certain exceptions. In early 2016, the Company implemented a further process improvement to eliminate the most common exception for not relocating an inside meter, service renewal by insertion. As a result, the Company relocated more meters outside in 2016 than in each of the prior two years. The Company expects the number of meter relocations to remain consistent for the next few years, including in the Rate Year and Data Years, and is not proposing further changes to the program at this time.

Q. What level of investment in the Proactive Main and Service Replacement Program is required in the Rate Year and Data Years to achieve the Company's LPP retirement goals?

A. As shown in Exhibit __ (GIOP-1), annual program spending is $48.1 million in the Rate Year and $49.4 million and $50.6 million in Data Years 1 and 2, respectively. The total capital cost of the Proactive Main and Service Replacement Program is based on a forecast LPP replacement unit cost of approximately $186 per foot for the proactive retirement of approximately 48 miles per year of LPP and associated services (the other two miles to meet the 50 mile/year base target are expected to be achieved through other programs, such as public works, reinforcements, and reliability programs), plus approximately $1 million per year to address the one mile of non-LPP reinforcements, adjusted for inflation.

Q. How does the Company manage the costs of its Proactive Main and Service Replacement Program?

A. To mitigate costs, retirement of LPP is coordinated with other programs (such as the public works, reinforcement and reliability programs) to capture efficiency savings and cost avoidance. Niagara Mohawk will look for more of these opportunities to deploy construction resources more efficiently and will identify areas of the gas network where entire LPP systems can be retired efficiently and cost effectively. The Company is also proposing an incentive, described in the Gas Safety Panel testimony, aimed at reducing unit costs for LPP retirement.

Q. What is the Company's proposal to recover the cost of retiring incremental LPP miles?

A. To encourage full retirement of LPP earlier than scheduled, the Company proposes a Gas Safety and Reliability Surcharge under which the Company would be allowed to recover a return on investment and depreciation expense associated with prudent investment in LPP retirement incremental to the level funded in base rates. Because the Company is committing to retire an average of 50 miles of LPP each year (with an associated negative revenue adjustment for failing to achieve the penalty target, as discussed by the Gas Safety Panel), permitting cost recovery for additional LPP retirements provides flexibility to target additional replacements when resources are available and other opportunities present to complete the work more cost effectively. The surcharge mechanism ensures that Niagara Mohawk will recover LPP retirement costs only to the extent it is successful in delivering its program.

The Gas Safety and Reliability Surcharge is discussed in more detail by the Gas Safety Panel, the Revenue Requirements Panel, Exhibit __ (RRP-9), and the Gas Rate Design Panel.

Q. Is the Company proposing an incentive regarding its retirement of LPP?

A. Yes. The Company is proposing a productivity incentive measuring the Company's ability to cost-effectively retire LPP (excluding LPP retired through other programs, such as public works), as well as an incentive for retirement of additional miles. The Gas Safety Panel discusses the Company's proposed incentive.

Q. Does the Company propose to continue reporting on LPP retirement?

A. Yes. The Company will continue to provide Department of Public Service Staff ("Staff") with visibility to the status of LPP retirement. The Company proposes to report to Staff on a quarterly basis, including main retired (feet, location), cost data, opportunistic retirements, and the status of the Company's LPP retirement work plan.

B. <u>Integrity Management and Integrity Verification Programs</u>

Q. What is the Company's IMP?

A. The Company's transmission pipeline IMP is a safety program mandated by the Pipeline Safety Improvement Act of 2002 and corresponding DOT regulations. The IMP identifies and addresses potential issues affecting the physical soundness of Company facilities before they become safety or performance issues. The Company conducts baseline and periodic reassessments of transmission facilities to identify and evaluate potential threats to "Covered Segments" of pipelines, *i.e.*, transmission pipelines that could affect High Consequence Areas (areas where a pipeline failure could have significant adverse consequences), as well as remediation of significant defects discovered during such assessments. In regions of the U.S. where older gas distribution systems are common, IMPs have become a key component of ensuring pipeline integrity.

Q. Please describe the IMP capital investments.

A. Table 2 shows the IMP investments that are necessary to support in-line inspections (*e.g.*, installation of pig launchers and receivers, and pipe reconfiguration/replacement) and to resolve issues discovered during pipeline inspections. The construction activities associated with these expenditures involve the installation of "hot tap" fittings, the reconfiguration of such fittings to allow in-line inspection ("ILI") passage, the construction of access points to allow tethered in-line inspection and, in some cases, the replacement of pipeline segments. Currently, 17 percent of the Company's DOT pipeline is ILI enabled. The Company's capital plan will result in 60 percent of the Company's DOT pipeline being ILI enabled. This will significantly improve the Company's ability to identify integrity issues.

Table 2: Integrity Management Program Capital Expenditures

($000)	FY19	FY20	FY21
Capital Expenditures	13,308	16,759	21,250

Q. Why does the forecast for IMP expenditures increase from the Rate Year to Data Year 2?

A. IMP spending can fluctuate significantly because of the IMP workplan. The IMP workplan began in 2002 based on initial assessments using the Company's existing risk model. Segments were prioritized for ILI enablement over a multi-year workplan based on a combination of their risk score and other relevant factors, such as facility characteristics or geography, to determine what work to do when. The workplan is updated annually and as required assessments are completed. Additionally, ILI projects typically consist of two years of design and procurement work followed by construction in the third year. This changes spending year to year depending on the projects in the workplan.

Q. What is the status of the pending federal regulations in this area?

A. The federal regulations in this area are evolving. In May of 2016, PHMSA issued a Notice of Proposed Rulemaking ("NPRM"), which proposes new pipeline safety regulations that include a requirement for increased inspection of IMP-covered pipelines utilizing ILI technology and an expanded definition of High Consequence Areas, as well as a host of other requirements. To meet these requirements, transmission pipelines must be ILI enabled.

There is some uncertainty regarding when PHMSA will issue its final rulemaking; however, it is possible that some version of the proposed regulations will become effective during the Rate Year or Data Years. Because the Company believes it is a prudent expenditure regardless of the implementation date, and in anticipation of PHMSA's new regulations expanding IMP, the Company believes that its proposed IMP program is a reasonable and conservative approach to managing pipeline integrity during the Rate Year and Data Years.

Q. What if the heightened requirements associated with the Pipeline Safety Act of 2011 do not become effective during the Rate Year or Data Years?

A. The Company is constantly evaluating the performance of the gas system and analyzing the need for capital investment and maintenance. Having spent considerable time examining the San Bruno, Allentown, East Harlem and other incidents, and having closely followed the legislative process that culminated in the Pipeline Safety Act of 2011, the Company is being proactive rather than reactive to address important safety issues and to incorporate lessons learned in its capital plan. These capital proposals are prudent investments that will improve system safety and performance. Moreover, these investments should go a long way toward satisfying the heightened safety requirements expected to result from the Pipeline Safety Act of 2011.

Q. What is covered in the Company's IVP Program?

A. The Pipeline Safety Act of 2011 also mandates that PHMSA establish rules requiring operators to demonstrate their pipelines are "fit for service" by reviewing construction records for each pipeline segment to confirm it is operating within design parameters. The May 2016 NPRM also proposes new rules regarding the maximum allowable operating pressure ("MAOP") and pressure testing requirements for existing pipelines, including (i) eliminating the exemption for establishing the MAOP of pre-1970 "grandfathered" pipe segments; (ii) mandating additional pressure testing or replacement for pipelines without adequate pressure test records; and (iii) requiring operators who lack certain records to establish material properties using approved methods (*e.g.*, cutting and testing pipe samples). In advance of a final rulemaking, PHMSA issued an advisory bulletin (ADB-11-01) directing operators to perform a detailed threat and risk analysis that includes a records review of their systems.

The Company's IVP program began in 2011 and includes thorough record reviews, pipeline replacement, and retirement of non-essential pipeline segments. As with the IMP, the IVP is based on the Company's assessment of system risks, while also incorporating PHMSA's proposed rulemaking.

Q What is the status of the Company's IVP records review and its IVP Program proposal for the Rate Year?

A. Through its IVP to date, Niagara Mohawk has completed the MAOP records review on 100 percent of its DOT-jurisdictional pipelines. Going forward, the IVP addresses transmission main replacements and testing necessitated by incomplete records identified by the review and pressure testing. Where the Company has identified incomplete records, pipelines will be replaced or records will be recreated through testing. This work is necessary to ensure system integrity regardless of PHMSA's proposed requirements. The IVP work plan is levelized by year to manage spending at $4.5 million in the Rate Year and each subsequent year (subject to inflation), not including the PL-34 Replacement Project, which is separately budgeted.

C. Albany Loop Closure Project

Q. Please describe the Albany Loop Closure Project.

A. The Albany Loop Closure Project involves the installation of 38,000 feet of 16-inch, 225 psig transmission main from the south end of the Albany transmission loop ("Albany Loop") in Glenmont to the northeast end in Troy. This project is an on-system reinforcement that allows more gas to flow through the Tennessee Gas Pipeline's ("TGP") South Albany city gate station into the Albany Loop, which will help mitigate the "East Gate" supply constraint. The project will also enhance reliability in the event of a Dominion Transmission Inc. ("DTI") interruption at the Troy city gate.

The northeastern part of Niagara Mohawk's service territory, including the Albany area, is the most capacity-constrained segment of the Company's distribution system. The majority of the gas is supplied from DTI to the East Gate. Currently, DTI cannot increase deliveries to the East Gate without significant upgrades. These constraints impact the Company's ability to serve existing interruptible gas customers and expand service to new customers in the area.

Additionally, the northern part of the Albany Loop area currently is supplied by DTI from the Troy city gate. On a day with a 24-hour average temperature of five degrees, if DTI were to interrupt supply to this gate, as many as 50,000 Niagara Mohawk customers could lose gas service. More customers could lose service on a design day (24-hour average temperature of minus 10 degrees). The Albany Loop Closure Project would eliminate that contingency and allow the Company to maintain service.

The capital plan includes $3 million in the Rate Year for engineering and procurement for the Albany Loop Closure Project. Construction will occur during the Data Years, and the project is scheduled to be completed during FY 2021.

D. <u>Pipeline 34 Replacement Project</u>

Q. Why does the Company plan to replace Pipeline 34?

A. This project addresses the long term risk associated with identified lap welded segments of pipe on Pipeline 34 ("PL 34"). Lap welding is an outdated pipe manufacturing process whereby the overlapping ends of rolled pipe were heated in a furnace and welded together, creating a wider weld joint that was sometimes irregular. Manufacturers no longer use the lap welding process because of integrity concerns, and risks associated with lap welded pipe have been recognized by both PHMSA and the American Society of Mechanical Engineers. Replacement of PL 34 with new seamless pipe, or seam-welded pipe manufactured according to current standards, is the best way to mitigate these risks.

Q. Please describe the PL 34 Replacement Project and the Rate Year investment.

A. The project replaces approximately 15,000 feet of 8-inch pipe (of which a majority is lap welded pipe) with new pipe. The project requires $4.45 million in the Rate Year to begin the design phase, with construction occurring during the Data Years. The project is scheduled to be completed in FY 2021.

E. <u>Transmission Services Removal Program</u>

Q. Please describe the Transmission Services Removal Program.

A. This is a five-year program (beginning in FY 2018) to remove 271 gas services from Transmission Pipeline E-31 ("E-31 Services"), a 200 psig transmission pipeline located in Saratoga County, and connect them to distribution main. The program involves transferring 68 of the E-31 Services to nearby existing distribution main and extending 6.4 miles of new distribution main to serve the remaining 203 customers that are located more than 200 feet from existing distribution main.

Q. Why is this program necessary?

A. From 2013 to 2015, the Company reviewed the E-31 Services through its Process Hazard Analysis ("PHA") to determine the overall process safety risk associated with the E-31 Services and concluded that the cumulative safety risk exceeded the Company's internal process safety risk threshold. The PHA utilized a Layers of Protection Analysis technique developed by the Center for Chemical Process Safety based on equipment failure scenarios, such as third party excavator damage, pressure regulator failure, non-gas related structure fires, vehicular damage to above ground equipment, and weather related failures, to determine the quantitative risk level for each failure scenario. At the completion of the risk assessment process, the Company concluded the total cumulative failure risk for the E-31 Services exceeds the Company's internal risk guidelines due to insufficient layers of protection and, therefore, relocation of these services to distribution main is necessary.

Q. What are the capital investments required for this program?

A. The program involves installation of new distribution pipelines, new distribution rated service lines, and the decommissioning, abandoning and securing of each transmission service tee. The cost estimate for this project is $4.01 million in the Rate Year.

Q. Is the Company taking steps to mitigate the risk associated with the E-31 Services prior to the Rate Year?

A. Yes. The Company plans to replace the existing service regulators with high pressure service regulators during FY 2018. Additionally, beginning in FY 2018, the Company will conduct annual inspections that will continue until all of the E-31 Services have been retired or relocated. When other work presents an opportunity to retire or relocate an E-31 Service, the Company will do so (the Company has already retired or relocated fifteen E-31 Services over the past two years). The proposed program will retire or relocate the remaining 271 E-31 Services within five years.

F. <u>AMI</u>

Q. Please describe the capital investment in the AMI project.

A. The AMI project involves the installation of AMI compatible encoder receiver transmitters ("ERTs") on the Company's gas meters. The Rate Year investment in this program is set forth in Exhibit __ (GIOP-1). The details of AMI capabilities and the benefits of the program are described in the direct testimony of the AMI Panel.

IV. Gas Infrastructure Capital Investment

Q. How much is the Company planning to invest in its gas system assets in the Rate Year and Data Years?

A. The Company plans to invest approximately $168.61 million in its gas infrastructure and other capital investments in the Rate Year. Exhibit __ (GIOP-2), which provides the actual or budgeted capital investment for FYs 2014 to 2021, is segmented into four spending rationales: "Growth," "Mandated," "Reliability," and "Non-Infrastructure/Miscellaneous." Table 3 summarizes the planned capital investment for the Historic Test Year and FYs 2019 to 2021 in each of these categories:

Table 3: Capital Budget by Spending Rationale ($000)

Spending Rationale	Historic Test Year	FY 2019	FY 2020	FY 2021
Growth	32,077	39,184	42,058	47,949
Mandated	70,947	103,307	120,112	130,985
Reliability	6,018	24,360	52,733	54,183
Non-Infrastructure/Misc.	(874)	1,758	1,807	1,850
Total	**108,168**	**168,609**	**216,710**	**234,967**

Each spending rationale is broken down further into sub-categories that identify specific programs and projects. In addition to the forecast Rate Year capital investment levels, Exhibit __ (GIOP-1) shows actual capital spending for the Historic Test Year and projected capital spending for the Rate Year and Data Years in each of these categories.

Q. How were the capital forecasts for the Rate Year and Data Years derived?

A. The Rate Year and Data Year forecasts for each project or program set forth in Exhibit __ (GIOP-1) are based on historic work levels and project estimates plus any anticipated new requirements, new programs, and projects or other known factors that might impact costs in the Rate Year and Data Years.

Examples of programs that are based on unit costs include Base Growth Install New Main and Services and Proactive Main and Service Replacement (LPP). Programs forecast based on historic work levels tend to be reactive in nature, including the Reactive Main Replacement (Reactive) and Tools & Equipment – Various programs. Projects or programs that fall outside of routine work, such as safety-driven programs (*e.g.*, Methane Emission Reduction) and new programs (*e.g.*, Albany Loop Closure), are based on project-specific estimates using the most recent material, labor, and overhead costs.

Q. What are the primary drivers of the difference in the Company's planned capital spending in the Rate Year compared to the Historic Test Year?

A. As Exhibit __ (GIOP-1) shows, the primary drivers of the increase in planned capital investment in the Rate Year compared to the Historic Test Year are increased investment in Mandated and Reliability programs. Investments in these programs are approximately 45.6 percent and 304.7 percent higher, respectively, in the Rate Year than in the Historic Test Year, and collectively account for approximately 83.9 percent of the difference between the total annual capital levels between the two periods.

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

A. Yes. In addition to the capital costs, there is a level of cost of removal required to implement the Company's infrastructure investment plan. The capital forecasts for each program presented herein are inclusive of cost of removal.

Q. What types of activities are associated with cost of removal?

A. The Company defines removal as any work on an asset that results in it being removed from the asset inventory, whether or not a different asset is added in its place. This type of work would include, but is not limited to, the activities associated with disconnection, removal and disposal (or retirement in place) of gas mains, gas services, and related facilities.

Q. What information is presented in Exhibit __ (GIOP-4)?

A. Exhibit __ (GIOP-4) provides additional information for each of the significant gas capital projects and programs the Company expects to perform during the Rate Year. This additional information includes:

- Project or program title
- Spending rationale
- Brief project or program description

- Project or program justification
- Total project cost breakdown
- Customer benefit description
- Alternatives
- Studies/references that support the program

Q. Please describe some of the technologies and practices the Company uses to reduce the total cost of its capital expenditures.

A. The Company continues to utilize a number of technologies and best practices designed to deliver cost-effectively its capital program. These practices include:

- Increasing the amount of planned capital work (versus reactive work)
- Increasing coordination among capital programs to increase efficiencies (*e.g.*, leveraging LPP opportunities)
- Installing more small diameter, high-pressure facilities that can be installed at lower cost
- Using smaller excavating equipment, increasing operating efficiency and reducing instances of damage (because of decreased size and weight of equipment)

- Employing "low dig" technology as opposed to traditional open cut methods for main installation, including use of small directional drilling machines for services and small diameter mains
- Using "coring and keyhole" technology to repair existing mains
- Enhancing contractor management
- On-site reporting for work crews in many large construction projects

Q. Did the recent Gas Management Audit address any aspects of the Company's gas operations?

A. Yes. While the Gas Management Audit found the Company's gas operations perform well overall in providing gas service in a reliable manner, the audit identified a number of findings and recommendations addressing aspects of the Company's system planning, engineering, project management, and work management functions. These audit recommendations, which are in varying stages of implementation, suggest that the Company: (i) develop an integrated natural gas system-wide plan that includes all reliability work, mandated replacements, growth projects and system planning work identifiable over a five year period (completed); (ii) update and consolidate the Company's IMP (completed); (iii) develop an estimating program for the Company's gas projects (completed); (iv) implement a program to track and manage crew and individual worker productivity (in progress); and (v) develop a manpower planning program (in progress). Once fully implemented, these recommendations will enhance the Company's system planning, estimating, and work management capabilities. The separate testimony of Company Witness Keri Sweet Zavaglia discusses the status of the Gas Management Audit implementation.

A. <u>Capital Planning, Budgeting and Sanctioning Process</u>

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

A. Each year, the Company develops a ten-year capital plan to achieve its performance objectives of delivering safe, reliable service. In the summer of each year, Investment Planning compiles proposed spending for programs and individual capital projects. Programs and projects are categorized into one of four spending rationales (Mandated, Growth, Reliability and Non-Infrastructure). The proposed spending for each program or project includes the latest cost estimates for in-progress projects as well as initial estimates for new projects. Expected deviations from historic trends in mix, volume, and cost of work are considered.

All known mandatory programs and projects are included in the ten-year capital plan. Once the budget level has been established for Mandated work, the programs and projects in the other spending rationales are reviewed for inclusion in the plan. Whether any other project is included in the plan is based on several factors, including, but not limited to, whether the project is new or in-progress, the project risk score and/or resource availability. In addition, program work is examined to capture any possible cost efficiencies, specifically with respect to LPP retirement.

In late fall, the capital plan is reviewed by the New York Jurisdictional President (Company Witness Kenneth Daly) and the Vice President, Finance, New York (Company Witness David Doxsee). The New York Jurisdictional 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 mix of investments.

In early winter, the capital plan is presented to the National Grid Board of Directors and the National Grid plc Executive Committee and, in early spring, the capital portfolio is presented to the National Grid plc Board of Directors for review and approval.

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

A. Yes. Aside from the capital planning and budgeting process, specific delegation of authority ("DOA") approval must be obtained for any project in the ten-year capital plan to proceed. This process includes the sanctioning documentation and review for projects over $1 million and other levels of review for smaller projects. Presently, all projects greater than $1 million require some level of sanctioning documentation and review. The U.S. Sanctioning Committee ("USSC") was established by the National Grid Board of Directors specifically for this purpose. Projects between $8 million and $25 million are reviewed and approved by the USSC. Effective January 1, 2016, projects between $25 million to $176 million are reviewed by the USSC and then are forwarded to a Senior Executive Sanctioning Committee ("SESC") for review and approval. For projects between $1 million and $8 million, the USSC has delegated review to an informal committee led by the investment planning group and including, but not limited to, managers and directors from the regulatory, estimating, asset management, and procurement groups. The committee reviews and finalizes sanctioning papers for these projects at a weekly meeting, and the committee then forwards the final sanction documents to the executive sponsor of the project for approval and signature. Projects less than $1 million do not require sanctioning and are approved through a supervisory delegation of authority hierarchy based on certain established 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 Year. As described above, the Company develops a long term investment plan that is used as the basis for the forecast for the Rate Year and Data Year 1 and Data Year 2 proposals. Project sanctioning, however, generally occurs immediately prior to the fiscal year for which the investment is planned. For example, projects and programs included in the FY 2019 capital plan will generally 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. Please describe how the Company's DIMP impacts its capital investment planning.

A. The DIMP involves a risk-based assessment of the Company's distribution system to identify threats in seven categories: corrosion, natural forces, excavation damage, other outside force damage, material and weld failure, equipment failure/malfunction and inappropriate operation. The DIMP requires evaluation and prioritization of the risks that these threats pose, and the implementation of measures to address the highest risks with an emphasis on leak management, enhanced damage prevention, operator qualification to reduce human error and system replacement. Consistent with the DIMP, the Company prioritizes asset replacements in its investment plan based on a risk ranking that considers, among other things, leak repair history, types of leak, pipe material, surrounding geography, segment length, nearby construction activity, field conditions, customer issues, open leaks and engineering judgment. The Company carefully designs the risk ranking factors to consider known differences in the performance of asset subclasses, extensive experience with asset failures, current performance data for the asset subclasses for various threat categories, and subject matter experts' analysis and opinions on the future performance of the assets.

B. <u>Growth Category of Capital Spending</u>

Q. What portion of the Company's capital investment plan is in the Growth spending category?

A. The Growth category of work accounts for approximately 23.2 percent ($39.18 million) of the total planned capital investment in the Rate Year.

Q. Please describe what is included in the Growth category.

A. Expanding the availability of natural gas in Niagara Mohawk's service territory can bring significant economic benefits in the form of energy cost savings for customers, job creation, and increased local tax revenues, as well as environmental benefits associated with lower carbon emissions. To enable growth, the Company must make significant capital investments in mains, services, and system reinforcements. Growth programs are designed to support forecast customer growth and add new load by increasing system utilization in a cost-effective way. Growth programs involve the installation of new mains, services and meters and include base growth and system reinforcement. Contained in the Growth category are the estimated capital costs of new mains, services, and meters required to serve additional load. As shown in Exhibit __ (GIOP-1), this program also includes continuation of the Neighborhood Expansion Program, which is discussed in the Gas Customer Panel's testimony.

Q. Please describe recent growth trends in the Company's service territory.

A. Recent growth trends show a slight increase in the multifamily sector. While overall growth is marginal, there is a slight decrease in the residential conversion markets due to lower oil pricing and saturation levels, but a slight increase in the commercial sector that is expected to level off in CY 2017, particularly near the capital region due to the stronger economy. Stronger economic conditions have also driven increases in new construction in the residential and multi-family markets.

The Company forecasts growth increasing at two percent in the Rate Year and three percent in each of the Data Years.

Q. Please describe the System Reinforcement category.

A. The System Reinforcement category contains projects intended to ensure that minimum system pressures are maintained throughout the gas network during periods of peak demand. The Company models peak demand based on the sendout forecasts developed by Analytics, Modeling and Forecasting (Company Witness Theodore E. Poe). As a result of growth in gas usage in its service territory, Niagara Mohawk has determined that it is necessary to complete a number of projects to ensure its ability to meet peak requirements. These reinforcement projects are essential to serve growing demand and to maintain reliable service to existing customers.

During the winter of 2015/2016, Niagara Mohawk recorded two of its top ten sendout records, including the second-coldest firm load record of 997,343 dekatherms on February 14, 2016, when the average of Syracuse and Albany daily temperatures was minus two degrees Fahrenheit, and the third-coldest firm load record of 987,172 dekatherms on February 13, 2016, when the average daily temperature was minus 7.5 degrees Fahrenheit. The recent growth in peak sendout underscores the need to ensure that minimum system design pressures are maintained throughout the distribution network during periods of peak demand.

Q. Please provide examples of System Reinforcement projects.

A. Examples of System Reinforcement projects include:

- Replacing undersized mains with larger diameter mains. LPP is targeted whenever practical during this work
- Looping or connecting system endpoints by installing new main (*e.g.* the Albany Loop Closure Project described above)
- System pressure uprates (*e.g.*, 15 pounds per square inch ("psi") to 60 psi)
- Installing new district regulators and replacing existing undersized district regulators
- Transferring existing low pressure customers to an adjacent high-pressure main (*i.e.*, load shedding)

C. <u>Mandated Category of Capital Spending</u>

Q. What portion of the Company's capital investment plan is Mandated?

A. The Mandated category of work accounts for approximately 61.3 percent ($103.31 million) of the total planned capital investment in the Rate Year.

Q. Please describe what is included in the Mandated spending category.

A. Projects covered by the Mandated spending category are those needed to comply with regulatory obligations and rate plan commitments, including: City/State Construction projects that require the Company to relocate facilities, code-required corrosion testing and mitigation or other pipeline integrity related activity, proactive and reactive capital main and service replacement, proactive replacement of main on structures, reactive transmission main replacement, required meter replacement, cross bore investigations, and transmission washouts. Exhibit __ (GIOP-4) includes a summary description of each of the significant projects included in the Company's Mandated spending category, along with the estimated annual funding during the Rate Year and Data Years for each.

Q. Please describe what is included in the City/State Construction sub-category.

A. City/State Construction work is performed to accommodate third-party, municipal construction activity that could impact the integrity of the Company's natural gas facilities. Typical third-party construction activities that impact gas facilities include work on water, sewer and drainage infrastructure, street reconstruction, road realignment and bridge replacement. State regulations and Company procedures require the replacement of eight-inch and smaller cast iron gas mains if roadway or underground construction is being performed in such a way that would impact the integrity of the Company's mains. Non-cast iron gas mains (*i.e.*, steel and plastic) are not subject to the same replacement regulations and are typically supported and protected if not in direct conflict with third-party construction. Direct conflicts are addressed through relocation regardless of material type.

Niagara Mohawk forecasts its City/State expenditures by reviewing the known and planned work identified by municipalities, historic work volumes, and unit information. The forecast cost for this program is approximately $6.1 million in the Rate Year.

Q. Are there opportunities to retire LPP during City/State Construction projects?

A. Yes. As part of the City/State Construction program, the Company looks to identify cost-effective opportunities to retire LPP when main replacements are required to accommodate municipal construction. City/State construction projects present opportunities to perform safety and reliability upgrades on the Company's infrastructure, the costs of which can be offset by coordinating construction activities (shared trenching and paving) and securing third-party reimbursements. Of the approximately 23,699 linear feet of City/State construction main replacements in the Historic Test Year, the Company retired approximately 12,418 linear feet (approximately 2.4 miles) of LPP.

Q. Please describe what is included in the Corrosion Control Program.

A. This program funds work consisting of field testing, monitoring, upgrades and repairs to existing corrosion control systems. Part of this program addresses above ground gas mains at bridge locations which includes complete recoating of existing aged, dis-bonded, deteriorated or uncoated gas mains, as well as retirement of LPP where it extends underground near these crossings. In addition, this program addresses the installation and testing of cathodic protection systems on buried piping.

Q. Is the Company proposing any changes to its capitalization policy for corrosion control activities?

A. Yes. Accounting for some corrosion control activities is currently expensed by the Company. However, applicable accounting principles and regulations permit the installation/replacement of new test stations and rectifiers, among other items, to be capitalized. The Company is proposing to capitalize these corrosion control activities in accordance with Accounting Standards Codification 360, the Federal Energy Regulatory Commission's accounting regulations and International Accounting Standard 16. Testing and inspection activities related to corrosion control will remain as expensed items. The changes are described in detail in Exhibit __ (GIOP-4).

Q. Please describe what is included in the Replace Pipe on Structures Program.

A. This program will replace gas pipe on structures at three locations due to specific integrity concerns that were identified through corrosion inspections. Funding for these replacements is not addressed in any other capital program budget. The Proactive Main and Service Replacement (LPP) Program does not include replacement of pipe on bridges and structures due to cost and complexity. The Corrosion Control Program has typically addressed identified issues on structures through re-coating; however, the Company has identified three structures that require more than re-coating. The complexity and level of corrosion at the identified locations warrants an incremental, stand-alone program.

The Company is recommending replacing one location per year beginning in the Rate Year. The capital plan includes $0.83 million in the Rate Year based on a project-specific estimate for the replacement of pipe at the Washington Avenue, Rensselaer location. The identified structures/locations and schedule for replacement are shown on Table 4.

Table 4: Pipe Replacement on Structures Locations

Location	FY
Washington Ave. at Rt. 443 over Rt. 90, Rensselaer	2019
Delaware Ave. at Rt. 443 over Rt. 90, Albany	2020
Russell Rd at Rt. 90, Albany	2021

Q. Please describe what is included in the Transmission Main Reactive Program.

A. This program covers the capital projects required to reactively mitigate integrity related issues on gas transmission pipelines. Integrity issues are identified by the Company's IMP, mandated inspections, and during normal operations. These integrity issues can be caused by corrosion, third party damage, valve failures, and other issues that affect the integrity of pipelines.

This program covers mitigation projects that are more urgent or of a higher priority and that are not addressed as part of the IMP workplan. Projects consist of pipe replacement by direct trenching and directional drill, and may include valve replacement. A reactive program is required to address higher-risk transmission integrity issues as they are discovered.

Q. Please describe the Cross Bore Investigation Program.

A. A cross bore is an unintended consequence of horizontal directional drilling ("HDD"). It occurs when a plastic gas main compromises a sewer lateral that was not identified during the gas installation process. A cross bore can block the sewer line, and any attempt to clear the blockage can damage the gas line and cause gas to migrate into a building. In recent years, several such incidents have occurred in the industry and, as a result, many utilities have initiated programs to identify and remedy this situation.

The Company updated its HDD procedures in 2014 to address and eliminate possible cross bores. Historically, Niagara Mohawk's drilling procedures and the typical depth of sewer laterals in the Company's service territory due to frost permeation depths would have mitigated against the occurrence of cross bores. However, prior to 2014, the risk specific to cross bores was not known; thus, the Company cannot determine with certainty that cross bores did not occur absent inspection of pre-2014 installations. This program includes inspection of a representative sample of pre-2014 installations.

Q. Please describe what is included in the Purchase Meters Program.

A. This program includes the purchase, testing, processing and delivery of gas meters and associated instrumentation needed to support the Meter Change program and Base Growth.

Q. Please describe what is included in the Meter Change Program.

A. The Meter Change Program involves the labor to replace gas meters that are retired from service due to required periodic testing, damage, failure, or any other reason.

Q. Please describe the Transmission Pipeline Washouts Program.

A. During normal operations, gas transmission system pipelines can be exposed to environmental conditions that can affect the integrity of the pipeline. These environmental conditions may include localized flooding, scouring/erosion of stream bottoms under normal flow, and ground subsidence due to subsurface geological activity. Both federal and state regulations require operators to perform continuing surveillance and follow-up mitigation activity to insure the integrity of these pipelines. Recent PHMSA Advisory Bulletins highlight actions operators must take to ensure that flooding events, normal river scour and river channel migration do not affect integrity of pipelines. These Advisory Bulletins also outline actions needed after severe storms such as hurricanes.

This program covers the capital projects required to mitigate the effects of environmental damage to existing gas transmission pipelines. Projects consist of pipe replacement by direct trenching, directional drilling and civil engineering repairs.

Q. Please describe what is included in the Reactive Main and Service Replacement Programs.

A. The Reactive Main and Service Replacement Programs provide for the replacement of gas mains and services during urgent or emergency situations that fall outside the normal scope of integrity, reinforcement, reliability and public works programs. These replacements are performed in lieu of repair in instances when repairing damaged facilities is not possible, or where the pipeline segment is too short to be covered by the proactive programs.

D. <u>Reliability Category of Capital Spending</u>

Q. What portion of the Company's capital investment plan is Reliability?

A. The Reliability category accounts for approximately 14.4 percent ($24.36 million) of the total planned capital investment in the Rate Year.

Q. Please describe the goals of the Gas System Reliability Program.

A. Investments in this category are intended to maintain reliable service to customers by ensuring that all facilities on the gas system are operating efficiently and reliably.

Q. Please describe what is included in the Reliability category.

A. The Reliability category includes programs related to gas control, heaters, reactive Instrument & Regulation ("I&R"), pressure regulating facilities, valve installation/replacement, remote-controlled valves, gas planning reliability, water intrusion, system automation and control line integrity, special station projects (including over-pressurization protection), physical security upgrades for critical gas infrastructure, and other programs described in more detail below. Exhibit __ (GIOP-4) includes a summary description of significant projects included in the Reliability spending category, along with the estimated cost during the Rate Year and Data Years for each project.

Q. Please describe the Gas Control Telemetry Upgrade Project.

A. The two-year Telemetry Upgrade Project will upgrade obsolete telemetry equipment from 3G to 4G cellular technology. In Niagara Mohawk's service territory, there are approximately 60 telemetry devices that transmit data back to the Gas Control Room. Verizon has announced it is sunsetting its 3G network by 2021 to free up space for its newer networks. If left as is, the Company's current telemetry devices will be unable to communicate. The Company's I&R personnel will replace the 3G telemetry devices with new 4G devices.

Q. Please describe what is included in the Gas System Reliability - Gas Planning/Remote Controlled Valve ("RCV") programs.

A. The Gas System Planning Reliability programs include capital projects required to maintain system minimum pressures on the gas network in the event of an abnormal operating condition (failure involving a regulator station, gate station, critical main or other major pressure facility on the system). The Gas Planning program ensures that customers continue to have reliable service and that no customers experience interruptions as a result of an unplanned outage of a facility under normal winter conditions. The RCV program involves the installation of additional RCVs on transmission pipelines to improve emergency response capability and reduce the risk of gas releases. In the event of a pipeline failure, RCVs allow control room operators to stop the flow of gas and to remotely isolate and shut down a portion of the system. Currently, most transmission pipelines can only be shut down using manually-controlled isolation valves, which can take longer to close and result in a larger customer impact. Improving response time through the expanded deployment of RCVs reduces the quantity of gas released and can limit the harm to the public and property.

Q. Please provide examples of Gas Planning Reliability projects.

A. Examples of Gas Planning Reliability projects include: eliminating distribution systems fed by a single district regulator or main, integrating distribution systems with the same operating pressures through pipeline connections, expanding supply diversity, and projects targeting areas of the system where large numbers of customers would experience a service interruption if a single gas facility became inoperable when the average daily temperature is five degrees Fahrenheit.

Q. Please describe what is included in the Valve Installation and Replacement Program.

A. Federal and state regulations require installation, inspection, operation and maintenance of critical pipeline valves on all gas distribution systems. The purpose of these valves is to facilitate the rapid shutdown of distribution piping during gas emergencies such as third-party damage or water intrusion. A secondary purpose of these valves is to facilitate maintenance and pipe replacement on associated distribution piping.

This program will strengthen the Company's emergency response capabilities by improving the level at which Field Operations personnel can safely and efficiently isolate sections of the distribution system while mitigating customer impacts (*e.g.*, reducing the duration of future outages). Installation of a sufficient number of valves, and replacement of valves when necessary, will improve public safety and is essential to the effective operation of the Company's gas distribution system.

Q. Please describe what is included in the Water Intrusion and Distribution Main Exposure Program.

A. The Water Intrusion and Distribution Main Exposure Program is designed to address water entering the gas distribution system, resulting in main obstructions, poor pressure and/or freezing customer services and undermines/exposures, and distribution main exposures that may result from flooding, third party damage, valve failures and other conditions. This reactive program also targets the retirement of LPP that is susceptible to water intrusion but is not prioritized for replacement under other main replacement programs because of the absence of leaks and/or historic leak repair activity.

Q. Please describe what is included in the I&R Reactive Program.

A. The reactive I&R budget provides capital investment in pressure regulating and control stations. Typical projects in this category include unplanned capital work resulting from emergency conditions, including the replacement of station valves, regulators and relief valves, as well as related capital work on station equipment. Capital investments necessary to maintain Niagara Mohawk's existing compressed natural gas ("CNG") filling stations are also included in this program, excluding the incremental investment in a portable CNG tube trailer, which is separately budgeted.

Q. Please describe the Company's proposed investment in I&R portable temporary regulator stations ("PTRS").

A. Niagara Mohawk proposes to construct three PTRS in the Rate Year. During the maintenance and construction of its gas regulating stations, the Company is often limited to certain methods of construction to maintain a steady gas feed to a distribution system while the work is being conducted. It is not always possible to shut down a station while conducting maintenance or reconstruction of the station. In such instances, a PTRS is the most efficient work-around. Additionally, when unexpected issues arise that may require extensive repairs, such as main replacements or incremental main installations, a PTRS will provide a temporary solution to allow for continuing flow of gas while permanent repairs can be made. The three new PTRS will employ a more standardized design approach that will enable the Company to put a PTRS into operation within minutes of arrival at any location.

Q. Please describe the Portable CNG Program.

A. This program is to purchase a portable CNG tube trailer. CNG tube trailers are used to provide temporary portable supply of natural gas. Portable CNG is deployed to facilitate main replacement and pipeline construction, provide supply to communities and neighborhoods when there is a disruption of permanent supply sources due to an emergency or weather, reinforce gas distribution systems during winter peak demand periods, and temporarily supply customers when they are refurbishing their own piping systems. As detailed in Exhibit __ (GIOP-4), the Company has experienced situations during severe weather events in which CNG supply played a critical role in providing a safe, reliable supply of gas to vulnerable customers. Acquiring a CNG tube trailer avoids both the future cost of procuring portable CNG at the time of an emergency and the risk that none may be available when needed.

Q. Please describe the I&R Field Test and Training Lab Project.

A. This project is to design and procure a field test and training lab in the form of a fully functioning pressure regulation facility, identical to that found in the Company's actual stations, that operates on compressed air instead of natural gas. This facility will simulate field examples of normal operation, over pressure protection, and other abnormal conditions and will enable employees to practice diagnosing and controlling simulated emergencies and abnormal operating conditions in a safe and controlled manner. The lab will also allow for testing future designs and new technologies. This facility will enhance knowledge and understanding of station operations for field workers, design engineers, safety professionals and others by facilitating hands-on operational experience under controlled conditions.

Q. Please describe the Gas Regulator Station Security Project.

A. This project will enhance and improve security measures at critical gas pressure reducing stations that are not scheduled for full station replacement. In December 2016, PHMSA issued an Advisory Bulletin (AB-2016-06) recommending enhanced security for critical energy infrastructure following an incident on an interstate gas pipeline. The Gas Regulator Station Security Project targets 55 regulator stations that are critical to reliable operation of the system. Niagara Mohawk will assess these key city gate and regulator stations to determine vulnerabilities to vandals, activists, out of control vehicles, and other external physical threats to safe operations. The results of the security assessments, combined with the relative importance of the facility to reliable and safe operation of the overall transmission and distribution system, will determine the level and types of security enhancements.

Examples of security measures include remotely operated cameras connected to gas control centers, lighting, fencing, ID card access, intrusion alarms, redundant communications systems, physical barriers, and hardened locks and cables to protect exposed valves and equipment.

Q. Please describe the Methane Emission Reduction (Odorant Pump) Project.

A. The project will retrofit the pneumatic odorant pumps at 23 city gate stations so that compressed air replaces high pressure gas as the driver to pump odorant into the gas. At each city gate station, an electric air compressor and associated filters, dryers and controls will be installed, and pump power gas systems will be converted from natural gas to air. This will eliminate natural gas emissions associated with odorization at these stations.

Q. **Please describe what is included in the System Automation Program.**

A. This program will install Remote Terminal Units ("RTUs") at multiple city gate and regulator stations. RTUs provide temperature, pressure and flow data back to the Gas Control Room. RTUs can also monitor gas detectors and intrusion alarms and allow Gas Control Operators to adjust flow and pressure set points at regulator stations. The benefits include enhanced calibration of network models from automation and telemetry data, improved accuracy of network analysis, and enhanced ability to forecast the need for capital reinforcements, which will lead to more efficient capital planning. Automation allows Gas Control Operators to selectively close valves, raise or lower pressures, and shut down take stations. System alarms also alert Gas Control Operators to system issues and allow quick pinpointing of the source of the alarm.

PHMSA regulations regarding control room management require Operators to ensure that "practices and procedures within their control rooms are adequate to maintain pipeline safety and integrity." These rules indicate that Operators should have telemetry to monitor pipelines, because it would increase system awareness and enable a proactive response to abnormal operating conditions. The System Automation Program complies with these regulations by providing for increased deployment of telemetry on the Company's system.

Q. How is system performance monitored currently?

A. Currently, 56 percent of the pressure regulation stations are equipped with some form of telemetry, while the rest of the system relies on paper chart recorders. RTUs installed under the System Automation Program will provide enhanced ability to monitor system performance and remotely adjust pressures on the gas system. The program will also replace ageing and obsolete telemetry equipment.

Q. Please describe what is included in the Heater and Regulator Station Management Programs.

A. There are 40 natural gas heaters currently operating on the Company's system. Because high-pressure gas cools when the pressure is reduced, heaters are required at pressure regulating stations to prevent freeze-ups that can impact flow control devices. In addition, cold gas temperatures can lead to reduced pipe toughness and increased potential for frost heave and cold temperature-induced stresses. The Heater Program adds new heaters (where required) and replaces or rebuilds existing heaters that have reached the end of their useful lives or require component replacement.

There are 409 pressure regulating stations operating on the Company's system. The Regulator Station Management Program provides funding for replacement and/or rebuilding and reconditioning of existing regulating and control stations. Pressure regulating facilities (or stations) are designed to control system pressures and maintain continuity of supply during normal operating conditions and during periods of peak gas demand. Niagara Mohawk has assessed regulating stations on its system including evaluating factors such as pressure, location and the number of dependent customers for each station. In addition, the assessment considered station condition including pipe corrosion, location and type of overpressure protection, station automation, condition of vaults, vault covers, wall sleeves, piping vents and ladders. The results of the assessment were used to create an overall risk rating for each station that serves as the basis for prioritizing projects in this program. This program includes full or partial replacement of existing stations.

The investments in the Regulator Station Management Program do not cover the special project capital improvements to specific stations that are separately set forth in the investment plan and described below.

Q. Please describe the Pressure Regulation Special Projects.

A. Pressure Regulation Special Projects are capital investments to address reliability issues at specific stations that are separately budgeted and are not included in any other blanket reliability programs. These projects are described in detail in Exhibit __ (GIOP-4). The projects target facilities that have the highest potential customer impact. Depending on the asset, these projects include station replacement or rebuild, incorporation of odorization, gas quality validation, pressure regulation, overpressure protection and addition of process pre-heating equipment.

E. Non-Infrastructure and Miscellaneous Capital Spending

Q. What portion of the Company's capital investment plan is Non-Infrastructure and Miscellaneous?

A. The Non-Infrastructure and Miscellaneous category accounts for approximately one percent ($1.76 million) of the total planned capital investment in the Rate Year. These investments shown on Table 5 include special projects not included in the Company's other investment programs such as the purchase of tools and a safety project to restrict public access to elevated gas facilities.

Table 5: Non-Infrastructure and Misc. Capital

($000)	FY 2019	FY 2020	FY 2021
Tools and Equipment	706	726	743
Restrictions for Elevated Gas Infrastructure	1,052	1,081	1,107

Q. What is included in the Purchase of Miscellaneous Capital Tools and Equipment Program?

A. The Purchase of Miscellaneous Capital Tools and Equipment Program captures the items that meet the criteria for capitalization and are not used for specific projects but support the safe, efficient day-to-day operations of the gas business.

Q. Please describe the Restrictions for Elevated Gas Infrastructure program.

A. This is a ten-year program beginning in the Rate Year to install fencing or other physical deterrents to restrict and/or deter public access to elevated gas facilities (four feet or higher above the ground or across a body of water). The purpose of this program is to reduce the risk to the public of climb and fall injuries or fatalities.

Q. Is the Company allocated indirect capital costs?

A. Yes, Niagara Mohawk is allocated a portion of indirect costs, such as facilities, fleet services, and inventory management/warehouse management. These costs, and examples of the major projects/expenditures during the Rate Year and Data Years, are set forth in the direct testimony of the Electric Infrastructure and Operations Panel.

V. Gas O&M Expenses

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

A. The Panel addresses major expenses associated with operating the Company's gas delivery system and incremental O&M expenses the Company expects to incur in the Rate Year.

Q. Please generally describe the nature of the Company's gas system O&M expenses.

A. O&M expenses relate to work performed to provide customer support, respond to emergencies, perform safety inspections and other compliance activities, restore service, and maintain the life of capital assets. The Company has a significant maintenance program to ensure that system assets are utilized to their fullest potential life expectancy. As gas facilities age, maintenance costs increase. These costs include more frequent inspections and testing, increased volume of repairs and more complex repair work. These expenditures are required to prevent failure and maintain the life of the assets until replacement occurs.

The Company's O&M programs also are designed to maintain the service commitments in its gas safety performance metrics, which cover various aspects of its performance in the areas of reliability and safety, including metrics measuring emergency response, leak management, and damage prevention. These metrics are described in detail in the testimony of the Gas Safety Panel.

Q. What is the projected incremental Rate Year O&M expense for operating the gas system?

A. As shown on Exhibit __ (GIOP-5), the Company projects its Rate Year non-labor O&M expense to be approximately $11.654 million. As shown in Exhibit __ (GIOP-6), the Company also proposes to hire 78 total incremental FTEs in the Rate Year and Data Years. The costs for these FTEs are presented in the Revenue Requirements Panel testimony and exhibits.

Q. Please summarize the adjustments to the Historic Test Year O&M expense necessary to arrive at the proposed Rate Year expense.

A. Increases in O&M expense are primarily driven by (i) an increase in the Company's O&M workload, (ii) increased costs associated with the Company's increasing capital investments, and (iii) initiatives the Company is undertaking in the Rate Year to address new or expanding safety requirements and performance measures. The Company's incremental O&M costs include, for example, implementation of enhanced pipeline survey and inspection programs, damage prevention risk mitigation programs, and incremental costs for operational support employees to deliver Niagara Mohawk's significant capital plan.

Q. What is the Company doing to manage its O&M costs?

A. Prior to the Historic Test Year, the Company implemented various initiatives to reduce its O&M expenses, including:

- Increasing the use of scheduled O&M work appointments to reduce multiple unproductive field visits to complete work;
- Coordinating O&M activities required at each premise so that multiple maintenance requirements can be completed during a single visit;
- Increasing the use of coring and low-dig technology, reducing debris removal and paving restoration costs associated with smaller roadway excavations; and
- Modifying shift schedules to more efficiently respond to higher leak volumes.

Q. How will the Company manage the hiring of the incremental FTEs in the Rate and Data Years?

A. The Company intends to hire incremental FTEs throughout the Rate Year and Data Years in accordance with the needs of the departments and programs the employees will support. As shown in Exhibit __ (GIOP-6), of the Company's incremental 78 employees to be hired in the Rate Year and Data Years, 26 are supporting delivery of the incremental capital and O&M work plans (for example, engineers, designers, project managers). The most significant increases within individual functional areas are the addition of 14 I&R technicians and trainers who are field personnel necessary to deliver the incremental capital and O&M work plans and 17 mapping technicians and support personnel necessary to address historic staffing deficiencies and execute new initiatives. The remaining positions are in various areas including, for example, contractor management, resource planning, field employee training, estimating, and first responder training. Given the relatively modest FTE increases for the individual groups, the Company does not anticipate material challenges in hiring and onboarding employees. That said, the Company recognizes the total proposed increase in FTEs is not insignificant and, therefore, has taken care to ensure the hiring is reasonably phased throughout the Rate Year and Data Years to align with the anticipated work requirements. Exhibit __ (GIOP-7) sets forth the Company's hiring plan for incremental FTEs in the Rate Year and Data Years.

A. <u>Increased O&M Workload</u>

Q. Has the Company identified areas where the O&M workload is forecast to be higher in the Rate Year?

A. Yes. Table 6 sets forth O&M items where the Company expects to see an increase in workload in the Rate Year. The more significant O&M items are described below.

<u>Table 6</u>: Incremental O&M Workload

Category	FY 2019 ($000)
Damage Prevention	408
IMP/IVP Inspections	2,640
Transmission Station Inspection	798
I&R Increased Pipeline Surveys	1,000
Vegetation Management	114
GIS Mapping System	2,997
GRO-MWork Interface (CMS Ipads)	775
Traditional Gas R&D	55

<u>Damage Prevention</u>

Q. Please describe the incremental O&M associated with the Company's Damage Prevention Program.

A. As discussed in the Gas Safety Panel's testimony, damage to gas facilities from third parties digging near pipelines is a major cause of gas accidents and a contributing factor to some of the worst incidents in the history of the natural gas industry. To mitigate the risk of damages during excavation, the Company implemented its Damage Prevention Advisor Program, whereby contractors oversee excavation at various locations (as identified by the 811 tickets) throughout the service territory to educate and inspect on safe digging practices. The Company also recently implemented a Ticket Risk Assessment system that utilizes an algorithm to evaluate and prioritize the tickets generated from 811 calls based on the probability of damage to the Company's underground facilities. This enables the Company to respond to those tickets with the highest risk for damage.

To maximize the benefits of the ticket risk assessment and further mitigate the risk of third party damages, the Company proposes to expand its Damage Prevention Advisor program to add three contractors to respond to a greater volume of the highest risk tickets and cover additional territory. The incremental O&M expense to expand the program in the Rate Year is $0.345 million. As set forth in Exhibit __ (GIOP-5) and further described in the Gas Safety Panel's testimony, the Company also proposes to wrap ten vehicles per year with damage prevention awareness messaging and has included the modest ongoing O&M costs associated with maintaining the Ticket Risk Assessment system. The incremental O&M expense for those programs in the Rate Year totals approximately $0.063 million. Finally, the Company proposes to add one Damage Prevention field supervisor, which is set forth in Exhibit __ (GIOP-6).

<u>IMP/IVP Inspections and Transmission Station Integrity</u>

Q. Please describe the incremental O&M costs of the IMP/IVP in the Rate Year?

A. Incremental O&M is required to conduct the required inspections via External Corrosion Direct Assessments ("ECDA") on pipelines that are not ILI-enabled and to conduct ILI on those that are already enabled. These costs include excavation and support for ECDA inspections, evaluation of testing data and the costs of non-capital repairs such as repair sleeves and on-site material testing.

Q. Please explain the O&M inspection requirements for transmission stations.

A. The Company proposes an O&M program to conduct a records review of city gate stations and transmission regulator stations similar to the capital IVP Program. Because the properties and characteristics of transmission facilities are the same regardless of whether they are inside or outside of a station, it is prudent to perform records verification of materials, welds, welding materials and procedures, and hydrostatic testing of piping and other elements within the stations. PHMSA's 2016 NPRM supports this interpretation, and the regulations may eventually require inclusion of transmission station facilities in the IVP program. The Company will begin an IVP-type records review of its transmission stations in the Rate Year.

I&R Survey

Q. What are the incremental O&M costs associated with transmission pipeline inspections?

A. The Company proposes to increase the aerial patrol frequency on gas transmission Pipeline E-18 in the Albany area and Pipeline 16 in the Syracuse area. A failure analysis on each pipeline concluded that the highest failure risk was associated with third party damage, and both pipelines are partially located in High Consequence Areas. Accordingly, the Company will patrol Pipeline 16 twice a week and Pipeline E-18 weekly. The incremental O&M expense to perform the patrols in the Rate Year is approximately $1.00 million.

Vegetation Management

Q. Please describe the Company's proposed incremental vegetation management O&M.

A. Certain vegetation management services are performed exclusively for, and at the request of, the I&R department. These services include the costs of managing phragmites (an invasive species of wetland grass), canopy trimming, danger tree removal and routine mowing along the Company's gas utility corridors and rights of way and around regulator stations and other facilities. In the Rate Year, to ensure aerial patrols have adequate visibility and to mitigate the risk associated with phragmites, the Company's vegetation management program will include incremental clearing totaling approximately $0.114 million.

GIS Mapping System

Q. Please describe the Company's proposed GIS Mapping System Program.

A. To further mitigate the risk of third party damages to the Company's gas facilities, the Company proposes to map its approximately 600,000 services into its GIS program. Currently, mapping gas services involves three systems: GIS, Fortis, and CSS. GIS is the National Grid mapping system. Fortis is the National Grid scanned document system that contains all of the Company's service cards. CSS is the Company's customer account system that contains all customer information. To map its services into GIS, the Company proposes to (i) retain an outside contractor to access the Fortis system and use the service cards to update all maps in GIS and (ii) hire three FTEs prospectively to maintain the GIS (as set forth in Exhibit __ (GIOP-6)). This will ensure new service records are recorded in both systems. As shown in Exhibit ___ (GIOP-5), the non-labor cost to map the services to GIS is approximately $2.997 million in the Rate Year and $4.203 million in Data Year 1.

Q. Is the Company proposing technology enhancements in the Rate Year and Data Years?

A. Yes. As explained in Section VI below, the Company has undertaken a long-term initiative to deliver new work and asset management systems and enhance gas safety, compliance, customer service and performance. Because this project will take time, the Company is proposing two interim technology solutions to bridge the gap to the long-term solution. Specifically, the Company proposes to enhance the Pipeline Compliance System ("PCS") and create a Gas Repair Order – MWork Interface.

The Corrosion Department uses the PCS to manage its work. The Company will retain a vendor to enhance the PCS to include automatic work flow (*e.g.*, inspections) notifications, as well as escalation of notifications to those responsible for completing corrosion activities. This will provide much needed controls and assurance that mandated activities are systematically routed through the process and completed timely.

Gas Operations currently maintains its Gas Repair Orders ("GROs") in paper format. The information is subsequently entered into the Gas Asset Management System ("GAMS"). The proposed interim solution will link the Company's work management system (MWork) and GAMS by implementing an electronic data capture system to generate GROs in electronic format (and do away with paper) thereby eliminating data transfer and documentation challenges associated with paper records. As shown in Exhibit ___ (GIOP-5), the cost to implement the PCS and the GRO totals $0.500 million and $0.775 million in the Rate Year, respectively.

Traditional Gas R&D

Q. Please describe the Company's Traditional Gas R&D Program.

A. The Traditional Gas R&D Program is for short-term research associated with gas operations, end use, natural gas appliances, supply related storage, safety and related measures that do not qualify for funding under the Millennium Program. Based on the R&D projects identified in the Rate Year, including outstanding NYSEARCH projects that do not qualify for Millennium funding, the Company is proposing to increase funding for this program by $0.055 million.

B. <u>Incremental O&M Costs Associated with Capital Investments</u>

Q. Please describe the Company's need for incremental O&M costs associated with its planned capital investments.

A. As discussed above, the Company's capital investment program is increasing in the Rate Year, which will result in higher operating expense. For example, additional FTEs are required to support increased deployment of pressure regulating, heaters, gas quality, and system automation assets, as well as process safety improvements for I&R assets.

As shown in Exhibit ___ (GIOP-5), the Company estimates incremental non-labor O&M costs of approximately $0.332 million in the Rate Year directly related to the Company's capital investments.

Q. What O&M services will the various construction support functions provide to support the Company's increased capital investments?

A. Construction support functions include internal groups providing contract administration, project management, budgeting and resource planning. While the majority of costs from these functions are directly charged to capital projects, the Company incurs limited O&M expenses for costs such as training. The Company estimates that approximately ten percent of construction support employees' time is O&M expense.

Importantly, as Niagara Mohawk increases its capital expenditures and executes incremental maintenance work, the Company requires the resources set forth in Exhibit __ (GIOP-5), including field workers (I&R technicians) and capital support resources, including gas system engineering (estimators, designers, engineers), investment planning (analysts, coordinators), operations support (mapping technicians, inspectors, program managers) and resource and investment planners.

C. <u>O&M Costs Related to Safety and Reliability Programs</u>

Q. Please explain the O&M costs associated with incremental gas safety and reliability programs in the Rate Year?

A. Table 7 sets forth the incremental O&M expenses related to safety and reliability.

<u>Table 7</u>: Safety and Reliability Programs

Category	**FY 2019 ($000)**
Residential Methane Detection	150
First Responder Training	500
GPS Transmission Pipelines	1,300

Residential Methane Detection

Q. What is residential methane detection?

A. Similar to residential smoke alarms and carbon monoxide detectors, residential methane detectors sense the presence of methane/natural gas in the air and alert occupants to a potential gas leak. Utilization of these detectors offers another layer of protection to enable the public to react quickly in gas emergencies. While methane detectors are commercially available today, the natural gas industry is continuing to research and test the technology before embracing full-scale deployment to ensure issues such as false reads do not diminish the detector's effectiveness.

Q. What is Niagara Mohawk's proposal for advancing the use of residential methane detection?

A. The Company proposes to purchase 3,000 residential methane detection units at a cost of approximately $0.150 million in the Rate Year, as shown in Exhibit __ (GIOP-5). The Company will distribute the units to residential customers at no cost and will work collaboratively with Staff to determine the most effective means to identify the recipients and distribute the units.

<u>Gas Emergency First Responder Training</u>

Q. Please describe the Companies' efforts to train first responders on gas safety.

A. As discussed in the Gas Safety Panel testimony, for many years, Niagara Mohawk has provided gas safety training to first responders (fire, police and ambulance). In 2014, the Company launched the First Responder Fundamental Gas Safety E-learning Program ("E-Program"), which has been well received and recognized.

Q. Is the Company proposing to enhance its first responder training?

A. Yes, the Company proposes to enhance its First Responder training by working with first responders to create standard operating procedures so they are better informed about what to do, what not to do, and how to operate certain devices before a situation arises. The Company will also expand its Fire Fighter 1st Class, as well as other training curriculum to include information and protocols regarding natural gas.

In addition, the Company proposes to implement the following:

- Train-the-Trainer sessions for representatives of each fire department in the Company's service territory hosted at a Company training facility

- Mobile Training where Company instructors will travel to the fire departments to deliver classroom and hands-on practical demonstrations utilizing a mobile leak field

Q. What are the anticipated costs of the First Responder initiatives?

A. As shown in Exhibit __ (GIOP-5), the non-labor costs associated with the enhancements to the First Responder program are approximately $0.574 million in the Rate Year, which include the costs of a leased mobile vehicle, course materials and equipment, and travel expenses.

<u>GPS Location – Transmission Pipelines</u>

Q. Please explain the incremental O&M costs associated with performing the GPS location of certain transmission pipelines.

A. The Company uses GPS locating equipment to create accurate maps of pipelines operating at stress levels greater than twenty percent Specified Minimum Yield Strength ("SMYS"). However, approximately 400 miles of non-DOT gas transmission pipelines operating at levels below 20 SMYS in the Company's service area are not GPS located. The Company proposes to GPS locate and build maps for these 400 miles of pipelines, which are critical for ensuring that these facilities are not damaged by third party construction activities. As set forth in Exhibit __ (GIOP-5), the incremental O&M costs associated with this initiative total approximately $1.300 million in the Rate Year and in Data Year 1.

VI. GBE Program

Q. What is the GBE Program?

A. The GBE Program is a comprehensive framework of new technology solutions and business process changes necessary to strengthen and improve the performance of National Grid's U.S. gas business. Currently, the U.S. gas business faces a number of challenges. These challenges include the need to replace aged computer systems, drive continuous improvement in gas safety performance, deliver an expanding and increasingly complex capital investment program, and meet evolving customer expectations, including the increased demand for new customer connections.

The GBE Program was developed through a collaboration among National Grid's U.S. gas business and Information Services, Procurement, Customer, Finance, Shared Services, Customer Meter Services (electric and gas), and Human Resources functions, among others. The program has been designed as a holistic transformation of National Grid's U.S. gas business to deliver process improvements across people, systems, and technology to strengthen operational and safety performance and build a platform that supports future growth and customer demands.

Q. Why is the GBE Program needed?

A. Before the end of the Rate Year, 94 percent of the systems used by National Grid's U.S. gas business will be at their end of life. The average age of these systems today is 14 years compared to an industry average of six. Because the age of these systems limits the ability to make modifications and increases the amount of time the systems are down, it is becoming increasingly difficult to support safe, compliant operations and meet ongoing regulatory obligations. In addition, the current systems, many of which still rely on paper records, no longer support the way today's gas companies need to work, manage performance, and provide employees with the right information and effective tools. Modern, supported solutions are also needed to help reliably deliver significant capital investment and growth.

Q. What are the benefits of the GBE Program?

A. The GBE Program provides numerous benefits such as:

Gas Safety. The GBE Program will strengthen in several respects the Company's ability to operate a safe, reliable gas distribution system. First, GBE will implement new GIS to improve the Company's ability to capture, store, access, and analyze geographical asset information concerning its gas distribution network. This will provide a single view of all assets, which will facilitate data-driven investment and maintenance decisions. The GBE Program investments will consolidate information on all required O&M work, rather than across multiple, manual spreadsheets. Finally, implementing modern, more reliable platforms will provide better records to document compliance and decreases the likelihood of system outages impacting the ability to deliver work.

National Grid's Pipeline Safety and Compliance organization has a central role in the GBE Program to ensure that GBE initiatives have a direct linkage to improving pipeline safety and compliance. For instance, the Company is in the process of implementing a Pipeline Safety Management System ("PSMS"), a process safety model based on employing and strengthening the ten essential elements of the American Petroleum Institute's recommended pipeline safety management standards (Recommended Practice 1173 ("API 1173")). GBE Program initiatives have been mapped to the ten elements of API 1173 for strong alignment to enhance safety and compliance upon implementation. Furthermore, the Company has enlisted a third party consultant (P-Pic) to independently validate that GBE Program initiatives will strengthen the Company's PSMS.

Improved Operational Performance. The main objective of the GBE Program is to consolidate and replace many of the Company's disparate and aging systems, as well as the associated work processes to achieve a step change in operational performance. The GBE Program investments will also drive continuous improvement in regulatory compliance and transparency with more complete data capture and reporting, less reliance on paper, and greater visibility of required work.

Operations Support. The GBE program will support delivery of a longer term solution to the work management and productivity reporting recommendations from the Commission's Gas Management Audit (Case 13-G-0009); specifically, that National Grid develop a program to track and manage crew and individual worker productivity, including the standardization of business processes for enhanced visibility of work and more efficient scheduling.

Customer. Another benefit of the GBE Program is enhanced customer service through improved scheduling and dispatch. This includes enhanced appointment booking and an interactive customer framework (described below), as well as the ability for dispatch and field crews to create a consolidated view of past, scheduled, and potential future work for customers so they will be better equipped to answer customer questions.

Q. What are the key elements of the GBE Program?

A. *Replacement of Aged, Core Systems.* Initially, the GBE Program will integrate, standardize, and simplify core delivery processes and systems onto a modern platform (comprising approximately 19 solution components, down from the 99 disparate applications used today). Specifically, the core systems GBE will design, standardize, and implement include:

- an industry-standard enterprise asset and work management platform;
- a scheduling platform to support optimized scheduling, work bundling, and routing of work;
- a GIS with accurate foundation maps and conversion of gas service records and sketches, available with mobile functionality;
- a field mobility solution with base capabilities that include views of work assignment, electronic work packages, capture of work status and completion data, and capabilities to initiate work, attach pictures, and view legacy maps;
- a standardized enterprise project portfolio management platform for project routing and approval, with the ability to forecast cost, integrated with scheduling, and design;
- an Asset Investment Planning and Management tool (*i.e.*, software application) to perform asset condition assessment and risk ranking/prioritization of asset replacement.

The integration of these core systems will support a more holistic management of assets and administration of work. In addition, updating and integrating these core system will enable new tools such as a mobility solution for leak investigation and inspection work orders; drive improvement in gas safety performance; improve capital delivery effectiveness; and lead to better employee utilization, and ultimately customer service.

Customer & Employee Interaction Platforms. A flexible interface will be built on top of the core systems to allow customers, call center, and field employees to operate on a common platform and more easily access data. An application portal will be developed and integrated with work management and scheduling solutions that allow customers to interact with the Company such as by receiving updates based on their preferences for appointments, addressing inquiries for new gas connections and conversions, and accessing information about work on their street or neighborhood. Similarly, an employee portal will be developed and further integrated with the work management, scheduling, dispatch, and GIS systems to provide call center representatives and field employees with a consolidated view of relevant information to support enhanced delivery of customer service. This interface also builds the capabilities necessary to rapidly adapt processes, capture data, and address developing channels for customer engagement in the evolving energy marketplace. Examples of the customer and employee improvements GBE will enable, include:

- self-service appointment scheduling and re-scheduling
- notification on service request progress and field crew location
- prompts for accurate capture of required information for compliance

- field mobile access to data, maps and process documentation
- instructor and video based training on mobile devices

Standardized Processes and Training. The GBE Program will also implement standardized operations processes and training that to this point has been fragmented due to the significant complexity of multiple supporting systems. This will reduce the level of requirements that would need to be designed, built, tested and trained, and as a result, mitigate the costs of the new technical solution. In addition, standardized processes and training will further support more consistent delivery and performance reporting.

Q. Please explain the Company's approach to implementing the GBE Program.

A. National Grid has established a project organization to support the development and implementation the GBE Program. There is a dedicated Senior Vice President (Mr. Johnston) overseeing the project delivery, schedule, and budget. National Grid worked with two of the top system integrators in the U.S., Accenture and PWC, to complete a high-level design and develop a roadmap that leverages modern system implementation approaches to minimize risk and maximize the likelihood that the desired business outcomes are successfully delivered. Detailed design and project implementation will also be supported by a system integrator consultant experienced with similar, large-scale implementations.

Q. Please describe the planned implementation.

A. The initial focus of the GBE Program will be development of standardized processes, implementation of asset management, work management and scheduling applications along with an integrated mapping (*i.e.*, GIS) solution. The Company will focus on replacing aged, core applications and implementing updated solutions as quickly as possible to help reduce the risk associated with critical, unsupported applications. This will create the foundation for building incremental enhanced capabilities to support safety performance, operational efficiency, the customer experience, and a performance-oriented culture. Examples of such enhanced capabilities include advanced analytics on asset demographic, condition, health, and other information to provide a consolidated view of asset risk geospatially; the customer and employee interaction portals; advanced analytics for work forecasting and planning; and supervisor field mobile capabilities on viewing and tracking crew and work order progress spatially; and auto work notifications.

The first release implementation will occur at National Grid's Rhode Island gas distribution company, The Narragansett Electric Company (gas segment), given its significant reliance today on paper-based operations and its manageable scale (*i.e.*, fewer operating yards). A stage-gate methodology will be employed to manage delivery and implementation in other service territories and operating companies once pre-defined thresholds of performance have been successfully demonstrated in Rhode Island. The GBE Program will implement agile development methods wherever it is appropriate to do so. Under this model, business and IS teams work collaboratively in short-cycles to prioritize functionality and get to a minimum viable product (*i.e.*, the simplest solution that can be implemented) allowing earlier release of initial functionality and reprioritization of enhancements based on learning.

Implementation is planned for Niagara Mohawk beginning in the Rate Year as shown in Exhibit __ (GIOP-8) with the following capabilities:

- Enterprise Asset Management integration with SAP and corrosion system;
- Initial work management for field collections and non-appointments;
- Basic scheduling and dispatching;
- Basic field data capture; and
- Standard GIS data model/improved data quality.

Q. Please describe how Software as a Service ("SaaS") is utilized by the GBE Program, and the benefits of its use.

A. The GBE Program is exploring the use of SaaS cloud solutions wherever options are available and best meet overall requirements. Examples are in the core systems like enterprise asset and work management, scheduling and dispatch, and field mobile as well as for data analytics and visualization.

Use of SaaS cloud solutions will provide several benefits including faster implementation and enhancement adoption, fewer upgrades to legacy infrastructure, easier upgrades when needed, reduced risk of obsolescence in the future, and the opportunity to enhance security. SaaS also provides strategic advantages by facilitating external interfaces with third party partners. SaaS can also be more easily scaled for additional capacity when required to enable growth

Q. How does the GBE Program address cyber security?

A. Protection of confidential customer information, asset data, and proprietary gas network information is essential to the success of the program. The program team is committed to meet or exceed National Grid's stringent cyber security requirements, which are based on best practices in the utility and other industries. National Grid's Digital Risk and Security department will provide cyber security guidance in testing and development activities. Digital Risk and Security will also implement device and personnel authentication, monitoring for unauthorized access to information, cloud data security services, malware protection, and identity and access management control.

The program also has a Cyber Security Architect dedicated to the project beginning in April 2017. In addition, the system integrator, existing partner suppliers, and security analysts will serve as supplemental cyber security experts.

Q. Please describe the specific projects/capabilities that will go in-service in the Rate Year and Data Years for Niagara Mohawk.

A. Exhibit __ (GIOP-9) describes the specific projects and capabilities that will go in-service in the Rate Year and Data Years for Niagara Mohawk.

Q. What is the total cost of the GBE Program?

A. The total cost of the GBE program for National Grid's U.S. operating companies is currently estimated at approximately $458.1 million. Of this amount, approximately $293.6 million comprise capital costs, and $164.5 million comprise operating expense. An additional $61 million has been budgeted as contingency in the event of unforeseen scope changes, changing market conditions affecting vendor and procurement costs, and unanticipated project complexity; this contingency has not been reflected in Niagara Mohawk's revenue requirement. While the GBE Program is ultimately expected to be delivered within the total budgeted costs, it is important to note that costs may shift between the Rate Year and Data Years as each of the projects completes detailed design.

Importantly, in February 2017, the GBE Program team received National Grid plc approval for the program's proposed $458.1 million budget (plus the incremental $61 million contingency). The GBE Program team is currently securing U.S. Sanctioning Committee approval as the final step in National Grid's approval process, while at the same time moving forward with program mobilization.

Q. What is the cost of the GBE Program to Niagara Mohawk?

A. Because the GBE Program is a shared National Grid investment, a portion of the total capital costs will be allocated to Niagara Mohawk in the form of an annual rent expense as part of the overall IS service rent expense charged to Niagara Mohawk. Niagara Mohawk's portion of the annual rent expense attributable to the GBE Program investment is $1.775 million, $3.881 million, and $5.939 million for the gas business in the Rate Year and Data Years, respectively as shown in Exhibit __ (RRP-11), Workpapers to Exhibit __ (RRP-3), Schedule 9, Workpapers 3, 6, and 9. The annual rent expense attributable to the electric business is $0.537 million and $1.093 million in Data Year 1 and 2, respectively, as shown in Exhibit__(RRP-11), Workpapers to Exhibit__(RRP-3), Schedule 9, Workpapers 6 and 9.

Niagara Mohawk's share of the $164.5 million total incremental operating expense in the Rate Year, as shown in Exhibit __ (GIOP-10), is $9.631 million for the gas business and $0.198 million for the electric business. Exhibit __ (GIOP-10) also shows the forecast of incremental operating expense allocated to Niagara Mohawk for the Data Years.

Q. Please explain how costs for the GBE program will be allocated to Niagara Mohawk.

A. Most GBE Program costs will be allocated among all of National Grid's gas operating companies based on the number of gas retail customers. As shown in Exhibit __ (GIOP-9), Exhibit __ (GIOP-10), and Exhibit______(RRP-11), Workpapers to RRP-3, Schedule 9, Workpapers 6 and 9, the costs of the Customer, Leak Investigation & Inspections and Company Driven Work: Collections and non-Appointment Offs initiatives will be split between the gas and electric business based on the number of Customer Meter Services Field

Technicians supporting each business because these projects implement process standardization, applications, and field devices for all Customer Meter Services gas and electric employees. The electric portion will be allocated among all electric operating companies based on the number of electric distribution customers.

Q. Please explain what costs comprise the incremental operating expense for Niagara Mohawk in the Rate Year and Data Years.

A. The incremental project operating expense included in Exhibit __ (GIOP-10) relates to end user training, data conversion from the legacy applications to the new GBE applications, business process documentation that is non-system related, and GBE Program management of schedule, resources, finance, risks, and performance.

Q. Does the Historic Test Year include costs for the GBE program?

A. Yes, the Historic Test Year includes certain non-recurring costs for the GBE Program related to the development of the business case, assessment of processes and applications, and high-level design for the GBE Program. Niagara Mohawk has made a normalizing adjustment of $0.643 million for the gas business to remove these non-recurring costs from the Rate Year.

Q. Are there any incremental post-implementation run the business costs associated with GBE?

A. Yes. As shown in Exhibit__(GIOP-11), the Company will incur additional run the business costs to support the GBE Program post-implementation. These costs include (i) a team to support business functions in the use of the new systems, design new processes to take full advantage of the new system, and monitor business controls embedded in the system; (ii) hardware, software, and mobile solutions license maintenance fees and subscriptions; and (iii) support costs to maintain certain legacy applications following implementation until these legacy applications are replaced or maintained in an upgraded future state, as appropriate.

Support costs for the legacy applications will decrease from the Rate Year to the Data Years. Additional support costs will be required for legacy applications that will continue to remain after full implementation due to, regulatory reporting needs and outstanding legal hold obligations.

As legacy software systems are retired due to functional replacement as part of the GBE Program, the run the business costs for operating the servers, software systems, and field devices will be eliminated. As shown in

Exhibit__(GIOP-11), the Company has netted these costs against the forecast run the business costs expected in the Rate Year.

Q. What are the incremental post-implementation run the business costs associated with GBE in the Rate Year and Data Years?

A. As shown in Exhibit __ (GIOP-11), Niagara Mohawk's allocated share of these costs is $1.2 million. Niagara Mohawk's allocated share of these costs in the Data Years is $2.608 million and $3.095 million, respectively, as shown in Exhibit __ (GIOP-11).

Q. Has the Company quantified the benefits associated with the GBE Program?

A. Yes. As explained earlier, the main objective of the GBE Program is to consolidate the many duplicate and aging applications and systems across the enterprise. As essentially an asset replacement program, the primary benefit is a reduction in operational risk.

The new asset, work, and mobility systems will lay the foundation for enhanced capabilities that will drive a broad range of operational benefits and performance improvements, some of which are anticipated to result in cost reductions. Specifically, implementation of enhanced capabilities could provide the following benefits:

Type I (Spend Reduction) – the benefit has a direct, quantifiable and sustainable impact in reducing costs. For example, the GBE Program investments are anticipated to deliver increased clerical and back office productivity beginning in Data Year 2 as a result of automation of some manual tasks (*e.g.*, time entry), elimination of paper based processes, as well as streamlining of data updates performed by clerical staff.

Type II (Capacity Savings) – the benefit is a process improvement that consists of resources freed up or future cost or increased potential for penalty avoidance as enhanced capabilities are embedded. For example, the work and asset management will provide improved scheduling, bundling of work, and enhanced, prescriptive routing for field technicians. In turn, these enhancements will allow optimization of drive time and existing resources freeing additional resource capacity (*i.e.*, additional jobs completed per shift).

Q. Have forecast cost reductions associated with the GBE Program been reflected in this filing?

A. Yes. While it is unknown if the savings estimates can be achieved, Niagara Mohawk has made an adjustment to the Rate Year and Data Years for its gas business to reflect its allocated share of the estimated Type I savings from the GBE Program initiatives. The adjustment reduces the revenue requirement by $0.007 million in the Rate Year, $0.158 million Data Year 1, and $1.025 million in Data Year 2. No adjustment is being made for Type II savings because they do not result in a direct cost reduction, but rather increase capacity for work that otherwise would not be completed. No adjustment is being made for penalty avoidance savings since penalties are not recovered from customers.

Exhibit __ (GIOP-12), Page 1 provides the total U.S. benefits (Type I and Type II, and capital and operating expense benefits) for the GBE Program. As reflected in Exhibit __ (GIOP-12) Page 1, the majority of benefits will be realized after Data Year 2. Once the enhanced capabilities are fully embedded, which is expected by FY 2024, the GBE Program estimates total potential combined Type I and II benefits of $39.615 million annually.

Q. How were initiatives that targeted capital related savings treated in the filing?

A. With respect to initiatives estimated to result in capital savings, those savings are embedded in the capital plan and not reflected as separate adjustments in the revenue requirement.

Q. What training will be delivered as part of the GBE Program?

A. Comprehensive training will be provided to all users of the systems, both field and office workers as well as first line and upper levels of management. Training will be delivered using various media such as computer-based instruction, video, classroom, mobile and written help guides.

Q. How will the program team assess the readiness of the business to begin using the various functional parts of a project?

A. Early in the process, working with gas business leadership, the GBE team will identify business readiness requirements and develop business readiness checklists and go/no go checkpoints to ensure business readiness by geography.

Q. Does this conclude your testimony?

A. Yes, it does.

Exhibits of
GIOP

Index of Exhibits

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Exhibit __ (GIOP-1)

Actual and Projected Capital Expenditures: Historic Test Year,

Rate Year and Data Years

Niagara Mohawk
Gas Capital and Cost of Removal

Classification	Rate Case Category	Historic Test Year ($000's)	FY'18 Business Plan ($000's)	FY'19 Rate Year ($000's)	FY'20 Data Year 1 ($000's)	FY'21 Data Year 2 ($000's)
Growth	Base Growth - Install Main	$ 8,117	$ 6,176	$ 7,208	$ 7,626	$ 8,043
	Base Growth - Install Services	$ 12,701	$ 11,855	$ 13,696	$ 14,491	$ 15,284
	Base Growth - Neighborhood Expansion Program - Main	$ 4	$ 623	$ 679	$ 698	$ 715
	Base Growth - Neighborhood Expansion Program - Services	$ -	$ 375	$ 489	$ 502	$ 514
	Base Growth - Customer Contributions	$ (1,182)	$ (2,048)	$ (1,241)	$ (1,275)	$ (1,305)
	Base Growth - Fitting	$ 6,613	$ 4,614	$ 5,719	$ 5,874	$ 6,015
	Base Growth - Install Meter/Regulator	$ 3,694	$ 2,302	$ 3,877	$ 3,983	$ 4,078
	Base Growth - Meter Purchases	$ 1,986	$ 1,145	$ 2,197	$ 2,302	$ 2,404
	Gas System Reinforcement	$ 787	$ 3,322	$ 6,560	$ 7,857	$ 12,201
	Marcy NanoTech Center (MV Edge)	$ 1,022	$ 9,559	$ 500	$ -	$ -
	Marcy NanoTech Center (MV Edge) CIAC	$ (1,527)	$ (9,559)	$ (500)	$ -	$ -
	Global Foundries	$ (69)	$ -	$ -	$ -	$ -
	Global Foundries CIAC	$ (69)	$ -	$ -	$ -	$ -
Subtotal Growth		**$ 32,077**	**$ 28,364**	**$ 39,184**	**$ 42,058**	**$ 47,949**
Mandated	CSC/Public Works	$ 5,163	$ 6,000	$ 6,064	$ 6,229	$ 6,379
	CSC/Public Works - Reimbursable	$ 7	$ 8	$ -	$ -	$ -
	CSC/Public Works - Reimbursements	$ 87	$ (8)	$ -	$ -	$ -
	Corrosion	$ 2,542	$ 1,826	$ 2,367	$ 2,431	$ 2,490
	Main Replacement (Proactive) - Leak Prone Pipe	$ 34,356	$ 46,662	$ 48,060	$ 49,366	$ 50,551
	10-12-14-Inch CI Program	$ 28	$ -	$ -	$ -	$ -
	Replace Pipe on Structures	$ -	$ -	$ 825	$ 1,578	$ 795
	Main Replacement (Reactive) - Maintenance	$ 1,160	$ 828	$ 1,217	$ 1,250	$ 1,280
	Cross Bore Investigation	$ -	$ 1,026	$ 612	$ 629	$ -
	Atmospheric Corrosion Inside Inspections (Remediation)	$ 187	$ 670	$ 196	$ 201	$ 206
	Transmission Services	$ -	$ 429	$ 4,008	$ 4,117	$ 4,216
	Purchase Meters (Replacements)	$ 3,650	$ 4,307	$ 4,116	$ 4,313	$ 4,505
	Install Elevated Pressure Meter Correctors	$ -	$ -	$ 911	$ 936	$ 958
	Advanced Metering Infrastructure (AMI) - ERTS	$ -	$ -	$ -	$ 1,017	$ 19,796
	Meter Changes	$ 4,962	$ 5,772	$ 4,862	$ 5,094	$ 5,320
	Other Meter Work	$ 72	$ -	$ -	$ -	$ -
	Soft-Offs	$ 16	$ -	$ -	$ -	$ -
	Pipeline Integrity IMP (Integrity Management Program)	$ 7,146	$ 12,181	$ 13,308	$ 16,759	$ 21,250
	Pipeline Integrity IVP (Integrity Verification Program)	$ 46	$ 4,500	$ 4,500	$ 4,514	$ 4,526
	PL 34-8 Inch Replacement	$ -	$ -	$ 4,453	$ 13,657	$ 500
	PL 36-16 Inch Replacement	$ -	$ -	$ -	$ -	$ -
	Transmission Pipeline Washout	$ 2,459	$ 500	$ 500	$ 514	$ 526
	Transmission Pipeline (Reactive)	$ 674	$ 500	$ 500	$ 514	$ 526
	Service Replacements - Proactive	$ 12	$ -	$ -	$ -	$ -
	Service Replacement (Reactive) - Leaks	$ 4,144	$ 4,816	$ 4,336	$ 4,454	$ 4,561
	Service Replacements (Reactive) - Non-Leaks/Other	$ 4,341	$ 4,590	$ 2,472	$ 2,539	$ 2,600
	Lock Numbers 10 & 11 Washout	$ (105)	$ -	$ -	$ -	$ -
Subtotal Mandated		**$ 70,947**	**$ 94,607**	**$ 103,307**	**$ 120,112**	**$ 130,985**
Reliability	Gas System Control	$ -	$ 86	$ 88	$ 90	$ 93
	Gas System Control - Gas Control (Telemetry Upgrade 3G to 4G)	$ -	$ -	$ 100	$ 100	$ -
	Gas System Control - Gas Control (Training Simulator)	$ -	$ -	$ -	$ 60	$ 340
	Gas System Reliability - Gas Planning/RCV Programs	$ 776	$ 985	$ 2,511	$ 2,843	$ 2,704
	Gas System Reliability - Albany Loop Closure	$ -	$ 250	$ 3,000	$ 32,318	$ 33,459
	Valve Installation/Replacement	$ 67	$ 290	$ 245	$ 252	$ 258
	Water Intrusion	$ 53	$ 905	$ 668	$ 686	$ 703
	I&R - Reactive / CNG	$ 317	$ 386	$ 333	$ 342	$ 350
	I&R CNG Construct 3 Portable Gas Regulator Stations	$ -	$ -	$ 225	$ -	$ -
	I&R CNG Purchase Portable CNG Tube Trailer	$ -	$ -	$ 750	$ -	$ -
	I&R Training Facilities	$ -	$ -	$ 500	$ -	$ -
	Security At Critical Infrastructure	$ -	$ -	$ 1,550	$ 1,550	$ 1,550
	Methane Emmission Reduction	$ -	$ -	$ 800	$ 800	$ 700
	System Automation	$ 237	$ 750	$ 1,400	$ 1,438	$ 1,472
	Heater Installation Program	$ 143	$ -	$ 2,000	$ 2,365	$ 2,500
	Pressure Regulating Facilities	$ 3,545	$ 2,710	$ 4,640	$ 4,310	$ 4,390
	Overpressure Protection Program	$ -	$ -	1,050	1,079	1,104
	Pressure Reg Station - Lamphear Rd - GRS 824-695	$ -	$ 50	$ -	$ -	$ -
	Pressure Reg Station - Alplaus - GRS 924-426	$ -	$ 400	$ 1,290	$ 80	$ -
	Pressure Reg Station - Mariaville Road Rotterdam - GRS 924-434	$ -	$ -	$ 400	$ 1,700	$ 80
	Pressure Reg Station - Putnam Gate - GRS 924-450	$ -	$ 250	$ 25	$ -	$ -
	Pressure Reg Station - Campion Road GRS 824-688	$ -	$ -	$ 500	$ -	$ 1,800
	Pressure Reg Station - Brookview Gate Station	$ 3	$ 225	$ 1,210	$ -	$ -
	Pressure Reg Station - Chestnut St GRS 824-175,201	$ 738	$ 75	$ -	$ -	$ -
	Pressure Reg Station - Oneida Supply - GRS 824-709	$ -	$ -	$ 500	$ 2,100	$ 80
	Pressure Reg Station - Elton Ave & Salina St GRS 824-043	$ 91	$ 2,000	$ 75	$ -	$ -
	Pressure Reg Station - Cold Springs Rd - GRS 824-127	$ -	$ -	$ 500	$ -	$ 2,000
	Pressure Reg Station - Washington & Fuller - GRS 924-313	$ -	$ -	$ -	$ 620	$ -
	Pressure Reg Station - Sandy Creek GRS 824-216A, 216B	$ -	$ -	$ -	$ -	$ 600
	Pressure Reg Station - Valentine Rd GRS 924-452	$ -	$ -	$ -	$ -	$ -
	Pressure Reg Station - Dams Corners GRS 824-697	$ -	$ -	$ -	$ -	$ -
	Pressure Reg Station - All Other	$ 48	$ -	$ -	$ -	$ -
Subtotal Reliability Sum		**$ 6,018**	**$ 9,362**	**$ 24,360**	**$ 52,733**	**$ 54,183**
Non-Infrastructure	Tools & Equipment - Various	$ 673	$ 942	$ 706	$ 726	$ 743
	Combustable Gas Indicators	$ (183)	$ -	$ -	$ -	$ -
	Restrictions for Elevated Gas Infrastructure	$ -	$ -	$ 1,052	$ 1,081	$ 1,107

Classification	Rate Case Category	Historic Test Year ($000's)	FY'18 Business Plan ($000's)	FY'19 Rate Year ($000's)	FY'20 Data Year 1 ($000's)	FY'21 Data Year 2 ($000's)
Subtotal Non-Infrastructure		**$ 490**	**$ 942**	**$ 1,758**	**$ 1,807**	**$ 1,850**
Misc	Misc	$ (1,364)	$ -	$ -	$ -	$ -
Subtotal Misc		**$ (1,364)**	**$ -**	**$ -**	**$ -**	**$ -**
Total Direct Capital (Capital and COR)		**$ 108,168**	**$ 133,275**	**$ 168,609**	**$ 216,710**	**$ 234,967**
Cost of Removal		$ 6,771	$ 8,773	$ 10,839	$ 11,288	$ 13,772
Total Direct Capital (Capital)		**$ 101,397**	**$ 124,502**	**$ 157,770**	**$ 205,422**	**$ 221,195**

Exhibit __ (GIOP-2)

Actual and Projected Annual Investment Levels, FYs 2014 – 2021

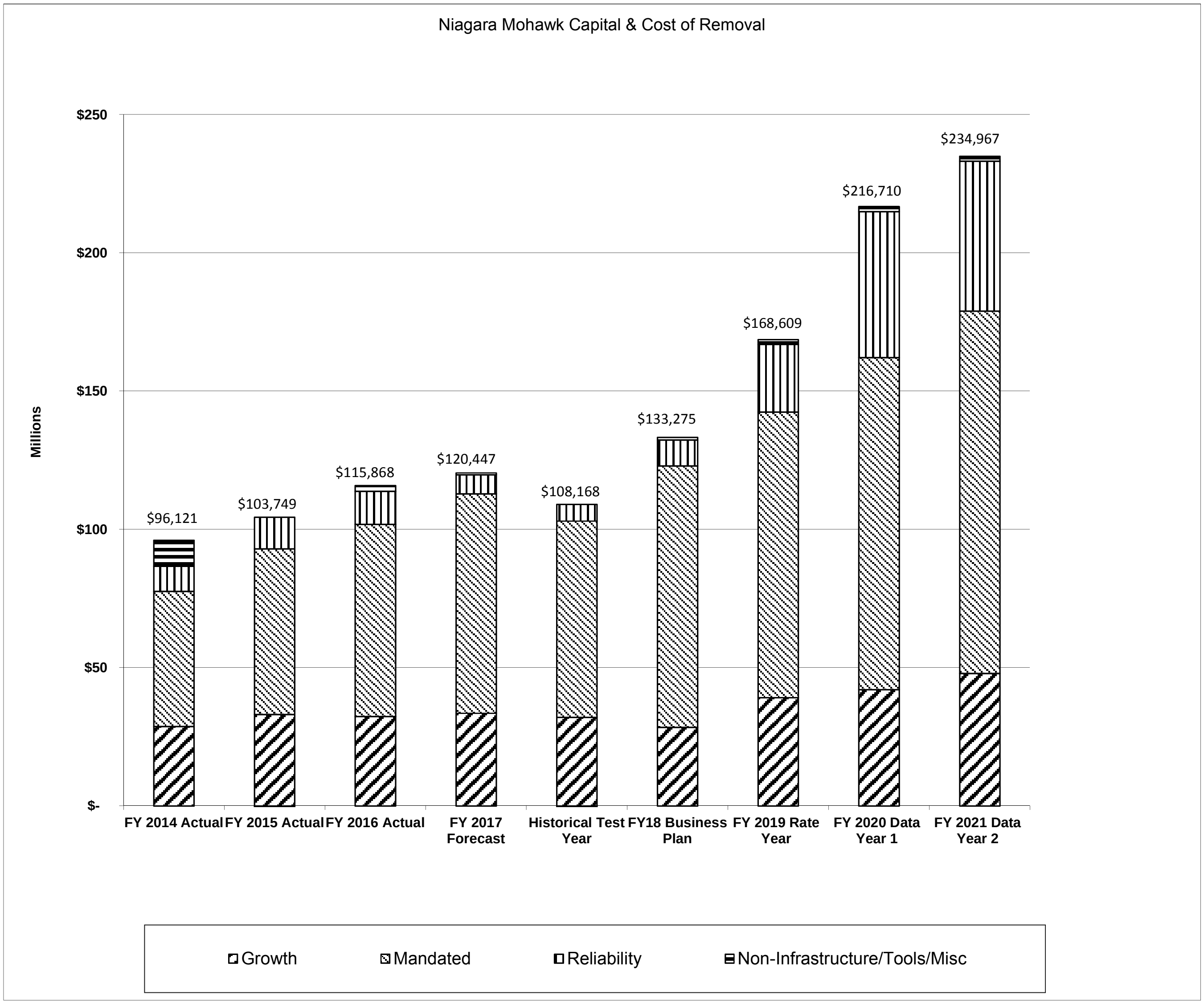

Niagara Mohawk Capital & Cost of Removal
Millions
$250
$200
$150
$100
$50
$-
$96,121
$103,749
$115,868
$120,447
$108,168
$133,275
$168,609
$216,710
$234,967
FY 2014 Actual
FY 2015 Actual
FY 2016 Actual
FY 2017 Forecast
Historical Test Year
FY18 Business Plan
FY 2019 Rate Year
FY 2020 Data Year 1
FY 2021 Data Year 2
Growth
Mandated
Reliability
Non-Infrastructure/Tools/Misc

Exhibit __ (GIOP-3)

Projected Leak Rates for Leak Prone Pipe for Different

Main Replacement Strategies

Exhibit__(GIOP-3)
Page 1 of 1

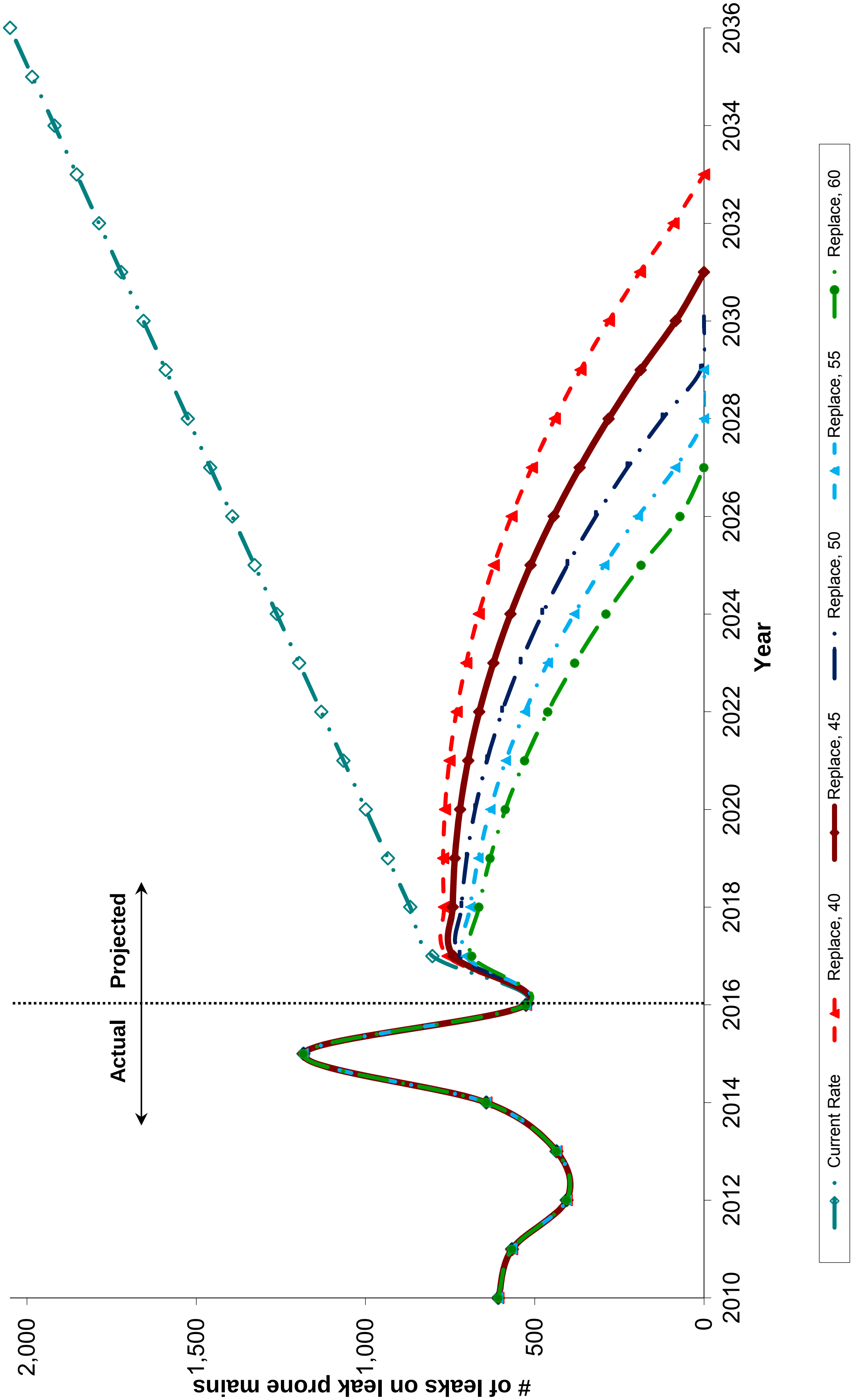


Exhibit__ (GIOP-4)

Exhibit __ (GIOP-4)

Data Sheets for Significant Capital Programs

Program Title: Base Growth Program

Spending Rationale: ☐ Mandated ☒ Growth

☐ Reliability ☐ Non-Infrastructure

Brief Description:

Niagara Mohawk's Base Growth Program involves the installation of new main, services and meters to serve projected customer/demand growth, including the capital requirements necessary to meet increasing customer demand resulting from construction activity in the service territory. This program also includes the continuation of the Neighborhood Expansion Program, which is discussed in the Gas Customer Panel testimony. The total cost breakdown below is for base growth, exclusive of the Neighborhood Expansion program.

Program Justification:

Conversions: The growth trend shows a slight decrease due to low oil pricing, saturation and system issues in the multifamily and commercial, and residential conversion markets. Conversely the trend shows a slight increase in the commercial sector due to the stronger economy which is primarily realized (75%) in the Eastern Division or Capital Region area.

New Construction: Due to the stronger economic conditions, there is an increasing trend in both the residential and multi-family market segments with a slight decrease within the commercial market segment. Overall there has been a transition from a trending growth in the conversion connections to a stronger showing within the New Construction category.

The overall growth forecast is currently at two percent in the Rate Year and three percent per year in Data Year 1 and Data Year 2. The forecast considers the implications of (a) changes in the various market segments; (b) large project inventories; (c) rate/regulatory changes; and (d) system constraint. The forecast also considers Historic Test Year costs for main and services, as well as the following factors that drive growth projections and the associated capital expenditures:

- Fuel pricing – oil versus natural gas
- Inventory levels and turnover ratios
- Saturation levels
- Marketing lead performance
- Designs and resourcing that supports the delivery of capital at efficient pricing
- Economic conditions/building starts
- Gas system constraints

Forecasted main and service installations for Rate Year, Data Year 1 and Data Year 2 (exclusive of the Neighborhood Expansion Program) are as follows:

Base Growth Forecast	FY 2019	FY 2020	FY 2021
Services	3,362	3,463	3,567
Main (feet)	169,770	174,863	180,109

Historic main and service installations (exclusive of the Neighborhood Expansion Program) are as follows:

Base Growth Historic	FY 2012	FY 2013	FY 2014	FY 2015	FY 2016
Services	2,974	3,527	3,640	3,109	3,229
Main (feet)	111,216	178,153	167,946	181,460	193,384

Growth Capital Program Cost Breakdown:

The capital growth program will provide support to meet the anticipated customer demand for a five-year period.

CAPEX $000	**FY 2019**	**FY 2020**	**FY 2121**
Base Growth - Install Main	7,208	7,626	8,043
Base Growth - Install Services	13,696	14,491	15,284
Base Growth - Customer Contributions	(1,241)	(1,275)	(1,305)
Base Growth – Install Meter/Regulator	3,877	3,983	4,078

Customer Benefits:

Based on a 15-year life expectancy of the energy efficient equipment installed, more than 4,222 gas heating conversions in Niagara Mohawk's service territory could have positive economic and environmental benefits, as shown below:

Average Annual Economic Benefits (2018 to 2032) *

Number of Customers	Annual Dth Per Customer	Total Dth Converted	Fuel Cost Savings Per Customer	Total Fuel Cost Savings ($m)	Annual Jobs Created	Annual GDP Created ($m)	Annual Income Created ($m)	State Tax Revenue Impact ($m)
4,222	100	422,200	$1,822	$7.7	40	$3.7	$2.5	$0.2

* Source: REMI regional economic model. Results based on annual fuel cost savings for 4,222 conversions. Results are for the State of New York.

Summary of Annual Environmental Benefits **
"Converting" to Natural Gas from Oil with Efficiency Improvement ***

Customer Segment	Number of Conversions	Annual Gas Dth Per Conversion	Total Oil Dth Converted	Local Emissions Reduction (lbs)	CO2 Emissions Reduction (lbs)	Gallons of Oil Displaced	Barrels of Oil Displaced	Equivalent Cars
Residential	4,222	100	422,200	32	20,977	4,082,813	97,210	50,612

** Source: EPA emissions factors for natural gas and oil (see "Environmental Benefits" tab).
*** Assumes new gas furnace AFUE of 88% and old oil furnace AFUE of 65%.
Equivalent cars equals the number of cars that would have to be taken off the road for one year in order to match the CO2 emissions reductions from oil-to-gas conversions over the minimum 15-year life of the new gas heating equipment.

Estimated per customer:

- $1,822 annual energy savings
- 967 gallons of oil eliminated
- $13,142 individual GDP created
- Equivalent emissions reduction removing twelve cars off the road annually

<u>Alternatives:</u>

Alternative 1: Tariff Change to Increase Contributions in Aid of Construction (CIAC)

Propose amending the tariff to require smaller customers to pay for necessary reinforcements to provide service. This alternative is rejected because it increases customer costs and will likely lead to reduced growth.

Program Title: Gas System Reinforcement Program

Spending Rationale: ☐ Mandated ☒ Growth

☐ Reliability ☐ Non-Infrastructure

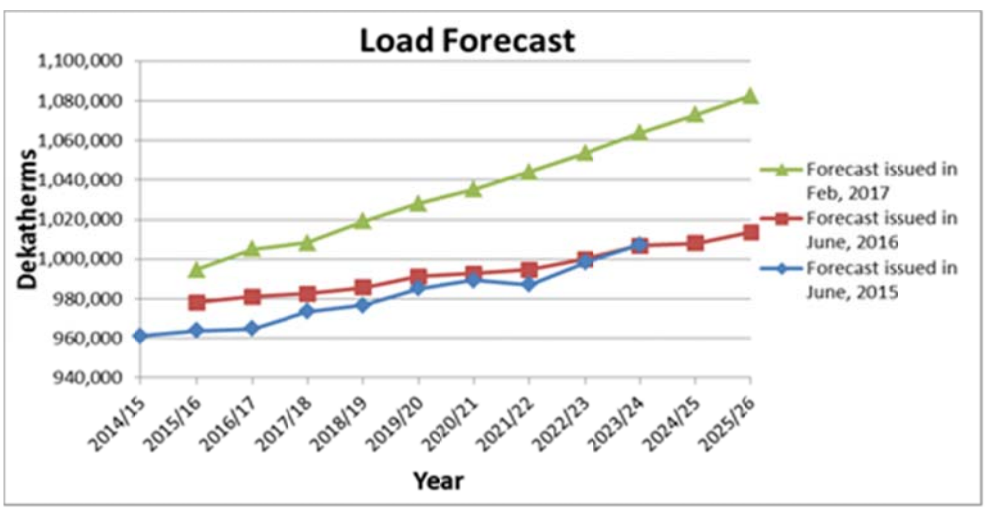
Brief Description:

The Gas System Reinforcement Program consists of capital reinforcement projects required to maintain pressure above system minimums on the gas network during periods of peak demand, thereby maintaining continuous service to all gas customers. This program is a five-year program covering the winter periods for 2017/18 through 2021/22.

Program Justification:

Federal (49 CFR 192.623) and New York State (16 NYCRR 255.623) regulations require the Company to maintain minimum pressures on the gas system necessary to maintain reliable service to all firm customers. The Gas System Reinforcement Program identifies projects required to maintain service under peak day, peak hour conditions. Niagara Mohawk's gas system is designed for a peak day with an average temperature of -10°F (75HDD – Heating Degree Days), with five percent of the daily send-out as a peak hour. The peak demand is based on the same forecast utilized to develop the gas supply portfolio, and the Gas System Reinforcement program is a critical component for enabling delivery of that gas supply to firm customers. In some cases, even small to moderate increases in the overall forecast can result in significant reinforcements due to certain regions experiencing high growth rates while other regions may be experiencing low growth rates or decreasing system demands.

The Analytics, Modeling, and Forecasting ("AMF") group's load forecast shows an increasing trend as demonstrated in the below graph.



Examples of distribution system reinforcement projects include, but are not limited to, the following:

- Replacing existing undersized mains with larger diameter mains targeting leak prone pipe whenever practical
- Looping or connecting system endpoints by installing new main
- Installing new district regulators as well as replacing and/or rebuilding existing undersized district regulators
- Transferring existing customers supplied from low-pressure mains to adjacent high-pressure mains (*i.e.,* load shedding)

Total Project Cost Breakdown:

$000	**FY 2019**	**FY 2020**	**FY 2021**
CapEx	6,560	7,857	12,201

Customer Benefit:

Installing these reinforcements will ensure that service is maintained to all firm gas customers on the system. Without the reinforcement program, as many as 25,310 customers are at risk of experiencing pressures below minimum design pressures and, therefore, at risk of losing service. The estimated cost to relight these customers is $25.3M (approximately $1,000 per customer based on previous experiences). A secondary benefit of the program is the elimination of leak prone pipe wherever practicable. For example, the program represents a replacement rate of about 23.5 percent, approximately 8,535 feet (1.6 miles), of leak prone pipe in the Rate Year.

Alternatives

Alternative 1: Do Nothing

This alternative is rejected because as many as 25,310 customers may experience pressures below minimum design levels and may be at risk of losing service if design conditions were to be experienced during the five-year heating season term under the current gas supply send-out forecast.

Studies/References That Support the Program:

Studies were run on the Company's network models using Synergi, which is an industry standard software. The models, which are validated on an annual basis, were loaded with the forecast provided by the Company's Analytics, Modeling, and Forecasting ("AMF") department. Additionally, AMF provided a forecast at a zip code level. There is a high degree of confidence in the accuracy of the modeling and forecast and that the appropriate reinforcement projects were identified.

Program Title: Public Works Program (City/State Construction)

Spending Rationale: ☒ Mandated ☐ Growth

☐ Reliability ☐ Non-Infrastructure

Brief Description:

The City/State Construction ("CSC") Program consists of work to accommodate infrastructure projects by various Upstate New York municipalities, as well as the New York State Department of Transportation ("NYSDOT"). The CSC program is directed at replacing gas infrastructure that will be compromised by third-party construction activities.

The scope of the FY 2019 program includes approximately 26,523 linear feet (5.023 miles) of main installation to accommodate municipal capital infrastructure improvements. The program will contribute approximately 5,750 linear feet (one mile) of LPP retirement to the Company's Proactive Main and Service Replacement Program. The LPP retirement mileage and spending estimates are based on historical information and the current schedule of municipal work.

Program Justification:

The Company's facilities are often in direct conflict with proposed municipal infrastructure installations or are required to be relocated based on regulatory requirements.

Niagara Mohawk's CSC budget is divided into reimbursable and non-reimbursable categories. Projects are placed into either category based on the project funding source. Public works projects initiated by the NYSDOT, cities, counties, and third-party private entities are occasionally reimbursable. Reimbursable projects include relocation of existing facilities on private ROW and relocations required by private entities. Conversely, non-reimbursable projects include required relocation of existing facilities that are on public ROW and are funded by the NYSDOT or the numerous municipalities that Niagara Mohawk serves.

The Company's government liaisons work closely with engineers and consultants from the NYSDOT and Upstate New York municipalities to minimize any direct conflicts with the existing gas infrastructure. Collaborating with municipalities reduces the Company's O&M costs, maximizes remuneration and reduces risk exposure to the Company.

Total Capital Project Cost Breakdown:

$000	FY 2019	FY 2020	FY 2021
CSC/Public Works - Non Reimbursable	6,064	6,229	6,379
CSC/Public Works - Reimbursable	-	-	-
CSC/Public Works - Reimbursements	-	-	-

Customer Benefit:

- The CSC Program will contribute approximately 5,750 linear feet (one mile) of LPP retirement in Niagara Mohawk's service territory.
- Efficiency opportunities are realized through integration with other operational program work including, but not limited to, main and service replacement, customer driven construction, reliability, and long term planning.

Alternatives:

None.

Studies/References That Support the Program:

The program is supported by the Company's obligations under New York State laws and regulations including General Obligations Law Section 11-102, NYSDOT's rules and & regulations under 17 NYCRR Part 131, and the Commission's regulations under 16 NYCRR 255.755, 756 & 757.

Program Title: Gas Corrosion Control Program

Spending Rationale: ☒ Mandated ☐ Growth

☐ Reliability ☐ Non-Infrastructure

Brief Description:

This program funds work on gas mains at bridge locations, railroad crossings and other structures and includes complete recoating of existing aged, dis-bonded, deteriorated or uncoated gas mains, as well as retirement of LPP where it extends underground near these crossings. In addition, this program includes corrosion mitigation for buried piping and upgrades to existing cathodic protection systems.

Corrosion mitigation for buried piping requires two items:

1. Protective Coating/Barrier – installed and tested at the mill or in the field and provides a protective barrier from the elements and the naturally occurring corrosion process

2. Cathodic Protection System – installation of cathodic protection system and acceptance testing of buried piping, which is typically performed during the installation of the piping or shortly thereafter. There are two types of cathodic protection systems:
   i. Galvanic – provides direct current (DC) onto the pipe through the use of sacrificial anodes (typically 17 pounds of magnesium) that corrode away, which in turn protect the pipe from corrosion
   ii. Rectifier – takes alternating current (AC) and changes it to DC while utilizing specialized anodes (due to the higher current demands of the piping system)

In summary, all cathodic protection systems require the following:

- Proper protective coatings
- Isolation from other metallic structures
- Test boxes with anodes & lead wires
- Periodic inspection and testing
- Periodic upgrades (remediation measures) to provide for extended life of the asset

Program Justification:

Corrosion can lead to failures in plant infrastructure and equipment, which typically are costly to repair. Decisions regarding the future integrity of a structure or its components depend entirely upon an accurate assessment of the conditions affecting its corrosion and rate of deterioration. The Corrosion group performs field testing, monitoring, upgrades and repairs to existing corrosion control systems in accordance with federal and state code requirements (49 CFR Part 192 – Transportation and 16 NYCRR Part 255 – Transmission and Distribution of Gas), as well industry standards. This includes periodic testing, inspection, monitoring and diagnostic troubleshooting of existing corrosion control systems. The Corrosion group provides engineering standards as well as the design and development of new cathodic protection systems and upgrades to existing cathodic protection systems. The work identified is in applicable corrosion control programs and mandated by federal and state regulations.

Total Project Cost Breakdown:

$000	FY 2019	FY 2020	FY 2021
CapEx	2,367	2,431	2,490

Niagara Mohawk seeks to change the accounting treatment of corrosion work to reflect asset improvements that have historically been expensed as capital. The Company seeks to capitalize the upgrading of cathodic protection systems, which includes installation of test stations, insulating joints, rectifiers, impressed current ground beds, main recoats and AC mitigation.

The work can be either routine expense work or capital depending on the activity being performed:

- OpEx work includes periodic testing, inspection, monitoring, diagnostic troubleshooting and upgrading of the existing corrosion control system in accordance with state and federal codes;
- CapEx work includes asset improvements such as recoating of pipelines to remediate corrosion and extend the life of the asset.

As a result of this change, Niagara Mohawk's corrosion program will see an increase in capital expense but a decrease in operations and maintnanence expense spending for the future rate years. The above forecast takes into account the proposed change.

Proposed changes from OpEx to CapEx:

- Install test station (TS) on Main
- Install TS on main across Insulated Joints (IJ)
- Install TS on Distribution Service
- Install TS on Main with anode(s)
- Install TS on main across IJ with anode(s)
- Install TS on Distribution Service with anode(s)
- Install/Replace IJ at Meter
- Install/Replace IJ on Main
- Special Request - Renew Service with Plastic
- Install new Rectifier

Customer Benefit:

The Company expects minimal customer impact during the performance of the corrosion control programs. Customers can benefit from the program in the following ways:

- Improved public safety due to reduced risk of gas incidents
- Fewer unplanned service interruptions
- Fewer unplanned disruptions to traffic on roads

Alternatives:

None

Studies/References that Support the Program:

This program is in accordance with the Company's standards and complies with federal and state pipeline safety regulations under 49 CFR Part 192 and 16 NYCRR Part 255.

Program Title: Proactive Main and Service Replacement (Leak Prone Pipe)

Spending Rationale: ☒ Mandated ☐ Growth

☐ Reliability ☐ Non-Infrastructure

Brief Description:

Currently, the Company is required to retire leak prone pipe ("LPP") at a rate of 45 miles/year in FY2017 and 53 miles in FY2018. Failure to retire 98 total miles of LPP in CY 2016 and CY 2017 will result in penalties. For the reasons described below, the Company is recommending a LPP retirement target of 50 miles per year in FY 2019 through FY 2021, which will eliminate all remaining LPP over the next thirteen years, versus sixteen years under the current plan.

Niagara Mohawk considers LPP as including pipe less than 16 inches that is (i) unprotected (i.e., non-cathodically protected) steel pipe (whether bare or coated) and (ii) cast and wrought iron pipe, and associated services. Beginning in the Rate Year, the Company intends to include in this program retirement of pre-1985 vintage Aldyl-A plastic pipe and pre-1974 plastic services that are located along the remaining LPP inventory.

This program also includes funding to perform upgrades on approximately one mile of non-leak prone distribution main per year beginning in the Rate Year in order to address low pressure issues that will result from retirement of LPP in some areas.

Program Justification:

LPP accounts for approximately eight percent of the Company's distribution main inventory, yet it accounts for 87 percent of leak repairs (excluding damages). At the end of CY 2016, the remaining inventory of LPP was 675 miles (218 miles of unprotected steel, 453 miles of cast iron/wrought iron and four miles of pre-1985 vintage Aldyl-A plastic pipe). The current leak repair rate for all distribution piping is 0.07 leaks per mile, excluding damages from excavations, which represents a slight increase from 0.06 leaks per mile in 2012. The current leak repair rate for LPP is 0.77 leaks per mile. The leak rate increased significantly during 2014 and early 2015 due to exceptionally cold weather in the Northeast. The impact of cold weather on the system and leak rates suggest that retirement of LPP is warranted.

The retirement of LPP is also supported by the Company's Distribution Integrity Management Plan ("DIMP"), which specifies that the Company: (i) know its distribution piping system, (ii) understand the threats to the system, and (iii) evaluate the risks and prepare replacement programs for its leak prone mains and services inventory to help mitigate those risks.

Leak predictive models show that main retirement levels below a certain threshold will cause leak rates to increase exponentially. Retirement levels below this amount will cause leaks to increase to a point where it will not be feasible to react in a timely manner to the quantity of new leaks. The model shows that there is a practical limit to how many leaks a system can have and continue to operate safely.

The Company proposes adding to this program retirement of pre-1985 vintage Aldyl-A plastic pipe and pre-1974 HDPE services associated with LPP. Some early vintages of plastic pipe and services are known to have performance issues, including brittle cracking. Retirement of pre-1985 Aldyl-A plastic mains is consistent with the KEDLI and KEDNY LPP retirement strategy. Furthermore, safety advisory bulletins published by PHMSA in 1999 concluded that pre-1974 installed plastic is highly susceptible to brittle-like cracking due to the low-ductile inner walls ("LDIW"). This includes DuPont's "Aldyl-A", HDPE, and other various resins. The Company has increasingly experienced such failures of service pipe since 2010. Therefore, vintage HDPE (pre-1974) services located on remaining LPP inventory should be retired in conjunction with the retirement of the associated LPP main.

Additionally, in some areas of the Company's service territory, retirement of LPP will result in low pressures on surrounding non-leak prone distribution main. The Company estimates that reinforcements to approximately one mile of non-leak prone main per year beginning in the Rate Year will be required in order to retire LPP.

Total Project Cost Breakdown:

The total costs shown below are comprised of the forecasted LPP retirement unit cost of $185.76 per foot for the retirement of approximately 48 miles of LPP and associated services (the other two miles to meet the 50 mile/year target are expected to be achieved through other programs, such as public works, reinforcements, and reliability programs) plus approximately $1 million per year to address the one mile of non-LPP reinforcements, adjusted for inflation.

$000	FY 2019	FY 2020	FY 2021
Proactive Main and Service Replacement (LPP)	48,060	49,366	50,551

Note: The Company is also proposing a productivity incentive measuring the Company's ability to cost effectively replace LPP, as well as an incentive and surcharge recovery mechanism for retirement of additional miles. Proposed incentives are discussed in the direct testimony of the Gas Safety Panel.

Customer Benefit:

The key benefits of LPP retirement include:

- Improved public safety by reducing the risk of gas related incidents

- Improved system reliability and customer satisfaction
- Compliance with federal and state code requirements, including US Department of Transportation's DIMP requirements
- Increased efficiency resulting from reduced commodity loss
- Reduction of methane emissions to help reduce greenhouse gases
- Fewer unplanned service interruptions
- Fewer unplanned disruptions to traffic and roadways

Alternatives:

Alternative 1: Minimal Replacement

This option would replace only the quantity of main required to hold leak rates to present levels. This option increases safety risks and does not align with the Company's or the Commission's goals.

Alternative 2: Do Nothing

Eliminating this program will result in increasing leak activity and increased risk to public safety. This will put the Company in violation of its federally-regulated DIMP.

Studies/References that Support the Program:

This program is supported by the Company's DIMP and complies with the requirement in 49 CFR 192.1005, 1007, 1009, 1011 and 1013. The proposed rate of LPP retirement is also consistent with the Commission's stated goal of reducing the statewide LPP average retirement timeline to 20 years (Case 15-G-0151).

Recent gas related incidents in the industry have emphasized the urgency of eliminating the aging infrastructure at a faster pace. Annual System Integrity Analysis, which reviews the last ten years of system trends, clearly demonstrates the benefits of leak reduction due to LPP main retirements.

Program Title: Gas Infrastructure Replacement on Structures

Spending Rationale: ☒ Mandated ☐ Growth

☐ Reliability ☐ Non-Infrastructure

Brief Description:

This program will replace gas pipe on structures at three locations due to specific integrity concerns that were identified through corrosion inspections. The Company is proposing to replace one location per year beginning in the Rate Year. The locations are:

Location	FY
Washington Ave. at Rt. 443 over Rt. 90, Rensselaer	2019
Delaware Ave. at Rt. 443 over Rt. 90, Albany	2020
Russell Rd at Rt. 90, Albany	2021

Program Justification:

The program is necessary because the configuration, condition and maintenance of mains on the identified structures require investment in replacement that is not addressed by other programs due to cost and complexity. The Proactive Main and Service Replacement (LPP) Program does not include replacement over bridges and structures, and the Corrosion Control Program includes remediation of condition issues on structures (re-coating) but does not address the type full replacements required at the listed locations.

Total Project Cost Breakdown:

Costs are based on project-specific estimates for each location.

$000	FY 2019	FY 2020	FY 2021
CapEx	825	1,578	795

Customer Benefit:

This project will help improve the reliability and enhance safety of gas infrastructure.

Alternatives

Alternative 1: Include Identified Structures in the Proactive Main and Service Replacement (LPP) Program

This option could limit the amount of LPP retirement the Company could complete each year because the cost to replacing mains on bridges/structures is significantly higher.

Alternative 2: Do Nothing

This option is rejected due to the condition issues at the identified locations.

Program Title: Main Replacement (Reactive)

Spending Rationale: ☒ Mandated ☐ Growth

☐ Reliability ☐ Non-Infrastructure

Brief Description:

This program will fund the replacement of smaller sections of main segments and associated services that are identified during leak surveys that cannot be repaired by simple leak clamps. This program allows Field Operations to make quick decisions on replacing actively deteriorating segments of pipe without Gas Engineering approval. The program covers Niagara Mohawk's inventory of (i) non-cathodically protected steel pipe (whether bare or coated), (ii) cast and wrought iron pipe, and (iii) pre-1985 Aldyl-A plastic pipe.

Program Justification:

The goal of this program is to quickly replace small sections of actively corroded mains and reduce the risk associated with leak prone pipe ("LPP") in Niagara Mohawk's distribution system. The program is also supported by the Company's Distribution Integrity Management Plan ("DIMP"), which specifies that the Company implement measures to know its system, understand the threats to its distribution piping system, and evaluate risks and prepare replacement programs to help mitigate the risks associated with its leak prone mains and services inventory.

Total Project Cost Breakdown:

$000	FY 2019	FY 2020	FY 2021
CapEx	1,217	1,250	1,280

Customer Benefit:

Minimal customer impact is expected during the performance of these projects. The benefits of performing this work include improved community and government relations and reduced greenhouse gas emissions.

Alternatives

Alternative 1: Reduce or eliminate the Reactive Main Replacement Program

This alternative would result in increased O&M costs for leak response and repair and could delay the current LPP retirement schedule. It would also increase the exposure to risk associated with leaks, and may increase customer complaints.

Program Title: Cross Bore Investigation

Spending Rationale: ☒ Mandated ☐ Growth

☐ Reliability ☐ Non-Infrastructure

Brief Description:

Niagara Mohawk is proposing a cross bore investigation program. A cross bore is an unintended consequence of horizontal directional drilling ("HDD") technology where a plastic gas main has been bored through a sewer lateral that is not positively identified (marked) during the installation process. This program will address all pre-2014 HDD installations to ascertain if a cross bore has occurred. If cross bores are discovered the Company will take proactive steps to remediate the situation.

The Company updated its HDD procedures in 2014 to reduce the possibility of cross bores. Historically, Niagara Mohawk's drilling procedures and the typical depth of sewer laterals in the Company's service territory due to frost permeation depths would have mitigated against the occurrence of cross bores. However, prior to 2014, the risk specific to cross bores was not known such that the Company cannot determine with certainty that cross bores did not occur absent inspection of pre-2014 installations. To determine the order of magnitude of risk associated with cross bores, the Company's proposal is to investigate a statistical sampling of pre-2014 HDD installations using CCTV technology to inspect sewer laterals that could have been compromised during the main installation process. Niagara Mohawk has an estimated population of 6,500 sewer laterals requiring inspection.

Program Justification:

The program will address a potential hazardous situation that exists as a result of cross bore situations. In these cases, a sewer line may blocked. Using a mechanical clearing tool to remove the blockage may damage the gas line, causing the gas to migrate into the building. Over the years, several incidents have occurred in the industry due to cross bores. Many utilities have initiated programs to address this substantial risk. Pipeline and Hazardous Materials Safety Administration ("PHMSA") has taken a step further and declared the necessity for operators to review and assess the risk that cross bore poses on their system as a part of their Distribution Integrity Management Plan ("DIMP"), and depending on the risk evaluation, to identify and implement measures to reduce the risk.

Total Project Cost Breakdown:

$000	FY 2019	FY 2020	FY 2021
CapEx	612	629	0

Customer Benefit:

Minimal customer impact is expected during the operation of this project. This program will enhance public safety due to the reduced risk of gas incidents.

Alternatives:

Alternative 1: Inspect only when requested by customer.

This option could miss potential situations where customer is not fully aware of the possibility of a cross bore.

Alternative 2: Do Nothing

This option is not consistent with the Company's DIMP requirements.

Studies/References that Support the Program:

This program is in accordance with the Company's recently developed DIMP; complies with Federal Code 49 CFR, 192.1005, 1007, 1009, 1011 and 1013.

Program Title: Reactive Replacement - Atmospheric Corrosion & Plastic Fusions Inspections

Spending Rationale: ☒ Mandated ☐ Growth

☐ Reliability ☐ Non-Infrastructure

Brief Description:

This program replaces gas mains and service piping to remediate condition issues discovered through: 1) atmospheric corrosion inspections required by state and federal codes, and 2) plastic fusion inspections, as well as issues discovered during regular course of business.

Atmospheric corrosion inspection of outside and inside services includes the visual inspection of the:

- Service riser, soil to air interface as applicable
- Service piping through the outlet of the meter, meter(s), regulator(s) and fittings
- Wall penetration or point of entry as applicable

This project addresses both inside and outside gas service meter location assets. Inspections of above-grade outside piping and inside service sets are performed by Operations. Remediation and repairs to substandard conditions are corrected whenever discovered. Historically, there have been few issues associated with inside service inspections due to the generally protected environments on inside piping. However, recent industry failures and safety concerns have increased awareness by gas operators of potential risks.

Plastic fusion inspection incorporates all uncovered plastic fuses during the course of business. If any plastic fuse on the gas infrastructure fails inspection, its proactive replacement will remediate and enhance employee and public safety.

Program Justification:

Atmospheric Corrosion: Federal regulation 49 CFR 192.481 requires operators to monitor and inspect for evidence of atmospheric corrosion at least once every three (3) calendar years. 49 CFR 192.479 requires operators to clean and coat each pipeline that is exposed to the atmosphere as/if required.

Plastic Fusion: The Commission's "Order Requiring Local Distribution Companies to Follow and Complete Remediation Plans as Modified by This Order and to Implement New Inspection Protocols" issued and effective May 15, 2015 in Case 14-G-0212, requires the Company to keep records of each fuse uncovered in the regular course of business and to remediate any fuse that fails visual inspection.

Total Project Cost Breakdown:

$000	FY 2019	FY 2020	FY 2021
CapEx	196	201	206

Customer Benefit:

Successful execution of the program will further ensure the safety of gas service piping exposed to atmospheric corrosion and addresses any failed plastic fuse that might pose an integrity issue.

Allocating dedicated funding provides for a prompt managed replacement program. This program will improve public safety and gas system reliability. Additional benefits highlighted include:

- Reduction of risk associated with exposed service piping
- Improved public and employee safety by reducing the risk for gas related incidents.
- Enhance customer satisfaction while achieving efficiencies through integration with other programs (*e.g.* leak survey etc.)
- Compliance with federal and state code requirements including the US Department of Transportation (“USDOT”) Distribution Integrity Management Program requirements (“DIMP”)
- Improved public, community and government relations due to decreased odor calls
- Improve system performance
- Contributes positively towards the Company’s greenhouse gas reduction goals

Alternatives:

Do Nothing – This option does not allow atmospheric corroded services piping issues and failed plastic fusions to be identified and repaired for consideration through the budget planning process.

Program Title: Transmission Services[1] Removal Program

Spending Rationale: ☒ Mandated ☐ Growth

☐ Reliability ☐ Non-Infrastructure

Brief Description:

Niagara Mohawk has 271 services connected to Transmission Pipeline E-31 in Saratoga County. Pipeline E-31 has a maximum allowable operating pressure of 200 psig. Recently, the Company adopted new process safety standards for transmission assets in accordance with API 1173. The current design and construction of these transmission services no longer meet the Company's internal process safety standards. The Company is proposing a five-year program that will permanently remove these high risk services from transmission mains and will transfer these services to existing or new distribution main. In the last two years, the Company has retired approximately fifteen transmission services along E-31. Once this work is completed, the Company will not have any services connected to transmission mains.

Program Justification:

Risk Analysis

As part of its Process Safety Management Program, the Company performed a Process Hazards Analysis ("PHA") to determine the overall process safety risk associated with the E-31 services and concluded that the cumulative safety risk exceeded the Company's internal process safety risk threshold. The PHA utilized a Layers of Protection Analysis ("LOPA") technique developed by the Center for Chemical Process Safety ("CCPS"). The study included scenarios such as third party damage, pressure regulator failure, vehicular damage to above-ground equipment, debris in the gas, and weather related failures. The analysis also included common cause failures that simultaneously would damage the regulator and its internal relief valve. The study concluded that the cumulative process safety risk exceeded the Company's "Broadly Acceptable" risk profile due to insufficient layers of protection to manage the risk of transmission pressure reaching the customer premises. The customer service regulators are not rated for full transmission pressure and do not satisfy the CCPS criteria for an independent layer of protection, leaving the design in the "Broadly Unacceptable" risk region of National Grid's risk matrix.

Proposed Course of Action

While the Company has previously implemented process safety upgrades to these services, the Company is increasingly concerned with regard to their overall risk profile

[1] Niagara Mohawk historically referred to these services as "farm taps." However, these services do not meet the New York State definition of a "farm tap" (section 255.3.4); thus the Company no longer uses this terminology in reference to these services.

and has concluded it is necessary to significantly reduce the overall operating risks by transferring these services to distribution main over a period of five years.

Of the current 271 transmission services, 68 are within 200 feet of an existing distribution pipeline. Approximately 6.4 miles of new distribution pipeline will be required to provide a source of gas supply to the remaining transmission service customers. The program involves installing new distribution pipelines, new distribution rated service lines, and the decommissioning, abandoning and securing of each transmission service tee, including the use of custom mechanical coupling to secure abandon transmission service tees thereby avoiding costly welding procedures, non-destructive examination, hydrostatic testing, and multiple excavation openings.

As an interim step, in FY 2018, Niagara Mohawk will replace the service regulators with high pressure service regulators rated for full transmission pressure (this work is budgeted separately and is not included in the program budget below). Additionally, beginning in FY2018, the Company will conduct annual inspections of these services that will continue until no E-31 transmission services remain.

Total Project Cost Breakdown:

The total cost of the five-year program[2] is comprised of the following estimates:

- 6.4 miles of new distribution main @ $160 per foot = $5,406,720
- 271 service retirements @ $50,000 per retirement = $13,550,000
- 271 new distribution services @ $4,000 per service = $1,084,000
- Over five years, $ required per year = $4,008,144, adjusted for inflation

The costs included in the Rate and Data Years are as follows:

$000	FY 2019	FY 2020	FY 2021
CapEx	4,008	4,117	4,216

The annual inspections will require one incremental FTE (I&R technician) in the Rate Year which is included in Exhibit __ (GIOP-5).

Customer Benefit:

[2] A previous proposal to remove these services over a longer period of time did not sufficiently address the risk associated with these services in a timely manner and neglected to include removal of the service tees and mechanical coupling.

This program will ensure that residential customers currently served from Pipeline E-31 continue to receive reliable gas service while improving safety through lowering of risks associated with the operation of the Company's equipment. This program will thus improve public safety and gas system reliability.

Alternatives:

Alternative 1: Downgrade Pipeline E-31 to 124psi

Downgrading Pipeline E-31 to 124psi is not feasible because, at 124psi, the pipeline cannot meet the customer gas load demand.

Alternative 2: Construct new transmission line and downgrade Pipeline E-31 to distribution pressure

This option would be very expensive. Furthermore, a new transmission main for that line is not in the scheduled projects and would take several years to design and complete.

Alternative 3: Upgrade transmission services to current Company process safety standards

This option will avoid the necessity of transferring service connections to nearby distribution pipelines and the need to construct new distribution pipelines. Above ground pressure regulating equipment would need to be replaced with more robust equipment, and new steel underground service lines would need to be installed to the customer services. Additionally, the annual inspection program would need to be continued for the life of the services.

Alternative 4: Do Nothing

This alternative would leave all the transmission services attached to Pipeline E-31 in their current state. This alternative fails to mitigate the operational risks identified through the PHA and LOPA analyses.

Program Title: Meter Purchases

Spending Rationale: ☒ Mandated ☒ Growth

☐ Reliability ☐ Non-Infrastructure

Brief Description:

This program includes the purchase, testing, processing, and delivery of gas meters and associated instrumentation to support Niagara Mohawk's mandated meter test/replacement program and growth targets. The estimated number of meters required to support both programs for FY 2019 to FY 2021 are as follows:

	FY 2019	**FY 2020**	**FY 2021**
Purchase Meters (Growth)	5,573	5,684	5,798
Purchase Meters (Replacement)	17,042	17,383	17,731
Total	22,615	23,067	23,529

Program Justification:

The primary driver for meter and metering instrumentation purchases is compliance with state regulations governing meter accuracy and measurement of gas usage for customer bills.

The Commission's requirements stipulate a random sample and associated remediation/ retirement program for installed gas meters.

Each year, Niagara Mohawk is required to randomly select and remove from service a quantity of meters to be tested for accuracy. The number of meters removed and tested is sufficient to assure a statistical confidence level of 95%. Test results are entered into a program that performs statistical calculations based upon an approved ANSI Standard. The Commission has set accuracy limits for both residential (AQL 10%), and commercial (AQL 20%) meter types. Meter groups that fall beyond the specified limits are placed in a retirement program and are subsequently removed from service and retired.

In addition to the mandated meter change program, meters are required to support growth targets, as well as to support CMS operational requirements (load change, meter and/or service relocations, damage, & stopped meters).

Project Cost Breakdown:

CAPEX $000	FY 2019	FY 2020	FY 2021
Purchase Meters (Growth)	2,197	2,302	2,404
Purchase Meters (Replacements)	4,116	4,313	4,505
Total	6,313	6,615	6,909

Customer Benefit:

- Metering and billing accuracy
- Fewer unplanned service interruptions
- Ensure meters meet safety standards

Alternatives:
None

Program Title: Elevated Pressure Metering Program

Spending Rationale: ☒ Mandated ☐ Growth

☐ Reliability ☐ Non-Infrastructure

Brief Description:

Niagara Mohawk is proposing a three-year program beginning in the Rate Year to upgrade meters for a small population of elevated delivery pressure customers from fixed factor metering to electronic volume corrector instrumentation ("EVCs"). This will include the purchase, installation, inspection, and maintenance of EVCs, and meters to accommodate them.

Program Justification:

Niagara Mohawk has approximately 4,600 elevated delivery pressure meters within its territories. Currently, there are two options for metering elevated delivery pressures: fixed factor metering and high pressure instrumented metering.

The Company completed a review of the elevated pressure meters to analyze the benefits of installing EVCs within certain parameters (i.e., delivery pressure set point range and nature of customer usage). The Company's Elevated Pressure Metering Policy (CMS04005) was reviewed against the current fixed factor meters listed in the meter information tracking system ("MITS"). The review highlighted a population of 524 meters that are 1.25 psi delivery pressure and higher across meter sizes ranging from 1.5M – 16M. These 524 meters were identified as candidates for conversion from fixed factor metering to an EVC.

ECVs are expected to provide more accurate billing to these customers.

Total Project Cost Breakdown:

$000	FY 2019	FY 2020	FY 2021
CapEx	911	936	958

Incremental O&M is shown on Exhibit __ (GIOP-5).

Customer Benefit:
- Provide more accurate billing to customers
- Elimination of multiple visits to perform annual fixed factor inspections

Alternatives:

Alternative 1: Allow fixed factor metering to remain on identified population

Continued fixed factor metering risks less accurate billing, which could result in customer complaints. Also, the Company would need to continue to perform multiple annual fixed factor inspections while the customer may be running during the months of January through March.

Program Title: Gas Meter Change Program

Spending Rationale: ☒ Mandated ☐ Growth

☐ Reliability ☐ Non-Infrastructure

Brief Description:

Niagara Mohawk's Gas Meter Change Program is the labor required to replace gas meters that are retired from service due to required periodic testing, damage, failure, or any other reason.

Program Justification:

The Commission's regulations require random sampling of gas meter performance on an annual basis. Meters are classified based on manufacturer/model, and the number of meters to be tested within each of these classifications is determined by the population size. The Commission's regulations also require remediation of meters that do not meet the required level of accuracy. The Company is typically allowed eight years to remove and replace a "failed" meter population. The Commission has the discretion, however, to require utilities to remove the population at a faster rate. In addition, the regulations allow for the retirement of meter groupings. Niagara Mohawk currently has meters in each of the meter change program types (random, remediation, and retirement). The quantity of meters changed annually is based on the prior year's performance and remediation program status.

In addition to the mandated programs, the Company also initiates requests to change meters based on performance. These meters are known as "change for cause" meters.

Total Project Cost Breakdown:

$000	FY 2019	FY 2020	FY 2021
CapEx	4,862	5,094	5,320

Customer Benefit:

Testing and replacing meters supports accurate meter reading and customer billing.

Alternatives

None

Program Title: Integrity Management Program

Spending Rationale: ☒ Mandated ☐ Growth

☐ Reliability ☐ Non-Infrastructure

Brief Description:

This program covers projects related to the management of Niagara Mohawk's gas transmission system, specifically the O&M and capital projects that are components of the US Department of Transportation's ("DOT") mandated Integrity Management Program ("IMP").

The Pipeline Safety Improvement Act of 2002 ("2002 Act") requires operators of DOT-reportable gas transmission systems to develop and implement an IMP for all pipelines operating above 20 percent specified minimum yield strength ("SMYS") in a high consequence area ("HCA"). The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 ("2011 Act") mandates that Pipeline and Hazardous Material Safety Administration ("PHMSA") consider whether the existing transmission IMP should be expanded beyond the current requirements, including increased inspections of IMP-covered pipelines using in-line inspection ("ILI") technology.

Niagara Mohawk proposes an improved IMP that incorporates the elements of the current IMP along with proactive programs such as retrofitting pipelines for ILI including free swimming, robotic and tethered tools. The proposed IMP enhancements provide the greatest amount of risk reduction, thereby improving system safety and reliability. Additionally, it is anticipated that the program will better enable the Company to comply with future regulatory requirements.

Program Justification:

Pursuant to the 2002 Act, the DOT promulgated rules on managing the integrity of transmission pipelines used by the gas and hazardous liquids industries under 49 CFR Part 192.901 – 192.951, which became effective on January 14, 2004. These regulations require pipeline operators to develop and implement an IMP for "covered" transmission pipelines, which are defined as certain pipelines in HCAs. The program required that the first cycle of pipeline assessments be completed no later than 2012. Reassessments are required to be completed at intervals not exceeding seven years thereafter from the last assessment. The assessments are comprised of external corrosion direct assessment ("ECDA") and ILI. The results of each operator's program are summarized and reported to the DOT on an annual basis.

Pipeline safety laws and regulations constantly evolve driving progressive changes in utility operations and asset management. San Bruno and several other high profile pipeline incidents have set in motion recommendations, proposed rulemaking, and the 2011 Act signed into law on January 3, 2012. The 2011 Act, and the regulations to follow, will create very significant compliance challenges for the gas LDCs. In 2016 PHMSA issued a Notice of Proposed Rulemaking ("NPRM") that will address the 2011 Act mandates and implement a number of additional changes to the regulations for gas pipelines. The NPRM has proposed the following significant items that will affect the IMP:

- Make all pipeline segments operating at or over 20 percent SMYS ILI enabled
- Consider expansion of IMP beyond HCAs
- Develop requirements for medium consequence areas ("MCA")
- Consider reduction of the IMP reassessment time cycle
- Reduce or eliminate the use of ECDA
- Require advanced risk modeling, including quantitative assessments

There is some uncertainty regarding when PHMSA will issue its final rulemaking; however, it is possible that some version of the proposed regulations will become effective during the Rate Year or Data Years.

Because the Company believes it is a prudent expenditure regardless of the implementation date, and in anticipation of PHMSA's new regulations expanding IMP, the Company believes that its proposed IMP program is a reasonable and conservative approach to managing pipeline integrity during the Rate Year and Data Years.

Total Project Cost Breakdown:

$000	FY 2019	FY 2020	FY 2021
CapEx	13,308	16,759	21,250

Incremental O&M for IMP inspections is shown on Exhibit __ (GIOP-5).

Customer Benefit:

The program seeks to further reduce the risk of operating the gas transmission system, which will improve public safety and the reliability of the gas delivery system.

Alternatives:

Alternative 1: Maintain Current IMP

Proceed with the current IMP utilizing current inspection methods until such time as US DOT/PHMSA issues final rule making from the Pipeline Safety Act of 2011. Proceeding with the current IMP plan does not position the Company to improve on risk reduction or public safety.

This approach also fails to account for the likely impact of expected future rule making. Compliance with new code requirements will likely be required within a prescribed schedule. The established regulation time frame will likely require accelerated project and assessment schedules. Accordingly, the Company risks not meeting new established deadlines or having to spend on an accelerated basis, which is not effective. The new proposed rulemaking also has provisions for large fines for non-compliance and not meeting deadline requirements.

Description	MAOP >124psig	DOT >20% SMYS	HCA
Transmission Pipe (Miles, Total)	599	272	78
Existing IMP			
ECDA	69 (12%)	69 (25%)	69 (88%)
ILI	45 (8%)	45 (17%)	9 (12%)
Sub Total	114	114	78
Proposed IMP			
ECDA	30 (5%)	30 (11%)	30 (39%)
ILI	163 (27%)	163 (60%)	48 (61%)
Sub Total	193	193	78

Current vs Proposed Assessment Method Summary

Studies/References That Support the Program:

Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 ("Pipeline Safety Act of 2011"), signed into law by the President on January 3, 2012 (Public Law. No. 112-90).

Pipeline Safety: Safety of Gas Transmission Pipelines; Advance Notice of Proposed Rulemaking, Federal Register, Vol. 76, No. 165 (August 25, 2011).

NTSB Safety Study: NTSB/SS-15/01 PB2015-102735 (Integrity Management of Gas Transmission Pipelines in High Consequence Areas) – January 27, 2015

PHMSA Docket No. PHMSA-2011-0023 Revised Pipeline Safety Regulations (NPRM)

Appendix A

Project Breakdown

Project Name	FY19	FY20	FY21
PL E36 ILI	$ 2,250,000	$ -	$ -
PL 35 ILI Therm City to Taunton	$ 500,000	$ -	$ 1,500,000
PL 15 VLV 1504 Replacement	$ 1,400,000		
PL 15 VLV 1506 Replacement	$ 1,400,000		
PL 58 ILI Hall Road to Independence Indeck	$ 758,000	$ 3,000,000	
PL 55 ILI Walnut Street GRS to Oswego Steam	$ 750,000	$ 3,000,000	$ 10,000,000
PL 52 ILI Velasko Rd GRS to McBride St GRS	$ 500,000	$ 3,000,000	
PL 51 ILI Kingdom Rd GRS to Walnut & Burkle GRS	$ 750,000	$ 1,500,000	
PL 16 VLV 1605 Replacment		$ 1,500,000	$ 2,000,000
PL 16 VLV 1607 Replacment		$ 1,500,000	
PL 65 ILI Collamer Rd GRS to Carr St CoGen		$ 1,500,000	$ 2,500,000
PL 43 ILI Watertown Feed		$ 250,000	$ 2,000,000
PL 48 ILI Watertown Feed		$ 500,000	
PL 49 ILI Watertown Feed		$ 500,000	
Pl E8 Replacement Burdeck St GRS to Seneca St GRS		$ 100,000	
PL 39 ILI Hall Rd to Watertown			$ 1,500,000
PL 16 Valve 1603 Replacement			$ 1,500,000
PL 15 Scribners to Lampear Drip Removal for ILI	$ 1,500,000		
PL E20 King Fuel Main Relocation	$ 3,000,000		
TVC Project Close Outs	$ 500,000	$ 409,000	$ 250,000
Grand Total Program / Blanket	**$ 13,308,000**	**$ 16,759,000**	**$ 21,250,000**

Program Title: Integrity Verification Process Program

Spending Rationale: ☒ Mandated ☐ Growth

☐ Reliability ☐ Non-Infrastructure

Brief Description:

This program covers projects related to the US Department of Transportation's pending rules on Integrity Verification Process ("IVP") programs. The renewed Pipeline Safety Act of 2011 mandates that Pipeline and Hazardous Materials Safety Administration ("PHMSA") establish rules requiring operators to demonstrate their pipelines are "Fit For Service." This includes reviewing existing records to determine if prior strength tests (hydro static pressure tests) were completed at the time of construction, as well as other records that prove the pipeline is operating within design parameters. On January 10, 2011, PHMSA issued advisory bulletin ADB-11-01 directing operators to conduct a comprehensive records review and verification prior to issue of the final rule making.

Niagara Mohwak proposes an IVP Program that incorporates the elements of the proposed IVP rulemaking and PHMSA guidance document ADB-11-01 along with proactive programs, records review, pipeline replacement and the retirement of non-essential pipeline segments. The proposed IVP Program provides the greatest amount of risk reduction, thereby improving system safety and reliability. Additionally, it is anticipated that the program will better enable the Company to comply with future regulatory requirements.

Program Justification:

In 2016, PHMSA issued a Notice of Proposed Rulemaking ("NPRM") that will address the 2011 Pipeline Safety Act mandates and implement a number of additional changes to the regulations for gas pipelines. Among the proposed are the establishment of maximum allowable operating pressure ("MAOP") and testing mandates for existing pipelines. PHMSA has proposed eliminating the exemption clause for establishing the MAOP of pre-1970 "grandfathered" pipe, which allows certain pipelines to operate at the highest actual operating pressure to which they were subjected during the five years prior to July 1, 1970, without having to perform a pressure test. PHMSA has also proposed that all pipelines not previously pressure tested at or above 1.1 times MAOP should be required to be pressure tested in accordance with current regulations. Another initiative proposed is PHMSA's IVP, which will require operators lacking certain records to conduct pressure tests to confirm MAOP, and require operators with missing records, inadequately validated or traceable material documentation ("TVC") to design and implement a program to establish material properties by one or more of the following methods: (1) cutting out and testing pipe samples; (2) institute non-destructive testing; (3) field verification of code stamp for components such as valves, flanges, and fabrications; or (4) other verifications.

Some pipelines without adequate material and pressure test documentation will be required to be retired or replaced. The IVP Program will also require an operator to develop a "Fit for Service Program" to establish that all pipelines are operating within their design parameters. On January 10, 2011 PHMSA issued advisory bulletin ADB-11-01 directing operators to conduct a comprehensive records review and verification prior to issue of the final rule making.

The Act requires PHMSA to:

- Issue rules to eliminate grandfathering of non-hydrostatically tested pipe satisfying the following three criteria: (i) installed prior to 1970, (ii) having a MAOP >30% specified minimum yield strength ("SMYS"), and (iii) are located in HCAs. Such pipelines will now be subject to hydrostatic testing. The threshold of 30% SMYS supports recent studies which have shown that pipe operating below the 30% level will fail as a leak as opposed to rupture.
- Require operators to confirm the records they use to justify MAOP ("TVC")
- Re-Hydro test pipe segments
- Run in-line inspection tools ("ILI")
- Abandon/retire pipelines
- Replace pipelines
- Material sampling to establish properties
- Advance fit for service analysis

Total Project Cost Breakdown:

$000	FY 2019	FY 2020	FY 2021
CapEx	4,500	4,514	4,526

Incremental O&M is shown on Exhibit __ (GIOP-5).

The projects included in the above forecast are shown below (totals below do not reflect inflation adjustment):

Project Name	FY 2019	FY 2020	FY 2021
IVP Main Replacement	$500,000	$500,000	$500,000
PL E13: PL E13-10	$1,000,000	-	-
PL E8: PL E8-4	$3,000,000	-	-
PL 31: PL 31-17, PL 31-18, PL 31-19	-	$4,000,000	-
PL 31: PL 31-2	-	-	$4,000,000
Total	**$4,500,000**	**$4,500,000**	**$4,500,000**

Customer Benefit:

The program seeks to further reduce the risk of operating the gas transmission system, which will improve public safety and the reliability of the gas delivery system. The balanced approach focuses on smaller pipeline segments allowing levelized spending year to year.

Alternatives:

Alternative 1: Maintain current IVP

Do not proceed with the IVP Program until such time as USDOT/PHMSA issues the final rule based on the Pipeline Safety Act of 2011. Proceeding with the current IVP plan does not position the Company to improve on risk reduction or public safety. This approach also fails to account for the likely impact of expected future rule making. Compliance with new code requirements will likely be required within a prescribed schedule. The established regulation time frame will likely require accelerated project and assessment schedules. Accordingly, there is a risk of not meeting new established deadlines, or spending on an accelerated basis which is not necessarily effective. The new proposed rulemaking also has provisions for large fines for non-compliance and not meeting deadline requirements.

Studies/References That Support the Program:

Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 ("Pipeline Safety Act of 2011"), signed into law by the President on January 3, 2012 (Public Law. No. 112-90).

Pipeline Safety: Safety of Gas Transmission Pipelines; Advance Notice of Proposed Rulemaking, Federal Register, Vol. 76, No. 165 (August 25, 2011).

PHMSA Advisory Bulletin (ADB-11-01) 1/10/11

PHMSA Docket No. PHMSA-2011-0023 Revised Pipeline Safety Regulations (NPRM)

<u>Program Title</u>: PL 34 Replacement Project

Spending Rationale: ☒ Mandated ☐ Growth

☐ Reliability ☐ Non-Infrastructure

Brief Description:

This project addresses the long-term risk associated with identified lap welded pipe in Pipeline 34 ("PL 34"). The project replaces approximately 15,000 feet of eight-inch pipe (of which a majority is lap welded pipe) with new pipe. PL 34 has a maximum allowable operating pressure ("MAOP") of 300 psig. The piping to be replaced begins at the Walnut and Burkle Street station in Oswego, NY and proceeds south until a transition where the pipeline diameter increases to ten-inch nominal pipe. The project scope is shown on a map appended below.

The project was initially proposed to begin in fiscal year ("FY") 2019, but the schedule has been moved forward to allow sufficient time for design, permitting and procurement. The updated fiscal year schedule, including the Rate Year is as follows:

FY 2018
- Begin design for piping replacement

FY 2019 (Rate Year)
- Complete design for piping replacement
- Complete permitting, land acquisition and material procurement

FY 2020
- Install approximately 15,000 feet of new 12-inch pipe in the same right-of-way (ROW) parallel to the existing 8 inch piping
- Remove Pipeline 34 from service and tie in the new section of piping at the Walnut and Burkle Street Station and at the joint where the piping diameter changes
- Retire/abandon the existing eight-inch piping

FY 2021
- Perform any remaining restoration

Project Justification:

While the Company was conducting External Corrosion Direct Assessment ("ECDA") of a parallel pipeline, the Company discovered that a majority of the eight-inch section of PL 34 is lap welded pipe. Lap welding is an outdated pipe manufacturing process in which the overlapping ends of rolled pipe were welded together. The process created a wider weld joint that was sometimes irregular. Welds produced by lap welding are not as reliable as those created by modern methods. Manufacturers no long use lap welding because of these integrity concerns.

Both the US Department of Transportation Pipeline and Hazardous Materials Safety Administration ("PHMSA") and the American Society of Mechanical Engineers ("ASME") have recognized the integrity risks associated with lap welded pipe. ASME has created a joint factor for lap welded pipe that is 80 percent of seamless pipe. The long term risk associated with leaving the lap welded pipe in service includes increased susceptibility to cracking or failure at the weld due to an inconsistent bond. The inherent weakness of lap-welded pipe seam comes from the inability to achieve consistent and reliable bonding due to the forging type process. Studies have shown through burst testing that the long seam average strength is only 92 percent compared to the pipe body. Replacement of PL 34 with new seamless pipe or seemed pipe manufactured according to current standards is the best way to mitigate these risks.

<u>Total Project Cost Breakdown</u>:

$000	**FY 2019**	**FY 2020**	**FY 2021**
CapEx	4,453	13,657	500

<u>Customer Benefit:</u>
The customer benefits from a significant reduction in risk of failure at a lap seam joint versus new seamless pipe or new pipe with a seam manufactured through modern processes.

<u>Alternatives:</u>

Alternative 1: De-rate PL 34
This alternative is rejected because it reduces, but does not eliminate the risk of failure at the lap seam weld. Additionally, de-rating PL 34 puts a strain on the surrounding transmission and distribution system in the area. System modelling has shown that the maximum operating pressure cannot be reduced.

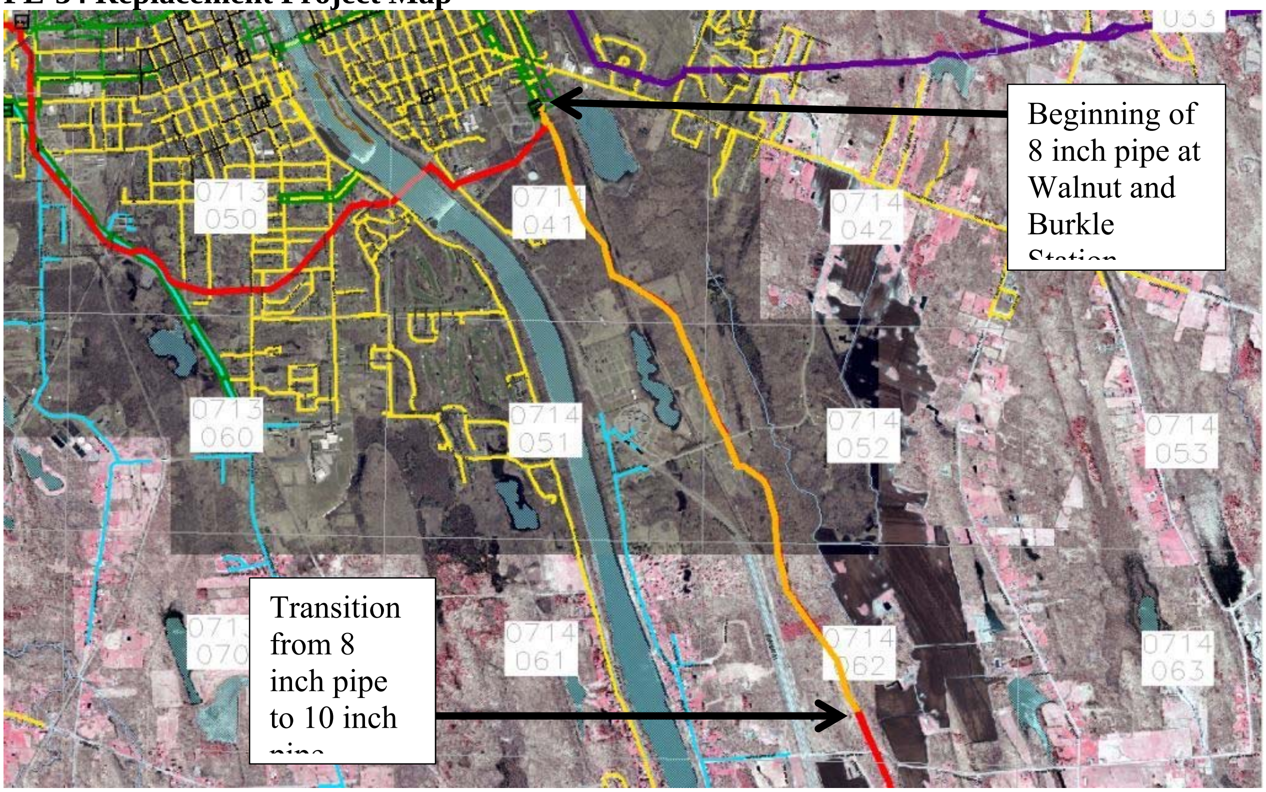
Alternative 2: Feed Station from Pipeline 58 ("PL 58")
The Company could route a spur from PL 58 (473 psig MAOP) to the Walnut and Burkle Station and retire PL 34 from Kingdom Road Station to Walnut and Burkle Station. This alternative was rejected because it would require acquisition of a new transmission ROW through a residential and commercial area and would require re-design of the Walnut and Burkle Station and the Kingdom Road Station. This will result in higher costs than a replacement of the pipe along its present alignment.

Alternative 3: Do Nothing

This alternative is rejected because indefinite operation of the lap welded pipe carries a risk of eventual failure of a lap seam joint.

Supporting References:
https://primis.phmsa.dot.gov/comm/FactSheets/FSPipeManufacturingProcess.htm
https://primis.phmsa.dot.gov/comm/FactSheets/FSMaterialWeldFailure.htm

PL-34 Replacement Project Map



Program Title: Transmission Main Washouts

Spending Rationale: ☒ Mandated ☐ Growth

☐ Reliability ☐ Non-Infrastructure

Brief Description:

This program covers projects related to the management of Niagara Mohawk's gas transmission system, specifically the capital projects required to mitigate the effects of environmental damage to existing gas transmission pipelines. Environmental damage is caused by river/stream flooding, ground subsidence and erosion. Projects consist of pipe replacement by direct trenching, directional drill and civil repairs, such as gabion matts.

Program Justification:

During normal operations, gas transmission system pipelines can be exposed to environmental conditions that can affect the integrity of the pipeline. These environmental conditions can be from localized flooding, scouring/erosion of stream bottoms under normal flow and ground subsidence due to subsurface geological activity. Both federal and state regulations require operators to perform continuing surveillance and follow up mitigation activity to insure the integrity of the pipelines.

Recent Pipeline and Hazardous Materials Safety Administration's Advisory Bulletins highlight actions operators must take to ensure that flooding events, normal river scour and river channel migration do not affect integrity of pipelines. Advisories also outline actions needed after severe storms such as hurricanes.

Total Project Cost Breakdown:

$000	**FY 2019**	**FY 2020**	**FY 2021**
CapEx	500	514	526

In FY 2015 and FY 2016, the Company addressed a large backlog of washout projects, which inflated the historic test year expenditures in this program. Going forward, the number of washouts is expected to be more consistent with prior trends, as reflected in the Rate Year forecast.

Customer Benefit:

The program seeks to further reduce the risk of operating the gas transmission system, which will improve public safety and the reliability of the gas delivery system.

Studies/References That Support the Program:

PHMSA Advisory Bulletin: ADB-2015-01 – Docket Number PHMSA-2015-0105
Potential for Damage to Pipeline Facilities Caused by Flooding, River Scour, and River Channel Migration, Notice: Issuance of Advisory Bulletin

PHMSA Advisory Bulletin: ADB-2015-02 – Docket Number: PHMSA-2015-0140
Pipeline Safety: Potential for Damage to Pipeline Facilities Caused by the Passage of Hurricanes; ACTION: Notice; Issuance of Advisory Bulletin

Code of Federal Regulations (CFR) Title 49, Part 192

Section 192.613 – Continuing surveillance

Section 192.935 – What additional preventive and mitigative measures must an operator take?

New York Codes, Rules and Regulations, Part 16, Chapter 255

Section 255.613 – Continuing Surveillance

Section 255.935 – Preventative and Mitigative Measures to Protect the High Consequence Areas

Program Title: Transmission Main Reactive

Spending Rationale: ☒ Mandated ☐ Growth

☐ Reliability ☐ Non-Infrastructure

Brief Description:

This program covers projects related to the management of Niagara Mohawk's gas transmission system, specifically the capital projects required to reactively mitigate integrity related issues on gas transmission pipelines. Integrity issues are identified by the Company's Integrity Management Program ("IMP"), mandated inspections and during normal operations. These can be related to corrosion, third party damage, valve failures and other items that affect the integrity of the pipeline. This program covers mitigation projects that are more urgent or of a higher priority and that are not adequately addressed as part of the IMP work plan. Projects consist of pipe replacement by direct trenching, directional drill, and valve replacement.

Program Justification:

Both federal and state regulations require operators to perform continuing surveillance and follow up mitigation activity to insure the integrity of the pipelines. These projects are required to continue the safe operation of the gas transmission system. Planned inspections beginning in the Rate Year that are likely to generate reactive activities such as pipe replacement and capital repairs include inline inspections of the following pipelines:

- PL E36
- PL 58
- PL 55
- PL 52
- PL 51
- PL 16

Total Project Cost Breakdown:

$000	FY 2019	FY 2020	FY 2021
CapEx	500	514	526

The forecast for this program is based on the three-year average historic spend of $290,000 plus a modest allowance for the uncertainties of a reactive program.

Customer Benefit:

The program will improve public safety and the reliability of the gas delivery system.

Alternatives:

None. A reactive program is required to address higher-risk transmission integrity issues as they are discovered.

Studies/References That Support the Program:

49 CFR Part 192

Part 192.613(a)(b) Continuing Surveillance – Follow Up Action

Parts 192.935 What Additional Preventive And Mitigative Measures Must An Operator Take

16 NYCRR Part 255

Part 255.613 Continuing Surveillance

Part 255.935 Preventative and Mitigative Measures to Protect the High Consequence Areas

Program Title: Service Replacement (Reactive Leaks)

Spending Rationale: ☒ Mandated ☐ Growth

☐ Reliability ☐ Non-Infrastructure

Brief Description:

The reactive service replacement program consists of non-discretionary work that is randomly generated through public leak reports, programmed leak survey, mandated activities, and customer-generated requests.

Program Justification:

The goal of this program is to reduce the risk associated with leaks on existing services in order to enhance safety and reliability of the Company's system. The program provides funding for the reactive replacement of gas services to address leak work activities that fall outside the normal scope of the integrity, reliability, public works and growth programs. The proactive main and service replacement programs upgrade existing customer services prioritized by risk based on pressure, material, vintage, location, and select other variables. The reactive service replacement program addresses leaks and other maintenance activities on the remaining services.

The program budget consists of costs to replace leaking services, damages, service abandonments due to inactivity or demolition requests, customer driven relocations of existing services, and other substandard conditions.

Total Project Cost Breakdown:

$000	**FY 2019**	**FY 2020**	**FY 2021**
CapEx	4,336	4,454	4,561

Customer Benefit:

This program will reduce the risk associated with these services and improve community and government relations.

Alternatives

None

Program Title: Service Replacement (Reactive Non-Leaks)

Spending Rationale: ☒ Mandated ☐ Growth

☐ Reliability ☐ Non-Infrastructure

Brief Description:

The reactive non-leak service replacement program consists of non-discretionary work that is randomly generated through compliance needs and mandated activities.

Program Justification:

The goal of this program is to enhance safety and reliability of the Company's system by reducing the risks associated with damages, service abandonments due to inactivity or demolition requests, customer driven relocations of existing services, and other substandard conditions. The program provides approved funding for the reactive replacement of gas services to address non-leak work activities that fall outside the normal scope of the integrity, reliability, public works and growth programs.

The proactive main and service replacement programs upgrade existing customer services prioritized by risk based on pressure, material, vintage, location, and select other variables. The reactive service replacement program addresses the responses to correct deficiencies on remaining services.

The program budget consists of costs to replace as a result of damages, service abandonments due to inactivity or demolition requests, customer driven relocations of existing services, and other substandard conditions.

Total Project Cost Breakdown:

$000	FY 2019	FY 2020	FY 2021
CapEx	2,472	2,539	2,600

Customer Benefit:

This program will reduce the risk associated with these services and improve community and government relations.

Alternatives

None

Program Title: Gas Control Telemetry Upgrade 3G to 4G

Spending Rationale: ☐ Mandated ☐ Growth

☒ Reliability ☐ Non-Infrastructure

Brief Description:

In Niagara Mohawk's service territory, there are approximately 60 telemetry devices that transmit data back to the Gas Control Room. These telemetry devices will become obsolete when the cellular network technology they utilize sunsets by 2021. Under the Telemetry Upgrade project, the Company's Instrumentation and Regulation personnel will replace the 3G telemetry devices with new 4G devices.

Program Justification:

Currently, approximately 63 percent of the Company's pressure regulating stations are equipped with some form of telemetry technology, and twelve percent of such devices use the 3G network. Recent changes in federal regulations on control room management focus on increasing system awareness and providing proactive response to abnormal operating conditions. The Telemetry Upgrade project supports compliance with these regulations. This program also supports the standardization of telemetry across Niagara Mohawk's gas transmission and distribution system. Enhanced calibration of network models from automation and telemetry data improves the accuracy of network analysis and enhances the ability to forecast future capital reinforcements, which leads to more efficient capital expenditure.

Verizon has announced that it is sunsetting its 3G network by 2021 to free up space for its newer networks. If left as is, the Company's current telemetry devices will be unable to communicate.

Total Project Cost Breakdown:

$000	**FY 2019**	**FY 2020**	**FY 2021**
CapEx	100	100	0

Customer Benefit:

Without telemetry technology, Gas Control would not be able to monitor pressure, flow and temperature at the regulator stations. Telemetric devices allow the Company to accurately identify the source of any system problem. Without telemetry, crews must be dispatched to several locations in order to determine where the actual problem is. This process is inefficient and not responsive to system operating requirements as crews travel from location to location checking equipment and looking for problems.

Alternatives

Alternative 1: Do nothing

Doing nothing will adversely impact cost, customer satisfaction and reliability. Furthermore, this alternative does not meet the Company's objective to actively manage system pressures and leak activity.

Program Title: Gas System Reliability – Gas Planning/Remote Control Valve ("RCV") Program

Spending Rationale: ☐ Mandated ☐ Growth

☒ Reliability ☐ Non-Infrastructure

Brief Description:

The Gas System Reliability program includes capital projects required to maintain system minimum pressures on the gas network in the event of an abnormal operating condition (failure involving a regulator station, gate station, critical main or other major pressure facility on the system). This program includes new RCVs on transmission pipelines in high consequence areas to improve emergency response capabilities and reduce risk. In the event of a pipeline failure that results in a release of natural gas, RCVs will allow control room operators to stop the flow of gas, isolate and shutdown a portion of the system, and mitigate further consequences utilizing a remote command.

Program Justification:

Gas planning reliability concerns include transmission and distribution systems with a limited number of feeds (*i.e*., city gate stations or regulator stations), systems that are either weakly integrated or consist of long single-feed laterals, networks that contain a wide variety of operating pressures, and varying design philosophies associated with system and supply redundancy (*e.g*., production plants, city gate stations, regulator stations).

Gas safety concerns focus on our ability to quickly and efficiently shut down gas supply remotely following a pipeline failure resulting in the release of natural gas to ensure the safety of the first responders, impacted gas customers and the public. The use of RCVs also eliminates the need to locate and excavate manual valves.

The Company also anticipates that federal regulations will eventually require the installation of RCVs. The Pipeline and Hazardous Materials Safety Administration's May 2016 Notice of Proposed Rulemaking ("NPRM") delayed consideration of whether to require RCVs to allow for further consideration of the issue, but the NPRM also includes a rule that would require consideration of RCVs as part of an operator's maintenance program. The Company's RCV program follows PHMSA criteria and will position the Company for eventual compliance.

Total Project Cost Breakdown:

$000	FY 2019	FY 2020	FY 2021
CapEx	2,511	2,843	2,704

Customer Benefit:

The Gas Planning Reliability program ensures that service is maintained in the event of a failure on a major pressure facility. Reliability is improved by adding supply flexibility, integrating single feed systems, making progress to eliminate single feed systems, and by installing RCVs. Without this program, greater numbers of customers are at risk of losing service in the event of a facility failure.

Niagara Mohawk's goal is to proactively upgrade the existing valves or install new valves in certain high-volume and high-risk locations to enhance reliability and safety by reducing the amount of time needed to stop the flow of gas in the event of a pipeline failure thereby mitigating the consequences of any such event. Installation of RCVs will be undertaken in a manner that will ultimately comply with regulatory guidance.

Alternatives:

Alternative 1: Do Nothing

Removal of the Gas Planning Reliability program increases risk of system failures including pressures below minimum design levels and possible customer outages.

If RCVs are not installed, a pipeline failure would require a manual shutdown of the transmission pipe. This may result in longer times to contain the incident and could result in more damage. Also, by not adding any RCVs the isolation area could be larger in some instances, resulting in a larger loss of service to customers. Given pending PHMSA regulations, this option would leave the Company in violation of industry code requirements.

Studies/References that Support the Program:

Studies were run on the Company's network models using Synergi, which is an industry standard software. The models, which are validated on an annual basis, were loaded with the forecast provided by the Analytics, Modeling, and Forecasting ("AMF") Department. Individual facilities were taken out of service, and reliability projects were then identified to bring pressures back above minimum.

Several studies have been conducted regarding the benefits of RCVs. Oak Ridge National Laboratory in their report "Studies for the Requirements of Automatic and Remotely Controlled Shutoff Valves on Hazardous Liquids and Natural Gas Pipelines with Respect to Public and Environmental Safety" issued on October, 2012 have mentioned that the swiftness of valve closure has a potentially beneficial effect on mitigating fire damage to buildings and personal property located in Class 1, Class 2, Class 3, and Class 4 HCAs when combined with fire fighter intervention. The study emphasizes that “rapid detection of the break followed by immediate implementation of corrective actions including closing block valves to isolate the damaged pipeline segment reduces the total volume of natural gas released which in turn reduces the radiant heat flux produced by combustion of the released natural gas.” National Transportation Safety Board (“NTSB”) in its accident report “Pacific Gas and Electric Company Natural Gas Transmission Pipeline Rupture and Fire San Bruno, California September 9, 2010” concluded that the damage from the accident could have been reduced if the pipeline operator had installed either automatic shutoff valves (“ASVs”) or RCVs and issued recommendation of requiring that ASVs or RCVs be installed in high consequence areas and in class 3 and 4 locations. It is evident from these studies that the true benefit of RCVs is to minimize the loss of natural gas after the incident had occurred minimizing the impact of the incident on the operation of the gas system (such as pressure collapse due to a rupture). In addition RCVs may shorten the duration of the event (*i.e.* gas fueled fire) and that could help to reduce the amount of damage resulting from the event.

Program Title: Albany Loop Closure

Spending Rationale: ☐ Mandated ☐ Growth

☒ Reliability ☐ Non-Infrastructure

Brief Description:

The Albany Loop Closure project is an on-system reinforcement that will provide increased reliability to the Company's gas system by allowing more gas to flow through the Tennessee Gas Pipeline's ("TGP") South Albany city gate station into the Albany transmission loop ("Albany Loop"). This project helps to mitigate against the loss of either the Dominion Transmission Inc. ("DTI") Troy city gate or the upstream supply to the Troy city gate. The project also addresses the "East Gate" supply constraints by allowing additional gas supplies into the gas system and reducing the system's dependence on DTI's currently constrained gas system in the northeastern part of the Company's gas system.

This project will install 38,000 feet of 16-inch 225 psig transmission main from the south end of the Albany Loop in Glenmont to the northeast end in Troy. The engineering and procurement of materials are scheduled to be completed in the Rate Year and the construction in the following two years. A map showing the project scope is appended below.

Project Justification:

The Albany Loop Closure project will improve system reliability to existing customers and allow for continued system growth.

With respect to the DTI city gates, those located in Amsterdam, New York and west are referred to collectively as the "West Gate," whereas those located east of Amsterdam are referred to as the "East Gate." The Company has broadened these terms to include its TGP and Empire city gates. The Company's TGP city gate is in the East Gate region; the Company's Empire city gates are in the West Gate region.

The northeastern part of the Company's gas distribution system is currently supply constrained. The majority of the gas is supplied from DTI to the East Gate. Currently, DTI cannot increase deliveries to the East Gate without significant upgrades. DTI supplies seven (7) of the city gate stations into the northeastern part of the Company's system, and only one city gate station in Glenmont is supplied by TGP at the Bethlehem city gate. Currently, even if upstream gas supply was available from Tennessee, the TGP station can move approximately 60 Mdt on a design day (75 Heating Degree Days). This may leave the system supply constrained especially during the peak hour on a design day, which can lead to a moratorium on sales in the northeastern part of the Company's system. In order to move additional supplies into the system, the proposed program would construct 16-inch transmission main to close the Albany Loop as pictured on the map, below. This project will increase the take away from the current TGP Bethlehem city gate and allow up to 100 Mdt per day of gas to be moved into the system under the current system loads.

In addition, the northern part of the Albany loop is currently supplied by DTI from the Troy city gate. On a day with a 24-hour average temperature of 5 degrees, if DTI were to interrupt supply at this gate, as many as 50,000 Niagara Mohawk customers could lose gas service. More customers could lose service on a design day (24-hour average temperature of minus 10 degrees). This project would eliminate that contingency and allow the Company to maintain service.

Total Project Cost Breakdown:

$000	FY 2019	FY 2020	FY 2021
CapEx	3,000	32,318	33,459

Customer Benefit:

The project will increase the reliability of gas supply into the northeastern part of Niagara Mohawk's system, especially in the Albany area, by enhancing the Company's ability to respond to an interruption in supply at the Troy city gate. Furthermore, by enabling procurement of gas supply from a different pipeline, the project reduces the impact of any interruption of supply at DTI's Troy city gate.

Alternatives

Alternative 1: New Pipeline Lateral

Contract with one of the upstream interstate pipelines to build a lateral to the northern end of the Albany Loop near the DTI Troy city gate. While this would be able to supply the additional supply to help with the East Gate constraint, it is not a comprehensive solution because it would not allow the Company the additional flexibility to move gas at the existing gates. This solution would require federal permitting.

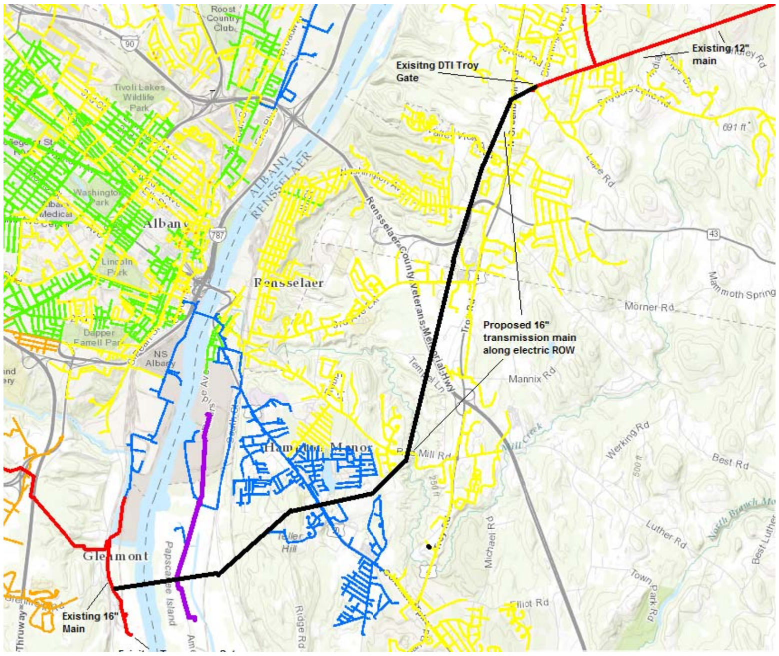
Alternative 2: Do Nothing

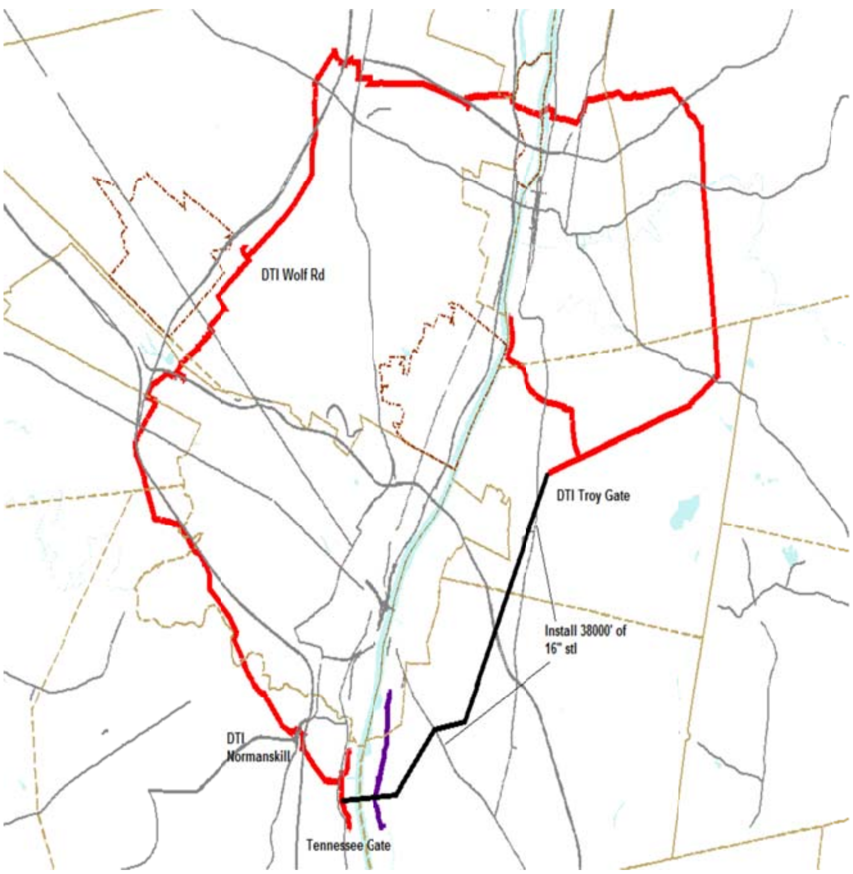
Without reinforcements that address the supply constraints on the northeastern part of the Company's system, the Company's future gas sales will be hindered and the duration and frequency of service interruptions may increase. If supply issues arise at DTI's Troy city gate or an upstream event on the DTI pipeline feeding the Troy gate, up to 50,000 customers may lose gas service. Such a substantial outage can cost up to $50 million in restoration costs, including claims for property damage, lost business, etc. Also, without this project, the Company would greatly limit its upstream supply options to meet long-term growth. This project allows for the Company to fully maximize utilization of the existing South Albany city gate in order to serve future customer requirements. Potential interim solutions to address the East Gate constraint set forth in the testimony of Company Witness Elizabeth C. Arangio, such as the use of LNG and portable CNG, are not expected to provide the volumes needed to meet long-term growth.

Studies/References That Support the Program:

Studies were run on the Company's network models using Synergi, which is an industry standard software. The models, which are validated on an annual basis, were loaded with the forecast provided by the Analytics, Modeling, and Forecasting (AMF) department. Information about East Gate supply constraints was obtained from the supply planning group.

Albany Loop Project Maps





Program Title: Valve Installation and Replacement Program

Spending Rationale: ☐ Mandated ☐ Growth

☒ Reliability ☐ Non-Infrastructure

Brief Description:

The Valve Installation and Replacement Program addresses valve replacements in addition to new valve installations necessitated by ongoing annual inspections. The program will strengthen the emergency response capabilities of the gas organization by improving the level at which Field Operations can safely and efficiently isolate sections of the distribution system while ensuring minimum customer impact and will benefit Niagara Mohawk's customers by reducing the duration of future outages.

Program Justification:

Niagara Mohawk is required by federal (49 CFR 192.181) and state (16 NYCRR 255.181) regulations to install, inspect, maintain and operate critical pipeline valves on all gas distribution systems. These valves facilitate the rapid shutdown of distribution piping or regulator stations during gas emergencies such as third party damage, water intrusion, or other operational reasons. The valves also facilitate maintenance and pipe replacement activities on associated distribution piping. Ensuring all critical valves are properly maintained and operable is a key public safety function and is critical to the effective operation of the Company's gas distribution system.

In New York, the local gas distribution yards are responsible for performing annual valve inspections and any resulting repair and/or replacement work identified through the inspections. Program status and compliance is reported monthly. Gas Asset Management has enterprise-wide responsibility for the Valve Installation and Replacement program. This includes valve selection criteria and determination, as well as development of system isolation districts. The Gas Operations Engineering and Project Engineering & Design teams also provide ongoing support to Field Operations through diagnosis of inoperable valves, identification of alternate valves and selection of new valves.

Total Project Cost Breakdown:

$000	FY 2019	FY 2020	FY 2021
CapEx	245	252	258

Customer Benefit:

Successful execution of the program will ensure the safety and reliability of the gas assets while focusing on improvements in customer satisfaction. The primary driver for this program is to improve distribution system and customer reliability while maintaining the highest standards for safety of the gas distribution assets. The program will minimize the unplanned release of gas during restoration of damage to Company facilities.

Alternatives:

Alternative 1: Do Nothing

The valves found to be deficient will need to be managed on a case by case basis, creating process and investment inefficiencies. Inability to properly plan and employ uniform criteria to these issues increases risk to the Company and can portray a negative image of the organization to customers, investors and regulators.

Studies/References That Support the Program:

Outage Restoration Costs Study

Estimates for relighting customers and recovering from a system outage have been prepared to quantify the impact of outages related to insufficient system capacity during periods of peak demand and severe winter cold.

Actual relight costs have been captured from recent incidents to quantify company expenses related to restoring service. These were all related to outages that occurred for reasons other than insufficient system capacity and operations were conducted under benign weather conditions. It is likely that during severe winter weather, costs would increase.

The claims data related to burst pipes and equipment damage due to a lack of heat during severe cold weather was captured from National Grid incidents in other jurisdictions. The combined cost of relighting customers and resolving claims in those incidents averaged $1,764 per customer. Recognizing the amount of variability in different incidents such as weather conditions, different types of neighborhoods, variable labor costs, economies of scale, etc., for purposes of evaluating the benefits of reinforcement projects, an average value of service restoration costs and claims of $1,000 per customer is used.

Program Title: Water Intrusion and Distribution Main Exposure Program

Spending Rationale: ☐ Mandated ☐ Growth

☒ Reliability ☐ Non-Infrastructure

Brief Description:

Niagara Mohawk's Water Intrusion and Distribution Main Exposure program is a reactive program with two components. First, the program will address unanticipated (*i.e.*, emergent) water intrusions that cause service disruptions and poor pressures, which require investigation by I&R, CMS and Field Operations. The second part of the program will address unanticipated infrastructure undermines/main exposures that may occur on the distribution system during storms, heavy rains and/or seasonal snow melting, which can cause damage to facilities, delayed emergency response and potential loss of service to customers. The program will address water intrusion projects that have already been identified and manage emergent reliability problems as they arise. Attached as an appendix is a list of currently identified projects. Newly identified locations that meet the program criteria will be risk-ranked and prioritized for replacement or other action within the existing budgetary limits.

Program Justification:

The Water Intrusion and Main Exposure program will support two critical areas not linked to specific capital or operating expense budgets. Previous efforts linked these emergent projects with LPP retirement activities whenever practical. The program will allow the Company to better manage capital and operating expenses related to emergent activities. The program will also facilitate swift decision making based upon predetermined criteria for project execution. Successful execution of the program will further ensure the safety and reliability of the Company's gas system while focusing on improvements in service delivery.

Total Project Cost Breakdown:

$000	FY 2019	FY 2020	FY 2021
CapEx	668	686	703

Customer Benefit:

Customers will benefit from improved service delivery. The program targets unplanned customer outages that drive poor system reliability in low pressure distribution systems. Disruptions of gas service, inconvenience associated with relight process and customer costs associated with remedy and/or repair of customer-owned equipment can negatively impact customer satisfaction and Company reputation. The program will reduce the number of recurring disruptions to customers on low pressure systems and will support continued efforts to eliminate low pressure distribution systems by upgrading to elevated pressure whenever practical. The program will decrease the number of unplanned outages, which will result in fewer unplanned road excavation. Such improvements will lead to better public and municipal relations.

Alternatives:

Alternative 1: Previously-Identified Projects Only

This option would address only previously-identified water intrusion and main exposure projects meeting the criteria for replacement under the proposed program, but would exclude newly-identified intrusions and exposures. Additional in-year emergent issues would need to be managed on a case-by-case basis and will require reallocation of funding from other programs.

Alternative 2: Do Nothing

This option does not allow water intrusion and undermine/exposure issues on the distribution system to be identified for consideration through the budget planning process. Further, the emergent issues presented in this proposal are likely to continue and will need to be managed on a case by case basis, which will require additional funding support from other programs. These occurrences can cause pipe failure due to unsupported segments. Failure of the pipelines can create safety and system reliability concerns, leading to increased OpEx and customer dissatisfaction.

Appendix – List of Identified Projects:

Projects	**Location**
Clear path for vets	Cazenovia
Homewood Drive	Clinton
Amsterdam	Amsterdam
Pipeline 9 Reber Road	Rome
Pipeline 9 1.75 off Reber Road	Rome
Pipeline 9 Route 69 (school)	Rome
FM High School	FM
Long Branch Road	Baldwinsville

Program Title: I&R Reactive & Compressed Natural Gas ("CNG")

Spending Rationale: ☐ Mandated ☐ Growth

☒ Reliability ☐ Non-Infrastructure

Brief Description:

Pressure regulating facilities have been designed to safely and reliably control system pressures and maintain continuous supply during periods of normal and peak gas demand. Niagara Mohawk has approximately 390 pressure regulating facilities in its service territory. The Instrumentation & Regulation ("I&R") Reactive program focuses on capital upgrades and improvements, as well as replacements of pressure regulating facility components throughout the year. The CNG program will also be managed under this program, which includes two CNG filling stations. This program contributes to the reliability of Niagara Mohawk's gas distribution system.

Program Justification:

This program is an annual capital program. The work plan mainly consists of projects discovered during maintenance inspections and other normal work. Equipment may be malfunctioning or damaged due to normal use, weather events such as lightning storms or floods, damage by vehicles, power surges, etc. Many capital replacements of this nature must be completed at or near the time of discovery to maintain safe and reliable pressure regulation facility operation. Because these types of capital replacements are not in a long term planning and replacement program, another means of funding is necessary.

The I&R Reactive budget is designed to address smaller and less complex capital project requirements over and above what the Pressure Regulating Facilities program budget provides. I&R Reactive projects may include instrumentation replacement due to weather or vehicular damage, replacement of smaller obsolete/unreliable equipment such as regulators, pilots, boilers, heat exchangers, valves, odorant equipment, building doors, windows, fences, gates, and other small capital assets.

Total Project Cost Breakdown:

$000	FY 2019	FY 2020	FY 2021
CapEx	333	342	350

Customer Benefit:

The primary customer benefit is the continuous, safe, and reliable supply of natural gas without unplanned outages due to facility shutdowns or malfunctions. This program maintains pressure regulating facility reliability by facilitating rapid replacement of smaller individual pieces of equipment critical to safe operations.

Alternatives

Doing nothing or deferring this program does not meet our obligation to provide safe and reliable gas service, nor the longer term objective of improving the operation and performance of the pressure regulating stations. The consequences of not completing the work scheduled will result in increased risks associated with the failure of station equipment and/or the stations associated piping. Specifically, failure to complete identified work would reduce the integrity of the system and potentially result in significant customer outages.

Program Title: Portable Temporary Regulator Stations

Spending Rationale: ☐ Mandated ☐ Growth

☒ Reliability ☐ Non-Infrastructure

Brief Description:

This program proposes to construct three Portable Temporary Regulating Stations ("PTRS") to correct certain flaws to its PTRS inventory, create a more standardized design approach for all regions within the Company's service territory, and enable the Company to put a PTRS into operation within minutes of arrival.

The new PTRS design will incorporate solutions to security issues, transportation problems, compliance related concerns, ease of installation, and redundancy concerns. It will also allow for communication with the Gas System Operations ("GSO") group 24/7.

1. The new design will be constructed in a covered-lockable trailer. The trailer will have hook ups for the inlet and outlet of gas, but will maintain the critical components such as valves, control lines, regulators, and relief valves within the confines of the locked trailer. This will relieve most of the safety concerns.
2. The trailer will be constructed with multiple runs built at the appropriate ANSI classifications. Thus, a single trailer will allow for the work on transmission pressures as well as low pressures.
3. The additional parallel regulator run will provide the gas in the event of the failure of the primary regulator in the closed position. This will ease the concern with the loss of gas on a dead end system.
4. The trailer will incorporate a large solar panel on the roof that will supply sufficient power to run a RTU and corresponding transducers. This will allow for the cellular communication with the Company's GSO.
5. The trailer will offer several chart boxes that will allow Niagara Mohawk to remain in compliance while operating the temporary regulating station. In addition, the temporary station will be incorporated with the Company's yearly inspection program ensure that its equipment is ready for service in the event of an emergency situation.
6. The fact that it is in a covered trailer will allow Niagara Mohawk to drop the PTRS off on-site and install it to the infected area in an expeditious manner. The inlet may be attached to CNG if required.

Program Justification:

During the maintenance and construction of its gas regulating stations, Niagara Mohawk is often limited to certain methods of construction in order to maintain a steady gas feed to a distribution system while the work is being conducted. It is not always possible to shut down a station while conducting maintenance or reconstruction of the station. In such instances, a PTRS is the most efficient work-around.

The safety risks associated with working in close proximity of live and complex piping systems, as found in regulating stations, are exponentially higher than the risks associated with working around a shutdown station; this not only includes the risk of serious or fatal injury to the Company's employees, but also the risk associated with losing the flow of gas to the Company's distribution system. In addition, the alternative methods of construction often add incremental costs to jobs. The use of a PTRS would help reduce such costs.

Lastly, when unexpected issues arise that may require extensive repairs such as main replacements or incremental main installations, a PTRS will provide a temporary solution to allow for continuing flow of gas while permanent repairs can be made.

Total Project Cost Breakdown:

Total capital expenditure is estimated at $225k to construct three portable gas regulator stations. An annual operations and maintenance cost will be necessary to perform inspections and exercising the stations when not in use.

$000	**FY 2019**	**FY 2020**	**FY 2021**
Construct 3 Portable Regulator Stations	225	0	0

Incremental O&M is shown on Exhibit __ (GIOP-5).

Customer Benefit:

The primary customer benefit is the continuous, safe, and reliable supply of natural gas. Portable regulator stations provide support for ongoing main replacement construction projects that enhance ease of construction and reduce customer interruptions. Portable stations also help mitigate supply interruptions due to emergency, weather, or third party damage.

Program Title: Portable Compressed Natural Gas ("CNG")

Spending Rationale: ☐ Mandated ☐ Growth

☒ Reliability ☐ Non-Infrastructure

Brief Description:

This project is to procure and purchase a portable CNG tube trailer. CNG tube trailers are used to provide temporary portable supply of natural gas and can be needed for many purposes. Portable CNG can be used to facilitate main replacement and pipeline construction, providing supply to communities and neighborhoods when permanent supply sources are disrupted by emergency or weather, reinforce gas distribution systems during winter peak demand periods, and temporarily supply customers when they are refurbishing their own piping systems.

A CNG tube trailer contains several high pressure storage tanks that are pressurized with natural gas. When called upon, the trailer is transported to the needed area and connected to a pipeline using flexible high pressure stainless steel hoses. The trailer uses on-board pressure regulators, overpressure protection devices, and gas heaters to inject natural gas into the downstream pipeline safely. Once the natural gas stored in the trailer is depleted, it is hooked up to a CNG filling station and pressurized for additional use (National Grid owns two CNG filling stations in Upstate). The capacity of the tube trailer varies depending on the physical size of the cylinders, the contained pressure, and the pressure in the downstream system.

Program Justification:

Currently, if an emergency were to occur that necessitates the use of portable CNG, Niagara Mohawk would need to source a portable CNG trailer from one of its affiliates in Downstate New York or New England.

In 2011, Tropical Storm Lee caused extensive damage from flooding in the Schoharie and Rotterdam regions. As a result of the heavy rain, flooding caused a gas supply disruption to the Village of Rotterdam Junction. During that time, the Rotterdam Volunteer Fire Department headquarters was being used as an emergency shelter. When the gas supply was interrupted, the emergency shelter was no longer able to support the needs of the local residents. Ultimately, Niagara Mohawk was able to secure a small portable CNG trailer from New England and install it at the Rotterdam Fire Department headquarters, but it took nearly ten hours to accomplish.

A portable CNG tube trailer would support customers and communities during emergencies like the one in Rotterdam. During Tropical Storm Lee, the Company was able to leave the CNG trailer connected for more than a week. Had the storm been more widespread, or if the New England equipment was already being used, emergency support in Rotterdam likely would have needed to be relocated elsewhere.

A portable CNG tube trailer will require a small amount of annual maintenance and inspection in order to ensure the equipment is functional and operates safely.

Total Project Cost Breakdown:

$000	**FY 2019**	**FY 2020**	**FY 2021**
Purchase CNG Tube Trailer	750	0	0

Incremental O&M is shown on Exhibit __ (GIOP-5).

Customer Benefit:

The primary customer benefit is the continuous, safe, and reliable supply of natural gas and the ability to mitigate supply interruptions due to system emergencies, weather events, and construction activities.

Program Title: I&R Field Test & Training Lab – Pressure Regulation Facility

Spending Rationale: ☐ Mandated ☐ Growth

☒ Reliability ☐ Non-Infrastructure

Brief Description:

This project is to design and procure a field test and training lab in the form of a pressure regulation facility. This pressure regulation facility, to be centrally located in Upstate New York, will be a fully functioning station that operates on compressed air instead of natural gas. The project will be designed and built with sustainability in mind, allowing for plug-and-play of various design considerations, layouts, and types of equipment including meters, pressure regulators, filters, valves, telemetry, and overpressure protection equipment. This facility will simulate field examples of normal operation, over pressure protection, and other abnormal conditions using equipment identical to that found in actual operating pressure reducing stations. Because the training facility is fully operational, employees will be able to practice diagnosing and controlling simulated emergencies and abnormal operating conditions in a safe and controlled manner. It will provide simulation of the activities associated with performing routine maintenance on various components and examining issues that need to be considered when retrofitting or making alterations to current operating practices, as well as allow for testing future designs and new technologies. This facility will enhance knowledge and understanding of station operations for field workers, design engineers, safety professionals and others by facilitating hands-on operational experience under controlled conditions.

Program Justification:

Niagara Mohawk has a diverse workforce that will benefit from this lab environment. The program will assist and support field employees who operate and maintain the regulation facilities and components on a day to day basis, employees who design or influence the design of regulation facilities and component selection, and field management who need to have a fundamental knowledge of how pressure regulating facilities function to maintain the integrity and safety of the system.

The multi-use, hands-on field lab will further develop the workforce beyond traditional methods. Employees will be trained with actual hands on samples, enhancing their development and complementing on-the-job training and classroom modules. Employees will feel more engaged and confident about designing, supervising, and/or performing the work safely and efficiently. This year-round facility provides the ability to learn the equipment, to recognize and diagnose malfunctions and abnormal conditions, and to teach proper response methods in a controlled manner using a safe medium.

Niagara Mohawk will benefit from having a centrally located in-house pressure regulation facility for use of training and testing, which results in gained knowledge for future design of capital projects.

A field test and training lab pressure regulation facility will require a small amount of annual maintenance and inspection in order to ensure the equipment is functional and operates safely.

Total Project Cost Breakdown:

$000	FY 2019	FY 2020	FY 2021
Design & Build Pressure Regulation Facility	500	0	0

Incremental O&M is shown on Exhibit __ (GIOP-5).

Customer Benefit:

The primary customer benefit is the continuous, safe, and reliable supply of natural gas and ability to efficiently design, construct, and maintain pressure regulation facilities. Additional benefits include enhanced ability to respond to and manage emergency situations and equipment malfunctions, enhanced employee safety, and the ability to evaluate new technologies and equipment in a functioning test environment.

Program Title: Gas Regulator Station Security

Spending Rationale: ☐ Mandated ☐ Growth

☒ Reliability ☐ Non-Infrastructure

Brief Description:

This program is intended to enhance and improve security measures at critical gas pressure reducing stations. Niagara Mohawk will assess key pressure reducing stations in its service territory to determine vulnerabilities to vandals, activists, out of control vehicles, and dedicated external threats to safe operations. The results of the security assessments, combined with the relative importance of the facility to reliable and safe operation of the overall transmission and distribution system, will determine the types of security enhancements to be made.

Examples of security measures include remotely operated cameras connected to gas and/or security control centers, lighting, fencing, ID card access, intrusion alarms, redundant communications systems, physical barriers, and hardened locks and cables to protect exposed valves and equipment. The Company expects it will assess and enhance security measures for approximately 55 of its facilities across its service territory.

Program Justification:

Niagara Mohawk's gas service territory is served through approximately 400 pressure reducing and metering stations. Stations are located in a variety of environments (*i.e.*, rural, urban, inner city) and in numerous configurations, both above and below ground. Stations also have varying degrees of importance for the safe and reliable operation of the overall gas transmission and distribution system. While some stations are critical in that they operate at high pressure or are the single source of supply to a large number of customers, others may be less important to the overall operation of the gas system because of redundancy elsewhere. The facilities included in this program include all city gate stations that are primary feeds and other stations that are critical nodes points with multiple feeds or large stations feeding dead ends. The type of security measures necessary for a station will depend on the degree of its necessity to the overall system operation and safety.

Enhanced security measures are important because third parties have many means to obtain the knowledge and skills needed to seriously impact pressure regulator station operations. Information on how to operate station equipment and the general design of pressure regulation facilities can be found on the internet and other publicly available resources. In December of 2016, PHMSA issued an Advisory Bulletin (AB-2016-06) recommending enhanced security at critical energy infrastructure following an incident on an interstate gas pipeline. The American Gas Association has also published a "Commitment to Cyber and Physical Security" noting the need for gas system operators to remain resilient to growing and dynamic cyber and physical security threats.

(https://www.aga.org/sites/default/files/sites/default/files/media/commitment_to_cyber_and_physical_security_sep2016.pdf). A proactive security risk assessment at the Company's key gas facilities will help to ensure continued reliable and safe operations.

City Gate Stations
City gate stations receive natural gas from upstream interstate pipelines. City gate stations are critical because they deliver natural gas into the Company's high pressure gas transmission system. Niagara Mohawk will examine all of its twenty-four (24) city gate stations for security vulnerabilities.

Loss or disruption of certain city gate stations during winter can cause the Company to close valves and deliberately isolate extensive portions of the gas distribution system to allow other connected systems to operate. Such loss can impact entire towns and cities and cause significant and widespread consequences for tens of thousands of customers.

Furthermore, damage to a city gate station that causes pressure regulating equipment to be either bypassed or made non-functional may cause over-pressurization on downstream systems and potentially cause damage to customer property and/or result in loss of life.

All city gate stations house certain quantities of odorant. Deliberate damage to odorization equipment can cause either un-odorized or highly odorized gas to be delivered into downstream distribution systems. Intentional release of liquid odorants into the atmosphere has the potential to cause thousands of leak calls over a widespread area, causing real leaks to be masked or ignored.

Given the importance of city gate stations, and that they typically operate at high pressures, the Company seek to apply the most effective controls. The installation of cameras, infrared motion detectors, perimeter alarms, card access, intrusion alarms, and enhanced fencing are all likely at these facilities. On average, the Company estimates each station will require a $200,000 capital investment, spread over a four-year period, to mitigate security vulnerabilities.

Transmission to Distribution Pressure Reducing Stations

Transmissions-to-distribution ("T&D") pressure reducing stations receive gas from the Company's transmission system and distribute it to the larger gas distribution network. Although T&D stations are generally smaller than city gate stations, damage or unscheduled shut downs can create serious problems on downstream distribution systems. All the security risks described for city gate stations are relevant for T&D stations with the exception of odorant, but greater redundancy and smaller sizes somewhat reduce the overall risks to the greater system.

The Company will assess approximately 30 T&D stations for security vulnerabilities. Anticipated enhancements would include cabinet intrusion alarms, fencing, area lighting, and securing valve operators. On average, each station would require an estimated $50,000 to complete the enhancements.

Total Project Cost Breakdown:

The annual cost is based on six city gate stations and seven distribution stations per year.

$000	FY 2019	FY 2020	FY 2021
Gate station assess and enhance	1,200	1,200	1,200
T&D station assess and enhance	350	350	350
Total CapEx	1,550	1,550	1,550

Incremental O&M is shown on Exhibit __ (GIOP-5).

Customer Benefit:

Customers will benefit from the continuous, safe, and reliable supply of natural gas.

Alternatives

Alternative 1: Do nothing

- Allows existing vulnerabilities to remain in an increasingly volatile environment.

Alternative 2: Decrease funding.

- Requested amount is based on estimated ability to complete the required security enhancements over a reasonable timeframe. Decreased funding would extend the length of time existing security vulnerabilities would exist.

Program Title: Methane Emission Reduction (Odorant Pump) Project

Spending Rationale: ☐ Mandated ☐ Growth

☒ Reliability ☐ Non-Infrastructure

Brief Description:

This project will convert odorant injection pump power gas from natural gas to air at 23 city gate stations. Injection of odorants (mercaptans) is necessary to ensure natural gas has an adequate odor so customers can detect potential gas leaks. In Niagara Mohawk's service territory, odorant is injected into natural gas at 24 gate stations. At 23 of the stations, the pumps used to inject odorant into the gas pipelines are pneumatically operated and use high pressure natural gas to drive the pumps. At the completion of each pump stroke, the natural gas in the pump's power cylinder is discharged through a carbon filter into the atmosphere.

The program proposes to use air as the power gas to drive the pneumatic odorant pumps. At each gate station, an electric air compressor and associated filters, dryers and controls will be installed, and pump power gas systems will be converted from natural gas to air. This will eliminate natural gas emissions associated with odorization to the atmosphere. The natural gas power gas systems will be retained for use only in emergencies when the compressed air supply is not available.

Program Justification:

Methane, the principal component in natural gas, is a significant greenhouse gas. Niagara Mohawk is committed to reducing fugitive methane emissions from all sources. The Company conducted an analysis that included information on the types of odorant pumps in use at Niagara Mohawk, the amount of gas that needs to odorized, and the various odorant concentration levels to determine the estimated amount of methane emitted to the atmosphere each year.

Over a five year period, total conversion of power gas supply to air for Niagara Mohawk's system would reduce methane emissions from odorant injection by an estimated 130 to 170 metric tons.

Total Project Cost Breakdown:

The estimated installation cost is $100,000 per site over a three-year installation period. Annual operating and maintenance costs include $1,800 per site for electricity usage, 96 labor hours per site for preventative maintenance and inspection, and $1,000 per year for materials and parts.

$000	FY 2019	FY 2020	FY 2021
CapEx	800	800	700

Incremental O&M is shown on Exhibit __ (GIOP-5).

Customer Benefit:

The primary customer benefit is the continuous, safe, and reliable supply of natural gas and environmental benefits associated with reduced methane greenhouse gas emissions.

Program Title: System Automation & Control

Spending Rationale: ☐ Mandated ☐ Growth

☒ Reliability ☐ Non-Infrastructure

Brief Description:

This program will install remote terminal units ("RTUs") at multiple city gate stations and regulator stations in Niagara Mohawk's service territory. RTUs provide temperature, pressure and flow data back to the Gas Control Room. Where required, RTUs can also monitor gas detectors and intrusion alarms and allow Gas Control to adjust flow and pressure set point at the regulator stations. Data is transmitted via phone lines or cellular networks. The system automation project includes installing raise/lower controllers to remotely adjust pressure on the gas system. The program also includes gas analyzers to provide gas composition and BTU content.

The program's objective is to standardize operations, maintain custody check metering and increase control and monitoring at city gate stations and regulator stations. The project will also increase operational understanding of the system to identify abnormal operating conditions and allow the Company to take a proactive approach to alarm management in support of current PHMSA requirements (*i.e*. Control Room Management which became final in January, 2010). The program also adopts a best practice with respect to check metering and leak management.

Program Justification:

The system automation program is necessary to enhance system reliability. Increasing the level of automation at pressure regulating stations enhances the Company's ability to pinpoint problems and take corrective action. Changes in federal regulations for control room management focus on increasing system awareness and providing proactive response to abnormal operating conditions. The proposed program supports compliance with these regulations. This program also supports the standardization of telemetry across Niagara Mohawk's gas transmission and distribution system. Enhanced calibration of network models from automation and telemetry data improves the accuracy of network analysis and enhances the ability to forecast future capital reinforcements, which leads to more efficient capital investment. This program also enhances pressure management on the system within the maximum allowable operating pressure limits (MAOP).

Currently, the Company's gas system has a limited amount of system automation – 56 percent of the pressure regulating stations are equipped with some form of telemetry, while 44 percent of the system relies on paper chart recorders. Some of the equipment, including modems and telemetry, was installed many years ago and has become obsolete. Updating this obsolete equipment supports the standardization of telemetry across Niagara Mohawk's gas transmission and distribution system.

The recent change from traditional Gulf gas supplies to Marcellus shale gas has brought about a significant need for new equipment to measure and monitor the gas quality at change of custody points. Where gas is introduced into the Company's system, gas monitoring instruments are needed to monitor odorant levels, BTU, composition, hydrates, and hydrocarbon dew point (HCDP). This equipment will be installed at city gate stations (transfer of custody points) under a separate program ("Pressure Regulation Special Projects" program) but this equipment will be utilized to monitor the analyzers.

Also, due to the increased scrutiny placed on system automation in the aftermath of the San Bruno pipeline incident, it is anticipated that federal regulations will require additional levels of system automation on both transmission and distribution systems.

Total Project Cost Breakdown

$000	FY 2019	FY 2020	FY 2021
CapEx	1,400	1,438	1,472

This program will require eight years to complete. It will add telemetry and control to 135 stations and replace obsolete RTU's at an additional 57 stations.

Customer Benefit: More reliable system performance with fewer customer outages

The advantages of system automation and telemetry are that the source and location of any system problem can be more readily and accurately identified from the Gas Control Center. Crews can be dispatched immediately to the location of the problem. This process saves valuable time and will reduce the need to wait for customers to call in and report a problem. In addition, the removal of paper charts recorders provides a more accurate and timely record of station pressures and this information is also available for Gas Planning.

Alternatives

Alternative 1: Do nothing

Doing nothing does not meet the long term Company objective to actively manage system pressures and leak activity. Also, this alternative will leave approximately 90 percent of Niagara Mohawk's service territory without the ability to remotely manage operating pressures.

Studies/References that Support the Program:

National Grid Policy PL 030002 – SCADA Instrument & Control

This policy requires that new telemetry points are approved by Gas Control in accordance with the U.S. Department of Transportation - Pipeline and Hazardous Materials Safety Administration (PHMSA) Control Room Management standards (49 CFR 192.631)

<u>Program Title</u>: Heater and Regulator Station Management Programs

<u>Spending Rationale</u>: ☐ Mandated ☐ Growth

☒ Reliability ☐ Non-Infrastructure

<u>Brief Description:</u>

This program covers capital projects involving the pressure regulating facilities and heaters utilized on the Company's gas system. There are two elements to consider when ensuring adequate safety and reliability of pressure regulators stations: heater management and pressure regulator station management.

Using data from the annual performance testing ("PT"), cathodic protection ("CP") testing, risk assessments and on-site inspections, technical assessments were made for each pressure regulating station taking into account pipe and equipment condition, regulator performance, corrosion data, and heater and scrubber performance. In addition, Guided Bulk Wave Testing ("GBWT") has been used in regulator vaults to determine if there are any anomalies in the pipe within the vault penetrations. The results of these tests and assessments, combined with an analysis of the potential customer impact resulting from a station outage, were used to prioritize and schedule capital projects in the Heater and Regulator Station Management program.

<u>Program Justification:</u>

Pressure Regulating Facilities: Planned replacements will eliminate regulating stations that do not meet current Company standards for design (i.e. over pressure protection, vault penetrations, control lines), as well as regulatory requirements for the operation of the gas system, thereby improving public safety and enhancing the integrity of the system.

Collaboration with other programs such as the Main Replacement, System Reinforcement and System Reliability programs can change the scope of work for an existing pressure regulation station by increasing flow, reducing flow or allowing the station to be retired.

An event at any gas regulating station could jeopardize the customers downstream through loss of supply or by over pressurizing the system. The program addresses corrosion issues, structural vault problems, obsolete pressure control valves, inadequate by-pass designs, accessibility and maintainability (automation is handled within a separate System Automation program).

Heaters: The Company's policy on management of cold gas temperatures recommends that heaters be considered for installations where pressure drops of 200 psi or more occur. Since natural gas temperature will decrease approximately 14 degrees given a 200 psi pressure drop, the temperature of the gas leaving a pressure regulating station can fall below freezing if heat is not added. On a cold day, flowing gas temperatures may average 40 degrees or less. After a 200 psi pressure reduction, the gas will be flowing at 26 degrees or less. Frost heave can occur as ice forms below 32 degrees and piping can begin to lose strength (become more brittle) as temperature falls below 20 degrees.

The heaters in the program are earmarked for full replacement as they are reaching the end of their service life. Natural gas heaters are made from carbon steel, which contain a glycol-water mixture similar to the antifreeze in an automobile radiator. These heaters have a life expectancy of approximately 25 years, which can be extended or diminished according to maintenance practices. However, at some point, the integrity of the steel tubes within the heater can become compromised at which time a leak will develop. Since all of these heaters are connected to transmission piping, they are subject to higher pressures and the impact of a leak or tube failure can be catastrophic.

There have been past pipeline failures on Niagara Mohawk affiliates' systems due to increased stresses associated with cold gas being introduced into the distribution network. The higher stresses have created axial contraction, coupled with frost heave and lower pipe toughness which has resulted in weld failures. The installation of additional heaters will help to address these issues.

Total Project Cost Breakdown:

Heaters direct cost are between $125,000 for a 770 MBTU Heater and $500,000 for a 4.6 MMBTU heater each to purchase. Installation of the heaters will range from $400,000 - $1,000,000.

$000	**FY 2019**	**FY 2020**	**FY 2021**
Pressure Regulating Facilities	4,640	4,310	4,390
Heater Installation Program	2,000	2,365	2,500
Total CapEx	6,640	6,675	6,890

Customer Benefit:

The primary customer benefit is the continuous, safe, and reliable supply of natural gas without unplanned outages due to pressure regulating facility shutdowns. Pressure regulating stations supply from hundreds of customers for low pressure distribution stations to hundreds of thousands of customers for high pressure stations.

Alternatives – Pressure Regulating Facilities:

Alternative 1: Full replacement

The entire station is replaced from the station inlet to the outlet. A full replacement is appropriate when:

- Severe corrosion; usually occurs where no CP was installed (i.e. Pre-DOT pipe; pre-1971)
- It is not cost effective to repair or modify
- Under capacity – the station is too small and would require new vaults new piping with larger valves and regulators as identified by Gas System Planning
- Structural problems with vaults or buildings, coupled with flooding and traffic problems that needs to be addressed

Cost: $775,000 - $950,000 per station dependent on size and location

Alternative 2: Station Rebuild

The station can be rebuilt and brought to current standards. This may require the following:

- Control line rework or replacement
- Minor work to ensure adequate sustained CP readings
- New regulators or replacement of "soft goods"
- New sleeves, ladders, vault covers, and pipe stubs
- Recoating of all exposed piping with epoxy
- Vault rehabilitation
- Building rehabilitation

Station rebuilds can extend the life of an existing station by twenty (20) years or more and are cost effective.

Cost: $100,000 - $500,000 depending on size, condition, and extent of rebuild

Alternatives – Heaters:

Alternative 1: Rebuild existing heaters

The main components of gas heaters can be replaced; however, the manufacturers of older heaters are generally no longer in business after 25 years. For example, BS&B, and NATCO are heater manufacturers that have gone out of business in the last 20 years. This presents a unique problem as replacement parts are not available and large components would have to be custom fabricated. The cost to remove and replace large components in the field coupled with the availability generally makes the cost to rebuild a heater as high (or higher) than the replacement cost.

Cost: $350,000 depending on size, condition, and extent of rebuild

Studies/References that Support the Program:

The Company's Distribution Integrity Management Program was put in place in 2011. The program includes a risk ranked approach for ranking pressure regulating facilities according to Health & Safety Risks and the Technical risks associated with their age and condition.

<u>TI 020040 - Management of Cold Gas Temperatures</u>. This TI provides the Company's general strategy which is that all stations with a pressure drop of 200 psi or greater should have heaters where practical. It supports the operation of natural gas heaters and the need to add or replace heaters.

Program Title: Pressure Regulation Special Projects

Spending Rationale: ☐ Mandated ☐ Growth

☒ Reliability ☐ Non-Infrastructure

Brief Description:

This program covers special capital projects involving transmission pressure regulating stations and custody transfer stations that are not included in other program budgets. These facilities have the highest potential customer impact, and have multiple elements that ensure adequate and safe delivery of natural gas to customers. Depending on the asset, these projects may include complete overhaul or partial rebuild of a station or replacement of obsolete equipment. Projects may also incorporate odorization, gas quality validation, pressure regulation, and process pre-heating equipment. Newly constructed sites will also include state of the art telemetry and remote operable equipment. This program also includes installation of additional layers of overpressure protection equipment at custody transfer stations. This work reduces the risk of overpressurization and the consequences it would have on the Company's systems. A list of the proposed projects is included in the cost breakdown table, below.

Program Justification:

The Pressure Regulation Special Projects are complex projects typically located at city gate stations that operate at transmission pressure. A typical city gate station overhaul includes replacement of obsolete equipment, building improvements, and any required piping replacement or reconfiguration to meet load demand. In conjunction with the facility rebuild/replacement, the Company also may take improvements to enhance odorant spill containment systems and/or install updated gas analyzers and measurement equipment. These improvements are described in more detail below.

Using data from the annual Performance Testing ("PT"), Cathodic Protection ("CP") testing, risk assessments and on-site inspections, technical assessments were made for each station taking into account pipe and equipment condition, regulator performance, corrosion data and heater and scrubber performance. Additionally, Guided Bulk Wave Testing ("GBWT") has been used in regulator vaults to determine if there are any anomalies in the pipe within the vault penetrations. The results of these tests and assessments, combined with an analysis of the potential customer impact resulting from a station outage, were used to prioritize and schedule the special capital projects described below.

Odorant Systems

The odorant systems at city gate stations are responsible for adequately odorizing the natural gas before it is introduced to the distribution network. Adequacy and functionality of these systems is critical to ensure natural gas is supplied safely to customers. Odorant system upgrades will replace dated odorant injection systems (*i.e.* wick odorant systems or aging pump systems).

Additionally, emphasis will be put towards enhancing odorant spill containment systems by adding vacuum exhaust systems (with charcoal canisters at discharge ducts), mercaptan sensing equipment, and spill containment kits. These measures will mitigate the impact of any loss in containment of odorant by enabling improved response time, while reducing the potential for public incident.

Gas Quality Verification

Ensuring a high standard of natural gas entering the Company's system from suppliers is important to maintain safe and reliable operation of the Company's system. To ensure adequate gas quality, new water and hydrogen-sulfide detection systems will be installed at custody transfer stations. These installations will be telemetered to the SCADA system that will enable Company personnel to monitor the concentrations of these compounds. In addition to these detection systems, outdated chromatographs will be replaced when necessary to better ensure accurate reflection of gas composition and heating values.

Remote Capability

In the event of a pipeline rupture, having remote shut-off capability could result in mitigating impacts or diminishing the time a hazardous condition is present. Since these stations serve as the source of natural gas within the Company's distribution network, having the ability to remotely stop the supply into a system is critical.

As well as remote shutoff capability, the ability to remotely adjust the pressure settings of a station is critical to ensure reliable and safe service to our customers. Remote actuation and adjustment can help accommodate for regulator droop or prevent pressures from exceeding MAOP.

Security

Security enhancements at these stations are managed in a separate program ("Gas Regulator Station Security" program).

Overpressure Protection

Within the Niagara Mohawk service territory, 19 of the 24 take stations do not have Company-owned regulating equipment. Furthermore, of those 19 facilities, 14 do not have any method of Company-owned overpressure protection. While there may be overpressure protection on the suppliers' sides, the Company is not able to control, test or verify these systems. This leaves Company facilities susceptible to any accidental over-pressurization from pipeline suppliers.

Installing Company-owned overpressure protection assets at these facilities gives greater assurance that the equipment is regularly inspected and tested according to Company procedures. Adding this equipment enhances Niagara Mohawk's ability to provide safe and reliable service to its customers. When practical, overpressure protection upgrades will be performed in conjunction with any city gate station rebuilds.

Total Special Project Program Cost Breakdown:

$000	FY 2019	FY 2020	FY 2021
GRS 824-043 Elton & Salina Overhaul	75	0	0
GRS 924-426 Alplaus Overhaul	1,290	80	0
GRS 924-450 Putnam City Gate Partial Rebuild	25	0	0
GRS 924-336 Brookview City Gate Partial Rebuild	1,210	0	0
GRS 924-434 Mariaville Rd Overhaul	400	1,700	80
GRS 824-688 Old Campion Rd Overhaul	500	0	1,800
GRS 824-709 Oneida Supply Overhaul	500	2,100	80
GRS 824-127 Cold Springs Road	500	0	2,000
GRS 924-313 Washington & Fuller Overhaul	0	620	0
GRS 824-216A Sandy Creek Overhaul	0	0	600
Overpressure Protection	1,050	1,079	1,104
Total	5,550	5,579	5,664

Note: Funding to perform as-builts and project closeouts is provided a year after construction (i.e. Elton & Salina FY 2019, Alplaus FY 2020, etc.).

Customer Benefit:

The primary customer benefit is the continuous, safe, and reliable supply of natural gas without unplanned outages due to facility shutdowns. Critical pressure regulating stations and custody transfer stations can supply to hundreds of thousands of customers for high pressure stations.

Alternatives – Special Projects

Alternative 1: Full replacement**.** The entire station is replaced from the station inlet to the outlet. A full replacement is appropriate when:

- Severe corrosion; usually occurs where no CP was installed (*i.e.* Pre-DOT pipe; pre-1971)
- It is not cost effective to repair or modify
- Under capacity – the station is too small and would require new vaults, new piping with larger valves and regulators as identified by Gas System Planning
- Structural problems with vaults, coupled with flooding and traffic problems that needs to be addressed

Cost: $1,500,000 - $3,000,000 per station dependent on size and location

Alternative 2: Station Rebuild. The station can be rebuilt and brought to current standards. This may require the following:

- Control line rework or replacement
- Minor work to ensure adequate sustained CP readings
- New regulators or replacement of "soft goods"
- New sleeves, ladders, vault covers, and pipe stubs
- Recoating of all exposed piping with epoxy
- Vault rehabilitation
- Building rehabilitation
- Addition of overpressure protection
- Update of odorant systems
- Update of gas quality verification systems

Station rebuilds can extend the life of an existing station by twenty (20) years or more and are cost effective.

Cost: $500,000 - $1,500,000 depending on size, condition, and extent of rebuild

<u>Alternatives – Overpressure Protection</u>

Alternative 1: Relief valve installation. A relief installation is appropriate when:

- The current facility is in good condition and it does not require a complete overhaul
- Upstream regulating equipment cannot pass excessive volumes of natural gas during failure
- Remote operability of the system is already in place, or not immediately needed

Cost: $100,000 - $350,000 per station dependent on size of the relief equipment and the extent of piping rework required.

Alternative 2: Control valve/actuator installation. An actuating valve installation is appropriate when:

- The current facility is in good condition and it does not require a complete overhaul
- There is a valve that can be readily mounted with an actuator, and the valve is in an appropriate location
- A new valve and actuator can be installed during a temporary outage or by-pass operation
- Remote operability is not already in place and is desired
- Multiple relief valves would be required, making them non-cost effective
- Relief valves cannot be installed due to proximity to the public or electric facilities

Cost: \$100,000 - \$500,000 per station dependent on size of the equipment and the extent of piping rework required.

Studies/References that Support the Program:

The Company's Distribution Integrity Management Program ("DIMP") was put in place in 2011. The program includes a risk ranked approach for ranking pressure regulating facilities according to Health & Safety Risks and the Technical risks associated with their age and condition.

Program Title: Restrictions for Elevated Gas Infrastructure

Spending Rationale: ☐ Mandated ☐ Growth

☐ Reliability ☒ Non-Infrastructure

Brief Description:

Niagara Mohawk is proposing a program to reduce the risk of public injury by restricting and/or deterring public access to the Company's elevated gas facilities.

Program Justification:

The purpose of this program is to reduce the risk of climb and fall injuries or fatalities. In 2014 in the United Kingdom, a fatality occurred resulting from a climb and fall accident on an elevated gas pipeline at a bridge crossing operated by a National Grid affiliate company. Currently, Niagara Mohawk has approximately 374 locations where exposed gas pipelines are four feet or higher above the ground or across a body of water. Only 81 of these locations are not publicly accessible or have barriers or deterrents in place to discourage the public from climbing or accessing the facilities. This is a ten-year program beginning in the Rate Year to install fencing or other physical deterrents at the remaining 293 locations.

Total Project Cost Breakdown:

The budget for the Rate Year and Data Years is derived from the total ten-year program cost of approximately $10.5 million ($0.04 million per location), adjusted for inflation.

$000	FY 2019	FY 2020	FY 2021
CapEx	1,052	1,081	1,107

Customer Benefit:

This program improves public safety.

Alternatives:

Alternative 1: Raise public awareness through signage only

Raising public awareness of the risk associated with elevated pipelines through warning signs alone will reduce risk to a lesser extent than fencing or other physical barriers that restrict access.

Alternative 2: Do Nothing

This alternative does not mitigate the public risk of climb and fall accidents and fatalities.

Exhibit __ (GIOP-5)

Incremental O&M Non-Labor Expenditures: Rate Year and Data Years

GIOP-5 Incremental O&M FY19-FY21

Testimony Category	Program/Position	FY19 Non Labor	FY20 Non Labor	FY21 Non Labor
Increased OpEx Workload	Damage Prevention- Damage Prevention Advisor Program	$ 345,000	$ 355,350	$ 366,011
	Damage Prevention- Ticket Risk Assessment Costs	$ 32,564	$ 34,192	$ 35,902
	Gas Transmission Engineering- IMP/IVP Inspections (PHSMA)	$ 2,639,913	$ 992,913	$ 1,045,913
	I&R- Increased Pipeline Survey	$ 1,000,000	$ 1,000,000	$ 1,000,000
	I&R- Vegetation Management Gas Maintenance	$ 113,876	$ 101,089	$ 38,087
	Pressure Regulation Engineering- Transmission Station Integrity Management Program	$ 798,000	$ 798,000	$ 798,000
	Geographic Information system ("GIS"), Mapping Gas Services	$ 2,997,000	$ 4,203,000	
	Enhance Pipeline Compliance System (“PCS”)	$ 500,000		
	CMS- Ipads	$ 775,000	$ 150,000	$ 150,000
	Gas Work Methods & Standards- Traditional Gas RD&D	$ 55,000	$ 58,000	$ 60,000
Increased OpEx Workload Total		**$ 9,256,353**	**$ 7,692,544**	**$ 3,493,913**
OpEx related to CAPEX	Elevated Pressure Metering Program Maintenance	$ 47,000	$ 96,000	$ 147,000
	I&R- Field Tests & Training Lab	$ 25,000	$ 27,000	$ 31,000
	I&R- Gas Regulator Station Security	$ 8,000	$ 32,000	$ 55,000
	I&R- Odorant Injection Pump Air Supply	$ 86,000	$ 156,000	$ 221,000
	I&R- Portable Compressed Natural Gas (CNG)	$ 43,000	$ 55,000	$ 59,000
	I&R- Portable Temporary Regulator Station	$ 15,000	$ 15,000	$ 15,000
	I&R- Dry line Heater Flushing	$ 7,500	$ 7,500	$ 7,500
	AMF- Advanced Metering Functionality		$ 1,120,000	$ 880,000
	Gas Operations- Tools	$ 100,000	$ 100,000	$ 100,000
OpEx related to CAPEX Total		**$ 331,500**	**$ 1,608,500**	**$ 1,515,500**
OpEx Safety Programs	Damage Prevention- Wrapping Company Vehicles	$ 30,000	$ 30,000	$ 30,000
	I&R- Agricultural Depth Survey			$ 750,000
	Gas Pipeline and Safety Compliance- First Responder Training- Mobile Hands on Training	$ 500,400	$ 311,400	$ 311,400
	Gas Pipeline Safety & Compliance- Public Awareness Inside Inspections	$ 12,000	$ 12,000	$ 12,000
	Gas Pipeline Safety & Complaince- Residential Methane Detector Pilot	$ 150,000	$ 150,000	$ 150,000
	Gas Pipeline and Safety Compliance-First Responder Training- Train the Trainer	$ 74,000	$ 54,000	$ 54,000
	Damage Prevention- GPS Location of Transmission Pipeline	$ 1,300,000	$ 1,300,000	
OpEx Safety Programs Total		**$ 2,066,400**	**$ 1,857,400**	**$ 1,307,400**
Grand Total		**$ 11,654,253**	**$ 11,158,444**	**$ 6,316,813**

Exhibit__(GIOP-5)
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Exhibit__ (GIOP-6)

Exhibit __ (GIOP-6)

Incremental Full Time Equivalent Positions by Function in the

Rate Year and Data Years

GIOP-6 Incremental FTEs FY19-FY21

Testimony Category	Program/Position	FY19	FY20	FY21	Description
Increased OpEx Workload	CMS- Service Representative	2	0	0	To support CMS Field Operations
	Damage Prevention- Supervisor	1	0	0	To respond to increased volume of one call tickets and cover additional territory
	Geographic Information system ("GIS"), Mapping Gas Services- Mapping Techs	3			To prospectively maintain GIS of new and historic mapped services
	Field Personnel & Contractor Training- Senior Instructors	4			To train and support new and less experienced employees in the field
Increased OpEx Workload Total		**10**	**0**	**0**	
OpEx related to CAPEX	Contract Management- Analyst	4			To enhance contractor oversight program including managing operator qualification and training oversight
	Gas Long Term Planning- Engineer	1			To support increase in capital program
	Gas Operations Engineering- Engineer	1			To support increase in capital program
	Gas System Engineering- Estimator	3	0	1	To support increase in capital program and respond to increased scope of responsibilities
	Gas Transmission Engineering- Engineer	1			To support increase in capital program
	Gas Work Methods & Standards- Engineer	1			To support increase in capital program
	I&R- Field Trainer	2	0	0	To support field employees in delivering increased capital and O&M programs
	I&R- Techs	12	0	0	To execute incremental work plan requirements
	Long Term Resource Planning- Program Manager	1			To support increase in capital program
	Operational Controls- Manager	1			To support increase in capital program
	Operational Controls- Program Manager	2			To support increase in capital program
	Operations Support- Clerical	6	0	0	To address historic understaffing to meet
	Operations Support- Mapping Coordinators	2	0	0	To address historic understaffing and meet work plan requirements
	Operations Support- Mapping Technicians	5	0	0	To address historic understaffing and meet work plan requirements
	Pressure Regulation Engineering- Engineer	1			To support increase in capital program
	Project Engineering & Design- Clerical	1			To support increase in capital program
	Project Engineering & Design- Designer	1			To support increase in capital program
	Project Management- Project Manager	1			To support increase in capital program
	Rate Case Support- Program Manager	1			To support increase in capital program
	Resource Planning- Program Manager	3	0	0	To support increase in capital program
	Scada Support- Engineer	1			To support increase in capital program
	Gas Distribution Engineering- Engineer	1			To support increase in capital program
	Operations Support- Supervisor	1	0	0	To support increase in capital program
	Process & Performance- Analyst	2			To support increase in capital program
OpEx related to CAPEX Total		**55**	**0**	**1**	
OpEx Safety Programs	Process Safety- Engineer	2	0		To support increase in capital program
	Gas Emergency Planning- Program Manager	1			To support increase in capital program
	Gas Pipeline and Safety Compliance- QA/QC Inspectors	4	0	0	To expand program to include additional areas of review
	Gas Pipeline Safety & Compliance- Public Awareness- Public Safety Liason	1			To provide incremenal Public Outreach
	Gas Pipeline and Safety Compliance- First Responder Training- Senior Instructor	4			To implement new train the trainer and mobile programs
OpEx Safety Programs Total		**12**	**0**	**0**	
Grand Total		**77**	**0**	**1**	

Exhibit__(GIOP-6)
Page 1 of 1

Exhibit __ (GIOP-7)

Hiring Plan for Incremental Full Time Equivalent Positions in the Rate Year and Data Years

GIOP-7 FTE Hiring Plan FY19-FY21*

*Plan subject to change depending on program needs

Testimony Category	Program/Position	Start Date: 4/1/18	Start Date: 7/1/18	Start Date: 8/1/18	Start Date: 4/1/20	Grand Total
Increased OpEx Workload	CMS- Service Representative	2				2
	Damage Prevention- Supervisor	1				1
	Field Personnel & Contractor Training- Senior Instructors	4				4
	Geographic Information system ("GIS"), Mapping Gas Services- Mapping Techs	3				3
Increased OpEx Workload Total		**10**				**10**
OpEx related to CAPEX	Contract Management- Analyst		4			4
	Gas Distribution Engineering- Engineer	1				1
	Gas Long Term Planning- Engineer		1			1
	Gas Operations Engineering- Engineer		1			1
	Gas System Engineering- Estimator	3			1	4
	Gas Transmission Engineering- Engineer		1			1
	Gas Work Methods & Standards- Engineer		1			1
	I&R- Field Trainer			2		2
	I&R- Techs			12		12
	Long Term Resource Planning- Program Manager		1			1
	Operational Controls- Manager		1			1
	Operational Controls- Program Manager		2			2
	Operations Support- Clerical	6				6
	Operations Support- Mapping Coordinators	2				2
	Operations Support- Mapping Technicians	5				5
	Operations Support- Supervisor	1				1
	Pressure Regulation Engineering- Engineer	1				1
	Process & Performance- Analyst	2				2
	Project Engineering & Design- Clerical	1				1
	Project Engineering & Design- Designer	1				1
	Project Management- Project Manager	1				1
	Rate Case Support- Program Manager		1			1
	Resource Planning- Program Manager		3			3
	Scada Support- Engineer		1			1
OpEx related to CAPEX Total		**24**	**17**	**14**	**1**	**56**
OpEx Safety Programs	Gas Emergency Planning- Program Manager	1				1
	Gas Pipeline and Safety Compliance- First Responder Training- Senior Instructor		4			4
	Gas Pipeline and Safety Compliance- QA/QC Inspectors	4				4
	Gas Pipeline Safety & Compliance- Public Awareness- Public Safety Liason	**1**				**1**
	Process Safety- Engineer		2			2
OpEx Safety Programs Total		**6**	**6**			**12**
Grand Total		**40**	**23**	**14**	**1**	**78**

Exhibit__(GIOP-7)
Page 1 of 1

Exhibit __ (GIOP-8)

GBE Program High-Level Roadmap Showing Phased Implementation
and Capabilities

High Level Roadmap of Capabilities to be Delivered Over Five Years

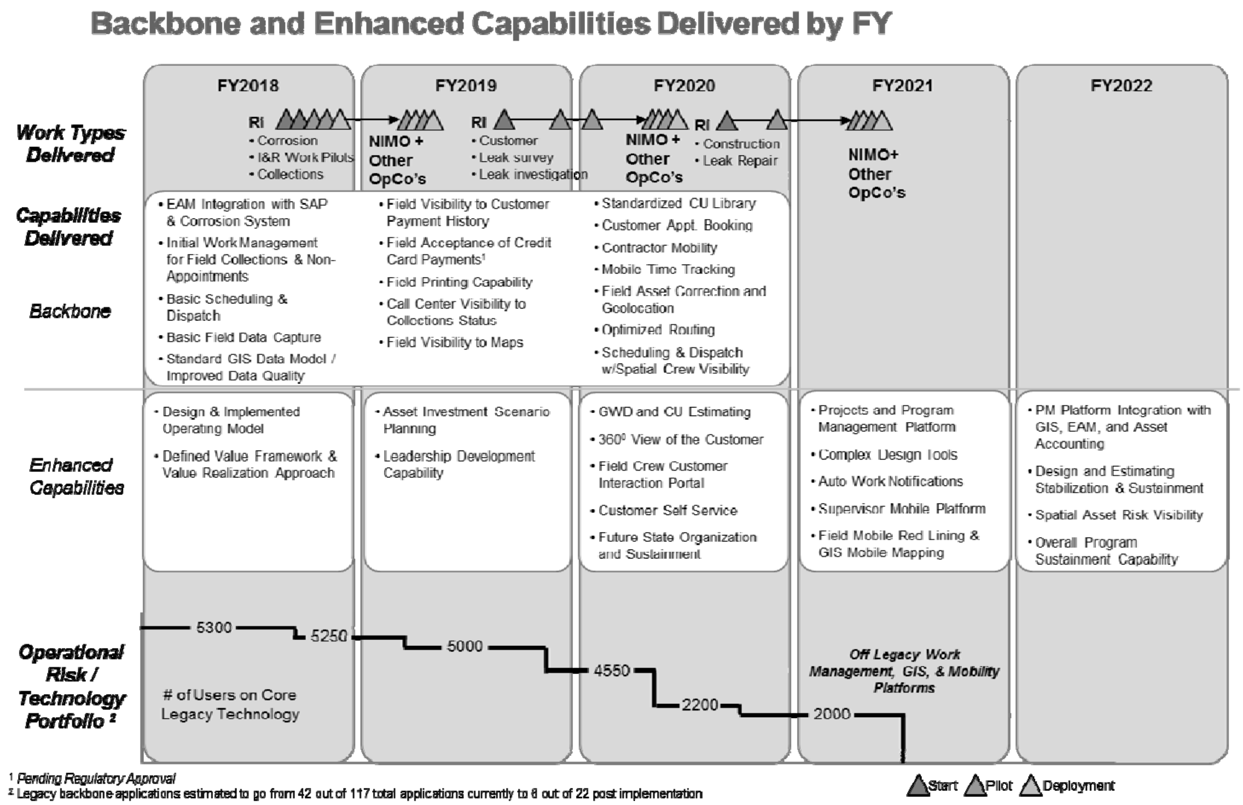

Exhibit__ (GIOP-9)

Exhibit __ (GIOP-9)

GBE Program Description of the Specific Projects, Capabilities, and Benefits that will go In-Service in the Rate and Data Years for Niagara Mohawk

GAS BUSINESS ENABLEMENT INVESTMENTS – CAPABILITIES/ CUSTOMER BENEFITS

FY2018 - Investments In-Service

PowerPlan Architecture Enhancements (November 2017)
Description/Capabilities/Customer Benefits
- Removes the "real-time" dependency of the Enterprise Asset Management ("EAM") Platform on PowerPlan for the Work Order creation process by creating direct interfaces to SAP
- Establishes a batch schedule on which SAP (back office system) feeds all work order, operation and cost data, to PowerPlan
- Simplifies real time work order creation process
- Removes the delay in updates to the work order estimates in SAP
- Foundational component to deliver the Gas Business Enablement systems

Comprehensive Integration Service (Enhancement) (December 2017)
Description/Capabilities/Customer Benefits:
- Facilitates the process of developing, securing, and monitoring the integrations between applications whether on premise or in the cloud
- Foundational component to deliver the Gas Business Enablement systems

Application (Environment) Infrastructure Upgrades (December 2017)
Description/Capabilities/Customer Benefits:
- Defines and establishes infrastructure environments (on-premises and cloud) to enable the implementation of Enterprise Asset Management, Scheduling and Dispatch, Mobility, Analytics, Data Management, GIS, and Asset Investment Planning application platforms and products
- Foundational component to deliver the Gas Business Enablement systems

<u>Data Management Implementation (Quality & Cleansing)</u> (December 2017)
Description/Capabilities/Customer Benefits

- Platform (suite) of technologies for data management of critical gas operations data throughout its lifecycle: from when the data is created until it is deleted. The platform (suite) of technology covers architecture, platforms, and applications necessary to successfully enable a data management practice that will include the following: profiling; cleansing; enriching; transforming; migrating; monitoring and reporting; archiving; and deleting activities. Includes cloud based integration tools for large data movement to cloud based platforms
- Establishes data operations processes that would manage the Common Data Model, manage the movement of data from the source application, cleaning the data, conversion of the data and preparing the data for loading into target system(s). establish the data retention policies (Business, Regulatory, and Legal holds), data archiving policies, and the data deletion and destruction policies
- Improves accessibility of data to support employee interactions internally and externally
- Improves data accuracy
- Improves record-keeping

<u>Risk Management (Tx Mains & Dx Mains)</u> (December 2017)
Description/Capabilities/Customer Benefits

- A commercial off-the-shelf (COTS) solution to enhance the capabilities of the integrity management program for transmission and distribution assets, replacing current home-grown solutions in use
- Includes integrations for GIS, EAM, and Data Historian
- Flexible processes to accommodate evolving business and PHMSA needs
- Makes a clear delineation of the system of record for asset information
- Training for Engineers and Managers in advanced statistical reliability models and applications working with National Grid Advanced Data Analytics group
- Strengthens gas safety efforts and priorities
- Improves the process and timeframe for closing work orders and capturing updated asset and facility records

<u>Business Architecture Design</u> (December 2017)
Description/Capabilities/Customer Benefits:

- Detailed business process designs for Asset Management, Work Management and Customer processes
- Defines the standard business processes for work performed by internal and contracted resources
- Defines the Asset Hierarchy for the gas assets as the basis for the subsequent EAM and GIS initiatives
- Key design decisions and business requirements regarding EAM, Scheduling, Mobility, GIS, Finance, Supply Chain and operationally-related Customer Interactions

RATE YEAR – Investments In Service

Operations/Systems Monitoring (August 2018)
Description/Capabilities/Customer Benefits:

- Installs and configures monitoring software so that application events, outages, security incidents are routed to ServiceNow (SNOW)
- Minimizes system downtime
- Improves data security

Corrosion and I&R Work (October 2018)
Description/Capabilities/Customer Benefits:

- Implements EAM platform with base capabilities including work order creation/updates, job plans, asset lifecycle management (i.e., creation/maintenance of assets and locations), inventory management (*i.e.*, issue/transfer of materials, storerooms setup), reports, and preventative maintenance
- Implements a schedule and dispatch platform with base capabilities that include schedule/dispatch work, work bundling, view/update crew structure, view work/field crew location spatially, work progress tracking, and view resource skills and classification
- Implements a field mobility platform with base capabilities that include view work assignment, electronic work package, view attachments, attach pictures, initiate work, update work status, view maps (legacy maps) and capture work completion data
- Increases visibility to work lifecycle
- Improved schedule and dispatch
- Improves work completion data quality
- Increases visibility to work progress/work completed by contractors

CU Governance & Library – process (November 2018)
Description/Capabilities/Customer Benefits

- Builds and implements a common Compatible Unit library utilized by engineers and designers incorporating standard design, material, labor, equipment and accounting information
- Drives the use of standardized construction and material standards enabling more efficient and consistent execution of work across National Grid field operations and external alliance partners/contractors working under a master services agreement (MSA)
- Improves estimate accuracy to drive improved forecasting and budget management

<u>Asset Investment Planning and Management ("AIPM") Tool – Enhancements</u> (December 2018)
Description/Capabilities/Customer Benefits:

- Allows development of a multi-year pipeline of asset investments/work (capital, maintenance, emergency, and customer)
- Facilitates setting up of multi-year programs and associated projects
- Allows tracking of asset risk and prioritization at the asset level
- Provides the ability to evaluate different investment options and evaluate CapEx and OpEx tradeoffs
- Forecast blanket work including emergency work, customer growth, municipal/city/state requests based on historical/projected data and to establish placeholder annual blanket budgets
- Facilitates identification of opportunities for bundling projects based on asset type, geography, asset risk factor, category (*e.g.,* growth, end-of-life maintenance capital, regulatory driven, mandatory, non-mandatory, O&M)
- Allows development of rolling multi-year repair vs. replace vs. run to failure vs. maintain decision process
- Improved work planning and scheduling

<u>Additional Integrity Management ("IM") Modules</u> (February 2019)
Description/Capabilities/Customer Benefits:

- Implements additional Integrity Management Modules to support Maximum Allowed Operating Pressure ("MAOP") Management, In-Line Inspection Data Management, and Leak Finder. These applications provide enhanced capabilities to import SCADA data (*i.e.,* system operating pressure data) and integrity management data captured utilizing various direct and indirect assessment tools)
- Enhances gas system safety and reliability

<u>Data Remediation, GIS Upgrade/ Migration & GIS Mobility</u> (March 2019)
Description/Capabilities/Customer Benefits:

- Landbase - provides a consistent base map across the enterprise that includes a street centerline and aerial imagery
- Data Conversion - conversion of gas service records to GIS including conversion of street centerline maps of NYC and graphic (scanned) sketches and the associated record attributes noted on the sketch and from various legacy systems
- Conflation – realignment of the gas GIS linear and non-linear assets to a more spatially accurate landbase allowing for integration with outside data sets
- GIS Upgrade Migration and Mobility - consolidated GIS platform to ESRI/Schneider and up-to-date view of the GIS data in a portal and mobile viewer available to National Grid's field and office employees
- Improves ability to model and estimate customer work
- Strengthens gas safety efforts
- Improves compliance

<u>Enable the Data Archival Process</u> (March 2019)
Description/Capabilities/Customer Benefits:

- Defines the data archival process that adheres to the Record Retention Policies with the necessary quality control and quality assurance steps
- Defines and implements system decommissioning, moving data to a low cost storage solution
- Improves record-keeping

DATA YEAR 1 CAPABILITIES AND CUSTOMER BENEFITS

EAM-FIN Integration (June 2019)
Description/Capabilities/Customer Benefits
- Process and solution enhancements to integrate AIPM tool with EAM and Corporate Finance (FIN)
- Implements automatic updates to the asset hierarchy in AIPM from EAM
- Integrate with FIN to obtain actual project cost (as constructed) to inform defer/accelerate decisions of future work in the Annual Work Plan
- Run reports to identify projects outside of budget and schedule tolerances and variances of actual costs from estimates
- Improves accessibility and visibility to investment planning and capital execution process

CxT Portal & Channel Management (June 2019)
Description/Capabilities/Customer Benefits:
- Implementation of digital interactive support tools to enable simple and effective interactions between National Grid and the customer based on customer channel preferences
- Enhances core customer community foundation (e.g. website and mobile applications) including login, registration and general User Interface (UI) / User Experience (UX) enhancements

Regulatory / Compliance (September 2019)
Description/Capabilities/Customer Benefits:
- Implements modern, more reliable platform(s) that will decrease the likelihood of system outages impacting the ability to deliver work
- Improves electronic field data capture with prompts and controls developed within the solution to drive accurate and complete capture of required information, and will enhance records to document compliance with less reliance on paper
- Improves field access to customer and asset data with enhanced visibility utilizing maps and process documentation on mobile devices to provide employees with the right information to comply with regulatory requirements
- Improved training and job aids such as instructor and video-based training on mobile devices to improve operational performance

Integrity Management Integrations (October 2019)
Description/Capabilities/Customer Benefits

- Implements integration with EAM, GIS, Data Historian on risk management to decrease manual data entry and promote 'one source of the truth, 'eliminate the time needed to extract and import files, and increase the frequency of the ability to plan/model the network
- Improved data accuracy

Company Driven Work: Collections and non-Appointment Offs – ELECTRIC/GAS (October 2019)
Description/Capabilities/Customer Benefits:

- Implements additional capabilities of scheduling and field mobility along with integration between customer information systems (CIS), and customer relationship management system (CRM)
- Enhances scheduling and dispatch tool capabilities which include schedule/dispatch of collections and collections offs work orders
- Enhances field mobility platform with additional capabilities to include the ability to view customer balances and payments due, capture credit card payments, scan checks and print receipts for customer
- Implements capability for Call Center Representative to view status and progress of Collections orders and provide accurate updates when customers inquire

Customer, Leak Investigation & Inspections – ELECTRIC/GAS (October 2019)
Description/Capabilities/Customer Benefits:

- Enhances integrations between EAM with Scheduling, Field Mobile, SAP Labor & Time, SAP Accounts Payable, SAP Accounts Receivable, SAP ERP (*i.e.*, Supply Chain - Materials Management & Procurement), Document Management system and customer information systems
- Data conversions including additional work orders (i.e., history and in progress), relevant assets/locations (*i.e.,* premise, meters, main, valves), job plans, tools, materials catalog, and customer data
- Implements supervisor field mobile capabilities, which include view of multiple crew work assignments, initiate work, field audit, view attachments, attach pictures, view/update work status
- Enhances real time scheduling and dispatch tool capabilities to include adding an appointment calendar for booking customer work, schedule/dispatch of Customer, Leak Investigation and Inspection work orders
- Provides contractors with mobility capabilities, which includes sending work completion data, and record materials
- Enhanced scheduling of customer appointments
- Improves process and timeframe for work order completion
- Strengthens gas safety efforts and process

<u>Employee Support Interaction</u> (Release 1 – October 2019, Release 2 - July 2020)
Description/Capabilities/Customer Benefits:

- Interactive support tool leveraging the existing CRM platform specifically focused on creating visibility for National Grid Employees about field activities to make them more effective in managing field work
- Provides National Grid employees with:
    - Enhanced, real-time communications between Call Center, Dispatch, field employees and other customer support groups (peer to peer)
    - Ability to view, schedule and adjust appointments
    - Ability to set appointment reminders based on customer preference
    - Ability to receive customer photos (e.g. meter read) to support quicker problem resolution
    - Ability to view status of a customer-driven work request and status of field work impacting customers (*i.e.*, construction progress)
    - Ability to view location of crews in the vicinity
- Provides National Grid Field Employees information to:
    - Send email/text message to the customer with tailored information based on channel preferences (i.e. links to National Grid web pages)

<u>Customer Interaction</u> (Release 1 – October 2019, Release 2 - January 2021)
Description/Capabilities/Customer Benefits:

- Leverages the CxT Portal and enhances the core customer processes to significantly improve the self-service customer experience
- Provide Customers with:
    - Ability to schedule appointments with National Grid on customers' own terms for home or business – and change appointments as required to better fit the customer's schedule
    - Ability to receive reminders from National Grid about appointments and other activities
    - Ability to submit photos to National Grid to describe issue or problem.
    - Ability to follow up on progress of work requests / appointments and status
    - Ability to view website and understand if National Grid's crew(s) are in the vicinity

DATA YEAR 2 CAPABILITIES AND CUSTOMER BENEFITS

Customer Relationship Management (CRM) / Contact Center (June 2020)
Description/Capabilities/Customer Benefits:
- Further enhances the existing interactive support tool delivering the full 360 degree view of customer contacts, interactions and account history in one place on the CRM platform
- Provides a platform for National Grid employees to handle customer interactions including:
  - Ability to find information about how to establish gas service, the cost for the service (i.e. CIAC)
  - Ability to perform account inquiries including billing issues, service suspension, etc.
  - Ability to create and adjust payment arrangements
  - Ability to escalate compliments / complaints
  - Ability to view outage status and customers impacted in one location
- Enhances analytics and in-app reporting and dashboards to more effectively drive business performance

PowerPlan Integration & Enhancements (June 2020)
Description/Capabilities/Customer Benefits:
- Configuration of application and business rules in PowerPlan to support strengthening and creating visibility of the funding approval processes
- Enhanced integrations between EAM, SAP Finance, and PowerPlan to reduce manual processes

Large Commercial & Landlord Interaction (July 2020)
Description/Capabilities/Customer Benefits:
- Allows large commercial and property owners to
  - Bundle appointments to help manage time more effectively
  - View status and progress of requests and appointments
  - Delegate communication and interaction preferences (e.g., delegate point of contact for each property)
  - Receive notifications/alerts about an issue at one of the premises assigned
  - More efficient and flexible scheduling and service to customers

Design (GWD), Estimating (CU), & Mobility (September 2020)
Description/Capabilities Customer Benefits:
- Develops, refines, and standardizes the Engineering design and estimation processes and technology. All work will be designed with graphical work design (GWD) and estimated with compatible units (CUs)
- Integrates Field Mobile and EAM

- Implements an integrated set of design tools that can be used by all design employees and that will incorporate the same standards across all operating companies
- Drives opportunity for more accurate estimates of customer work cost due to greater integration of cost components.
- Graphical designs (i.e. electronic work packages) available to field employees More effective dispatching of work based on integration of mobile capability

Construction Work & Leak Repair (September 2020)
Description/Capabilities/Customer Benefits:

- This release is set up to implement additional capabilities of EAM, Scheduling, and Field Mobility along with integration to GIS and Asset Accounting (PowerPlan). This release will also implement Construction and Leak Repair work orders on a mobility solution
- Work orders include New Service, Service Relocation, Service Replacements, Fitting (Ops), Customer Outages (Ops), Leak Repair, Main Replacement, Encroachments, New Mains, Valve Inspection, Restoration Repairs, Service Cut Offs, Service Valve Installations, Leak Survey (Contractor - OPS), and Leak Surveillance (Ops)
- Implements integration between EAM, GIS, and Asset Accounting (PowerPlan). Enhance integrations between EAM and Project Accounting (Enterprise Finance)
- Enhances scheduling & dispatch tool capabilities which include schedule/dispatch of Construction and Leak Repair work orders
- Improves ability to schedule customer work orders and ensure that customer appointments are met
- Better communication with customers regarding work orders affecting them and their neighborhoods

Asset Analytics Integration (December 2020)
Description/Capabilities/Customer Benefits:

- Process and solution enhancements to integrate with Asset Management and Resource Planning
- Enhances ability to prioritize asset investments according to various risk factors including asset risk. Strong emphasis on utilizing asset analytics for determining asset risk
- Capability to monetize asset risk per dollar of asset investment
- Capability to provide current and future levels of asset risk after asset investment
- More effective asset value and risk assessment, ensuring best cost scenario for customers

GIS (GWD/CU) – Project Portfolio Management ("PPM") Integration (December 2020)
Description/Capabilities/Customer Benefits:

- Accepts inputs on project estimates from the GWD/CU and Computer Aided Design (CAD)/Estimating Software ESW libraries, and provides consolidated and individual views for people, material, and equipment needs

- Enhanced bundling capability to spatially visualize project location and to bundle and unbundle based on location
- Incorporates work volumes tied with financials for the 5-10-year plan (maintenance and capital work) for both project and blanket estimates (e.g. emergency work budgets, corporate requests with changes in spend/budget, maintenance program, etc.)
- Integrates with PPM to proactively understand potential project overrun issues in advance and take corrective action. Utilize Earned Value (EV), Estimate to Complete (ETC), Estimate at Completion (EAC), Budget Variance (BV), Schedule Variance (SV), etc.
- Optimizes the investment plan under resource (labor, equipment, materials, etc.), financial (CapEx and OpEx), regulatory and network constraints and to identify and compare tradeoffs between investment options, including but not limited to risk reduction, cost, and resource use
- Ability to translate projects into supply/demand forecasts for resources (people, material, and equipment) and to communicate the information
- Drives opportunity for more accurate estimates of customer work cost due to greater integration of cost components
- More effective long term plans (5 – 10 years) due to enhanced long term modeling

Test Automation Implementation (December 2020)
Description/Capabilities/Customer Benefits:

- Develops Test Automation Capabilities including the following:
  - Test automation best practices and framework to increase test coverage and reliability, shorten the testing and regression cycles, and mitigate risks for product version upgrades
  - Defines usage of testing tools
  - Facilitates capture of test cases with individual work streams
  - Identifies testing automation limitations for each platform and application
  - Maintains tool environment and facilitates efficient use

GIS-EAM Integration (December 2020)
Description/Capabilities/Customer Benefits:

- Integration of GIS and EAM systems allowing all asset information to be viewed across all applicable functional groups at varying levels of detail (spatial, technical and financial)
- Changes to asset information will be updated across the two applications, without retaining redundant information. EAM and GIS will achieve a tight integration such that information will pass back and forth between them to keep each up to date. EAM will contain all of the asset information, including maintenance records, manufacturer, etc. while GIS will contain location and connectivity characteristics about the asset
- More consistent and accurate information across all information systems, which are used to provide information to customers.

- Faster response to customers' requests for information or quote, due to consistency of information across systems.

Complex Design (CAD) & Estimating (ESW) (March 2021)
Description/Capabilities/Customer Benefits:
- Develops, refines, and standardizes the Engineering design and estimation processes and technology. All work will be designed with CAD and estimated with ESW
- Greater reliability of design due to standardization of engineering design and consistent CAD design
- Greater reliability of design estimates due to standardization of estimation methodology

Use Case No.1 - Asset Risk (March 2021)
Description/Capabilities/Customer Benefits:
- Provides the capability to aggregate multiple data sources of asset demographic, condition, health, and other information to provide a consolidated view of asset risk within and across asset classes
- Provides the ability to view assess asset risk geospatially
- Facilitates asset planning management, and asset information management. Includes the capability to allow Asset Managers to better bundle, coordinate outages/customer interruption
- Improved maintenance scheduling and the consequent improvement in reliability

PROGRAMMATIC SUPPORT (These initiatives comprised multiple releases across the Rate and Data Years as required for design, testing, and implementation activities of the GBE Program investments)

AM Program Leadership

- Includes the program leader and supporting management team to lead and support the Asset Management work stream throughout its lifecycle, including establishment of direction and priorities, program oversight to insure delivery of scope within established budget, schedule and quality requirements, and issue and risk management
- Supports cross-portfolio integration and provides input and recommendations to the Portfolio Leadership Team as appropriate

Program Learning Management

- Defines the overall Program Learning Strategy
- Coordinates learning standards, facility, infrastructure and support needs with National Grid's Learning & Development organization
- Coordinates standard, consistent leading approaches to learning across all technology / process initiatives
- Serves a learning solution architect and coordination role, ensuring that standards and leading practices are being uniformly adopted across initiatives, especially with regard to agile learning approaches
- Ensures the sustainability of the Program Learning content and capabilities

Supply Chain Program Leadership

- Includes the program leader and supporting management team to lead and support the Supply Chain work stream throughout its lifecycle
- Support includes establishment of direction and priorities, program oversight to insure delivery of scope within established budget, schedule and quality requirements, and issue and risk management with appropriate escalations to the Portfolio Leadership Team
- Close collaboration with the Work Management Field Enablement (WMFE) Team to align the future state processes, manage integrations and dependencies between the work management application and the existing SAP supply chain solution

Program Business Sustainment

- Coordinates business readiness activities
- Aligns the scope and timing of the changes to the impact on each organization, business resource requirements and the development of Readiness Action Plans that demonstrate business preparedness to receive upcoming changes
- Works closely with deployment teams and initiative-level agile change management and training efforts to assess readiness and facilitate go-live decisions

Program Transformational Change Office

- Program level office focused on enablement, coordination, and standardization in collaboration with all program portfolios
- Defines and manages the overall change architecture of the program, including defining tailored interventions for each workgroup and driving leadership engagement and alignment across the program
- Defines and executes a comprehensive communications strategy to engage and align employees.

Data Management & Governance Program Leadership

- Leads and supports the Data Management & Governance work stream throughout its lifecycle including establishment of direction and priorities, program oversight to insure delivery of scope within established budget, schedule and quality requirements, and issue and risk management
- Supports cross portfolio integration

Development Operations & BPA Enablement

- Standardizes agile process/delivery methods
- Deployment of tools, techniques, processes for Requirement Management and Continuous Deployment of code
- Deployment of Test Automation Software
- Creates the Business Process Analysis tools for process capture, modeling, and a repository for business process analysts to continuously update information

Mobility CoE & End-User Computing

- Establishes standard hardware and software components, packaging and assembly, and policies (including security) for the field mobile platform
- Addresses the management of the mobile deployment process including the refresh cycle to ensure all employees adhere to standards

SAP and Application Integration Development

- Includes development for integrating the new core Gas Business Enablement applications (Enterprise Asset and Work Management Scheduling/Dispatch and Field Mobility) with existing applications that will remain in the US Gas Operations portfolio. Examples include SAP, Business Intelligence Environments, Customer Information Systems, and other applications as required
- Includes changes to existing applications to prepare them to integrate with the new Gas Business Enablement applications

Solution Architects & Agile Coaches

- Develops standards and guidelines and provides subject matter expertise to program teams to insure that technical solutions and deployment methodologies are delivered in a consistent and integrated manner
- Ensures that Gas Business Enablement objectives are aligned to National Grid's strategic intent for its technical landscape and service model
- Solution Architects – manage the business solution blueprint and coordinate across the development teams to provide an "end-to-end" view of the processes and systems
- Agile Coaches – provide standards and guidance for implementing agile methodology across the multiple teams operating within the overall program

Portfolio Management Leadership

- Overall responsibility for accomplishment of all GBE objectives within sanctioned budgets and timelines and at the level of quality and completeness required to deliver the GBE business case
- Provides the planning, analytical and oversight capabilities required to develop milestone and integration plans, budgets, resource models and program charters
- Establishes and maintains the management and governance framework that insures that GBE programs operate consistently and efficiently and provides visibility to GBE performance, risks, issues, changes and opportunities

WMFE Program Leadership

- Includes the program leader and supporting management team to lead and support the WMFE work stream throughout its lifecycle including establishment of direction and priorities, program oversight to ensure delivery of scope within established budget, schedule and quality requirements, and issue and risk management
- Supports cross-portfolio integration

Customer Experience Program Leadership

- Includes the program leader and supporting management team to lead and support the Customer Experience work stream throughout its lifecycle including establishment of direction and priorities, program oversight to ensure delivery of scope within established budget, schedule and quality requirements, and issue and risk management
- Supports cross-portfolio integration

Exhibit__ (GIOP-10)

Exhibit __ (GIOP-10)

Incremental Operating Expenses for the GBE Program Allocable to

Niagara Mohawk in the Rate Year and Data Years

Niagara Mohawk Power Corporation d/b/a National Grid
Gas Business Enablement
Incremental Operating Expenses

Line	Investment Name	Program/Release Description	Segment	12-Months Ending March 31, 2019	12-Months Ending March 31, 2020	12-Months Ending March 31, 2021	Total OPEX Spend
1	AIPM	Enhancements	Gas	$31.6	$0.0	$0.0	$31.6
2	AM Program Leadership	AM Program Leadership - 2	Gas	$1,196.0	$0.0	$0.0	$1,196.0
3	AM Program Leadership	AM Program Leadership - 3	Gas	$0.0	$1,225.0	$0.0	$1,225.0
4	AM Program Leadership	AM Program Leadership - 4	Gas	$0.0	$0.0	$311.8	$311.8
5	Asset - Advanced Analytics	Use Case No.1 - Asset Risk	Gas	$0.0	$0.0	$189.0	$189.0
6	Customer Experience Program Leadership	Customer Experience Program Leadership - 1	Gas	$780.7	$0.0	$0.0	$780.7
7	Customer Experience Program Leadership	Customer Experience Program Leadership - 2	Gas	$0.0	$798.8	$0.0	$798.8
8	Customer Experience Program Leadership	Customer Experience Program Leadership - 3	Gas	$0.0	$0.0	$609.5	$609.5
9	Customer Interaction	Customer Interaction	Gas	$93.7	$158.7	$0.0	$252.4
10	Customer Interaction	Customer Interaction - Second Release	Gas	$0.0	$0.0	$105.8	$105.8
11	Customer Interaction	CxT Portal & Channel Management	Gas	$351.6	$273.4	$0.0	$625.0
12	Customer Interaction	Large Commercial & Landlord Interaction	Gas	$0.8	$1.0	$74.3	$76.1
13	Data Management	Building An Advanced Analytics Capability	Gas	$0.0	$0.0	$453.7	$453.7
14	Data Management	Building Score Cards & Metrics Capability	Gas	$0.0	$0.0	$453.7	$453.7
15	Data Management	Data Enrichment Through Record Digitization	Gas	$0.0	$30.0	$1,057.8	$1,087.8
16	Data Management	Data Management Implementation (Quality & Cleansing)	Gas	$7,770.4	$6,762.7	$4,905.0	$19,438.0
17	Data Management	Enable the Data Archive Process	Gas	$234.7	$7.5	$0.0	$242.2
18	Data Management & Governance Program Leadership	Data Management & Governance Program Leadership - 2	Gas	$263.9	$0.0	$0.0	$263.9
19	Data Management & Governance Program Leadership	Data Management & Governance Program Leadership - 3	Gas	$0.0	$269.1	$0.0	$269.1
20	Enabling Capabilities	Development Operations & BPA Enablement - 2	Gas	$428.6	$0.0	$0.0	$428.6
21	Enabling Capabilities	Development Operations & BPA Enablement - 3	Gas	$0.0	$329.1	$0.0	$329.1
22	Enabling Capabilities	Development Operations & BPA Enablement - 4	Gas	$0.0	$0.0	$332.2	$332.2
23	Enabling Capabilities	IS Operating Model (Delivery / Support, Run)	Gas	$0.0	$0.0	$693.9	$693.9
24	Enabling Capabilities	Testing Center of Excellence	Gas	$258.7	$190.9	$72.0	$521.6
25	Engineering, Design, Estimating & Mobility	Complex Design (CAD) & Estimating (ESW)	Gas	$0.0	$0.0	$154.3	$154.3
26	Engineering, Design, Estimating & Mobility	Data Remediation, GIS Upgrade/ Migration & GIS Mobility	Gas	$10,514.9	$6,952.7	$0.0	$17,467.7
27	Engineering, Design, Estimating & Mobility	Design (GWD), Estimating (CU), & Mobility	Gas	$192.1	$546.7	$355.7	$1,094.6
28	Gas Business Enablement Portfolio Management Office	Portfolio Management Leadership - 2	Gas	$6,433.4	$0.0	$0.0	$6,433.4
29	Gas Business Enablement Portfolio Management Office	Portfolio Management Leadership - 3	Gas	$0.0	$6,483.7	$0.0	$6,483.7
30	Gas Business Enablement Portfolio Management Office	Portfolio Management Leadership - 4	Gas	$0.0	$0.0	$5,567.7	$5,567.7
31	Integrated Supply & Demand Planning	Construction Planning	Gas	$0.0	$806.8	$0.0	$806.8
32	Integrated Supply & Demand Planning	Maintenance & Inspection Planning	Gas	$788.1	$0.0	$0.0	$788.1
33	Integrated Supply & Demand Planning	Program and Project Management Planning	Gas	$788.1	$0.0	$0.0	$788.1
34	Integrated Supply Feasibility Evaluation and Strategy	Integrated Supply Feasibility Assessment	Gas	$260.2	$0.0	$0.0	$260.2
35	Integrity Management	Additional IM Modules	Gas	$39.4	$12.5	$0.0	$51.9
36	Inventory Optimization	Inventory Optimization	Gas	$677.2	$0.0	$0.0	$677.2
37	Inventory Optimization	Inventory Strategy	Gas	$406.3	$0.0	$0.0	$406.3
38	Operating Model & Value Framework	Business Architecture - Organization Design & Transition	Gas	$2,537.0	$152.7	$0.0	$2,689.7
39	Operating Model & Value Framework	Leadership Capability Development	Gas	$1,566.6	$169.9	$0.0	$1,736.6
40	Operating Model & Value Framework	Operations Performance, Governance & Value Realization	Gas	$1,022.9	$227.7	$173.3	$1,424.0
41	Operating Model & Value Framework	Skills/ Capability Assessment & Curriculum Redesign	Gas	$556.9	$171.6	$0.0	$728.5
42	Program Business Readiness & Sustainment	Knowledge Transition & Collaboration Strategy	Gas	$613.2	$0.0	$0.0	$613.2
43	Program Business Readiness & Sustainment	Program Business Readiness	Gas	$1,232.9	$1,126.7	$464.6	$2,824.2
44	Program Business Readiness & Sustainment	Program Business Sustainment - 1	Gas	$208.8	$0.0	$0.0	$208.8
45	Program Business Readiness & Sustainment	Program Business Sustainment - 2	Gas	$0.0	$0.0	$665.3	$665.3
46	Program Level People Strategy	Labor Contract Strategy & Implementation Support	Gas	$76.4	$78.5	$80.6	$235.4

Exhibit__(GIOP-10)
Schedule 1
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Niagara Mohawk Power Corporation d/b/a National Grid
Gas Business Enablement
Incremental Operating Expenses

Line	Investment Name	Program/Release Description	Segment	12-Months Ending March 31, 2019	12-Months Ending March 31, 2020	12-Months Ending March 31, 2021	Total OPEX Spend
47	Program Level People Strategy	Program Learning Management - 2	Gas	$390.6	$0.0	$0.0	$390.6
48	Program Level People Strategy	Program Learning Management - 3	Gas	$0.0	$519.2	$0.0	$519.2
49	Program Level People Strategy	Program Learning Management - 4	Gas	$0.0	$0.0	$587.2	$587.2
50	Program Level People Strategy	Program Transformational Change Office - 2	Gas	$2,642.4	$0.0	$0.0	$2,642.4
51	Program Level People Strategy	Program Transformational Change Office - 3	Gas	$0.0	$1,806.0	$0.0	$1,806.0
52	Program Level People Strategy	Program Transformational Change Office - 4	Gas	$0.0	$0.0	$678.0	$678.0
53	Program Level People Strategy	Workforce Strategy Planning & Implementation Support	Gas	$784.6	$176.2	$58.9	$1,019.7
54	Projects & Program Management	Core Projects & Program Management	Gas	$0.0	$0.0	$348.2	$348.2
55	Regulatory/ Compliance	Regulatory/ Compliance	Gas	$9,000.0	$6,350.0	$500.0	$15,850.0
56	SC - Business Architecture Design	SC - Business Architecture Design	Gas	$445.9	$0.0	$0.0	$445.9
57	Solution Architects & Agile Coaches	Solution Architects & Agile Coaches - 2	Gas	$440.5	$0.0	$0.0	$440.5
58	Solution Architects & Agile Coaches	Solution Architects & Agile Coaches - 3	Gas	$0.0	$313.8	$0.0	$313.8
59	Supply Chain Master Data Improvements	Data Cleansing Execution	Gas	$543.1	$0.0	$0.0	$543.1
60	Supply Chain Master Data Improvements	Defined Data Cleansing Approach	Gas	$362.1	$0.0	$0.0	$362.1
61	Supply Chain Program Leadership	Supply Chain Program Leadership - 1	Gas	$1,695.1	$0.0	$0.0	$1,695.1
62	Supply Chain Program Leadership	Supply Chain Program Leadership - 2	Gas	$0.0	$705.8	$0.0	$705.8
63	Support Interaction	CRM / Contact Center	Gas	$800.0	$200.0	$0.0	$1,000.0
64	Support Interaction	Employee Support Interaction	Gas	$203.8	$214.9	$0.0	$418.6
65	Support Interaction	Employee Support Interaction - Second Release	Gas	$0.0	$0.0	$15.4	$15.4
66	Supporting through Data	Campaign Management	Gas	$0.0	$0.0	$38.5	$38.5
67	Supporting through Data	Channel Analytics	Gas	$0.0	$0.0	$78.5	$78.5
68	Technology Initiatives	Operations/System Monitoring	Gas	$29.4	$0.0	$0.0	$29.4
69	Warehousing and Network Optimization	Networking Transportation & Optimization Analysis	Gas	$1,083.5	$0.0	$0.0	$1,083.5
70	Warehousing and Network Optimization	Networking Transportation & Optimization Implementation	Gas	$1,083.5	$0.0	$0.0	$1,083.5
71	Warehousing and Network Optimization	Warehousing Optimization	Gas	$406.3	$0.0	$0.0	$406.3
72	WMFE Program Leadership	WMFE Program Leadership - 2	Gas	$1,691.1	$0.0	$0.0	$1,691.1
73	WMFE Program Leadership	WMFE Program Leadership - 3	Gas	$0.0	$1,785.0	$0.0	$1,785.0
74	WMFE Program Leadership	WMFE Program Leadership - 4	Gas	$0.0	$0.0	$465.2	$465.2
75	Work Management & Field Enablement	Company Driven Work: Collections and non-Appointment Offs - ELECTRIC	Electric	$2.3	$0.0	$0.0	$2.3
76	Work Management & Field Enablement	Company Driven Work: Collections and non-Appointment Offs - GAS	Gas	$4.2	$0.0	$0.0	$4.2
77	Work Management & Field Enablement	Construction Work & Leak Repair	Gas	$0.0	$592.8	$1,190.9	$1,783.7
78	Work Management & Field Enablement	Corrosion and I&R Work	Gas	$1,667.4	$0.0	$0.0	$1,667.4
79	Work Management & Field Enablement	CU Governance & Library - process	Gas	$184.3	$0.0	$0.0	$184.3
80	Work Management & Field Enablement	Customer, Leak Investigation & Inspections - ELECTRIC	Electric	$460.9	$615.5	$0.0	$1,076.5
81	Work Management & Field Enablement	Customer, Leak Investigation & Inspections - GAS	Gas	$856.0	$1,143.1	$0.0	$1,999.1
82	Work Management & Field Enablement	PowerPlan Integration & Enhancements	Gas	$0.0	$101.7	$114.6	$216.3
83	Work Management & Field Enablement	WMFE Optimization	Gas	$0.0	$38.5	$331.6	$370.2
84	Work Management & Field Enablement	Work Forecasting & Planning - solution	Gas	$0.0	$0.0	$189.8	$189.8
85		Total Fiscal Year O&M Spend for Gas Business Enablement		$64,102.0	$41,338.5	$21,317.1	$126,757.6
86		Less: To remove Base Labor and overheads included in Labor & Benefits		$6,667.2	$6,916.9	$6,884.7	$20,468.8
87		Adjusted Total Fiscal Year O&M Spend for Gas Business Enablement		$57,434.8	$34,421.7	$14,432.3	$106,288.8
88							

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Niagara Mohawk Power Corporation d/b/a National Grid
Gas Business Enablement
Incremental Operating Expenses

Line	Investment Name	Program/Release Description	Segment	12-Months Ending March 31, 2019	12-Months Ending March 31, 2020	12-Months Ending March 31, 2021	Total OPEX Spend
89				FY 19	FY20	FY21	Total
90		Total Gas Operating Expenses		$57,019.78	$33,909.13	$14,432.34	$105,361.2
91							
			% of Retail Customers				
92		Company Description	(C-210)				
93		Niagara Mohawk Power Corp. - Gas	16.89%	$9,630.6	$5,727.25	$2,437.6	$17,795.5
94		KeySpan Energy Delivery New York	34.87%	$19,882.8	$11,824.11	$5,032.6	$36,739.5
95		KeySpan Energy Delivery Long Island	16.27%	$9,277.1	$5,517.02	$2,348.1	$17,142.3
96		Boston Gas Company	19.02%	$10,845.2	$6,449.52	$2,745.0	$20,039.7
97		Colonial Gas Company	5.58%	$3,181.7	$1,892.13	$805.3	$5,879.2
98		Narragansett Gas Company	7.37%	$4,202.4	$2,499.10	$1,063.7	$7,765.1
99							
100							
101		Total Electric Operating Expenses		$415.0	$512.5	$0.0	$927.5
			% of Retail Customers				
102		Company Description	(C-198)				
103		Niagara Mohawk Power Corp.- Electric Distr.	47.71%	$198.0	$244.5	$0.0	$442.5
104		Massachusetts Electric Company	37.69%	$156.4	$193.2	$0.0	$349.6
105		Nantucket Electric Company	0.38%	$1.6	$1.9	$0.0	$3.5
106		Narragansett Electric Company	14.22%	$59.0	$72.9	$0.0	$131.9
107							
108							
109		Total Allocated to NMPC, Gas, Exhibit___(RRP-3), Schedule 27		$9,630.6	$5,727.3	$2,437.6	$17,795.5
110							
111		Total Allocated to NMPC, Electric, Exhibit____(RRP-3), Schedule 27		$198.0	$244.5	$0.0	$442.5

Line 85: Sum of Lines 1-84
Line 87: Line 84 - Line 86
Line 90: Sum of Gas Segment Lines 1-84 - Line 86 * Ratio (Sum of Gas Segment Lines 1-84 / Line 85)
Line 101: Sum of Electric Segment Lines 1-84 - Line 86 * Ratio (Sum of Electric Segment Lines 1-84 / Line 85)
Line 109: Equals Line 93
Line 111: Equals Line 103

Exhibit__(GIOP-10)
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Exhibit __ (GIOP-11)

Additional Run the Business Costs to Niagara Mohawk to Support
the GBE Program Post-Implementation

Niagara Mohawk Power Corporation d/b/a National Grid
Gas Business Enablement (GBE)
Incremental Run the Business (RTB) Operating Expenses

Line	Description Of Run the Business (RTB) Costs	For 12-Months Ending March 31, 2019	For 12-Months Ending March 31, 2020	For 12-Months Ending March 31, 2021
1	Software License Maintenance / Subscriptions	$3,396,499	$7,933,079	$10,851,487
2	Hardware License Maintenance / Mobile Subscription	$1,615,176	$3,772,506	$5,160,330
3	GBE team to support systems and applications	$2,817,960	$5,635,920	$5,635,920
4	Subtotal of Additional RTB for GBE Applications	$7,829,635	$17,341,505	$21,647,737
5	Legacy Application Support (Replace)	$2,177,811	$1,662,399	$650,780
6	Legacy Application Support (Future State - non-Replace base)	$985,250	$985,250	$985,250
7	Legacy Application Support (Future State - Increase)	$49,263	$98,525	$147,788
8	Subtotal of Legacy RTB Costs	$3,212,324	$2,746,174	$1,783,818
9	Total of RTB Costs	$11,041,958	$20,087,680	$23,431,555
10	Current RTB Costs	$3,937,137	$4,647,841	$5,105,040
11	Total Incremental RTB Costs due to GBE Applications	$7,104,821	$15,439,839	$18,326,515
12	Allocation to Niagara Mohawk, Gas, Exhibit___(RRP-3), Schedule 27	$1,200,004	$2,607,789	$3,095,348

Allocation to Companies:

	Company Description	% of Customers
13	Niagara Mohawk Power Corp. - Gas	16.89%
14	KeySpan Energy Delivery New York	34.87%
15	KeySpan Energy Delivery Long Island	16.27%
16	Boston Gas Company	19.02%
17	Colonial Gas Company	5.58%
18	Narragansett Gas Company	7.37%

Line 4: Sum of Lines 1-3
Line 8: Sum of Lines 5-7
Line 9: Line 4 + Line 8
Line 11: Line 9 - Line 10
Line 12: Line 11 * Line 13

Exhibit __ (GIOP-12)

Total U.S. Type I and Type II Savings Estimates (Capital and O&M) and Niagara Mohawk Allocated Type I Savings Estimates Identified in Connection with the GBE Program

Niagara Mohawk Power Corporation d/b/a National Grid
Gas Business Enablement (GBE)
Total Benefits Forecasted as a Result of GBE Implementation
For Fiscal Years Ending March 31, 2019 through 2027

Initiative Description	Benefit Description	Benefit Type	12-Months Ending March 31, 2019	12-Months Ending March 31, 2020	12-Months Ending March 31, 2021	12-Months Ending March 31, 2022	12-Months Ending March 31, 2023	12-Months Ending March 31, 2024	12-Months Ending March 31, 2025	12-Months Ending March 31, 2026	12-Months Ending March 31, 2027
Asset - Advanced Analytics	Reduction / Redirection in Opex via AIPM	Type I	$0	$0	$13,750	$1,223,750	$1,980,000	$1,980,000	$1,980,000	$1,980,000	$1,980,000
Engineering, Design, Estimating & Mobility	Reduction in Damages due to Data Quality Errors	Type I	$143,315	$573,259	$573,259	$573,259	$573,259	$573,259	$573,259	$573,259	$573,259
Work Management & Field Enablement	Clerical / Back Office Productivity Improvement	Type I	$0	$29,603	$1,835,367	$2,131,393	$2,131,393	$2,131,393	$2,131,393	$2,131,393	$2,131,393
Work Management & Field Enablement	Damage Prevention - Reduced Travel Mileage	Type I	$0	$37,275	$49,700	$49,700	$49,700	$49,700	$49,700	$49,700	$49,700
Work Management & Field Enablement	M&C Productivity Improvements - Base	Type I	$0	$1,024,595	$7,274,626	$7,377,085	$7,377,085	$7,377,085	$7,377,085	$7,377,085	$7,377,085
Customer Interaction	Reduce Move Call Volume through Self-Service	Type II	$0	$0	$0	$0	$642,130	$906,536	$906,536	$906,536	$906,536
Customer Interaction	Reduce Non-Move Call Volume through Self-Service	Type II	$0	$0	$61,278	$502,480	$588,270	$588,270	$588,270	$588,270	$588,270
Data Management	Reduction in Data Cleansing / Scrubbing Effort - Analyst	Type II	$0	$105,749	$750,821	$761,396	$761,396	$761,396	$761,396	$761,396	$761,396
Engineering, Design, Estimating & Mobility	Complex Jobs - Engineering Productivity Improvement	Type II	$0	$0	$4,886	$302,941	$351,803	$351,803	$351,803	$351,803	$351,803
Engineering, Design, Estimating & Mobility	Complex Jobs - Estimating Accuracy Fine Avoidance	Type II	$0	$0	$0	$45,833	$550,000	$550,000	$550,000	$550,000	$550,000
Engineering, Design, Estimating & Mobility	Reduction in Mappers via Field Data Entry	Type II	$0	$8,934	$553,899	$643,238	$643,238	$643,238	$643,238	$643,238	$643,238
Integrated Supply & Demand Planning	Improved Project Delivery - Construction	Type II	$0	$35,278	$2,187,222	$2,540,000	$2,540,000	$2,540,000	$2,540,000	$2,540,000	$2,540,000
Customer Interaction	Reduction in Service Quality Penalties	Type II	$0	$0	$0	$0	$629,809	$889,142	$889,142	$889,142	$889,142
Regulatory/ Compliance	Reduced Compliance and Gas Safety Penalties	Type II	$876,348	$5,070,300	$9,577,233	$13,207,819	$13,520,800	$13,520,800	$13,520,800	$13,520,800	$13,520,800
Work Management & Field Enablement	CMS Collections Jobs - Reduction in Mileage	Type II	$0	$0	$0	$0	$117,384	$165,718	$165,718	$165,718	$165,718
Work Management & Field Enablement	CMS Collections Jobs - Reduction in Travel Time	Type II	$0	$0	$0	$0	$561,142	$792,200	$792,200	$792,200	$792,200
Work Management & Field Enablement	CMS Planned Jobs - Reduction in Available Time via Autodispatch	Type II	$0	$202,349	$269,798	$269,798	$269,798	$269,798	$269,798	$269,798	$269,798
Work Management & Field Enablement	CMS Planned Jobs - Reduction in Mileage	Type II	$0	$83,430	$111,240	$111,240	$111,240	$111,240	$111,240	$111,240	$111,240
Work Management & Field Enablement	CMS Planned Jobs - Reduction in Travel Time	Type II	$0	$252,363	$336,484	$336,484	$336,484	$336,484	$336,484	$336,484	$336,484
Work Management & Field Enablement	CMS Planned Jobs - Reduction in UTCs	Type II	$0	$38,760	$51,680	$51,680	$51,680	$51,680	$51,680	$51,680	$51,680
Work Management & Field Enablement	Damage Prevention - Reduced Travel Time	Type II	$0	$90,007	$120,009	$120,009	$120,009	$120,009	$120,009	$120,009	$120,009
Work Management & Field Enablement	Inspections - Reduced Travel Mileage	Type II	$0	$0	$0	$0	$3,718	$5,249	$5,249	$5,249	$5,249
Work Management & Field Enablement	Inspections - Reduced Travel Time	Type II	$0	$0	$0	$0	$19,064	$26,914	$26,914	$26,914	$26,914
Work Management & Field Enablement	M&C and CMS Jobs - Reduced Summonses	Type II	$0	$0	$0	$0	$2,037,959	$4,446,457	$4,446,457	$4,446,457	$4,446,457
Work Management & Field Enablement	Reduction in Field Tech Communications	Type II	$0	$99,566	$265,511	$265,511	$265,511	$265,511	$265,511	$265,511	$265,511
Work Management & Field Enablement	Reduction in Meter Verification Jobs	Type II	$0	$121,024	$161,365	$161,365	$161,365	$161,365	$161,365	$161,365	$161,365
	Total of Benefits Forecasted as a result of GBE Implementation		$1,019,663	$7,772,492	$24,198,128	$30,674,982	$36,394,237	$39,615,248	$39,615,248	$39,615,248	$39,615,248

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Niagara Mohawk Power Corporation d/b/a National Grid
Gas Business Enablement
Customer Benefits - Forecasted for Niagara Mohawk Power Corporation
For Rate Year Ending March 31, 2019 and Data Years Ending March 31, 2020 and 2021

Line	Benefit Description	Benefit Type	12-Months Ending March 31, 2019	12-Months Ending March 31, 2020	12-Months Ending March 31, 2021
1	Clerical / Back Office Productivity Improvement	Type I	$0	$1,706	$105,767
2	Damage Prevention - Reduced Travel Mileage	Type I	$0	$4,627	$6,169
3	M&C Productivity Improvements - Base	Type I	$0	$124,375	$883,064
4	Reduction / Redirection in Opex via AIPM	Type I	$0	$0	$2,279
5	Reduction in Damages due to Data Quality Errors	Type I	$6,937	$27,748	$27,748
6	CMS Planned Jobs - Reduction in Available Time via Autodispatch	Type II	$0	$2,517	$3,356
7	CMS Planned Jobs - Reduction in Mileage	Type II	$0	$18,436	$24,582
8	CMS Planned Jobs - Reduction in Travel Time	Type II	$0	$62,225	$82,967
9	CMS Planned Jobs - Reduction in UTCs	Type II	$0	$5,168	$6,890
10	Complex Jobs - Engineering Productivity Improvement	Type II	$0	$0	$125
11	Damage Prevention - Reduced Travel Time	Type II	$0	$12,156	$16,208
12	Improved Project Delivery - Construction	Type II	$0	$571	$35,372
13	Reduce Non-Move Call Volume through Self-Service	Type II	$0	$0	$12,945
14	Reduced Compliance and Gas Safety Penalties	Type II	$512,037	$2,962,500	$5,595,833
15	Reduction in Data Cleansing / Scrubbing Effort - Analysts	Type II	$0	$13,082	$92,880
16	Reduction in Field Tech Communications	Type II	$0	$21,859	$58,291
17	Reduction in Mappers via Field Data Entry	Type II	$0	$276	$17,110
18	Reduction in Meter Verification Jobs	Type II	$0	$29,427	$39,236
19			$518,974	$3,286,674	$7,010,824
20					
21	All Type I Benefits Included in Revenue Requirement, Exhibit____(RRP-3), Schedule 27		$6,937	$158,456	$1,025,028