Boston Gas Company and Colonial Gas Company
each d/b/a National Grid
D.P.U. 17-170
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STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

CASE 16-G-0058 -	Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of KeySpan Gas East Corp. d/b/a Brooklyn Union of L.I. for Gas Service	Before Hon. David R. Van Ort
CASE 16-G-0059 -	Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of The Brooklyn Union Gas Company d/b/a National Grid NY for Gas Service	Hon. James A. Costello

AFFIDAVIT OF JOHNNY JOHNSTON

COUNTY OF KINGS :
:ss
STATE OF NEW YORK :

JOHNNY JOHNSTON, being duly sworn, deposes and says:

1. I am employed by National Grid USA Service Company as Senior Vice President for Gas Business Enablement. My business address is One MetroTech Center, Brooklyn, New York.

2. I submit this affidavit in support of the written testimony and exhibits I sponsored on behalf of The Brooklyn Union Gas Company d/b/a National Grid NY ("KEDNY") and KeySpan Gas East Corporation d/b/a National Grid ("KEDLI") in the above captioned matters as a member of KEDNY and KEDLI's Gas Infrastructure and Operations Panel.

3. Specifically, on behalf of KEDNY, as a member of the Gas Infrastructure and Operations Panel, I sponsored (i) the Direct Testimony of the Gas Infrastructure and Operations Panel dated January 29, 2016 (pre-marked for identification as Exhibit 48), along with six exhibits that were pre-marked for identification as Exhibits 49 (GIOP-1) through 54 (GIOP-6); (ii) the Corrections and Updates Testimony of the Gas Infrastructure and Operations Panel dated April 4, 2016 (pre-marked for identification as Exhibit 211), along with three exhibits that were pre-marked for identification as Exhibits 212 (GIOP-1CU), 213 (GIOP-5CU), and 214 (GIOP-6CU); and (iii) the Rebuttal Testimony of the Gas Infrastructure and Operations Panel dated June 10, 2016 (pre-marked for identification as Exhibit 271), along with two exhibits that were pre-marked for identification as Exhibits 272 (GIOP-1R) and 273 (GIOP-2R).

4. On behalf of KEDLI, as a member of the Gas Infrastructure and Operations Panel, I sponsored (i) the Direct Testimony of the Gas Infrastructure and Operations Panel dated

January 29, 2016 (pre-marked for identification as Exhibit 55), along with six exhibits that were pre-marked for identification as Exhibits 56 (GIOP-1) through 61 (GIOP-6); (ii) the Corrections and Updates Testimony of the Gas Infrastructure and Operations Panel dated April 4, 2016 (pre-marked for identification as Exhibit 215), along with two exhibits that were pre-marked for identification as Exhibits 216 (GIOP-1CU) and 217 (GIOP-5CU); and (iii) the Rebuttal Testimony of the Gas Infrastructure and Operations Panel dated June 10, 2016 (pre-marked for identification as Exhibit 271), along with two exhibits that were pre-marked for identification as Exhibits 272 (GIOP-1R) and 273 (GIOP-2R).

5. The above identified testimony and exhibits were prepared by me or under my supervision as a member of the Gas Infrastructure and Operations Panels.

6. I further attest to the truthfulness and accuracy of said testimony and exhibits to the best of my knowledge, information, and belief.

JOHNNY JOHNSTON

Sworn to before me this
[illegible] day of October, 2016

Notary Public

GIFTY A. BENTUM-ESHUN
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
May 14, 2021

Before the Public Service Commission

THE BROOKLYN UNION GAS COMPANY d/b/a NATIONAL GRID NY and KEYSPAN GAS EAST CORPORATION d/b/a NATIONAL GRID

Rebuttal Testimony

of

Gas Infrastructure and Operations Panel

Ross W. Turrini
Johnny Johnston
Laurie T. Brown

Case 16-G-0058
Case 16-G-0059

Dated: June 10, 2016

Case 16-G-0058
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Rebuttal Testimony of the Gas Infrastructure and Operations Panel

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Rebuttal Testimony of the Gas Infrastructure and Operations Panel

I. Introduction

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

A. The Gas Infrastructure and Operations Panel ("Panel") consists of Ross W. Turrini, Johnny Johnston and Laurie T. Brown.

Q. Is this the same Gas Infrastructure and Operations Panel that submitted testimony previously in these proceedings?

A. Yes. The terms defined in the Panel's direct testimony have the same definitions here.

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

A. The purpose of the Panel's rebuttal testimony is to respond to certain recommendations set forth in the prepared testimony of the Staff Infrastructure and Operations Panel ("Staff" or "SGIOP"), the City of New York Infrastructure and Operations Panel and Witnesses Radley Horton and Susanne DesRoches (collectively, "CNY"), and the Environmental Defense Fund ("EDF") regarding the Companies' proposed capital investment and operations plans. Specifically, the Panel's rebuttal testimony will address:

- Unit Costs: The Panel will explain in more detail the basis for the Companies' projected unit cost increases and the impacts of Staff's

significant downward unit cost adjustments on the Companies' ability to deliver their accelerated LPP replacement and growth programs.

- Rate Year Forecast Versus Sanctioned Amounts: In response to Staff's downward adjustments to several capital programs to reflect the currently sanctioned amount, the Panel explains why a program's sanctioned amount does not necessarily reflect the level of investment required in the Rate Year.
- Blanket Reliability Programs: The Panel will address the consequences of Staff's proposed downward adjustments to the proactive Pressure Regulating Facilities program, System Automation program, Remote Control Valve installation program and the I&R Reactive/Compressed Natural Gas ("CNG") programs. The Panel will also discuss Staff's adjustments to the Companies' Water Intrusion programs.
- LNG Programs: The Panel will discuss proposed adjustments to KEDNY's salt water pump house, truck load/unload and maintenance area projects at the Greenpoint LNG Plant. The Panel will also discuss funding for the cold blowers at KEDLI's Holtsville LNG Plant.
- AMR Installations and Replacements: The Panel will address Staff's proposal to defer KEDNY's AMR Installation program and the impact

of this proposal on projected O&M savings. The Panel will also clarify the scope of KEDNY's AMR Replacement program.

- KEDLI's Brightwaters Yard Upgrade Project: The Panel will explain in more detail the budget and benefits of this project to upgrade an operating yard on Long Island.
- KEDNY's Newtown Creek Project: The Panel will discuss Staff's recommendation to remove the Newtown Creek project from the Rate Year capital budget.
- Enhanced Reporting Recommendations: The Panel will address Staff's recommendations for enhanced reporting on the Companies' capital investments.
- FTE and Salary Adjustments: The Panel will discuss certain of Staff's recommendations related to the Companies' O&M plans, including salary adjustments and recommendations to eliminate certain positions.

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

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

Exhibit __ (GIOP-1R): Map of KEDLI's LPP Replacements

II. Unit Costs

Q. Please describe Staff's recommendations with regard to unit costs.

A. Staff identifies concerns with regard to increases in the Companies' unit cost forecasts compared to historic spending and recommends significant downward unit cost adjustments based on historic averages for KEDLI's accelerated LPP replacement program and the Companies' growth main programs.

A. KEDLI LPP Unit Cost Adjustment

Q. Please discuss Staff's recommended unit cost adjustment for KEDLI's LPP program and its impact.

Staff calculated its proposed $149/foot unit cost based on a three-year average using calendar year data that was presented in the Companies' response to Information Request ("IR") DPS-477 (MT-14). The result is a downward adjustment of $46.36 million (nearly 45 percent) to KEDLI's forecast cost of its proactive LPP replacement program. This adjustment would effectively prevent KEDLI from executing its accelerated LPP replacement program and, therefore, is inconsistent with the Commission's stated policy of removing all

LPP in 20 years. Moreover, reducing KEDLI's allowed unit cost has the effect of incenting the Company to target main replacements based on the lowest cost, instead of prioritizing main replacements based on risk (assessed using the Company's DIMP) and leak reductions, as supported by Staff's Gas Safety Panel and other intervenors. This is not the right result from a public policy or a safety perspective.

Q. Please explain the basis for Staff's downward adjustment based on the historical three-year (CY 2013 to 2015) LPP unit cost as a proxy for the unit cost in the Rate Year.

A. Staff based its adjustments on KEDLI's presentation of its historic unit cost data by calendar year in IR DPS-477 (MT-14), which contained an error. IR DPS-477 sought information on the Companies' historical unit costs for their proactive main replacement programs. In its response, KEDLI presented calendar year unit costs that were very low as compared to the fiscal year unit costs reported for corresponding years (Exhibit __ (SGIOP-1), Page 151 of 162). For example, the response to IR DPS-477 indicates a unit cost of just $94 per foot for CY 2013, a year in which KEDLI replaced 47.6 miles of LPP through its main replacement program. This was approximately 48 percent lower than the unit cost average for the other four years presented in IR DPS-477.

Upon further investigation, KEDLI determined that its response to IR DPS-477 did not fully reflect its LPP replacement costs in several years impacted by Superstorm Sandy. Specifically, while the LPP main replacement miles performed to address system damage resulting from Superstorm Sandy were reflected in the total annual replacement miles, the cost totals did not include the cost of these replacements, which were tracked separately. When the Superstorm Sandy-related LPP replacement costs are added to the calendar year cost totals, the unit cost for the affected years increases to levels consistent with the numbers reported for corresponding fiscal years (*e.g.*, the CY 2013 unit costs increased from $94 per foot to approximately $242 per foot).

Table 1: Revised KEDLI Historic Unit Costs

Calendar Year	2011	2012	2013	2014	2015	Three-Year Average
Unit Cost per IR DPS-477	$203	$173	$94	$142	$210	$149
Revised Unit Cost	$204	$174	$242	$174	$220	$212
Inflation Adjusted 2017 Unit Cost	$230	$192	$262	$185	$229	$225

Accordingly, KEDLI's revised three-year average (CYs 2013 to 2015) for its proactive main replacement program is $212 per foot. When adjusted for inflation, the three-year average increases to $225 per foot.

Q. Does Staff recommend a higher rate allowance for any incremental main replaced in the Rate Year?

A. Yes. While recommending a rate allowance of just $149 per foot for KEDLI's base mileage, Staff recommends a unit cost cap of $221 per foot (more than 48 percent higher) for any incremental miles replaced under the Gas Safety and Reliability Surcharge (SGIOP Page 114, Lines 18-22). Staff's higher cap is based on an analysis of the Company's historic fiscal year unit costs (FYs 2013 to 2015) (Exhibit __ (SGIOP-2), Page 7). This disparity highlights the inequity of using the understated historic unit cost data as a basis for the base mileage allowance. Clearly, the rate allowance for the base LPP mileage and incremental mileage should align.

Q. Does the Panel believe that KEDLI's historic unit costs for LPP replacements are indicative of its costs to complete this work in the Rate Year and Data Years?

A. No. Even KEDLI's revised historic three-year average understates the unit costs for the Rate Year and Data Years because the historic costs do not include factors (discussed below) that KEDLI expects will increase its costs significantly in these years. KEDLI's adjusted unit costs for the Rate Year and Data Years include the anticipated impacts of these factors and are reflected in its forecasts for the LPP replacement program.

Q. Please identify the factors contributing to the increasing unit cost estimates for LPP replacement in KEDLI's forecasts.

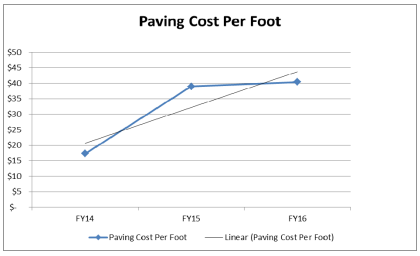
A. KEDLI's unit cost forecasts for LPP replacement consider the following factors that are not fully reflected in its historic unit costs: increased municipal permitting and paving costs, higher construction costs to work in urban and coastal areas, and the changing mix of LPP replacement work to include more large diameter main.

Q. Please describe the impact of increasing paving and municipal permitting costs.

A. Historic costs do not reflect escalating paving and municipal permitting costs. Over the last several years, KEDLI has seen its paving costs increase as a result of more onerous municipal paving requirements. Faced with increasing costs to maintain their infrastructure, municipalities are looking to utilities to bear more costs to repave streets by requiring larger restoration areas, even curb-to-curb repaving, as a condition to permitting roadway excavations. These requirements, which are increasingly prevalent in KEDLI's service territory, have increased the Company's paving costs for its LPP replacements. For example, several municipalities (*e.g.*, Freeport, Glen Cove, Brookhaven, Islip, East Hampton, Huntington and Southold) have increased their paving cutback requirements (*i.e.*, the area that must be restored around

an excavation) from 6-12 inches to two feet. Hewlett Harbor, Hewlett Neck, Woodsburgh and Muncy Park now require curb-to-curb restoration for many excavations. Additionally, county and state roads on Long Island now require panel-to-panel restoration (*i.e.*, the concrete slabs under the asphalt). As a result of more onerous paving requirements, KEDLI saw its paving costs increase from approximately $17 per foot of LPP in FY 2014 to $40 per foot of LPP in FY 2016.

Table 2: KEDLI Paving Costs



At the same time, KEDLI's cost to secure municipal road opening permits has increased from approximately $251 per permit in FY 2013 to more than $366 per permit in FY 2015.

Table 3: KEDLI Permit Costs

FY Year	# of Permits	Total Permit Cost ($M)	Cost/Permit
2013	9,550	$2.398	$251.12
2014	10,605	$2.798	$263.87
2015	9,906	$3.631	$366.52

KEDLI's accelerated LPP replacement program is only expected to exacerbate the upward trend for permitting and paving costs as municipalities react to the increased scope of work.

Q. Why is KEDLI forecasting higher unit costs to reflect more work in urban and coastal areas?

A. KEDLI has historically targeted the highest risk-ranked main segments in the less densely populated areas of Long Island (*e.g.*, side streets and soft ground areas) where LPP can be removed from the system cost effectively. However, as the Company further accelerates its rate of main replacement, KEDLI will need to target LPP in more densely populated areas (*e.g.*, western Nassau County) and this will increase costs. Increased costs are attributable to, *inter alia*, more onerous work time restrictions around rush hour construction, which requires more work to be performed off hours and during nights and weekends. Other factors increasing costs in urban areas of KEDLI's service territory include:

- Increased traffic control costs (additional flagpersons and signage)
- More costly excavation because of concrete and thicker roadways
- A higher concentration of underground infrastructure, which restricts the Company's ability to utilize cost effective technologies, *i.e.*, horizontal directional drilling and other trenchless installation methods
- Higher costs to stage materials and equipment

KEDLI works closely with municipalities to minimize costs associated with construction (*i.e.*, by coordinating main replacements with municipal paving projects), but many of these costs are driven by demographic and geographic factors and, therefore, are not within the control of the Company to reduce.

Work in coastal areas (*i.e.*, flood prone) requires upgrading lower pressure systems to high pressure systems, which are generally more expensive projects because of the additional meter and regulator work, as well as the cost associated with retiring low pressure regulator stations. Exhibit __ (GIOP-1R) is a map showing that KEDLI's LPP replacements for CY17, CY18 and CY19 will be concentrated in the more urban, congested and coastal areas of western Long Island.

Q. Please explain how the mix of work for replacement main is changing and impacting unit costs.

A. The Company expects an increase in replacement of large diameter pipe as compared to prior years, and the DIMP risk-based approach dictates that the Company prioritizes higher-risk, not necessarily lower cost replacements. Because large diameter pipe is generally more expensive to replace, KEDLI's average unit costs will continue to rise as it targets more of its large main over the next several years.

Q. What are the risks of underestimating unit costs?

A. Staff's proposed unit cost will frustrate KEDLI's ability to deliver its aggressive goals for LPP replacement in 20 years and, therefore, is inconsistent with Commission policy. While the Companies appreciate Staff's concerns for managing increasing unit costs, the reality is that the cost to perform LPP replacements is trending up, not down. KEDLI and Staff need to ensure that allowed unit costs fairly reflect the costs the Company will incur to complete this important work in the Rate Year and the years to follow.

Q. Does the Panel agree with the Staff Gas Safety Panel's recommendation to increase inside meter relocations as part of the LPP replacement program?

A. Yes. As discussed in the rebuttal testimony of the Companies' Gas Safety Panel, the Companies support relocating more meters outside when it is safe and practical in coordination with the LPP replacement program. However, this additional work will result in additional costs. While the Companies' forecasts assume some number of meter relocations in their unit cost estimates, accelerating meter relocations will require additional resources. Therefore, the Companies' main replacement forecasts will need to be adjusted to reflect the additional cost of relocating meters consistent with Staff's recommendation. The cost to relocate meters generally ranges from $500 to $2,000 in KEDLI's territory and from $500 to $2,500 in KEDNY's territory. Relocations in New York City can be more expensive as a result of the need for protection posts, additional piping, carpentry work, paving or brick work. The Companies have not included these costs in their current LPP replacement forecasts.

Q. Please address CNY's recommendation that the Companies' accelerate the replacement of LPP in designated flood zones and EDF's

recommendation to consider methane emissions in the Companies' LPP prioritization.

A. With regard to CNY's recommendation, the Companies are agreeable to working with CNY and Staff to evaluate potential modifications to the LPP risk ranking algorithm to provide additional consideration for the replacement of main segments in FEMA designated flood zones. Similarly, as discussed in EDF's testimony, the Companies will analyze potential modifications to the algorithm to consider methane emissions as a factor in prioritizing main segments for replacement.

B. <u>Growth Main Unit Cost Adjustments</u>

Q. Please describe Staff's proposed recommendations on the Companies' growth main budgets.

A. Staff recommends downward adjustments in the Rate Year for the following KEDNY growth program line items: Growth Commercial Main from $446 to $356 per foot and Growth Residential Main from $294 to $173 per foot. For KEDLI, Staff recommends a downward adjustment for Growth Residential Main from $240 to $89 per foot. These adjustments are based on five-year averages of the Companies' fiscal year costs in these categories. The Companies are concerned that these downward adjustments to unit costs for

the growth programs are not realistic and may limit the Companies' abilities to meet actual demands for new services.

Many of the same factors driving increases in LPP unit costs will impact KEDNY's cost to install growth main (*e.g.*, increased permitting and paving costs). Therefore, KEDNY believes that Staff's adjustment based on the five-year historical average is not appropriate because it fails to account for the impact of these factors on unit costs in the Rate Year and Data Years.

Q. Please describe Staff's proposed adjustments to KEDLI's growth main unit costs.

A. Staff's recommended downward adjustment to the unit costs for KEDLI's growth residential program is unclear. Staff's testimony states that the adjustment is to the residential growth category, but the numbers referenced appear to address the commercial growth category. KEDLI assumes that Staff intended to adjust the commercial growth category from $240 to $89 per foot based on a five-year average, because $240 is the Company's unit cost forecast for the commercial growth category, and $89 is the five-year average of the Company's historic unit costs in the commercial growth category.

A downward adjustment based on the five-year average historical unit costs is not appropriate given the upward cost pressure on the Company's main installations.

III. Rate Year Forecast Versus Sanctioned Amounts

Q. Staff has made several downward adjustments to reduce the Rate Year forecast to reflect the amount currently sanctioned for FY 2017. Does the Panel agree with Staff's downward adjustments to reflect the currently sanctioned amounts rather than the forecast amounts?

A. No. These adjustments appear to be based on a misunderstanding of the Companies' budgeting and sanctioning processes and/or a misunderstanding about how the Rate Year forecasts, presented in this case on a calendar year basis, translate to fiscal year budgets for sanctioning purposes. Downward adjustments to the Companies' Rate Year forecasts based on the currently sanctioned amounts are not justified.

Q. Please clarify the misunderstanding.

A. Sanctioned amounts do not reflect the program funding requirements in the Rate Year. The timing of the sanction process is not aligned with the capital planning process for purposes of forecasting the Rate Year budgets. As described in more detail in the Panel's direct testimony, the Companies

developed long term investment plans that were used to develop the forecast for the Rate Year and Data Years. Project sanctioning, however, normally occurs immediately prior to the fiscal year in which the investment is planned. For example, the FY 2018 capital plan (which includes nine months of CY 2017 from April 2017 to December 2017) will be formally sanctioned in early 2017. Thus, currently sanctioned or partially sanctioned dollars shown in FY 2017 sanctioning documents do not represent the full forecast for projects proposed in the Rate Year. Sanctioned dollars are not a substitute for the Companies' Rate Year forecasts. Setting budgets for the Rate Year based on currently sanctioned amounts will drastically under fund the Companies' capital programs.

With regard to Staff's assertion that the lack of sanctioning papers has compromised its ability to analyze certain capital programs, the Companies note that they have provided detailed descriptions for significant capital programs in the Rate Year. These descriptions contain information that is sufficiently similar to the information in sanctioning papers (Exhibit __ (GIOP-4). Moreover, the Companies have answered numerous IRs regarding their proposed capital programs.

Exhibit __ (GIOP-2R) reconciles the difference between the sanctioned amounts and the Companies' Rate Year forecasts for the programs subject to Staff's recommended adjustments.

Q. Would the Panel provide an example where a proposed sanctioning adjustment would negatively impact the Companies' ability to manage their systems?

A. As an example, Staff proposes a downward adjustment for KEDNY's IMP program of $9.67 million (59 percent) to reflect the currently sanctioned FY 2017 amount. As described in the Panel's direct testimony, the Company's IMP is a safety program mandated by the Pipeline Safety Improvement Act of 2002 that requires operators to assess transmission pipelines using in-line inspections ("ILI") and other assessment methods.

KEDNY's IMP budget is "zero based," meaning the level of investment is developed based on the actual amount and type of work planned in each year. In the Rate Year, KEDNY proposes IMP investments to make additional pipelines ILI enabled. Staff's Gas Safety Panel supports the Companies' proposed IMP investments, including the expanded use of ILI (Staff Gas Safety Panel Page 74, Line 23-24). Staff's proposed reduction to the program based on the currently sanctioned amount, however, would prevent KEDNY

from executing its IMP program and would delay the Company's ability to comply with the ILI requirements that are currently pending with PHMSA.

IV. Blanket Reliability Programs

Q. Is the Panel concerned with Staff's proposed adjustments to the Companies' blanket reliability programs?

A. Yes. The Panel is concerned that these recommendations appear to be based on a misconception that the Companies' larger, special reliability projects should enable the Companies to reduce spending for blanket reliability programs to levels more aligned with recent historic costs. In fact, the Companies' special reliability projects do not address the work included in blanket programs for necessary replacement of aging regulating stations and obsolete telemetry equipment. De-funding the proactive Pressure Regulating Facilities, System Automation, RCV and I&R Reactive/CNG programs will impair system safety and reliability.

Q. Please explain why the Companies' investments in the Pressure Regulating Facilities category are required to maintain system reliability.

A. The Pressure Regulating Facilities forecast is part of the budget for the Companies' blanket Heater and Regulator Station Management programs, as described in the Companies' respective Exhibits __ (GIOP-4). These budgets

are dedicated to replacement or overhaul of older regulating stations that no longer meet current company standards for design (*i.e.*, over pressure protection) and are at, or near, the end of their useful lives. These replacements/overhauls enable compliance with regulatory requirements for the operation of the gas system, are necessary to maintain system integrity and are not included in any other budgets. These stations are critical to safe and reliable system operation. Failure to perform replacements/overhauls of these stations could result in station failures.

Q. Please explain the need for incremental investments in system automation.

A. As stated in the Panel's direct testimony, the System Automation Program includes installation of Remote Terminal Units ("RTUs") to provide enhanced ability to monitor system performance and remotely adjust pressures on the gas system, which gives Gas Control and system operators visibility to system conditions and the ability to react to changing operations. The program also includes replacing aging and obsolete telemetry equipment that is used to communicate with pressure regulating stations and increase deployment of telemetry equipment on the Companies' systems. CNY's testimony supports these types of investments in the interest of enhancing the Companies' communication capabilities and ability to monitor pressures and operability of

gate stations, particularly in areas prone to flooding (CNY's Gas Infrastructure Panel (KEDNY), Page 16, Lines 14-18). Furthermore, system automation helps to reduce leaks and methane emissions by providing a mechanism to reduce pressures automatically if a leak or equipment failure is detected on the system.

Q. Is it necessary to replace aging telemetry equipment?

A. Yes. The need for replacing aging telemetry equipment is critical. As stated in the program description found in the Companies' respective Exhibits __ (GIOP-4), in the stations that are currently equipped with telemetry equipment, that equipment will soon be obsolete. This equipment is no longer supported by third-party communications vendors (Verizon and AT&T) and, therefore, can no longer communicate effectively with receiving telemetry equipment outside the station. Staff's adjustment to the system automation budget eliminates the funding for these critical replacements.

Q. Does the Company agree with Staff's recommended removal of the RCV program from the Rate Year based on PHMSA's deferral of the RCV issue from its current notice of proposed rulemaking to a future rulemaking?

A. No. The Companies believe investment in RCVs is prudent to improve the safety of the gas systems in light of recent incidents such as San Bruno. RCVs were an important component of the National Transportation Safety Board's recommendations following that incident. While PHMSA has delayed formal action on RCVs, it is still anticipated they will enact requirements in a future rulemaking.

Q. What would be the effect of Staff's proposed downward adjustment to the I&R Reactive/CNG budget?

A. Because much of the I&R Reactive program budget involves mandated reliability work, a reduction to the forecast incremental spend in this category will primarily impact the Companies' plans to refurbish and maintain CNG fill stations. If this budget is reduced, the Companies will no longer be able to maintain the CNG fill stations, and some may need to be retired.

Q. What are the benefits of continuing to maintain the CNG fill stations?

A. Functioning CNG fill stations are critical to the viability of natural gas vehicles ("NGV") in the service territory. The Companies support the expansion of NGVs because of the significant economic and environmental benefits. Staff has also expressed support for expanding NGV utilization in

the Companies' service territories (Staff Gas Policy and Supply Panel, Page 22, Lines 6-9).

Q. Does the Panel agree with Staff's adjustments to the Companies' Water Intrusion programs?

A. Yes. KEDNY and KEDLI's Water Intrusion programs address unanticipated instances of water in gas mains that can potentially cause service disruptions. Based on the Companies' historic three-year average expenditures in this area, Staff recommends downward adjustments in the Rate Year for KEDNY and KEDLI of $0.828 million and $0.216 million, respectively (SGIOP Pages 47-48). Because it is difficult to forecast the amount of Water Intrusion work that will be required in the Rate Year and Data Years, the Companies agree to this adjustment to their capital budgets. The Companies have been successful in coordinating water intrusion work with other construction activities whenever practical and believe that the programs can be adequately managed to Staff's recommended budgets.

V. <u>LNG Program Investments</u>

Q. What adjustments did Staff make to KEDNY's capital plans for the Greenpoint LNG Plant?

A. Staff recommends adjustments to KEDNY's forecasts for the salt water pump house project, the truck/load unload station project, and the project to relocate the plant's maintenance area because they believe these costs are reflected in other programs, not justified and/or not expected to be completed in the Rate Year.

Q. Does the Panel agree with Staff's recommended adjustments to the Salt Water Pump House project?

A. Yes, in part. KEDNY agrees that a downward adjustment in the amount of $0.169 million is appropriate because the Company inadvertently included these costs twice. However, while Staff agrees that there is a need to update, rebuild and storm harden the plant's fire suppression systems as soon as practicable, Staff recommends an additional downward adjustment to the remaining budget for the pump house project ($6.5 million total) on the basis that the Company should delay investment in this project until it has fully considered other alternatives. The Panel disagrees with this adjustment. The fresh water system in the area of the plant is not sufficient to support the fire suppression system. A salt water pump house is the only viable option for providing the required volumes of water. In addition, the Commission has directed KEDNY to accelerate fire suppression system upgrades at the

Greenpoint LNG Plant (Case 12-G-0544). For these reasons, KEDNY believes is it prudent to proceed with this project in the Rate Year.

Q. Does KEDNY agree that the Truck Load/Unload Station program should be removed from the Rate Year because the Fire Department of New York City ("FDNY") has not yet approved it?

A. No. KEDNY acknowledges that the FDNY has not yet approved the project, but is actively pursuing approval. KEDNY has provided the FDNY information to facilitate its review, and the Company is in regular contact with the FDNY regarding this project. The Company anticipates approval prior to the Rate Year and believes the project should stay in the budget.

Q. What is KEDNY's position on Staff's proposed elimination of the Relocation of Maintenance Area special program?

A. KEDNY does not oppose deferral of this program from the Rate Year, but intends to pursue the project in the near term and would propose to include it in a multi-year rate plan.

Q. Does the Panel have any comments on Staff's recommendations for KEDLI's Holtsville LNG Plant capital plans?

A. Yes. Staff recommends removing the cold blower replacement project because, in Staff's view, the Company has not articulated sufficient justification for the project. During extreme weather when barometric changes occur rapidly, two cold blowers are required to be in service to maintain LNG tank pressure and prevent venting LNG vapor to the atmosphere. A third blower has already been purchased, but the existing piping system is too small to allow it to operate in tandem with either of the other blowers. The project included in the CY 2017 Special Project budget is to install the third blower and to make piping modifications to allow any two blowers to operate in tandem. This project will provide operational reliability in the event one of the blowers fails.

VI. Non-Infrastructure Adjustments

A. AMR Programs

Q. Regarding KEDNY's AMR Installation Program, Staff recommends levelizing installation of the remaining AMR units over five years. From an operations perspective, can KEDNY accommodate this change from a three-year program to a five-year program?

A. Yes, the Company could extend this program over five years, but recommends an alternative to the levelized installation schedule Staff proposes to mitigate incremental O&M costs.

Q. What O&M costs result from extending the AMR Installation program from three to five years?

A. The Company currently forecasts completing AMR deployment in CY 2019, with the majority of the remaining AMRs installed in CYs 2017 and 2018. Delaying full AMR deployment for an additional two years, and levelizing installation over that period, will necessitate continued manual meter reading for a longer period, and to a greater extent, than forecast. The Company previously estimated that full AMR deployment would result in a total annual O&M savings of $5.8 million. If the AMR deployment is levelized over a five-year period, the Company will not realize its forecast O&M savings until full deployment is reached.

Q. What does KEDNY recommend to mitigate the increased O&M costs for a five-year program?

A. Instead of the levelized schedule proposed by Staff, KEDNY recommends a front loaded schedule with more installations in the Rate Year and Data Years. Accelerating deployment in the first three years will decrease O&M requirements in later years of the program as the Company reduces the number of manual meter reads.

Table 4: Revised AMR Deployment Schedule

CY	Proposed Budget ($M)	Estimated Installs
2016	7.87	160,000
2017	8.7	140,000
2018	8.13	100,000
2019	5.0	70,000
2020	3.0	50,000

Because KEDNY will be required to manually read meters through 2020 under this revised AMR deployment schedule, the Company's forecast meter reading expenses would increase by approximately $1.4 million in Data Year 1 and $2.8 million in Data Year 2.

Q. Staff also recommends decreasing KEDNY's AMR Replacement line item on the basis of Staff's unit cost calculation for replacing 35,000 AMR devices in the Rate Year. Does the Panel agree with this adjustment?

A. No. Staff's adjustment does not reflect all of the AMR units the Company anticipates purchasing in the Rate Year. This budget item includes the cost to purchase the devices used to facilitate AMR communication, *i.e.*, encoder receiver transmitters ("ERTs"). The Companies purchase ERTs every year to (i) proactively replace existing ERTs that are at or near the end of their 20-year service lives, (ii) reactively replace existing ERTs on meters because of unanticipated failures, (iii) install ERTs on new meters purchased for the Base

Growth-Meter Purchases program, and (iv) install ERTs on the meters required for the mandated Purchase Meters (Replacement) program. The 35,000 units used to calculate Staff's adjustment represents only the proactive ERT replacements the Company anticipates it will perform in the Rate Year. KEDNY's Rate Year forecast for this program also includes the cost to purchase the ERTs required for the reactive replacements (10,000 units) and those required for the base growth and mandated programs (approximately 38,000 units). In FY 2016, KEDNY purchased 96,310 ERTs through this program at a cost of approximately $5.8 million, which aligns with Staff's proposed unit cost of approximately $61 per unit, including unit cost and installation.

B. KEDLI's Brightwaters Yard Upgrade Project

Q. Does the Panel agree with Staff's adjustment to remove the Brightwaters Yard Upgrade Project from KEDLI's forecast?

A. No. As described in the Panel's Corrections and Updates testimony, this project will upgrade the Brightwaters operating yard to provide a welding shop and additional storage for construction equipment. The proposed Brightwaters Yard facility will provide a controlled environment for welders to work on piping and regulation station projects. Additionally, the welding facility will reduce welder time lost to inclement weather days, travel time to

and from project sites, field set up/break down for welders and support personnel, field staff required to support the welders, and the need for crane rentals and equipment to support field welding operations. The facility will also provide for storage of Company coring, drilling and weather sensitive equipment that is being purchased to support the increased work load that requires inside storage. These efficiencies will help to control costs and support KEDLI's increased capital workload on Long Island.

VII. KEDNY's Newtown Creek Project

Q. Please describe Staff's position on the Newtown Creek project.

A. Pointing to a recently identified issue with the volume of biogas produced by the wastewater treatment plant and the fact that the Company has never attempted this type of project before, Staff expresses concern that the project's in-service date will not occur during the Rate Year. Staff also expresses concern that the project's budget has increased significantly over the past several years. For these reasons, Staff recommends a downward adjustment to remove the project's revenue requirement from the Rate Year.

Q. Does the Panel agree with Staff's adjustment to remove the project from the Rate Year forecast?

A. No, but the Panel acknowledges the project schedule has been extended and there is a risk of further extensions. If the biogas production issue is resolved in the next several months, then construction will commence in CY 2016 and the project should be in service in the Rate Year. If the production issue is not resolved in the next few months, the project's in-service date would be delayed beyond the Rate Year. In either case, the Company believes the Newtown Creek project should be included in a multi-year rate settlement because the Company fully expects to complete this project in the next one to two years.

Q. Does Staff make any recommendations regarding recovery of the Newtown Creek project's costs?

A. Yes. Staff suggests that the Commission should consider: (i) limiting the level of investment reflected in the cost of service to be more in line with the projected revenues from the sale of biogas, (ii) requiring any excess revenues be used to write down the assets in lieu of the proposed sharing mechanism, and (iii) encouraging the City of New York to provide full property tax abatement for 20 years to improve the economics of the project.

Q. Does the Company support Staff's proposed modifications for cost recovery for the Newtown Creek project?

A. No. Because this project will support the development of renewable gas supply sources for the benefit of the Company's customers, as well as environmental benefits in KEDNY's service territory in the form of reduced carbon emissions, the Company believes it should recover the full revenue requirement with an offsetting credit for the value of gas sold to sales customers, as described in the Panel's direct testimony. The revenue sharing mechanism with the City of New York will only operate to the extent the Company's customers have been fully compensated for the project through the sale of gas and any environmental credits and, therefore, is a reasonable accommodation to the City for the use of its property and the biogas. That said, the Company is agreeable to using its share of any excess revenues to write down the project. The Company also supports any further tax abatements that may be available for the project.

VIII. <u>Capital Investment Reconciliation and CSC Deferral Mechanisms</u>

Q. Does the Panel agree with Staff's proposed Capital Investment Reconciliation Mechanism?

A. No. Under Staff's proposal, the Capital Investment Reconciliation Mechanism would act as a downward only capital tracker measuring the actual net revenue requirement for the plant in service in the Rate Year with the net revenue requirement approved by the Commission. To the extent the

Companies' net plant in service was lower than forecast, the revenue associated with the plant not in service would be deferred with carrying charges for the benefit of customers (SGIOP Pages 105-106). While KEDNY and KEDLI are willing to consider a net plant reconciliation mechanism, particularly one that includes upside incentives, in the context of a multi-year rate plan, the Companies do not believe a capital tracker in a one-year case is appropriate or necessary.

Q. Does the Panel agree with Staff's recommendation not to include a deferral mechanism to recover City/State construction ("CSC") costs in excess of the Rate Year allowance?

A, No. Staff suggests that a CSC deferral mechanism is not appropriate in a one-year case because the Companies have a dedicated staff to manage CSC spending and the Companies should be incented to control their CSC costs. Staff's position fails to acknowledge the extent to which these costs are increasing beyond the Companies' control and difficult to forecast - even in the near term. As discussed in the Panel's direct testimony, the Companies' CSC forecasts are based on their current estimates of municipal construction activity in the Rate Year, which are informed by historical spending levels and guidance from municipalities on future spending. In practice, the Companies' forecasts have regularly underestimated the level of CSC spending in recent

years as municipalities have increased infrastructure investments to unprecedented levels. For example, KEDNY overspent its FY 2016 CSC budget by more than $85 million to accommodate increased work in the City of New York. Forecasting CSC spending is particularly challenging because the Companies do not always have the municipalities' construction plans until after CSC budgets are set, and large municipal projects (*e.g*, Flatlands and LaGuardia) can be added, removed, accelerated or delayed at any time on relatively short notice. For these reasons, the Panel believes a two-way deferral mechanism for its CSC costs is appropriate to ensure the Companies are reasonably compensated for the work required to accommodate municipal construction.

IX. Enhanced Capital Reporting Recommendations

Q. What does the Panel propose with regard to Staff's recommended reporting requirements?

A. The Company will work with Staff to develop a mutually agreeable reporting format that addresses Staff's recommendations. Ideally, the reporting format would incorporate aspects of the Companies' internal reporting practices to minimize the incremental administrative burden. The Companies will also examine the reports the Commission currently receives to determine whether they could be leveraged or consolidated. The Companies will determine the

most efficient means to gather and organize the requested information, and will consult with Staff on a mutually agreeable format.

X. O&M Salary Adjustments and FTEs

Q. Does the Panel agree with Staff's adjustment to the salaries of the Companies' incremental FTEs?

A. No. Staff adjusts the Companies' forecast salary expense to reflect the lower range of salaries by position. However, the Companies' recent experience is that salaries at the low end of the range will not attract sufficient talent to fill these positions. Given the constrained labor market, particularly for engineers who are in high demand, recruiting qualified personnel demands that the Companies offer salaries at the mid-point of the market or risk losing candidates to competitors offering higher salaries. Accordingly, the Rate Year salaries for these new positions should reflect the mid-point rates consistent with the Companies' proposal.

Q. Does the Panel agree with Staff's adjustments to the Companies' proposed incremental FTEs?

A. Not entirely. The Companies do not agree with the following FTE adjustments:

- KEDNY LNG Field Engineer – Staff recommends removing this position consistent with the delay in certain capital investments at the Greenpoint LNG Plant. This position should be retained because engineering support precedes capital expenditures. Engineering support to develop the project scope and detailed design occurs at least one year prior to capital investment. A delay in hiring LNG engineers could further delay needed investment in KEDNY's LNG plant.
- I&R Technicians – Staff proposes downward adjustments to the number of I&R Technicians (KEDNY 2; KEDLI 0.75) because Staff believes the maintenance requirements for newly installed I&R equipment should be minimal. The Companies believe this adjustment is inappropriate because these technicians are not only required to maintain the newly installed I&R equipment, but also maintain the Companies' aging equipment that will require increasing levels of repair as this equipment approaches the end of its useful life.
- Compliance Analysts – these positions are addressed in the rebuttal testimony of the Companies' Gas Safety Panel.

The Companies agree with Staff's recommended adjustment to eliminate one Gas Estimator FTE from each Company and to reduce each Company's allocation of the Gas Estimating Manager position from 0.5 to 0.33 FTE.

Q. Does this conclude your testimony?

A. Yes, it does.

Case 16-G-0058
Case 16-G-0059

Rebuttal Testimony of the Gas Infrastructure and Operations Panel

Index of Exhibits

Exhibit ___ (GIOP-1R)	Map of Planned KEDLI LPP Replacements
Exhibit ___ (GIOP-2R)	FY Budget/Sanctioned Amounts Compared to CY Forecasts

Exhibit__ (GIOP-1R)

Case 16-G-0058
Case 16-G-0059

Rebuttal Testimony of the Gas Infrastructure and Operations Panel

Exhibit __ (GIOP-1R)

Map of Planned KEDLI LPP Replacements

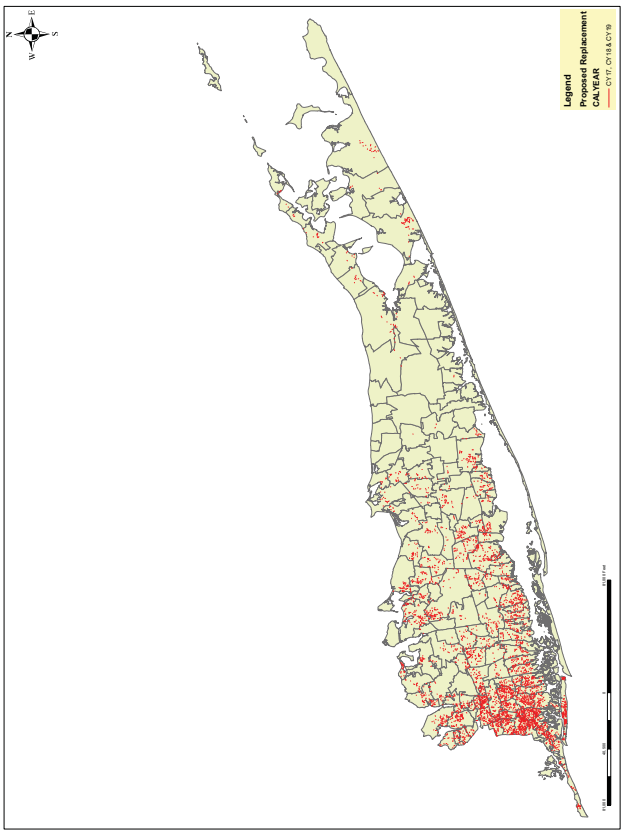

Legend
Proposed Replacement
CALYEAR
CY17, CY18 & CY19

Exhibit__ (GIOP-2R)

Case 16-G-0058
Case 16-G-0059

Rebuttal Testimony of the Gas Infrastructure and Operations Panel

Exhibit __ (GIOP-2R)

FY Budget/Sanctioned Amounts Compared to CY Forecasts

KEDNY
Capital Investment Plan vs FY17 Sanctioning
$000

Classification	Category	FY'17 Capital Plan	FY'18 Capital Plan	FY17 Blanket / Program Sanction Paper (CapEx / COR)			CY'17 Capital Plan	CY'18 Capital Plan	CY'19 Capital Plan
				CapEx	COR	Total			
Growth	Base Growth- Meter Purchases	$ 1,872	$ 2,048	$ 1,872	$ -	$ 1,872	$ 2,027	$ 2,138	$ 2,244
Mandated	Pipeline Integrity - IMP	$ 7,210	$ 18,782	$ 7,210	$ -	$ 7,210	$ 16,877	$ 11,818	$ 4,226
Mandated	Purchase Meters (Replacements)	$ 3,436	$ 3,758	$ 3,436	$ -	$ 3,436	$ 3,719	$ 3,923	$ 4,119
Reliability	Gas System Reliability - Gas Planning /RCV Program	$ 480	$ 6,601	not required (under $1m)			$ 3,557	$ 5,815	$ 5,098

Notes:
Annual Blankets/Programs are sanctioned on a FY basis once the Capital Plans are approved.
Only annual FY Blakets/Programs over $1m require sanctioning.
Only first year of approved Blanket/Program Capital Plans is sanctioned.
The above FY'17 Blankets/Programs were sanctioned in Feb/Mar.
The CY'17 Capital Plan rate case request was based on the time phasing of the FY'17/FY'18 Capital Plans.
There are no sanction papers for the CY'17 Capital Plan rate case request.
Base Growth - Meter Purchases and Purchase Meters (Replacements) are sanctioned together.

KEDLI
Capital Investment Plan vs FY17 Sanctioning
$000

Classification	Category	FY'17 Capital Plan	FY'18 Capital Plan	FY'17 Blanket/Program Sanction Paper (CapEx/COR)			CY'17 Capital Plan	CY'18 Capital Plan	CY'19 Capital Plan
				CapEx	COR	Total			
Growth	Base Growth- Meter Purchases	$ 2,162	$ 2,297	$ 2,188	$ -	$ 2,188	$ 2,284	$ 2,398	$ 2,518
Mandated	Latent Damage	$ 988	$ 2,000	$ 1,000	$ -	$ 1,000	$ 1,750	$ 2,030	$ 2,071
Mandated	Purchase Meters (Replacements)	$ 2,768	$ 2,941	$ 2,666	$ 135	$ 2,801	$ 2,924	$ 3,070	$ 3,224
Reliability	Gas System Reliability - Gas Planning/RCV Program	$ 143	$ 2,618	not required (under $1m)			$ 2,000	$ 2,893	$ 3,109

Notes:
Annual Blankets/Programs are sanctioned on a FY basis once the Capital Plans are approved.
Only annual FY Blakets/Programs over $1m require sanctioning.
Only first year of approved Blanket/Program Capital Plans is sanctioned.
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Before the Public Service Commission

KEYSPAN GAS EAST CORPORATION d/b/a NATIONAL GRID

Corrections and Updates Testimony

of

Gas Infrastructure and Operations Panel

Ross W. Turrini
Johnny Johnston
Laurie T. Brown

April 4, 2016

Corrections and Updates Testimony of the Gas Infrastructure and Operations Panel

TABLE OF CONTENTS

I. Introduction

Q. Please identify the members of the Gas Infrastructure and Operations Panel ("GIOP").

A. The Panel consists of Ross W. Turrini, Johnny Johnston and Laurie T. Brown. This is the same Panel that submitted direct testimony as part of the Company's January 29, 2016 filing. The terms defined in the Panel's direct testimony have the same definitions here.

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

A. The purpose of the Panel's testimony is to identify and explain the following corrections and updates:

- Updates to the capital plan – The Panel identifies certain capital projects and programs that have been deferred or delayed to accommodate budget and work plan priorities. The Panel also describes a new project to upgrade an operating yard in Suffolk County.
- PHMSA Notice of Proposed Rulemaking ("NOPR") – The Panel briefly summarizes PHMSA's NOPR (issued March 17, 2016) addressing pipeline integrity management. The NOPR proposes new pipeline integrity management and verification regulations that, once effective, will increase the need for capital investment in this area.

- Updates to the O&M forecast – The Panel corrects and updates its O&M forecast to reflect: (i) a correction to the Company's estimate for Disconnect and Reconnect costs and (ii) an update on the cost of the Independent Compliance Assessment.

Q. Is the Panel sponsoring any exhibits as part of its corrections and updates filing?

A. Yes. The Panel sponsors the following exhibits, which were prepared by one or more members of the Panel or under their supervision and direction:

- Exhibit ___ (GIOP-1CU) Revised Actual and Projected Capital Expenditures: Historic Test Year, Rate Year and Data Years
- Exhibit ___ (GIOP-5CU) Revised Incremental O&M Expenditures: Historic Test Year, Rate Year and Data Years

II. Corrections and Updates

A. Updates to the Capital Plan

Q. Please summarize the updates to the Company's capital plan and Exhibit __ (GIOP-1).

A. KEDLI's capital forecast has been updated to reflect scheduling and/or budget changes in the Rate Year and Data Years to the following two capital programs: (i) the Cast Iron Lining Program and (ii) the Holtsville LNG Tank

Modernization Project. The Company is also adding a new project to the capital plan in the Non-Infrastructure spending category: the Brightwaters Yard Upgrade Project. The revised capital plan is provided as Exhibit __ (GIOP-1CU), which highlights the changes from the plan included with the Panel's direct testimony. The update to each program is discussed in more detail below.

Q. Has the Company also revised its capital forecast for CY 2016?

A. Yes, the Company has revised its CY 2016 forecast based on the actual expenditures for the first two months of CY 2016 and adjustments to the capital work plan for the remainder of the year to reflect updated project schedules and revised cost estimates.

Q. What is the impact of these changes on the Company's forecast capital expenditures for CY 2016, the Rate Year and Data Years?

A. The Company has updated its capital forecast to reflect a net increase in CY 2016 of $8.9 million, a net decrease in the Rate Year of $3.75 million (approximately one percent), a net decrease of $12.6 million in Data Year 1, and a net decrease of $6.6 million in Data Year 2.

Table 1: Capital Forecast 2016 to 2019

($000)	CY16	CY17	CY18	CY19	Total
Original Forecast	$231,448	$340,503	$382,502	$372,070	$1,326,523
Revised Forecast	$240,383	$336,753	$369,939	$365,507	$1,312,582
Variance	8,935	(3,750)	(12,563)	(6,563)	$(13,941)

The cumulative impact of these changes over the four-year period is a $13.9 million decrease to KEDLI's capital forecast. The Revenue Requirement Panel's Corrections and Updates testimony addresses the revenue requirement impact of the Company's revised capital forecast.

i. Cast Iron Lining Program

Q. Please describe the updates to the Cast Iron Lining Program.

A. The Cast Iron Lining Program is described in the Panel's direct testimony at pages 31 to 33 and in Exhibit __ (GIOP-4), pages 18 to 20. The Rate Year budget for this program has been reduced by approximately $0.5 million as a result of the deferral of pipe lining work initially planned for the first quarter of CY 2017. This work is being delayed to address budget priorities affecting the first three months of the Rate Year.

ii. *Holtsville LNG Tank Modernization*

Q. Please describe the updates to the Holtsville LNG Tank Modernization Project.

A. The Holtsville LNG Tank Modernization Project (discussed in Exhibit __ (GIOP-4) at pages 62 to 63), which was scheduled to begin during the Rate Year, has been deferred to CY 2019. The budget for this project has not changed but is now reflected in the Company's capital forecast for CY 2019 and subsequent years.

Q. Why is this project being deferred?

A. The original project schedule would require that the Holtsville LNG Tank be out of service during the 2019/20 heating season. However, a recent reliability assessment identified several projects that will first need to be completed to facilitate removing the tank from service for an entire heating season. Also, this project must be coordinated with KEDNY's Greenpoint LNG Tank Modernization Project because the two tanks cannot both be out of service during the same heating season without negatively impacting system reliability.

The revised Holtsville LNG project plan will remove the tank from service for the 2021/2022 heating season, which aligns with the anticipated in-service

dates of the Transco Lower New York Bay Lateral Project (scheduled to be in service in November 2019), KEDNY's MRI Project (scheduled to be in service in November/December 2020) and the Greenpoint LNG Tank Modernization Project (scheduled to be completed in 2021).

iii. *Brightwaters Yard Upgrade Project*

Q. Please describe the Brightwaters Yard Upgrade Project that is being added to the capital plan.

A. This project will upgrade the Company's gas operations facility in Brightwaters, New York by installing prefabricated buildings (as well as paving and other related work) that will provide a welding shop and additional storage for construction equipment. These additions will enhance the facility's ability to support gas operations in Suffolk County. The project is scheduled to begin in CY 2017, and the forecast capital expenditures are $2 million in the Rate Year and $1 million in Data Year 1, as shown on Exhibit __ (GIOP-1CU).

B. PHMSA Notice of Proposal Rulemaking

Q. Please summarize PHMSA's NOPR as it relates to the Company's capital plan.

A. As stated in the Panel's direct testimony at pages 35 to 40, the Company's mandated Integrity Management Program ("IMP") and Integrity Verification Program ("IVP") are designed to comply with PHMSA's current regulations governing transmission pipeline integrity management and verification, including requirements to conduct in-line inspections of existing transmission pipelines. These programs are also intended to address emerging pipeline integrity requirements that will result from new PHMSA regulations in this area.

On March 17, 2016, PHMSA issued its long anticipated NOPR for new IMP and IVP regulations (Docket Number PHMSA-2011-23). While the Company is still considering the potential impacts of the 549 page rulemaking, PHMSA's NOPR addresses most of the elements the industry was expecting, such as expanded in-line inspection requirements, enhanced IMP data collection and analysis requirements, new regulations regarding maximum allowable operating pressure (MAOP) verification and new IMP/IVP documentation requirements. PHMSA's rulemaking also proposes

new regulations for assessing and repairing pipelines in designated "high consequence areas," among other new requirements.

Q. Is the Company planning any changes to its IMP and IVP in the Rate Year based on the NOPR?

A. Not at this time. PHMSA's rulemaking will undergo an extensive comment and review period before new regulations are adopted. Accordingly, the timing and impact of the final regulations cannot be predicted at this time. As stated in the Panel's direct testimony, the Company believes its proposed IMP and IVP expenditures are prudent investments to manage system risks, while also addressing elements of PHMSA's proposed regulations. The Company's IMP/IVP proposals are generally consistent with the requirements described in the NOPR, and will help support KEDLI's compliance when the regulations are finalized. The Company will continue to invest in its integrity management programs, and will address the changes required by the new regulations when they are adopted.

C. <u>Updates to Operations and Maintenance (O&M) Forecast</u>

Q. Please describe the updates to the O&M forecasts.

A. The corrections and updates to the Company's O&M forecast are shown in Exhibit __ (GIOP-5CU) and are summarized as follows:

- Disconnects and Reconnects – The Company's forecast for Disconnects and Reconnects (the cost to disconnect and then reconnect gas services from main segments as they are replaced) has been corrected to reflect better unit cost data. As a result, the Company has reduced its forecast for incremental Disconnects and Reconnects expense in the Rate Year from $5.1 million to $3.8 million.
- Independent Compliance Assessment – The Gas Safety Panel's Correction and Updates testimony discusses the reduction to the cost estimate to conduct an independent assessment of the Company's compliance with pipeline safety regulations. The Company has lowered the cost estimate in the Data Years from approximately $0.25 million to $0.13 million.

Q. Does this conclude your corrections and updates testimony?

A. Yes, it does.

Corrections and Updates Testimony of the Gas Infrastructure and Operations Panel

List of Exhibits

Exhibit ___ (GIOP-1CU)	Revised Actual and Projected Capital Expenditures: Historic Test Year, CY16, Rate Year, and Data Years
Exhibit ___ (GIOP-5CU)	Revised Incremental O&M Expenditures: Historic Test Year, CY16, Rate Year and Data Years.

Exhibit __ (GIOP-1CU)

Corrections and Updates Testimony of the Gas Infrastructure and Operations Panel

Exhibit __ (GIOP-1CU)

Revised Actual and Projected Capital Expenditures: Historic Test Year, CY16, Rate Year, and Data Years

KEDLI
Capital Investment Plan
$000

Classification	Category	Historic Test Year	CY'17 Capital Plan	CY'18 Capital Plan	CY'19 Capital Plan
Growth	Base Growth - Install Main	$ 52,559	$ 16,140	$ 11,596	$ 8,821
	Base Growth - Install Services	$ 51,406	$ 31,147	$ 28,748	$ 27,070
	Base Growth - NEP Main	$ -	$ 11,974	$ 12,125	$ 12,125
	Base Growth - NEP Services	$ -	$ 4,380	$ 5,574	$ 7,014
	Base Growth - Customer Contributions	$ (2,342)	$ (2,313)	$ (2,417)	$ (2,417)
	Base Growth - Install Meter / Regulator	$ 1,912	$ 1,144	$ 1,169	$ 1,194
	Base Growth- Meter Purchases	$ 787	$ 2,284	$ 2,398	$ 2,518
	Gas System Reinforcement	$ 30,401	$ 33,083	$ 23,291	$ 25,667
	Total Growth	**$ 134,723**	**$ 97,839**	**$ 82,484**	**$ 81,992**
Mandated	CSC/Public Works - Non Reimbursable	$ 3,971	$ 5,064	$ 5,226	$ 5,331
	CSC/Public Works - Reimbursable	$ 2,047	$ 5,107	$ 5,272	$ 5,377
	CSC/Public Works - Reimbursements	$ (1,376)	$ (783)	$ (799)	$ (815)
	Corrosion	$ 1,199	$ 940	$ 958	$ 978
	Service Replacement (Reactive) - Leaks	$ 2,941	$ 4,848	$ 5,965	$ 6,302
	Service Replacements (Reactive) - Non Leaks - Other	$ 6,578	$ 2,955	$ 3,014	$ 3,074
	Atmospheric Corrosion Inside Inspections	$ 99	$ 497	$ 507	$ 517
	Service Replacements - Proactive	$ 1,679	$ -	$ -	$ -
	Main Replacements (Proactive) - Leak Prone Pipe	$ 60,044	$ 130,546	$ 143,335	$ 146,202
	Cross Bore Remediation	$ -	$ 2,643	$ 2,805	$ 2,805
	Latent Damage	$ -	$ 1,750	$ 2,030	$ 2,071
	Large Diameter CI Lining Program	$ -	$ 2,875	$ 3,575	$ 3,600
	Main Replacements (Reactive) - Maintenance	$ 4,699	$ 2,902	$ 2,975	$ 3,034
	Plastic Fusions - New	$ -	$ 1,491	$ 1,943	$ 2,393
	Meter Changes	$ 3,719	$ 1,228	$ 1,252	$ 1,277
	Pipeline Integrity - IMP	$ 3,312	$ 1,168	$ 5,844	$ 4,265
	Pipeline Integrity - IVP	$ -	$ 250	$ 250	$ 250
	ISO Joints	$ 4,184	$ -	$ -	$ -
	Purchase Meters (Replacements)	$ 1,131	$ 2,924	$ 3,070	$ 3,224
	Misc Mandated Work	$ 271	$ -	$ -	$ -
	Total Mandated	**$ 94,498**	**$ 166,405**	**$ 187,222**	**$ 189,885**
Reliability	Gas System Control	$ 2	$ 152	$ 155	$ 209
	Gas System Control - M2M Upgrade	$ -	$ 23	$ -	$ 41
	Gas System Reliability - Gas Planning/RCV Program	$ 17	$ 2,000	$ 2,893	$ 3,109
	East End Reliability Program	$ 1,138	$ -	$ -	$ -
	Valve Installations/Replacements	$ (44)	$ 130	$ 130	$ 130
	Heater Installation Program	$ 1,088	$ 1,500	$ 1,500	$ 1,500
	Pressure Regulating Facilities	$ 2,318	$ 3,129	$ 4,218	$ 5,046
	Bay Shore Take Station Overhaul	$ -	$ 860	$ 340	$ -
	Rockville Centre Take Station Overhaul	$ -	$ -	$ 860	$ 340
	Long Beach Gate Station Overhaul	$ -	$ -	$ -	$ 860
	System Automation	$ 525	$ 1,358	$ 1,370	$ 1,392
	Water Intrusion	$ 1,588	$ 939	$ 1,033	$ 1,075
	Storm Hardening - Remote Service Shutoff Valves	$ -	$ 8,295	$ 11,225	$ 11,445
	I&R - Reactive/CNG	$ (20)	$ 1,654	$ 1,679	$ 1,704
	LNG - Blanket	$ 1,580	$ 1,935	$ 1,633	$ 540
	LNG - Special Projects	$ 3,577	$ 8,907	$ 8,000	$ 3,458
	LNG - Tank Upgrade	$ -	$ -	$ -	$ 5,250
	Northwest Nassau Transmission Main & Control Valve	$ -	$ 34,000	$ 60,000	$ 53,750
	Misc Reliability Work	$ 834	$ -	$ -	$ -
	Total Reliability	**$ 12,603**	**$ 64,882**	**$ 95,036**	**$ 89,849**
Non- Infrastructure	AMR Installation/Replacements	$ 18,274	$ 835	$ 855	$ 873
	Tools & Equipment - All	$ 1,589	$ 1,789	$ 1,953	$ 2,129
	Brightwaters Facility Upgrade	$ -	$ 2,000	$ 1,000	$ -
	Telecomm	$ -	$ 109	$ 109	$ 109
	Combustible Gas Indicators	$ 198	$ -	$ -	$ -
	Brightwaters Facility Upgrade	$ -	$ -	$ -	$ -
	Total Non- Infrastructure	**$ 20,061**	**$ 4,733**	**$ 3,917**	**$ 3,111**
Misc	SuperStorm Sandy	$ 4,068	$ -	$ -	$ -
	Misc	$ (1,605)	$ -	$ -	$ -

KEDLI
Capital Investment Plan
$000

Classification	Category	Historic Test Year	CY'17 Capital Plan	CY'18 Capital Plan	CY'19 Capital Plan
	Total Misc	**$ 2,463**	**$ -**	**$ -**	**$ -**
	Total Direct Gas (Capital & COR)	**$ 264,348**	**$ 333,859**	**$ 368,659**	**$ 364,837**
	Cost of Removal	$ 6,885	$ 13,598	$ 14,804	$ 15,269
	Total Direct Gas (Net of COR)	**$ 257,463**	**$ 320,261**	**$ 353,855**	**$ 349,568**
Indirect Capital					
Facilities/Customer/Other	Facilities	$ 7,413	$ 200	$ 200	$ 200
	Customer - Office Equipment	$ -	$ 248	$ -	$ -
	Customer - Gas REV Pilots	$ -	$ 751	$ -	$ -
	Other	$ 694	$ -	$ -	$ -
	COR	$ -	$ 50	$ 50	$ 50
	Total Facilities/Customer	**$ 8,107**	**$ 1,249**	**$ 250**	**$ 250**
Fleet/IM/IR (Capex only)	Fleet	$ 496	$ 1,560	$ 960	$ 350
	IM/IR	$ -	$ 85	$ 70	$ 70
	Total Fleet/IM/IR (Capex only)	**$ 496**	**$ 1,645**	**$ 1,030**	**$ 420**
	Total Capital/COR	**$ 272,951**	**$ 336,753**	**$ 369,939**	**$ 365,507**

Corrections and Updates Testimony of the Gas Infrastructure and Operations Panel

Exhibit __ (GIOP-5CU)

Revised Incremental O&M Expenditures:
Historic Test Year, CY16, Rate Year and Data Years.

GIOP-5 KEDLI Incremental O&M CY17-CY19

Company	Testimony Category	Program/Position	CY17			CY18			CY19		
			Labor	Non-labor	Total	Labor	Non-labor	Total	Labor	Non-labor	Total
KEDLI	Increased OPEX Workload	CMS- Director	69,368	-	69,368	71,449	-	71,449	73,593	-	73,593
		CMS- Field Collections	94,270	-	94,270	97,120	-	97,120	100,055	-	100,055
		CMS- Gas Leak Investigations	55,622	-	55,622	57,303	-	57,303	59,035	-	59,035
		CMS- Meter Oriented Services	805,920	-	805,920	315,366	-	315,366	324,682	-	324,682
		CMS- Meter/Regulator	27,811	-	27,811	28,650	-	28,651	29,517	-	29,517
		CMS- Supervisor	78,436	-	78,436	80,789	-	80,789	83,213	-	83,213
		Field Operations- Pressure Testing	-	21,980	21,980	-	21,980	21,980	-	21,980	21,980
			-	5,786	5,786	-	5,786	5,786	-	5,786	5,786
		Field Operations- Type II Leaks	277,741	-	277,741	286,136	-	286,136	294,785	-	294,785
			-	338,692	338,692	-	338,692	338,692	-	338,692	338,692
		I&A- Techs	266,079	-	266,079	253,317	-	253,317	261,380	-	261,380
		I&A- Utility/Other Increases	-	148,600	148,600	-	148,600	148,600	-	148,600	148,600
	Increased OPEX Workload Total		$ 1,155,247	$ 514,858	$ 1,670,105	$ 1,192,131	$ 514,858	$ 1,706,989	$ 1,226,069	$ 514,858	$ 1,740,927
	OPEX related to CAPEX	Complex Construction- Contractor Oversight	18,757	-	18,757	19,313	-	19,313	81,117	-	81,117
		Complex Construction- Expenses	-	2,431	2,431	-	2,431	2,431	-	2,431	2,431
		Construction- I&A	-	1,802,241	1,802,241	-	3,517,746	3,517,746	-	3,793,220	3,793,220
		Construction- Main Replacement- Construction Inspectors	50,108	-	50,108	103,244	-	103,244	159,567	-	159,567
		Construction- Main Replacement- Engineer	24,808	-	24,808	42,588	-	42,588	61,411	-	61,411
		Construction- Main Replacement- Supervisor	9,228	-	9,228	9,505	-	9,505	19,579	-	19,579
		Construction- Permit/Summon/Paving Coordinator	17,850	-	17,850	18,386	-	18,386	18,937	-	18,937
		Contract Strategy & Administration- Program Manager	12,589	-	12,589	12,966	-	12,966	13,355	-	13,355
		Corrosion- Techs	17,786	-	17,786	18,323	-	18,323	18,877	-	18,877
		Damage Prevention- Mismcut Tickets	-	193,687	193,687	-	193,687	193,687	-	193,687	193,687
		Damage Prevention- Supervisor	92,278	-	92,278	95,046	-	95,046	97,897	-	97,897
		Gas Control- Control Room Operator	293,642	-	293,642	302,246	-	302,246	311,313	-	311,313
		Gas Control- SOP Coordinator	151,545	-	151,545	156,092	-	156,092	160,774	-	160,774
		Gas Distribution Engineering- Engineer	78,560	-	78,560	80,916	-	80,916	83,344	-	83,344
		Investment Planning- In Year Budget- Program Manager	8,992	-	8,992	9,262	-	9,262	9,540	-	9,540
		Investment Planning- Rate Case- Program Manager	17,984	-	17,984	18,523	-	18,523	19,079	-	19,079
		Investment Planning- Work Order Closeout- Clerks	11,365	-	11,365	11,709	-	11,709	12,063	-	12,063
		Investment Planning- Work Order Closeout- Inspectors	16,703	-	16,703	17,228	-	17,228	17,748	-	17,748
		Investment Planning- Work Order Closeout- Lead Program Manager	9,332	-	9,332	10,674	-	10,674	10,994	-	10,994
		Investment Planning- Work Order Closeout- Manager	12,959	-	12,959	13,297	-	13,297	13,696	-	13,696
		Investment Planning- Work Order Closeout- Program Manager	17,984	-	17,984	18,523	-	18,523	19,079	-	19,079
		LNG- Field Engineer	82,694	-	82,694	85,175	-	85,175	87,730	-	87,730
		LNG- Mechanics	227,685	-	227,685	234,566	-	234,566	241,656	-	241,656
		LNG- Techs	205,066	-	205,066	211,264	-	211,264	217,650	-	217,650
		Operations Support- ISW Analyst	34,083	-	34,083	35,105	-	35,105	36,158	-	36,158
		Operations Support- Manager	12,909	-	12,909	13,297	-	13,297	13,696	-	13,696
		Operations Support- Mappers	155,068	-	155,068	167,255	-	167,255	170,669	-	170,669
		Operations Support- Permit Clerks	22,710	-	22,710	35,126	-	35,126	36,188	-	36,188
		Project Controls- Analyst	12,781	-	12,781	13,163	-	13,163	13,559	-	13,559
		Project Controls- Expenses	-	765	765	-	765	765	-	765	765
		Project Management- Expenses	-	1,566	1,566	-	1,132	1,132	-	1,566	1,566
		Project Management- Project Manager	33,720	-	33,720	34,732	-	34,731	35,773	-	35,773
		Resource Planning- Analyst	25,562	-	25,562	26,329	-	26,329	27,119	-	27,119
		Resource Planning- Coordinator	8,925	-	8,925	9,193	-	9,193	9,469	-	9,469
		Resource Planning- Expenses	-	15,113	15,113	-	15,113	15,113	-	15,113	15,113
		Resource Planning- Program Manager	31,472	-	31,472	32,416	-	32,416	33,388	-	33,388
		Resource Planning- Report Analyst	25,562	-	25,562	26,329	-	26,329	27,119	-	27,119
		Resource Planning- Work Package Reviewer- Program Manager	8,992	-	8,992	9,262	-	9,262	9,540	-	9,540
		Gas Long Term Planning- Engineer	66,155	-	66,155	8,518	-	8,518	8,773	-	8,773
			-	18,700	18,700	-	18,700	18,700	-	18,700	18,700
		Pressure Regulation Engineering- Engineer	33,078	-	33,078	34,070	-	34,070	35,092	-	35,092
		Gas Estimating Office of Excellence- Estimator	12,404	-	12,404	12,776	-	12,776	13,160	-	13,160
		Gas Estimating Office of Excellence- Manager	3,227	-	3,227	3,324	-	3,324	3,424	-	3,424
		Gas Operations Engineering	66,155	-	66,155	68,160	-	68,160	70,184	-	70,184
		Gas Project Eng & Design- Designer	24,808	-	24,808	25,553	-	25,553	26,319	-	26,319
		Gas Project Eng & Design- Engineer	82,694	-	82,694	85,175	-	85,175	87,730	-	87,730
		Main & Service Replacement- Engineer	12,404	-	12,404	12,776	-	12,776	13,160	-	13,160
	OPEX related to CAPEX Total		$ 2,060,994	$ 4,084,168	$ 6,075,497	$ 2,141,991	$ 3,751,614	$ 5,893,605	$ 2,305,937	$ 3,987,462	$ 6,293,399
	Other OPEX	CMS- Investigations	(20,834)	-	(20,834)	(21,497)	-	(21,497)	(22,139)	-	(22,139)
		CMS- Other Emergency	(6,953)	-	(6,953)	(7,363)	-	(7,361)	(7,379)	-	(7,379)
		CMS- Related to Meter Reading	(458,879)	-	(458,879)	(472,745)	-	(472,749)	(487,038)	-	(487,038)
		CMS- Shift Work	(69,527)	-	(69,527)	(71,629)	-	(71,629)	(73,794)	-	(73,794)
		Gas Control- Service Contract	-	88,000	88,000	-	91,000	91,000	-	110,000	110,000
	Other OPEX Total		$ (556,217)	$ 88,000	$ (468,217)	$ (573,070)	$ 91,000	$ (482,235)	$ (590,349)	$ 110,000	$ (480,349)
	Safety Programs	CMS- Inactive Accounts	144,007	-	144,007	150,620	-	150,620	154,967	-	154,967
		Construction- Plastic Fusion New	-	130,000	130,000	-	130,000	130,000	-	130,000	130,000
		Damage Prevention- Latent Damage- Advisors	-	246,288	246,288	-	246,288	246,288	-	246,288	246,288
		Field Operations- Inactive Accounts	140,930	-	140,930	145,390	-	145,390	149,578	-	149,578
			-	63,709	63,709	-	63,708	63,709	-	63,709	63,709
		Gas Distribution Engineering- Latent Damage	-	2,000,000	2,000,000	-	2,000,000	2,000,000	-	2,000,000	2,000,000
		Gas Pipeline and Safety Compliance- Ind Paty Independent Compliance Assessments	-	250,000	250,000	-	130,000	130,000	-	130,000	130,000
		Gas Pipeline and Safety Compliance- Compliance Analyst	298,225	-	298,225	307,172	-	307,172	316,387	-	316,387
		Gas Pipeline and Safety Compliance- Public Awareness	-	820,000	820,000	-	820,000	820,000	-	820,000	820,000
		Gas Pipeline and Safety Compliance- QA/QC Inspectors	83,604	-	83,604	86,112	-	86,112	88,696	-	88,696
		Pressure Regulation Engineering- Transmission Station Integrity Testing	-	208,300	208,300	-	208,300	208,300	-	208,300	208,300
		Process Safety- Analyst	17,041	-	17,041	17,553	-	17,553	18,079	-	18,079
		Process Safety- Director	32,640	-	32,640	33,623	-	33,623	34,632	-	34,632
		Process Safety- Engineering	33,078	-	33,078	34,070	-	34,070	35,092	-	35,092
		Process Safety- Lead Program Manager	59,727	-	59,727	61,519	-	61,519	63,366	-	63,366
	Safety Programs Total		$ 791,257	$ 3,718,297	$ 4,509,554	$ 815,059	$ 4,188,297	$ 4,453,356	$ 839,177	$ 3,996,297	$ 4,837,474
KEDLI Total			$ 3,431,281	$ 8,353,458	$ 11,784,939	$ 3,574,152	$ 7,965,769	$ 11,529,921	$ 3,780,834	$ 8,210,617	$ 11,991,801

Before the Public Service Commission

THE BROOKLYN UNION GAS COMPANY d/b/a NATIONAL GRID NY

Corrections and Updates Testimony

of

Gas Infrastructure and Operations Panel

Ross W. Turrini
Johnny Johnston
Laurie T. Brown

April 4, 2016

Corrections and Updates Testimony of the Gas Infrastructure and Operations Panel

TABLE OF CONTENTS

I. Introduction

Q. Please identify the members of the Gas Infrastructure and Operations Panel ("GIOP").

A. The Panel consists of Ross W. Turrini, Johnny Johnston and Laurie T. Brown. This is the same Panel that provided direct testimony as part of the Company's January 29, 2016 filing. The terms defined in the Panel's direct testimony have the same definitions here.

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

A. The purpose of the Panel's testimony is to identify and explain the following corrections and updates:

- Updates to the capital plan – The Panel identifies certain capital projects and programs that have since been deferred or delayed to accommodate budget and work plan priorities.
- PHMSA Notice of Proposed Rulemaking ("NOPR") – The Panel briefly summarizes PHMSA's NOPR (issued March 17, 2016) addressing pipeline integrity management. The NOPR proposes new pipeline integrity management and verification regulations that, once effective, will increase the need for capital investment in this area.
- Updates to the O&M forecasts – The Panel updates its O&M forecast to reflect (i) an updated meter reading estimate based on changes to the

implementation schedule for the AMR Program, (ii) a correction to the Company's estimate for Disconnect and Reconnect costs, (iii) an update on the Company's forecast costs to address inactive accounts based on modifications to the meter lock procedures and (iv) an update on the cost of the Independent Compliance Assessment.

Q. Is the Panel sponsoring any exhibits as part of its corrections and updates filing?

A. Yes. The Panel sponsors the following exhibits, which were prepared by one or more members of the Panel or under their supervision and direction:

- Exhibit ___ (GIOP-1CU) Revised Actual and Projected Capital Expenditures: Historic Test Year, Rate Year and Data Years
- Exhibit ___ (GIOP-5CU) Revised Incremental O&M Expenditures: Historic Test Year, Rate Year and Data Years
- Exhibit __ (GIOP-6CU) Revised Incremental Full Time Equivalent Positions by Function in the Rate Year and Data Years

II. Corrections and Updates

A. Updates to Capital Plan

Q. Please summarize the updates to the Company's capital plan and Exhibit __ (GIOP-1).

A. KEDNY's capital plan has been updated to reflect scheduling and/or budget changes in the Rate Year and Data Years to the following five capital programs: (i) the LaGuardia Airport Redevelopment Project, (ii) the Greenpoint LNG Tank Modernization Project, (iii) the MRI Project, (iv) the AMR Installation Project and (v) the Newtown Creek Project. The revised capital forecast is provided as Exhibit __ (GIOP-1CU), which highlights the changes from the plan included with the Panel's direct testimony. The update to each program is discussed in more detail below.

Q. Has the Company also revised its capital forecast for CY 2016?

A. Yes, the Company has revised its CY 2016 forecast based on the actual expenditures for the first two months of CY 2016 and adjustments to the capital work plan for the remainder of the year to reflect updated project schedules and revised cost estimates.

Q. What is the impact of these changes on the Company's forecast capital expenditures in CY 2016, the Rate Year and Data Years?

A. The Company has updated its capital forecast to reflect a net decrease in CY 2016 of $21.9 million, a net increase in the Rate Year of $10.6 million (approximately 1.7 percent), a net decrease of $17.4 million in Data Year 1, and a net decrease of $23.8 million in Data Year 2.

Table 1: Capital Forecast 2016 to 2019

($000)	CY16	CY17	CY18	CY19	Total
Original Forecast	$502,595	$610,075	$680,831	$636,758	$2,430,259
Revised Forecast	$480,676	$620,697	$663,390	$612,943	$2,377,706
Variance	(21,919)	10,622	(17,441)	(23,815)	(52,553)

The cumulative impact of these changes over the four-year period is a $52.6 million decrease to KEDNY's capital forecast. The Revenue Requirement Panel's Corrections and Updates testimony addresses the revenue requirement impact of the Company's revised capital forecast.

i. LaGuardia Airport Redevelopment Project

Q. Please describe the changes to the LaGuardia Airport Redevelopment Project.

A. The LaGuardia Airport Redevelopment Project is described in Exhibit __ (GIOP-4), pages 9 to 11. As discussed in the GIOP direct testimony, the Company is required to relocate its gas facilities at the airport to accommodate a major redevelopment project. The project design has recently changed such that KEDNY will now relocate its facilities to a location off the airport property, rather than to a location within the airport's existing footprint. This design change decreases the total cost of the project, but necessitates additional capital investment in the Rate Year.

Table 2: LaGuardia Airport Redevelopment Project

($000)	CY 2017	CY 2018	CY 2019	Total
Original Estimate	4,573	20,210	3,595	28,378
Revised Estimate	15,588	7,704	1,050	24,342

ii. *Greenpoint LNG Tank Modernization Project*

Q. Please describe the changes to the Greenpoint LNG Tank Modernization Project.

A. The Greenpoint LNG Tank Modernization Project (Exhibit __ (GIOP-4) pages 71-72), which was scheduled to begin during the Rate Year, has been deferred to CY 2018. The budget forecast for this project has not changed, but is now reflected in the Company's capital plan for CY 2018 and CY 2019.

Q. Why is this project being deferred?

A. The current project schedule would require the tank to be out of service during the 2018/19 heating season. However, a recent reliability assessment identified several projects that will first need to be completed to facilitate removing Greenpoint Tank 2 from service for an entire heating season. Also, this project must be coordinated with KEDLI's Holtsville LNG Tank Modernization Project because the two tanks cannot both be out of service during the same heating season without negatively impacting system reliability.

The revised project plan will remove the tank from service for the 2020/2021 heating season, which aligns with the scheduled in-service dates for the Transco Lower New York Bay Lateral Project (scheduled to be in service in November 2019) and the Company's MRI Project (scheduled to be in service in November/December 2020).

iii. *Metropolitan Reliability Infrastructure Project*

Q. Please describe the changes to the MRI Project.

A. Certain work for the MRI Project (Exhibit __ (GIOP-4), pages 75 to 77) has been deferred from CY 2016 and, as a result, the budget has increased by $1.35 million in the Rate Year and $0.150 in Data Year 1. This schedule change is not anticipated to impact the project's in-service date.

Additionally, there is a correction to a typographical error in the Panel's direct testimony with regard to the MRI Project. Page 83 of 128, lines 18-19 of the testimony states, "The MRI Project will enable KEDNY to move an additional 850 dekatherms each day by 2021." The number 850 dekatherms is incorrect and should be replaced with 850,000 dekatherms.

iv. *Automated Meter Reading*

Q. Please describe the changes to the AMR Installation Project.

A. The AMR Installation Project (Exhibit __ (GIOP-4) pages 81-82) was scheduled to be completed in early CY 2018 but the program has been extended to accommodate budget priorities in CYs 2016 and 2017. The remaining AMR installations are now scheduled to be performed in CYs 2016-2019. Accordingly, while the majority of the work is still scheduled to be completed in CY 2017, full deployment of AMR will not be completed until 2019.

Table 3: Automated Meter Reading

($000)	CY 2017	CY 2018	CY 2019
Original Estimate	17,718	-	-
Revised Estimate	15,821	7,065	600

v. *Newtown Creek Project*

Q. Please describe the changes to the Newtown Creek Project.

A. As stated in the Panel's direct testimony at pages 116 and 117, the Newtown Creek Project was approximately 90 percent through the design phase when the direct testimony was filed, and the budget was subject to change pending final engineering review and permitting. Based on additional design work completed since the Panel's direct testimony was filed, the CY 2017 budget has increased from $6.9 million to $10.7 million. The budget increase for the

Rate Year is attributable to (i) additional instrumentation and controls for the project, (ii) design modifications to comply with the FDNY's fire suppression and fire detection permitting requirements, (iii) revised construction cost estimates and additional engineering/design work and (iv) a revised project schedule that deferred some capital work into the Rate Year.

B. PHMSA Notice of Proposal Rulemaking

Q. Please summarize PHMSA's NOPR as it relates to the Company's capital plan.

A. As stated in the Panel's direct testimony at pages 35 to 40, the Company's mandated Integrity Management Program ("IMP") and Integrity Verification Program ("IVP") are designed to comply with PHMSA's current regulations governing transmission pipeline integrity management and verification, including requirements to conduct in-line inspections of existing transmission pipelines. These programs are also intended to address emerging pipeline integrity requirements that will result from new PHMSA regulations in this area.

On March 17, 2016, PHMSA issued its long anticipated NOPR for new IMP and IVP regulations (Docket Number PHMSA-2011-23). While the Company is still considering the potential impacts of the 549 page

rulemaking, PHMSA's proposed regulations address most of the elements the industry was expecting, such as expanded in-line inspection requirements, enhanced IMP data collection and analysis requirements, new regulations regarding MAOP verification, and new IMP/IVP documentation requirements. PHMSA's rulemaking also proposes new regulations for assessing and repairing pipelines in designated "high consequence areas," among other new requirements.

Q. Is the Company planning any changes to its IMP and IVP in the Rate Year based on the NOPR?

A. Not at this time. PHMSA's rulemaking will undergo an extensive comment and review period before new regulations are adopted. Accordingly, the timing and impact of the final regulations cannot be predicted at this time. As stated in the Panel's direct testimony, the Company believes its proposed IMP and IVP expenditures are prudent investments to manage system risks, while also addressing elements of the proposed regulations. The Company's IMP/IVP proposals are generally consistent with the requirements described in the NOPR, and will help support KEDNY's compliance when the regulations are finalized. The Company will continue to invest in its integrity management programs, and will address the changes required by the new regulations when they are adopted.

C. Updates to operations and maintenance (O&M) forecasts

Q. Please describe the updates to the O&M forecasts.

A. The corrections and updates to the Company's O&M forecast are shown in Exhibit __ (GIOP-5CU) and are summarized as follows:

- AMR Deployment and Meter Reading – As discussed above, KEDNY has deferred full deployment of AMR until 2019. As a result, the Company will continue to perform manual meter readings for a portion of the Company's meters in the Rate Year and Data Years. The CMS – Meter Reading budget in Exhibit __ (GIOP-5CU) has been updated to reflect the current forecast for meter reading reductions in those years. While the estimated meter reading savings (including the elimination of 25 meter reading positions) from the AMR program have not changed, the reductions to the Company's meter reading expense will not be realized as quickly as initially anticipated because of the revised timing of the AMR deployment. Accordingly, the Company's forecast meter reading expenses have increased by approximately $1.25 million in the Rate Year.
- Disconnects and Reconnects – The Company's forecast for Disconnects and Reconnects (the cost to disconnect and then reconnect gas services from main segments as they are being replaced) has been corrected to reflect better unit cost data. Following a detailed review of actual Disconnect and Reconnect costs, the Company identified certain costs that

had not been fully reflected in its unit cost calculation. As a result, the Company has increased its forecast for incremental Disconnects and Reconnects expense in the Rate Year from $3.26 million to $4.3 million.

- Inactive Accounts – The Company has increased its forecast for O&M costs to address inactive accounts by approximately $1 million in the Rate Year based on further modifications to the Company's meter lock procedures. Under the modified procedure, the Company will schedule an appointment to lock the gas service/meter in all cases when a customer requests termination of service. The Company forecasts this modification to the procedure will require an incremental 180 customer visits per day, which is equivalent to 15.1 FTEs.
- Independent Compliance Assessment – The Gas Safety Panel's Correction and Updates testimony discusses the revised forecast for the costs to conduct an independent assessment of the Company's compliance with pipeline safety regulations. The Company has lowered the cost estimate in the Rate Year from $0.525 million to $0.350 and in the Data Years from $0.525 million to $0.160 million.

Exhibit ___ (GIOP-6CU) provides a revised estimate of the FTEs by function in the Rate Year and Data Years to reflect these changes to the Company's O&M programs.

Q. Does this conclude your testimony?

A. Yes, it does.

Corrections and Updates Testimony of the Gas Infrastructure and Operations Panel

List of Exhibits

Exhibit ___ (GIOP-1CU)	Revised Actual and Projected Capital Expenditures: Historic Test Year, CY16, Rate Year, and Data Years
Exhibit ___ (GIOP-5CU)	Revised Incremental O&M Expenditures: Historic Test Year, CY16, Rate Year and Data Years.
Exhibit ___ (GIOP-6CU)	Revised Incremental Full Time Equivalent Positions by Function in the Rate Year, Data Year 1 and Data Year 2.

Exhibit__(GIOP-1CU)

Corrections and Updates Testimony of the Gas Infrastructure and Operations Panel

Exhibit __ (GIOP-1CU)

Revised Actual and Projected Capital Expenditures: Historic Test Year, CY16, Rate Year, and Data Years

KEDNY
Capital Investment Plan
$000

Classification	Category	Historic Test Year	CY'17 Capital Plan	CY'18 Capital Plan	CY'19 Capital Plan
Growth	Base Growth - Install Main	$ 21,853	$ 48,136	$ 48,889	$ 48,356
	Base Growth - Install Services	$ 22,401	$ 23,106	$ 22,279	$ 22,165
	Base Growth - Customer Contributions	$ (2,438)	$ (4,896)	$ (3,298)	$ (2,500)
	Base Growth - Install Meter/Regulator	$ 2,338	$ 1,108	$ 1,120	$ 1,120
	Base Growth- Meter Purchases	$ 1,455	$ 2,027	$ 2,138	$ 2,244
	Gas System Reinforcement	$ 35,794	$ 65,752	$ 66,440	$ 62,239
	Total Growth	**$ 81,403**	**$ 135,234**	**$ 137,568**	**$ 133,624**
Mandated	CSC/Public Works - Non Reimbursable	$ 111,953	$ 112,528	$ 115,985	$ 118,305
	CSC/Public Works - Reimbursable	$ 70,122	$ 84,488	$ 86,985	$ 88,724
	CSC/Public Works Reimbursements	$ (5,678)	$ (16,117)	$ (17,158)	$ (17,158)
	LaGuardia Redevelopment	$ -	$ 15,588	$ 7,704	$ 1,050
	Flatlands	$ 9,309	$ -	$ -	$ -
	Atmospheric Corrosion Inside Inspections	$ 18	$ 507	$ 519	$ 530
	Service Replacements - Proactive	$ 680	$ 1,696	$ 1,700	$ 1,700
	Main Replacements - (Proactive) - Leak Prone Pipe	$ 52,572	$ 77,375	$ 87,189	$ 88,933
	Cross Bore Remediation	$ -	$ 477	$ 510	$ 510
	Latent Damage	$ -	$ 700	$ 812	$ 828
	Large Diameter CI System Sealing/Lining Program	$ -	$ 14,340	$ 19,282	$ 19,682
	Corrosion	$ 184	$ 857	$ 881	$ 898
	Service Replacement (Reactive) - Leaks	$ 5,850	$ 5,786	$ 6,011	$ 6,131
	Service Replacement (Reactive) - Non-Leaks - Other	$ 6,113	$ 5,173	$ 5,337	$ 5,445
	Main Replacements - (Reactive) - Maintenance	$ 3,517	$ 2,521	$ 2,591	$ 2,643
	Plastic Fusions - New	$ -	$ 2,103	$ 2,355	$ 2,582
	Pipeline Integrity - IMP	$ 6,072	$ 16,877	$ 11,818	$ 4,226
	Pipeline Integrity - IVP	$ -	$ 1,829	$ 2,000	$ 2,000
	Local Law 30	$ 7,317	$ 9,714	$ 12,777	$ 16,702
	Purchase Meters (Replacements)	$ 2,277	$ 3,719	$ 3,923	$ 4,119
	Meter Changes	$ 2,613	$ 1,785	$ 1,847	$ 1,884
	Misc Mandated Work	$ 289	$ -	$ -	$ -
	Total Mandated	**$ 273,208**	**$ 341,946**	**$ 353,068**	**$ 349,734**
Reliability	Gas System Control	$ -	$ 113	$ 117	$ 189
	Gas System Control - M2M Upgrade	$ -	$ 292	$ -	$ 1,160
	Gas System Reliability - Gas Planning /RCV Program	$ 3,032	$ 3,557	$ 5,815	$ 5,098
	Valve Installations / Replacements	$ -	$ 141	$ 142	$ 142
	Pressure Regulating Facilities	$ 4,226	$ 4,928	$ 5,742	$ 5,571
	Heater Installation Program	$ -	$ -	$ -	$ -
	Canarsie Gate - Repair Penatrations	$ 752	$ 76	$ -	$ -
	Citizens Gate - Bulkhead	$ 69	$ 3,376	$ 4,300	$ 1,075
	Coney Island Heater	$ 2,124	$ 30	$ -	$ -
	Tetco Relief Valve Retirement	$ -	$ 1,107	$ 525	$ -
	Varick Reg Station Retirement	$ -	$ 717	$ 1,000	$ 283
	Bay Ridge Retirement	$ -	$ 91	$ -	$ -
	Bowery Bay Station Upgrade	$ -	$ 1,147	$ 453	$ -
	McGuiness Mini Gate	$ -	$ -	$ 1,183	$ 468
	Kings Plaza Mini Gate	$ -	$ -	$ -	$ 1,218
	Maspeth Decommishing	$ 1,268	$ 61	$ -	$ -
	System Automation	$ 630	$ 1,617	$ 1,697	$ 1,700
	Control Line Integrity Program	$ -	$ 270	$ 390	$ 100
	Water Intrusion	$ 1	$ 975	$ 1,155	$ 1,183
	Storm Hardening - Remote Service Shutoff Valves	$ -	$ 3,518	$ 4,758	$ 4,848
	I&R - Reactive/CNG	$ 168	$ 1,626	$ 1,667	$ 1,697
	LNG - Blanket	$ 2,208	$ 2,571	$ 2,575	$ 2,065
	LNG - Special Projects	$ 776	$ 16,988	$ 11,876	$ 9,870
	LNG - Tank 2 Upgrade	$ -	$ -	$ 3,645	$ 15,795
	LNG - Salt Water Pump House Upgrade	$ -	$ 6,500	$ 8,125	$ 4,250
	Paerdegat Basin ILI	$ (2,517)	$ -	$ -	$ -
	Verrazano Narrows Upgrade	$ 2,054	$ -	$ -	$ -
	Bklyn Queens Interconnect Phase I	$ 3,907	$ -	$ -	$ -

KEDNY
Capital Investment Plan
$000

Classification	Category	Historic Test Year	CY'17 Capital Plan	CY'18 Capital Plan	CY'19 Capital Plan
	Bklyn Queens Interconnect Phase II	$ 16,592	$ -	$ -	$ -
	Bklyn Queens Interconnect Phase III	$ 193	$ -	$ -	$ -
	Northern Queens Gas T&D	$ 57,737	$ -	$ -	$ -
	MRI- Metropolitan Reliability Infrastructure	$ 526	$ 46,819	$ 86,692	$ 56,721
	Newtown Creek	$ 5,457	$ 10,774	$ -	$ -
	Spring Creek Reconfiguration	$ -	$ 5,416	$ 10,937	$ 2,159
	Spring Creek - Repair Penetrations	$ -	$ -	$ -	$ -
	Citizens Tunnel - Upgrade	$ -	$ -	$ -	$ -
	Misc Reliability Work	$ (39)	$ -	$ -	$ -
	Total Reliability	**$ 99,164**	**$ 112,710**	**$ 152,794**	**$ 115,592**
Non-Infrastructure	AMR Installation	$ -	$ 15,821	$ 7,065	$ 600
	AMR Replacement	$ 4,042	$ 5,078	$ 5,225	$ 5,330
	Tools & Equipment - All	$ 3,060	$ 3,432	$ 3,796	$ 4,138
	Telecomm	$ -	$ 101	$ 104	$ 105
	Combustible Gas Indicators	$ 1,986	$ -	$ -	$ -
	Total Non-Infrastructure	**$ 9,088**	**$ 24,432**	**$ 16,190**	**$ 10,173**
Misc	Misc	$ (853)	$ -	$ -	$ -
	Total Misc	**$ (853)**	**$ -**	**$ -**	**$ -**
	Total Direct Gas (Capital & COR)	**$ 462,010**	**$ 614,322**	**$ 659,620**	**$ 609,123**
	Cost of Removal	$ 21,064	$ 38,332	$ 39,433	$ 37,579
	Total Direct Gas (Net of COR)	**$ 440,946**	**$ 575,990**	**$ 620,187**	**$ 571,544**
Indirect Capital					
Facilities/Customer/Other	Facilities	$ 6,047	$ 2,400	$ 2,480	$ 2,560
	Customer - Gas REV Pilots	$ -	$ 790	$ -	$ -
	Other	$ 665	$ -	$ -	$ -
	COR	$ -	$ 600	$ 620	$ 640
	Total Facilities/Customer	**$ 6,712**	**$ 3,790**	**$ 3,100**	**$ 3,200**
Fleet/IM/IR (Capex only)	Fleet	$ 59	$ 2,500	$ 400	$ 350
	IM/IR	$ -	$ 85	$ 270	$ 270
	Total Fleet/IM/IR	**$ 59**	**$ 2,585**	**$ 670**	**$ 620**
	Total Capital/COR	**$ 468,781**	**$ 620,697**	**$ 663,390**	**$ 612,943**

Corrections and Updates Testimony of the Gas Infrastructure and Operations Panel

Exhibit __ (GIOP-5CU)

Revised Incremental O&M Expenditures:
Historic Test Year, CY16, Rate Year and Data Years.

GIOP-5 Corrections and Updates KEDNY Incremental O&M CY17-CY19

Company	Testimony Category	Program/Function	CY17			CY18			CY19		
			Labor	Non-labor	Total	Labor	Non-labor	Total	Labor	Non-labor	Total
KEDNY	Increased OPEX Workload	CMS- Director	67,736	-	67,736	69,768	-	69,768	71,861	-	71,861
		CMS- Field Collections	501,302	-	501,302	516,669	-	516,669	531,587	-	531,587
		CMS- Gas Leak Investigations	980,541	-	980,541	1,008,605	-	1,008,605	1,039,779	-	1,039,779
		CMS- Investigations	389,351	-	389,351	379,902	-	379,902	391,444	-	391,444
		CMS- Meter Oriented Services	1,401,104	-	1,401,104	1,492,655	-	1,492,655	1,538,771	-	1,538,771
		CMS- Meter/Regulator	50,189	-	50,189	51,650	-	51,650	53,199	-	53,199
		CMS- MSR (Helpers)	332,864	-	332,864	342,991	-	342,991	353,975	-	353,975
		CMS- Other Emergency	44,876	-	44,876	46,161	-	46,161	47,587	-	47,587
		CMS- Related to Meter Reading	1,261	-	1,261	1,297	-	1,297	1,337	-	1,337
		CMS- Supervisor	229,771	-	229,771	236,660	-	236,660	243,766	-	243,766
		CMS- Surveillance	554,020	-	554,020	569,876	-	569,876	587,280	-	587,280
		CMS- Working Leader	404,644	-	404,644	416,225	-	416,225	429,090	-	429,090
		Construction- Local Law 30	-	14,729,178	14,729,178	-	20,642,778	20,642,778	-	20,253,578	20,253,578
		Field Operations- Pressure Testing	-	177,786	177,786	182,874	-	182,874	188,526	-	188,526
		Field Operations- Pressure Testing	-	26,762	26,762	-	26,762	26,762	-	26,762	26,762
		Field Operations- Type 2 Leaks	334,567	-	334,567	337,560	-	337,560	130,883	-	130,883
		Field Operations- Type 3 Leaks	-	120,000	120,000	-	120,000	120,000	-	120,000	120,000
		I&R- Supervisor	147,666	-	147,666	152,073	-	152,073	156,636	-	156,636
		I&R- Techs	1,052,885	-	1,052,885	1,083,519	-	1,083,519	1,116,493	-	1,116,493
		I&R- Utility/Other Expenses	-	228,214	228,214	-	228,214	228,214	-	228,214	228,214
		MID- Newtown Creek Maintenance	-	349,167	349,167	-	710,023	710,023	-	703,669	703,669
		Increased OPEX Workload Total	**$ 6,470,591**	**$ 15,833,101**	**$ 21,304,692**	**$ 6,656,388**	**$ 21,760,777**	**$ 28,417,260**	**$ 6,861,620**	**$ 21,696,205**	**$ 28,557,825**
		OPEX related to CAPEX	CMS/CMO- Engineer	-	-	-	9,269	-	9,538	9,774	-	9,774
			Complex Construction- Construction Inspectors	90,432	-	90,432	93,165	-	93,165	95,939	-	95,939
			Complex Construction- Expenses	-	5,462	5,462	-	5,062	5,462	-	5,262	5,262
			Construction- I&R	-	4,285,509	4,285,509	-	2,685,549	2,685,549	-	1,252,893	1,252,893
			Construction- Main Replacement- Construction Inspection Supervisor	9,228	-	9,228	9,505	-	9,505	39,579	-	39,579
			Construction- Main Replacement- Construction Inspectors	41,899	-	41,899	86,196	-	86,196	133,291	-	133,291
			Construction- Main Replacement- Engineer	24,808	-	24,808	42,588	-	42,588	61,411	-	61,411
			Construction- Main Replacement- Manager	12,909	-	12,909	13,297	-	13,297	13,696	-	13,696
			Construction- Permit/Dummore/Paving Coordinator	17,850	-	17,850	18,386	-	18,386	18,937	-	18,937
			Construction- Public Works- Engineer	16,539	-	16,539	17,035	-	17,035	17,546	-	17,546
			Construction- Public Works- Joint Billing	-	900,000	900,000	-	990,000	990,000	-	1,089,000	1,089,000
			Construction- Public Works- Support & Protect	-	8,939,522	8,939,522	-	5,589,522	5,589,522	-	6,638,522	6,638,522
			Contract Strategy & Administration- Program Manager	28,776	-	28,776	29,637	-	29,637	30,527	-	30,527
			Corrosion- Techs	17,836	-	17,836	18,357	-	18,357	18,910	-	18,910
			Damage Prevention- A Inspector	167,396	-	167,396	172,393	-	172,393	177,721	-	177,721
			Damage Prevention- Workload Increases	-	374,720	374,720	-	374,720	374,720	-	374,720	374,720
			Gas Control- Control Room Operator	293,662	-	293,662	302,266	-	302,266	311,313	-	311,313
			Gas Control- SOP Coordinator	151,545	-	151,545	156,050	-	156,050	160,774	-	160,774
			Gas Distribution Engineering- Engineer	79,560	-	79,560	80,916	-	80,916	81,166	-	81,166
			Gas Estimating Office of Excellence- Estimator	12,434	-	12,434	12,776	-	12,776	13,160	-	13,160
			Gas Estimating Office of Excellence- Manager	3,227	-	3,227	3,316	-	3,316	3,416	-	3,416
			Gas Long Term Planning- Engineer	8,269	-	8,269	8,518	-	8,518	8,773	-	8,773
			Gas Long Term Planning- Engineer	-	28,992	28,992	-	28,992	28,992	-	28,992	28,992
			Gas Operations Engineering	152,311	-	152,311	136,282	-	136,282	140,369	-	140,369
			Gas Project Eng & Design- Designer	24,808	-	24,808	25,533	-	25,533	26,319	-	26,319
			Gas Project Eng & Design- Engineer	57,896	-	57,896	59,623	-	59,623	61,411	-	61,411
			Gas Transmission Engineering- Engineer	6,135	-	6,135	6,259	-	6,259	6,387	-	6,387
			Investment Planning- Jr. Test Budget- Program Manager	8,952	-	8,952	9,262	-	9,262	9,560	-	9,560
			Investment Planning- Rate Case Support- Program Manager	17,984	-	17,984	18,523	-	18,523	19,079	-	19,079
			Investment Planning- Work Order Closeout- Clerks	11,604	-	11,604	11,730	-	11,730	12,093	-	12,093
			Investment Planning- Work Order Closeout- Inspectors	16,760	-	16,760	17,260	-	17,260	17,795	-	17,795
			Investment Planning- Work Order Closeout- Lead Program Manager	9,932	-	9,932	10,670	-	10,670	10,994	-	10,994
			Investment Planning- Work Order Closeout- Manager	12,909	-	12,909	13,297	-	13,297	13,696	-	13,696
			Investment Planning- Work Order Closeout- Program Manager	17,984	-	17,984	18,523	-	18,523	19,079	-	19,079
			LNG- Clerk	57,020	-	57,020	58,652	-	58,652	60,366	-	60,366
			LNG- Field Engineer	82,694	-	82,694	85,175	-	85,175	87,730	-	87,730
			Main & Service Replacement- Designer	12,434	-	12,434	12,776	-	12,776	13,160	-	13,160
			Operations Support- ESRI Analyst	34,083	-	34,083	35,105	-	35,105	36,158	-	36,158
			Operations Support- Manager	12,909	-	12,909	13,297	-	13,297	13,696	-	13,696
			Operations Support- Mappers	53,783	-	53,783	73,764	-	73,764	76,016	-	76,016
			Operations Support- Permit Clerks	57,020	-	57,020	70,382	-	70,382	72,557	-	72,557
			Operations Support- Supervisor	18,656	-	18,656	19,009	-	19,009	19,579	-	19,579
			Pressure Regulation- Engineering- Engineer	16,539	-	16,539	17,035	-	17,035	17,546	-	17,546
			Project Controls- Analyst	94,083	-	94,083	95,105	-	95,105	96,158	-	96,158
			Project Controls- Expenses	-	2,040	2,040	-	2,040	2,040	-	2,040	2,040
			Project Management- Expenses	-	9,360	9,360	-	9,360	9,360	-	9,360	9,360
			Project Management- Project Manager	67,208	-	67,208	76,409	-	76,409	78,701	-	78,701
			Resource Planning- Analyst	25,562	-	25,562	26,329	-	26,329	27,119	-	27,119
			Resource Planning- Coordinator	8,925	-	8,925	9,193	-	9,193	9,469	-	9,469
			Resource Planning- Expenses	-	19,711	19,711	-	19,711	19,711	-	19,711	19,711
			Resource Planning- Manager	12,909	-	12,909	13,297	-	13,297	13,696	-	13,696
			Resource Planning- Program Manager	31,472	-	31,472	32,416	-	32,416	33,388	-	33,388
			Resource Planning- Report Analyst	25,562	-	25,562	26,329	-	26,329	27,119	-	27,119
			Resource Planning- Work Package Reviewer- Program Manager	9,302	-	9,302	9,262	-	9,262	9,560	-	9,560
		OPEX related to CAPEX Total	**$ 1,858,220**	**$ 14,189,233**	**$ 16,047,458**	**$ 2,011,265**	**$ 9,663,172**	**$ 11,674,438**	**$ 2,102,917**	**$ 11,020,717**	**$ 13,164,754**
		Other OPEX	CMS- Meter Reading	-	-	-	-	(1,289,121)	(1,289,121)	-	(2,697,936)	(2,697,936)
			Gas Control- Service Contract	-	1,610,000	1,610,000	-	1,661,000	1,661,000	-	1,792,000	1,792,000
		Other OPEX Total	**$ -**	**$ 1,610,000**	**$ 1,610,000**	**$ (1,289,121)**	**$ 1,661,000**	**$ 371,879**	**$ (2,697,936)**	**$ 1,792,000**	**$ (905,936)**
		Safety Programs	CMS- Inactive Accounts	2,078,986	-	2,078,986	2,158,687	-	2,158,687	2,324,585	-	2,324,585
			Construction- Plastic Fusion New	-	150,000	150,000	-	150,000	150,000	-	150,000	150,000
			Damage Prevention- Latest Damage- Advisors	-	586,500	586,500	-	586,500	586,500	-	586,500	586,500
			Field Operations- Inactive Accounts	124,171	-	124,171	127,725	-	127,725	131,472	-	131,472
			Field Operations- Inactive Accounts	-	109,382	109,382	-	109,382	109,382	-	109,382	109,382
			Gas Distribution Engineering- Latest Damage	-	1,900,000	1,900,000	-	1,900,000	1,900,000	-	1,900,000	1,900,000
			Gas Pipeline and Safety Compliance- 3rd Party Independent Compliance Assessments	-	360,000	360,000	-	360,000	360,000	-	360,000	360,000
			Gas Pipeline and Safety Compliance- Compliance Analyst	298,225	-	298,225	307,172	-	307,172	316,387	-	316,387
			Gas Pipeline and Safety Compliance- Gas Residential Methane Detection	-	150,000	150,000	-	150,000	150,000	-	150,000	150,000
			Gas Pipeline and Safety Compliance- Public Awareness	-	1,760,000	1,760,000	-	1,760,000	1,760,000	-	1,760,000	1,760,000
			Gas Pipeline and Safety Compliance- QA/QC Inspectors	83,604	-	83,604	86,112	-	86,112	88,696	-	88,696
			Pipeline Integrity- IMP/FVP	-	1,137,809	1,137,809	-	677,809	677,809	-	2,627,809	2,627,809
			Pressure Regulation Engineering- Transmission Station Integrity Testing	-	-	-	308,300	-	308,300	308,300	-	308,300
			Process Safety- Analyst	17,041	-	17,041	17,553	-	17,553	18,079	-	18,079
			Process Safety- Director	52,644	-	52,644	53,623	-	53,623	54,632	-	55,632
			Process Safety- Engineering	33,078	-	33,078	34,070	-	34,070	35,092	-	35,092
			Process Safety- Lead Program Manager	39,727	-	39,727	40,919	-	40,919	42,146	-	42,146
			Roadway Depression Inspections	-	1,130,000	1,130,000	-	870,000	870,000	-	870,000	870,000
		Safety Programs Total	**$ 2,727,476**	**$ 7,515,691**	**$ 10,243,167**	**$ 2,795,861**	**$ 6,402,691**	**$ 9,217,552**	**$ 2,871,290**	**$ 8,782,691**	**$ 11,653,981**
KEDNY Total			**$ 11,616,502**	**$ 38,756,665**	**$ 49,305,568**	**$ 10,168,288**	**$ 39,726,981**	**$ 49,895,297**	**$ 9,238,994**	**$ 43,038,911**	**$ 52,547,905**

Exhibits__(GIOP-6CU)

Corrections and Updates Testimony of the Gas Infrastructure and Operations Panel

Exhibit __ (GIOP-6CU)

Revised Incremental Full Time Equivalent Positions by Function in the Rate Year, Data Year 1 and Data Year 2

GIOP-6 KEDNY Incremental FTEs CY17-CY19

Company	L05 Receiving Cost Center	CY17	CY18	CY19	Grand Total
KEDNY	110-Complex Project Mgmt	5.5	2.0	-	7.5
	110-Contract Management	13.0	-	-	13.0
	110-Gas Control	4.5	-	-	4.5
	110-LNG/Propane-NY Downstate	2.0			2.0
	110-Ops Support Services	11.5	2.0		13.5
	110-Program Management	8.5		-	8.5
	120-Customer Meter Svcs	105.8	(25.0)	(25.0)	55.8
	120-Gas Pipeline Safety & Compliance	7.5	-	-	7.5
	120-Maint & Const-NY Gas	44.0	7.0	8.0	59.0
	130-Corrosion Control	2.0			2.0
	130-Gas Distribution Engineering	1.0	-	-	1.0
	130-Gas Estimating Office of Excellence	3.5			3.5
	130-Gas Investment Planning	11.0			11.0
	130-Gas Long Term Planning	1.0			1.0
	130-Gas Operations Engineering	2.0			2.0
	130-Gas Project Eng & Design	10.0			10.0
	130-Gas Transmission Engineering	0.5			0.5
	130-Main & Service Replacement	3.0			3.0
	130-Pressure Regulation Engineering	3.0	-	-	3.0
KEDNY Total		239.3	(14.0)	(17.0)	208.3

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-____
Case 17-G-____

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

Testimony of the Gas Infrastructure and Operations Panel

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. 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.

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:

- Sections I and II are introductory sections outlining the Panel's testimony.
- Section III 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

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.

Testimony of the Gas Infrastructure and Operations Panel

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.

Testimony of the Gas Infrastructure and Operations Panel

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.

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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?

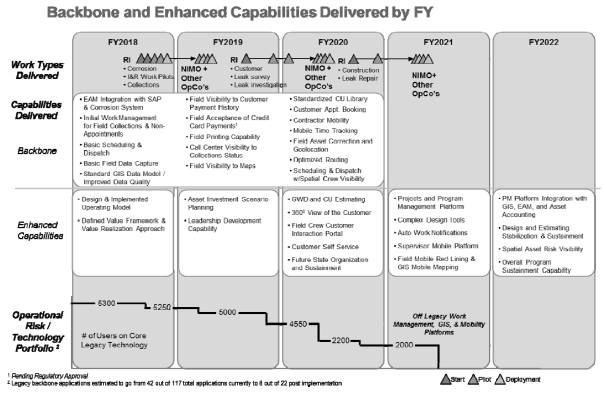
A. Yes, it does.

Testimony of Gas Infrastructure and Operations Panel

Exhibit __ (GIOP-8)

GBE Program High-Level Roadmap Showing Phased Implementation and Capabilities

High Level Roadmap of Capabilities to be Delivered Over Five Years



Before the Public Service Commission

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID

Rebuttal Testimony

of

Johnny Johnston

Dated: September 15, 2017

Case 17-E-0238
Case 17-G-0239

Rebuttal Testimony of Johnny Johnston

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Rebuttal Testimony of Johnny Johnston

I. Introduction

Q. Please state your name and business address.

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

Q. Are you the same Johnny Johnston who previously submitted testimony in these proceedings?

A. Yes. I provided direct testimony on the Gas Business Enablement ("GBE") Program as a member of the Gas Infrastructure and Operations Panel ("GIOP"). The defined terms in my direct testimony as part of the GIOP have the same definitions here.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to address certain adjustments and recommendations set forth in the testimony of the Department of Public Service Staff ("Staff") Gas Business Enablement Panel ("SGBEP") and the Staff Information Services Panel ("SISP") concerning the Company's GBE Program. Specifically, my rebuttal testimony will address:

(i) Staff's recommendation to apply cost adjustments to the GBE Program, including a slippage adjustment to capital expenditures and

operating and run the business expenses; and an adjustment to the Service Company return on all IS investments;

(ii) Staff's proposal for downward-only reconciliation of capital expenditure capital expenditure and reporting requirements for the Company's IS investments;

(iii) the SGBEP's recommendations for benchmarks measuring the successful implementation of the GBE Program;

(iv) the SGBEP's proposal for a cap on the costs of the GBE Program; and

(v) the SGBEP's recommendations concerning the Company's financing proposal.

Q. Do you sponsor any exhibits?

A. Yes. I sponsor the following exhibits that were prepared under my direction and supervision.

- Exhibit ___ (JJ-1R) Summary of Differences Between the GBE Program and IS Projects;
- Exhibit ___ (JJ-2R) Proposed Value Framework Metrics as Benchmarks for GBE Program; and
- Exhibit ___ (JJ-3R) Referenced Information Requests.

II. Staff Recommendations for Customer Protections

Q. Do you agree with the SGBEP's proposal (at 38-39) to implement customer protections for the GBE Program?

A. No. The SGBEP proposes customer protections for the GBE Program to address concerns regarding: (i) the Company's implementation plan for the GBE Program; (ii) the inherent difficulty in estimating the costs given the scale of the GBE investment; and (iii) perceived implementation and cost estimation challenges for National Grid IS projects. While I appreciate the SGBEP's concern that the GBE Program be delivered on time and on budget, the Company has addressed each of the concerns identified by the SGBEP and, therefore, the proposed customer protections are not warranted.

Q. The SGBEP contends (at 22-23) that the Company has not built sufficient controls into the GBE program to ensure it remedies the gas safety and compliance issues the program is intended to address. Do you agree with this statement?

A. No, I do not. The Company has taken great care to ensure that appropriate internal controls have been built into the design, implementation approach, and governance of the GBE Program. The Company has paid particular attention to strengthening controls in the area of gas safety and compliance. Specifically, the GBE Program is being designed to deploy systems that will:

(i) improve scheduling and management of gas safety and compliance obligations in a manner that provides greater visibility to due dates for work requirements;

(ii) enable better methods for documenting work activities, such as electronic data capture functionality in field mobile applications, auto-validation of fields and pre-populated drop down lists to improve data capture and quality; and

(iii) enable auto-generation of orders to support follow-up activities, such as leak survey, customer warning tags, and other mandated work.

Applications and systems developed by the GBE Program will put more information in the hands of the Company's employee (*e.g.*, call center representative and field technician) and allow real-time sharing of information to diagnose and solve problems more quickly and effectively. The GBE Program will also enhance internal gas safety controls with field mobile access to process documentation, instructor and video-based training, as well as standardized operations processes and training.

Importantly, in designing the program requirements, National Grid's Vice President for Pipeline Safety & Compliance was an active and key team member. His leadership and expertise during the program's strategic

assessment phase ensured that gas safety compliance and controls were identified and incorporated into the program roadmap.

Q. Please continue.

A. The GBE Program's implementation approach involves a similar focus on internal controls through a strict governance framework. The GBE Steering Group is comprised of various senior subject matter experts, along with the Chief Financial Officer of National Grid and the Group Head of Audit. In addition, in October 2017, the GBE Program will establish a Risk and Controls team to work with the Finance function's Controls Evaluation Team, the gas business Operational Controls team, and other organizations to support alignment of National Grid's operational and finance risk and controls frameworks. At least one subject matter expert on internal controls will also support business process and solution design activities for the GBE Program. Further, as noted in the Company's response to Information Request No. DPS-431(AT-4), PricewaterhouseCoopers ("PwC") was selected as a business assurance partner for National Grid to provide additional confirmation that the business design/roadmap developed for GBE is fit-for-purpose and meets National Grid's requirements for business functionality and deliverability (including risk management) (*see* Exhibit ___ (JJ-3R), Pages 23-35 of 65).

Q. The SGBEP claims (at 26-27) that the Company's capital review and planning process does not focus on identifying drivers of spending variances. Do you agree?

A. No. As noted on page 26 of the SGBEP's testimony, the GBE Program utilized zero-based budgeting to forecast both capital and O&M budgets. This, combined with fixed price vendor contracts and oversight by the GBE Steering Committee, will enable the Company to have clear visibility on drivers of capital spending variances.

It is also important to note that the GBE Program will enable the gas business to identify underlying capital spending variances. In its response to Information Request No. DPS-433(4) (AT-6), the Company explained and identified the specific GBE initiatives that will enable the Company to more accurately estimate capital spending, including: graphic work design tool and compatible unit libraries, the Asset Investment Planning and Management tool, asset integrity management tools, and enterprise asset system and financial system integrations (*see* Exhibit ___ (JJ-3R), Pages 41-42 of 65). Many of the same tools can be leveraged to provide greater insight into project spending variances to identify the underlying drivers of those variances. For example, implementing a compatible unit library for standard work will allow the Company to gain greater insights and visibility for project

change orders, specifically with more detail regarding third-party contractors' mains and services bid units. The work management system will allow field supervisors to document change orders and support more robust governance for the change order control process. Overall, GBE's work management and mobile tools will enable back office and field personnel to access and capture more information to provide better explanations of variances.

Q. Please address the SGBEP's concerns (at 29-30, 36-38) regarding the perceived difficulty in estimating GBE Program costs.

A. As explained in my direct testimony and the Company's response to Information Request DPS-431 (AT-4), GBE Program costs were developed with Accenture, one of the top system integrators, utilizing a bottom-up approach, validated by comparison to actual experience on other programs of similar size and scope (*see* Exhibit ___ (JJ-3R), Pages 23-35 of 65). PwC was selected as a business assurance partner for National Grid to validate that GBE meets National Grid's requirements for cost efficiency. PwC's Report on the strategic assessment and roadmap concluded that the cost estimate for GBE (i) was appropriate compared with the total costs of other industry benchmarks of similar scale projects and (ii) that the 4.5 year deployment duration in the roadmap is achievable.

In the response to Information Request No. DPS-433(1) (AT-6), the Company also addressed how it would deliver its GBE proposal on budget and on time including:

(i) adopting various best practices in program governance and management with a framework of eight Critical Success Factors (CSFs) to ensure the successful delivery of the GBE Program, such as a GBE Program Steering Group exercising oversight on budget, timing, and resources; change management and business engagement activities throughout the Program; and rigorous stage gating and established governance documents with independent reviewers;

(ii) selected deployment strategies and development methodologies, such as phased implementation to manage risks and improve outcomes; and

(iii) retaining a third party value assurance partner to evaluate program direction and deliverables

(*see* Exhibit ___ (JJ-3R), Pages 36-45 of 65).

The Company has addressed all of the SGBEP's concerns underlying its proposal for customer protections; as such, application of the proposed customer protections is not appropriate for the GBE Program and should not be adopted.

III. Information Services Adjustments/Customer Protections

A. Application of Information Services Adjustments Generally to GBE

Q. Please describe the IS spending protections proposed by the SISP and the SGBEP for the GBE Program.

A. The SGBEP recommends that the cost adjustments and customer protections proposed by the SISP for IS investments, generally, apply to the GBE Program as well because it is part of the overall IS investment. This includes the 37 percent slippage adjustment to account for historical IS underspending; adjustment to the Service Company return on all IS investments; the downward-only reconciliation for IS capital expenditures; and expanded reporting requirements.

Q. Do you agree with the application of Information Services cost adjustments to GBE?

A. No. As discussed above, the GBE Program has incorporated a number of best practices and controls including working with two of the top system integrators in the U.S., Accenture and PwC, to ensure that implementation or cost estimation issues previously experienced by the Company for large scale projects do not occur with GBE. A separate GBE Steering Committee, comprised of senior business executives, oversees the program, including with regard to the deployment timeline and costs. Delivery of the systems solutions is occurring with separate competitively bid delivery partners dedicated to the program. For all of these reasons, the application of the cost adjustments and customer protections for IS projects suggested by the SISP and SGBEP should not be applied to the GBE Program.

In addition, an adjustment should not be applied to the GBE Program simply because it includes an IS component as the SISP and SGBEP seem to suggest. GBE is a stand-alone, single, business-led and separately resourced program, apart from the other IS-sponsored initiatives that are delivered in a separately prioritized IS portfolio. Indeed, as shown in the Company's response to Information Request No. DPS-730 (AAM-45), FY18 GBE costs are not included in the IS investment plan (*see* Exhibit ___ (JJ-3R), Pages 55-59 of 65). The GBE Program is a separately managed effort with its own cost center and a dedicated team. The program will design and build a separate business-led organization for post-implementation support. Exhibit __ (GBE-1R) further describes the governance, budgeting, resource, and delivery differences between IS projects and business programs such as the GBE Program.

B. <u>Slippage Adjustment</u>

Q. Please summarize the proposed slippage adjustments on GBE Program costs.

A. The SISP applied a slippage adjustment to Service Company IS rent expense, upfront/project operating expenses associated with GBE and Grid Modernization projects, and ongoing run the business expenses. This results in a decrease to the Rate Year rent expense for GBE of approximately $0.650

million for Niagara Mohawk's gas business. Similarly, the SISP and SGBEP recommended a slippage adjustment of 37 percent to upfront operating expenses associated with GBE, resulting in a decrease to operating expenses in the Rate Year of approximately $0.072 million for Niagara Mohawk's electric business and $3.524 million for Niagara Mohawk's gas business. The same slippage adjustment was applied to run the business costs associated with GBE, resulting in a decrease to operating expenses in the Rate Year of approximately $0.439 million for Niagara Mohawk gas.

Staff argues that the slippage adjustments are appropriate to address concerns the Company can deliver on its proposal to spend its full Rate Year IS budget of $286.2 million. The SISP further notes that the proposed slippage adjustment reflects a decrease to Rate Year capital expenditures based on the review of past spending variances. The SISP calculated the slippage adjustment of 37 percent based on a historical multi-year average of actual-to-budget spending for IS projects for FY14-FY16.

Q. Do you agree that adjustments to GBE costs should be made for slippage?

A. No. The SGBEP and SISP have provided no evidence that the justifications for slippage adjustments apply to the GBE Program. The GBE Program is on

track to deliver its first release for FY18 as planned in the sanctioned roadmap. Further, business engagement and strategic change initiatives have started on time and are tracking to plan. More than 200 internal and contractor resources have already been on-boarded and are working on the GBE Program. In addition, the program is in the process of securing software solutions for work and customer management initiatives – a favorable leading indicator of progress on program implementation.

As discussed in the Company's response to Information Request Nos. DPS-431 (AT-4), DPS-433 (AT-6), the GBE Program has incorporated a number of best practices and controls to review deliverability and costs along with a value assurance partner to provide ongoing independent assessment of program delivery (*see* Exhibit ___ (JJ-3R), Pages 23-45 of 65). In addition, the GBE Program has conducted competitive bidding of delivery partners to confirm and validate the initial cost estimates reflected in the Company's filing. Under fixed price, milestone based contracts, overall program costs are anticipated to remain at approximately $458M (plus a $61 million contingency, which was not included in the Company's revenue requirement) consistent with the GBE Program cost forecast discussed in the testimony of the GIOP.

Q. Would the application of the slippage adjustment affect National Grid's ability to delivery GBE capabilities to Niagara Mohawk?

A. Yes. To deliver the GBE Program within the limits of the slippage adjustment, the Company would be required to forgo the development of certain capabilities and limit others. As explained in the direct testimony of the GIOP and in the partial sanction paper for the program provided in Attachment 5 to Information Request No. DPS-275 (IS-4) Supplemental, the GBE Program team devoted a significant portion of FY17 to the development of the business case, assessment of processes and applications, and high-level design for the GBE Program (*see* Exhibit ___ (JJ-3R), Pages 1-22 of 65). Application of Staff's significant slippage adjustment would require a re-planning effort to re-align activities to the reduced funding resulting in (i) a loss of 8 to 12 weeks re-planning timing; (ii) an increase to the length of the five year program to seven or eight years (assuming a linear increase in program timeline to the slippage); (iii) greater risk of failure of the already aged systems given the extended timelines discussed above; (iv) increased project costs for certain program level support such as the Project Management Office, architects, key leadership and subject matter experts due to the extended program timeline; and (v) increased vendor costs due to any significant changes in the roadmap, all resulting in an increase to the overall

program costs and delaying delivery of customer benefits without adding any incremental value for customers.

C. Adjustment to Service Company Return on All IS investments

Q. Do you agree with the SISP and SGBEP recommendations to use the pre-tax weighted average cost of capital of 8.74 percent, consistent with Staff's proposed stand-alone Niagara Mohawk rate of return, rather than the Company's proposed 9.91 percent?

A. No. The Company's objection to this proposal is discussed in the rebuttal testimony of Joshua Nowak.

D. Downward-Only Reconciliation of Capital Expenditures

Q. Do you agree with Staff's proposed reconciliation mechanism for GBE capital expenditures?

A. No. Under Staff's proposal, the reconciliation mechanism would act as a downward only capital tracker. The Company does not believe a capital tracker in a one-year case is appropriate or necessary. In addition, as noted in the direct testimony of the GIOP, while the GBE Program is ultimately expected to be delivered within the total budgeted costs, costs may reasonably

shift between years as detailed project design and delivery of projects occurs across multiple years.

E. Reporting and Documentation Improvements

Q. Do you agree with Staff's recommended reporting requirements for GBE?

A. In part, yes. The SGBEP proposes applying the same reporting requirements for GBE as the SISP (at 64-67, 72) recommends for IS, with a GBE-specific section on report (SGBEP at 38). However, as explained earlier, the GBE Program's budgeting and governance is handled separately from that of IS. As a result, the Company proposes to provide separate reports for the GBE Program, and discontinue reporting after FY24 when the program is fully implemented. Further, because GBE is a single, standalone Program, the prioritization summary and five-year capital plan for investments prior to the start of each Rate Year would be unnecessary and uninformative for GBE. The quarterly filings should provide sufficient information on the costs and investment direction of the GBE Program. The Company further proposes to file quarterly reports within 60 days after the end of each quarter to allow for sufficient time to provide informative variance analyses. For quarterly and annual reports, the Company proposes to provide variances for capital and operating expenses for GBE to reflect total costs.

The Company will work with Staff to develop a mutually agreeable reporting format that addresses Staff's recommendations. Ideally, the reporting format would incorporate aspects of the Company's internal reporting practices to minimize the incremental administrative burden.

IV. Additional GBE-Specific Customer Protections

A. Cap on GBE Costs

Q. Does the Company agree with Staff's proposal (at 39-40) for a cap on GBE costs?

A. No. It is not appropriate to cap the total forecast of $458 million. A cap is unnecessary and duplicative given the proposed benchmarks to address delivery of program benefits (discussed below). In addition, costs are always subject to Commission review, including as part of regular rate proceedings, management audit, or other proceedings the Commission may order. Further, a cap would needlessly constrain the ability of the Company to deliver additional capabilities for customers. Indeed, the proposed reporting requirements should provide sufficient visibility to Staff on the Company's spend and program delivery.

B. Benchmarks

Q. Please describe Staff's proposals on instituting benchmarks (at 41-47) for the GBE Program.

A. To demonstrate the successful delivery of enhanced capabilities, Staff proposed the following benchmarks:

- reductions in customer appointment windows from eight hours to between two and four hours;
- number of damages due to data quality errors; and
- incurred negative revenue adjustments on certain gas safety penalties GBE will address through a mobile application; and

Staff also encouraged the Company to propose any additional benchmarks. Staff recommends that, for any benchmark the Company cannot demonstrate, a prorated portion of Niagara Mohawk's $31.2 million share of the $185 million incremental investment over the "backbone" option will be returned to customers via a deferred liability. For example, if the Company meets two of the three benchmarks, it would be entitled to recovery of two thirds, or 66.7 percent, of the $31.2 million, or $20.817 million and the remaining one third, or $10.418 million, would be refunded through a deferred liability.

Q. Does the Company agree with Staff's proposal?

A. The Company acknowledges the importance of demonstrating timely and successful delivery of capabilities. However, the Company has concerns with the benchmarks proposed by Staff, and the calculation of the deferred liability.

Q. Please explain.

A. The benchmarks suggested by Staff are very narrowly focused on certain areas and based on certain misconceptions. For example, Staff proposes that the benchmark of reduction in customer appointment windows from the Company's response in Information Request No. DPS-658 (AT-12) (*see* Exhibit ___ (JJ-3R), Pages 46-54 of 65). In that response, the Company provided an analysis showing the savings in customer time of a shift of all customer appointments and commitments to two or four hours from two hours for appointments and eight or four hours for customer commitments. Importantly, as noted in Information Request No. DPS-689 (AT-15), this benefit was calculated at a high level and was not included in the Company's filing or the GBE business case as it was a customer time savings benefit (*see* Exhibit ___ (JJ-3R), Pages 64 of 65). The Company, therefore, does not believe it is an informative indicator of the overall delivery of business case benefits. To the extent Staff insists on utilizing this benchmark, measurement of the benefit will need to begin 12-18 months after the in-service date to

allow time for the Company to stabilize the solution and fully realize the benefits.

With respect to the number of damages due to data quality errors, the Company notes that data management and GIS initiatives will not find and correct all of the Company's legacy asset records deficiencies. These legacy data issues mean that this proposed benchmark may not fully reflect the benefits of the GBE Program.

In addition, Staff's proposed benchmarks proffer an all or nothing approach to determining whether benefits are delivered to customers. For example, under Staff's proposed benchmark of elimination of incurred negative revenue adjustments on certain gas safety penalties, if the Company incurs a single negative revenue adjustment on a penalty due to human error or non-GBE related issue, the entire benchmark would not be considered delivered and the Company would forfeit recovery on one-third of the revenue requirement for the $185 million in enhanced capabilities. This all or nothing approach makes Staff's proposed overly punitive, rather than protective of customer benefits.

Q. What does the Company propose with respect to benchmarks for demonstrating the successful delivery of capabilities?

A. In place of the benchmarks proposed by Staff, the Company proposes utilizing the GBE Program's Value Framework metrics, consisting of six key performance indicators ("KPIs") developed to measure performance. Use of the Value Framework metrics provides a holistic, consistent, measurable method to determine delivery of benefits across the GBE business case. As shown in Exhibit __ (JJ-2R), the six key metrics have been identified by National Grid across multiple benefits areas representing over 80 percent of the business case.

The Company's proposed KPIs are simple and focused on successful delivery of outputs for National Grid and its customers to demonstrate the benefits of the GBE investment. Because the GBE Program has created the Value Framework KPIs to provide consistent framework across all jurisdictions and operating companies to measure performance on delivery, these KPIs create alignment between the Company and customers, as well as with delivery vendors, and reduce administrative burden of tracking and reporting on different metrics separately.

Benchmarks based on the Value Framework KPIs can be designed on a sliding scale to provide a more graduated approach. The KPIs across the framework are consolidated using an equal weighting as shown in Exhibit __

(JJ-2R) and support the business case benefits included in Exhibit __ (GIOP-12). The Company proposes a prorated portion of Niagara Mohawk's $31.2 million share of the $185 million incremental investment over the "backbone" will be returned to customers via a deferred liability for any percent under 100 percent of the Value Framework that is not demonstrated as agreed to with Staff. In the context of a multi-year settlement, the Company proposes to explore with Staff an upside incentive mechanism in the event it is able to achieve more than 100 percent of the Value Framework benchmarks.

V. <u>Financing Proposal</u>

Q. Please explain Staff's position (at 47-55) on the Company's third party financing proposal for GBE.

A. Staff believes they cannot make a recommendation to the Commission on the Company's proposal to utilize a third party financing entity/bank to finance all GBE Program costs. Given the early stages of the evaluation of the third party financing option, Staff expressed concerns about its ability to evaluate the accuracy of the Company's analysis demonstrating an overall cost reduction for the GBE Program to the benefit of customers, as well as impacts to capitalization at the parent company level. Acknowledging that National Grid intends to implement the GBE Program not only for Niagara Mohawk, but also for KEDNY and KEDLI, Staff recommends that the third party

financing option should not be decided in the context of this proceeding such that if the Company intends to pursue this financing option, appropriate notice should be given so that parties in KEDNY and KEDLI, as well as Niagara Mohawk, can participate in the vetting of the alternative financing option.

Q. Please explain the Company's position on pursuing an alternative financing proposal for the GBE Program.

A. The Company understands that Staff requires additional information to aid the Commission in determining if the third party or other financing option provides benefits for all of National Grid's New York customers and that the issue may not be decided in the context of this rate proceeding. The GBE Program is a foundational investment in the future of National Grid's U.S. gas business that will deliver operational, safety, and customer service benefits for the Company and its customers. Because the GBE Program is a significant financial investment, and is being deployed across multiple jurisdictions on a staggered schedule, National Grid must equitably align recovery of the investment with the implementation of GBE functionality by the U.S. operating companies, realization of its benefits by their customers, and mitigation of execution risk. To the extent equitable rate recovery cannot be secured for certain operating companies, including KEDNY and KEDLI in New York, the Company may need to delay investments at those operating

companies. Because the roadmap and deployment plans currently reflect implementation on a staggered schedule, de-scoping of certain operating companies can result in significant incremental costs to the remaining companies that will see implementation of GBE as some of the foundational costs of the solutions, such as core solution design and development, will be allocated among fewer companies.

Q. Does this conclude your testimony?

A. Yes, it does.

Case 17-E-0238
Case 17-G-0239

Rebuttal Testimony of Johnny Johnston

Index of Exhibits

Case 17-E-0238
Case 17-G-0239
Rebuttal Testimony of Johnny Johnston

Exhibit ___ (JJ-1R)

Summary of Differences Between GBE Program and IS Projects

Information Services / Business Project Definition and Sanctioning

Area	Information Services (IS) Programs/Projects	Business Programs/Projects
Project Sponsorship	Project Sponsor is from the Business.	Project Sponsor is from the Business.
Project Management	Project Manager and technical project resources are part of the IS organization. Since the project is part of a prioritized IS portfolio of varying size and duration, Staffing is dynamic.	Project Manager and technical project resources are assigned to the project and report within the Business organization. Project may draw on specialized talent (e.g. database support), from the IS organization.
Oversight – Business Activities	Business activities such as business process changes and user training are managed by IS project management resources with participation by the line organizations within the Business.	Business activities such as business process changes and user training are managed by the project team, which resides within the Business, with participation by the line organizations within the Business.
Funding	Project is typically funded within the IS business plan.	Project is typically funded within the business plan of the Business line organization(s) which will benefit from the project.
Sanctioning Process	Sanction review process begins in IS with review by the IS technical and financial stakeholders, and is then passed on to the sanctioning committees for approval.	The Business has its own pre-sanction review process which includes financial and technical review. IS technical review typically occurs within the Business project team, since the IS technical resources reside within the project team in the Business organization, and since funding is typically within the Business.
	Projects with costs greater than $1 million and less than $25 million are approved by the United States Sanctioning Committee (USSC).	Projects with costs greater than $1 million and less than $25 million are approved by the United States Sanctioning Committee (USSC).
	Projects with costs equal to or greater than $25 million are approved by the Senior Executive Steering Committee (SESC), after review and noting by the USSC.	Projects with costs equal to or greater than $25 million are approved by the Senior Executive Steering Committee (SESC), after review and noting by the USSC.

Case 17-E-0238
Case 17-G-0239
Rebuttal Testimony of Johnny Johnston

Exhibit ___ (JJ-2R)

Proposed Value Framework Metrics as Benchmarks for GBE Program

Exhibit __ (JJ-2R)
Page 1 of 1

Exec. KPI Target and Weighting

Value Category	KPI	Baseline Test Year	FY19 Target Rate Year	FY20 Target Data Year 1	FY21 Target Data Year 2	Weighting
Work Mgmt CMS	Avg. # of Completed Jobs per Worker (jobs/day)	2.70	2.71	2.74	2.76	16.67%
Work Mgmt M&C	Avg. ft. of Main Repl./Worker (ft/day)	12.03	12.07	12.21	12.30	16.67%
Back Office	Work Orders Processed/Back Office FTE (Wos/yr.)	577	596	672	720	16.67%
Customer	Total Call Volume (calls/year)(move & non move)	1,148,881	1,148,881	1,109,157	1,089,295	16.67%
Asset & Inventory	Inventory Turnover	1.30	1.37	1.44	1.44	16.67%
Gas Safety & Compliance	Total non-compliance Occurrences	398*	247	123	24	16.67%

*Three year average of # of non-compliance occurrences based on 2013, 2014, 2015

nationalgrid | gas business enablement

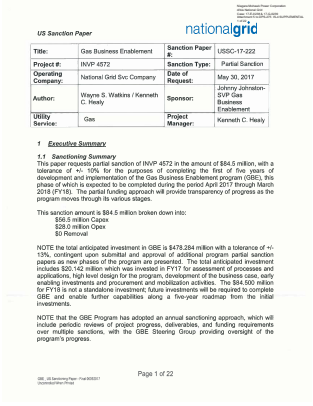
Exhibit __ (JJ-3R)

Case 17-E-0238
Case 17-G-0239

Rebuttal Testimony of Johnny Johnston

Exhibit ___ (JJ-3R)

Referenced Information Requests



US Sanction Paper

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Title:	Gas Business Enablement	**Sanction Paper #:**	USSC-17-222
Project #:	INVP 4572	**Sanction Type:**	Partial Sanction
Operating Company:	National Grid Svc Company	**Date of Request:**	May 30, 2017
Author:	Wayne S. Watkins / Kenneth C. Healy	**Sponsor:**	Johnny Johnston-SVP Gas Business Enablement
Utility Service:	Gas	**Project Manager:**	Kenneth C. Healy

1 *Executive Summary*

1.1 Sanctioning Summary

This paper requests partial sanction of INVP 4572 in the amount of $84.5 million, with a tolerance of +/- 10% for the purposes of completing the first of five years of development and implementation of the Gas Business Enablement program (GBE), this phase of which is expected to be completed during the period April 2017 through March 2018 (FY18). The partial funding approach will provide transparency of progress as the program moves through its various stages.

This sanction amount is $84.5 million broken down into:
- $56.5 million Capex
- $28.0 million Opex
- $0 Removal

NOTE the total anticipated investment in GBE is $478.284 million with a tolerance of +/- 13%, contingent upon submittal and approval of additional program partial sanction papers as new phases of the program are presented. The total anticipated investment includes $20.142 million which was invested in FY17 for assessment of processes and applications, high level design for the program, development of the business case, early enabling investments and procurement and mobilization activities. The $84.500 million for FY18 is not a standalone investment; future investments will be required to complete GBE and enable further capabilities along a five-year roadmap from the initial investments.

NOTE that the GBE Program has adopted an annual sanctioning approach, which will include periodic reviews of project progress, deliverables, and funding requirements over multiple sanctions, with the GBE Steering Group providing oversight of the program's progress.

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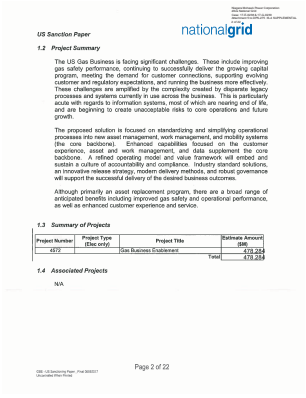

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1.2 Project Summary

The US Gas Business is facing significant challenges. These include improving gas safety performance, continuing to successfully deliver the growing capital program, meeting the demand for customer connections, supporting evolving customer and regulatory expectations, and running the business more effectively. These challenges are amplified by the complexity created by disparate legacy processes and systems currently in use across the business. This is particularly acute with regards to information systems, most of which are nearing end of life, and are beginning to create unacceptable risks to core operations and future growth.

The proposed solution is focused on standardizing and simplifying operational processes into new asset management, work management, and mobility systems (the core backbone). Enhanced capabilities focused on the customer experience, asset and work management, and data supplement the core backbone. A refined operating model and value framework will embed and sustain a culture of accountability and compliance. Industry standard solutions, an innovative release strategy, modern delivery methods, and robust governance will support the successful delivery of the desired business outcomes.

Although primarily an asset replacement program, there are a broad range of anticipated benefits including improved gas safety and operational performance, as well as enhanced customer experience and service.

1.3 Summary of Projects

Project Number	Project Type (Elec only)	Project Title	Estimate Amount ($M)
4972		Gas Business Enablement	479.254
		Total	479.254

1.4 Associated Projects

N/A

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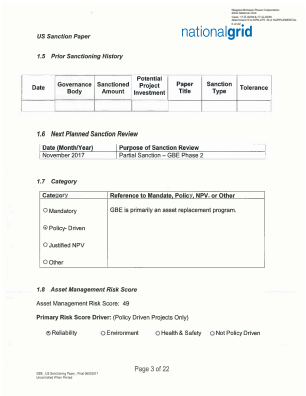

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1.5 Prior Sanctioning History

Date	Governance Body	Sanctioned Amount	Potential Project Investment	Paper Title	Sanction Type	Tolerance

1.6 Next Planned Sanction Review

Date (Month/Year)	Purpose of Sanction Review
November 2017	Partial Sanction – GBE Phase 2

1.7 Category

Category	Reference to Mandate, Policy, NPV, or Other
○ Mandatory ⊙ Policy- Driven ○ Justified NPV ○ Other	GBE is primarily an asset replacement program.

1.8 Asset Management Risk Score

Asset Management Risk Score: *49*

Primary Risk Score Driver: (Policy Driven Projects Only)

⊙ Reliability ○ Environment ○ Health & Safety ○ Not Policy Driven

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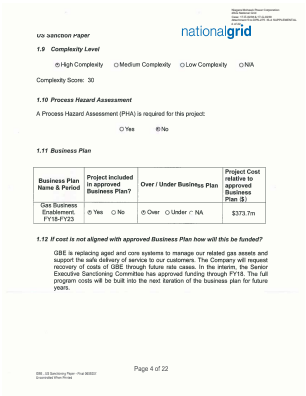

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1.9 Complexity Level

◉ High Complexity ○ Medium Complexity ○ Low Complexity ○ NA

Complexity Score: 30

1.10 Process Hazard Assessment

A Process Hazard Assessment (PHA) is required for this project:

○ Yes ◉ No

1.11 Business Plan

Business Plan Name & Period	Project included in approved Business Plan?	Over / Under Business Plan	Project Cost relative to approved Business Plan ($)
Gas Business Enablement FY18-FY23	◉ Yes ○ No	◉ Over ○ Under ○ NA	$373.7m

1.12 If cost is not aligned with approved Business Plan how will this be funded?

GBE is replacing aged and core systems to manage our related gas assets and support the safe delivery of service to our customers. The Company will request recovery of costs of GBE through future rate cases. In the interim, the Senior Executive Sanctioning Committee has approved funding through FY18. The full program costs will be built into the next iteration of this business plan for future years.

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US Sanction Paper

1.13 Current Planning Horizon

		Current Planning Horizon						
		Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr. 6 +	
$M	Prior Yrs	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	Total
CapEx	0.000	56.504	104.639	73.693	47.613	10.332	0.815	293.596
OpEx	20.142	27.972	64.102	41.339	21.317	9.087	0.729	184.688
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
CIAC/Reimbursement	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total	20.142	84.476	168.741	115.032	68.930	19.419	1.544	478.284

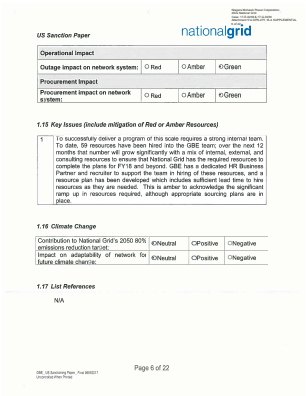
1.14 Key Milestones

Milestone	Target Date: (Month/Year)
Start Up	04/2017
Partial Sanction	05/2017
Begin Requirements and Design	05/2017
Begin Development and Implementation	07/2017
Partial Sanction	11/2017
Partial Sanction	11/2018
Partial Sanction	11/2019
Full Sanction	11/2020
Move to Production / Last Go Live	03/2021
Project Complete	03/2022
Project Closure Sanction	07/2022

NOTE that the timelines above cover the anticipated GBE roadmap, including beyond this partial sanction. The sanctioning approach will include periodic reviews of project progress, deliverables, and funding requirements over multiple sanctions. The next sanction request will occur in Q3 FY18.

1.14 Resources, Operations and Procurement

Resource Sourcing			
Engineering & Design Resources to be provided	☑ Internal	☑ Contractor	
Construction/Implementation Resources to be provided	☑ Internal	☑ Contractor	
Resource Delivery			
Availability of internal resources to deliver project:	○ Red	◉ Amber	○ Green
Availability of external resources to deliver project:	○ Red	○ Amber	◉ Green



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Operational Impact			
Outage impact on network system:	○ Red	○ Amber	◐ Green
Procurement Impact			
Procurement impact on network activities:	○ Red	○ Amber	◐ Green

1.15 Key Issues (include mitigation of Red or Amber Resources)

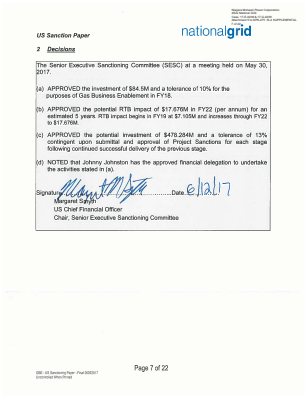
1	To successfully deliver a program of this scale requires a strong internal team. To date, 59 resources have been hired into the GBE team; over the next 12 months that number will grow significantly with a mix of internal, external, and consulting resources to ensure that National Grid has the required resources to complete the plans for FY18 and beyond. GBE has a dedicated HR Business Partner and recruiter to support the team in hiring of these resources, and a resource plan has been developed which includes sufficient lead time to hire resources as they are needed. This is amber to acknowledge the significant ramp up in resources required, although appropriate sourcing plans are in place.

1.16 Climate Change

Contribution to National Grid's 2050 80% emissions reduction target:	◐Neutral	○Positive	○Negative
Impact on adaptability of network for future climate change:	◐Neutral	○Positive	○Negative

1.17 List References

N/A



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2 Decisions

The Senior Executive Sanctioning Committee (SESC) at a meeting held on May 30, 2017,

(a) APPROVED the investment of $84.5M and a tolerance of 10% for the purposes of Gas Business Enablement in FY18.

(b) APPROVED the potential RTB impact of $17.676M in FY22 (per annum) for an estimated 5 years. RTB impact begins in FY19 at $7.105M and increases through FY22 to $17.676M.

(c) APPROVED the potential investment of $478.284M and a tolerance of 13% contingent upon submittal and approval of Project Sanctions for each stage following continued successful delivery of the previous stage.

(d) NOTED that Johnny Johnston has the approved financial delegation to undertake the activities stated in (a).

Signature ..... Date 6/12/17

Margaret Sutyla
US Chief Financial Officer
Chair, Senior Executive Sanctioning Committee

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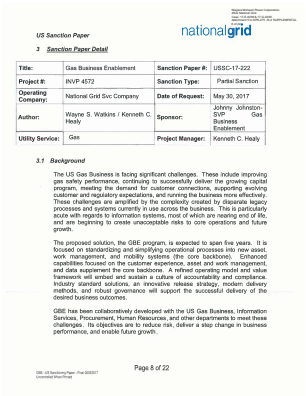

US Sanction Paper

3 Sanction Paper Detail

Title:	Gas Business Enablement	**Sanction Paper #:**	USSC-17-222
Project #:	INVP 4572	**Sanction Type:**	Partial Sanction
Operating Company:	National Grid Svc Company	**Date of Request:**	May 30, 2017
Author:	Wayne S. Watkins / Kenneth C. Healy	**Sponsor:**	Johnny Johnston-SVP Gas Business Enablement
Utility Service:	Gas	**Project Manager:**	Kenneth C. Healy

3.1 Background

The US Gas Business is facing significant challenges. These include improving gas safety performance, continuing to successfully deliver the growing capital program, meeting the demand for customer connections, supporting evolving customer and regulatory expectations, and running the business more effectively. These challenges are amplified by the complexity created by disparate legacy processes and systems currently in use across the business. This is particularly acute with regards to information systems, most of which are nearing end of life, and are beginning to create unacceptable risks to core operations and future growth.

The proposed solution, the GBE program, is expected to span five years. It is focused on standardizing and simplifying operational processes into new asset, work management, and mobility systems (the core backbone). Enhanced capabilities focused on the customer experience, asset and work management, and data supplement the core backbone. A refined operating model and value framework will embed and sustain a culture of accountability and compliance. Industry standard solutions, an innovative release strategy, modern delivery methods, and robust governance will support the successful delivery of the desired business outcomes.

GBE has been collaboratively developed with the US Gas Business, Information Services, Procurement, Human Resources, and other departments to meet these challenges. Its objectives are to reduce risk, deliver a step change in business performance, and enable future growth.

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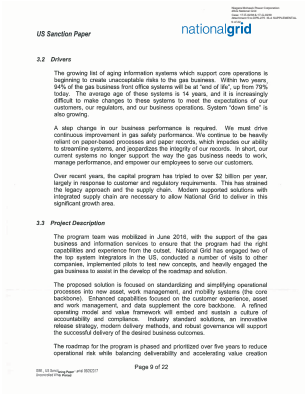

US Sanction Paper

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3.2 Drivers

The growing list of aging information systems which support core operations is beginning to create unacceptable risks to the gas business. Within two years, 94% of the gas business front office systems will be at "end of life", up from 79% today. The average age of these systems is 14 years, and it is increasingly difficult to make changes to these systems to meet the expectations of our customers, our regulators, and our business operations. System "down time" is also growing.

A step change in our business performance is required. We must drive continuous improvement in gas safety performance. We continue to be heavily reliant on paper-based processes and paper records, which impedes our ability to streamline systems, and jeopardizes the integrity of our records. In short, our current systems no longer support the way the gas business needs to work, manage performance, and empower our employees to serve our customers.

Over recent years, the capital program has tripled to over $2 billion per year, largely in response to customer and regulatory requirements. This has strained the legacy approach and the supply chain. Modern supported solutions with integrated supply chain are necessary to allow National Grid to deliver in this significant growth area.

3.3 Project Description

The program team was mobilized in June 2016, with the support of the gas business and information services to ensure that the program had the right capabilities and experience from the outset. National Grid has engaged two of the top system integrators in the US, conducted a number of visits to other companies, implemented pilots to test new concepts, and heavily engaged the gas business to assist in the develop of the roadmap and solution.

The proposed solution is focused on standardizing and simplifying operational processes into new asset, work management, and mobility systems (the core backbone). Enhanced capabilities focused on the customer experience, asset and work management, and data supplement the core backbone. A refined operating model and value framework will embed and sustain a culture of accountability and compliance. Industry standard solutions, an innovative release strategy, modern delivery methods, and robust governance will support the successful delivery of the desired business outcomes.

The roadmap for the program is phased and prioritized over five years to reduce operational risk while balancing deliverability and accelerating value creation

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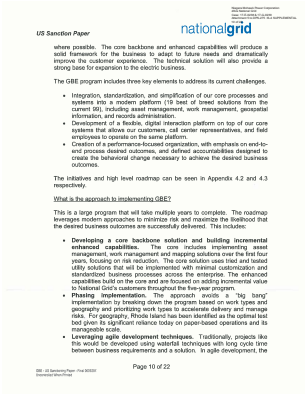

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where possible. The core backbone and enhanced capabilities will produce a solid framework for the business to adapt to future needs and dramatically improve the customer experience. This technical solution will also provide a strong base for expansion to the electric business.

The GBE program includes three key elements to address its current challenges.

- Integration, standardization, and simplification of our core processes and systems into a modern platform (19 best of breed solutions from the current 99), including asset management, work management, geospatial information, and records administration.
- Development of a flexible, digital interaction platform on top of our core systems that allows our customers, call center representatives, and field employees to operate on the same platform.
- Creation of a performance-focused organization, with emphasis on end-to-end process desired outcomes, and defined accountabilities designed to create the behavioral change necessary to achieve the desired business outcomes.

The initiatives and high level roadmap can be seen in Appendix 4.2 and 4.3 respectively.

What is the approach to implementing GBE?

This is a large program that will take multiple years to complete. The roadmap leverages modern approaches to minimize risk and maximize the likelihood that the desired business outcomes are successfully delivered. This includes:

- **Developing a core backbone solution and building incremental enhanced capabilities.** The core includes implementing asset management, work management and mapping solutions over the first four years, focusing on risk reduction. The core solution uses tried and tested utility solutions that will be implemented with minimal customization and standardized business processes across the enterprise. The enhanced capabilities build on the core and are focused on adding incremental value to National Grid's customers throughout the five-year program.
- **Phasing Implementation.** The approach avoids a "big bang" implementation by breaking down the program based on work types and geography and prioritizing work types to accelerate delivery and manage risks. For geography, Rhode Island has been identified as the optimal test bed given its significant reliance today on paper-based operations and its manageable scale.
- **Leveraging agile development techniques.** Traditionally, projects like this would be developed using waterfall techniques with long cycle time between business requirements and a solution. In agile development, the

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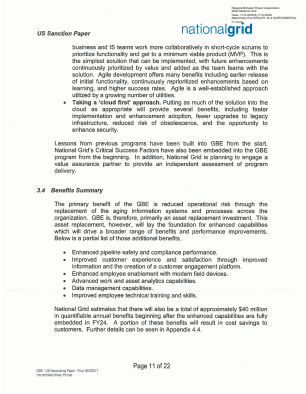


business and IS teams work more collaboratively in short-cycle scrums to prioritize functionality and get to a minimum viable product (MVP). This is the simplest solution that can be implemented, with future enhancements continuously prioritized by value and added as the team learns with the solution. Agile development offers many benefits including earlier release of initial functionality, continuously reprioritized enhancements based on learning, and higher success rates. Agile is a well-established approach utilized by a growing number of utilities.

- **Taking a 'cloud first' approach.** Putting as much of the solution into the cloud as appropriate will provide several benefits, including faster implementation and enhancement adoption, fewer upgrades to legacy infrastructure, reduced risk of obsolescence, and the opportunity to enhance security.

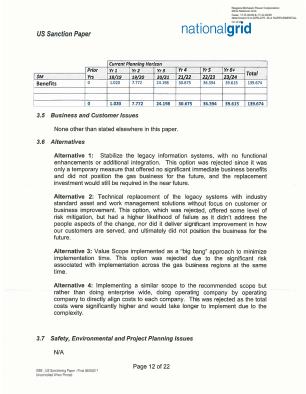
Lessons from previous programs have been built into GBE from the start. National Grid's Critical Success Factors have also been embedded into the GBE program from the beginning. In addition, National Grid is planning to engage a value assurance partner to provide an independent assessment of program delivery.

3.4 Benefits Summary

The primary benefit of the GBE is reduced operational risk through the replacement of the aging information systems and processes across the organization. GBE is, therefore, primarily an asset replacement investment. This asset replacement, however, will lay the foundation for enhanced capabilities which will drive a broader range of benefits and performance improvements. Below is a partial list of those additional benefits.

- Enhanced pipeline safety and compliance performance.
- Improved customer experience and satisfaction through improved information and the creation of a customer engagement platform.
- Enhanced employee enablement with modern field devices.
- Advanced work and asset analytics capabilities.
- Data management capabilities.
- Improved employee technical training and skills.

National Grid estimates that there will also be a total of approximately $40 million in quantifiable annual benefits beginning after the enhanced capabilities are fully embedded in FY24. A portion of these benefits will result in cost savings to customers. Further details can be seen in Appendix 4.4.



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		Current Planning Horizon						
£M	Prior Yrs	Yr 1 18/19	Yr 2 19/20	Yr 3 20/21	Yr 4 21/22	Yr 5 22/23	Yr 6+ 23/24	Total
Benefits	0	1,028	7,772	24,098	30,875	30,594	39,615	134,074
	0	1,028	7,772	24,098	30,875	30,594	39,615	134,074

3.5 Business and Customer Issues

None other than stated elsewhere in this paper.

3.6 Alternatives

Alternative 1: Stabilize the legacy information systems, with no functional enhancements or additional integration. This option was rejected since it was only a temporary measure that offered no significant immediate business benefits and did not position the gas business for the future, and the replacement investment would still be required in the near future.

Alternative 2: Technical replacement of the legacy systems with industry standard asset and work management solutions without focus on customer or business improvement. This option, which was rejected, offered some level of risk mitigation, but had a higher likelihood of failure as it didn't address the people aspects of the change, nor did it deliver significant improvement in how our customers are served, and ultimately did not position the business for the future.

Alternative 3: Value Scope implemented as a "big bang" approach to minimize implementation time. This option was rejected due to the significant risk associated with implementation across the gas business regions at the same time.

Alternative 4: Implementing a similar scope to the recommended scope but rather than doing enterprise wide, doing operating company by operating company to directly align costs to each company. This was rejected as the total costs were significantly higher and would take longer to implement due to the complexity.

3.7 Safety, Environmental and Project Planning Issues

N/A

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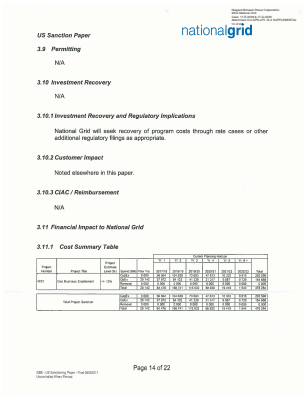
3.8 Execution Risk Appraisal

Number	Detailed Description of Risk / Opportunity	Probability	Impact		Score		Strategy	Pre-Trigger Mitigation Plan	Residual Risk	Post Trigger Mitigation Plan
			Cost	Schedule	Cost	Schedule				
1	Mis-alignment / lack of integration and coordination between programs	3	3	3	9	9	Avoid	Agile Delivery Methodology to be leveraged is structured to provide key checkpoints on a frequent cadence through Agile Program Increments Sessions. Additionally, the GBE Program will leverage independent third party expertise to provide insight into methodology and delivery effectiveness	Low	Agile approaches help identify most relevant solutions. Program will retain independent expertise to provide proactive feedback on the effectiveness of program integration activities
2	Delays in the SI procurement process will delay the start of critical Phase 2 projects and programs	3	2	3	6	9	Avoid	Robust commercial process to find partners with desired capability at the right price is underway and on schedule, with the goal of downselecting an SI partner that will be onboarded by July 1st. Program is executing pre-mobilization plan to reduce SI mobilization timelines	None	
3	A large group of people will be impacted by new devices and tools. Learning curve could be steep, especially in regions that are currently only using basic system tools to complete their work. This could impact operations and slow the realization of construction work	4	3	3	12	12	Mitigate	Leverage Pilots - to build learning early; Phased implementations to manage risk and manage change; Agile development approaches to engage employees more actively in design of new practices and processes; Alignment of operating model attributes to drive accountability for desired behaviors and outcomes.	Low	Change office and ongoing organizational health metrics to diagnose organizational state
4	GBE will not be able to staff the program to peak levels with the necessary SMEs given current scope and schedule	3	3	3	9	9	Mitigate	Developing realistic resource plan for recruitment of program full-time resources and engaging HR early, Engaging business leadership on a weekly basis to provide visibility into part time SME resource requirements, Robust commercial process to find partners with the ability to provide appropriate expertise as a short-term measure to fill gaps	Low	Continue proactively engaging with Business leadership to provide transparency in resource planning.



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3.9 Permitting

N/A

3.10 Investment Recovery

N/A

3.10.1 Investment Recovery and Regulatory Implications

National Grid will seek recovery of program costs through rate cases or other additional regulatory filings as appropriate.

3.10.2 Customer Impact

Noted elsewhere in this paper.

3.10.3 CIAC / Reimbursement

N/A

3.11 Financial Impact to National Grid

3.11.1 Cost Summary Table

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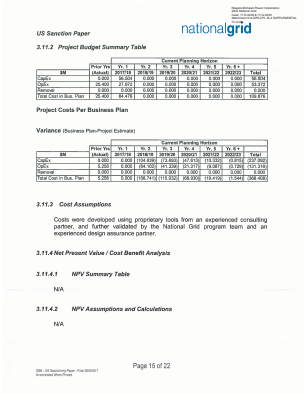

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3.11.2 Project Budget Summary Table

		Current Planning Horizon						
	Prior Yrs	Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr. 6 +	
$M	(Actual)	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	Total
Capex	0.000	56.924	0.000	0.000	0.000	0.000	0.000	56.924
Opex	35.400	37.472	0.000	0.000	0.000	0.000	0.000	72.872
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Cost in Bus. Plan	35.400	94.476	0.000	0.000	0.000	0.000	0.000	129.876

Project Costs Per Business Plan

Variance (Business Plan-Project Estimate)

		Current Planning Horizon						
	Prior Yrs	Yr. 1	Yr. 2	Yr. 3	Yr. 4	Yr. 5	Yr. 6 +	
$M	(Actual)	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	Total
CapEx	0.000	0.000	[134.836]	[13.460]	[47.613]	[13.333]	[0.615]	[207.856]
OpEx	0.000	0.000	[0.000]	[0.000]	[0.000]	[0.000]	[0.000]	[0.000]
Removal	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Cost in Bus. Plan	0.265	0.000	[168.741]	[115.932]	[68.936]	[10.416]	[1.544]	[368.408]

3.11.3 Cost Assumptions

Costs were developed using proprietary tools from an experienced consulting partner, and further validated by the National Grid program team and an experienced design assurance partner.

3.11.4 Net Present Value / Cost Benefit Analysis

3.11.4.1 NPV Summary Table

N/A

3.11.4.2 NPV Assumptions and Calculations

N/A

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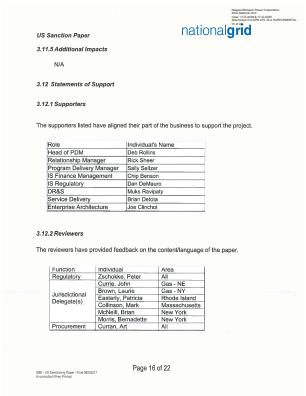

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3.11.5 Additional Impacts

N/A

3.12 Statements of Support

3.12.1 Supporters

The supporters listed have aligned their part of the business to support the project.

Role	Individual's Name
Head of PDM	Deb Rollins
Relationship Manager	Rick Shaw
Program Delivery Manager	Sally Seltzer
IS Finance Management	Chip Benson
IS Regulatory	Dan DeMauro
DR&S	Muks Ravipaty
Service Delivery	Brian Delcia
Enterprise Architecture	Joe Clinchot

3.12.2 Reviewers

The reviewers have provided feedback on the content/language of the paper.

Function	Individual	Area
Regulatory	Zschokke, Peter	All
Jurisdictional Delegate(s)	Currie, John	Gas - NE
	Brown, Laurie	Gas - NY
	Easterly, Patricia	Rhode Island
	Collinson, Mark	Massachusetts
	Michelli, Brian	New York
	Morris, Bernadette	New York
Procurement	Curran, Art	All

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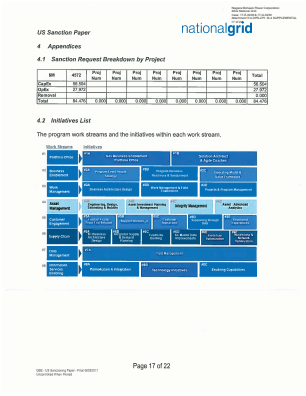

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4 Appendices

4.1 Sanction Request Breakdown by Project

$M	4072	Proj Num	Proj Num	Proj Num	Proj Num	Proj Num	Proj Num	Proj Num	Total
Capex	90.504								90.504
Opex	27.970								27.970
Removal									0.000
Total	82.474	0.000	0.000	0.000	0.000	0.000	0.000	0.000	34.474

4.2 Initiatives List

The program work streams and the initiatives within each work stream.

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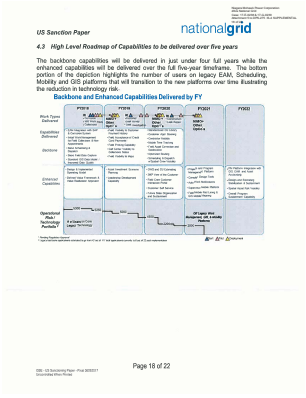

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4.3 High Level Roadmap of Capabilities to be delivered over five years

The backbone capabilities will be delivered in just under four full years while the enhanced capabilities will be delivered over the full five-year timeframe. The bottom portion of the depiction highlights the number of users on legacy EAM, Scheduling, Mobility and GIS platforms that will transition to the new platforms over time illustrating the reduction in technology risk.

Backbone and Enhanced Capabilities Delivered by FY

FY2018 FY2019 FY2020 FY2021 FY2022

Work Types Delivered

Capabilities Delivered

Electronic Capabilities

Operational Risk Reduction by Portfolio

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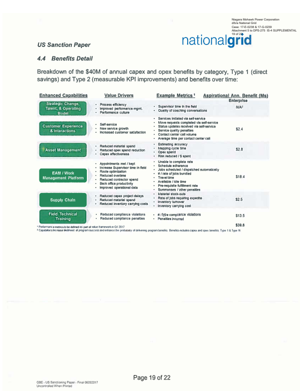

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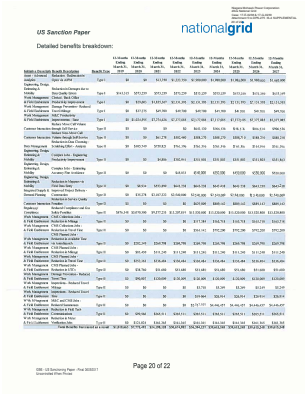
4.4 Benefits Detail

Breakdown of the $40M of annual capex and opex benefits by category, Type 1 (direct savings) and Type 2 (measurable KPI improvements) and benefits over time:

Enhanced Capabilities	Value Drivers	Example Metrics [1]	Aspirational Ann. Benefit (Ms) Enterprise
Strategic Change, Talent, & Operating Model	• Process efficiency • Improved performance mgmt. • Performance culture	• Supervisor time in the field • Quality of coaching conversations	N/A[2]
Customer Experience & Interactions	• Self-service • New service growth • Increased customer satisfaction	• Services initiated via self-service • Move requests completed via self-service • Status updates received via self-service • Service quality penalties • Contact center call volume • Average time per contact center call	$2.4
Asset Management	• Reduced material spend • Reduced opex spend reduction • Capex effectiveness	• Estimating accuracy • Mapping cycle time • Opex spend • Risk reduced / $ spent	$2.8
EAM / Work Management Platform	• Appointments met / kept • Increase Supervisor time in field • Route optimization • Reduced overtime • Reduced contractor spend • Back office productivity • Improved operational data	• Unable to complete rate • Schedule adherence • Jobs scheduled / dispatched automatically • # / rate of jobs bundled • Travel time • Available / idle time • Pre-requisite fulfillment rate • Summonses / other penalties	$18.4
Supply Chain	• Reduced capex project delays • Reduced material spend • Reduced inventory carrying costs	• Material stock-outs • Rate of jobs requiring expedite • Inventory turnover • Inventory carrying cost	$2.5
Field Technical Training	• Reduced compliance violations • Reduced compliance penalties	• # /type compliance violations • Penalties incurred	$13.5
			$39.6

[1] Performance metrics to be defined as part of value framework in Q1 2017
[2] Capabilities increase likelihood of program success and enhance the probability of delivering program benefits. Benefits includes capex and opex benefits. Type 1 & Type II



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Detailed benefits breakdown:

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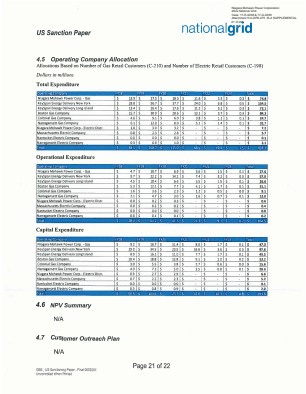

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4.5 Operating Company Allocation

Allocations Based on Number of Gas Retail Customers (C-210) and Number of Electric Retail Customers (C-108)

Dollars in millions

Total Expenditure

Allocation Percentage	FY20	FY21	FY22	FY23	FY24	FY25	Total
Niagara Mohawk Power Corp. - Gas	$ 28.7	$ 29.2	$ 29.5	$ 29.7	$ 30.0	$ 30.3	$ 176.4
Niagara Mohawk Power Corp. - Elect	$ 28.1	$ 28.6	$ 28.9	$ 29.1	$ 29.4	$ 29.7	$ 173.0
Keyspan Energy Delivery New York	$ 12.4	$ 12.6	$ 12.8	$ 12.9	$ 13.0	$ 13.2	$ 76.9
Boston Gas Company	$ 26.7	$ 27.2	$ 27.5	$ 27.7	$ 28.0	$ 28.3	$ 165.4
Colonial Gas Company	$ 4.5	$ 4.6	$ 4.6	$ 4.7	$ 4.7	$ 4.8	$ 28.0
Narragansett Gas Company	$ 11.1	$ 11.3	$ 11.4	$ 11.5	$ 11.6	$ 11.8	$ 68.7
Niagara Mohawk Power Corp. - Electric Elec	$ 0.8	$ 0.8	$ 0.8	$ 0.8	$ —	$ —	$ 3.3
Massachusetts Electric Company	$ 0.8	$ 0.8	$ 0.8	$ 0.8	$ —	$ —	$ 3.3
Narragansett Electric Company	$ 0.3	$ 0.3	$ 0.3	$ 0.3	$ —	$ —	$ 1.2
Total	$ 123.3	$ 125.4	$ 126.7	$ 127.5	$ 126.5	$ 126.2	$ 755.6

Operational Expenditure

Allocation Percentage	FY20	FY21	FY22	FY23	FY24	FY25	Total
Niagara Mohawk Power Corp. - Gas	$ 27.7	$ 28.2	$ 28.5	$ 28.7	$ 29.0	$ 29.3	$ 171.4
Keyspan Energy Delivery New York	$ 11.7	$ 11.9	$ 12.1	$ 12.2	$ 12.3	$ 12.5	$ 72.6
Niagara Mohawk Power Corp. - Electric Elec	$ 27.1	$ 27.6	$ 27.9	$ 28.1	$ 28.4	$ 28.7	$ 167.3
Boston Gas Company	$ 25.3	$ 25.8	$ 26.1	$ 26.3	$ 26.6	$ 26.9	$ 157.0
Colonial Gas Company	$ 4.3	$ 4.4	$ 4.4	$ 4.5	$ 4.5	$ 4.6	$ 26.6
Narragansett Gas Company	$ 10.5	$ 10.7	$ 10.8	$ 10.9	$ 11.0	$ 11.2	$ 65.2
Niagara Mohawk Power Corp. - Electric Elec	$ 0.8	$ 0.8	$ 0.8	$ 0.8	$ —	$ —	$ 3.3
Massachusetts Electric Company	$ 0.8	$ 0.8	$ 0.8	$ 0.8	$ —	$ —	$ 3.3
Narragansett Electric Company	$ 0.3	$ 0.3	$ 0.3	$ 0.3	$ —	$ —	$ 1.2
Total	$ 108.2	$ 110.1	$ 111.4	$ 112.2	$ 111.1	$ 111.2	$ 668.2

Capital Expenditure

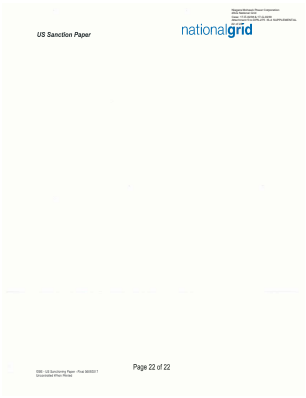
Allocation Percentage	FY20	FY21	FY22	FY23	FY24	FY25	Total
Niagara Mohawk Power Corp. - Gas	$ 8.1	$ 8.2	$ 8.3	$ 8.3	$ 8.4	$ 8.5	$ 49.8
Keyspan Energy Delivery New York	$ 3.3	$ 3.4	$ 3.4	$ 3.4	$ 3.4	$ 3.5	$ 20.4
Niagara Mohawk Power Corp. - Electric Elec	$ 8.0	$ 8.1	$ 8.2	$ 8.3	$ 8.4	$ 8.5	$ 49.4
Boston Gas Company	$ 8.4	$ 8.6	$ 8.7	$ 8.7	$ 8.8	$ 8.9	$ 52.2
Colonial Gas Company	$ 1.4	$ 1.5	$ 1.5	$ 1.5	$ 1.5	$ 1.5	$ 8.8
Narragansett Gas Company	$ 3.5	$ 3.5	$ 3.6	$ 3.6	$ 3.7	$ 3.7	$ 21.5
Niagara Mohawk Power Corp. - Electric Elec	$ 0.3	$ 0.3	$ 0.3	$ —	$ —	$ —	$ 0.8
Massachusetts Electric Company	$ 0.3	$ 0.3	$ 0.3	$ —	$ —	$ —	$ 0.8
Narragansett Electric Company	$ 0.1	$ 0.1	$ 0.1	$ —	$ —	$ —	$ 0.3
Total	$ 33.5	$ 34.1	$ 34.5	$ 34.7	$ 34.4	$ 34.4	$ 205.1

4.6 NPV Summary

N/A

4.7 Customer Outreach Plan

N/A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Date of Request: June 28, 2017 Request No. DPS-431 AT-4
Due Date: July 10, 2017 NMPC Req. No. NM-1004

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
Case No. 17-E-0238 and 17-G-0239 –
Niagara Mohawk Power Corporation d/b/a National Grid – Electric and Gas Rates

Request for Information

FROM: DPS Staff, Andrew Timbrook

TO: National Grid, Gas Information Systems Panel

SUBJECT: **GAS BUSINESS ENABLEMENT (GBE) – COST ESTIMATION**

Request:

In this interrogatory, all requests for data, workpapers or supporting calculations should be construed as requesting any Word, Excel, or other computer spreadsheet models in original electronic format with all formulae intact.

Concerning the cost estimation process for the proposed GBE program, provide the following:
a. A description of Accenture & PwC's roles in the cost estimation process;
b. Any inputs and assumptions used to estimate program costs;
c. The historic performance of Accenture when estimating the costs of similar programs; and
d. Explain how the Company verified that the cost estimates were reasonable.

Response:

a. As noted in the initial testimony of the Gas Infrastructure and Operations Panel, National Grid worked with two of the top system integrators ("SI") in the U.S., Accenture and PwC, to complete a high-level design and develop a roadmap for the Gas Business Enablement ("GBE") Program.

Accenture:
Accenture was selected as the Strategic Assessment (Design) partner to help develop the high-level design, road map, and business case. In support of these efforts, Accenture's role included consulting on the current state/gap analysis, future state technical design,

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implementation approach, change analysis/strategy, risk analysis, and draft work packet for the SI.

Cost estimates for the GBE Program were developed by Accenture utilizing its proprietary "Delivery Estimator" model described in Attachment 1. Costs were developed utilizing a bottom-up approach for each initiative that included (i) the labor effort required (as determined by Accenture from their actual experience with prior technology and platform implementations of a similar size and scope); (ii) software and hardware costs (utilizing the latest vendor quoted prices where available or Accenture's experience), and (iii) labor rates, which were derived from National Grid's internal labor rates and, where internal rates were not applicable, current external market labor rates were used. As discussed further in response to part (d), as part of the development of cost estimates described above, Accenture validated the estimates by comparing them to their actual experience with other programs of similar size and scope.

PwC:
PwC was selected as a business assurance partner for National Grid to provide additional assurance that the business design/roadmap developed for GBE is "fit-for-purpose" and meets National Grid's requirements for business functionality, deliverability (including risk management), and cost efficiency. PwC's role included reviewing and analyzing business/technology and project design alignment; market and best practices; design flexibility and process; implementation strategy; integration plan; design process; and risk analysis. Attachment 2 includes PwC's Stage Gate Report ("Report") on the Future State Design and Scope and Roadmap for GBE. Attachment 3 is National Grid's response to PwC's report. A key finding of PwC's Report was that the cost estimate for GBE was appropriate compared with the total costs of other industry benchmarks of similar scale projects. PwC also noted that the final version of the SI Work Package provides the level of information necessary for SIs to understand the full scope of the GBE Program and to enable National Grid to compare equivalent bids.

The following are other key assurance findings in PwC's Report:

- the solution design was based on industry leading software applications that can support National Grid's GBE Program objectives;
- the proposed GBE roadmap work streams and initiatives provide a program scope well matched to achieve the targeted objectives of GBE;
- the initiative scope goes beyond process and technology to address gaps across the full set of elements of the required core operational business capabilities; and
- the 4.5 year deployment duration in the roadmap work streams and initiative listing is achievable.

b. Please see response to part (a) and Attachment 4.

c. Please see page 5 of Attachment 1.

d. The Company has verified and plans to continue to validate that cost estimates are reasonable throughout the Program's life cycle:

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- As described above, the Company retained Accenture to help develop and validate cost estimates for the GBE Program. As shown in Attachment 1, Accenture's estimates of prior similar projects were within acceptable variance ranges.
- Importantly, National Grid provided Accenture much of the raw data from workshops with the business on the technology gaps. In addition, National Grid's internal GBE team engaged representatives from Information Services departments, including Enterprise Architecture, Strategic Solution Delivery, Service Delivery, and Digital Risk and Security to review technical and cost outputs. Also included in the review were representatives from the Company's Asset Management and Process Excellence teams, with experience in work and asset management platforms, financial systems, field force systems, meter management, and GIS.
- In addition, National Grid partnered with PwC, another highly experienced system integrator, to review the cost estimates and SI work packages to provide additional assurance that cost estimates were reasonable and assurance that the SI work packages would allow National Grid to pursue a rigorous competitive procurement process.
- Finally, as the GBE Program proceeds into design and implementation, National Grid will utilize a competitive procurement process for change leadership and ten key modules of GBE including: Work Management, Asset Management, Customer Engagement, GIS, and Supply Chain and Data Management. In addition, National Grid will competitively bid any core software, hardware, infrastructure, and application products and alternatives available in the market.

Name of Respondent:
Johnny Johnston

Date of Reply:
July 10, 2017

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CONFIRMATION OF ACCENTURE ESTIMATE ACCURACY

June 14, 2017

accenture | nationalgrid

VERIFICATION OF ACCURACY OF ACCENTURE ESTIMATORS
Accenture employs robust and industrialized calibration processes for our estimators in order to ensure accuracy of estimates we provide
Accenture conducts two ongoing processes to enable accuracy of its estimating tools:
Harvesting
Conduct periodic harvests of actuals from project specific technologies and platforms
Calibration
Collaborate with practice sponsors to calibrate the estimators to better align with actuals
The estimators are re-certified every 2 years based on harvesting and calibration of at least 6 projects within that timeframe
accenture
nationalgrid

COST ESTIMATING OF GBE PROGRAM

- GBE program costs were estimated using Accenture Delivery Estimators built up using bottom-up details for all initiatives

Effort	The labor effort for each initiative was estimated using one of 2 distinct approaches: 1. Factor-based estimates using Accenture Development Methodology estimators to create a detailed resource plan 2. Capacity-based estimates using historical experience aligned to initiative scope to create a detailed resource plan
Software / Hardware	Software and hardware estimates used the latest vendor quoted prices where possible; Accenture experience used where vendor quoted prices were not available
Rates	Labor rates were applied to labor effort and were derived from 2 sources: 1. National Grid current daily labor rates for various roles and levels validated by National Grid Finance 2. External SI daily labor rates calculated by Accenture based on typical "market rates"

Costs were compared with other transformation programs to validate program costs based on program scope

ACCENTURE DEVELOPMENT METHODOLOGY ESTIMATOR APPROACH
Accenture's employs a standard approach within its Development Methodology Estimators
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COST ESTIMATE COMPARISONS

Solution Component	NG Estimate Approach	National Grid	Utility A	Utility B	Utility C
Scope		- 6 OpCos - 3 states - Gas Only (includes Electric CMS), D Only	- 4 OpCos - 4 states - Gas and Electric, T & D	- 1 OpCo - 1 State - Electric Only, T & D	- 2 OpCos - 2 States - Gas and Electric, T & D
Transformation Office	Capacity-Based	X	X	X	X
EAM / Scheduling / Mobility	Factor-Based	X	X	X	X
PowerPlan	NG Estimated	X	-	-	-
GIS	Factor-Based	X	-	-	-
Engineering, Design, Estimation, Mobility	Factor-Based	X	Process only	Process only	X
AIPM	Capacity-Based	X	-	X	X
Asset Analytics	Capacity-Based	X	X	X	X
Integrity Management	Capacity-Based	X	-	-	X
Integrated Resource Planning	Capacity-Based	X	X	-	X
Project and Program Management	Capacity-Based	X	X	-	-
Supply Chain	Capacity-Based	Process only	X	-	"Lite"
Customer Experience	High-Level Comparison	X	-	-	-
Data Management	Capacity-Based	X	"Lite"	"Lite"	-
Legacy Remediation	Capacity-Based	X	X	X	X
IS Capabilities / Other	Capacity-Based	X	X	-	-
Business Enablement	Capacity-Based	X	X	X	X
Compliance / Technical Training	NG Estimated	X	-	-	-
		$458M	**$330M**	**$158M**	**$211M**

Actuals for Utilities A, B, and C landed within acceptable success thresholds.

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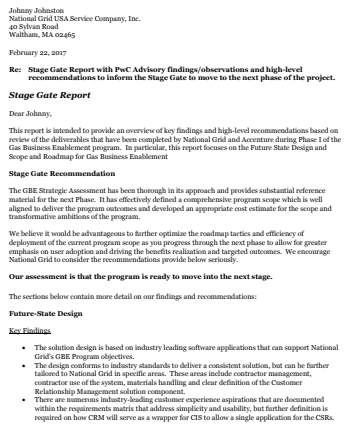
Niagara Mohawk
Power Corporation
d/b/a National Grid
Case 17-E-0238 and
17-G-0239



Johnny Johnston
National Grid USA Service Company, Inc.
40 Sylvan Road
Waltham, MA 02465

February 22, 2017

Re: Stage Gate Report with PwC Advisory findings/observations and high-level recommendations to inform the Stage Gate to move to the next phase of the project.

Stage Gate Report

Dear Johnny,

This report is intended to provide an overview of key findings and high-level recommendations based on review of the deliverables that have been completed by National Grid and Accenture during Phase I of the Gas Business Enablement program. In particular, this report focuses on the Future State Design and Scope and Roadmap for Gas Business Enablement

Stage Gate Recommendation

The GBE Strategic Assessment has been thorough in its approach and provides substantial reference material for the next Phase. It has effectively defined a comprehensive program scope which is well aligned to deliver the program outcomes and developed an appropriate cost estimate for the scope and transformative ambitions of the program.

We believe it would be advantageous to further optimize the roadmap tactics and efficiency of deployment of the current program scope as you progress through the next phase to allow for greater emphasis on user adoption and driving the benefits realization and targeted outcomes. We encourage National Grid to consider the recommendations provide below seriously.

Our assessment is that the program is ready to move into the next stage.

The sections below contain more detail on our findings and recommendations:

Future-State Design

Key Findings

- The solution design is based on industry leading software applications that can support National Grid's GBE Program objectives.
- The design conforms to industry standards to deliver a consistent solution, but can be further tailored to National Grid in specific areas. These areas include contractor management, contractor use of the system, materials handling and clear definition of the Customer Relationship Management solution component.
- There are numerous industry-leading customer experience aspirations that are documented within the requirements matrix that address simplicity and usability, but further definition is required on how CRM will serve as a wrapper for CIS to allow a single application for the CSRs.

- The design would benefit from a clearer and more systematic linkage of scope to initiatives (e.g. mapping of business processes, data objects, RICEFW/RAWICE Objects, operating model decisions, KDDs, applications to the program initiatives) and the precedence linking of the initiatives; this can be refined during the next phase and will help with governance decisions during delivery
- Impact to the business roles and responsibilities and overall Change Impact is also in early stages of development and is planned to be a focus in the next stages of the project.

Recommendations

- Minimization of customizations is critical to providing the agility to evolve the solution by upgrading with each new product release. This should be a guiding principle for the detailed design teams.
- Establish design governance processes to maintain tight controls on Requirements and Key Design Decisions.
- Conduct an early deep dive to drive out the details in contractor management, contractor use of the system and materials handling to streamline the detailed design effort.
- A similar deep dive concerning the Customer Relationship Management solution component should be conducted early in the detailed design. Particular attention should be devoted to how the Customer Relationship Management solution will serve as a wrapper for CIS allowing a single application for the CSRs.
- The future state for technology is evolving. Emphasis should be placed on the data flow, system of record/entry for key data objects and the overall integration model to ensure that data is synchronized and consistent and supports business processes and analysis for continuous improvement.
- Continue to socialize the solution with the business so they develop a clear vision and build a sense of ownership in decision making within their areas.

Gas Business Enablement Scope and Roadmap

Key Findings

- The proposed GBE roadmap work streams and initiatives provide a program scope well matched to achieve the targeted outcomes and objectives of GBE. The initiative scope goes beyond process and technology to address gaps across the full set of elements of the required core operational business capabilities.
- The 4.5 year deployment duration for the GBE scope elements in the roadmap work streams and initiative listing is achievable.
- When comparing the total costs of this transformation to other industry benchmarks, a business case estimate of >$500 million is appropriate to cover a transformation of this scale.
- The final version of the SI Work Package provides the level of information necessary for System Integrators to understand the full scope of the Gas Business Enablement program and to enable National Grid to compare equivalent bids.
- National Grid should consider increasing program focus on user adoption of new work practices and tools and resulting benefits realization. This is underserved in the current roadmap where activity typically stops after initial support periods for deployments of new applications and processes..
- We believe the deployment planning of the EAM/WM scope will benefit from further analysis to (a) understand the pros and cons of the proposed "work type" phased approach (which increases

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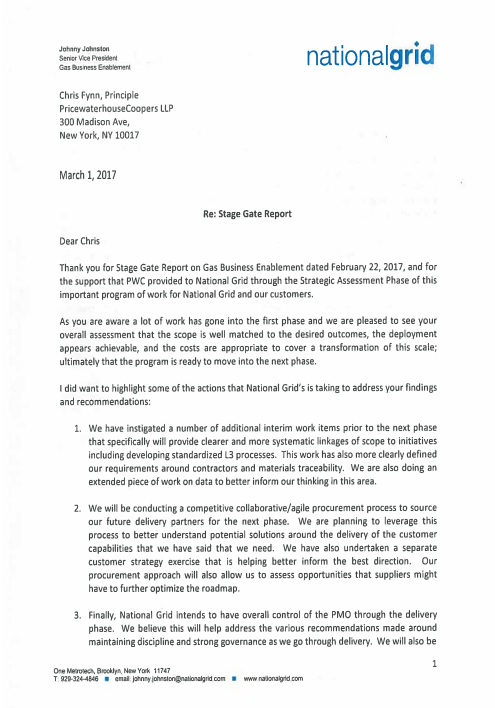
Niagara Mohawk
Power Corporation
d/b/a National



Johnny Johnston
Senior Vice President
Gas Business Enablement

nationalgrid

Chris Fynn, Principle
PricewaterhouseCoopers LLP
300 Madison Ave,
New York, NY 10017

March 1, 2017

Re: Stage Gate Report

Dear Chris

Thank you for Stage Gate Report on Gas Business Enablement dated February 22, 2017, and for the support that PWC provided to National Grid through the Strategic Assessment Phase of this important program of work for National Grid and our customers.

As you are aware a lot of work has gone into the first phase and we are pleased to see your overall assessment that the scope is well matched to the desired outcomes, the deployment appears achievable, and the costs are appropriate to cover a transformation of this scale; ultimately that the program is ready to move into the next phase.

I did want to highlight some of the actions that National Grid's is taking to address your findings and recommendations:

1. We have instigated a number of additional interim work items prior to the next phase that specifically will provide clearer and more systematic linkages of scope to initiatives including developing standardized L3 processes. This work has also more clearly defined our requirements around contractors and materials traceability. We are also doing an extended piece of work on data to better inform our thinking in this area.

2. We will be conducting a competitive collaborative/agile procurement process to source our future delivery partners for the next phase. We are planning to leverage this process to better understand potential solutions around the delivery of the customer capabilities that we have said that we need. We have also undertaken a separate customer strategy exercise that is helping better inform the best direction. Our procurement approach will also allow us to assess opportunities that suppliers might have to further optimize the roadmap.

3. Finally, National Grid intends to have overall control of the PMO through the delivery phase. We believe this will help address the various recommendations made around maintaining discipline and strong governance as we go through delivery. We will also be

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Attachment DIV 7-49-40
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Niagara Mohawk
Power Corporation
d/b/a National Grid

Johnny Johnston
Senior Vice President
Gas Business Enablement

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looking to hire a Value Assurance partner that will provide independent assurance that we are continuing to focus on the right things to support a successful outcome.

I did want to follow up on one area of recommendations where perhaps you didn't have full visibility to all the work we have been doing; that was around Pipeline Safety Management and API 1173. This has been an area of focus for us since the beginning of the program. However we have been leading this work through Dan McNamara with support from a niche consulting firms P-Pic and Mosaic. This has been done in parallel with the Accenture work that PWC has been overseeing and so might be why you believed there were still some gaps. I can confirm materials traceability is part of our requirements and there is a significant piece of work looking at the management of change, particularly related to our policies and procedures. As we move into the next phase we will look to do a better job of articulating how this all comes together into a single roadmap that covers people, process, technology, training and governance to support the implementation of all the elements of API 1173 into National Grid as part of the Gas Enablement program.

Thank you again for the work of your team over the last year, I am excited to see this move into implementation and the difference that this program will make for our employees and customers.

Yours sincerely,

Johnny Johnston,
Senior Vice President, Gas Business Enablement

One Metrotech, Brooklyn, New York 11747
T: 929-324-4846 ■ email: johnny.johnston@nationalgrid.com ■ www.nationalgrid.com

2

Date of Request: June 28, 2017 Request No. DPS-433 AT-6
Due Date: July 10, 2017 NMPC Req. No. NM-1006

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
Case No. 17-E-0238 and 17-G-0239 –
Niagara Mohawk Power Corporation d/b/a National Grid – Electric and Gas Rates

Request for Information

FROM: DPS Staff, Andrew Timbrook

TO: National Grid, Gas Information Systems Panel

SUBJECT: **GAS BUSINESS ENABLEMENT (GBE) - IMPLEMENTATION**

Request:

In this interrogatory, all requests for data, workpapers or supporting calculations should be construed as requesting any Word, Excel or other computer spreadsheet models in original electronic format with all formulae intact.

Concerning the proposed GBE program, provide the following:

1. Fully explain how the Company plans to deliver GBE on time and on budget. Include in your response a full explanation of how the current approach differs from the development and delivery of major Information Systems (IS) projects implemented previously.

2. Did the Company interview peers that have implemented major IT projects? If so, explain:
   a. The lessons learned from those discussions; and
   b. How the lessons validated, or were incorporated into, the plan.

3. Explain how the Company plans to train its employees to maximize productivity.

4. How will GBE impact the execution of the Capital plan in the Rate Year and Data Years?

5. Provide an assessment of how GBE relates to the overall IS program. Include in your response answers to the following questions:
   a. Does GBE rely on any IS programs for functionality, or can it function as a stand-alone project?
   b. Are there any duplicate budget items between GBE and the other IS projects?

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c. Are any of the IS investments (other than GBE) required to achieve the full benefits of GBE? If yes, identify each such investment and explain why it is required.

Response:

1. To deliver the GBE Program on time and on budget, National Grid has (i) adopted various best practices in program governance and management; (ii) selected deployment strategies and development methodologies to manage risks and improve outcomes; (iii) is implementing a new approach to change management; and (iv) retaining a third party value assurance partner to evaluate program direction and deliverables.

Program Governance and Management:

After studying the lessons learned from past IS projects at National Grid as well as accepted industry best practices, National Grid developed a framework of eight Critical Success Factors (CSFs) to ensure the successful delivery of the GBE Program. The GBE Program has been closely adhering to these CSFs since the beginning of the program and continually checks itself against them. The CSFs are:

Active Sponsors – Performance for the sponsor is linked to success of the project

- The GBE Program Steering Group includes senior executives from National Grid US and National Grid plc. The Steering Group meets periodically with the Program Sponsor to exercise oversight, including on budget and timing, over the GBE Program and to provide guidance and access to resources as required.
- A full time Program Sponsor has been appointed to lead the Program and ensure alignment and focus on strategic business priorities and outcomes.
- The Program Sponsor and Leadership Team's success is directly tied to the achievement of the GBE Program as well as budget and timing.

Carefully Managed Scope – Project scope is realistic and achievable

- High level design workshops with participation from business subject matter experts and leadership were conducted. These served to focus the GBE Program scope on business need and opportunity, tightly aligned with the business case, and supported by the business itself.
- Prior to the start of work, the GBE Program will roll out a comprehensive change control – including scope – process and educate all team members on their responsibilities in scope management process

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Clear Success Criteria – Project outcomes are clear and compelling

- Clear ambitions have been set for this program – to reduce operational risk, improve operational performance and create a flexible platform for the future.
- The program team has defined business benefits anticipated as a result of GBE as detailed in Exhibit __ (GKOP-12).
- National Grid has developed a value framework to baseline, measure and track improvements in operational performance metrics as a result of GBE.

Readied Business – An informed, engaged business is ready to successfully implement the change.

- Change management and business engagement activities will occur continuously throughout the GBE Program's lifecycle and have been planned and resourced with the same rigor as the systems delivery work streams.
- Business resources will participate in all phases of the work including design, development, testing and deployment. This will facilitate smooth handover from the GBE Program team to the business user community.

Rigorous Stage Gating – Tightly defined criteria must be met for projects to move between stages.

- Stage gating is built into GBE Program plans and management frameworks.
- The GBE Program will use a scaled agile development methodology that is performance data driven and includes regular planning workshops to evaluate progress, quality, risk and outcomes achieved.

Good Governance – Established governance groups, supported to operate effectively.

- A comprehensive GBE Program Handbook has been developed including processes, tools, templates, roles and responsibilities. The Handbook supports integrated program planning, resource and finance management, scope control, risk and issues management, commercial management, quality assurance, performance management and governance support.
- The GBE Program engages independent reviewers to provide feedback on deliverable quality, process compliance, alignment to business case and strategic business objectives and priorities.

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Well Managed Partners – The right partners/resources fit for the GBE Program, held accountable to deliver.

- A rigorous sourcing process is underway to retain highly capable consulting partners at competitive rates.
- Service levels and incentives are tied to achievement of the National Grid business benefit case and captured in contracts.
- Contracts with experienced delivery partners are being established, it is expected that these will be on a fixed price basis, supported by rigorous oversight and change control processes.
- The GBE Portfolio Office has established the capability to manage all program consulting and service contracts.

High Performing Teams – One team, the right people, highly motivated.

- The GBE Program is competitively recruiting all team members for the right mix of capabilities, skills and experience, as well as alignment with National Grid and GBE values and culture.
- Program "ways of working" are designed to foster a "badge-less, one team" culture between employees and consultants.

Attachment 1 provides a further description of the CSFs.

Deployment Strategies and Development Methodologies

The GBE Program differs from previous major implementation in that it is placing greater emphasis on upfront and continuous business engagement and alignment and has invested significant effort in ensuring that the scope and road map are aligned and supportable. This supports on time, on budget delivery by reducing unplanned scope change, facilitating timely business resource availability and handover of GBE solutions. Different from previous programs, the performance of both GBE consulting partners and the National Grid team is directly measured by success in realizing the business case. Additionally, in the past, some programs and projects did not sufficiently enable their governance and management organizations to support the size and complexity of the efforts they were supporting. National Grid is deploying a governance structure that is appropriate to the size, scale and impact of the GBE Program. The GBE Program management organization is enabled with the resources, tools and capabilities necessary to support on time, on budget delivery of the program scope of work.

To lower overall costs, reduce and manage delivery risks and accelerate the time between kick-off and deployment of functionality and capabilities to the user community, the GBE Program will deploy multiple work streams working concurrently and delivering in a phased approach based on geography and work type. Further, the program will adopt an agile deployment method based on SAFe (Scaled Agile Framework) that supports

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quicker development of initial functionality, routinely engaging the user community throughout, and providing an approach to prioritizing and delivering enhancements. The GBE Program will also leverage cloud-based industry standard solutions to support faster deployments, provide greater scalability and security, and reduce legacy infrastructure upgrades and risk of obsolescence.

Change Management

A key learning from National Grid's past experience and from discussions with peer companies is that change management must be a core program capability and must be active throughout the entire program lifecycle. Additionally, all levels of the organization must be engaged through a managed plan including communications and activities that maintain a strong link between the user community and the GBE Program. The GBE Program's phased deployment strategy breaks the level of change that users will experience into more manageable increments and reduces the likelihood of process disruptions and delays as the various phases of the program are implemented.

In some previous programs, change management tended to be regarded as more of a "back end" activity performed by a select group of change specialists focused more on educating users on solutions they were receiving rather than engaging them in the actual process of developing the solution. Additionally, business engagement tended to be more episodic and focused primarily on the employees who would be directly using the solution. The GBE Program treats change management as an essential capability and key enabler of successful program delivery. Change management activities occur continuously throughout the program lifecycle, are supported by the entire program team, and engage not only the US gas business leaders and employees but also stakeholders within the Jurisdictional teams, support organizations such as Supply Chain and Information Services, as well as other parts of the US Business.

Third Party Value Assurance

The GBE Program is planning on procuring a third party "Value Assurance" partner. Their role will be to provide ongoing independent assessment of program delivery to either provide confidence the program is on track or early warning of any changes needed to secure the desired outcomes. The Value Assurance partner will report directly to the Program Sponsor and Steering Group on their findings.

2. Attachment 2 describes the interviews with peers on similarly complex projects.

3. GBE will provide comprehensive training to all users of the system, including office and field employees at all levels in the organization. Training will be tailored to the type of employee (e.g., manager, service technician) based on the level of detail required by that type of employee. Training design will be a collaborative effort between a dedicated GBE training team and the business to ensure that the training is appropriately targeted and minimizes the disruption to business operations. The training will be delivered through various media such as computer based training, video, and classroom. In addition to pre-

Form 103

deployment training, procedures, help guides, and strategically located subject matter experts will be available following deployment.

In addition to system training, managers at all levels will be trained in change leadership beginning in October 2017. As the program progresses, leaders will be formally coached on how to lead their teams through system implementation. This approach has been shown by change experts to effectively prepare teams for the upcoming changes and minimize productivity issues. Work on the training plan and materials will commence shortly, and the initial materials will be developed over the next 3-4 months.

GBE will also be implementing a tailored approach to engage, upskill and enhance capability of the field force and front-line management to change behaviors, remove obstacles and enable change with respect to serving and interacting with customers. The timing of this training will follow the established release schedule.

4. Implementation of the GBE Program roadmap and initiatives is not expected to adversely impact delivery of the capital plan in the Rate or Data Years.

The GBE Program initiatives will deploy capabilities to support capital plan execution in the following areas:

- Deployment of a graphic work design tool and compatible unit estimating to improve the accuracy of project estimates to actual performance enabling improved planning of work and associated resources;
- Enterprise Asset Management system deployment along with new methodology and mobile tools for employee time capture, equipment assignment, and materials allocations by project with greater traceability for installed assets. Further, enhanced ability for contractors to submit invoices electronically against CU estimates with enhanced reporting capability will improve in-year budget forecasting as a result of greater transparency and accuracy with project spending.
- Increased estimate accuracy and forecasting will support capital planning activities
- Development and deployment of asset integrity management tools to support the selection and prioritization of mains as part of proactive replacement programs

As detailed in Exhibit __ (GIOP-9), the following GBE initiatives with in-service dates by the Rate and Data Years specifically support the execution of the capital plan:

- CU Governance & Library – process (in-service November 2018)
- Asset Investment Planning and Management ("AIPM") Tool – Enhancements (in-service December 2018)
- Additional Integrity Management ("IM") Modules (in-service February 2019)
- EAM-FIN Integration (in-service June 2019)
- PowerPlan Integration & Enhancements (in-service June 2020)
- Design (GWD), Estimating (CU), & Mobility (in-service September 2020)
- Construction Work & Leak Repair (in-service September 2020)
- Asset Analytics Integration (in-service December 2020)

Form 103

- GIS (GWD/CU) – Project Portfolio Management ("PPM") Integration (in-service December 2020)
- GIS-EAM Integration (in-service December 2020)
- Complex Design (CAD) & Estimating (ESW) (in-service March 2021)
- Use Case No.1 - Asset Risk (in-service March 2021)

5.

a) The GBE Program implements a suite of work and asset management systems that will assist in managing the Company's gas business. Besides feeding other systems such as the financial and asset register systems, the GBE Program does not rely on other IS programs for functionality. Please note that Attachment 1 to DPS-278 (IS-7) described certain Technology Modernization investments (RAS/VPN Re-Platform/Mobile, US Network Programme, ICE Replacement, US VSTIG Programme, US Wireless Programme) as technical changes, network upgrades, and wireless capabilities that can be leveraged for the GBE program; however, these investments are not specific requirements of the GBE Program but rather function to facilitate the future implementation of any new systems required by the business such as GBE and NY REV/grid modernization.

b) Beginning late last year, the GBE team conducted a review of all projects in the IS portfolio to determine if any IS projects overlapped with GBE initiatives. That review occurs on an ongoing basis to determine if any new projects that are proposed impact GBE. No duplicate budget items between GBE and other IS projects have been identified.

c) No other IS investments are required to achieve the full benefits of GBE.

Name of Respondent:
Christopher Murphy
John Stavrakas

Date of Reply:
July 10, 2017

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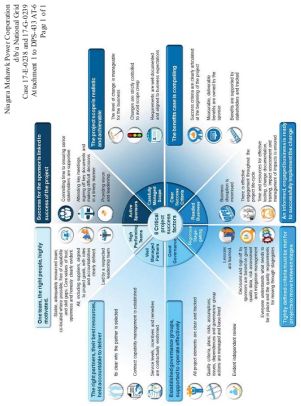
Exhibit ___ (JJ-3R)
Page 43 of 65



The National Grid Gas Business Enablement (GBE) team conferred with three peer utility companies to gain insight and lessons learned from their experiences implementing similarly complex IT projects.

These lessons learned have informed the GBE Program's development of strategy, delivery approach and methods as well as governance and management frameworks. Lessons learned and how they validated, or were incorporated into, the GBE plan are shown below.

Company	Key Lessons Learned	Impact
One Gas • 2.1M Customers over 3 states • 5 Year Maximo, CGI and Copperleaf Implementation	• Take a phased approach to implementation and use pilots • "Grow your own talent" by hiring new college graduates and letting them learn the solution from the ground up. They bring new and fresh perspectives • When working with legacy data, be careful about its quality. It can unfavorably skew analysis results • Make sure you have thought through, designed and built your initial Day 1 reporting • Don't assume that sending messages, to VP's will result in trickle down through the organization. Your change program should directly engage the impacted users • Get your change program established right up front	• The GBE roadmap is built around the concept of phased deployment of functionality and solutions with the first release serving as a pilot. Once that release is stable, functionality is progressively deployed over time • The GBE team is recruiting team members both internally and externally – based on "best fit" for the capabilities required. External hires include qualified new college graduates who are learning the solution at a fundamental level while adding value through personal capabilities, skills and perspectives. • GBE stood up a data management team at the outset of the program to evaluate legacy data quality and provide input to program plans, estimates and scope • GBE has adopted an end to end process approach that captures process and reporting requirements • GBE has developed a governance model and communication approach that engages leadership and users at all levels • Change Management has been established as a core program capability and has been actively engaged throughout
ATMOS Energy • 3M Gas Customers across 8 states • 3 Year SAP, Click, Scylo Implementation	• CEO set the tone for a culture of change management and employee engagement and common values to insure alignment between business and program • Formed a process council of business leaders that were accountable for key process design decisions to support ownership and buy-in • Addressed data cleansing from the	• US Gas Business Leadership has visibly demonstrated support of the GBE program and have actively participated in a series of events designed to engage employees at all levels and foster alignment between program and business • A Design Authority consisting of the leaders of US gas business units and key supporting functions was formed to directly engage the business in key process

Company	Key Lessons Learned	Impact
	beginning of the program and continuously throughout • Focused program scope on key processes rather than trying to fix everything at once	design decisions and to provide input on program scoping, planning and delivery activities • Data cleansing activities occur throughout the program lifecycle. Program governance and management activities insure these activities are appropriately prioritized, monitored and resourced • The GBE Program conducted a Strategic Assessment activity to define scope, business case and roadmap that aligned to business and strategic priorities
DTE Energy • 1.1M Gas customers • Implemented Maximo, CGI, and SAP in 2007	• Training needs to include the business process, not just how to operate a screen. Users need to be taught how to do their job in the new solution • At the very beginning of the program, focus on getting data hierarchies correct – they are very expensive to change later • Engaged unions early and regularly, used a quarterly "pulse check" to understand how people are feeling • Developed a strong performance management cadence including daily stand-up/Hub meeting, weekly performance calls etc.	• The GBE Program will incorporate the process / job orientation into training protocols and development standards • The GBE Integrated Program Plan will support alignment of the Data Management Team with Work Streams and Projects within the GBE Program to insure that hierarchies are developed in a timely and complete manner • GBE business engagement plans include union specific activities. An employee engagement evaluation process will be deployed- similar to a "Pulse Check" • The GBE Program participates in the US Gas Business performance cadence to further support business/program alignment. The GBE Program has a regular cadence of "Hub" and performance oriented meetings which will be expended as appropriate during mobilization. Tools and processes are being deployed to support a dynamic approach to program and project management

Date of Request: July 21, 2017 Request No. DPS-658 AT-12
Due Date: July 31, 2017 NMPC Req. No. NM-1322

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
Case No. 17-E-0238 and 17-G-0239 –
Niagara Mohawk Power Corporation d/b/a National Grid – Electric and Gas Rates

Request for Information

FROM: DPS Staff, Andy Timbrook

TO: National Grid, Gas Infrastructure & Operations Panel

SUBJECT: **CUSTOMER BENEFITS**

Request:

In this interrogatory, all requests for data, workpapers or supporting calculations should be construed as requesting any Word, Excel, or other computer spreadsheet models in original electronic format with all formulae intact.

Exhibit __(GIOP-12) lists the benefits from implementing Gas Business Enablement (GBE) for both National Grid and Niagara Mohawk. For Niagara Mohawk, does GBE provide any customer benefits that do not impact the Company's revenue requirement? If so, describe each benefit, indicate why it occurs, and explain how it will impact customers. Quantify benefits where possible.

Response:

Yes, the Gas Business Enablement (GBE) Program will deliver a number of benefits to customers that do not impact the Company's revenue requirement. These benefits include:

- Enhanced Customer Information. Increased information available to customers from the Company's call center representatives who will have more information on field activities, such as the status of customer-driven work requests or the locations of field crews. Examples of the enabling initiatives for this benefit include the Employee Support Interaction (first and second release), Customer Relationship Management (CRM)/Contact Center, and Large Commercial & Landlord Interaction initiatives described in Exhibit __ (GIOP-9);

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- Self-Serve Information. Customers will have the ability to access more information without the need to call the call centers through self-service routes, which enable quick and convenient provision of information. The Company's website and customer applications will provide this enhanced functionality. Please see capabilities for Customer Interaction (first and second release), Customer Relationship Management (CRM) / Contact Center, and Large Commercial & Landlord Interaction initiatives detailed in Exhibit __ (GIOP-9);
- Appointment Booking. An enhanced ability to book appointments for work, as appointment availability will be linked directly to resource capacity and a scheduling engine compared to the manual process today. Please see capabilities for Customer Interaction (first and second release), Employee Support Interaction, Customer Relationship Management (CRM) / Contact Center, Large Commercial & Landlord Interaction initiatives detailed in Exhibit __ (GIOP-9);
- Appointment Management. The flexibility to manage appointments either through the call center or directly through self-service channels. Because the appointments will be linked to actual availability, it will be much easier to re-schedule appointments in real-time. Please see capabilities for Customer Interaction (first and second release), CxT Portal & Channel Management, Employee Support Interaction and Customer Relationship Management (CRM) / Contact Center initiatives detailed in Exhibit __ (GIOP-9);
- Customer Notifications. Improved customer notifications from National Grid on work that is being completed, including providing the name(s) of the technician(s) performing the work. These notifications will keep customers informed of the status of work, particularly when there is an unforeseen delay, and will also provide them with enhanced security as they will know who to expect from National Grid. Please see capabilities for Customer Interaction (first & second release), CxT Portal & Channel Management, Large Commercial & Landlord Interaction, and Customer Relationship Management (CRM) / Contact Center initiatives detailed in Exhibit __ (GIOP-9); and
- Appointment Windows. Potential for more appointment windows and reduced timeframe for current 4 and 8 hour customer commitment windows through the enhanced scheduling platform. Please see capabilities for Company Driven Work: Collections and non-Appointment Offs – Gas/Electric and Customer, Leak Investigation & Inspections – Gas/Electric; Customer, Leak Investigation & Inspections – Electric) initiatives detailed in Exhibit __ (GIOP-9).

These incremental services will provide significant value for customers in the form of enhanced customer service. It is difficult to quantify the value of these benefits to customers. However, as described below, the GBE Program team has estimated that providing smaller appointment windows for Niagara Mohawk customers could be worth $7-$14M a year to them in time savings.

The estimated customer benefits are based on weighted average hourly wages ($18.11) for the counties in Upstate New York from the U.S. Bureau of Labor Statistics (2016). The analysis is based upon the number of annual electric and gas appointments/commitments for 2016:

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- Appointments Made (Electric & Gas) – 30,292
- Customer Commitments Day (8am – 4pm) – 111,419
- Customer Commitments Night (4pm – 8pm) – 47,751

The analysis highlights a customer savings of approximately $7M by adjusting the customer appointment/commitment window from 8 hours to 4 hours and approximately $14M by reducing the customer appointment/commitment window from 8 hours to 2 hours. Please refer to Attachment 1 highlighting the analysis and assumptions used to calculate the customer savings.

Name of Respondent:
Johnny Johnston

Date of Reply:
July 31, 2017

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NMPC Customer Appointment & Commitment Analysis

Scenario 1 - Move all customers appointments/commitments to 4hrs

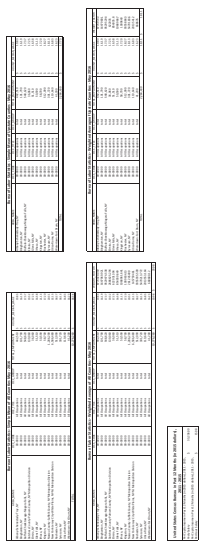
	2016 job Count (source Resource Management & Dispatch)	Appointment / Commitment Window (hrs)	Hypothetical new Appointment Windows with modern scheduling system	Customer Waiting Time saved per Appointment / Commitment	Total Hours Saved	Cost per Hour* (to the customer)	Total 'Financial Benefit' to customers due to reduced wait times
Appointments Made (Electric & Gas)	30,292	2	4	-2	(60,584)	$ 18.11	$ (1,097,353.30)
Customer Commitments Day (8am-4pm)**	111,419	8	4	4	445,676	$ 18.11	$ 8,072,494.91
Customer Commitments Night (4pm-8pm)**	47,751	4	4	0	-	$ 18.11	$ -
Total	**189,462**				**385,092**	**Total**	**$ 6,975,141.60**

* Bureau of Labor Statistics - Weighted Average of Upstate Counties - May 2016 - See Labor Rate Data Worksheet for Details
** Total customer commitments = 159,170. Assumed 70% day appointments in this analysis

Scenario 2 - Move all customers appointments/commitments to 2hrs

	2016 job Count (source Resource Management & Dispatch)	Appointment / Commitment Window (hrs)	Hypothetical new Appointment Windows with modern scheduling system	Customer Waiting Time saved per Appointment / Commitment	Total Hours Saved	Cost per Hour* (to the customer)	Total 'Financial Benefit' to customers due to reduced wait times
Appointments Made (Electric & Gas)	30,292	2	2	0	-	$ 18.11	$ -
Customer Commitments Day (8am-4pm)**	111,419	8	2	6	668,514	$ 18.11	$ 12,108,742.36
Customer Commitments Night (4pm-8pm)**	47,751	4	2	2	95,502	$ 18.11	$ 1,729,820.34
Total	**189,462**				**764,016**	**Total**	**$ 13,838,562.70**

* Bureau of Labor Statistics - Weighted Average of Upstate Counties - May 2016 - See Labor Rate Data Worksheet for Details
** Total customer commitments = 159,170. Assumed 70% day appointments in this analysis



Entity	Link
US Census Bureau	https://www.census.gov/quickfacts/fact/map/NY/INC910215#viewtop
Bureau Of Labor Statistics	https://www.bls.gov/oes/current/oes_ny.htm
Bureau Of Labor Statistics	https://www.bls.gov/oes/current/oes_3600001.htm
Bureau Of Labor Statistics	https://www.bls.gov/oes/current/msa_def.htm#3600001

UNY Elec CY16 Meter Changes													
Category	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	CY16 Total
Meter Change - Capital Total	1,684	1,717	1,823	2,147	1,429	1,344	1,083	1,359	1,497	1,721	1,346	1,485	**18,635**
Meter Change - O&M Total	58	15	12	21	6	13	8	9	16	31	18	20	**227**
Total UNY Elec	**1,742**	**1,732**	**1,835**	**2,168**	**1,435**	**1,357**	**1,091**	**1,368**	**1,513**	**1,752**	**1,364**	**1,505**	**18,862**

UNY Gas CY16 Meter Changes													
Category	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	CY16 Total
Meter Change - Capital Total	1,516	1,670	1,484	2,037	2,000	1,153	686	1,506	1,120	1,105	1,246	1,204	**16,727**
Meter Change - O&M Total	138	99	186	253	221	198	145	178	154	217	204	244	**2,237**
Total UNY Gas	**1,654**	**1,769**	**1,670**	**2,290**	**2,221**	**1,351**	**831**	**1,684**	**1,274**	**1,322**	**1,450**	**1,448**	**18,964**

UNY CY16 Meter Changes													
Category	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	CY16 Total
Meter Change - Capital Total	3,200	3,387	3,307	4,184	3,429	2,497	1,769	2,865	2,617	2,826	2,592	2,689	**35,362**
Meter Change - O&M Total	196	114	198	274	227	211	153	187	170	248	222	264	**2,464**
Total UNY Gas	**3,396**	**3,501**	**3,505**	**4,458**	**3,656**	**2,708**	**1,922**	**3,052**	**2,787**	**3,074**	**2,814**	**2,953**	**37,826**

	Appointments - 2016													
INDICATOR	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	YTD Total	YTD Avg
Appointments made	2,083	2,353	2,332	2,721	2,693	2,738	2,115	2,364	2,673	2,958	2,671	2,185	**30,293**	**2,524**
Appointments kept	2,008	2,274	2,274	2,702	2,696	2,671	2,053	2,326	2,647	2,865	2,629	2,149	29,983	**2,499**
Met Goal ?	96%	Yes	98%	Yes	100%	Yes	97%	Yes	99%	97%	98%	98%	99%	99%

Month Name	Year	Appointment Renegotiated	Count - Other Orders Completed	Count - Other Orders UTC	Count - Elec and Gas WrkOrders	Count - Electric Orders Completed	Count - Electric Orders UTC	Count - Gas Orders Completed	Count - Gas Orders UTC	# Early Appointments	# Late Appointments	# On Time Appointments	# Total Appointments
JAN	2016	N	38	9	641	345	89	726	143	5	8	1978	1991
JAN	2016	Y	0	0	21	21	1	49	0	0	2	90	92
FEB	2016	N	44	3	686	428	89	758	110	6	21	2091	2118
FEB	2016	Y	1	0	24	18	0	40	2	0	2	83	85
MAR	2016	N	82	9	711	449	98	754	133	14	25	2197	2236
MAR	2016	Y	4	0	32	25	2	33	0	1	0	95	96
APR	2016	N	48	4	861	462	78	1,055	130	12	11	2615	2638
APR	2016	Y	2	0	26	22	0	32	1	0	0	83	83
MAY	2016	N	46	0	998	453	82	893	117	5	19	2565	2589
MAY	2016	Y	1	0	40	21	2	41	4	0	1	108	109
JUN	2016	N	69	8	1,113	513	81	748	107	6	14	2619	2639
JUN	2016	Y	3	0	48	20	4	23	1	0	1	98	99
JUL	2016	N	39	3	1,007	439	74	409	71	8	11	2023	2042
JUL	2016	Y	2	0	26	16	4	23	2	1	0	72	73
AUG	2016	N	50	4	1,238	559	91	796	143	8	19	2854	2881
AUG	2016	Y	0	0	37	15	1	30	0	1	0	82	83
SEP	2016	N	47	2	1,091	508	97	721	122	7	19	2562	2588
SEP	2016	Y	1	0	36	16	1	31	0	0	0	85	85
OCT	2016	N	55	3	1,032	497	100	976	139	8	31	2763	2802
OCT	2016	Y	0	1	32	21	3	46	2	0	0	105	105
NOV	2016	N	68	5	952	487	107	807	149	9	31	2535	2575
NOV	2016	Y	1	0	27	27	3	35	3	0	2	94	96
DEC	2016	N	52	4	760	434	101	623	113	15	22	2050	2087
DEC	2016	Y	2	0	28	15	3	46	6	0	1	99	100
2016			655	55	11,467	5,811	1,111	9,695	1,498			29,946	30,292
TOTALS			Total Other =	710		Total Elec =	6,922	Total Gas =	11,193				

Date of Request: August 14, 2017 Request No. DPS-730 AAM-45
Due Date: August 24, 2017 NMPC Req. No. NM-1623

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
Case No. 17-E-0238 and 17-G-0239 –
Niagara Mohawk Power Corporation d/b/a National Grid – Electric and Gas Rates

Request for Information

FROM: DPS Staff, Allison Manz

TO: National Grid, Information Services Panel

SUBJECT: **IS**

Request:

In these interrogatories, all requests for workpapers or supporting calculations should be construed as requesting any Word, Excel, or other computer spreadsheet models in original electronic format with all formulae intact.

Provide the FY18 IS budget and year to date spending, by project, by month.

Response:

Please see Attachment 1 for the FY18 project budget and year to date spending. Please note that the Company provided a more refined view of IS project costs in its response to DPS-501 (AAM-23) that filtered out projects that do not allocate costs to Niagara Mohawk, and new demand that was not included in the Company's base rate case filing. The Company's response also adjusted accounting entries for projects that were completed prior to FY18. For FY18, IS project spending is ramping up slowly, which is normal for the start of a fiscal year for IS projects, as the start of a year is typically spent preparing sanction requests and requirements to get projects sanctioned prior to incurring significant project spending towards the end of the fiscal year. IS's current focus on efforts to bring project management in-house has also resulted in a slow ramp up of FY18 spend on projects with a variance to budget that the Company fully expects will be eliminated by fiscal year end. There are seven projects that make up the vast majority of the $17.8 million YTD variance to budget

- $5M - Customer Contact Center

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- The contract for services is currently being finalized with the vendor. The Company has opted not to purchase software and instead will be implementing a Software as a Service arrangement (SaaS). This reduced the early year capital spend forecast, and shifted some of those costs to RTB (expense). Additional scope items are being evaluated for inclusion in the project. This will impact the overall capital requirement, and will be finalized as part of the contract finalization.

- $3M - CNI SCADA Upgrade
  - The SCADA Program is scheduled to receive a full sanction in October 2017 and capital expenditures will ramp up after that point. The FY18 budget for this project also reflects milestone payments scheduled for later in the year. .
- $2M - Future Cyber Program (Cyber Security 2 Program)
  - The first quarter costs were lower than budget as a result of the need to finalize design and resource requirements prior to the sanctioning of various projects under the Future Cyber Security Program (INVP 3683). As each project released under the Future program is sanctioned, spending will begin to ramp up in the next fiscal quarter and, overall, program costs are expected to be incurred in line with the program sanction amounts.
- $2M - Document Management System Replacement
  - Delays in the required procurement and establishment of the server environment have occurred. Capital expenditures are expected to ultimately align with the year to date budget upon resolution of the delays.
- $2M - Regulatory Mandates
  - There are a number of new mandates where requirements are currently being determined and project spending is expected to ramp up in the second half of the year.
- $1M - Data Visualization Program
  - The project has experienced a delay with Verizon in establishing connectivity. Capital expenditures are expected to ultimately align with the year to date budget upon resolution of the delay.
- $1M - Storms / iScheduler
  - The project has experienced a delay for DXC, National Grid's infrastructure vendor partner, to build the necessary infrastructure to support the build and test phases resulting in an impact to planned spending. This delay also impacted the fixed milestone payments to CGI, the vendor that owns and supports STORMS/iScheduler. As a result, build and test spend is expected to be incurred in the next fiscal quarter. National Grid anticipates that the project will meet its timeline despite the delays.

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Name of Respondent:
Alex Likerman
Thomas Gill

Date of Reply:
August 24, 2017

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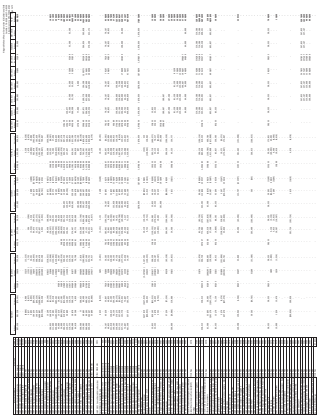
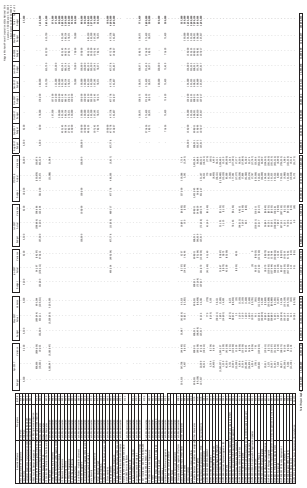
Exhibit ___ (JJ-3R)
Page 58 of 65





Date of Request: July 27, 2017
Due Date: August 7, 2017

Request No. DPS-689 AT-15
NMPC Req. No. NM-1361

NIAGARA MOHAWK POWER CORPORATION d/b/a NATIONAL GRID
Case No. 17-E-0238 and 17-G-0239 –
Niagara Mohawk Power Corporation d/b/a National Grid – Electric and Gas Rates

Request for Information

FROM: DPS Staff, Andy Timbrook

TO: National Grid, Gas Infrastructure and Operations Panel

SUBJECT: **GAS BUSINESS ENABLEMENT (GBE)**

Request:

In this interrogatory, all requests for data, workpapers or supporting calculations should be construed as requesting any Word, Excel, or other computer spreadsheet models in original electronic format with all formulae intact.

The alternatives considered for the GBE program are shown in Slide 36, Attachment 9 to your response to DPS-275. With reference to that response:

1. Provide a description of each alternative. Include the project scope (e.g., what would be replaced, how it would be replaced, and with what new programs and in what timeframe it would be replaced) and identify how well the alternative met the following GBE needs and objectives:
   a. Platform Consolidation;
   b. Regulatory Compliance;
   c. Workforce/Asset Management;
   d. Customer Service Improvements; and
   e. Training

For the alternatives that were not selected, explain why not and how far along in development the rejected alternative had proceeded, in terms of cost estimation and implementation schedule

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as compared to the selected alternative, before the decision was made not to continue with the rejected alternative.

Response:

Below is a brief summary of each of the options considered on Slide 36, Attachment 9 of DPS-275:

Option 1: Tech Stabilization

Description: The Tech Stabilization option would extend the life of National Grid's current systems by 1) sourcing incremental system support, where available, for the systems that are no longer fully supported; and 2) updating the supporting infrastructure and devices, where possible.

Project Scope: No existing systems would be replaced. This option would involve a number of tactical investments.

Delivery/Time Frame: This would be on-going until the systems are ultimately replaced.

Reasons Rejected: The Tech Stabilization option would have a limited positive impact on system down time due to the overall age of the current systems, which limits the availability of support and upgrade infrastructure. There are no further anticipated benefits with this option. This option would further defer the necessary investments to upgrade/replace near obsolete and unsupported systems and, therefore, would not be a sustainable solution. For the above-mentioned reasons, the Tech Stabilization option was rejected early in the strategic assessment in August 2016 and only a high level cost estimate and implementation schedule were developed.

Option 2: Like for Like Replacements

Description: This option provides the minimum required investment to upgrade or replace current core unsupported and aging IS systems to modern, supported equivalents with no focus on enhancing capability.

Project Scope/Delivery: The main solutions that would be upgraded or replaced for Niagara Mohawk include Mwork and Storms for work delivery, iScheduler for scheduling, Gas Asset Management System ("GAMS") for asset management and engineering.

Delivery/Time Frame: This option would be delivered over at least four years using waterfall techniques where a solution is not delivered until all business requirements have been designed and developed.

Reasons Rejected: This option would be a pure technology remediation project and would not look to align processes, increase integration between systems, or address the broader challenges and opportunities that Niagara Mohawk's gas business faces. There would be a moderate improvement to application availability, but limited other improvements. Specifically, this option would not address performance improvements in gas safety and compliance that require

process improvements, systems integration, technical training and data improvements. As a result, this option was rejected early in the strategic assessment in August 2016 and only a high level cost estimate and implementation schedule were developed.

Option 3: Backbone

Description: This option is the minimum required investment to address the system requirements to support performance improvements in gas safety and compliance and mitigate key risk. It should be noted that this option does not address all elements in these areas nor does it enable many of the improvement opportunities, but it would improve system downtime and data sharing between teams and enable more consistent reporting.

Project Scope: The Backbone option would focus on replacing the multiple legacy work and asset management systems with a core enterprise work and asset management system (EAM). It would deliver process, integration and capability improvements limited to the work and asset management systems. The main solutions upgraded or replaced for Niagara Mohawk would be Mwork, Storms, Public Building, and Cascade (gas) for work delivery; iScheduler for resource scheduling; GAMS, Meter Inventory Tracking System ("MITS"), Pictometry, MapFrame, and Gas Leak Tracking for asset management and engineering; Fortis for document management; and Smallworld for GIS. The legacy systems will be replaced with Maximo for work and asset management, ESRI for GIS, and a Scheduling/Dispatch/Mobile application.

Delivery/Time Frame: The backbone only option would be implemented over 3.5 years using the more traditional waterfall implementation method on premise (*i.e.*, no Software as a Service or cloud solutions).

Reasons Rejected: The backbone option would be a largely focused on technology implementation. Specifically, it would not fully address performance improvements in gas safety and compliance that require behavioral/technical training, data improvements, such as mapping of services that are on paper today, and the focus on change management to support the organization through the implementation. As discussed in the Company's response to DPS-660, the backbone only option also does not provide the call center with visibility to work or the customer experience elements. It also does not fully integrate asset management and work management solutions including supporting graphical electronic data capture (*i.e.*, red lining) in the field. Other capabilities that would not be delivered include advanced analytics for work and asset management, supply chain solutions, and strategic change, which help to mitigate operational and technical risk of implementation. With the reduced focus on the operating model and change management, it is anticipated that any financial benefits would be offset by inefficient and inconsistent use of the new systems. A timeline and costs (leveraging some input from Accenture's model) were developed for this option but it was ultimately rejected by the Steering Group in December 2016 for the reasons noted above.

Option 4: Value Oriented – Jurisdiction Deployment

Description: This option was selected as the minimum required investment to address the risk of the legacy systems and performance improvements in gas pipeline safety and compliance, provide improvements in business performance and enhancements in the customer experience,

and create a platform for the future. Specifically, the Value Oriented – Jurisdiction Deployment includes the scope of Option 3 (Backbone) with additional enhanced capabilities such as:

- advanced asset management capabilities to enable graphical work design and electronic field data capture. This will improve record accuracy and increase the speed to update maps with new assets. It also will link the EAM to an Asset Investment Planning and Management (AIPM) tool to enable prioritizing asset investments across a number of criteria including risk as discussed in the Company's response to EDF-1(NK-4);
- advanced work management capabilities that include integrating resource management and planning to improve the effectiveness and efficiency of delivered work;
- a customer interaction layer that places the front line employee, dispatch, the call center and ultimately the customer on the same platform to provide visibility of the work to all stakeholders and enable customers the flexibility to book, move and get information on appointments using their preferred communication channel. This also includes a new call center front end so that customer representatives have visibility to the work in the field;
- change management capabilities reflecting lessons learned from past programs and industry best practice that (1) are delivered throughout the program lifecycle; (2) engage users in the actual process of developing the solution; and (3) involve support from the program team, business leadership, and support organizations such as Supply Chain and Information Services;
- field training via multiple media (including mobile) to improve employees' technical skills and simplify work methods resulting in enhanced field employees' capabilities to consistently deliver work safely for customers, follow the correct procedures and record the required information correctly;
- supply chain integration to the EAM to improve effectiveness of the supply chain in supporting capital project delivery;
- automated testing capabilities that would enable agile development techniques; and
- cloud and SaaS solutions where available to move this solutions onto modern platforms that will make it easier for the Company to keep the solutions up-to-date and supported against the latest cyber security threats.

Project Scope: The main solutions to be upgraded or replaced for Niagara Mohawk include Mwork, Storms, Public Building, and Cascade (gas) for work delivery; iScheduler for resource scheduling; GAMS, MITS, Pictometry, MapFrame, and Gas Leak Tracking for asset management and engineering; Fortis for document management; Smallworld for GIS; and CSS for call center terminals only. The solutions will be replaced with integrated versions of Maximo for work and asset management, Copperleaf for asset investment planning and management, ESRI for GIS and Salesforce for scheduling, dispatch, mobility, call center terminals and customer interaction.

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Delivery/Time Frame: The Value Oriented – Jurisdiction Deployment option will be delivered using predominately cloud solutions and hybrid agile development techniques over 5 years. Under the agile development methodology, business and IS development 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 reprioritizaiton of enhancemenets based on learning. It should be noted that despite the overall longer five year implementation timeframe for the enhanced capabilities in this option, implementation of the enhanced capabilities will not extend the 3.5 year timeframe of the backbone capabilities as the focus remains on risk prioritized replacement of the core systems.

Reasons Selected: This option would be a broader transformation project focused on people, process and technology designed to address gas pipeline safety and compliance, customer experience and improved business performance. Solutions will be developed on a modern technical architecture to support the business for a long period of time. Approximately $39M a year in measurable benefits would be realized, as detailed in Exhibit __ (GIOP-12), page 1, once the solutions are fully embedded, including Type I savings to Niagara Mohawk as shown on Exhibit __ (GIOP-12), page 2. Additional customer benefits that do not impact the Company's revenue requirements, including saving customers time by increasing the number and reducing the length of appointment windows, are discussed in detail in the Company's response to DPS-658.

This was the minimum cost solution to deliver the desired program outcomes. For all of the above-mentioned reasons, this option was recommended by the Steering Group in December 2016, and includes most refined timeline and cost modeling, as reflected in the Company's responses to DPS-431 and DPS-654. Importantly, National Grid did look at developing the solutions independently for each operating company, rather than consolidated as an enterprise-wide solution, but ruled it out as it was more costly (requiring duplicative design, development and testing of core functionality) than doing an enterprise-wide solution with individual releases across the operating companies as functionality is demonstrated.

Option 5: Value Oriented – Accelerated Deployment

Description/Project Scope/Delivery/Time Frame: The Value Oriented – Accelerated Deployment looked to implement the same scope as Option 4, but on an accelerated implementation timeframe for four and a half years.

Reasons Rejected: Accelerated deployment increased delivery costs as well as implementation risks. This option was further developed similar to Option 4 in terms of timeline and costs utilizing the detailed cost model developed with Accenture. However, the option was ultimately rejected by the Steering Group in December 2016 given the higher delivery costs, implementation risk, and recognition that implementation of a complex program such as GBE requires a measured approach, allowing sufficient time for comprehensive change management and system/regression testing.

The following summary table depicts how each of the options meet each of the GBE objectives of platform consolidation, regulatory compliance, workforce/asset management, customer

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service improvements and training discussed in detail above. Red circles (R) denote that the objective is not met by the option, amber (A) that they are partially met and green (G) that they are fully met.

	Platform Consolidation	Regulatory Compliance	Workforce/ Asset Management	Customer Service Improvements	Training
Option 1: Tech Stabilization	R	R	R	R	R
Option 2: Like for Like Replacements	R	R	A	R	R
Option 3: Backbone	G	A	G	R	R
Option 4: Value Oriented – Jurisdiction Deployment	G	G	G	G	G
Option 5: Value Oriented – Accelerated Deployment	G	G	G	G	G

Name of Respondent:
Johnny Johnston

Date of Reply:
August 7, 2017

Form 103

Information Request AG-21-3

Request:

Please provide the curriculum vitae for Reihaneh Irani-Famili.

Response:

Please see Attachment AG-21-3-1 for the Curriculum Vitae of Mrs. Irani-Famili.

Prepared by or under the supervision of: Anthony H. Johnston and Reihaneh Irani-Famili

Boston Gas Company and Colonial Gas Company
each d/b/a National Grid
D.P.U. 17-170
Information Request AG-21-4
March 12, 2018
H.O. Pieper
Page 1 of 1

Information Request AG-21-4

Request:

Referring to page 4 of Exhibit NG-GBE-1, where Ms. Irani-Famili states that she not previously testified before a regulatory commission. Please provide copies of any and all testimony, affidavits, exhibits, attachments, and any other evidence provided, submitted, or sponsored by Reihaneh Irani-Famili in any court or other adjudicatory proceeding, arbitration, mediation, or other forum for dispute resolution.

Response:

Mrs. Irani-Famili has not provided testimony, affidavits or exhibits in any other proceeding.

Prepared by or under the supervision of: Anthony H. Johnston and Reihaneh Irani-Famili

Boston Gas Company and Colonial Gas Company
each d/b/a National Grid
D.P.U. 17-170
Information Request AG-21-5
March 15, 2018
H.O. Pieper

Information Request AG-21-5

Request:

Please provide copies of any and all testimony, affidavits, exhibits, attachments, and any other evidence concerning the GBE Program submitted by the Company in any court or other adjudicatory proceeding, regulatory proceeding or docket, or arbitration, mediation, or other forum for dispute resolution.

Response:

Please see Attachment AG 21-5-1 for the GBE Program testimony and exhibits submitted in Rhode Island on November 27, 2017. Please refer to Attachments AG 21-2-7 and AG 21-2-8 for Gas Business Enablement Program related testimony and exhibits filed in New York.

Prepared by or under the supervision of: Anthony H. Johnston and Reihaneh Irani-Famili

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket No. 4770
Witnesses: Johnston and Connolly

JOINT PRE-FILED DIRECT TESTIMONY

OF

ANTHONY H. JOHNSTON

AND

CHRISTOPHER J. CONNOLLY

Dated: November 27, 2017

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket No. 4770
Witnesses: Johnston and Connolly

SUMMARY

Anthony H. Johnston is the Senior Vice President overseeing the design, development, and delivery of the National Grid's multi-year, enterprise-wide, gas-business program, referred to as the Gas Business Enablement Program, and its anticipated benefits. Christopher J. Connolly is the Vice President of Process and Business Requirements for the Gas Business Enablement Program overseeing the development of standard business processes and the implementation of Gas Business Enablement capabilities across National Grid's gas and electric distribution operations. Specifically, their joint testimony presents an overview of the Gas Business Enablement Program and the Company's proposal for associated cost recovery.

THE NARRAGANSETT ELECTRIC COMPANY
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I. Introduction

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

A. My name is Anthony H. 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 National Grid USA Service Company, Inc. (the Service Company), a subsidiary of National Grid USA (National Grid). Effective April 1, 2016, I was appointed Senior Vice President for National Grid's Gas Business Enablement Program. In this role, I am accountable for the design, development, and delivery of the Gas Business Enablement Program and its anticipated benefits.

Q. Please describe your educational background and professional experience.

A. I earned a Master of Engineering Science from Oxford University in 2002 and a Master of Business Administration from Cranfield University in 2006. I am also a Chartered Professional Engineer. I started with National Grid in 1997 and have held a number of technical positions in system operations and network design, based in the United Kingdom. I subsequently moved to the United States to join GridAmerica LLC, a wholly-owned subsidiary of National Grid based in Cleveland, Ohio, where I was engaged in transmission planning. In 2006, I returned to the United Kingdom to work in National Grid's U.K. gas distribution business, where I was responsible for network design, including renewable gas projects. In 2010, I was promoted to the position of Vice

President of Customer Operations. In this role, I had responsibility for the gas call centers, resource planning, and dispatch and mapping teams. Beginning in 2012, I served as Chief of Staff for the Company's former global Chief Executive Officer, Steve Holliday.

In 2014, I relocated to the United States as the Vice President of Customer Meter Services, where I had responsibility for more than 2,400 personnel supporting National Grid's electric and gas distribution businesses in the United States. With respect to the Rhode Island gas business, I had oversight responsibility for all field service personnel providing gas emergency response, meter-related activities (including meter installation and removal), meter reading, bill investigations, collections, and other field operations related to billing. I was also responsible for overseeing the gas dispatch centers. I held this role until assuming my current position in April 2016.

Q. Have you previously testified before any regulatory commissions?

A. Yes. I submitted pre-filed testimony to the New York Public Service Commission in the 2016 KeySpan Energy Delivery NY[1] and KeySpan Energy Delivery Long Island[2] Rate Case 16-G-0058 and 16-G-0059 and the 2017 Niagara Mohawk Power Corporation Rate Case 17-E-0238 and 17-G-0239. Most recently, I submitted pre-filed direct testimony to

[1] The Brooklyn Union Gas Company d/b/a National Grid NY (formerly d/b/a KeySpan Energy Delivery New York) (KeySpan Energy Delivery New York).
[2] KeySpan Gas East Corporation d/b/a National Grid (formerly d/b/a KeySpan Energy Delivery Long Island) (KeySpan Energy Delivery Long Island).

the Massachusetts Department of Public Utilities in the 2017 Boston Gas Company and Colonial Gas Company, each d/b/a National Grid Rate Case Docket No. D.P.U. 17-170.

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

A. My name is Christopher J. Connolly. My business address is 404 Wyman Street, Waltham, Massachusetts 02451.

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

A. I am employed by the Service Company as Vice President of Process and Business Requirements for the Gas Business Enablement Program. In this role, I am responsible for developing standard business processes across the operating companies and the implementation of capabilities in the new solutions driven from business requirements that will support enhanced customer satisfaction, improved safety and compliance performance, and enhanced employee engagement.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science in Mechanical Engineering Technology from Northeastern University in 1999. I have worked in the energy industry for approximately 19 years in various capacities, first as a contract engineer for DistriGas of Massachusetts Corporation beginning in June 1998 until October 1999 when I joined Boston Gas Company. From October 1999 through October 2001, I held various engineering and operations supervisory roles at Boston Gas Company including oversight for gas system

relocation and infrastructure modernization activities associated with Boston's Central Artery Tunnel "Big Dig" Project. Following its acquisition of Boston Gas Company in 2001, I continued my tenure in operations with KeySpan Corporation from 2001 to 2007 with responsibility for the design and execution of complex construction projects across KeySpan Corporation's New England service territory in Massachusetts and New Hampshire. In 2007, when National Grid acquired KeySpan Corporation, through 2016, I held a number of end-to-end process focused-leadership positions of increasing responsibility within gas engineering and operations. I co-led the development of the Process Excellence Organization in 2013 through 2015, during which time I assembled a process-focused stakeholder team responsible for identifying improvements in safe and reliable gas system operations while ensuring compliance across all jurisdictions. Further, I directed enterprise-wide engineering teams advancing complex engineering, capital work plan strategies, public works projects coordination, and gas growth analysis. In addition, the teams I supervised supported the safe and reliable execution of the gas capital work plan and provided engineering support during emergencies. From February 2015 through July 2015, I took on the role of Acting Vice President of Gas Systems Engineering and subsequently the role of Director, Gas Project Development from August 2015 through April 2016. I was named to my current position on May 1, 2016.

Q. Have you previously testified before any regulatory commissions?

A. I have testified before the Massachusetts Energy Facilities Siting Board on behalf of Colonial Gas Company d/b/a National Grid in support of its petition for approval to

replace 25 miles of high pressure distribution assets located on Cape Cod, Massachusetts in Docket No. EFSB 16-01.

Q. Would you please explain the naming conventions that you will be using in your testimony and associated schedules to identify the various entities involved in this proceeding?

A. Certainly. This proceeding is a ratemaking proceeding for the electric and gas distribution operations of The Narragansett Electric Company, which constitute the regulated operations that National Grid conducts in Rhode Island. In this case, we will refer to the regulated entity as the "Company," where the reference is to both electric and gas distribution operations on a collective basis. Where there is a need to refer to the "stand-alone" or individual electric or gas operations of The Narragansett Electric Company, we will use the terms "Narragansett Electric" or "Narragansett Gas," respectively, as appropriate. Where we refer to "National Grid USA", we will use the term "National Grid"; where we refer to "National Grid plc," we will use that specific term.

Q. What is the purpose of this joint testimony?

A. The purpose of this joint testimony is to present an overview of National Grid's multi-year, enterprise-wide, gas-business program referred to as the Gas Business Enablement Program, as well as the Company's proposal for associated cost recovery. The Gas Business Enablement Program will implement three, inter-related, core operating

capabilities (Work Management, Asset Management, and Customer Enablement) necessary to support National Grid's U.S. gas distribution business. National Grid estimates that it currently relies on approximately 117 sub-systems, applications, databases, or spreadsheet systems across the U.S. gas business to perform the work processes that support these capabilities. With full implementation, this number will be reduced by over 75 percent to less than 30 systems, sub-systems, and/or applications across six gas distribution companies operating in three jurisdictions (Rhode Island, Massachusetts, and New York). In Rhode Island specifically, National Grid estimates that implementation of the Gas Business Enablement Program will reduce the number of systems, applications, databases, and spreadsheet systems from 37 to 19. Schedule GBE-1 shows an illustrative view of the current and future state of these systems, applications, and databases.

The Gas Business Enablement Program will accomplish a number of important, customer-focused objectives. From a functional perspective, the Gas Business Enablement Program will streamline processes and create a single set of integrated applications for core operating systems, significantly improving the ability of employees to perform their job functions effectively. The Gas Business Enablement Program is also designed to improve National Grid's U.S. operating companies' ability to achieve and maintain compliance with state and federal regulatory requirements across all three jurisdictions by improving work management and the flow of information necessary for compliance. However, at its heart, the Gas Business Enablement Program is aimed at

improving the customer experience to meet the relatively high customer expectations that exist in today's operating environment, and which are simply not possible to meet using today's operating processes. Fundamentally, the implementation of Gas Business Enablement will improve the Company's ability to provide safe, reliable, and cost-effective delivery of natural gas to its customers. In addition, for certain business functions that have shared responsibilities across Narragansett Gas and Narragansett Electric, such as Customer Meter Services, Dispatch and Scheduling, and the Customer Contact Center, standardized processes and new solutions will be implemented through Gas Business Enablement to support electric customers.

For reasons that we will discuss in this joint testimony, implementation of the Gas Business Enablement Program represents a critical step-change in National Grid's operating platform that will require substantial investment across all three operating jurisdictions over a multi-year period (*i.e.*, annually through Fiscal Year 2023). Because the annual cost of capital investment by the Service Company is charged to its operating affiliates as expense, recovering the incremental expense change in each year of the Gas Business Enablement Program implementation will be necessary to support the program. Accordingly, this testimony is designed to: (1) provide the Rhode Island Public Utilities Commission (PUC) with detailed information about the Gas Business Enablement Program and the reasons for its implementation; and (2) support the Company's request for recovery of the reasonable and prudently incurred costs of making a step-change improvement for the direct benefit of customers.

Q. Why is it necessary for the PUC to consider allowing cost recovery for the Gas Business Enablement Program in this proceeding?

A. The total anticipated investment in Gas Business Enablement is approximately $478.3 million across the U.S. gas distribution business, which involves three operating jurisdictions – Rhode Island, Massachusetts, and New York – serving 3.5 million gas customers. Gas Business Enablement will be implemented in stages starting with Rhode Island, followed by Massachusetts, then followed by Niagara Mohawk Power Corporation in upstate New York, and finishing with KeySpan Energy Delivery Long Island and KeySpan Energy Delivery New York in downstate New York.

For the Rhode Island component, the estimated investment of $38.5 million for Narragansett Gas and $5.0 million for Narragansett Electric will take place beginning in Fiscal Year 2017 and continuing through Fiscal Year 2023. To accomplish implementation, National Grid will incur both capital costs and operating and maintenance (O&M) expense in each year of the program. The incremental annual cost will be significant, but will be commensurate with the value gained by customers in relation to gas safety, reliability, service, and efficiency. For example, in Rhode Island, the incremental annual expense associated with the Gas Business Enablement Program during the implementation period is projected as follows:

Fiscal Year (FY) Period	Revenue Requirements for Capital Costs	O&M (Gas)	Estimated Total Annual Expense Charged to the Company
FY 2017		$1,176,955	$1,176,955
FY 2018	$66,415 (Gas) $26,083 (Electric)	$1,284,801	$1,315,216
FY 2019	$1,830,808 (Gas) $472,309 (Electric)	$3,943,863	$5,774,671
FY 2020	$2,416,340 (Gas) $634,322 (Electric)	$2,282,372	$4,698,712
FY 2021	$3,223,587 (Gas) $578,931 (Electric)	$1,128,389	$4,351,976
	TOTAL ANNUAL EXPENSE – (2017-2021)		$17,317,530

Given the ramp-up of annual expense as the Gas Business Enablement Program is implemented, it will be difficult to set a representative level of expense in base distribution rates without either locking in an annual amount that (1) is at the highpoint and inordinately large as a line item in the revenue requirement (in Fiscal Year 2019, approximately $5.7 million for Narragansett Gas and approximately $0.5 million for Narragansett Electric), thereby imposing rate recovery on customers that is not aligned with actual program costs, or (2) understates and broadly under-collects the investment made in the Gas Business Enablement Program. Moreover, program implementation (and the associated cost) is scheduled to commence in 2018, while this case is pending before the PUC, making it difficult to capture costs in the related rate decision.

Given the overriding fact that the Gas Business Enablement Program is a unique, transformative initiative providing direct and tangible benefits to customers, consideration of the Gas Business Enablement Program costs in this docket is warranted

and appropriate because: (1) the Gas Business Enablement Program involves the replacement of systems that support three major, core operating capabilities on an integrated, rather than sequential, basis, because it is cost-effective to take this approach; (2) the Gas Business Enablement Program extends across six gas and four electric distribution companies operating in three jurisdictions, with differing timelines for rate cases and rate-recovery mechanisms in each jurisdiction; and (3) program implementation spans a relatively extended timeline of up to five years with substantial incremental expense in each year.

As discussed below, the development of work management, asset management, and customer-enablement capabilities reorganized onto a single, operating platform is critically needed due to the fact that the current systems, sub-systems, and/or applications currently supporting National Grid's U.S. gas business are difficult for employees to navigate, are in many cases no longer supported by vendors, or are otherwise unsuitable to support gas operations into the future. Implementation of the systems within the Gas Business Enablement Program on an integrated basis in all three jurisdictions to establish the three major capabilities will cost customers less than implementing the same systems one at a time by jurisdiction because it will avoid costs that would arise with work completed on differing timelines, with potentially differing vendors. For these reasons, it is imperative that the Company obtain revenue support for the Gas Business Enablement Program in this case to be able to continue implementation in Rhode Island, which will

ensure customers will receive improved safe and reliable gas service with significantly improved customer service.

Q. Are you presenting any schedules in addition to this joint testimony in support of the Company's request relating to the Gas Business Enablement Program?

A. Yes. In addition to this joint testimony, we are sponsoring the following schedules in support of the Company's request for cost recovery for the Gas Business Enablement Program:

Schedule Designation	Description
Schedule GBE-1	Depiction of Current and Future State Systems in Rhode Island
Schedule GBE-2	Key Initiatives By Gas Business Enablement Workstream
Schedule GBE-3	Gas Business Enablement Corporate Governance Structure
Schedule GBE-4	Gas Business Enablement Roadmap
Schedule GBE-5	Example of Gas Operations Capabilities with Gas Business Enablement
Schedule GBE-6	Example of Customer Experience Capabilities with Gas Business Enablement

Q. How is your testimony organized?

A. Section I of this testimony is the Introduction. Section II discusses the operating challenges that are creating the imperative for development and execution of the Gas Business Enablement Program. Section III discusses the Gas Business Enablement Program governance structure and procurement process to assure program costs are reasonable and prudently incurred. Section IV describes the process changes that will result from program implementation and identifies the efficiency improvements and customer benefits that will result from program implementation. Section V reviews the Company's proposal for cost recovery to support program implementation.

II. Imperative for Development of the Gas Business Enablement Program

Q. What is the genesis of the Gas Business Enablement Program?

A. In the course of day-to-day operations, employees are facing substantial challenges in scheduling and completing work, communicating both externally and internally regarding customer service needs, capturing and accessing data necessary for the various business processes, and discerning whether, when, and how work is getting done. These challenges arise from the fact that employees must navigate numerous, disparate, inefficient, and/or manual systems and processes within the gas distribution business to perform critical functions for gas operations and to provide quality field service to gas customers. In Rhode Island, this state of affairs has made it difficult to plan, schedule, and complete mandated programs to satisfy state and federal requirements for timely completion and tracking of the work. The Company continues to rely on manual, paper-

based processes to manage the work. Where automated systems do support the Company, the functionality is limited and still requires significant manual intervention to collect and input data, run reports, and track costs.

All work streams that would normally be associated with an overarching Work Management, Asset Management, and Customer Enablement system are performed by employees relying on less-than-adequate work and asset management systems resting on a combination of software applications, databases, and spreadsheets that are used in parallel with or to facilitate existing manual processes to manage the business. National Grid has used these systems for as long as possible to support business operations. However, at this point, the need for a broad-based software solution providing a stronger operating platform is an imperative because there is risk involved in continuing to rely on the current processes and sub-systems to support safe and reliable operations while meeting customer expectations.

Q. What is creating the imperative for the Customer Enablement component of the Gas Business Enablement Program?

As National Grid is confronting the challenge of establishing a new platform for the work management and asset management systems, the landscape for serving utility customers is undergoing unprecedented change in relation to digital technology and escalating customer expectations. The electric and gas distribution industries are experiencing pressure to meet customer expectations that are being formed by customer experiences

with other goods and services vendors increasingly supported by digital technology, allowing for quick and easy customer-service interfaces, among other advancements.

For example, many of National Grid's customers transact business with other vendors that offer customer-service features such as the ability for customers to choose their communication preference with the vendor (*e.g.* to communicate with the vendor on service visits through text messages; and to take advantage of shorter appointment windows). Many service providers now have easy-to-use web portals and customer applications that offer greater scheduling and rescheduling options. With other vendors, customers frequently have the option to make and/or reschedule service appointments by taking a few moments to log in online through a mobile device and choose another time for the appointment, without ever having to interact on a personal basis with the vendor's customer-service department.

For gas utility services, the same customer has no alternative for scheduling or rescheduling an appointment than to place a telephone call to customer service and get back in the queue for the next available appointment with no direct line of sight into the options available, because only the customer service representatives have access to the appointment schedule. Customers expect to have the same level of ease and convenience with their gas or electric utility as they do with other household vendors. As a result, it is necessary for National Grid to accomplish a step-change in the delivery of customer

service that can only be achieved with a technological solution that provides a fundamental upgrade from the systems relied on to provide service today.

Collectively, these two dynamics – the resolution of operating risk in relation to the sub-systems relied on to perform work functions and the need for improvement in customer-contact alternatives – create an indisputable imperative for implementation of the Gas Business Enablement Program. It is clear that National Grid must make a step-change to create the platform that will enable more effective front-line field operations and customer service. It is also clear that the intensifying pressure to create a digital platform that will allow for quick and easy customer interactions with National Grid needs to be addressed through the development of digital solutions. Therefore, National Grid has launched the Gas Business Enablement Program to meet the imperative and will accomplish a major step-change in the operating platform for the U.S. gas business with program completion.

Q. What are the specific factors creating operating risk in relation to front-line business processes?

A. Fundamentally, National Grid's U.S. gas business is in an unsustainable position in terms of meeting operating and customer-service requirements with current, legacy systems within the rapidly changing external environment. Approximately 94 percent of the "front office" systems currently used by the U.S. gas distribution business will reach the

end of useful life within two years, making it increasingly difficult to maintain the reliability of critical, core operating systems.

In particular, the ability to make modifications to the software to adapt to new needs or regulations is severely limited, if possible at all. Many of these systems are no longer supported by the vendor and the software is written in older code that is not flexible or modifiable and therefore cannot be used to address changing regulatory and customer expectations. The age of the existing applications drives a risk of system outage as reliability of the old systems continues to dwindle. The cost to update/upgrade the existing systems individually would be higher and would not result in the benefits envisioned with the Gas Business Enablement Program, which will replace the existing environment with a holistic solution on a new modern platform to address risk, reliability efficiency, and customer interaction.

Q. Are there any other considerations that impact the reliability of these systems in supporting operating activities?

A. Yes. Over time, as the gas distribution business has evolved, work processes have moved forward through reliance on successive stages of "work arounds," which have made those work processes more and more complex. Few of the legacy company practices and processes are standardized, particularly in relation to data storage, asset records, and mapping systems. The sub-systems/applications are databases, applications, and/or manual processes tracked through spreadsheets with severely limited connectivity to each

other. This complex patchwork of applications makes it very difficult for various operating units to work together or to have visibility of the work performed in the field or at a customer's home. Many of the processes are highly dependent on manual processes to track whether work is completed in compliance with applicable requirements. In addition, it is becoming increasingly difficult and costly to maintain these disparate systems and to engage employees in the work necessary to navigate the processes and to successfully meet the challenges imposed by this situation.

By replacing the existing sub-systems, applications, and databases with three core systems, the entire U.S. gas business can be reorganized onto a single operating platform, within three overarching systems to perform day-to-day work and customer interactions with greater effectiveness than is possible today.

Q. Will the implementation of Gas Business Enablement help to improve the Company's ability to achieve compliance with regulatory requirements and expectations?

A. Yes, it will. Gas safety for customers, the general public, and employees is of paramount importance. Aging, disparate, and duplicative systems hamper the Company's ability to demonstrate compliance and manage performance. They also lack the flexibility to address a changing regulatory and customer environment. Gas-safety compliance challenges arise not only as a result of system and data gaps, but also due to the difficulty of providing effective technical training to employees on complicated work methods and

procedures that are necessitated by the less-than-adequate work process associated with legacy systems. Implementation of the Gas Business Enablement Program will assist in addressing these considerations.

In addition, although regulatory requirements and expectations have been rapidly increasing since the 2010 San Bruno incident in the San Francisco area and events in Allentown, Pennsylvania and East Harlem, New York, the current systems cannot be modified to meet increasing requirements, thereby requiring manual work processes to achieve compliance. Gas Business Enablement will provide consistent applications throughout the business and provide the necessary tools to accurately track, store, and report on gas operations data. These items include the required data compilation and retention in relation to leak and corrosion repair work to manage the Company's Distribution Integrity Management Plan and Transmission Integrity Management Plan requirements and assistance in satisfying the ten key elements of the American Petroleum Institute's recommended pipeline safety standards (Recommended Practice 1173). Historic and future compliance issues are arising because of the existence of dis-jointed, disparate, outdated systems that make it difficult to keep up with current regulatory obligations and demonstrate compliance with them. In Rhode Island, for example, the disparate outdated systems make it difficult to take into account planned main replacements and repeat odor calls to the Customer Contact Center when prioritizing Grade 2 leak repair activities.

Q. Does the customer experience provided today through current systems meet the expectations of customers?

A. No. As mentioned above, without the replacement of the current systems, National Grid cannot adapt to the way customers expect to conduct business with a gas and electric utility. Customers today have different expectations of customer service. In particular, the expectation of fast, easy, mobile applications and solutions is shared by all customers, particularly as relatively younger customers join the customer base. Interactions with other industries have already established customer expectations and preferences and gas and electric utilities cannot meet these expectations without new systems. Customers expect to have access to mobile applications that can be used to set-up or reschedule service appointments, find out the status of their request, or obtain information about outages. Having mobile access and interactions with the utility that include text messages and information regarding service technicians that will be arriving to a customer's residence or business not only represents helpful information for customers, but reduces the inability to complete work due to customer availability and also constitutes a level of service and security that is unattainable in the absence of these technological solutions.

Q. What are some other examples of how customer expectations changing?

A. Today, customers of a gas or electric utility can use mobile applications to request a car for pick-up at a designated location and are almost instantly provided with the name, type of car, and picture of the person performing the pick-up, with payment made

simultaneously through the same application. Customers are also able to easily use mobile applications or websites to order groceries or other goods and have those goods delivered right to their front door within one day, or even sometimes the same day. When customers experience such a high level of service and ease of service in one area of their commercial transactions, they begin to expect that level of ease with other services they use.

For example, applications that allow customers to easily access information regarding the deployment of resources teach customers that all deployed resources can easily be tracked electronically. However, if a customer called National Grid today to ask why a National Grid truck was working at the end of the customer's street, it would not be a simple task to get that answer. The customer would need to call the Customer Contact Center and speak with a representative who would need to research the situation because the representative would not have visibility to the reason that work is being performed at the end of the customer's street. By the time an answer is provided to the customer, it may be of no use as the truck could already be gone from the area. With a single, streamlined work-management system in place across National Grid's operating jurisdictions, the Contact Center representative and others involved in the work process would have complete visibility into this information and could provide information to customers almost instantaneously.

Q. Are there other examples of how the front-line work processes and customer-service delivery can be improved through the Gas Business Enablement Program?

A. There are numerous examples of how the Company's operations would be made more effective and the customer experience improved as a result of Gas Business Enablement Program implementation. Implementation of the Gas Business Enablement Program and the establishment of an enterprise-wide Work Management, Asset Management, and Customer Enablement system will result in the upgrade of gas and customer processes conducted by the Company to perform day-to-day operations. The new systems will provide more complete data capture and enable associated data reporting; eliminate over-reliance on paper records; create greater visibility of work requirements; and improve the effectiveness of field work and customer interactions. To the customer, these changes will translate into the ability for National Grid employees to obtain information in the field regarding the customer's facilities and service requirements on a real-time basis without resorting to paper records; the ability to schedule work at one time that may otherwise have required multiple visits to the customer's residence or business; the ability to take and store pictures of the customer's facilities to track atmospheric corrosion and other conditions rather than relying on written notes; and the ability to instantly update mapping systems rather than waiting for data entry back at the office.

More formally, the Gas Business Enablement Program will design, standardize, and implement core systems to support operations and customer-service delivery in Rhode Island, Massachusetts, and New York. This includes:

1. Implementation of an enterprise-wide asset and work-management platform for the U.S. gas business;

2. Establishment of a scheduling platform to support optimized scheduling, work bundling, and routing of work;

3. Development of an integrated Geographic Information System (commonly referred to as GIS) with accurate land-based maps and conversion of gas-service records and sketches, available with mobile functionality;

4. Implementation of 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;

5. Implementation of the Customer Experience solution that will be deployed to the Customer Contact Center to support improved customer interactions with Contact Center representatives along with a web-based self-service customer portal;

6. Establishment of an enterprise-wide program portfolio management platform for program routing and approval, with the ability to forecast cost, integrated with scheduling, and design; and

7. Development of 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 housing records relating to gas distribution and gas transmission assets and various transactional data will support a more simplified approach to asset management and work administration. In addition, the integrated implementation of the core work management, asset management, and customer enablement systems will make available valuable tools such as a mobility solution for leak investigation and inspection work orders and enhanced employee utilization.

The Gas Business Enablement Program will also implement standardized operations processes and training in a number of areas, which have not previously been standardized

because of the complexities inherent in relying on multiple supporting systems. Some of the key work-process improvements would include:

1. Improved methods of employee training on new standardized processes and technology and a modernized approach to field technical training;

2. Establishment of data-management principles and governance processes that would manage the relationships among defined sets of data (on assets, people, work orders, etc.), the movement, cleansing, and conversion of data from a source application to a target system, data retention policies (business, regulatory, and legal holds), data archiving policies, data deletion and destruction policies, and digitization of records;

3. Specification of an organizational design including role descriptions, accountabilities, span-of-control analysis, retirement and attrition analysis, role title rationalization, and diagnostic recommendations;

4. Delineation of the standard processes for work performed by internal and contract resources;

5. End-to-end work processes will include the American Petroleum Institute's recommended pipeline safety standards (Recommended Practice 1173) to support compliance-driven requirements;

6. Identification of best practices for warehouse and transportation operations to increase material readiness and create inventory certainty; and

7. Standardization and improvement of the processes and related procedures between supply chain and gas operations functions.

Schedule GBE-2 identifies key initiatives within the Gas Business Enablement Program and the workstreams associated with each initiative.

Q. Please describe how Gas Business Enablement will address the customer experience.

A. Another key element of Gas Business Enablement is that it will provide improvements to customer and employee interaction. A flexible interface will be integrated with the core

systems to allow customers, Contact 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 will allow customers to interact with the Company by receiving updates based on their preferences for appointments; addressing inquiries for new gas connections and conversions; and having access to information about work on their streets or in their neighborhoods.

Similarly, an employee application portal will be developed and further integrated with the work management, scheduling, dispatch, and Geographic Information System to support one view of relevant information, such as asset and field data including past transactions for Contact Center representatives and field employees to better communicate with customers and meet their needs. This interface also builds the capabilities necessary to rapidly adapt processes, capture data, and address developing channels for customer engagement in the evolving future energy marketplace.

III. Gas Business Enablement Governance and Procurement

Gas Business Enablement Governance Framework

Q. How is National Grid approaching the management of the Gas Business Enablement Program given the broad scope, complexity, and cost of the program?

A. Given the broad scope, complexity, and cost of the Gas Business Enablement Program, National Grid has proceeded with program development using a well-defined management structure with defined leadership roles and accountabilities [depicted in

Schedule GBE-3]. In that context, National Grid has made a number of decisions in structuring the Gas Business Enablement governance framework to incorporate lessons learned from the past. For example, the planning assumptions for the Gas Business Enablement Program avoid a "Big Bang" approach to implementation and, instead, adopt a phased approach reflecting process, technology, and organizational limitations and opportunities.

In addition, National Grid is planning to deploy "off-the-shelf" capabilities to the maximum extent possible to minimize the customization of the system and preserve the flexibility and functionality of the system as designed. In addition, the Gas Business Enablement Program has developed a well-defined program roadmap to reduce risk in implementation and to provide clear visibility of critical path dependencies to assure successful implementation as each phase progresses [provided as Schedule GBE-4]. Lastly, National Grid has initiated a rigorous, competitive, and analytical process to identify third-party partners to assist in designing, planning, and executing the Gas Business Enablement Program subject to clearly defined contractual parameters and performance requirements.

This Gas Business Enablement Governance Framework and the rigorous procurement process employed to identify third-party partners to assist in developing the Gas Business Enablement Program are significant management tools to make sure that program costs are reasonably and prudently incurred in the course of achieving the identified program

benefits for customers. In particular, National Grid has limited the risk associated with implementation through a fixed-cost arrangement with the program-delivery vendors and clearly defined requirements and work-scopes within the contracts developed jointly by the National Grid team and vendors during the procurement process.

Q. Please provide an overview of the Gas Business Enablement governance framework, team, and delivery partners.

A. There are several components to the Gas Business Enablement governance framework, as shown in Schedule GBE-3. These components include the following:

The **Steering Group** will have ultimate authority over, and responsibility for, the completion of the Gas Business Enablement Program on a reasonable and prudent basis. The Steering Group consists of the U.S. Chief Executive Officer, U.S. Chief Financial Officer, Executive Vice President of Network Operations, Safety and Capital Development, Senior Vice President and U.S. Chief Information Officer, Senior Vice President of Human Resources and Chief Diversity Officer, Global Chief Procurement Officer, Group Director of Business Excellence, and Senior Vice President of Regulatory Affairs. The Steering Group will focus on program delivery and will provide strategic advice and guidance, address resource requirements, maintain prioritization of the work effort among other operational needs, and manage escalated issues (including changes to the portfolio anchors, potential increases in program costs, and review of unplanned customizations).

The **Senior Vice President of Gas Business Enablement** reports to National Grid's Executive Vice President of Network Operations, Safety, and Capital Development with accountability to the Steering Group for the successful delivery of the Gas Business Enablement Program and its anticipated benefits.

The National Grid **Gas Business Enablement Leadership Team** includes the Vice President of Process and Business Requirements, the Vice President of Solution Development and Delivery, the Vice President of Business Design and Readiness, and the Head of the Portfolio Management Office. Each of these business leaders has a defined role in the process, establishing accountability for: (1) defining the standard "to be" business processes, embedding data management and governance, and capturing and delivering the business requirements; (2) developing and delivering the information systems solution to meet gas business operating requirements and the ongoing support model; (3) defining the future gas operating model developing and implementing a change program to deliver the process, system, and cultural changes; (4) developing and deploying a refreshed approach to technical field training; and (5) keeping the Gas Business Enablement Program to time and budget goals, and maintaining compliance with program objectives.

The **Design Authority** consists of the Senior Vice President of Gas Process and Engineering along with Vice Presidents from the gas business, including Vice Presidents from each jurisdiction and work functions intrinsically related to, and affected by, the

Gas Business Enablement Program. This group works with the Gas Business Enablement Leadership Team and ensures that business leaders are informed on progress and key issues, sign-off on business decisions, endorse business requirements, and take responsibility for delivery of business benefits.

Independent, third-party **Delivery Partners** will work with National Grid as the program design and deployment leads to execute work on pre-designated work streams and will assist in building change leadership capability at all levels in the gas business so that employees (who are deeply immersed in the current practices and processes engendered by legacy systems) are prepared to realize the full capabilities and competencies of the Gas Business Enablement Program, once implemented. To ensure success of the program for National Grid's customers a value assurance partner has been chosen as an independent quality assurance function, monitoring the performance of the Gas Business Enablement Program and its workstreams and reporting to the Steering Group progress and recommendations for improvement.

The **Value Assurance** function will be performed by an independent, third party to ensure not only successful delivery of the program but also achievement of the anticipated benefits.

Q. Please describe what types of changes or outcomes will require approval from the Steering Group other executive leadership.

A. The Gas Business Enablement Program requires annual review by the U.S. Sanctioning Committee and the U.S. Senior Executive Sanctioning Committee, including annual approval of the budget for each fiscal year. In addition to the annual sanctioning process, any changes to the major portfolio anchors of the program, increase in program costs, or unplanned work requires the review and approval of the Steering Group. Lastly, the external Delivery Partners have executed fixed-price contracts for this program with specified program performance parameters. This structure provides for a process that will have fewer instances of large change in program costs over the course of the implementation and holds the external partners accountable for successful implementation of the portions of the program for which they are responsible.

Q. How will the Gas Business Enablement Program team assess the readiness of the business to begin using components of the Gas Business Enablement Program, as those components become functional?

A. The Gas Business Enablement Leadership Team will work with the Design Authority that is comprised of the Vice Presidents across the gas business, supporting functions, and jurisdictions to identify, by geography and functional group, readiness of their function to begin use of the Gas Business Enablement Program components as they become available. This will be accomplished by evaluating jointly developed readiness criteria at identified “go/no go” checkpoints to ensure that the functional group is prepared to

proceed. In addition, performance will be monitored throughout the "go-live" process and beyond to identify any problem areas that need to be addressed. The readiness criteria will include, but are not limited to, system readiness (including functionality and technical infrastructure) determined through user testing, people readiness determined through training delivery and leadership observations, and business readiness determined through review of processes and procedures.

Q. What is the purpose and value of "Change Management" within the Gas Business Enablement Program?

A. The best technology available to the Company will not deliver the potential value achievable for customers without the commitment of our employees to leverage the capabilities of the technology to drive performance. As a result, training and other "change management" strategies will be utilized to engage employees in the implementation of the Gas Business Enablement Program. Gas Business Enablement's Change Management strategy is designed to build leadership capability, define and reinforce new mindsets and behaviors to create a culture of focus and accountability, and transition the organization to new ways of working to better serve customers in line with their increasing expectations. Change management will also help to facilitate rapid adoption of new processes and work tools following program implementation.

As part of the change-management process, National Grid will provide comprehensive training to all users of the systems, both field and office workers as well as first line and

upper levels of management. Training materials and training exercises will be tailored to the audience, and the training will be delivered using various media such as computer-based instruction, video, classroom, mobile, and written help guides.

Although there is cost and time involved in training employees to levels adequate to not only operate, but optimize the functionality of the Gas Business Enablement Program components, there is great value that will be produced by this training. National Grid recognizes the significance of this aspect of the Gas Business Enablement Program and has created the change management office responsible for stakeholder engagement, training development, and deployment prior to implementation of the systems.

Gas Business Enablement Procurement Process for Delivery Partners and Value Assurance

Q. Please describe the scoping and authorization process for the Gas Business Enablement Program and associated procurement.

A. In November 2015, the conceptual basis for the Gas Business Enablement Program was brought to the Group Executive Committee for review, approval, and initial funding. This authorization was necessary to initiate the process to scope the solution and create the overarching strategy for procurement, implementation, and governance. The Group Executive Committee approved the concept for Gas Business Enablement and created the Gas Business Enablement Steering Group. The Group Executive Committee authorized funding in the amount of $25 million to perform an assessment of program alternatives and commence program planning. The Gas Business Enablement Steering Group was

charged with reviewing and approving the initial program scope and procurement strategy. Mr. Johnston was appointed Senior Vice President of Gas Business Enablement on January 1, 2016 and formally moved into the position in April 2016.

From there, Mr. Johnston began to build a competent, experienced program team dedicated exclusively to Gas Business Enablement Program implementation, with the expectation that independent, third-party service providers would be procured to assist in design, planning, and implementation of the Gas Business Enablement Program components. Once assembled, the program team worked for five to six months to evaluate each jurisdiction to identify current operating challenges in each jurisdiction and begin to develop an effective and efficient end-state vision. Members of the program team also visited other utility companies to learn about their experiences and gather input on lessons learned. In addition, National Grid conducted a detailed software review process that included demonstrations with software vendors. A formal evaluation of software applications was conducted with scoring of each solution from business, technical, and commercial perspectives.

The result of this Phase I strategic assessment helped to develop an efficient roadmap, an appropriate project scope, and a reliable cost estimate. This information was the basis of the procurement process to select partners for the second phase of the program, to implement the roadmap.

Q. How does National Grid plan to assure successful program management and a productive partnership with its external consultants?

A. In the first phase of program development, National Grid relied on a "Design Assurance" partnership to obtain independent advice on the quality of the program roadmap by testing whether the roadmap was complete and able to be successfully delivered. In addition, National Grid evaluated the estimates of potential costs and benefits associated with the program.

Following a comprehensive procurement process in the second phase of program development, National Grid selected two vendors to assist in moving the program forward. These vendors were PricewaterhouseCoopers (as the overall Delivery Partner) and Accenture (as the SalesForce Integrator). PricewaterhouseCoopers will serve as the lead system integrator for the Gas Business Enablement Program, with responsibility for assisting in the development and deployment of standard processes and solutions for Work Management, Asset Management, Geographic Information System implementation, and Data Management supporting each of the workstreams, along with overall delivery through the Portfolio Office and Change Management activities. Accenture is responsible for assisting in the development and deployment of the field mobility application, along with dispatch, scheduling including resource management and Customer Contact Center solutions along with development of the end-to-end customer processes and other elements of the Customer Engagement model. Kotter International, a world-leading change consultancy based in Cambridge, Massachusetts, was selected to

assist in the Strategic Change Management role, and PA Consulting was chosen to provide a third-party, independent view of the progress of the program to the Steering Group (Value Assurance).

Q. How will this intensive program-management structure help to control costs and achieve effective and timely implementation?

A. The fundamental purpose of the competitive procurement process is to develop the components of the Gas Business Enablement Program using capable and experienced third-party vendors that have the competency to assist in delivering the program on time, on budget, and with the stated capabilities. The Value Assurance function, independent of both the Company and the other third party vendors, will ensure that the program effectively meets the functionality and financial goals throughout the development process, and will have a direct line to program management. A rigorous process was followed to develop detailed Statements of Work for each workstream, as well as to develop Module Plans and an Integrated Program Plan to correlate the work efforts of the two System Integrators.

Thus, the key features of the contractual arrangements that will help to control program costs are the following:

- A carefully delineated Statement of Work by workstream for program completion;
- A complementary cultural fit between National Grid and its selected Delivery Partners;

- An integrated project plan aligned across workstreams and Delivery Partners;
- Alignment of goals and incentives between the National Grid team and its Delivery Partners;
- Negotiated fixed-cost contracts; and
- Utilization of a Value Assurance partner, reporting directly to the Steering Group, for independent oversight and control.

This approach will assure that the costs to fully implement the Gas Business Enablement Program are reasonable and prudently incurred to achieve the benefits available for customers through program implementation.

IV. Perspective on the Before and After Scenarios

Q. Please describe the planned implementation.

A. National Grid is implementing Gas Business Enablement in phases by breaking down the program by work types and geography. National Grid will begin implementation with the Rhode Island jurisdiction, which is highly reliant upon paper-based operations, and where both gas and electric operations will benefit and implementation risk can be mitigated given the jurisdiction's relatively smaller footprint. Initial focus in Rhode Island will be to implement the first solutions supporting asset management and work management activities related to the scheduling, assignment and dispatch of work, completion of work on a mobile device with electronic data capture, and the ability report the status of a particular job in real time. Implementing these updated solutions as quickly as possible to largely replace the current paper-based processes and disparate, outdated, and unsupported core applications with field mobility functionality will help

reduce the risk associated with those critical, unsupported applications for these asset management and work management activities. Additional capabilities will be implemented iteratively with greater functionality over the duration of the Gas Business Enablement Program as quickly as possible to increase asset and transactional records accuracy and enable employees to work more efficiently thus improving productivity.

This strategy will create a foundation for building incremental enhanced capabilities supporting safety performance, operations effectiveness, and customer experience. The first release implementation of the enterprise-wide solution will occur in Fiscal Year 2018 for the Company's gas distribution operations with initial deployment of the first minimum viable product solutions for corrosion, instrumentation and regulation, and collections. Following the release in Rhode Island, the Company will begin to deliver and implement Gas Business Enablement in other service territories. Schedule GBE-4 provides the roadmap regarding implementation of the key initiatives encompassed within the Gas Business Enablement Program. As shown in that schedule, implementation for Massachusetts is set to begin in Fiscal Year 2019 and for New York in Fiscal Year 2020.

Q. Please describe some of the specific programs/capabilities that will go in-service for the Company.

A. As mentioned above, the first phase of implementation in Rhode Island will occur in Fiscal Year 2018. This first phase in Rhode Island will involve the implementation of the

work-management functionalities supporting the Instrumentation and Regulation and Corrosion functions, as well as processes for field collections and customer meter services activities, basic scheduling, dispatching, and field data capture. In addition, the asset-management system will be placed in service for the Gas Transmission and Distribution Integrity Management Processes, which will standardize and improve data accuracy and enhance gas system safety and reliability.

The next phase of implementation in Fiscal Year 2019 for Rhode Island would include systems and capabilities to enhance the customer experience. These capabilities would include field visibility to customer payment history, field acceptance of credit card payments, field printing, call center visibility to collections status, and field visibility to maps. This phase will also involve full deployment of capabilities across Field Mobile applications to support all customer meter services activities, including real-time communications between call center, dispatch, field employees, and other customer support groups. Lastly, the standard Geographic Information System data model will be fully utilized in Rhode Island at this time.

The next phase to occur in Fiscal Year 2021 for Rhode Island would include systems and capabilities to enhance gas construction and leak-repair activities. These capabilities would include a standardized unit cost library enabling more accurate cost estimates, contractor mobility, customer appointment booking, mobile time tracking, and field asset correction and geographic location. Once these backbone systems are delivered in Rhode

Island over the four-year period (Fiscal Year 2018 through Fiscal Year 2021), the enhanced capabilities will begin functioning during Fiscal Year 2021 and Fiscal Year 2023. These enhanced capabilities will include items such as customer self-service, field crew/customer interaction portal, complex design tool for construction, and asset risk visibility.

Q. Please describe how National Grid's gas distribution operations currently function, from an overall perspective.

A. Today, National Grid's gas distribution operations operate from an inefficient patch-work of legacy systems and manual spreadsheets to perform critical gas operation activities. The current sub-systems and applications are only able to operate on older, unsupported operating systems and are accessed in the field from older hardware (*e.g.* truck-mounted laptops) that are beyond their useful life. These field devices require regular maintenance, causing inefficiency and necessary work arounds while these devices are being serviced. Procuring parts for these devices is becoming increasingly difficult because manufacturers no longer support the products.

The disparate systems make it difficult for employees to navigate the systems and are prone to human error, missing data, delays in information, lack of visibility among functions, and lack of ability to adapt to future regulatory expectations. For example, the many systems used today require manual controls, local tracking, and follow up as part of scheduling required work activity in the field including warning tags. Scheduling,

dispatching, and tracking of gas work today requires many manual controls across different systems, making full visibility of work required and how it is performed difficult.

For perspective of the volume of work, National Grid responds to approximately 2,300 service appointments *per day* across its three operating jurisdictions. This volume of work creates a significant challenge for National Grid to meet with current operations goals.

Q. How will these circumstances differ once Gas Business Enablement is fully implemented?

A. Once the Gas Business Enablement Program is fully implemented, the U.S. gas distribution business will operate from a standard suite of integrated software applications comprised of three core systems utilized by employees to execute critical work activities. These systems will include modern software applications with the ability to configure, integrate, and enhance over time in order to adapt to future operational, regulatory, and customer expectations. There will no longer be overall reliance on manual controls and/or multiple spreadsheets, but rather will allow for full visibility of required work, scheduling, and performance across functions. The work force will be trained on the new systems in a uniform way making work consistent enterprise-wide, subject to varying regulatory compliance requirements.

All work will be contained in an integrated suite of systems with pre-defined rules that will automatically schedule work in advance of a due date, and there will be central visibility to ensure all mandated activities are completed in a timely fashion. As an example, all field workers will have mobile devices that will allow warning tags to be completed electronically and printed in the field, which will enable validation of information as the tag is completed, and will give the Company an electronic copy of the tag. It will also enable follow up work to be automatically scheduled, significantly reducing the reliance on manual processes and controls, and provides the Contact Center visibility to tag information and enables better customer service for customer follow-up calls. National Grid will be able to track and manage crew and individual worker productivity, including the standardization of business processes for enhanced visibility of work and more efficient scheduling. Gas Business Enablement will also include a new Geographic Information System to improve National Grid's ability to capture, store, access, and analyze geographical asset information concerning its gas distribution and transmission network. The Geographic Information System will provide a single view of all assets, which will facilitate data-driven investment and maintenance decisions. This will strengthen National Grid's ability to operate a safe, reliable gas distribution and transmission system and drive continuous improvement in regulatory compliance and transparency with more complete data capture and reporting. Schedule GBE-5 illustrates the gas system capabilities post-Gas Business Enablement implementation.

Q. Please describe what the National Grid customer experience is like prior to Gas Business Enablement implementation.

A. Today, a customer does not have many options to engage with the Company other than a phone call placed to the Customer Contact Center or limited interaction through the Company's website. For example, to make a service appointment today, a customer must contact the Contact Center and speak to a representative to schedule an appointment. In addition, any question about repair work or other service questions would require a phone call to the Contact Center and significant follow-up to determine the status of work and/or why work is being performed in a customer's neighborhood.

Q. How will the customer experience differ after Gas Business Enablement Program implementation?

A. The Gas Business Enablement Program will provide enhanced customer service through improved scheduling and dispatch, with enhanced appointment booking and frequent communications with customers according to their media preferences, as well as the ability to create a 360-degree view of past, scheduled, and potential future work for customers. Following Gas Business Enablement implementation, in addition to contacting the Contact Center, the customer will have the option to use the National Grid website to make the appointment, and will be presented with a screen showing the available appointment windows. The customer will also have the option to receive a phone call or text message when the field worker leaves for the appointment. Finally, if a customer called to find out what work was being done on their street, they would be able

to receive an accurate answer from the Contact Center in real-time. Schedule GBE-6 illustrates the customer experience capabilities after Gas Business Enablement Program implementation.

V. <u>Proposal for Ratemaking Treatment</u>

Q. What is the anticipated cost of the Gas Business Enablement Program on an overall basis?

A. The total cost of the Gas Business Enablement Program for National Grid's U.S. gas distribution business is currently estimated at approximately $478.3 million over the period from Fiscal Year 2017 to Fiscal Year 2023. Of this amount, approximately $315.1 million represents capital costs and approximately $163.2 million represents one-time operating expenses necessary to complete the Gas Business Enablement initiatives. Although delivery of the Gas Business Enablement Program initiatives is expected to occur within the total costs stated herein, it is important to note that program costs may shift between the years as each of the programs completes detailed design. Therefore, 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 program complexity; this contingency has not been reflected in the Company's revenue requirements for Narragansett Gas or Narragansett Electric.

Q. What is the anticipated cost of the Gas Business Enablement Program for the Company?

A. Because the Gas Business Enablement Program is a shared investment, only a portion of the total investment would be allocated to Narragansett Gas and Narragansett Electric. Further, given that the program will be implemented over a multi-year period, the costs for Narragansett Gas and Narragansett Electric will be incurred at various points in time over the next few years. The allocation would be in the form of rent expense as part of the overall Information Services Service Company rent expense allocated to Narragansett Gas and Narragansett Electric. The total costs for Gas Business Enablement attributable to Narragansett Gas and Narragansett Electric are $10.2 million in operating expense and $33.8 million in Service Company capital costs allocated to Narragansett Gas and Narragansett Electric as rent expense.[3] Narragansett Gas's portion of the annual rent expense attributable to the Gas Business Enablement Program investment is $2.4 million, $2.8 million, and $3.2 million in the Rate Year and the two subsequent twelve-month periods ending August 31, 2020 (Data Year 1) and August 31, 2021 (Data Year 2) (Data Year 1 and Data Year 1 are collectively referred to as the Data Years), respectively, as shown on Schedule MAL-36, Page 5 provided with the pre-filed direct testimony of Company Witness Melissa A. Little. Narragansett Electric's portion of the annual rent expense attributable to the Gas Business Enablement Program investment is $619,818 in the Rate Year, and $611,224 and $557,442 in Data Year 1 and Data Year 2, respectively, as shown on Schedule MAL-36, Page 11.

[3] This includes the depreciation of $25 million and return of $8.7 million over the full life of the assets (through Fiscal Year 2033).

The Company's share of the $10.2 million total incremental operating expense in the Rate Year, as shown on Schedule MAL-36, Page 6, is $1.1 million for Narragansett Gas. This schedule also shows the forecast of incremental operating expense allocated to the Company for the Data Years.

Q. Please explain how costs for the Gas Business Enablement Program will be allocated to Narragansett Gas and Narragansett Electric.

A. In general, Gas Business Enablement Program costs will be allocated using the customer cost causation allocator under the guidelines of the Service Company Cost Allocation Manual. The majority of the program will be allocated among National Grid's gas distribution operating companies, with the exception of two workstreams: (i) Scheduling, Dispatch, and Mobility and (ii) Customer Engagement. These two workstreams will provide benefits to the electric distribution companies and therefore the costs associated with them will be shared with National Grid's electric distribution affiliates. The current expectation is that the allocation proportions among the jurisdictions for overall Gas Business Enablement costs will be approximately seven percent to Narragansett Gas and Narragansett Electric; 25 percent to Massachusetts operating affiliates; and 68 percent to New York affiliates.

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

A. The incremental project operating expense included in Schedule MAL-36 relates to end-user training, data conversion from the legacy applications to the new Gas Business Enablement Program applications, business process documentation that is non-system related, and Gas Business Enablement Program management of schedule, resources, finance, risks, and performance.

Q. Does the Test Year include costs for the Gas Business Enablement Program?

A. Yes. The Test Year includes certain non-recurring costs for the Gas Business Enablement Program related to the development of the business case, assessment of processes and applications, and high-level design for the Gas Business Enablement Program. The Company has made a normalizing adjustment of $1.5 million for Narragansett Gas to remove these non-recurring costs from the Rate Year.

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

A. Yes. As shown on Schedule MAL-36, the Company will incur additional run the business costs to support the Gas Business Enablement 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 because of regulatory reporting needs and outstanding legal hold obligations.

As legacy software systems are retired due to functional replacement as part of the Gas Business Enablement Program, the run the business costs for operating the servers, software systems, and field devices will be eliminated. As shown on Schedule MAL-36, 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 Gas Business Enablement in the Rate Year and Data Years?

A. As shown on Schedule MAL-36, Page 6, the Company's allocated share of these costs is $3.1 million in the Rate Year and $1.3 million in each of the Data Years.

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

A. Yes. Although it is unknown if the savings estimates can be achieved, the Company has made an adjustment to the Rate Year and Data Years for its gas business to reflect its allocated share of the estimated savings from Gas Business Enablement Program initiatives. The adjustment reduces the revenue requirement by ($0.057) million in the Rate Year, ($0.371) million in Data Year 1, and ($0.768) million in Data Year 2.

Q. How does the Company propose to recover the expenses associated with Gas Business Enablement Program implementation?

A. The Company is proposing to defer operating expenses incurred prior to the Rate Year and amortize those costs over a ten-year period based on the projected deferral balance at August 31, 2018. Cumulative operating expenses incurred by the Company for Gas Business Enablement through June 30, 2017 amounted to $1.5 million. The Company is also proposing to defer all post-Test Year Gas Business Enablement one-time operating costs on the Company's books to be amortized over a ten-year period, with return. The resulting annual amortization of $1,016,617 would be recoverable in the Company's cost of service over the ten-year period commencing September 1, 2018. These amounts are shown on Schedule MAL-36, Page 6.

For Gas Business Enablement expenses forecasted to be incurred during the Rate Year, the Company will recover rent expense consisting of the ten-year amortization amount with return in the total amount of $28.7 million at the Rate Year projected levels based on the estimated dates those investments are placed in-service. Operating expenses incurred

during the Rate Year would be recovered over a ten-year period, which is the useful life of the Gas Business Enablement capital investments. Incremental run-the-business costs would be recovered at the Rate Year projected levels net of incremental savings.

Q. How has the Company reflected the costs for Gas Business Enablement in the revenue requirements for Narragansett Gas and Narragansett Electric?

A. As shown on Schedule MAL-36, Page 6, the Company's share of O&M expenses is $10.2 million for Narragansett Gas. This amount has been included as an expense as shown on Page 6 of that schedule. The annual amortization of Gas Business Enablement O&M costs, $1,016,617, has been included in the cost of service for Narragansett Electric as shown on Page 6 of Schedule MAL-36. As part of this proceeding, the Company is requesting the PUC to approve the creation of a regulatory asset for the amortization of the Gas Business Enablement Program costs.

Q. Does this conclude your testimony?

A. Yes.

Schedules of
Johnston and Connolly

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket No. 4770
Witnesses: Johnston and Connolly

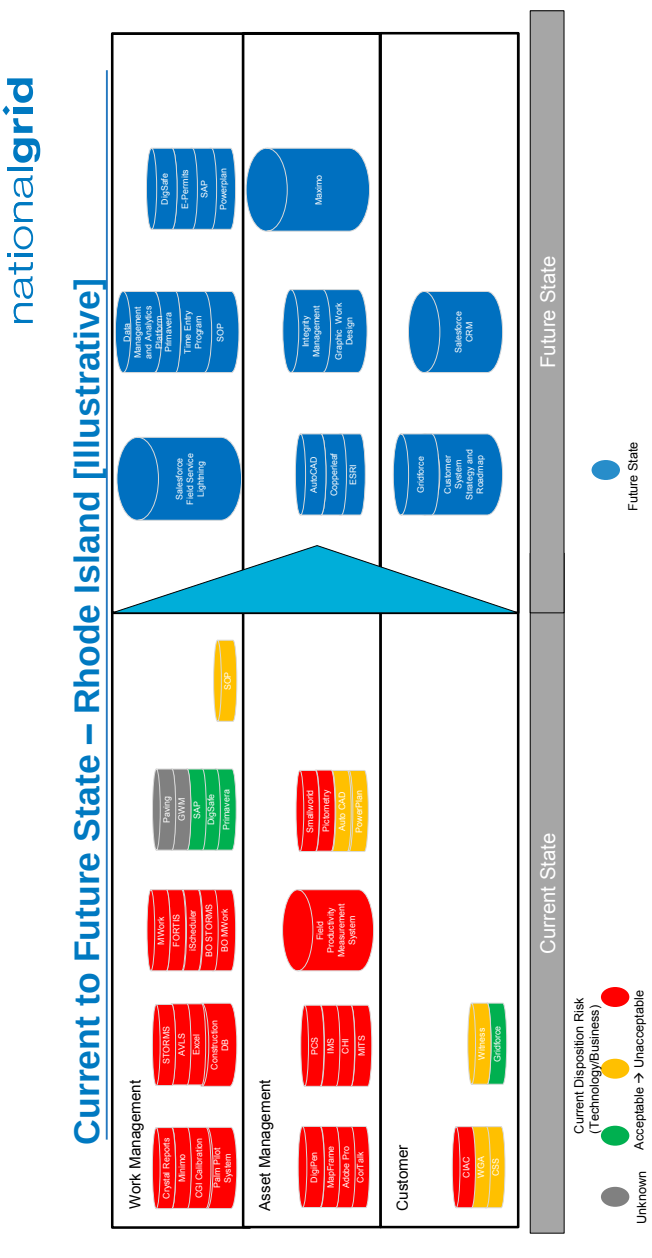
Index of Schedules

Schedule GBE-1

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket No. 4770
Witnesses: Johnston and Connolly

Schedule __ (GBE-1)

Depiction of Current and Future State Systems in Rhode Island


nationalgrid
Current to Future State – Rhode Island [Illustrative]
Work Management
Asset Management
Customer
Current State
Future State
Crystal Reports
Mimio
CGI Calibrator
Palm Pilot System
STORMS
AVLS
Excel
Construction DB
MWork
FORTIS
iScheduler
BO STORMS
BO MWork
SOP
Paving
GWM
SAP
DigiSafe
Primavera
DigiPen
MapFrame
Adobe Pro
CorFalk
PCS
IMS
CHI
MTS
Field Productivity Measurement System
SmallWorld
Pictometry
Auto CAD
PowerPlan
CIAC
WGA
GSS
Wireless
Gridforce
SAP
PowerPlan
E-Permits
DigiSafe
Data Management and Analytics Platform Primavera
Time Entry Program
SOP
Salesforce Field Service Lightning
Maximo
Integrity Management
Graphic Work Design
AutoCAD
Copperleaf
ESRI
Salesforce CRM
Gridforce
Customer System Strategy and Roadmap
Current Disposition Risk (Technology/Business)
Unknown
Acceptable → Unacceptable
Future State

Schedule GBE-2

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket No. 4770
Witnesses: Johnston and Connolly

Schedule __ (GBE-2)

Key Initiatives By Gas Business Enablement Workstream

Key Initiatives

nationalgrid | gas business enablement

Workstreams	Initiatives								
GBE Portfolio Office									
Change Management	Program Level People Strategy	Stakeholder Management & Engagement	Enablement	Business Readiness & Sustainment	Workforce Strategy / Labor Strategy				
Change Leadership	Organizational Change Readiness		Volunteer Network		Organizational Alignment				
Operating Model	Value Realization	Operations Performance Improvement	Organizational Structure & Design		Governance				
Asset Management	Integrity Management – Corrosion and I&R	Integrity Management – TIMP and DIMP	Asset Investment Planning and Management (AIPM) – Enhancements and Integrations		Advanced Analytics – Platform and Use Cases				
Customer Engagement	Structured Experiences	Contact Center Interaction	Field Interaction	Customer Interaction	Large Commercial & Industrial Landlord Interaction	Supporting Through Data			
GIS	GIS Consolidation	GIS Data Remediation	Landbase Conflation	GIS/EAM Integration	Graphical Work Design (GWD)	Complex Design (CAD) & Estimating (ESW)			
Work Management Field Enablement	Business Architecture Design	Corrosion and I&R	Customer, Collections, Resource Mgmt.	CU Governance and Library	PowerPlan Integration				
	Construction Work, Leak Inspection and Leak Repair	Projects and Program Management	Work Forecasting & Planning Solution	WMFE Optimization					
Supply Chain	Material Traceability	SC Master Data Improvements	Fulfillment Model / Inventory Optimization	Integrated Supply & Demand Planning / Integrated Business Planning	Warehouse & Network Optimization				
Field Technical Training	Employee Competence	Standard Operating Procedures	Technology						
Data Management	Data Governance	Data Profiling & Cleansing	Data Quality Dashboards & DQI Metrics	Integration & Conversion	Advanced Analytics				
ISE	Integration	Technology Initiatives	Enabling Capabilities						
Value Assurance									

Schedule GBE-3

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket No. 4770
Witnesses: Johnston and Connolly

Schedule __ (GBE-3)

Gas Business Enablement Corporate Governance Structure

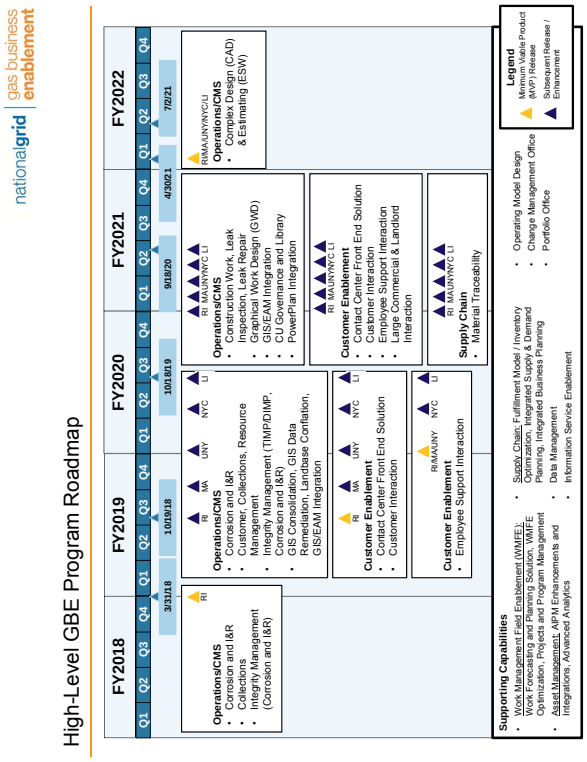
GBE governance framework, team and delivery partners:
nationalgrid | gas business enablement
Steering Group: Ensures focus remains on value delivery, provides strategic advice & guidance, ensures program has required resources, supports enterprise prioritization conflicts, and manages escalated issues (including changes to portfolio anchors, increases in program costs & unplanned customizations).
US CEO
US CFO
EVP, Net. Ops, Safety, and Cap. Del.
EVP, US CIO
SVP, HR and Chief Diversity Officer
Global CPO
Group Director, Business Excellence
SVP, Regulatory Affairs
GBE Sponsor:
SVP Gas Business Enablement: Accountable for ensuring the successful delivery of the program and its anticipated benefits
National Grid GBE Leadership Team:
VP of Business Process & Requirements : Accountable for defining the standard 'to be' business processes, ways or working, data and business requirements
VP of Solution Development & Delivery: Accountable to develop and delivery the IS solution to meet the business's requirements, develop & deliver the on-going support model
VP of Business Design & Readiness : Accountable for the future gas operating model, developing & implementing a change program to deliver the process, system & cultural changes, and develop & deploy a refreshed approach to technical field training
Head of the Portfolio Management Office : Accountable for keeping the program to time & budget, and maintaining compliance with the Critical Success Factors
Core IS:
Integration to legacy systems
Digital Risk & Security
Running environments
Supporting implemented systems
Design Authority:
SVP Gas Process & Engineering & VPs from the Gas Business (including from JDxs) & impacted functions
Inform – ensure business leaders are informed on progress and key issues
Decide – sign-off key business decisions that have broader business impacts
Endorse – business requirements (i.e. design) and Go / No Go Decisions
Own – defined business benefits and delivery of them
Delivery Partners:
PWC– overall program lead, lead SI for EAM (Maximo), lead for change management office, operating model, PMO, data management, & IS enabling
Accenture – lead SI for Scheduling, Dispatch, Mobility & Customer Engagement (Salesforce)
Kotter International – building change leadership capability at all levels in the gas business to support the change
Value Assurance:
PA Consulting - To provide independent assurance that GBE is on track for successful delivery of the program & anticipated benefits

Schedule GBE-4

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket No. 4770
Witnesses: Johnston and Connolly

Schedule __ (GBE-4)

Gas Business Enablement Roadmap

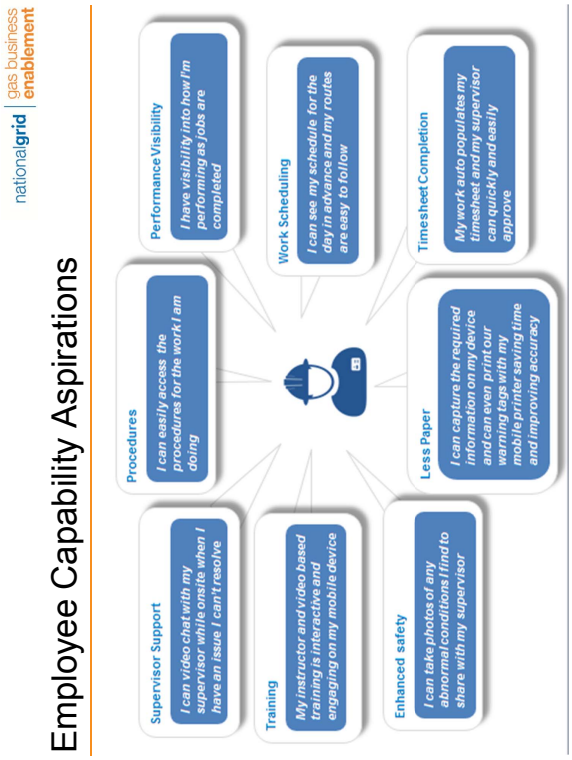

nationalgrid | gas business enablement
High-Level GBE Program Roadmap
FY2018
FY2019
FY2020
FY2021
FY2022
Q1 Q2 Q3 Q4 Q1 Q2 Q3 Q4 Q1 Q2 Q3 Q4 Q1 Q2 Q3 Q4 Q1 Q2 Q3 Q4
3/31/18
10/19/18
10/18/19
9/18/20
4/30/21
7/2/21
Operations/CMS
Corrosion and I&R
Collections
Integrity Management (Corrosion and I&R)
RI
Operations/CMS
Corrosion and I&R
Customer, Collections, Resource Management
Integrity Management (TIMP/DIMP, Corrosion and I&R)
GIS Consolidation, GIS Data Remediation, Landbase Conflation, GIS/EAM Integration
RI MA UNY NYC LI
Customer Enablement
Contact Center Front End Solution
Customer Interaction
RI MA UNY NYC LI
Customer Enablement
Employee Support Interaction
RI/MA/UNY NYC LI
Operations/CMS
Construction Work, Leak Inspection, Leak Repair
Graphical Work Design (GWD)
GIS/EAM Integration
CU Governance and Library
PowerPlan Integration
RI MA/UNY/NYC LI
Customer Enablement
Contact Center Front End Solution
Customer Interaction
Employee Support Interaction
Large Commercial & Landlord Interaction
RI MA/UNY/NYC LI
Supply Chain
Material Traceability
RI MA/UNY/NYC LI
RI/MA/UNY/NYC/LI
Operations/CMS
Complex Design (CAD) & Estimating (ESW)
Supporting Capabilities
Work Management Field Enablement (WMFE)
Work Forecasting and Planning Solution, WMFE Communication Pilots and Program Management
Asset Management, APM Enhancements and Integrations, Advanced Analytics
Supply Chain: Fulfillment Model / Inventory Optimization, Advanced Supply & Demand Planning, Integrated Business Planning
Data Management
Information Service Enablement
Operating Model Design
Change Management Office
Portfolio Office
Legend
Minimum Viable Product (MVP) Release
Subsequent Release / Enhancement

Schedule GBE-5

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket No. 4770
Witnesses: Johnston and Connolly

Schedule __ (GBE-5)

Example of Gas Operations Capabilities with Gas Business Enablement

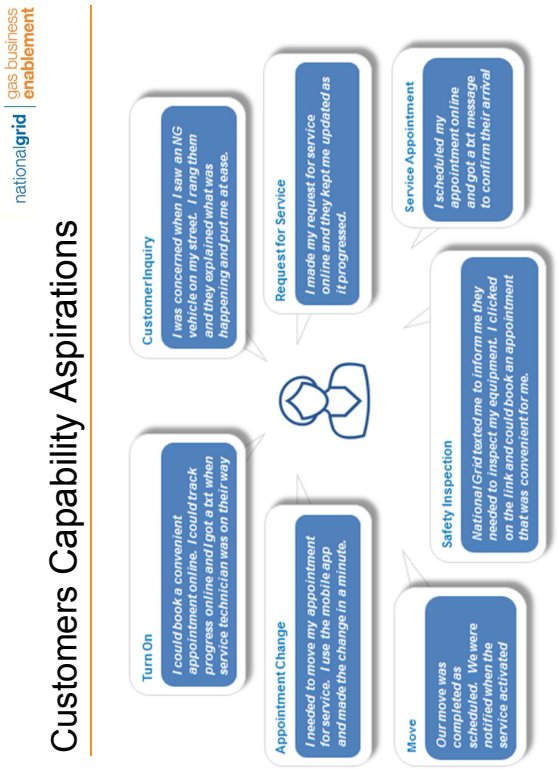

nationalgrid | gas business enablement
Employee Capability Aspirations
Performance Visibility
I have visibility into how I'm performing as jobs are completed
Work Scheduling
I can see my schedule for the day in advance and my routes are easy to follow
Timesheet Completion
My work auto populates my timesheet and my supervisor can quickly and easily approve
Procedures
I can easily access the procedures for the work I am doing
Less Paper
I can capture the required information on my device and can even print our warning tags with my mobile printer saving time and improving accuracy
Supervisor Support
I can video chat with my supervisor while onsite when I have an issue I can't resolve
Training
My instructor and video based training is interactive and engaging on my mobile device
Enhanced safety
I can take photos of any abnormal conditions I find to share with my supervisor

Schedule GBE-6

THE NARRAGANSETT ELECTRIC COMPANY
d/b/a NATIONAL GRID
RIPUC Docket No. 4770
Witnesses: Johnston and Connolly

Schedule __ (GBE-6)

Example of Customer Experience Capabilities with Gas Business Enablement


nationalgrid | gas business enablement
Customers Capability Aspirations
Turn On
I could book a convenient appointment online. I could track progress online and I got a txt when service technician was on their way
Customer Inquiry
I was concerned when I saw an NG vehicle on my street. I rang them and they explained what was happening and put me at ease.
Request for Service
I made my request for service online and they kept me updated as it progressed.
Service Appointment
I scheduled my appointment online and got a txt massage to confirm their arrival
Appointment Change
I needed to move my appointment for service. I use the mobile app and made the change in a minute.
Safety Inspection
National Grid texted me to inform me they needed to inspect my equipment. I clicked on the link and could book an appointment that was convenient for me.
Move
Our move was completed as scheduled. We were notified when the service activated

Information Request AG-21-6

Request:

Referring to page 5 of Exhibit NG-GBE-1, please provide a complete and detailed description of the meaning of the following terms, as the Company uses it with reference to the both National Grid's U.S. gas distribution business and the GBE Program:

a. "Work Management;"
b. "Asset Management;" and
c. "Customer Enablement."

Response:

a. **Work Management**: The work-management system is used to coordinate, document and manage all work projects completed by the Company. The work management system will have an integrated field mobile application allowing a single view of all work with the ability to prioritize work. Attributes of the system include the following:

   - An enterprise-wide work management system, including scheduling and mobility platforms with ability to optimize routes.
   - Planning and prioritization capabilities to ensure commitments are met, mandated work is completed, and capital work is delivered.
   - Enterprise-wide standardized processes and roles.

b. **Asset Management**: The asset-management platform is used to coordinate, document and manage the installation, maintenance and repair of distribution assets. The asset management system will be integrated with the work management system and will provide a single view of all assets and system of record. Attributes of the system include the following:

   - An enterprise-wide Geographic Information System ("GIS"), investment planning, integrity management, and design tools integrated with the work management system.
   - Enterprise-wide investment planning and asset risk management capabilities.

c. **Customer Enablement**: Customer Enablement is a customer relationship management platform that will be integrated with the work management system to enable easier customer interactions through greater visibility to planned activities and scheduling of upcoming work. Attributes of the system include the following:

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- A common digital interaction platform utilized by Customer Contact Center with multi-channel, customer self-service options.
- Field employee access to real-time customer premise information and history.

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