BEFORE THE
RHODE ISLAND PUBLIC UTILITIES COMMISSION

DOCKET NO. 4770

TESTIMONY OF TINA BENNETT & ALLEN NEALE

ON BEHALF OF THE
RHODE ISLAND DIVISION OF PUBLIC UTILITIES AND CARRIERS

April 6, 2018

I. INTRODUCTION

Q. Please state your name, position, and business address.

A. My name is Tina Bennett. I am a Principal Consultant and Vice President at Daymark Energy Advisors (Daymark). My business address is 370 Main St., Suite 325, Worcester, Massachusetts 01608.

Q. Please summarize your professional experience and qualifications.

A. I have over 25 years of diverse energy industry experience. I am experienced in natural gas and electric market operations and have executive leadership experience in strategic decision making, management and operational effectiveness and critical IS initiatives.

I have served in my current role as a Principal Consultant at Daymark since April 2017 where I advises electric and natural gas industry clients on executive-level business operations, including strategic planning, capital planning, budgeting, resource development, and asset transactions. Since joining Daymark, my work has included management consulting, merger and acquisition support, wholesale market analysis, clean energy strategy and policy, and new resource review.

Prior to joining Daymark, I was President of Conservation Services Group where among other things, I led a strategic initiative to re-platform the company's IT infrastructure and IS systems. From 2001 to 2011, I held a variety of positions at International Power including: Vice President, Asset Management and Information Technology (2007-2011) where I delivered a complete transformation and realignment of the company's information technology infrastructure and service team; Vice President, Special Projects (2006) where I led an effort to assess and mitigate regulatory compliance gaps in the company's trading operations; Vice President of Risk Management (2002-2006) where I managed the regulatory, risk management and settlement functions for the company; and Director of Trading Operations (2001-2002). Prior to that, I held various positions at PG&E National Energy Group (1998 – 2001), EnergyVision (1997-1998) and New England Electric System (1989-1997).

I received a Master's of Business Administration from Northeastern University. I also hold a Bachelor's of Science degree in Economics/Finance from Bentley University. Exhibit GBE-1 contains a complete description of my qualifications.

Q. Please summarize Daymark and its business.

A. Daymark provides integrated policy, planning and strategic decision support services to the North American electricity and natural gas industries. Daymark serves a diverse clientele from our offices in Worcester, Massachusetts and Portland, Maine by providing consulting services to organizations involved with energy markets, including renewable energy producers, private and public utilities, transmission owners, energy producers and traders, energy consumers and consumer advocates, regulatory agencies, and public policy and energy research organizations. Our technical skills include cost allocation, rates and pricing, power market forecasting models and methods, economics, management, planning, energy procurement, infrastructure capital investment planning, contracting and portfolio management, and reliability assessments. Our experience includes detailed analyses of energy and environmental performance of electric systems, economic planning for transmission and distribution, and market analytics.

Q. Have you previously testified before this Commission?

A. No.

Q. Have you previously submitted expert testimony before other public utility commissions?

Yes. I filed testimony in New Hampshire and Massachusetts in the early 1990's.

Q. Please state your name, position, and business address.

A. My name is Allen R. Neale. I am a Consultant working in conjunction with Daymark Energy Advisors ("Daymark"). My business address is Allen R. Neale c/o Daymark Energy Advisors, 370 Main Street, Suite 325, Worcester, Massachusetts 01608.

Q. Could you please describe your educational background?

A. Yes. I received a Master's of Business Administration from Southern New Hampshire College. I also have a Bachelor of Science in Engineering Technology in Mechanical Engineering from Wentworth Institute.

Q. Please summarize your professional experience and qualifications.

A. Yes, I have over 25 years of experience in the Natural Gas Distribution business in Massachusetts. In 1973, I joined Essex County Gas Company (then Haverhill Gas) as a Junior Engineer and subsequently held the following positions: Corrosion Engineer; Supervisor of Distribution; Administrative Assistant; Vice President of Engineering, Meter Shop and Production; and finally, Vice President of Gas Supply, Planning, Rates, Regulatory, and Environmental Matters. As these various job titles indicate, I have a broad range of experience at various levels within a gas distribution company, including field work as a distribution system corrosion engineer and as a supervisor of distribution overseeing main and service repair, replacement and new installations. Later, I was in charge of the Department of Transportation ("DOT") and Massachusetts Department of Public Utilities Annual Reports. My years as a Vice President provided substantial management and executive decision-making experience as well as involvement in rates and regulatory affairs. In 1999, following regulatory approval of the merger involving Essex and the Boston Gas Company, I became the President of ARN Enterprises which owned and operated CRW Finishing Company, a metal finishing business. A copy of my resume is attached hereto as Exhibit GBE-2.

Q. Have you previously testified before this Commission?

A. Yes. I recently testified on behalf of the Division in the 2019 NGRID Gas ISR Filing – Docket No. 4781.

Q. Have you previously submitted expert testimony before other public utility commissions?

A. Yes. A complete listing of my appearances is included in Exhibit GBE-2.

Q. On whose behalf are you testifying in this proceeding?

A. We are testifying on behalf of the Rhode Island Division of Public Utilities and Carriers ("Division".)

Q. What is the purpose of your joint testimony?

A. Our testimony evaluates certain issues related to the Gas Business Enablement ("GBE") Program proposed by Narragansett Electric Company ("NECo" or "the Company") presented in the testimony and exhibits of Company Witnesses Anthony H. Johnston & Christopher J. Connolly. Issues reviewed include:

- The Need for the proposed GBE program in Rhode Island,
- Cost of the GBE program to Rhode Island customers,
- National Grid ability to implement the GBE program, and
- The proposed GBE cost recovery mechanism

Q. Please summarize your findings and recommendations regarding these issues.

A. Generally, we support the Company's implementation of the proposed GBE program for use in Rhode Island. However, GBE is the first large-scale, multi-year IS project that National Grid has embarked on since the U.S. Foundation Project ("USFP") implementation. We are concerned that the same, or similar issues could affect National Grid's effort to carry out the full scale of its planned GBE implementation and deliver the expected program benefits on time and on budget. We also have some concerns about potential impact on customers related to implementation of the GBE program happening first in Rhode Island.

As such, we have embedded in our recommendations certain protections (discussed in further detail in our testimony) that will provide protection to Rhode Island customers. The Division estimates that its GBE recommendations will result in a Rate Year revenue requirement of $2,922,991 for Narragansett Gas and $473,727 for Narragansett Electric, a revenue requirement reduction of $977,286 and $83,599, respectively, from the Company's March 2, 2018 updated GBE revenue requirement in MAL-36 (REV-1).

We may want to supplemental this testimony pending the Company's response to outstanding Division data request related to the Company's progress to date on implementing the GBE program.

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

A. Yes. I am sponsoring the following exhibits:

- GBE-1 - Resume of Tina Bennett
- GBE-2 – Resume of Allen Neale
- GBE-3 – Proposed GBE Revenue Requirement

II. OVERVIEW OF GAS BUSINESS ENABLEMENT

Q. Please briefly describe the Gas Business Enablement program being implemented by the Company.

A. As described by the Company, GBE is a multi-year, enterprise-wide program that

> *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. 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 the implementation of GBE will reduce systems applications, databases and spreadsheet systems from 37 to 19.* [1]

From a functional perspective, the Company expects that the GBE program will:

- *Streamline processes and creating a single set of integrated applications for core operating systems, significantly improving the ability of employees to perform their job functions effectively.*
- *Improve state & federal regulatory compliance across all three jurisdictions by improving work management and the flow of information necessary for compliance with state and federal regulatory requirements across all three jurisdictions.*
- *Improve the customer experience to meet the relatively high customer expectations that exist in today's operating environment.*[2]

In addition, for certain business functions that have shared responsibilities across Narragansett Gas and Narragansett Electric, standardized processes and new solutions will be implemented through the GBE to support electric customers.[3]

[1] Johnston and Connolly, page 5, line 22 – page 6, line 10.
[2] Johnston and Connolly, page 6, line 16 – page 7, line 2.
[3] Johnston and Connolly, page 7, lines 5-9.

Q. What has the Company presented as the estimated cost of the GBE program?

A. The Company estimates that it will cost approximately $478.3M, consisting of $315M of capital costs and $163.2M of one-time operating expenses.[4] to implement GBE. The GBE Costs will be incurred by National Grid USA Service Company, Inc. ("Service Company") and allocated to its affiliated U.S. operating companies including Narragansett Gas and Narragansett Electric as rent expense which will be discussed later in this testimony. The Company estimates a cost of $33.3M for Narragansett Gas and $3.8M for Narragansett Electric.[5]

Q. What is the Company's timeline to implement GBE?

A. The Company plans to implement GBE in stages starting in Rhode Island, followed by its Massachusetts companies, then Niagara Mohawk (NIMO) and finally Keyspan. The GBE program began in 2017 and is expected to continue through 2023. An implementation roadmap was provided by the Company in Schedule GBE-4. A timeline was provided in Attachment DIV 17-13, page 6 of 7.

III. GBE ANALYSIS

Q. What documents have you reviewed in your review and analysis of the Company's GBE program?

A. We have reviewed all the testimony in the application regarding the Company's GBE program. Our review focused on the testimony and schedules of Anthony H. Johnston & Christopher J. Connolly (Book 7 of 17) related to GBE, relevant sections of Melissa A. Little (Book 8 of 17) and Schedule MAL-36 (REV-1), National Grid U.S.A ("National Grid") GBE sanctioning documents[6], NY PSC GBE Panel

[4] Johnston and Connolly, page 42, lines 8-12
[5] Data Response Attachment DIV 3-61
[6] Discovery Request Attachment DIV 33-53.

Testimony in the Niagara Mohawk rate case in New York (Case 17-E-0238 & 17-G-0239) ("NIMO rate case") [7], and the NorthStar Report[8].

We have also issued discovery requests to the Company on the topics we have been requested to review. We have reviewed all responses to these requests and those from other parties pertaining to the topics we have been requested to review.

NEED FOR THE GBE PROGRAM IN RHODE ISLAND

Q. Why does the Company assert GBE is needed?

A. The Company asserts that 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 various business processes and discerning whether, when and how work is getting done.[9] In Rhode Island, the Company attributes these challenges to the number of manual, paper based processes used to manage work. The Company describes its current gas distribution operations functions as "an inefficient patch-work of legacy systems and manual spreadsheets to perform critical gas operation activities".[10]

The Company also points to the operational risk associated with the unsustainable position of its current, legacy systems as a significant factor creating the impetus for the GBE program. According to the Company, 94% of the "front office" systems currently used by National Grid's U.S. gas distribution business will reach end of useful life within two years, making it increasingly difficult to maintain the reliability of critical, core operating systems.[11] In Rhode Island 17 of the 37 (or 46%) of the systems used by Narragansett Gas are currently at end of

[7] In the Matter of Niagara Mohawk Power Corporation d/b/a National Grid, Cases 17-E-0238 & 17-G-0239, August 2017, Prepared Testimony of: Staff Gas Business Enablement Panel.
[8] Discovery Response Attachments PUC 5-23-1.
[9] Johnston and Connolly, page 12.
[10] Johnston and Connolly, page 38.
[11] Johnston and Connolly, page 15.

life. The Company plans to replace all 17 end of life systems as part of the GBE program. Narragansett Electric relies on 8 of the end of life systems that are planned for replacement by the GBE program. The Company defines end of life as "a system that is no longer receiving functional updates; no longer receiving security updates; and where commercial support arrangements from the system vendor are no longer available.[12]

The Company also cites customer enablement and changing customer expectations as creating an imperative for the GBE program.[13] Mr. Johnston and Mr. Connolly explain in their testimony that the electric and gas distribution industries are experiencing pressure to meet customer expectations formed by customer experiences with other goods and services vendors, that are increasingly supported by digital technology, allowing quick and easy customer-service interfaces.[14]

Q. Do you agree with the Company's assessment that the GBE program is needed for Rhode Island?

A. Yes, to a large degree. Based on our knowledge of Narragansett Gas operations through the Infrastructure, Safety and Reliability Plan proceedings the Company currently produces a System Integrity Report that informs them of the leak trends of its' pipeline system which should allow the Company to alter pipe replacement programs to more effectively reduce system risk. The Company's gas business appears to have adequate existing GBE systems especially concerning core pipe replacement functions. However, 46 percent of the operational systems Narragansett Gas relies on are no longer supported by the vendor and no longer receiving functional or security updates.[15] A serious failure of one of these systems could significantly impact the Company's operating capability and gas

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[12] Discovery Response to Division 12-2.
[13] Joint Testimony of Mr. Johnston and Mr. Connolly, Page 13-14.
[14] For example, allowing customers to choose their communication method such as on-line scheduling options and text messaging for service appointment updates.
[15] A list of the effected systems was provided by the Company in Attachment DIV 17-9, Tab 4 (b)(i)(ii)(iii)(v).

safety program in the future. Though the Company could rely on its own IT staff and third party vendors to support these systems, this approach is generally not sustainable. It is also not recommended for critical operating systems.

Complexity resulting from manual workarounds and security issues caused by a lack of vendor supported upgrades increase system risk over time. The addition of manual workarounds also increases operational risk associated with human errors and creates operational inefficiencies. Furthermore, once software becomes obsolete, it can become more difficult to find qualified support staff or third-party vendors to support it.

As systems approach end of life and need replacement, it is normal course of business for a company to evaluate and upgrade its operational systems taking into consideration changing business requirements. In this case, National Grid has taken this opportunity to upgrade its operational system to improve efficiencies by standardizing processes and minimizing manual systems and workarounds and adopting modern technologies that will provide an improved customer experience. In this context, it's important to evaluate whether the proposed GBE program is the preferred system upgrade for Rhode Island's gas operations. We evaluated this by reviewing the other alternatives considered by National Grid.

ALTERNATIVES CONSIDERED

Q. Please describe other alternatives National Grid considered before selecting the proposed GBE project.

A. Sanctioning documents and internal management presentations provided by the Company indicate that they evaluated the following 5 alternatives for GBE[16]:

[16] Page 5 of 51 of the Accenture National Grid Business Enablement Program Business Case Deliverable, December 9, 2016 provided in response to discovery request Attachment DIV 33-53-5.

1. *Tech stabilization* – This option was designed to provide limited support for the current systems and upgrade infrastructure where possible. Total National Grid U.S. cost of $15-$20M.
2. *Like for like replacement* – This alternative was designed to upgrade or replace current systems where possible on a standalone system bases with limited system consolidation. Total National Grid U.S. cost of $221M.
3. *Backbone* – This alternative focused on replacing the core asset management/workforce management systems with scope limited to what is required to mitigate key risks. Total National Grid U.S. cost of $273M.
4. *Value oriented - jurisdictional deployment ("Proposed GBE Solution")* This alternative included the backbone scope, plus enhanced capabilities with an initial focus on risk reduction. Enhanced capabilities include strategic change, talent & operating model, customer interaction, advanced asset & work management, supply chain & technical training. It addresses data quality and technical training gaps and transitions support and maintenance to a modern SaaS model. This option include deployment by jurisdiction to allow for refinements prior to a broader rollout. Total National Grid U.S. cost of $466M ($193M associated with enhanced capabilities).
5. *Value oriented – accelerated deployment* – This alternative is the same as 4., above, but takes a more aggressive deployment approach. Total National Grid U.S. cost of $466M ($193M associated with enhanced capabilities).

National Grid selected to implement Option 4. – the *Value oriented jurisdictional deployment* alternative.

Q. Why did the Company reject the other alternatives?

A. National Grid rejected the *Tech Stabilization* option on the basis that it did not address the any of the current IS issues and involved spending money on obsolete or unsupported systems. It would only have deferred the necessary investments to upgrade/replace near obsolete and unsupported systems and, therefore would not be a sustainable solution in the long-term.[17]

The *Like for Like* option was rejected on the basis that it would only address the issue of having aging, unsupported systems and would not deliver any additional capabilities, align processes, increase integration between systems or address the broader challenges and opportunities that National Grid's gas business faces specifically including gas safety and compliance challenges.[18]

After further evaluation, the Company also rejected the Backbone option because National Grid determined that this option would largely be a technology implementation-focused solution and would not provide the full range of benefits desired. National Grid determined that anticipated inefficiencies and inconsistent use of the system under this option (caused by lack of full integration and additional capabilities) would offset the financial benefits.[19]

The Value-oriented Accelerated Deployment alternative, identical to the GBE program selected by the Company except deployed on an accelerated timeframe (4 ½ years vs. 5 years), was rejected because of the higher cost ($466M vs. $458M), and higher implementation risk resulting from the accelerated deployment.[20]

A summary of the Company's assessment can be found in Attachment DIV 3-53-5, page 15 of 51.

[17] Discovery response to PUC 5-7.
[18] Ibid.
[19] Ibid.
[20] Ibid.

Q. Do you support the Company's selection of the proposed GBE solution for Rhode Island?

A. Yes. As described above, National Grid explored a variety of alternative solutions before the proposed solution was approved by its U.S. Sanctioning Committee. Based on National Grid's documented description and reasoning for rejection of the *Tech Stabilization*, *Like for Like Replacement* and the *Value-oriented Accelerated Deployment* alternatives provided in response to PUC 3-53, and summarized above, we accept National Grid's reasoning for rejecting these alternatives.

Based on the Company's description of the functionality in the proposed GBE program, we believe that the proposed solution if implemented as planned can meet the needs for RI. We also believe the *Backbone* alternative as summarized above could adequately meet the needs for Rhode Island at a $185M lower implementation cost (an estimated reduction in cost of $14.4M for Rhode Island if deployed across all jurisdictions).[21]

However, since National Grid has already decided to move forward with the proposed solution in its other jurisdictions, the *Backbone* replacement option would need to be evaluated as a Rhode Island only alternative.

Q. Do you believe a Rhode Island only alternative would be beneficial for Rhode Island?

A. No. We believe that a Rhode Island only *Backbone* replacement alternative would likely result in higher cost and higher implementation risk for Rhode Island for the following reasons:

- It would cost more for the Company to implement a standalone solution than a shared solution in Rhode Island due to the inability to leverage buying power, the implementation team and skill sets across jurisdictions

[21] Estimated by multiplying $185M by an average allocation factor for RI of 7.8%.

and share costs. National Grid performed a high-level analysis comparing a standalone system vs. an enterprise solution and concluded that for Rhode Island a standalone system would cost an estimated $86.5M ($49.4M (or 130%) more than Rhode Island's allocated cost of the enterprise solution of $37.1M) as proposed by the Company.[22]

- It would limit National Grid's ability to cost effectively integrate the system with other shared systems and therefore would limit NECo's ability to leverage additional capabilities and process improvements gained in other jurisdictions
- It would be a riskier program for National Grid to attempt to implement at the same that it is focused on deploying a more comprehensive solution across its other jurisdictions and as a result would subject NECo to greater implementation risk.

For these reasons, we support the Company's implementation of the proposed GBE program for use in Rhode Island. However, we ask the Commission to consider certain Division recommendations provided elsewhere in this testimony, and as further provided by the Division in the testimony of Mr. Ballaban related to the GBE program.

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ABILITY TO IMPLEMENT

Q. Do you have any concerns about the Company's ability to implement GBE in a timely and cost-effective manner?

A. Yes. The GBE program is a complex, multi-year, multi-jurisdictional project that impacts virtually all of the Company operational systems. Large scale projects like this are difficult to implement and require significant cultural and operational changes to occur. It's much like changing the tires on a bus while speeding down

[22] Discovery response to Division 3-64.

the highway. For a gas distribution company responsible for gas safety and reliability, the stakes are even higher.

To add further complexity, National Grid is also implementing a considerable number of IT projects over the same time period. In the Rate Year alone, the Company is seeking recovery of $271M of non-GBE IS investments comprised of 118 projects (investments).[23]

Q. Has National Grid undertaken any large scale IS investment in the past 5 years?

A. Yes. In 2012, National Grid was scheduled to implement USFP. USFP, similar to GBE was a solution developed by National Grid to replace and integrate multiple systems and processes across its operations following the merger between National Grid USA and Keyspan in 2007. The objective of the project was the integration of National Grid's Human Resources, Supply Chain and Finance (Back Office/Enterprise Resource Planning) information technology platforms and business processes.[24]

National Grid experienced significant challenges with the delivery of this program resulting in serious operational issues and substantial cost overruns. According to the NorthStar report, the program was approved at a budget of $393M in total project costs with a "go live" date of October 1, 2012. The system went live on November 5, 2012.[25] Soon after, several serious issues materialized. Remediation efforts required significant overspending beyond the project budget to address the issues. According to the NorthStar report, actual spending was $945M – more than double what National Grid had budgeted.[26]

[23] See workpapers MAL-6a to 6c for more detail.
[24] Attachment PUC 5-23-1, page 64.
[25] Discovery Attachment PUC 5-23-1, page 65 – 66.
[26] Discovery Attachment PUC 5-23-1, page 70.

GBE is the first large-scale, multi-year IS project that National Grid has embarked on since the USFP implementation. We are concerned that the same, or similar issues could affect National Grid's effort to carry out the full scale of its planned GBE implementation.

Q. How did you evaluate the Company's plan to implement GBE?

A. The NYPSC staff GBE panel performed a comprehensive technical review of the GBE program in the Niagara Mohawk system, including a review of the conclusions and recommendations provided in the NorthStar report and the steps taken by National Grid to address the NorthStar recommendations. We reviewed the NPYSC Staff GBE Panel testimony in the above referenced cases;[27] as well as, the Company's response to PUC 5-23 in which the Company explained how GBE as proposed addressed the NorthStar recommendations. We also reviewed other evidence provided by the Company in this case.

Q. What were the relevant findings of the NYPSC Staff GBE Panel as it relates to the Company's ability to implement the GBE program?

A. The NYPSC Staff identified 7 conclusions relevant to GBE and analyzed the National Grid's approach to addressing each conclusion as follows[28].

I. National Grid USA was unprepared for the complexity and magnitude of the USFP and should have had discussions with other utilities to gain industry experience before implementation.

In response to discovery request PUC 5-23, the Company explained that in the early stages of planning and business case development, the GBE team conferred with three peer utility companies to gain insight and lessons learned from their experiences implementing similar complex information

[27] In the Matter of Niagara Mohawk Power Corporation d/b/a National Grid, Cases 17-E-0238 & 17-G-0239, August 2017, Prepared Testimony of: Staff Gas Business Enablement Panel.
[28] Discovery response Attachment PUC 5-23-2, page 19-20.

technology projects.[29] The Company further stated that these lessons learned informed the program's development of strategy, delivery approach, and methods as well as governance and management framework. The Company further explained that the GBE team continues to engage with other companies directly and through various forums, networks and user groups.

We feel that National Grid has adequately addressed this concern as it relates to the GBE program and encourage the Company to continue engagement and learning from other companies during and post implementation of the new system.

II. National Grid USA's financial processes lacked sufficient internal control and while the USFP was expected to solve this issue, the end result was that the SAP program implemented through the USFP did not solve the internal control issue.

The NYPSC Staff GBE Panel found that National Grid had not addressed this issue in its implementation plan. Specifically, the Company had stated that it expects the GBE program to provide additional internal controls to improve its gas safety compliance by replacing manual processes with electronic ones. While the NYPSC Staff GBE Panel supports the GBE investment conceptually, they expressed concern that the internal controls built into the program functionality may not fully solve the Company's internal control issues, similar to what happened with the USFP financial internal controls.[30] In the Company's response to discovery request 5-23-3, it did not address this issue.[31] As a result, we

[29] Further details of lessons learned are provided in Discovery request Attachment PUC 5-23-3.
[30] In the Matter of Niagara Mohawk Power Corporation d/b/a National Grid, Cases 17-E-0238 & 17-G-0239, August 2017, Prepared Testimony of: Staff Gas Business Enablement Panel, page 22, line 17 – page 23, line 5.
[31] Discovery request PUC 5-23.

cannot disagree with the NYPSC Staff GBE Panel's findings, and share their concern.

III. National Grid USA was unable to quantify the incremental benefits from the USFP, such as improved operational efficiencies, consolidation of cost reductions, and therefore it was difficult to measure program success.

As a precursor to sanctioning (or approving) the GBE program, a high-level design, strategic roadmap and formal business case, including both costs and benefits, were developed.[32] This was confirmed by our review of the National Grid sanctioning documents and management presentations provided by the Company as Attachments DIV 3-53-1 through Attachment DIV 3-53-5. The GBE team has also developed a value framework to baseline, measure and track improvements in operational performance metrics as a result of the program. Benefits have been incorporated into various governance and contractual documents as measures of program success.[33] Attachment Division 12-3 contains a summary of the estimated benefit for Rhode Island as well as the detailed analysis showing how these benefits were calculated for and/or allocated to each state jurisdiction.

We are pleased that National Grid has incorporated these benefits into governance and contracts as a measure of program success. However, we are concerned that these benefits have not been reflected in the proposed revenue requirement. By not offsetting the implementation cost with the benefits, the risk of achieving these benefits falls solely on the backs of the ratepayers who are paying for the investment. It is also not clear how or when these benefits will flow through to rate payers. This will be addressed further in this testimony.

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[32] Ibid.
[33] Ibid.

IV. National Grid USA did not focus sufficiently on the individual utilities. The NorthStar report raised concerns that the "enterprise" level approach adopted by USFP did not sufficiently recognize the jurisdictional priorities and requirements, nor did it isolate the negative impacts of a problematic system deployment.

The Company explains that National Grid has addressed this by applying scaled agile principles and methodologies to its deployment of the GBE program. The Company further explains that although the solution will be standardized across all jurisdictions to the extent possible, its will be deployed on an operating company basis in multiple releases designed to shorten the time between program mobilization, delivery of new functionality and benefit capture. The Company claims this will also allow deployments to be customized to meet the needs of the operating company in terms of training and timing, etc. It should also limit the negative impact of issues, should they arise and allows for lessons learned to be incorporated from one deployment to the next.[34]

We concur with the NYPSC Staff GBE Panel conclusion that while only real world experience can definitively answer whether this approach will sufficiently address the issue, the agile approach reflects a reasonable effort to address the problems stemming from the universal go live date from the USFP.[35]

Nevertheless, we have concerns about National Grid implementing GBE first in Rhode Island. One of the features of the Agile approach is the ability to deliver a project in smaller increments beginning with a

[34] Ibid.
[35] In the Matter of Niagara Mohawk Power Corporation d/b/a National Grid, Cases 17-E-0238 & 17-G-0239, August 2017, Prepared Testimony of: Staff Gas Business Enablement Panel, page 25 line, 5-9.

Minimum Viable Product ("MVP")[36] release and iterating with additional features and functionality as you continue to implement the system. As shown on the GBE program Roadmap provided by the Company as GBE-4, following the initial MVP release in Rhode Island, the Company will begin to deliver and implement GBE in other service territories while expanding the feature set. We are concerned that because Rhode Island is going first, it is likely to experience greater issues than other jurisdictions. We are also concerned that there is a risk that National Grid's initial implementation in Rhode Island will not work in one of its larger, more complex jurisdictions. If the functional or process gap is material enough, it could result in significant program redesign that could result in cost overruns and delays in the implementation schedule. A delay in the implementation schedule will at best delay realization of GBE benefits in Rhode Island. However, if the MVP release initially deployed in Rhode Island doesn't fully meet the Company's operational needs, it could also result in higher operational risk and costly workarounds for NECo. Once the gaps are addressed, it could also mean redeployment of major pieces of functionality and/or process changes in Rhode Island which could cause incremental cost at the NECo operating company level. In addition, we are concerned that as National Grid turns its attention to deployments in larger, more complex jurisdictions, support issues unique to Rhode Island may get less attention.

V. The staffs at National Grid's NY utilities were not able to generate the reports needed for managers to make informed decisions due to lack of training or ability.

According to the Company, National Grid has addressed this finding in two ways. First, they have engaged field users and managers earlier in the

[36] Attachment DIV 3-53-5, page 17, Footnote 1 describes Minimum Viable Product as the least scope that could feasibly be deployed.

requirements gathering and design process helping to ensure that needed functionality is captured. Second, the GBE program is providing functional training not only to end users, but also to managers and other leaders on how to effectively lead change in their organization which they hope will significantly mitigate adoption-related challenges.[37]

We concur with the NYPSC Staff GBE Panel that generally the Company had addressed the issue, but we have continued reservations in this area, as it is difficult to quantify employee acceptance and preparedness for implementing and using the new processes.[38]

VI. Zero-based budgeting was not used to forecast operation and maintenance ("O&M") budgets.

The Company explained and the NYPSC Staff GBE Panel confirmed that zero-based budgeting was used to forecast O&M budgets for GBE. This means that each budget item was analyzed to determine its future cost from the bottom up starting at $0 without using historical costs.[39]

The Company further explains that the budget was developed by Accenture, one of the top system integrators, and reviewed by PwC, National Grids business assurance partner for the GBE program. PwC concluded that the cost estimate for the program:

i. Was appropriate compared with the total costs of other industry benchmarks of similar scale projects; and

[37] Discovery request PUC 5-23.
[38] In the Matter of Niagara Mohawk Power Corporation d/b/a National Grid, Cases 17-E-0238 & 17-G-0239, August 2017, Prepared Testimony of: Staff Gas Business Enablement Panel, page 25, line 23 – page 26, line 8.
[39] Discovery request PUC 5-23 and In the Matter of Niagara Mohawk Power Corporation d/b/a National Grid, Cases 17-E-0238 & 17-G-0239, August 2017, Prepared Testimony of: Staff Gas Business Enablement Panel, page 26, line 19-21.

ii. The 4.5-year deployment duration in the roadmap was achievable.[40]

VII. The capital review and planning process for National Grid USA focuses too heavily on spending variances and not enough on the underlying drivers of these variances.

The NYPSC Staff GBE Panel concluded that it could not discern from the information provided to them whether National Grid had addressed this finding[41].

In response to Discovery request PUC 5-23, the Company explained that the combination of zero-based budgeting to forecast both capital and O&M budgets, fixed priced vendor contracts and oversight by the GBE steering Committee will provide National Grid with clear visibility on drivers of spending variances.

Though we don't dispute the Company's response that National Grid will have better visibility on drivers of spending variances, we do not find that this response addresses the heart of the concern that "Senior management's emphasis on financial performance results in a "variance" management focus, rather than attention to root cause"[42].

Overall, the NYPSC Staff GBE Panel found that while National Grid did address many of the issues raised, it left others unaddressed.[43]

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[40] Discovery request PUC 5-23.
[41] NY testimony, page 27l, line 2 – 3.
[42] Attachment PUC 5-23-1 page 87 of 265.
[43] In the Matter of Niagara Mohawk Power Corporation d/b/a National Grid, Cases 17-E-0238 & 17-G-0239, August 2017, Prepared Testimony of: Staff Gas Business Enablement Panel, page 27 line 6-7.

Though the care and effort that National Grid has taken to improve its implementation capabilities are appreciated and appear directionally correct, it is difficult for us to assess whether the steps taken will lead to significantly better results. Ultimately, it all comes down to execution and the Company has yet to show that it is capable of fully implementing this level of IS investment on time and on schedule. As noted previously, the fact that National Grid will deploy the GBE program in Rhode Island first, in our opinion puts a higher degree of project risk on Rhode Island customers.

At this time, we are awaiting a response from the Company to the Division's data request 36.3 to determine if National Grid was on schedule (target release date 3/31/18) in delivering its first release in RI associated with integrated Operations/CMS functionality including:

- Corrosion and Instrument & Regulation,
- Collections and
- Integrity Management (Corrosion & I&R)

We also requested any updates or currently anticipated updates to the High Level GBE Roadmap provided in Schedule GBE – 4. Depending on the Company's response, we may want to supplement this testimony and the Division's recommendations herein.

COST RECOVERY

Q. How did the Company allocate the cost of the programs to its jurisdictional companies?

A. Because the GBE program is a shared investment, only a portion of the total cost of the program is allocated to Rhode Island. National Grid used allocators from its Service Company Allocation Manual[44] to allocate the GBE program costs to its operating companies. The resulting allocations to each operating company were

[44] The Service Company Allocation Manual contains a set of general allocators used to allocate multi-jurisdictional projects across its subsidiaries.

provided in Attachment DIV 17-11. The majority of the GBE program costs are allocated using the gas retail customer allocator – C210 which allocates cost based on the number of customers. Exceptions include two workstreams: (1) Power Plant enhancements that are allocated to all companies using G012 (the general all company 3 point allocator), and (2) workstreams related to customer engagement and workforce management SMD that are also allocated to electric distributions systems using the C-175 (all retail allocator)[45]. The allocations 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.

As a result, the Company estimates a cost of $10.2M in non-recurring operating expense related to GBE implementation as well as $32.9M in capital cost associated with the Rate Year and Data Years 1 and 2 ($25M in depreciation and $7.9M in return) for Narragansett Gas and Narragansett Electric combined[46].

Incremental run the business O&M expense of $5.7M is also projected to be incurred by NECo associated with end-user training, data conversion from the legacy applications, non-system related business process documentation and GBE program management of schedule, resources, finance, risks and performance off-set by Type I estimated cost savings[47].

Q. Does the allocation of cost fairly represent the benefits received?

A. No. As described above, National Grid's allocation methodology is fundamentally consistent with the generally accepted cost allocation principals used by National Grid to allocate prudently incurred Service Company costs to its operating companies.

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[45] Attachment Division 3-61.
[46] Schedule MAL-36 REV-1, pages 6 & 11.
[47] Ibid.

GBE Program Cost vs. Benefits ($Millions)

	Total Project	NGUSA Parent Share	NGUSA Parent Share % of Total	NY Share	NY Share % of Total	MA Share	MA % of Total	RI Share	RI % of Total
GBE Costs	$ 478.3	$ 0.9	0.3%	$ 109.7	42.5%	$ 41.0	15.9%	$ 37.1	7.8%
GBE Benefits	$ 258.5	$ 53.8	20.8%	$ 163.7	63.3%	$ 32.2	12.4%	$ 8.9	3.4%

However, as shown in the table above, the GBE program (as allocated) is expected to deliver a significantly higher proportion of benefits to New York than Rhode Island and Massachusetts. So much so that New York customers will receive a net benefit while NECo rate payers will pay 7.8% of the cost of the project while only receiving 3.4% of the benefits over the life of the system.[48]

Q. Should the Commission consider a different allocation methodology for the GBE Program?

A. To the extent the Commission continues to find merit in using the generally accepted set of generic cost allocators for all prudently incurred multi-jurisdictional projects, then the Division finds merit in the GBE plan being treated as any other multi-jurisdictional expense.

However, if the Commission accepts a different method of cost allocation related to other multi-jurisdictional investments, like the Company's proposed recovery of the GIS enhancements which is discussed in Chapter 3 of PST-1 that was originally filed in this docket, then the Division asks that the Commission recognize that in the case of the GBE program, Rhode Island is not getting the same level of benefit as other jurisdictions. And, in fairness to Rhode Island ratepayers, the Division recommends that the Commission review the cost allocators for the GBE program in the similar manner and ask the Company to revise its revenue requirement to reflect an allocation of cost on the basis of how benefits are expected to be realized.

Q. Is this the Division's only concern regarding the GBE cost allocation?

[48] Attachment PUC 9-18-1 and Attachment DIV 3-61.

A. No. As discussed above, we are concerned about the significant risks associated with implementing a project of this magnitude on time and on budget, particularly given the Company's recent history with the USFP. We are concerned that the use of general allocators could result in cost over runs caused by complexity in other jurisdictions and result in higher cost for Rhode Island rate payers.

Q. Did the Company remove non-recurring GBE program related costs from the test year?

A. Yes. The test year includes $1.5M of 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.[49] According to the Company as stated in the joint testimony of Johnston and Connolly, these costs have been removed from the test year.[50]

Q. Please summarize how the Company's proposes to recover the cost of GBE.

A. Schedule MAL 36 (REV-1), as resubmitted by the Company on March 2, provides a summary of the GBE revenue requirement for Narragansett Gas and Narragansett Electric. At a high level, the Company has proposed recovery of costs associated with non-recurring pre-rate year expenses as well as capital costs, non-recurring operating expenses and run the business expenses incurred in the rate year as well as data year 1 and data year 2. The proposed recovery of each of these components is discussed below.

Q. Please summarize how the Company's proposes to recover non-recurring pre-rate year GBE program implementation costs.

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

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[49] Joint Testimony of Johnston and Connolly, page 45, line 10-14.
[50] Ibid.

deferral balance at August 31, 2018. Cumulative operating expenses incurred by the company for GBE through June 30, 2017 amounted to $1.5 million.[51]

Q. Do you support the Company's proposal to recover non-recurring pre-rate year GBE program implementation costs?

A. No. A request for pre-rate year expenses goes against Rhode Island's longstanding judicially created rule against retroactive ratemaking that prohibits the Commission from using current rates to recover past losses or gains, subject to narrow exceptions. It should also be noted that National Grid did not propose recovery of pre-Rate Year GBE costs in the previously referenced Niagara Mohawk rate cases[52]. As previously discussed, the Company has acknowledged that the majority of its gas business operating systems are at end of life and are in need of replacement. The Company, in its normal course of business, should be evaluating and upgrading their operational systems as they approach end of life and as business needs change. We see no need to recommend an exception to this rule and therefore, recommend that the Commission deny recovery of pre-rate year expenses.

Q. Please summarize how the Company's proposes to recover capital expenses associated with the GBE program implementation costs.

A. The Company proposed traditional capital recovery including a return on and of capital expenses associated the GBE program implementation. The total capital cost associated with the GBE program is estimated at $315M. Narragansett Gas's allocation of this cost is estimated at $21.3. Narragansett Electric's allocation is estimated at $3.8.[53] National Grid will recover return on and of capital expenses associated with GBE Program costs through service rent expense, consistent with similar IS projects. National Grid will depreciate capital cost associated with the GBE program implementation over 10 years.

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[51] Joint Testimony of Johnston and Connolly, page 47, line 9-12.
[52] Discovery response Division 5-17.
[53] Discovery response Attachment DIV 3-61.

Q. Do you support the Company's proposal to recover capital expenses associated with the GBE program implementation costs?

A. Yes, but only in conjunction with certain recommendations that offer additional customer protections described in more detail below.

Q. Please summarize how the Company proposes to recover annual expenses estimated for the rate year and data year associated with the GBE program implementation.

A. The Company requested to create a regulatory asset for the rate year and data year annual expenses associated with implementation of the GBE program. Of the total estimated $478.3M GBE investment, approximately $162.M must be expensed as incurred under accounting standards. Narragansett Gas's and Narragansett Electric's combined allocation is estimated at $12M[54]. In response to Discovery 3-58, the Company explained that because of the magnitude of these incremental costs and the necessity of these costs to the success of the GBE program, the Company must be allowed timely recovery of these costs in the rate year and beyond.[55]

As further provided in Discovery 3-58, the Company estimates the incurrence of these costs to occur as follow:

Period	Total Non-Recurring Expense	Rhode Island Allocation
Rate Year	$48.4M	$3.3M
Data Year 1	$28.2M	$1.8M
Data Year 2	$13.0M	$0.8M
Total	**$89.6M**	**$5.9M**

[54] Discovery response to Division 3-58.
[55] The activities associated with these costs include: project management, training, data conversion and software as a service (SAAS).

Per Schedule MAL-36 (REV-1), the Company is proposing to amortize the recovery of $10.2M on a straight-line basis over the 10-year in-service period of each GBE system.

Per Schedule MAL-36 (REV-1), the Company also seeks to recover GBE program run the business expenses of $779,580 in the Rate Year as incurred[56]. It further proposes to offset these costs with an allocated share of the estimated savings from GBE program initiatives.

Q. Do you support the Company's proposal to recover annual expenses estimated for the rate year associated with the GBE program implementation?

A. Yes. But we do not support recovery beyond the rate year unless a multi-year rate plan was put in place that determined a comprehensive revenue requirement for each year of the plan beyond the first year, as described by Division witness Tim Woolf. To the extent this case only addresses one year of future costs, then the Division would not support an allowance of costs beyond the first year. In addition, however, support for the non-recurring one-time cost in the rate year still should be subject to additional customer protections described in more detail below.

Q. What other concerns and recommendations do you have regarding the Company's proposed cost recovery mechanism?

A. As previously discussed, GBE is the first large-scale, multi-year IS project that National Grid has embarked on since the USFP implementation. For reasons discussed previously, we have concerned about the Company's ability to carry out the full scale of its planned GBE implementation. We also have concerns about

[56] As previously noted, these costs are associated with end-user training, data conversion from the legacy applications, non-system related business process documentation and GBE program management of schedule, resources, finance, risks and performance off-set by Type I estimated cost savings.

the additional burden associated with implementing first in Rhode Island. In considering customer protections we reviewed the NYPSC recommendations for IS projects and GBE program costs summarized by the Division in the testimony of Mr. Ballaban. In the case of GBE, the Division recommends the Commission adopt the following customer protections:

- Limit cost recovery of and on capital in the Rate Year to 85% of the Rate Year allocated revenue requirement to Narragansett Gas and Narragansett Electric as filed by the Company in Docket 4770
- Limit the cost recovery of and for non-recurring operating expenses in the Rate Year to 85% of the Rate Year non-recurring operating expenses as provided by the Company in response to Division 3-58,
- In the event actual GBE costs are greater than 85%, but do not exceed filed amounts, allow the Company to create a regulatory asset to defer the balance of charges for future recovery subject to National Grid’s demonstration of cost and implementation results,
- Cap recovery of the GBE implementation program at the Company’s allocated cost of $37.1M ($33.3M for Narragansett Gas and $3.8M for Narragansett Electric) less pre-rate year expenses, and
- In the event actual GBE costs related to these investments are less than 85%, require the Company to create a regulatory liability to defer the balance of charges for the benefit of customers.

This recommendation does not preclude the Company from requesting recovery of future costs associated with the GBE program, but allows the Commission to review the Company’s implementation progress before approving recovery of such costs. The Division believes that these recommendations are appropriate to protect customers from potential cost overruns and provides a more appropriate allocation of risk to shareholders associated with cost control and project implementation. The resulting revenue requirement is summarized below and supported by the Division in the testimony of Mr. Ballaban.

Q. Do you have any other concerns or recommendations regarding the Company's proposed cost recovery mechanism?

A. Yes. In Discovery response Attachment DIV 9-18-1, the Company provided a schedule containing National Grid's estimate annual cost savings from the proposed GBE program over the next 10 years totaling $258.5M ($8.9M or 3.4% is estimated for Rhode Island). Furthermore, as documented in National Grid's sanctioning documents, part of its justification for the enhanced GBE program, the Company projected a 4.5 year payback on the proposed GBE program investment[57] This return is predicated on cost savings associated with Type I savings (direct cost savings) and Type II savings (indirect cost savings from workforce efficiencies). As discussed above, the Company's cost recovery proposal includes Type I as an offset to annual GBE program expenses. However, the Company did not include Type II savings as a reduction to the cost of the GBE program. As a result, it is unclear to us how these savings would result in savings to ratepayers.

We recognize that Type II cost savings are more difficult to achieve. Parkinson's law states that "work expands so as to fill the time available for its completion"[58]. This describes the organizational phenomenon that as the amount of work decreases, time is filled with other tasks or across the tasks that remain making efficiency savings difficult to achieve. It will take extreme discipline on behalf of National Grid to ensure that these savings are realized. Since this is a management risk, we feel that this risk should be borne by National Grid and its shareholders and not by ratepayers.

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[57] Discovery response Attachment DIV 3-53-5, page 16 of 51.
[58] http://www.businessdictionary.com/definition/Parkinson-s-Law.html.

Although Type II cost benefits only amount to between $12k - $124k[59] in the rate year, by setting the expectation that GBE cost savings will be used to offset GBE implementation costs, National Grid will be more incented to ensure timely delivery of these benefits to the benefit of ratepayers who paid for the program. Under the Company's proposal, rate payers are 100% at risk for the Company being able to produce the projected GBE cost savings. Even if some or all of the costs savings are delivered, there is currently no mechanism to return these savings to ratepayers until the Company decides to file its next rate case. Even then, it will be difficult to isolate these savings benefits from other movements in the Company's cost structure.

As an additional customer protection, the Division recommends that 85% of the Rate Year Type II GBE program benefits expected to be achieved in Rhode Island be used to offset the Rate Year GBE program implementation costs. The reduction from 100% reflects a discount to reflect a level of difficulty in accurately projecting efficiency benefits. We chose 85% for consistency with recommended holdback of a portion of the revenue requirement associated with the GBE program rate year costs discussed above. In addition, the Division recommends that any future GBE program cost recovery requests be offset against the expected benefits presented in the case over the same time period. The resulting revenue requirement is estimated below and supported by the Division in the testimony of Mr. Ballaban.

Q. What is the estimated impact of the Divisions proposed recommendations on the Rate Year revenue requirement?

A. The Divisions estimates that the GBE recommendations will result in a Rate Year revenue requirement of $2,922,991 for Narragansett Gas and $473,727 for Narragansett Electric, a revenue requirement reduction of $977,286 and $83,599,

[59] Using the sum of the FY 2019 and FY 2020 Type II benefits estimated by the company as a proxy for the rate year. Type II benefits continue to increase through time to an annual run rate of approximately $544,000 beginning in 2024 after full deployment and an initial operational burn in period.

respectively, from the Company’s March 2, 2018 updated GBE revenue requirement.

Q. Does this conclude your testimony?

A. Yes.

DAYMARK
ENERGY ADVISORS

Tina M. Bennett

Principal Consultant

Tina Bennett joined Daymark Energy Advisors in 2017, bringing over 25 years of diverse electric industry experience. Ms. Bennett has overseen the delivery of energy efficiency initiatives for large utilities and state agencies across the United States. She has managed investments in power generation facilities and is experienced in natural gas and electric market operations. She has ample hands-on experience in strategic decision making, management and operational effectiveness, asset transactions and contract negotiations. Drawing on her extensive industry knowledge and management experience, Ms. Bennett advises electric and natural gas industry clients on executive-level business operations, including strategic planning, capital planning, budgeting, resource development, and asset transactions with a focus the evolving areas of distributed energy resource planning, grid modernization policy and regulation and power sector decarbonization.

Before joining Daymark Energy Advisors in 2017, Ms. Bennett served as President of Conservation Services Group (CSG), now CLEAResult, and held senior roles at International Power, PG&E National Energy Group, EnergyVision, and New England Electrical System (now National Grid).

Ms. Bennett holds an M.B.A. from Northeastern University and a B.S. in Economics/Finance from Bentley College. She provides industry leadership as President of the Board of The Northeast Energy Commerce Association, as a Board member of the Northeast Clean Energy Council and as a Board member of PowerOptions.

SELECTED PROFESSIONAL EXPERIENCE

Management Consulting & Operational Effectiveness

- Improved an energy efficiency company's organizational effectiveness by reorganizing corporate functions; implementing company-wide annual goals and metrics; and transforming the company's governance structure to align resources and drive efficient decision making and accountability across the company.
- Improved an energy efficiency company's employee engagement and satisfaction scores by driving stronger cross- functional coordination of projects, enhancing internal communications, increasing the transparency of company performance and financial results, expanding employee development opportunities including implementing a formal mentoring program; increasing internal training and professional development opportunities across a variety of disciplines; and supporting employee driven initiatives (e.g. young professionals group, Toastmasters).
- Led a complete overhaul of an energy efficiency company's technology strategy and information systems operations. Addressed organizational and process issues, adopted agile development methodologies and invested in a two-year program to re-platform the company's IT infrastructure and information systems, with an immediate payback through improve system reliability and performance, lower ongoing support costs, and enhance program delivery and reporting capabilities. Core to the strategy was creating a layered architecture that allowed the company to leverage proven advances in third-party software solutions, cloud computing, and mobile/web technology.

- Implemented process improvements at an energy efficiency company that led to reducing new program start-up time from an unpredictable six to nine months to three months. Improvements also doubled the company's capability to handle multiple program start-ups.
- Increased an electric generation facility's return on capital improvements by introducing a thorough quantitative analysis to prioritize projects in the budget approval process and adding a post-implementation review to verify that results were realized.
- Assessed and mitigated regulatory compliance gaps at an independent power producer to prepare the company for passing its first regulatory compliance audit. Assessment included staff reviews, examination of policies and procedures against regulatory, market, and business requirements. Following the assessment, developed and implemented a comprehensive mitigation plan. As a result, the company passed the audit with no reportable deficiencies.

Renewable Energy & Energy Efficiency

- Served as President of a leading provider of energy efficiency services in the US with 21 offices in 14 states and revenues of $130M. Responsible for leading executive team; driving the company's strategic planning, budgeting, and goal-setting processes; managing day-to-day operations; and delivering against the company's annual operating budget and plan.
- Led an independent power producer's new business initiative in Puerto Rico, including analyzing solar and wind development projects in Puerto Rico.
- Managed emissions credits for an electric generation facility in Texas.
- Deep knowledge of energy efficiency and distributed resource cost/benefit analysis and the parameters required to quantify utility, customer and societal costs and benefits. Familiar with the new *National Standard Practice Manual for Assessing Cost-Effectiveness of Energy Efficiency Resources* (NSPM), recently published by the National Efficiency Screening Project and its potential application to other distributed energy resources.

Strategy & Decision Making

- Led a strategic planning effort and decision-making process that resulted in a decision to sell the business operations of a leading energy efficiency company.
- Provided executive leadership through the transition of a leading energy efficiency company to ensure a successful integration of the business operations and to support the assimilation of the team into the company.
- Oversaw a business review of a company's struggling national contact center business unit to determine the strategic value of providing third-party contact center services; to determine the cost/benefit of in-sourcing vs. outsourcing contact center services to support the company's energy efficiency program delivery business; and to develop a comprehensive operational improvement plan to improve profitability.
- Directed a business review of a company's national incentive processing centers to determine the cost/benefit of insourcing vs. outsourcing incentive processing services to support the company's energy efficiency program delivery business.
- Developed a transitional plan to integrate a company's training capabilities into an acquiring company and devised new methods to allow for leveraging content and scaling both internal and external training capabilities.

Asset Transaction & Contract Negotiation Services

- Led the deal team on all aspects of the sale of a leading energy efficiency company, including marketing, evaluation, due diligence, purchase and sale agreement and regulatory approval.
- Co-led $148M sale of a natural gas-fired power plant, significantly improving overall expected return on investment for the company. Managed the due diligence process and all post-close transition activities.
- Worked with an electric generation facility's management to negotiate a supplemental supply agreement with the Puerto Rico Electric Power Authority that allowed for the improved dispatch of plant by up to 20% while significantly reducing fuel volume and price risk associated with supplying the incremental dispatch.
- Represented an independent power producer in a joint-partnership negotiation with a major gas turbine parts and services provider and the execution of a long-term parts and services agreement that significantly reduced EcoEléctrica's major maintenance cost and outage risk.
- Represented an independent power producer in a renegotiation of a Power and Steam Sales Agreement and Operating Agreement with power & steam off-taker implementation of new technology at no risk to the company or its affiliates and partners.
- Led exploration of new business initiatives in Puerto Rico, including a new 270MW combined-cycle gas generator.

Market Participation

- Managed the U.S. risk management and settlement functions for an international independent power producer. Responsible for the measurement and reporting of the commercial risk inherent in its power and natural gas portfolio, implementing best practice risk controls, and accurate settlement of the company's energy trading transactions.
- Led an international independent power producer's regulatory affairs function responsible for working with key stakeholder groups, independent system operators, and regulatory and legislative bodies to promote International Power's position on various market issues and proposed rule changes in ERCOT, ISO-NE, PJM and the FERC.
- Led an international independent power producer's entry into the ERCOT market as a generator.
- Developed trading and bidding strategies for a portfolio of generation in the ISO-NE and ERCOT markets for several independent power producers.

EMPLOYMENT HISTORY

Daymark Energy Advisors, Inc.	Boston, MA
Principal Consultant	*2017 – Present*
Conservation Service Group/CLEAResult	Boston, MA
President/COO	*2011 – 2016*
International Power	Marlborough, MA
Vice President, Asset Management and Information Technology	*2007 – 2011*
Vice President, Special Assignment	*2006*
Vice President, Risk Management	*2002-2006*
Director of Trading Operations	*2001 – 2002*

PG&E National Energy Group — Bethesda, MA
Generation Trader — *1999 – 2001*
Director of Natural Gas Supply — *1998 – 1999*

EnergyVision, LLC — Burlington, MA
Director of Supply and Risk Management — *1997-1998*

New England Electric System *(currently National Grid)* — Westborough, MA
Principal Fuel Marketer — *1995 – 1997*
Senior Rate Analyst — *1990 – 1995*
Associate Accounting Analyst — *1989 – 1990*

EDUCATION

Northeastern University — Boston, MA
Master of Business Administration (Beta Gamma Sigma Honor Society)

Bentley College — Waltham, MA
B.S., Economics/Finance (Omicron Delta Epsilon Honor Society in Economics)

GROUPS & ASSOCIATIONS

Northeast Energy and Commerce Association
President — *2015 – Present*
Board of Directors and Member — *2009 – Present*

Northeast Clean Energy Council
Board of Directors — *2015 – Present*

PowerOptions
Board of Directors — *2012 – Present*

Allen R. Neale

Four Ashley Drive, Amesbury, MA 01913 (978) 388-0432 arneale@comcast.net

Experience

Allen Neale, d/b/a Allen Neale
2011 – Present Expert Witness

Advisor and expert witness on natural gas systems working in the areas of gas distribution system planning and expansion, network analysis, DIMP plans, accelerate infrastructure replacement programs and associated cost recovery, gas forecast and supply, LNG facilities, and capital budgeting.

Jack Sanborn & Son, Inc.
2005 – 2011 Administrative Assistant

Preformed accounts receivable, accounts payable, estimating, receiving, customer contact, business advice, and other company support services for a residential /commercial /industrial electrical contracting business.

ARN Enterprises, Inc, Nashua, NH
1999 – 2005 President

Owned and operated CRW Finishing Co. Company plated aluminum products for the Medical, Military, Hi-Tech and Telco Industries

ARN Consulting, Amesbury, MA
1998 – 1999 President

Provided consulting services for Amtrak, Pittsburg, PA regarding Natural Gas purchases and transportation issues

Essex County Gas Company, Amesbury, MA
1985 – 1998 Vice President

Worked in the areas of rates, regulatory affairs, gas supply and supply planning, peak shaving facilities, gas dispatch, engineering, meter shop, environmental matters, interruptible gas sales. Chaired Tennessee Gas Customer Group and Gasdex (NEGA regulatory arm), Member of Guild of Gas Managers, NEGA and AGA.

1981 – 1985 Administrative Assistant

Special projects, Local taxes, Annual Reports: DOT and DPU, Safety committee chair, Budgets and 5 Year forecasts

1979 – 1981 Supervisor of Distribution

Administered Department Budget, Supervision and Scheduling of: Company and Contracting crews, Installation of new and replacement projects, Maintenance of Mains and Services, Leak Detection, Regulator Station Maintenance

1973 – 1979 Corrosion Engineer/Student Engineer

Conduct to pipe to soil test, Design Cathodic Protection Systems, DOT Recordkeeping, Layout and Design new and replacement projects, Locate facilities for crews and contractors (Dig Safe), Member of NACE (National Association of Corrosion Engineers)

Education

New Hampshire College, Manchester, NH
1981 – 1986 Masters of Business Administration

Wentworth Institute, Boston, MA
1969 – 1973 B.S.E.T. Mechanical Engineering
Associate Engineering Mechanical Power Engineering

Selected Expert Witness Services

Year	Docket	Topic
On behalf of the Louisville/Jefferson County Metro Government		
2017	Case No. 2016-00317	Application of Louisville Gas and Electric Company for a declaratory order regarding the proper method of municipal franchise fee recovery
On behalf of the Illinois Office of the Attorney General		
2016	16-0376	The People's Gas Light and Coke Company's natural gas system modernization program
On behalf of the Maryland Office of People's Counsel		
2017	Case No. 9433	Application of Washington Gas Light Company for approval of revised tariff provisions that will facilitate access to natural gas
2016	Case No. 9417	Application of Columbia Gas of Maryland for authority to increase rates and charges
2015	Case No. 9335	Application of Washington Gas Light Company for approval of an amendment to its STRIDE plan
2014	Case No. 9335	Application of Washington Gas Light Company for approval of capital plan and rider
2014	Case No. 9332	Amended application of Columbia Gas of Maryland for authority to adopt an infrastructure replacement surcharge mechanism
2016	Case No. 9331	Application of Baltimore Gas and Electric Company for approval of first amendment to gas system Strategic Infrastructure Development and Enhancement (STRIDE) plan and accompanying cost recovery mechanism
On behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy		
2015	DPU 15-81	Fitchburg Gas and Electric Light Company d/b/a/Unitil gas rate case
2015	DPU 15-50	Bay State Gas Company d/b/a Columbia Gas of Massachusetts
2015	DPU 14-150	NSTAR Gas Company d/b/a Eversource Energy
2015	DPU 14-135	NSTAR Gas Company, proposed Gas System Enhancement Program (GSEP)
2015	DPU 14-134	Bay State Gas Company, proposed Gas System Enhancement Program (GSEP)
2015	DPU 14-133	Liberty Utilities proposed Gas System Enhancement Program (GSEP)
2015	DPU 14-132	Boston Gas Company and Colonial Gas Company, proposed Gas System Enhancement Program (GSEP)
2015	DPU 14-131	Berkshire Gas Company, proposed Gas System Enhancement Program (GSEP)
2015	DPU 14-130	Fitchburg Gas and Electric Light Company, proposed Gas System Enhancement Program (GSEP)
2014	DPU 14-64	NSTAR Gas Company, Hopkinton LNG facility proposal
2013	DPU 13-75	Bay State Gas Company d/b/a Columbia Gas of Massachusetts
2012	DPU 12-25	Bay State Gas Company d/b/a Columbia Gas of Massachusetts

Original Filing Schedule MAL-36
Opex Straight Lined 10 yrs

	RYE Aug 19	RYE Aug 20	RYE Aug 21
Return	$ 1,033,312	$ 1,102,323	$ 1,197,213
Amortization	$ 1,360,899	$ 1,657,897	$ 2,038,924
Incremental Opex (shaped vs SL)	$ 1,016,617	$ 1,016,617	$ 1,016,617
Run the Business (RTB)	$ 779,580	$ 1,226,561	$ 1,330,680
Savings offset	$ (57,283)	$ (370,875)	$ (767,726)
Total RR	$ 4,133,125	$ 4,632,523	$ 4,815,707
Capital - Related	$ 2,394,211	$ 2,760,220	$ 3,236,136
Operating Exp. Net of Savings	$ 1,738,914	$ 1,872,303	$ 1,579,570
Total Revenue Requirement	$ **4,133,125**	$ 4,632,523	$ 4,815,707

March 2, 2018 Schedule MAL-36 REV-1
Opex Straight Lined 10 yrs

	RYE Aug 19	RYE Aug 20	RYE Aug 21
Return	$ 800,464	$ 902,121	$ 1,016,128
Amortization	$ 1,360,899	$ 1,657,897	$ 2,038,924
Incremental Opex (shaped vs SL)	$ 1,016,617	$ 1,016,617	$ 1,016,617
Run the Business (RTB)	$ 779,580	$ 1,226,561	$ 1,330,680
Savings offset	$ (57,283)	$ (370,875)	$ (767,726)
Total RR	$ 3,900,276	$ 4,432,321	$ 4,634,622
Capital - Related	$ 2,161,363	$ 2,560,018	$ 3,055,052
Operating Exp. Net of Savings	$ 1,738,914	$ 1,872,303	$ 1,579,570
Total Revenue Requirement	$ **3,900,276**	$ 4,432,321	$ 4,634,622

Division Estimated Proposal
Opex Straight Lined 10 yrs

	RYE Aug 19	Detail
Return	$ 680.394	85% of Mal-36 (REV-1) Return
Amortization	$ 1,156,764	85% of Mal-36 (REV-1) Amortization
Incremental Opex (shaped vs SL)	$413,358	Rate Year O&M per discovery response to Div 3-58 amortized over 10 years (straight line)
Run the Business (RTB)	$729,756.82	Rate Year only - Decreased by 85% of Type II savings per Discovery Response Attachment PUC 9-18-1
Savings offset	($57,282.50)	Rate Year only
Total RR	$ 2,922,991	
Capital - Related	$ 1.837.158	
Operating Exp. Net of Savings	$ 1,085,832	
Total Revenue Requirement	$ **2,922,991**	

$	**(977,286)**	**Change from MAL-36 (REV-1) filed on 3/2**
$	**(1,210,134)**	**Change from MAL-36 filed on November**

Original Filing
Opex Straight Lined 10 yrs

	RYE Aug 19	RYE Aug 20	RYE Aug 21
Return	$ 269,071	$ 235,066	$ 181,285
Amortization	$ 350,747	$ 376,157	$ 376,157
Incremental Opex (shaped vs SL)	$ -	$ -	$ -
Run the Business (RTB)	$ -	$ -	$ -
Savings offset	$ -	$ -	$ -
Total RR	$ 619,818	$ 611,224	$ 557,442
Capital - Related	$ 619,818	$ 611,224	$ 557,442
Operating Exp. Net of Savings	$ -	$ -	$ -
Total Revenue Requirement	**$ 619,818**	$ 611,224	$ 557,442

March 2, 2018 Revision
Opex Straight Lined 10 yrs

	RYE Aug 19	RYE Aug 20	RYE Aug 21
Return	$ 206,578	$ 199,116	$ 172,736
Amortization	$ 350,747	$ 376,157	$ 376,157
Incremental Opex (shaped vs SL)	$ -	$ -	$ -
Run the Business (RTB)	$ -	$ -	$ -
Savings offset	$ -	$ -	$ -
Total RR	$ 557,326	$ 575,273	$ 548,894
Capital - Related	$ 557,326	$ 575,273	$ 548,894
Operating Exp. Net of Savings	$ -	$ -	$ -
Total Revenue Requirement	**$ 557,326**	$ 575,273	$ 548,894

Division Estimated Proposal
Opex Straight Lined 10 yrs

	RYE Aug 19	Detail
Return	$ 175,591	85% of Mal-36 (REV-1) Return
Amortization	$ 298,135	85% of Mal-36 (REV-1) Amortization
Incremental Opex (shaped vs SL)	$ -	
Run the Business (RTB)	$ -	
Savings offset	$ -	
Total RR	$ 473,727	
Capital - Related	$ 473.727	
Operating Exp. Net of Savings	$ -	
Total Revenue Requirement	**$ 473,727**	

$	83,599	**Change from MAL-36 (REV-1) filed on 3/2**
$	146,092	**Change from MAL-36 filed on November**