National Grid

The Narragansett Electric Company

2021 System Reliability Procurement Plan Year-End Report

May 23, 2022

Submitted to:
Rhode Island Public Utilities Commission

RIPUC Docket No. 5080

Submitted by:
nationalgrid

Filing Letter & Motion

Andrew S. Marcaccio
Senior Counsel

May 23, 2022

VIA ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: Docket No. 5080 – 2021 System Reliability Procurement Year-End Report

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a National Grid ("National Grid" or the "Company"), enclosed[1], please find the Company's 2021 System Reliability Procurement ("SRP") Year-End Report (the "Report" or "2021 Report"). The Report is being filed in accordance with R.I. Gen. Laws § 39-1-27.7 and Section 4.4.B of the Least Cost Procurement ("LCP") Standards.[2]

On November 20, 2020, the Company filed its 2021-2023 System Reliability Procurement Three--Year Plan (the "SRP Three-Year Plan" or "Plan").[3] Through the SRP Three-Year Plan, the Company requested approval by the Public Utilities Commission ("PUC") of various programmatic proposals all of which did not require any incremental funding. On December 22, 2020, in alignment with the proposed SRP Three-Year Plan, the PUC approved a $0 SRP rate which is a component of the Energy Efficiency ("EE") charge that became effective January 1, 2021. On June 1, 2021, the Company filed its 2020 SRP Year-End Report (the "2020 Report").[4] As of the date of this filing, the programmatic proposals contained within the SRP Three-Year Plan and the 2020 Report are pending PUC review and approval.

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[1] Per Commission counsel's update on October 2, 2020, concerning the COVID-19 emergency period, the Company is submitting an electronic version of this filing followed by five hard copies filed with the Clerk within 24 hours of the electronic filing.

[2] The LCP Standards were approved by the PUC on July 23, 2020 in Docket No. 5015. The LCP Standards may be viewed at: http://www.ripuc.ri.gov/eventsactions/docket/5015_LCP_Standards_05_28_2020_8.21.2020%20Clean%20Copy%20FINAL.pdf

[3] The SRP Three-Year Plan may be viewed at: http://www.ripuc.ri.gov/eventsactions/docket/5080-NGrid-SRP%202021-2023%20Three-Year%20Plan(11-20-2020)V1.pdf

[4] The 2020 SRP Year-End Report may be viewed at: http://www.ripuc.ri.gov/eventsactions/docket/5080-NGrid-2020%20SRP%20Year-End%20Plan%20(6-1-21).pdf

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As detailed in the Report, the Company respectfully requests that the PUC consider and approve several updates to the programmatic proposals contained within the Three-Year Plan. The following table provides an updated summary of the requested rulings for SRP factoring in both the Three-Year Plan and the Report.

Table 1. Updated Summary of Requested Rulings for SRP in 2021-2023

Applicable Section(s)	SRP Initiative/ Proposal	Requested Ruling in the SRP Three-Year Plan	Requested Ruling in the 2020 Report	Requested Ruling in the 2021 Report	Notes
Section 5 of SRP Three-Year Plan	SRP Funding Mechanism	The Company requests the PUC approve the Company's proposal that operational expenditure (opex)-type SRP investments be funded through the System Benefit Charge, or Energy Efficiency (EE) Charge, on customers' bills as described in Section 5 of the Plan.			Proposal only made in the Plan.
Section 5 of SRP Three-Year Plan	SRP Funding Mechanism	The Company requests the PUC approve the Company's proposal that capital expenditure (capex)-type SRP investments be filed and proposed in an SRP Investment Proposal as described in Section 5 of the Plan.			Proposal only made in the Plan.

Applicable Section(s)	SRP Initiative/ Proposal	Requested Ruling in the SRP Three-Year Plan	Requested Ruling in the 2020 Report	Requested Ruling in the 2021 Report	Notes
Section 6 of SRP Three-Year Plan	SRP Performance Incentive Mechanism	The Company requests the PUC approve the Company's proposed performance incentive mechanism (PIM) for calendar years 2021 through 2023 as described in Section 6 of the Plan.			Proposal only made in the Plan.
Section 7.2 of SRP Three-Year Plan Section 6.1 of the 2020 SRP Year-End Report	NWA Screening Criteria	The Company requests the PUC approve the proposed NWA screening criteria for Rhode Island as detailed in Table 5 of the Plan for calendar years 2021 through 2023.	The Company requests approval of the two proposed revisions to the NWA screening criteria for Rhode Island as detailed in Table 4 for calendar years 2021 through 2023.		NWA Screening Criteria established with background detail in the Plan. NWA Screening Criteria updated in the 2020 Report.

Applicable Section(s)	SRP Initiative/ Proposal	Requested Ruling in the SRP Three-Year Plan	Requested Ruling in the 2020 Report	Requested Ruling in the 2021 Report	Notes
Section 4 of the 2020 SRP Year-End Report Section 5 of the 2021 SRP Year-End Report	RI NWA BCA Model		The Company requests approval of the proposed revisions to the RI NWA Benefit-Cost Analysis (BCA) Model and the proposed corresponding revisions to the RI NWA BCA Model Technical Reference Manual (TRM) for calendar years 2021 through 2023.	The Company requests approval of the proposed revision to the RI NWA Benefit-Cost Analysis (BCA) Model for calendar years 2021 through 2023.	Proposals made in the 2020 and 2021 Reports. The Company proposes the PUC need only consider the version (version 1.2) proposed in the 2021 Report.
Section 7.3 of the 2020 SRP Year-End Report Section 8.2 of the 2021 SRP Year-End Report	NPA Screening Criteria		The Company requests approval of the proposed NPA Screening Criteria for Rhode Island as detailed in Table 5 for calendar years 2021 through 2023.	The Company requests approval of the two proposed revisions to the NPA screening criteria for Rhode Island as detailed in Table 6 for calendar years 2021 through 2023.	NPA Screening Criteria established with background detail in the 2020 Report. NPA Screening Criteria updated in the 2021 Report.

Applicable Section(s)	SRP Initiative/ Proposal	Requested Ruling in the SRP Three-Year Plan	Requested Ruling in the 2020 Report	Requested Ruling in the 2021 Report	Notes
Section 8 of SRP Three-Year Plan	NPAs in System Planning	The Company requests the PUC approve the development plan for the Non-Pipeline Alternatives program in calendar years 2021 through 2023 as described in Section 8 of the Plan.			Proposal only made in the Plan.
Section 12 of SRP Three-Year Plan	SRP Timeline: SRP Investment Proposals	The Company requests the PUC rule on SRP Investment Proposals within 60 days of filing as described in Section 12 of the Plan.			Proposal only made in the Plan.
Section 12 of SRP Three-Year Plan	SRP Timeline: Year-End Reports	The Company requests the PUC approve the annual reporting plan for SRP Year-End Reports for calendar years 2021 through 2023 as described in Section 12 of the Plan.			Proposal only made in the Plan.

As noted in Table 1 above, this Report contains proposals to update the Rhode Island Non-Wires Alternative Benefit-Cost Analysis Model ("RI NWA BCA Model") and the Non-Pipeline Alternative ("NPA") screening criteria. Please note that the proposals as updated do not require any additional, incremental funding. In addition, the Report also contains the budget spend for SRP in calendar year 2021.

Please be advised that the Company considers Appendix 9-RI NWA BCA Model for the Bonnet 42F1 NWA Opportunity (“Appendix 9”), Appendix 10-NWA Evaluation Results for the Bonnet 42F1 NWA Opportunity (“Appendix 10”), Appendix 11-RI NWA BCA Model for the South Kingstown NWA Opportunity (“Appendix 11”), and Appendix 12-NWA Evaluation Results for the South Kingstown NWA Opportunity (“Appendix 12”) of the Report to be confidential. Pursuant to 810-RICR-00-00-1.3(H)(3) and R.I. Gen. Laws § 38-2-2(4)(B), the Company respectfully requests that the Commission treat Appendices 9, 10, 11, and 12 as confidential. In support of this request, the Company has enclosed a Motion for Confidential Treatment. In accordance with 810-RICR-00-00-1.3(H)(2), the Company also respectfully requests that the Commission make a preliminary finding that Appendices 9, 10, 11, and 12 are exempt from the mandatory public disclosure requirements of the Rhode Island Access to Public Records Act.

Thank you for your attention to this filing. If you have any questions or concerns, please do not hesitate to contact me at 401-784-4263.

Sincerely,

Andrew S. Marcaccio

Enclosures

cc: Docket 5080 Service List
Jon Hagopian, Esq.
John Bell, Division

STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION

IN RE: THE NARRAGANSETT ELECTRIC COMPANY	:	
d/b/a NATIONAL GRID'S SYSTEM RELIABILITY	:	DOCKET NO. 5080
PROCUREMENT (SRP) YEAR-END REPORT 2021	:	

MOTION OF THE NARRAGANSETT ELECTRIC COMPANY D/B/A NATIONAL GRID FOR PROTECTIVE TREATMENT OF CONFIDENTIAL INFORMATION

The Narragansett Electric Company d/b/a National Grid (the "Company") hereby respectfully requests that the Public Utilities Commission ("PUC") grant protection from public disclosure certain confidential information submitted by the Company in the above referenced docket. The reasons for the protective treatment are set forth herein. The Company also requests that, pending entry of that finding, the PUC preliminarily grant the Company's request for confidential treatment pursuant to 810-RICR-00-00-1.3(H)(2).

The records that are the subject of this Motion that require protective treatment from public disclosure are four Excel files labeled as Appendix 9 – RI NWA BCA Model for the Bonnet 42F1 NWA Opportunity ("Appendix 9"), Appendix 10 – NWA Evaluation Results for the Bonnet 42F1 NWA Opportunity ("Appendix 10"), Appendix 11 – RI NWA BCA Model for the South Kingstown NWA Opportunity ("Appendix 11"), and Appendix 12 – NWA Evaluation Results for the South Kingstown NWA Opportunity ("Appendix 12") (collectively, referred to as the "Confidential Records"). The Confidential Records are appendices to the Company's System Reliability Procurement ("SRP") Year-End Report for 2021 which was filed by the Company on May 23, , 2022 in the above-referenced docket. The Company requests protective treatment of the Confidential Records in accordance with 810-RICR-00-00-1.3(H) and R.I. Gen. Laws § 38-2-2-(4)(B).

I. LEGAL STANDARD

For matters before the PUC, a claim for protective treatment of information is governed by the policy underlying the Access to Public Records Act (APRA), R.I. Gen. Laws § 38-2-1 et seq. See 810-RICR-00-00-1.3(H)(1). Under APRA, any record received or maintained by a state or local governmental agency in connection with the transaction of official business is considered public unless such record falls into one of the exemptions specifically identified by APRA. See R.I. Gen. Laws §§ 38-2-3(a) and 38-2-2(4). Therefore, if a record provided to the PUC falls within one of the designated APRA exemptions, the PUC is authorized to deem such record confidential and withhold it from public disclosure.

II. BASIS FOR CONFIDENTIALITY

The Confidential Records, which are the subject of this Motion, are exempt from public disclosure pursuant to R.I. Gen. Laws § 38-2-2(4)(B) as "[t]rade secrets and commercial or financial information obtained from a person, firm, or corporation that is of a privileged or confidential nature." The Rhode Island Supreme Court has held that this confidential information exemption applies where the disclosure of information is likely either (1) to impair the government's ability to obtain necessary information in the future; or (2) to cause substantial harm to the competitive position of the person from whom the information was obtained. Providence Journal v. Convention Center Authority, 774 A.2d 40 (R.I. 2001). The first prong of the test is satisfied when information is provided to the governmental agency and that information is of a kind that would customarily not be released to the public by the person from whom it was obtained. Providence Journal, 774 A.2d at 47. In this case, the Company would not customarily release the Confidential Records to the public.

Appendix 9 is the Rhode Island non-wires alternative ("NWA") benefit-cost analysis

("BCA") model that the Company used for the Bonnet 42F1 NWA opportunity. Appendix 10 is the NWA evaluation results matrix that the Company used for the Bonnet 42F1 NWA opportunity. Appendix 11 is the Rhode Island NWA BCA model that the Company used for the South Kingstown NWA opportunity. Appendix 12 is the NWA evaluation results matrix that the Company used for the South Kingstown NWA opportunity.

The Company considers these populated models and matrices to be commercial information because the models contain technical specifications and financial and pricing data provided by third-party vendors as part of their bid proposals to the Company's request for proposals ("RFPs") for the Bonnet 42F1 and South Kingstown NWA opportunities. The results matrices also contain technical specifications of a bidder's proposed technology, capabilities and limitations of a bidder's proposed technology, operational capabilities of a bidder company, and qualitative ratings data on third-party bidders. The Company would customarily not release third-party vendor financial or operational data to the public.

In addition, the release of the Confidential Records is likely to cause substantial harm to the competitive position of the Company as well as the competitive positions of the third-party bidder participants. The Confidential Records include sensitive information and other commercial details regarding the Company's analysis of NWA opportunities and of the third-party vendors who have participated in the NWA opportunities. Disclosing this information to the public could harm the Company's relationship with the market and vendors, harm the Company's ability to procure third-party NWA solution bids in the most cost-effective and unbiased manner and, ultimately, harm customers.

III. CONCLUSION

For the foregoing reasons, the Company respectfully requests that the PUC grant this motion for protective treatment of the Confidential Records.

Respectfully submitted,

NATIONAL GRID
By its attorney,

____

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National Grid
280 Melrose Street
Providence, RI 02907
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Dated: May 23, 2022

<u>CERTIFICATE OF SERVICE</u>

I hereby certify that on May 23, 2022, I delivered a true copy of the foregoing Motion via electronic mail to the parties on the Service List for Docket No. 5080.

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Joanne M. Scanlon

Certificate of Service

I hereby certify that a copy of the cover letter and any materials accompanying this certificate was electronically transmitted to the individuals listed below.

The paper copies of this filing are being hand delivered to the Rhode Island Public Utilities Commission and to the Rhode Island Division of Public Utilities and Carriers.

___________________________________ May 23, 2022

Joanne M. Scanlon Date

Docket No. 5080 - National Grid – System Reliability Procurement 2021-2023 Plan
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2021 SRP
Year-End Report

SYSTEM RELIABILITY PROCUREMENT

2021 YEAR-END REPORT

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Appendix 8 – Targeted EE-DR Assessments for South Kingstown and Bonnet 42F1 NWA Opportunities

Appendix 9 – RI NWA BCA Model for the Bonnet 42F1 NWA Opportunity

Appendix 10 – NWA Evaluation Results for the Bonnet 42F1 NWA Opportunity

Appendix 11 – RI NWA BCA Model for the South Kingstown NWA Opportunity

Appendix 12 – NWA Evaluation Results for the South Kingstown NWA Opportunity

Table of Terms

Term	Definition
3V0	Ground Fault (or Zero Sequence) Overvoltage
AESC	Avoided Energy Supply Components
AMF	Advanced Metering Functionality
Approximate Value	The estimated net present value of deferring the wires investment for the required timeframe.
BCA	Benefit-Cost Analysis
BCR	Benefit-Cost Ratio
BTM	Behind-the-Meter
Capex	Capital expenditure
CEM	Customer Energy Management
CHP	Combined Heat and Power
CLF	Conservation Law Foundation
CO_2	Carbon Dioxide
CRM	Cost Recovery Mechanism
CSA	Construction Service Agreement
C-Team	(EERMC) Consultant Team
DER	Distributed Energy Resource
DG	Distributed Generation
Division	Division of Public Utilities and Carriers
DPAM	Distribution Planning and Asset Management
DR	Demand Response
DRIPE	Demand Reduction Induced Price Effect(s)
DSP	Distribution System Planning
EE	Energy Efficiency
EE Plan	Energy Efficiency Program Plan
EEP	Energy Efficiency Program
EERMC	Energy Efficiency and Resource Management Council
EPC	Engineering, Procurement, and Construction
EPS	Electric Power System
ESA	Energy Service Agreement
ESS	Energy Storage System
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
Framework	Rhode Island Docket 4600 Benefit-Cost Framework
FTE	Full-Time Employee/Equivalent
FTM	Front-of-the-Meter
GAME	Gas Asset Management and Engineering
GHG	Greenhouse gas

Term	Definition
GMP	Grid Modernization Plan
ISO	Independent Systems Operator
ISO-NE	ISO New England Inc.
ISR	Infrastructure, Safety and Reliability Plan
kW	Kilowatt
kWh	Kilowatt-hour
LCP	Least-Cost Procurement
MW	Megawatt
MWh	Megawatt-hour
NECEC	Northeast Clean Energy Council
NERC	North American Energy Reliability Corporation
NOAA	National Oceanic and Atmospheric Administration
NOx	Nitrogen Oxides
NPA	Non-Pipeline Alternatives
NPV	Net Present Value
NWA	Non-Wires Alternative
O&M	Operations and Maintenance
OER	Office of Energy Resources
Opex	Operational expenditure
PIM	Performance Incentive Mechanism
Portal	Rhode Island System Data Portal
PST	Power Sector Transformation
PUC	Public Utilities Commission
PV	Photovoltaic
RD&D	Research, Design, and Development
REC	Renewable Energy Credits
REG	Renewable Energy Growth
RFP	Request for Proposals
RGGI	Regional Greenhouse Gas Initiative
RI NWA BCA Model	Rhode Island Non-Wires Alternative Benefit-Cost Analysis Model
RI NWA BCA Model TRM	Rhode Island Non-Wires Alternative Benefit-Cost Analysis Technical Reference Manual
RI NPA BCA Model	Rhode Island Non-Pipeline Alternative Benefit-Cost Analysis Model
RI NPA BCA Model TRM	Rhode Island Non-Pipeline Alternative Benefit-Cost Analysis Technical Reference Manual
RI Test	Rhode Island Benefit-Cost Test
RNG	Renewable Natural Gas
RPS	Renewable Portfolio Standards
SME	Subject Matter Expert

Term	Definition
SO_2	Sulfur Dioxide
SRP	System Reliability Procurement
T&D	Transmission and Distribution
TWG	Technical Working Group
VVO	Volt-VAR Optimization

2021 SYSTEM RELIABILITY PROCUREMENT YEAR-END REPORT

1. Executive Summary

The purpose of System Reliability Procurement (SRP) is to identify targeted alternative solutions, through customer-side and grid-side opportunities, for the electric and gas distribution systems that are cost-effective, reliable, prudent and environmentally responsible and provide the path to lower supply and delivery costs to customers in Rhode Island.

The role of National Grid[1] with respect to SRP is to identify potential Non-Wires Alternative (NWA) and Non-Pipeline Alternative (NPA) opportunities, to source viable alternative solutions that address system needs and defer, reduce, or remove the need for distribution wires and pipes investments, and to support projects and programs that enable such activity.

The Company summarizes the rulings requested of the Rhode Island Public Utilities Commission (PUC) in the table below. Note that no funding requests are associated with these proposals because SRP Year-End Reports are purposed for programmatic proposals only and not financial investment proposals.

Table 1: Summary of Requested Rulings for SRP

SRP Section	SRP Initiative/Proposal	Requested Ruling
5	RI NWA BCA Model	The Company requests approval of the proposed revision to the RI NWA Benefit-Cost Analysis (BCA) Model.
8.2	RI NPA Screening Criteria	The Company requests approval of the proposed revisions to the NPA Screening Criteria for Rhode Island as detailed in Section 8.2 for calendar years 2021 through 2023.

The commitments presented in this 2021 SRP Year-End Report and from the prior 2020 SRP Year-End Report of Docket No. 5080[2] are summarized in the following table with year-over-year progress indicated in the rightmost column. These commitments do not require additional, incremental SRP funding because they are actions covered by the work of full-time employees (FTEs).

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or Company).

[2] Docket No. 5080." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, The Narragansett Electric Company d/b/a National Grid, 20 Nov. 2020, www.ripuc.ri.gov/eventsactions/docket/5080page.html.

Table 2: Summary of 2021 SRP Commitments

SRP Commitment	Status
The Company plans to continue analyzing its current NWA screening and development processes to determine how NWAs might be best considered as both complete and partial solutions.	Ongoing, dynamic process
The Company commits to produce a detailed initial NPA Program at the end of the 2021-2023 SRP Three-Year Plan cycle.	Ongoing, dynamic process
The Company plans to continue analyzing its current NPA screening and development processes to determine how NPAs might be best considered as both complete and partial solutions.	Ongoing, dynamic process
The Company commits to performing background research on NPAs and exploring how NPAs align with Company policy and the Least-Cost Procurement Standards (LCP Standards) for the next update in the Three-Year Plan review.	Ongoing, dynamic process
The Company commits to engaging with stakeholders to discuss and understand opportunities and challenges regarding NPAs.	Ongoing, perpetual commitment
The Company intends to engage stakeholders continually throughout the development of the NPA program via SRP TWG meetings. The Company intends stakeholders to be engaged during the development of specific program parts.	Ongoing, perpetual commitment
Begin coordination work with the Company's proposed Grid Modernization Plan (GMP) regarding inclusion of hourly (8,760 hours) data in addition to peak load data once the Grid Modernization Plan with this update is approved for funding.	SRP to align with GMP
The Company recognizes that improved synchronization between SRP and Power Sector Transformation (PST), the Energy Efficiency Program Plan (EE Plan), the Infrastructure, Safety and Reliability Plan, the GMP, and the Advanced Metering Functionality (AMF) Business Case is necessary and intends to improve coordination between these filings.	Ongoing, perpetual commitment
Therefore, the Company commits to continued stakeholder engagement and continued participation in enhanced discussions regarding SRP, NWA, and related policy and programs with stakeholders.	Ongoing, perpetual commitment

SRP Commitment	Status
The Company also commits to continue its efforts to actively avoid double-counting shareholder incentives in SRP programs and projects.	Ongoing, perpetual commitment
The Company intends to implement robust stakeholder engagement and discussion on the electric forecasting process.	Ongoing, perpetual commitment
The Company will commit to development and implementation of a data governance plan in coordination with the work on the AMF and GMP filings and will continue stakeholder engagement and discussion.	SRP to align with GMP

Note that the ongoing, perpetual commitments in the table above are ones that the Company has so far aligned and delivered on and intends to continue to achieve.

Stakeholder engagement and discussions to date are detailed in Appendix 7.

The proposals and information the Company presents in this SRP Plan advance Power Sector Transformation (PST)[3] goals, align with Docket 4600[4] principles, are coordinated with the Company's other programs and filings, and adhere to Least-Cost Procurement (LCP) law.[5]

[3] "Power Sector Transformation Initiative." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, State of Rhode Island Office of the Governor Gina M. Raimondo, 8 Nov. 2017, www.ripuc.ri.gov/utilityinfo/electric/PST_home.html.
[4] "Docket No. 4600 and Docket No. 4600-A." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, Rhode Island Public Utilities Commission, 2 Nov. 2018, www.ripuc.ri.gov/eventsactions/docket/4600page.html.
[5] "39-1-27.7. System Reliability and Least-Cost Procurement." *TITLE 39 Public Utilities and Carriers* , State of Rhode Island General Assembly, http://webserver.rilin.state.ri.us/Statutes/title39/39-1/39-1-27.7.HTM.

2. Introduction

The Company is pleased to submit this 2021 System Reliability Procurement Year-End Report (Report) to the PUC. This Report has been developed by National Grid through an iterative process with the SRP Technical Working Group (the SRP TWG).[6]

This Report summarizes the work the Company has performed in the SRP Program for calendar year 2021.

National Grid respectfully submits this Report and seeks approval of its integral proposals in accordance with the guidelines set forth in Section 4 of the LCP Standards.

[6] Members of the SRP TWG presently include the Company, Acadia Center, CLF, the Division, Green Energy Consumers Alliance, OER, NECEC, Rhode Island Commerce, several EERMC members, and representatives from the EERMC's Consultant Team (EERMC C-Team).

3. Regulatory Basis for System Reliability Procurement

This Report is submitted in accordance with the regulatory basis detailed in the 2021-2023 SRP Three-Year Plan[7] and Section 4.4.B of the Rhode Island PUC's revised "Least-Cost Procurement Standards," which the PUC approved and adopted pursuant to Order No. 23890 in Docket No. 5015 (LCP Standards).[8]

Please see Sections 6.1 and 6.2 for detail on further alignment of the SRP program to the Standards with regard to the developing NPA program.

[7] "Docket No. 5080." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, The Narragansett Electric Company d/b/a National Grid, 20 Nov. 2020, www.ripuc.ri.gov/eventsactions/docket/5080page.html.

[8] "Least Cost Procurement Standards." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, Energy Efficiency and Resource Management Council, 21 Aug. 2020, http://www.ripuc.ri.gov/eventsactions/docket/5015_LCP_Standards_05_28_2020_8.21.2020%20Clean%20Copy%20FINAL.pdf.

4. SRP Budget Spend

This section details the calendar year spend for the SRP programs.

Table 3: SRP Budget Spend for CY 2021

Initiative/ Program	Program Detail	Budget Filed	Budget Spend
NWA	No specific NWA projects have been identified for proposal in CY 2021.	$0	$0
NPA	No specific NPA projects have been identified for proposal in CY 2021.	$0	$0
Rhode Island System Data Portal (Portal)	The Portal is an interactive online mapping tool developed by the Company. The Portal provides specific information for select electric distribution feeders and associated substations within the Company's electric service area in Rhode Island. The SRP Program handles new enhancements to the Portal.	$0	$0
SRP Market Engagement	SRP Market Engagement aims to raise awareness and perform outreach and engagement for the Rhode Island System Data Portal as needed, for NWA-related activities not covered by FTE work, and with third-party solution providers.	$0	$3,092
	Total	$0	$3,092

There was slight budget spend in the SRP Market Engagement category resulting from wrap-up in Q1 2021 of the RI Developer Portal Survey that occurred at the end of CY 2020. This $3,092 budget spend is still well within the remaining budget of approximately $57,409 from CY 2020. As no incremental costs are expected and no financial investment proposals are planned or projected for CY 2022, all remaining funds from SRP in the SRP fund balance have been reconciled back to the EE fund balance in December 2021.

5. RI NWA BCA Model

This section details the RI NWA BCA Model that the Company utilizes to assess cost-effectiveness of NWA projects.

The Company proposes the following minor change to the RI NWA BCA Model. No corresponding text updates were required in the RI NWA BCA Model Technical Reference Manual (TRM).

1. Correction of the formula for the “Lower than the Cost of the Standard Option” row series in the “Proposals Comparison” tab. The formula series was revised so that it correctly references the “Distribution Capital Cost” and “Transmission Capital Cost” inputs in the “Inputs-System” tab rather than the “Wires Option BCA Ratio” of the same tab.

This change was made in line with the identification and comment by the PUC in the Technical Session for Docket 5080 on July 26, 2021. This change allows for enhanced and accurate functionality in the RI NWA BCA Model.

Please see Appendix 4 for the updated RI NWA BCA Model.

The Company requests approval of the proposed revision to the RI NWA BCA Model.

6. RI NPA BCA Model

This section details the Rhode Island Non-Pipeline Alternative Benefit-Cost Analysis Model (RI NPA BCA Model) that the Company will utilize to assess cost-effectiveness of NPA projects.

Please see Appendix 5 for the initial version of the RI NPA BCA Model.

Sections 6.1 and 6.2 detail how the RI NPA BCA Model adheres to and supports the LCP Standards.

6.1 Cost Test

In accordance with Section 1.3.B of the revised Standards, the Company adheres to the Rhode Island Benefit-Cost Test (RI Test) for all SRP investment proposals. The Company has developed the RI NPA BCA Model, which is a derivative of the RI Test and utilizes the same Rhode Island Docket 4600 Benefit-Cost Framework (Framework), to more accurately assess NPA opportunities benefits and costs. Please see Appendix 5 for the RI NPA BCA Model.

The shift to using the RI NPA BCA Model has been a positive development for SRP. Per the LCP Standards, this specialized derivative of the RI Test is created using the RI Framework and accounts for applicable policy goals, PUC orders, regulations, guidelines, and other policy directives; accounts for all relevant, important aspects of the SRP and NPA programs; is symmetrical by including both costs and benefits for each relevant type of impact; is forward-looking by capturing the benefit-cost analysis over the life of the investment; and is transparent in its application and calculation.

Accounting for all costs and benefits associated with System Reliability Procurement provides a more robust accounting of the societal benefits that SRP investments deliver to electric customers, the state, and society.

The cost test and cost-effectiveness analyses of SRP investments use avoided cost impact factors developed by Synapse Energy Economics as part of the "Avoided Energy Supply Components in New England: 2021 Report" (2021 AESC Study), sponsored by New England's electric and gas energy efficiency program administrators.[9] The study utilizes state level avoided costs to reflect current and expected market conditions and are highly influenced by the cost of fossil fuels. Where applicable, the company utilizes site-specific calculations to augment the state level data. The cost-effectiveness analyses also include estimates of economic benefits applicable to System Reliability Procurement.

[9] "Avoided Energy Supply Components in New England: 2021 Report." *AESC 2021 Materials*, Synapse Energy Economics, Inc., 2021, https://www.synapse-energy.com/project/aesc-2021-materials.

Project-specific supply and distribution capacity values are also included. The company calculates a deferral value that utilizes the location-specific pipes solution expected cost, related operations and maintenance (O&M) costs, depreciation, and revenue requirements over the course of the expected lifetime of a pipes solution. A distribution deferral value is obtained by delaying the need date for a pipes solution or avoiding the pipes solution altogether.

The RI NPA BCA model will be continually reviewed by internal cross-functional teams and, in alignment with the SRP Year-End Report filings, externally on an annual basis by the EERMC Consultant Team (EERMC C-Team), Division, and the PUC.

The Company will use the RI NPA BCA Model, as detailed in Section 6 and Appendix 5, for assessing Rhode Island NPAs. Correspondingly, the RI NPA BCA Model Technical Reference Manual (RI NWA BCA Model TRM) is detailed in Appendix 6.

6.2 Cost-Effective

Cost-effectiveness is assessed at the program/project level in SRP. A cost-effectiveness analysis will be completed for potential NPA solutions. The SRP investment will be considered cost-effective if the benefit-cost ratio (BCR) for the resource is greater than 1.0. Utilizing the cost test as detailed in Section 6.1, NPA options will be compared to each other and the pipes option. This comparison will be utilized during the NPA evaluation process outlined in Section 8.4. Table 4 The Company plans to demonstrate cost-effectiveness for any specific projects by inclusion of the RI NPA BCA Model results in each SRP Investment Proposal filing. The benefit-cost analysis (BCA) methodology for SRP proposals is consistent with the language in the LCP Standards Section 1.3.C and Docket 4600 Framework.

Table 4 below summarizes the applicability of RI Test benefit and cost categories across the whole SRP program, including all categories applicable to the NPA and/or NWA programs. For specific applicability to the RI NPA BCA Model, please see Appendix 6 of this Report. For specific applicability to the RI NWA BCA Model, please see Appendix 5 of the 2020 SRP Year-End Report.

Table 4: Summary of RI Test Benefits and Costs Applicability

<table>
<tr><th>RI Test Category</th><th>Docket 4600 Category</th><th>SRP Program</th><th>Notes</th></tr>
<tr><td rowspan="4">Electric Energy Benefits</td><td>Energy Supply & Transmission Operating Value of Energy Provided or Saved (Power System Level)</td><td>X</td><td rowspan="4">(1)</td></tr>
<tr><td>Retail Supplier Risk Premium (Power System Level)</td><td>X</td></tr>
<tr><td>Criteria Air Pollutant and Other</td><td>X</td></tr>
<tr><td>Distribution System Performance (Power System Level)</td><td>X</td></tr>
</table>

RI Test Category	Docket 4600 Category	SRP Program	Notes
Renewable Portfolio Standards (RPS) and Clean Energy Policies Compliance Benefits	Renewable Energy Credits (REC) Value (Power System Level)	X	(1)
	Greenhouse Gas (GHG) Compliance Costs (Power System Level)	X	
	Environmental Externality Costs (Power System Level)	X	
Demand Reduction Induced Price Effects (DRIPE)	Energy DRIPE (Power System Level)	X	
Electric Generation Capacity Benefits	Forward Commitment Capacity Value (Power System Level)	X	(1)
Electric Transmission Capacity Benefits	Electric Transmission Capacity Value (Power System Level)	X	(1)
	Electric Transmission Infrastructure Costs for Site-Specific Resources	X	
Electric Distribution Capacity Benefits	Distribution Capacity Costs (Power System Level)	X	(1)
Natural Gas Benefits	Participant non-energy benefits: oil, gas, water, wastewater (Customer Level)	X	
Delivered Fuel Benefits		X	
Water and Sewer Benefits		O	(2)
Value of Improved Reliability	Distribution System and Customer Reliability/Resilience Impacts (Power System Level)	X	
Non-Energy Impacts	Distribution Delivery Costs (Power System Level)	O	(3)
	Distribution system safety loss/gain (Power System Level)	O	
	Customer empowerment and choice (Customer Level)	O	
	Utility low income (Power System Level)	O	
	Non-participant rate and bill impacts (Customer Level)	X	
Non-Embedded GHG Reduction Benefits	GHG Externality Cost (Societal Level)	X	
Non-Embedded Nitrogen Oxides (NOx) Reduction Benefits	Criteria Air Pollutant and Other Environmental Externality Costs (Societal Level)	X	
Non-Embedded Sulfur Dioxide (SO_2) Reduction Benefits	Public Health (Societal Level)	X	
Economic Development Benefits	Non-energy benefits: Economic Development (Societal Level)	O	(4)

RI Test Category	Docket 4600 Category	SRP Program	Notes
Utility Costs	Utility / Third Party Developer Renewable Energy, Efficiency, or Distributed Energy Resource (DER) costs	X	
Participant Costs	Program participant / prosumer benefits / costs (Customer Level)	X	
Notes An "X" indicates that the category is quantified while an "O" indicates the category is unquantified, as applicable for RI NPAs in the SRP program. (1) Electric-specific benefits/cost categories are captured in the RI NWA BCA Model and are not applicable to the RI NPA BCA Model. (2) These non-electric utility benefits are expected to be negligible for a site-specific targeted need (i.e., NWAs or NPAs). (3) Currently do not have data to estimate impacts for a targeted need case. (4) Sensitivity analysis is currently under development. This benefit is negligible unless sensitivity analysis determines otherwise.			

The following additional Docket 4600 Benefit Categories require further analysis to determine the appropriate methodology and magnitude of quantitative or qualitative impacts.

- Low-income participant benefits (Customer Level)
- Forward commitment avoided ancillary services value (Power System Level)
- Net Risk Benefits to Utility System Operations from DER Flexibility & Diversity (Power System Level)
- Option value of individual resources (Power System Level)
- Investment under uncertainty: real options value (Power System Level)
- Innovation and learning by doing (Power System Level)
- Conservation and community benefits (Societal Level)
- Innovation and knowledge spillover - related to demo projects and other Research, Design, and Development (RD&D) (Societal Level)
- Societal low-income impacts (Societal Level)
- National security and US international influence (Societal Level)

7. NWAs in System Planning

This section details the NWA Screening Criteria and the summary of the annual screening results analysis for the Company's Non-Wires Alternative program in Rhode Island.

7.1 Screening Criteria for NWA

The screening criteria for potential NWA opportunities are as follows:

Table 5: Screening Criteria for NWA Opportunities

Criteria Type	Criteria Requirement
Project Type Suitability	Project types include Load Relief and Reliability.[10] The need is not based on Asset Condition. Other types have minimal suitability and will be reviewed as suitability changes due to State or Federal policy or technological changes.
Timeline Suitability	Start date of solution implementation is at least 24 months in the future.
Cost Suitability	Cost of wires option is greater than $1M.
Load Level Suitability	If load reduction is necessary, then it will be less than 20% of the total load in the area of the defined need.

Additionally, by the Company's discretion, National Grid may pursue a project that does not pass one or more of these criteria if there is reason to believe that a viable NWA solution exists, assuming the benefits of doing so justify the costs.

No changes have been made to the NWA Screening Criteria since the prior proposals in the 2020 SRP Year-End Report.

These screening criteria are applied by the electric distribution planning team to all electric system needs that arise through planning analysis and system assessment. Such screening criteria are utilized during initial system assessment.

7.2 Analysis of System Needs

Detail on system needs that met the screening criteria and that the Company has determined may produce a potentially viable NWA opportunity are summarized in the table in Appendix 3 and detailed in the sections below as follows:

[10] For definition of reliability, see "Docket 3628: Proposed Service Quality Plan." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, Rhode Island Public Utilities Commission, 2004, www.ripuc.ri.gov/eventsactions/docket/3628page.html.

7.2.1 Bonnet 42F1

The Bonnet 42F1 NWA opportunity, formerly called Narragansett 42F1 NWA, intends to provide load relief in the Town of Narragansett by deferring or removing the need for feeder line work and reconfiguration on the Bonnet 42F1 feeder. The Bonnet 42F1 system need was identified as part of the South County East Area Study.

The Town of Narragansett is mostly supplied by four (4) 12.47 kV distribution feeders. Feeder 42F1 is projected to be loaded above summer normal ratings and lacks useful feeder ties to reduce loading below their ratings. Either more capacity must be added or load must be reduced in the town. The distribution system need can be addressed through SRP by implementation of an NWA solution that provides load reduction capability.

The Company expects that the Bonnet 42F1 NWA timeframe will span twelve years from 2023 to 2034, which is the maximum amount of time based on the current peak load forecast that the substation and feeder upgrade can be deferred with this solution. There is the potential for a partial or continued NWA solution following 2034 with the Bonnet 42F1 NWA; however, this option has not been assessed at this time.

The Company issued an RFP for the Bonnet 42F1 NWA opportunity on December 29, 2020 and received third-party bid proposals on April 6, 2021. The Company received two bid proposals. Through extensive evaluation, the Company determined that the submitted bids did not pass the NWA evaluation criteria.

One of the bids was not financially viable, it did not prove cost-effective per the RI NWA BCA Model. The other bid was, while slightly cost-effective, entailed a carbon-heavy technology as part of its solution. Ultimately, neither bid was lower than the cost of the wires option and therefore did not comply with LCP Standard 1.3.H.

The Company will proceed with the wires option for the Bonnet 42F1 system need. Currently, the wires solution for this system need is not in any near-term ISR plan, due to the fact that the Company was in the process of completing its evaluation of the NWA proposals. Now that the process is complete, the Company plans on opening funding projects for these wires solutions and working the projects into a future ISR budget plan year.

7.2.2 South Kingstown

The South Kingstown NWA opportunity intends to provide load relief in the Town of South Kingstown by deferring or removing the need for feeder line work and reconfiguration on the Peacedale 59F3 and Kenyon 68F2 feeders. The South Kingstown system need was identified as part of the South County East Area Study.

The western section of the Town of South Kingstown is supplied mostly by three (3) 12.47 kV distribution feeders. Feeders 59F3 and 68F2 are projected to be loaded above summer normal ratings and lack useful feeder ties to reduce loading below their ratings. Either new feeder ties must be constructed or load must be reduced in the western half of the town. The distribution system need can be addressed through SRP by implementation of an NWA solution that provides load reduction capability.

The Company expects that the South Kingstown NWA timeframe will span thirteen years from 2022 to 2034, which is the maximum amount of time based on the current peak load forecast that the substation and feeder upgrade can be deferred with this solution. There is the potential for a partial or continued NWA solution following 2034 with the South Kingstown NWA; however, this option has not been assessed at this time.

The Company issued an RFP for the South Kingstown NWA opportunity on November 23, 2020 and received third-party bid proposals on February 22, 2021. The Company received three bid proposals. Through extensive evaluation, the Company determined that the submitted bids did not pass the NWA evaluation criteria.

One of the bids did not address the system need and did not provide a technically viable solution; it was non-responsive to the RFP. One of the bids was not financially viable, it did not prove cost-effective per the RI NWA BCA Model. The other bid was, while slightly cost-effective, entailed a carbon-heavy technology as part of its solution. Ultimately, none of the bids were lower than the cost of the wires option and therefore did not comply with LCP Standard 1.3.H.

The Company will proceed with the wires option for the South Kingstown system need. Currently, the wires solution for this system need is not in any near-term ISR plan, due to the fact that the Company was in the process of completing its evaluation of the NWA proposals. Now that the process is complete, the Company plans on opening funding projects for these wires solutions and working the projects into a future ISR budget plan year.

8. NPAs in System Planning

This section details the Company's Non-Pipeline Alternatives program in Rhode Island.

The Company proposed to develop the NPA program, process, and its integration with gas system planning over calendar years 2021 through 2023 in its 2021-2023 SRP Three-Year Plan. Status and progress updates on NPA program development are provided as detailed below.

Particularly with respect to progress to date from 2020, and Q1 2021, the Company has refined the NPA screening criteria and the NPA evaluation process. Additionally, the Company has outlined the NPA planning process and integration with gas system planning and developed an RI NPA BCA Model and framework.

8.1 Program Development Approach

In developing the NPA Program, the Company is leveraging the NWA Program as a baseline. The NWA Program has been developed and improved upon over the past thirteen years. The Company strives for continuous improvement through internal and external feedback and has created and has maintained supporting documentation to streamline program development.

Prior to development of the NPA Program, knowledge-sharing discussions were held with the NWA team. These conversations will continue throughout the development of the NPA Program.

The Company recognizes that while there is opportunity for transferrable components of the program, there are fundamental differences between the gas and electric business units that would prompt divergent, unique, and tailored approaches. At this stage, internal working groups have been established to assess what changes would be needed to reflect and align with gas business requirements and standards. Within these discussions, peer utility reviews have been conducted to incorporate best practices from proposed NPA Programs.

This close internal coordination between the NWA and NPA teams and the external stakeholder input through the SRP TWG has been critical to delivering NPA Screening Criteria and an NPA Evaluation Process that are likely to result in robust and fair consideration of NPAs.

8.2 Screening Criteria for NPA

The Company proposes the following screening criteria for NPAs.

Table 6: Screening Criteria for NPA Opportunities

Criteria Type	Criteria Requirement
Timeline Suitability	Start date of solution implementation is at least 24 months in the future.
Cost Suitability	Cost of pipes option is greater than $0.5M.

Criteria Type	Criteria Requirement
Reliability of the Gas System	The pipes investment has negligible or no effect on critical reliability of the local or broader gas system. This effect on critical reliability will be determined through gas system modeling and will be determined based on engineering judgement.

Additionally, by the Company's discretion, National Grid may propose to pursue a project that does not pass one or more of these criteria if there is reason to believe that a viable NPA opportunity exists, assuming the benefits of doing so justify the costs.

The projects that meet the screening criteria will be prioritized in consideration of capacity-constrained locations. Capacity-constrained refers to areas of the gas network where the system is challenged to access natural gas when and where it is needed in sufficient quantities to meet customers' peak demand, as described in the Aquidneck Island Long-Term Gas Capacity Study.[11] These capacity-constrained areas serve to greater benefit from the implementation of an NPA in their potential to reduce usage or increase supply during timeframes of peak demand. The Company will prioritize NPA-eligible proposed projects that are in or affect these regions or sections of the gas network.

Timeline suitability considers the timeframe between when a proposed pipes investment is identified and the required in-service date.

Cost suitability is determined by the estimated cost of the proposed pipes investment. The Company set the initial floor price at $0.5M based on the consideration that any system need with a pipes option value less than $0.5M would not produce an economically viable NPA opportunity and that the market does not find such NPA opportunities to be fiscally prudent for their goals and policies. The Company will annually evaluate whether the initial floor price is appropriate based on market feedback and propose any modification through the SRP Program Year-End Reports.

Reliability of the gas system reflects the importance of continued safe and reliable operation. System modeling is utilized to assess immediate, local, and system-wide reliability impacts to the gas network and will be leveraged to identify the proposed pipes investments that have negligible to no effect on the critical reliability. National Grid utilizes Synergi Gas® modeling software to perform various analyses necessary for distribution system operations (e.g., regulator pressure settings, LNG requirements) and capital planning. As a part of the gas planning process, National Grid identifies asset investments that ensure continued safe and reliable operation of the gas system in meeting forecasted customer requirements. For asset replacement investments, the project scope is reviewed in the system model to assess immediate, local, and system-wide reliability

[11] *Aquidneck Island Long-Term Gas Capacity Study*, The Narragansett Electric Company d/b/a National Grid, Sept. 2020, www.nationalgridus.com/media/pdfs/other/aquidneckislandlong-termgascapacitystudy.pdf.

impacts to the gas network. If the system model determines there is a negative impact (e.g., peak system pressures decrease close to or near system minimum pressures or creates a system constraint) to system reliability locally or system-wide, scope changes will be recommended. The scope changes may include identifying a portion of the original proposed pipe scope of work that must be completed to alleviate the negative impact to system reliability, which may allow the NPA opportunity to go forward.

These screening criteria are applied by the Gas Asset Management and Engineering (GAME) team to gas system needs that arise through planning analysis and system assessment. Such screening criteria is utilized during initial system assessment.

The Company has updated its NPA screening criteria to incorporate lessons learned from NWA and feedback from stakeholders. Two revisions made to the NPA Screening Criteria include: removal of the separation between Small and/or Large Projects and expansion on the Reliability of the Gas System criteria. The Company feels this will simplify the criteria for the market while allowing the maximum number of projects to be eligible for NPA consideration.

The Company requests approval of the proposed revisions to the NPA Screening Criteria for Rhode Island as detailed in Section 8.2 for calendar years 2021 through 2023.

8.3 NPA Planning Process and Integration with Gas System Planning

This section illustrates the NPA planning process for distribution system planning.

Potential NPA opportunity screening and analysis are included as a standard part of the gas distribution system planning process.

This planning and integration process is very similar to the process followed by the NWA program. The key difference is that Initial System Assessment and Engineering Analysis are combined as one step in the NPA program, whereas these are two separate steps in the NWA program. This combination is driven by prioritization of capacity-constrained target areas as an output of the gas distribution system planning process. This output enables an engineering analysis within the same step to continue to refine an understanding of the system need.

The Company identifies and screens potential NPA opportunities through the following high-level sequential process once a system need is identified or an area study is initiated:

1. <u>Scoping</u>

The GAME team develops a scope for a specific system need or a scope that details the boundaries and concerns of an area or section of the distribution system. Planning criteria, Company standards, and forecasts are inputs to the Scoping stage.

A system study is an analysis for a specific section of the distribution system that assesses the gas system constraint characteristics and the health of infrastructure.

2. Initial System Assessment & Engineering Analysis

The GAME team performs an initial system assessment, either as part of a system study or when other targeted asset management and planning projects are initiated, such as for a specific system need.

The initial system assessment consists of a detailed analysis of a facilities and system performance within the identified study's geographic and gas scope. Initial system assessments are the first step to gather information for area studies and other system evaluations.
An engineering analysis is performed to gather detailed information for comprehensive plan development to solve the system need. This information is also included as part of development of an NPA opportunity and an NPA RFP as required.

Additionally, the potential for targeted EE and targeted DR sourced from internal Company programs is assessed at this stage, if timing for the system need allows, to determine whether they are viable components to include as part of an NPA solution. Formal evaluation of the internally-sourced targeted EE or targeted DR proposals is handled at the same time external bid proposals are evaluated.

System needs that are sufficiently out in the future are re-analyzed to determine whether the technical and economic requirements have changed in a way that allows an NPA option to be potentially feasible, per the NPA screening criteria. Timing of re-evaluation is established within and determined by the specific system study.

3. Plan Development

Plan development is the stage when pipes options and non-pipes options are developed.

To determine whether a potential NPA opportunity is feasible for a gas system need, the GAME team screens distribution projects with the criteria listed in Section 8.2, which are aligned with the Company's internal planning document. Feasibility is based on these screening criteria, which cover technical, economic, and timing factors.

These NPA screening criteria are applied to an identified gas system need and resulting potential NPA opportunities are investigated.

The NPA team develops the NPA RFP, sends the RFP to market, and receives and evaluates NPA bid responses during this stage. National Grid maintains a technology-agnostic approach to ensure that the active NPA market can propose a broad range of technologies would be considered with

NPA RFPs. Currently an NPA RFP could seek natural gas load reduction or load removal. For a load reduction NPA RFP, NPA technologies such as EE, weatherization, DR, partial electrification, and full electrification would be considered. For a load removal NPA RFP, only NPA technologies that eliminate the use of natural gas would be considered, meaning full electrification exclusively. This requirement would be outlined as a part of the NPA RFP to ensure the NPA RFP responses deliver the needed natural gas demand reduction and/or removal to defer or avoid the pipes investment. Please see Section 10.1 of the 2021-2023 SRP Three-Year Plan for the market engagement channels the Company utilizes for NPA outreach.

The NPA team analyzes and evaluates the NPA options in parallel to the pipe option, which is developed by the GAME team.

4. <u>Select Recommended Plan</u>

The GAME and NPA teams then collaboratively review and compare the pipes and non-pipes options with respect to project cost and the cost-effectiveness of the options, system reliability, safety, and other factors and finalize the recommended plan. Please refer to Section 6 for explanation on cost-effectiveness and BCA breakdown.

If an NPA option is selected as the solution for the gas system need, then the NPA solution is proposed through the next SRP Investment Proposal, as detailed in Section 12 of the 2021-2023 SRP Three-Year Plan.

If a pipes solution is the best option, and if actual load growth continues at a rate where the pipe investment is still needed, then that pipe investment is fully developed and incorporated into a future Gas Infrastructure, Safety and Reliability Plan (Gas ISR Plan). Gas ISR Plans are filed annually.

If the NPA option is determined to be more cost-effective than the pipe option but is nonetheless not selected, the Company will then provide a detailed explanation for the selection of the pipe option.

Once a pipe solution is selected for a distribution project and is proposed in an annual Gas ISR Plan filing, it is not screened for NPA feasibility again.

For reference on timing of the NPA review process and possible inclusion in a specific year's Gas ISR Plan please see Figure 1 and Figure 2, which illustrate the Distribution Planning Study Process and NPA Procurement Process, respectively. The Distribution Planning Study Process outlines the major steps and study-based inputs in the overall area study process.

Please note that capital infrastructure projects that have passed screening for potential NPA opportunities will not be advanced in the Gas ISR Plan unless they have been fully evaluated for

NPA. Also note that the Company reevaluates the potential for an NPA opportunity for a system need only if the technical and economic requirements of the system need and corresponding pipe option have changed significantly and if the timeframe allows according to the screening criteria. These reevaluation limits are set to prevent causing market and bidder exhaustion by persistently cycling through the same potential NPA opportunities that are ultimately deemed unviable by the market.

Please note that projects that have had the potential for NPA screened out, including any follow-up re-evaluation or re-screening of the system need, are progressed through the pipe option pathway. These pipe options are not proposed in a Gas ISR Plan for implementation until the pipe option is fully developed.

A general example of this process from the perspective of NPA options analysis is as follows:

1. GAME identifies a system need.
2. GAME screens the system need through the NPA screening criteria detailed in Table 6.
    a. If the system need fails any of the NPA screening criteria, then the Company pursues the pipe option.
    b. If the system need passes the NPA screening criteria, then the Company proceeds with NPA options analysis.
3. The NPA project manager (PM) gathers engineering data and the system need technical requirements from GAME.
4. The NPA PM assesses the potential for internally-sourced targeted EE and targeted DR from National Grid's EE and DR Programs. The NPA PM requests an internal targeted EE/DR option from the Customer Energy Management (CEM) team.
5. The NPA PM develops the RFP for the NPA opportunity.
6. The Procurement team sends the NPA RFP out to market and engages the market through the channels detailed in Section 10.1 of the 2021-2023 SRP Three-Year Plan.
7. Third-party bid proposals are received. The NPA opportunity is now in proposal review, as illustrated by Figure 2.
8. The review team comprised of subject matter experts (SMEs) and internal stakeholders evaluates all bid proposals received with the NPA evaluation criteria detailed in Table 8, including the internal targeted EE/DR option from the CEM team.
    a. If no bid proposals pass NPA evaluation, and are therefore deemed not viable, the Company pursues the pipe option.
    b. If at least one bid proposal passes NPA evaluation, then the Company continues with NPA proposal evaluation.
9. Additional step, Rhode Island only: the NPA PM and GAME lead compare the costs of the prime NPA option to the prime pipe option, which was developed and assessed by GAME in parallel to the NPA option developed and evaluated by the NPA team. This assessment is in line with LCP Standard 1.3.H, as referenced in Section 3.6 of the 2021-2023 SRP Three-Year Plan.

   a. If the NPA option is determined to be least-cost compared to the pipe option, then the NPA option is selected given that it already passed all NPA evaluation criteria.
   b. If the NPA option is determined to not be least-cost compared to the pipe option, then the pipe option is selected.
10. If the technical and economic requirements of the system need and corresponding pipe option change significantly following initial NPA options analysis and the timeframe allows according to the screening criteria, then the GAME team notifies the NPA team and the NPA PM begins a new NPA options analysis.
11. If the NPA option passed all NPA evaluation criteria and the LCP 1.3.H requirement, then the Company awards the NPA project to the winning bid and proceeds with contract negotiation with the respective bidder.
12. Following contract negotiation, the Company proposes the NPA project in an SRP Investment Proposal filing.
13. If the NPA project proposal is approved by the PUC, then the Company coordinates with the bidder to start NPA project implementation.

The Company plans to continue analyzing its current NPA screening and development processes to determine how NPAs might be best considered as both complete and partial solutions.

Figure 1: Gas Distribution Planning Study Process Flowchart

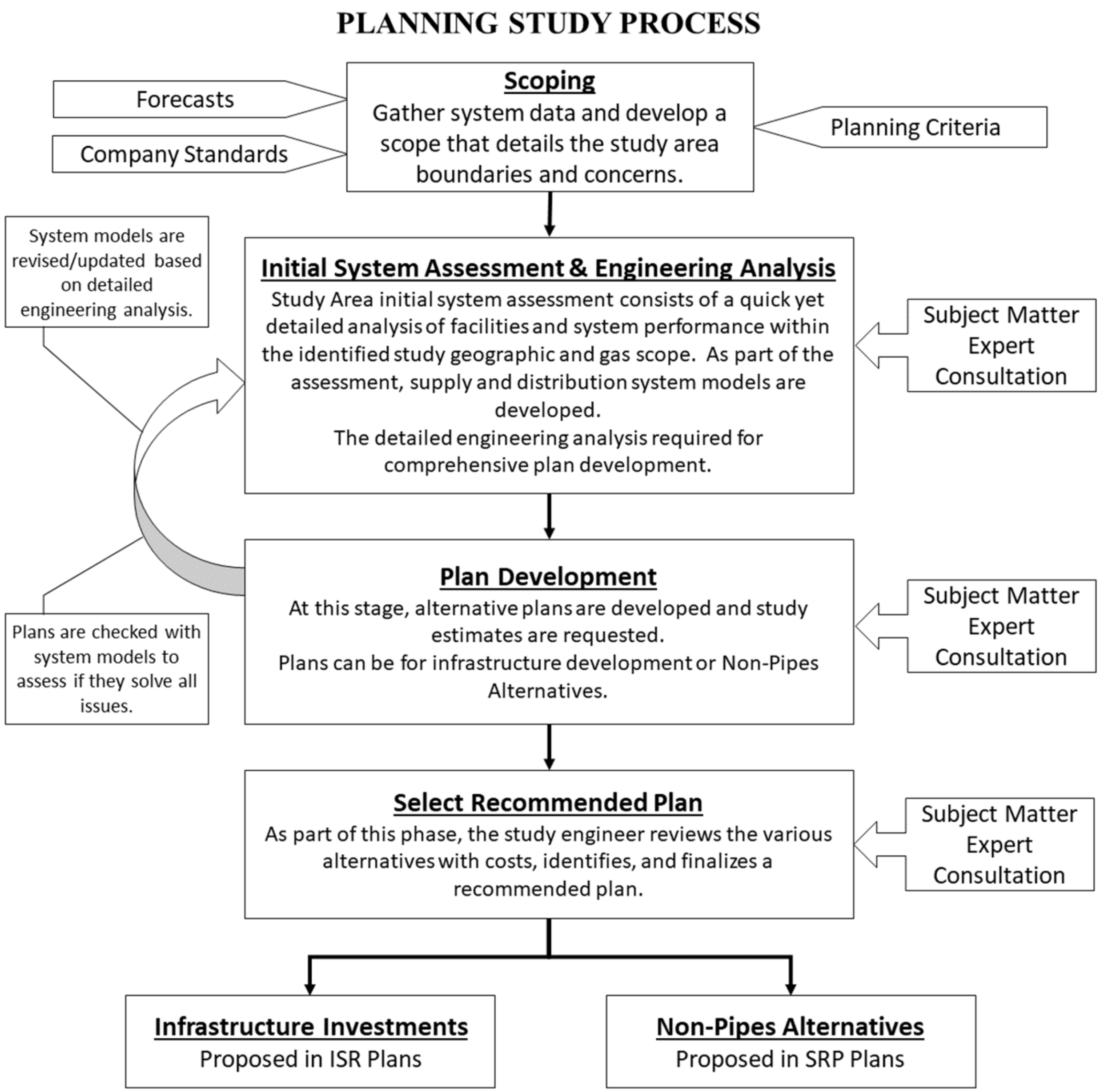
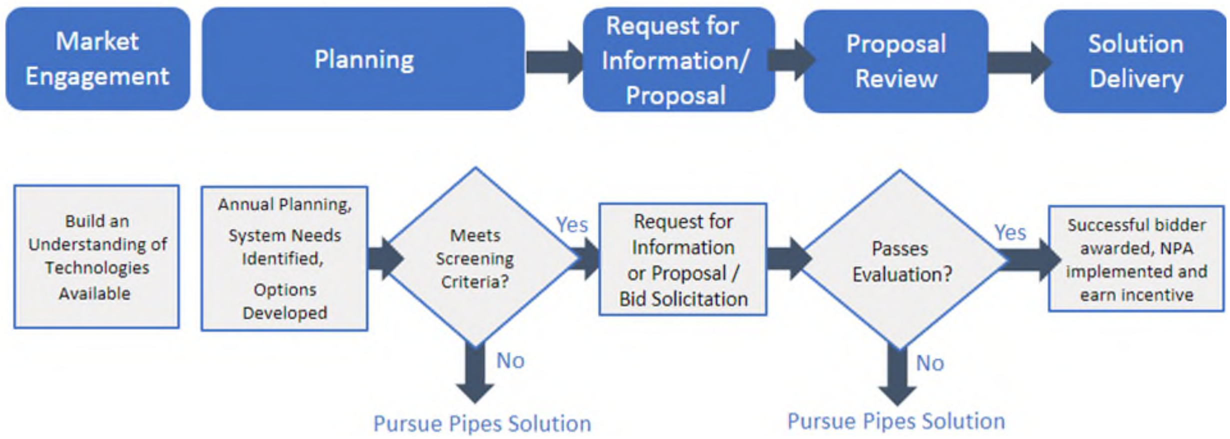


Figure 2: Overview of National Grid's NPA Procurement Process



8.4 Evaluation Process for NPA

Following receipt of all bid proposals from an NPA opportunity, National Grid proceeds directly into the evaluation stage of the NPA process. This evaluation and review of submitted bid proposals is comprised of four rounds of evaluation, with each round based on a high-level screening, detailed technical review, detailed economic review, customer acceptance, and final round selections, as detailed in the table and figure below. All bid proposals are evaluated in parallel through these four rounds.

This evaluation process is nearly identical to the process followed by the NWA program but has one difference. Namely, the NPA program considers and includes customer acceptance in Round 2.

Figure 3: National Grid NPA Evaluation Rounds

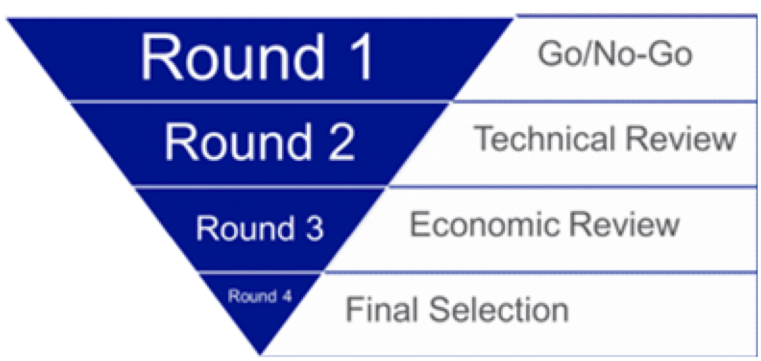


Table 7: National Grid NPA Evaluation Rounds Descriptions

Round	Evaluation Focus
Round 1	Go/No-Go: Preliminary BCA, bidder qualifications, technology type and maturity, schedule, engineering
Round 2	Detailed Technical Review: engineering, controls, communications and operations, customer acceptance, permitting, schedule and milestones
Round 3	Detailed Economic Review: full BCA, credit rating assessment, financing structure, payment structure, additional included costs and incentives
Round 4	Final Review of Shortlisted Bidders, winning bidder selection as applicable, contract negotiation

The “preliminary BCA”, as indicated in Round 1 in the table above, is to determine if the cost-effectiveness of the proposal is feasible. It involves the initial proposed solution cost and applicable benefits based on technology. The “full BCA”, as indicated in Round 3 in the table above, include the more complex factors, such as interconnection cost and any contract negotiation changes, and other factors that require deeper research to determine.

Customer Acceptance will play a critical role in the success of implementing an NPA. Within the 2020 SRP Year-End Report, the Company proposed customer acceptance determination as a separate round. As we have continued to develop the program and incorporating feedback from stakeholders, the Company will consider the likelihood of adoption of an NPA solution within the Detailed Technical Review in Round 2 and plans to review what is proposed by the vendor with input from internal subject matter experts.

Leveraging the knowledge and lessons learned gained through the Company's NWA Program and NWA evaluation process, the Company has referenced the NWA evaluation categories in order to develop the NPA evaluation process. These evaluation categories will be applied to every NPA bid proposal for any solution approach or technology type that National Grid receives. This includes proposals sourced from third-party solution providers or from an internal National Grid team.

Partial NPA opportunities are also assessed as an option. Partial NPAs are solutions that address part of a specified system need with the rest of the system need addressed by a pipes option. A partial NPA effectively reduces the scope of infrastructure projects.

The factors that will be considered within NPA evaluation include reliability, functionality, existing market conditions for the proposed technologies, societal and environmental impact, cost-effectiveness, safety and risk, flexibility, ability to meet the specific system need, bidder’s experience, and the ability for a solution proposal to pass the BCA. The NPA bid proposal that scores highest in total across all categories and meets the minimum criteria requirements (cost-effective, meets the technical need, and does not detrimentally impact the customer) is selected as the winning bid, as applicable. Additionally, in Rhode Island, the cost and cost-effectiveness are compared between the NPA option and the pipes option, in alignment with LCP 1.3.H. The NPA evaluation categories are detailed and described in Table 8 below.

Table 8: National Grid USA Evaluation Categories for NPA Proposals

Category	Description
Proposal Content & Presentation	Information requested has been provided by the bidder and is sufficiently comprehensive and well presented to allow for evaluation.
Bidder's Experience	The experience of the Bidder, any Engineering, Procurement and Construction (EPC) contractor, prime subcontractors and, if applicable, O&M operator or other entity responsible for the development, construction, or operation of the proposed solution.
Environmental	The Bidder's Proposal shall address impacts including but not limited to acoustic, aesthetic, air and greenhouse gas (GHG) emissions, water, and soil impacts, and permitting and zoning considerations. This includes greenhouse gas abatement and considers a proposal's ability to produce an outcome that reduces the amount of greenhouse gas emissions that would otherwise be produced from the pipes option.
Project Viability	The likelihood that the solution(s) associated with a Proposal can be financed and completed as required by the relevant agreement.
Functionality	The extent to which the proposed solution would meet the defined functional requirements and the ability to provide demand reduction during peak times and within the geographic area of need.
Technical Reliability	The extent to which the proposed type of technology and the equipment would meet the reliability need and can be integrated with utility operations including the ability to monitor and dispatch as applicable.
Safety	National Grid requires that the Bidders recognize safety is of paramount importance. Bidders will be required to provide safety information related to the proposed technology and information regarding safety history. The bid should comply with any jurisdictional compliance and regulatory safety codes.
Customer and Socioeconomic Impacts	The Bidder's Proposal shall address how the proposed technology impacts the customer in addition to temporary and permanent jobs to be created, economic development impacts, and property tax payments. National Grid also assesses public health and energy pricing impacts of each solution proposal.
Scheduling	The Bidder's Proposal shall include proposed timelines outlining milestones and provide sufficient detail for each deliverable, including meeting the in-service need date.
Offer Price	The Bidder's Proposal shall be based on project-specific values and financing requirements.

Category	Description
Adherence to Terms	The extent to which the Bidder accepts National Grid's proposed terms will be taken into consideration. The RFP evaluation may impute an additional amount to Bidder's Proposal to reflect any proposed modifications to the non-price terms and conditions by the Bidder that result in National Grid incurring additional costs or risks. Redlines to the terms shall be provided by the Bidder as part of its proposal for review by National Grid during the evaluation period.
Credit	Bidder's capability and willingness to perform all of its financial and other obligations under the relevant agreement will be considered by National Grid in addition to Bidder's financial strength, as determined by National Grid, and any credit assurances acceptable to National Grid that Bidder may submit with its Proposal.
Customer Acceptance	The extent to which the bidder provides compelling evidence for achieving sufficient customer adoption to achieve needed customer adoptions. This may include data, market research, outreach plans on how to promote customer adoptions.
Cost-Effectiveness	This analysis will be performed to determine the cost-effectiveness of a proposal and the RI NPA BCA Model will be used.

9. Rhode Island System Data Portal

This section details the Rhode Island System Data Portal and associated resources.

The Portal is an interactive online mapping tool developed by the Company. The Portal provides specific information for select electric distribution feeders and associated substations within the Company's electric service area in Rhode Island. This information includes feeder characteristics such as geographic locations, voltage, feeder ID, planning area, substation source, approximate loading, and available distribution generation hosting capacity.

The Portal provides this information to stakeholders, customers, and third-party solution providers. The main target audience is third-party solution providers and the main goal of the Portal is to provide information in order to engage the market for cost-effective grid solutions to reduce costs for Rhode Island customers. Therefore, the Portal is considered an SRP resource because it adheres to LCP standards and goals and is a complementary activity to meet electrical energy needs.

Costs related to Portal maintenance and routine operation of existing Portal aspects and work by FTEs are included in the current rate case. Only new enhancements to the Portal are covered in SRP Investment Proposals. New enhancements are expected to originate from collaborative consultation between National Grid and external stakeholders.

A public landing page for the Portal is located on the customer-facing National Grid website.[12]

9.1 Updates to the Portal in the Past Year

The Company has added the following new enhancements to the Portal in CY 2021:

- Application of nodal analysis to the Hosting Capacity map
- Addition of preset filters to the Heat Map to more easily allow for display of feeders based on % loading level
- Uploaded the 2021 and 2022 Electric Peak (MW) Forecast Reports to the "Company Reports" tab
- Uploaded all Electric ISR filings to date to the "Company Reports" tab

These updates were incremental and at no additional cost.

[12] See Rhode Island System Data Portal. *National Grid US*, National Grid USA Service Company, Inc., 2018, www.nationalgridus.com/Business-Partners/RI-System-Portal.

9.2 Portal to Date

To date, the Portal includes tabs that detail select Company reports, a distribution assets overview map, a heat map, a hosting capacity map, sea level rise, and National Grid's NWA program. Each map tab has the date listed in its about dropdown for when the tab data was last updated.

The Company Reports tab lists documents such as the annual SRP reports, annual ISR proposals, the electric peak forecast, and redacted area study reports.

The FAQ tab lists common questions with standard responses to proactively inform and resolve confusion for visitors to the Portal, such as third-party solution providers.

The Distribution Assets Overview tab contains a map that displays specific electric distribution feeder and substation information, summer normal ratings, and up-to-date recorded loading and forecasted loading.

The Heat Map tab contains an interactive color-coded map of distribution feeders based on forecasted load compared to summer normal rating. The heat map provides information on circuits that would benefit from DER interconnection for load relief, and on circuits that have existing capacity for electric vehicle (EV) charging stations, heat pumps, and other beneficial electrification opportunities.

The Hosting Capacity tab contains an interactive map of distribution feeders based on interconnected DG. The hosting capacity map also contains information on substation ground fault overvoltage (3V0) protection status. The Portal details if 3V0 is installed at a substation or if 3V0 is in construction or slated for construction and the proposed in-service date. Installation of 3V0 makes a substation transformer "DG-ready". The Hosting Capacity map now demonstrates nodal analysis to show variation in hosting capacity along the length of each feeder.

The Sea Level Rise tab is an interactive map that overlays National Oceanic and Atmospheric Administration (NOAA) federal sea level rise map data with National Grid's electric distribution network map data in Rhode Island. This map provides information intended to help third-party solution providers and DER developers identify locations on the National Grid electric distribution network in relation to areas that may experience potential coastal flooding impacts in the future. All sea level rise data is sourced and mirrored from the NOAA Sea Level Rise Viewer.[13]

The NWA tab contains a link to National Grid's NWA Website[14], which hosts information on the Company's NWA process and NWA RFP opportunities.

[13] "NOAA Sea Level Rise Viewer." *NOAA Sea Level Rise and Coastal Flooding Impacts*, National Oceanic and Atmospheric Administration of the United States Department of Commerce, https://coast.noaa.gov/slr/.
[14] "Non-Wires Alternatives." *National Grid Business Partners*, National Grid USA, Inc., 13 Nov. 2019, www.nationalgridus.com/Business-Partners/Non-Wires-Alternatives/.

10. SRP Market Engagement

This section provides information regarding the Company's market engagement efforts with respect to SRP.

SRP Market Engagement aims to raise awareness and perform outreach and engagement for the Rhode Island System Data Portal as needed, for NWA-related activities not covered by FTE work, and with third-party solution providers.

Outreach and engagement for activities specific to NPA and NWA, such as NPA or NWA RFPs, are already included in the work by FTEs dedicated to the development and pursuit of NWA opportunities and solutions. These FTEs are covered by the rate case.

SRP market engagement will enable third-party solution providers and vendors to more easily access available information about National Grid's electric distribution system and SRP opportunities in Rhode Island and therefore further enable these solution providers to create, submit and develop innovative energy solutions for Rhode Island customers. SRP Market Engagement upholds the commitment of National Grid and the State of Rhode Island to advance a more reliable, safe, and cost-effective energy landscape for residents and businesses of Rhode Island.

10.1 Market Engagement Activity of the Past Year

For calendar year 2021, the Company entered a maintenance phase with market engagement for the Rhode Island System Data Portal. Therefore, the only planned SRP Market Engagement activities for the Portal are to maintain web traffic analytics to the Portal landing page. These web traffic analytics have no cost to operate or acquire.

As stated in Section 4, slight budget spend did occur in the SRP Market Engagement category resulting from wrap-up in Q1 2021 of the RI Developer Portal Survey that occurred at the end of CY 2020. This survey is detailed in Section 9 and Appendix 7 of the 2020 SRP Year-End Report in Docket No. 5080.[15]

[15] Docket No. 5080." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, The Narragansett Electric Company d/b/a National Grid, 20 Nov. 2020, www.ripuc.ri.gov/eventsactions/docket/5080page.html.

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Appendix 1

Appendix 1 – Rhode Island Company Electric Service Projected Load Growth

Forecasted Load Growth for NWA Opportunities

This appendix provides an overview and update on the Rhode Island electric service projected load growth rates as well as the forecasted load growth for locations in Rhode Island that have the potential for NWA opportunities.

The Company's electric distribution system serves close to 500,000 customers in 38 cities and towns in Rhode Island. The residential class accounts for approximately 41% of the Company's total Rhode Island load, the commercial class accounts for approximately 49%, and the industrial class accounts for approximately 10%.

The forecasted load growth data is derived from the 2022 Electric Peak (MW) Forecast Report[16], which is publicly available in the Company Reports tab on the Rhode Island System Data Portal.

The forecasted load growth rates for counties in Rhode Island are shown in the Rhode Island Projected Load Growth Rates table below. Additionally, as seen in the sections below for Bristol, Kent, and Providence counties, the average annual growth rates are projected to be flat or negative over the next 10 years.

The Company has not presently identified other NWA opportunities through the distribution system planning process.

The Company accounts for DR, EE, EV, and PV impacts in the Company's electric peak load forecasting.

Forecasted Load Growth in Bristol County

The Bristol County area annual weather-adjusted summer peak is expected to increase at an average annual growth rate of 0.4% for the next 10 years. This rate is less than the statewide average annual growth rate of 0.6%.

Forecasted Load Growth in Kent County

The Kent County area annual weather-adjusted summer peak is expected to increase at an average annual growth rate of 0.1% for the next 10 years. This rate is less than the statewide average annual growth rate of 0.6%.

Forecasted Load Growth in Newport County

The Newport County area annual weather-adjusted summer peak is expected to increase at an average annual growth rate of 0.9% for the next 10 years. This rate is greater than the statewide average annual growth rate of 0.6%.

[16] Gredder, Joseph F., and Jingrui (Rain) Xie. "2022 Electric Peak (MW) Forecast Report." *Rhode Island System Data Portal*, The Narragansett Electric Company d/b/a National Grid, 12 Nov. 2021, ngrid-ftp.s3.amazonaws.com/RISysDataPortal/Docs/RI_PEAK_2022_Report.pdf.

Forecasted Load Growth in Providence County

The Providence County area annual weather-adjusted summer peak is expected to increase at an average annual growth rate of 0.4% for the next 10 years. This rate is less than the statewide average annual growth rate of 0.6%.

Forecasted Load Growth in Washington County

The Washington County area annual weather-adjusted summer peak is expected to increase at an average annual growth rate of 1.1% for the next 10 years. This rate is greater than the statewide average annual growth rate of 0.6%.

Table A1-1: Rhode Island Projected Load Growth Rates

			Annual Growth Rates (%)										5-year Average (%)	10-year Average (%)
State	County	Town	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2022 to 2026	2022 to 2031
RI			0.9	0.7	0.4	0.6	-0.1	0.9	0.6	0.6	0.7	0.7	0.5	0.6
	BRISTOL		0.7	0.5	0.1	0.3	-0.3	0.8	0.4	0.5	0.6	0.6	0.3	0.4
	KENT		0.2	0.0	-0.2	0.0	-0.6	0.5	0.2	0.3	0.4	0.4	-0.1	0.1
	NEWPORT		1.4	1.2	0.8	0.9	0.3	1.2	0.9	0.9	1.0	0.9	0.9	0.9
	PROVIDENCE		0.6	0.4	0.1	0.3	-0.3	0.8	0.4	0.5	0.6	0.6	0.2	0.4
	WASHINGTON		1.8	1.5	1.0	1.2	0.5	1.4	1.0	1.0	1.1	1.0	1.2	1.1

Appendix 2

Appendix 2 – Screened Wires Projects

Table A2-1: Screened Wires Projects

Count	Project ID	Project Description	NWA Comment	Partial NWA Comment	Capex Spending Rational	Date Initiated
1	C089195	RI Repl ACNW Vault Vent Blowers	Does not meet NWA screening requirements - Asset Condition Driven Project	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	11/8/2021
2	C088838	IRURD HIGH POINT & CIRCLE DR N.S.	Does not meet NWA screening requirements - Asset Condition Driven Project	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	9/16/2021
3	C087903	Langworthy 3V0 D-SUB	Does not meet NWA screening requirements - Programmatic Ground Fault Overvoltage Protection to address accumulated Distributed Energy Resource interconnections	This project would not be suitable for consideration of a Partial NWA	System Capacity & Performance	5/5/2021
4	C088009	Weaver Hill Rd. SubT Extension	Does not meet NWA screening requirements - the current feeders in the area experience operation, reliability, and voltage performance issues, that an NWA would not be suitable to offset. Also, the amount of load would be required is greater than 20% of the total area load.	This project would not be suitable for consideration of a Partial NWA	System Capacity & Performance	5/19/2021
5	C085414	Weaver Hill Rd Feeder DLine	Does not meet NWA screening requirements - the current feeders in the area experience operation, reliability, and voltage performance issues, that an NWA would not be suitable to offset. Also, the amount of load would be required is greater than 20% of the total area load.	This project would not be suitable for consideration of a Partial NWA	System Capacity & Performance	3/30/2020
6	C085412	Weaver Hill Rd DSub	Does not meet NWA screening requirements - the current feeders in the area experience operation, reliability, and voltage performance issues, that an NWA would not be suitable to offset. Also, the amount of load would be required is greater than 20% of the total area load.	This project would not be suitable for consideration of a Partial NWA	System Capacity & Performance	3/30/2020
7	C088058	New London 150F6 Reconductoring	Does not meet NWA screening requirements - <$1 Million in cost	This project would not be suitable for consideration of a Partial NWA	System Capacity & Performance	5/27/2021
8	C088052	Division St. 61F2 Reconductoring	Does not meet NWA screening requirements - Asset Condition Driven Project	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	5/27/2021
9	C087771	Nasonville gateway work	Does not meet NWA screening requirements - <$1 Million in cost	This project would not be suitable for consideration of a Partial NWA	System Capacity & Performance	4/16/2021
10	C089226	Wethersfield Commons URD	Does not meet NWA screening requirements - Asset Condition Driven Project	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	11/16/2021

Count	Project ID	Project Description	NWA Comment	Partial NWA Comment	Capex Spending Rational	Date Initiated
11	C088827	Valley and Farnum 23kV Conversion	Does not meet NWA screening requirements - Customer conversion project. 23kV supply to the area is being retired due to Asset Condition and reliability, therefore these customers have to be converted to 13.8kV	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	9/15/2021
12	C088062	2232 Industrial Dr. ERR	Does not meet NWA screening requirements - Asset Condition Driven Project	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	5/27/2021
13	C087862	Apponaug Long-Term Plan (D-Line)	Does not meet NWA screening requirements - Asset Condition Driven Project	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	4/28/2021
14	C087770	Nasonville 127 Substation Expansion	Does not meet NWA screening requirements - amount of load offset is greater than 20% of area loading.	This project would not be suitable for consideration of a Partial NWA	System Capacity & Performance	4/16/2021
15	C090149	RI Repl UG Fault Ind Dyer St/Ea Geo	Does not meet NWA screening requirements - Asset Condition Driven Project	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	3/16/2022
16	C089349	Prudence Island Backup Gen Site	Does not meet NWA screening requirements - Timeline of need was immediate, <$1 Million in cost	This project would not be suitable for consideration of a Partial NWA	System Capacity & Performance	12/3/2021
17	C088059	Kilvert 87F1 Line Extension	Does not meet NWA screening requirements - <$1 Million in cost	This project would not be suitable for consideration of a Partial NWA	System Capacity & Performance	5/27/2021
18	C088055	Hopkins Hill 63F6 Feeder Tie	Does not meet NWA screening requirements - Asset Condition Driven Project	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	5/27/2021
19	C088048	Coventry 54F1 Reconductoring	Does not meet NWA screening requirements - Asset Condition Driven Project	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	5/27/2021
20	C088047	Hope #15 Equipment Replacement	Does not meet NWA screening requirements - Asset Condition Driven Project	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	5/27/2021
21	C089682	Valley 102W51 Summer Prep Work	Does not meet NWA screening requirements - Timeline of need was immediate, <$1 Million in cost	This project would not be suitable for consideration of a Partial NWA	System Capacity & Performance	2/2/2022
22	C089060	2227 Line Str 13 Pole Replacement	Does not meet NWA screening requirements - Asset Condition Driven Project	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	10/18/2021
23	C088061	2232 Panto Rd. ERR	Does not meet NWA screening requirements - Asset Condition Driven Project	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	5/27/2021
24	C087783	Rebuild Centredale Substation	Does not meet NWA screening requirements - Asset Condition Driven Project	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	4/20/2021

Count	Project ID	Project Description	NWA Comment	Partial NWA Comment	Capex Spending Rational	Date Initiated
25	C088735	IR URD FAIR OAKS LN URD RI-LINCOLN	Does not meet NWA screening requirements - Asset Condition Driven Project	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	9/1/2021
26	C088337	EG Heights URD Cable Replacement	Does not meet NWA screening requirements - Asset Condition Driven Project	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	7/7/2021
27	C088057	Natick 29F1 Reconductoring	Does not meet NWA screening requirements - Timeline of need was immediate, <$1 Million in cost	This project would not be suitable for consideration of a Partial NWA	System Capacity & Performance	5/27/2021
28	C088046	Coventry #54 Sub Relocation	Does not meet NWA screening requirements - Asset Condition Driven Project	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	5/27/2021
29	C088007	Natick #29 Equipment Replacement	Does not meet NWA screening requirements - Asset Condition Driven Project	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	5/19/2021
30	C087912	3763 Pole Replacements	Does not meet NWA screening requirements - Asset Condition Driven Project	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	5/6/2021
31	C087861	Apponaug Long Term Plan (D-Sub)	Does not meet NWA screening requirements - Asset Condition Driven Project	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	4/28/2021
32	C088864	Clarkson St 3V0 D-SUB	Does not meet NWA screening requirements - Programmatic Ground Fault Overvoltage Protection to address accumulated Distributed Energy Resource interconnections	This project would not be suitable for consideration of a Partial NWA	System Capacity & Performance	9/20/2021
33	C088340	Paddock Estates URD Cable Replace	Does not meet NWA screening requirements - Asset Condition Driven Project	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	7/7/2021
34	C088006	Anthony #64 Equipment Replacement	Does not meet NWA screening requirements - Asset Condition Driven Project	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	5/19/2021
35	C088008	Warwick Mall #28 Equipment Replacem	Does not meet NWA screening requirements - Asset Condition Driven Project	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	5/19/2021
36	C087784	Centredale Getaways	Does not meet NWA screening requirements - Asset Condition Driven Project	This project would not be suitable for consideration of a Partial NWA because it is an Asset Condition Driven Program	Asset Condition	4/20/2021

Appendix 3

Appendix 3 – NWA Opportunities Summary

Table A3-1: NWA Opportunities Summary

Project Title	Project Purpose	System Need Detail	NWA Project Details	Affected System Components	Project Origination	Planned Wires Option Work	Planned Start Date	NWA Option Status
Bonnet 42F1 NWA	Load Reduction	The Town of Narragansett is mostly supplied by (4) 12.47 kV distribution feeders. Feeder 42F1 is projected to be loaded above summer normal ratings by 2024 and lacks useful feeder ties to reduce loading below their ratings. Either more capacity must be added or load must be reduced in the town.	Load reduction on Bonnet 42 substation, feeder 42F1 to defer or remove the need for feeder line work and reconfiguration.	Bonnet 42F1 feeder	South County East Area Study	Extend the 59F4 out of Peacedale down to the 17F3 and create a new feeder tie, as well as move existing load. Make switching steps to further adjust load on the system.	5/1/2023	No viable bids received
South Kingstown NWA	Load Reduction	The western section of the Town of South Kingston is supplied mostly by (3) 12.47 kV distribution feeders. Two of those feeders (59F3 and 68F2) are projected to be loaded above summer normal ratings and lack useful feeder ties to reduce loading below their ratings. Either new feeder ties must be created or load must be reduced in the western half of the town.	Load reduction on Peacedale 59F3 and Kenyon 69F2 feeders to defer or remove the need for feeder line work and reconfiguration.	Peace Dale 59F3 feeder Kenyon 69F2 feeder	South County East Area Study	Tap existing 68F5 Kenyon Feeder (at Biscuit City Road with new PTR, and extend 20,000' to P12 Tuckertown Road to create a new Normally Open tie point with the 59F3). With this new line extension, load from 68F2 and 59F3 can be transferred to the 68F5, offloading the two overloaded circuits.	6/1/2022	No viable bids received

Appendix 4

Appendix 4 – RI NWA BCA Model

The Company is providing Appendix 4 as an Excel file because it is too large to legibly produce as a PDF file.

Appendix 5

Appendix 5 – RI NPA BCA Model

The Company is providing Appendix 5 as an Excel file because it is too large to legibly produce as a PDF file.

Appendix 6

Appendix 6 – RI NPA BCA Model Technical Reference Manual

nationalgrid

National Grid's Technical Reference Manual
for the
Benefit-Cost Analysis
of
Non-Pipeline Alternatives
in
Rhode Island

For use by and prepared by

The Narragansett Electric Company d/b/a National Grid

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NATIONAL GRID's RHODE ISLAND NON-PIPES ALTERNATIVES BENEFIT-COST ANALYSIS TECHNICAL REFERENCE MANUAL

1. Introduction

National Grid's[1] Rhode Island Non-Pipeline Alternatives Benefit-Cost Analysis Technical Reference Manual (RI NPA BCA TRM) details how the Company assesses cost-effectiveness of Non-Pipeline Alternative (NPA) opportunities planned in Rhode Island through the Rhode Island Non-Pipeline Alternative Benefit-Cost Analysis Model (RI NPA BCA Model). This cost-effective assessment is in alignment with the Rhode Island Benefit Cost Test (RI Test) as detailed in the Docket 4600 Benefit-Cost Framework[2] and in accordance with Sections 1.3(B) and 1.3(C) of the Least-Cost Procurement Standards (LCP Standards) as detailed in Docket 5015[3], with both dockets respectively approved by the Rhode Island Public Utilities Commission (PUC)[4]. Although the LCP Standards were originally developed for the Company's Energy Efficiency (EE) program, the same principles have been applied to other benefit-cost analyses (BCA) conducted by the Company at the request of the PUC, including the RI NPA BCA Model.

The following RI NPA BCA Model approach was based on the LCP Standards:

I. Assess the cost-effectiveness of the NPA portfolio per a benefit-cost test that builds on the Total Resource Cost Test (TRC Test) approved by the Public Utilities Commission (PUC) in Docket 4443[5], but that more fully reflects the policy objectives of the State with regard to energy, its costs, benefits, and environmental and societal impacts. Based on the Company's EE Program Plans, in consultation with the EERMC, it was determined that these benefits should include resource impacts, non-energy impacts, distribution system impacts, economic development impacts, and the value of greenhouse gas (GHG) reductions, as described below.

II. Apply the following principles when developing the RI Test:

    a. **Efficiency and Conservation as a Resource.** EE improvements and energy conservation are some of the many resources that can be deployed to meet customers' needs. It should, therefore, be compared with both supply-side and demand-side alternative energy resources in a consistent and comprehensive manner.

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[1] The Narragansett Electric Company d/b/a National Grid (National Grid or Company).

[2] "Docket No. 4600 and Docket No. 4600-A." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, Rhode Island Public Utilities Commission, 2 Nov. 2018, www.ripuc.ri.gov/eventsactions/docket/4600page.html.

[3] "Least Cost Procurement Standards." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, Energy Efficiency and Resource Management Council, 21 Aug. 2020, http://www.ripuc.ri.gov/eventsactions/docket/5015_LCP_Standards_05_28_2020_8.21.2020%20Clean%20Copy%20FINAL.pdf.

[4] "RIPUC." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, State of Rhode Island, www.ripuc.ri.gov/.

[5] "Docket No. 4443." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, Energy Efficiency and Resource Management Council, 17 Sept. 2013, www.ripuc.ri.gov/eventsactions/docket/4443page.html.

b. **Energy Policy Goals.** Rhode Island's cost-effectiveness test should account for its applicable policy goals, as articulated in legislation (e.g., Resilient Rhode Island Act[6]), PUC orders, regulations, guidelines, and other policy directives.

c. **Hard-to-Quantify Impacts.** BCA practices should account for all relevant, important impacts, even those that are difficult to quantify and monetize.

d. **Symmetry.** BCA practices should be symmetrical, for example, by including both costs and benefits for each relevant type of impact.

e. **Forward Looking**. Analysis of the impacts of the investments should be forward-looking, capturing the difference between costs and benefits that would occur over the life of the NPA investment with those that would occur absent the investments (i.e., "Reference Case"). Sunk costs and benefits are not relevant to a cost-effectiveness analysis.

f. **Transparency.** BCA practices should be completely transparent, and should fully document and reveal all relevant inputs, assumptions, methodologies, and results.

III. With respect to the value of greenhouse gas reductions, the RI Test shall include the costs of carbon dioxide (CO_2) mitigation as they are imposed and are projected to be imposed by the Regional Greenhouse Gas Initiative (RGGI)[7]. The RI Test shall also include any other utility system costs associated with reasonably anticipated future greenhouse gas reduction requirements at the state, regional, or federal level for both electric and gas programs. The RI Test may include the value of greenhouse gas reduction not embedded in any of the above (e.g., non-embedded or societal CO_2 costs). The RI Test may also include the costs and benefits of other emissions and their generation or reduction through LCP (e.g., nitrogen oxides (NOx), sulfur dioxide (SO_2)).

IV. Benefits and costs that are projected to occur over the project life of the individual NPA projects shall be stated in present value terms in the RI Test calculation using a discount rate that appropriately reflects the risks and opportunity cost of the investment.

[6] "Resilient Rhode Island Act of 2014 - Climate Change Coordinating Council." *Chapter 42-6.2*, State of Rhode Island and Providence Plantations, 2014, http://webserver.rilin.state.ri.us/Statutes/TITLE42/42-6.2/INDEX.HTM.

[7] "State Statutes & Regulations - Rhode Island." *The Regional Greenhouse Gas Initiative*, RGGI, Inc., www.rggi.org/program-overview-and-design/state-regulations.

2. Overview of the Rhode Island Test

The RI Test compares the present value of a stream of **total benefits** to the **total costs** of the investment, **over the life** of that investment necessary to implement and realize the **net benefits**. The RI Test captures the value produced by the investment installed over the useful life of the investment. The investment life is based on the individual NPA contract timeframe and thus is expected to change on a per project basis.

The benefits calculated in the RI Test are primarily avoided resource (e.g., natural gas energy) supply and distribution costs, valued at marginal cost for the periods when there is a load reduction; and the monetized value of non-resource savings including avoided costs compared to a Reference Case (e.g., avoided utility capital and operations and maintenance (O&M) costs). The costs calculated in the RI Test are those borne by both the utility and by participants plus the increase in supply costs for any period when load is increased. All capital expenditure (CAPEX) (e.g., equipment, installation) and operational expenditure (OPEX) (e.g., evaluation and administration) are included.

All savings included in the value calculations are net savings. The expected net savings are typically an engineering estimate of savings modified to reflect the actual realization of savings based on evaluation studies, when available. The expected net savings also reflect market effects due to the program (*e.g.*, Demand Reduction Induced Price Effects (DRIPE)).

In accordance with Section 1.3.B of the revised Standards, National Grid adheres to the RI Test for all NPA investment proposals. National Grid has developed the RI NPA BCA Model, which is a derivative of the RI Test and utilizes the same Docket 4600 Benefit-Cost Framework, to more accurately assess NPA opportunities benefits and costs. The benefit categories and formulas in the RI NPA BCA Model are detailed in Section 3.

3. Description of Program Benefits and Costs

Table 1 summarizes the benefits and costs included in the RI Test and how they are treated in the Company's NPA BCA. Note that an "X" indicates that the category is quantified while an "O" indicates the category is unquantified, as applicable for RI NPAs. The "Docket 4600 Category" column in the table below references the categories and their respective details listed within Appendix A of Docket 4600.[8]

Table 1. Summary of RI Test Benefits and Costs and Treatment

<table>
<tr><th>RI Test Category</th><th>Docket 4600 Category</th><th>NPA</th><th>Notes</th></tr>
<tr><td rowspan="4">Electric Energy Benefits</td><td>Energy Supply & Transmission Operating Value of Energy Provided or Saved (Power System Level)</td><td>O</td><td rowspan="4">(1)</td></tr>
<tr><td>Retail Supplier Risk Premium (Power System Level)</td><td>O</td></tr>
<tr><td>Criteria Air Pollutant and Other</td><td>O</td></tr>
<tr><td>Distribution System Performance (Power System Level)</td><td>O</td></tr>
<tr><td rowspan="3">Renewable Portfolio Standards (RPS) and Clean Energy Policies Compliance Benefits</td><td>REC Value (Power System Level)</td><td>O</td><td rowspan="3">(1)</td></tr>
<tr><td>GHG Compliance Costs (Power System Level)</td><td>O</td></tr>
<tr><td>Environmental Externality Costs (Power System Level)</td><td>O</td></tr>
<tr><td>Demand Reduction Induced Price Effects</td><td>Energy DRIPE (Power System Level)</td><td>X</td><td></td></tr>
<tr><td>Electric Generation Capacity Benefits</td><td>Forward Commitment Capacity Value (Power System Level)</td><td>O</td><td>(1)</td></tr>
<tr><td rowspan="2">Electric Transmission Capacity Benefits</td><td>Electric Transmission Capacity Value (Power System Level)</td><td>O</td><td rowspan="2">(1)</td></tr>
<tr><td>Electric Transmission Infrastructure Costs for Site-Specific Resources</td><td>O</td></tr>
<tr><td>Electric Distribution Capacity Benefits</td><td>Distribution Capacity Costs (Power System Level)</td><td>O</td><td>(1)</td></tr>
<tr><td>Natural Gas Benefits</td><td rowspan="3">Participant non-energy benefits: oil, gas, water, wastewater (Customer Level)</td><td>X</td><td></td></tr>
<tr><td>Delivered Fuel Benefits</td><td>X</td><td></td></tr>
<tr><td>Water and Sewer Benefits</td><td>O</td><td>(2)</td></tr>
<tr><td>Value of Improved Reliability</td><td>Distribution System and Customer Reliability/Resilience Impacts (Power System Level)</td><td>X</td><td></td></tr>
<tr><td rowspan="3">Non-Energy Impacts</td><td>Distribution Delivery Costs (Power System Level)</td><td>O</td><td rowspan="3">(3)</td></tr>
<tr><td>Distribution system safety loss/gain (Power System Level)</td><td>O</td></tr>
<tr><td>Customer empowerment and choice (Customer Level)</td><td>O</td></tr>
</table>

[8] "Docket No. 4600-A." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, Rhode Island Public Utilities Commission, 3 Aug. 2017, www.ripuc.ri.gov/eventsactions/docket/4600A-PUC-GuidanceDocument-Notice_8-3-17.pdf. Appendix A.

RI Test Category	Docket 4600 Category	NPA	Notes
	Utility low income (Power System Level)	O	
	Non-participant rate and bill impacts (Customer Level)	O	
Non-Embedded GHG Reduction Benefits	GHG Externality Cost (Societal Level)	X	
Non-Embedded NOx Reduction Benefits	Criteria Air Pollutant and Other Environmental Externality Costs (Societal Level)	X	
Non-Embedded SO_2 Reduction Benefits	Public Health (Societal Level)	X	
Economic Development Benefits	Non-energy benefits: Economic Development (Societal Level)	O	(4)
Utility Costs	Utility / Third Party Developer Renewable Energy, Efficiency, or Distributed Energy Resources costs	X	
Participant Costs	Program participant / prosumer benefits / costs (Customer Level)	X	
Notes An “X” indicates that the category is quantified while an “O” indicates the category is unquantified, as applicable for RI NPAs in the SRP program. (1) Electric-specific benefits/cost categories are captured in the RI NWA BCA Model and are not applicable to the RI NPA BCA Model. (2) These non-electric utility benefits are expected to be negligible for a site-specific targeted need (i.e., NWAs). (3) Currently do not have data to claim benefits for a targeted need case. (4) Sensitivity analysis is currently under development. This benefit is negligible unless sensitivity analysis determines otherwise.			

The following additional Docket 4600 Benefit Categories require further analysis to determine the appropriate methodology and magnitude of quantitative or qualitative impacts:

- Low-income participant benefits (Customer Level)
- Forward commitment avoided ancillary services value (Power System Level)
- Net Risk Benefits to Utility System Operations from Distributed Energy Resource (DER) Flexibility & Diversity (Power System Level)
- Option value of individual resources (Power System Level)
- Investment under uncertainty: real options value (Power System Level)
- Innovation and learning by doing (Power System Level)
- Conservation and community benefits (Societal Level)
- Innovation and knowledge spillover - related to demo projects and other Research, Design, and Development (RD&D) (Societal Level)
- Societal low-income impacts (Societal Level)
- National security and US international influence (Societal Level)

All quantified NPA benefits are directly associated with the development of non-pipes compared to a Reference Case with no NPA options. The source for many of the avoided cost value components is the "Avoided Energy Supply Components in New England: 2021 Report" (AESC 2021 Study) prepared by Synapse Energy Economics for AESC 2021 Study Group in May, 2021.[9] This report was sponsored by the electric and gas EE program administrators of National Grid in New England and is designed to be used for cost-effectiveness screening in 2019 through 2021.

The AESC Study determines projections of marginal energy supply costs that will be avoided due to reductions in the use of electricity, natural gas, and other fuels, as well as avoided environmental compliance costs resulting from EE and other conservation programs. The AESC study is prepared every three years for the AESC Study Group, which is comprised of the Program Administrators as detailed in the AESC Study, as well as utilities throughout New England and other interested non-utility parties.

The AESC Study provides projections of avoided costs of energy in each New England state for a hypothetical future in which a myriad of EE and DER opportunities exist. The NPA BCA utilizes RI specific values where available. In some cases where RI specific values are not available, Southern New England values are used.

The RI NPA BCA methodology is technology agnostic and should be broadly applicable to all anticipated project and portfolio types, with some adjustments as necessary. Specific availability of a technology during the specified system need time may differ. This technology coincidence factor is based upon the association between the distribution system, supply, and peak demand for the specified NPA need. These generalized values are subject to change.

3.1 Electric Energy Benefits

Electric energy benefits due to NPA implementation can be a result of reduced energy usage (e.g., targeted EE or DR), a shift of usage from peak to off-peak (e.g., battery storage), or energy generation (e.g., solar). The resulting avoided electric energy costs are appropriate benefits for inclusion but are calculated and considered by using the RI NWA BCA Model. Electric energy benefits are valued using the avoided electric energy costs developed in the AESC 2021 Study, Appendix B.[10]

Electrification of end-uses is an NPA technology. Electric appliances and heating equipment can be used as an alternative to natural gas to reduce natural gas demand. To represent an increase in electric demand, the electric energy savings value should be negative.

Additional context on this benefit is included within the RI NWA Technical Reference Manual as detailed in Appendix 5 of the 2020 SRP Year-End Report as found in Docket No. 5080.[11]

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[9] "Avoided Energy Supply Components in New England: 2021 Report." *AESC 2021 Materials*, Synapse Energy Economics, Inc., 2021, https://www.synapse-energy.com/project/aesc-2021-materials

[10] "AESC 2021 Materials." *Avoided Energy Supply Components in New England: 2021 Report, Appendix B*, Synapse Energy Economics, Inc., 2021, https://www.synapse-energy.com/project/aesc-2021-materials

[11] Docket No. 5080." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, The Narragansett Electric Company d/b/a National Grid, 20 Nov. 2020, www.ripuc.ri.gov/eventsactions/docket/5080page.html.

3.2 RPS and Clean Energy Policy Compliance Benefits

This benefit category captures the value of avoided embedded CO_2 and SO_2 costs separately from the "Environmental and Public Health Benefits" category and is applicable electric energy benefits only. These RPS and Clean Energy Policy compliance benefits due to NPAs are the results of the reduced energy usage as described in Section 3.1. Additional context on this benefit is included within the RI NWA Technical Reference Manual as detailed in Appendix 5 of the 2020 SRP Year-End Report as found in Docket No. 5080.[12]

3.3 Demand Reduction Induced Price Effects

DRIPE is the reduction in prices in energy and capacity markets resulting from the reduction in need for energy and/or capacity due to reduced demand from electric system investments. These gas system investments can include NPAs. These investments avoid both marginal energy production and capital investments, but also lead to structural changes in the market due to lower demand. Over a period of time, the market adjusts to lower demand, but until that time the reduced demand leads to a reduction in the market price of the energy commodity. When this price effect is a result of NPAs, it is appropriate to include the impact in the RI NPA BCA Model.

DRIPE effects are very small when expressed in terms of an impact on market prices, i.e., reductions of a fraction of a percent. However, the DRIPE impacts are significant when expressed in absolute dollar terms over all the MMBtu transacted across the market. Very small impacts on market prices, when applied to all energy and capacity being purchased in the market, translate into large absolute dollar amounts. Gas Supply and Cross DRIPE values developed for the AESC 2021 Study are used in the RI NPA BCA Model. Gas Supply DRIPE is the value of reduced natural gas demand on gas commodity prices. This has a Zone-on-Zone component differentiated by state and Zone-on-Rest-of-Region DRIPE that accounts for reductions in one zone impact on New England customers. Since RI has its own zone this calculator uses those specific Zone DRIPE benefits. 3.1AESC also provides annual Cross DRIPE values to account for electricity price effects caused by a change in natural gas pricing. Each technology then has a coincidence and rating factor that is applied based on its system need.

Loss factors are applied to the Gas Supply and Cross DRIPE values to account for lost and unaccounted for gas (LAUF) from the point of delivery to the customer's facility.

The dollar value of annual benefits is therefore calculated as:

- GasSupplyDRIPE Benefit ($/yr) = NaturalGasSavings MMBtu/yr * GasSupplyDRIPE $/MMBtu * TechnologyCoincidence * TechnologyDerate * (1 + %LAUF) * (1 + %Inflation)^(year-2021)
- CrossDRIPE Benefit ($/yr) = NaturalGasSavings MMBtu/yr * CrossDRIPE $/MMBtu * TechnologyCoincidence * TechnologyDerate* (1 + %LAUF) * (1 + %Inflation)^(year-2021)

[12] Docket No. 5080." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, The Narragansett Electric Company d/b/a National Grid, 20 Nov. 2020, www.ripuc.ri.gov/eventsactions/docket/5080page.html.

Where:

- NaturalGasSavings(MMBtu/yr) = Estimated annual natural gas savings based on Engineering models
- GasSupplyDRIPE ($/MMBtu) = Projected annual values (AESC 2021, Appendix C, "Zone-on-Zone Gas Supply DRIPE")
- CrossDRIPE ($/MMBtu) = Projected annual values (AESC 2021, Appendix C, "Zone-on-Zone G-E cross DRIPE")
- TechnologyCoincidence = Coincidence factor applied based on the solution technology type
- TechnologyDerate = Derating factor applied based on solution technology type
- %LAUF = 2.7% (National Grid RI, Gas Distribution Annual Report for DOT Pipeline and Hazardous Materials Safety Administration, 2021)[13]
- %Inflation = 2% (AESC 2021, Appendix E, Page 327)

3.4 Electric Capacity Benefits

Electric capacity benefits due to NPAs are a result of load reductions or increases in electric demand as result of the NPA implementation (i.e., electrification). The resulting electric capacity benefits are appropriate for inclusion but are calculated and considered by using the RI NWA BCA Model. Electric energy benefits are valued using the avoided electric capacity costs developed in the AESC 2021 Study, Appendix B.[14] Additional context on this benefit is included within the RI NWA Technical Reference Manual as detailed in Appendix 5 of the 2020 SRP Year-End Report as found in Docket No. 5080.[15]

3.5 Natural Gas Benefits

An avoided resource benefit is produced when an NPA reduces natural gas usage. Natural gas energy and capacity benefits are considered and included in the RI NPA BCA Model calculations.

3.5.1 Natural Gas Energy Benefits

Natural gas energy benefits due to NPA implementation can be a result of reduced energy usage (e.g., EE) or the elimination of natural gas usage (e.g., electrification). The resulting avoided natural gas energy costs are appropriate benefits for inclusion in the RI NPA BCA Model. Natural gas energy benefits are valued by end use and developed in the AESC 2021 Study, Appendix C.[11]

Avoided costs may be viewed as a proxy for market costs. However, avoided costs may be different from wholesale market spot costs because avoided costs are based on simulation of market conditions, as opposed to real-time conditions. They may be different from standard offer commodity costs because of time lags and differing opinions on certain key assumptions, such as short-term fuel costs.

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[13] "Gas Distribution, Gas Gathering, Gas Transmission, Hazardous Liquids, Liquefied Natural Gas (LNG), and Underground Natural Gas Storage (UNGS) Annual Report Data." *PHMSA*, https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.

[14] "AESC 2021 Materials." *Avoided Energy Supply Components in New England: 2021 Report, Appendix B*, Synapse Energy Economics, Inc., 2021, https://www.synapse-energy.com/project/aesc-2021-materials

[15] Docket No. 5080." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, The Narragansett Electric Company d/b/a National Grid, 20 Nov. 2020, www.ripuc.ri.gov/eventsactions/docket/5080page.html.

In the RI NPA BCA benefits calculation, energy savings are grossed up using a lost and unaccounted for gas (LAUF) factor, because a reduction in energy use at the end user means that amount of energy does not have to generated, plus the extra generation that is needed to cover the losses that occur in the delivery.

AESC's avoided cost of gas at a retail customer's meter has two components: (1) the avoided cost of gas delivered to the local distribution company (LDC) and (2) the avoided cost of delivering gas on the LDC system. The retail costs of natural gas energy in the AESC 2021 Study are provided by end-use categories. Net energy savings are apportioned into these categories in the value calculation. The end-use categories are defined as follows:

- Non-Heating: Year-round end-uses generally constant gas usage throughout the year
- Hot Water: Year-round hot water end-uses generally constant gas usage throughout the year
- Heating: Space heating end-uses in which gas use is high during winter months
- All: Inclusive of heating and non-heating gas usage throughout the year

In cases where an energy use transfer occurs, energy reductions and increases could occur across fuel types (e.g., demand response). Each solution is considered by end-use category and then added together resulting in a net monetized energy reduction value. Furthermore, a derate factor is applied to solutions where customer behavior plays a role in the demand reduction achieved. This factor is used to scale the projected demand reduction to ensure the benefits of the solution are being characterized appropriately.

Natural gas energy savings created through NPAs are valued using the avoided cost of gas to retail customers by end-use from the 2021 AESC, Appendix C.[16] The values are then grossed up to account for distribution losses. Nominal annual benefits are then calculated using an average inflation rate to convert AESC's 2021 real dollar values to nominal values. Natural gas energy savings are specific to a measure and the end-use of natural gas they impact.

The dollar value of annual benefits is therefore calculated as:

- Natural Gas Energy Benefit ($/yr) = NaturalGasEnergySavings MMBtu/yr * $\text{RetailCost}_{\text{EndUse}}$ $/MMBtu * TechnologyCoincidence * TechnologyDerate * (1 + %LAUF) * (1 + %Inflation)^(year-2021)

Where:

- NaturalGasEnergySavings (MMBtu/yr) = Estimated annual natural gas energy savings based on Engineering models
- $\text{RetailCost}_{\text{EndUse}}$ ($/MMBtu) = Retail value to customers by end-use (AESC 2021, Appendix C, "Avoided cost of gas to retail customers for Southern New England (SNE) assuming no avoidable retail margin")
- TechnologyCoincidence = Coincidence factor applied based on the solution technology type

[16] "AESC 2021 Materials." *Avoided Energy Supply Components in New England: 2021 Report, Appendix C*, Synapse Energy Economics, Inc., 2021, https://www.synapse-energy.com/project/aesc-2021-materials

- TechnologyDerate = Derating factor applied based on solution technology type
- %LAUF = 2.7% (National Grid RI, Gas Distribution Annual Report for DOT Pipeline and Hazardous Materials Safety Administration, 2021)
- %Inflation = 2% (AESC 2021, Appendix E, Page 327)

3.5.2 Natural Gas Capacity Benefits

At the supply level, natural gas supply capacity benefits due to NPAs are a result of load reductions at winter peak. At the distribution and supply infrastructure site-specific level, natural gas capacity benefits are a result of the deferred system upgrade. This value is an avoided cost based on a time-deferred expected project cost of the system upgrade.

3.5.2.1 Natural Gas Supply Capacity Benefits

When additional natural gas capacity does not have to be procured because of NPAs, an avoided natural gas capacity benefit is created. An LDC builds its natural gas system and procures natural gas supply to maintain system pressures and conditions during peak demand. In New England, the system peak occurs in the winter during the coldest days of the year as natural gas is widely used for space heating today. Supply capacity benefits accrue when winter peak demand is reduced. To convert annual natural gas demand to peak load demand, a factor of 1.25% is used. This value is a company assumption derived from distribution design.

Supply capacity savings created through NPAs are valued using the avoided natural gas costs from the 2021 AESC, Appendix C.[17] The values are then grossed up to account for distribution losses. Nominal annual benefits are then calculated using an average inflation rate to convert AESC's 2021 real dollar values to nominal values. Capacity savings are specific to a measure and costing period based on how the program is designed. The highest monetary value and benefit is produced by a measure that can deliver during the peak times, which is in the winter during the coldest days of the year.

Avoided natural gas costs in the AESC 2021 Study are provided in six different costing periods. Net energy savings are apportioned into these periods in the value calculation. The six costing periods throughout the year are defined as follows:

- Highest 10 Days: Gas requirements that only occur on the coldest 10 days of the year
- Highest 30 Days: Gas requirements that only occur on the coldest 30 days of the year
- Highest 90 Days: Gas requirements that occur only during the coldest 90 days of the year
- Winter: November through March
- Winter/Shoulder: All months except June through August
- Baseload: Load that is constant throughout the year, all months

NPA system needs have a targeted demand reduction during a specific costing period. Each system need will therefore have a specific cost period to focus a solution to deliver demand reduction during specific times of the year. Natural gas supply capacity savings for NPAs are allocated to specific times of the year

[17] "AESC 2021 Materials." *Avoided Energy Supply Components in New England: 2021 Report, Appendix C*, Synapse Energy Economics, Inc., 2021, https://www.synapse-energy.com/project/aesc-2021-materials

and multiplied by the appropriate avoided capacity value. Generally, the system need is occurring during the winter season when natural gas demand is the highest.

The dollar value of annual benefits is therefore calculated as:

- Natural Gas Supply Capacity Benefit ($/yr) = CumulativeAnnualPeakSavings MMBtu * $\text{CapacityValue}_{\text{CostPeriod}}$ $/MMBtu * TechnologyCoincidence * TechnologyDerate * (1 +%LAUF) * (1 + %Inflation)^(year-2021)

Where:

- CumulativeAnnualPeakSavings (MMBtu) = Estimated peak natural gas capacity savings based on Engineering models
- $\text{CapacityValue}_{\text{CostPeriod}}$ ($/MMBtu) = Projected annual value associated with a specific costing period (AESC 2021, Appendix C, "Avoided natural gas costs by costs period – Southern New England")
- TechnologyCoincidence = Coincidence factor applied based on the solution technology type
- TechnologyDerate = Derating factor applied based on solution technology type
- %LAUF = 2.7% (National Grid RI, Gas Distribution Annual Report for DOT Pipeline and Hazardous Materials Safety Administration, 2021)
- %Inflation = 2% (AESC 2021, Appendix E, Page 327)

3.5.2.2 Natural Gas Distribution Capacity Benefits

Distribution Capacity benefit is based on the direct deferred distribution infrastructure due to the implementation of the NPA. This value includes such inputs as deferred capital expenditure, deferred O&M, and deferred taxes over the expected contract timeframe of the NPA.

3.5.2.3 Natural Gas Supply Infrastructure Site-Specific Benefits

Supply Infrastructure Site-Specific benefit is based on the direct deferred supply infrastructure due to the implementation of the NPA. This benefit category applies to supply infrastructure located on the distribution system that would be installed and operated by an LDC. This value includes such inputs as deferred capital expenditure, deferred O&M, and deferred taxes over the expected contract timeframe of the NPA. This value will typically be null for demand-side NPAs.

3.6 Delivered Fuel Benefits

Customers use a variety of fuels and energy sources to meet their energy needs. To consider fuels other than natural gas, the demand for alternative fuels is included in the RI NPA BCA models. Fuel oil delivered fuel is currently included and the RI NPA BCA model can be expanded to include additional fuel types as appropriate.

3.6.1 Fuel Oil Delivered Fuel Benefits

Fuel oil is often used as an alternative fuel to natural gas to reduce natural gas peak demand during peak times. Fuel oil when used in place of natural gas generates a fuel oil delivered fuel value. To represent an increase in fuel oil usage, the fuel oil savings value should be negative.

Fuel oil delivered fuel benefits created through NPAs are valued using the avoided costs of fuels from the 2021 AESC, Appendix D.[18] Nominal annual benefits are then calculated using an average inflation rate to convert AESC's 2021 real dollar values to nominal values. Furthermore, a derate factor is applied to solutions where customer behavior plays a role in the demand reduction achieved. This factor is used to scale the projected increase in alternative fuel consumption.

The dollar value of annual benefits is therefore calculated as:

- Fuel Oil Energy Benefit ($/yr) = FuelOilEnergySavings MMBtu/yr * $RetailCost_{DistFuelOil}$ $/MMBtu * TechnologyCoincidence * TechnologyDerate * (1 + %Inflation)^(year-2021)

Where:

- FuelOilEnergySavings (MMBtu/yr) = Estimated annual fuel oil energy savings based on the need to offset natural gas use
- $RetailCost_{DistFuelOil}$ ($/MMBtu) = Retail value to customers by sector (AESC 2021, Appendix D, "Avoided cost of petroleum fuels and other fuels by sector")
- TechnologyCoincidence = Coincidence factor applied based on the solution technology type
- TechnologyDerate = Derating factor applied based on solution technology type
- %Inflation = 2% (AESC 2021, Appendix E, Page 327)

3.7 Water and Sewer Benefits

An avoided resource benefit is produced when a project, in which customers have invested to save fuel or electricity, also reduces water consumption. Examples of reduced water consumption can include a cooling tower project that reduces makeup water usage or need. Water and sewer benefits are negligible for NPAs, so they are not included in the RI NPA BCA Model calculations.

3.8 Value of Improved Reliability

Due to the site-specific nature of these solutions, a reliability benefit should also be localized. The reliability benefit is currently difficult to quantify due to the new nature of the technologies that NPAs typically utilize. This benefit will be developed and applied as more projects are implemented and technology-specific reliability values are determined.

3.9 Non-Energy Impacts

Non-Energy Impacts (NEIs) can be produced as a direct result of NPA investments and are therefore appropriate for inclusion in the RI NPA BCA Model. Non-energy impacts may include but are not limited to: labor, material, facility use, health and safety, materials handling, national security, property values, and transportation. For income-eligible measures, NEIs also include the impacts of lower energy bills, such as reduced arrearages or avoided utility shut-off costs. The Company plans to conduct future bill

[18] "AESC 2021 Materials." *Avoided Energy Supply Components in New England: 2021 Report, Appendix D*, Synapse Energy Economics, Inc., 2021, https://www.synapse-energy.com/project/aesc-2021-materials

impact studies should non-participant rate and bill impacts be included in future. These benefits are currently seen to be negligible for NPAs.

3.10 Environmental and Public Health Impacts

Environmental benefits due to NPAs are a result of reduced energy use from the implemented solution. The resulting avoided environmental costs are appropriate benefits for inclusion in the RI NPA BCA Model. Reduction in the use of natural gas procured provides environmental benefits to Rhode Island and the region, including reduced greenhouse gas emissions and improved air quality. This BCA does account for net environmental impacts. Thus, in cases where the reduction in natural gas would be offset by increases in electricity or alternative fuel sources, a net environmental impact will be derived.

3.10.1 Non-Embedded Greenhouse Gas Reduction Benefits

Carbon dioxide and other GHG emissions come from a variety of sources, including the combustion of fossil fuels like natural gas, coal, gasoline, and diesel. Increase in atmospheric CO_2 concentrations contributes to an increase in global average temperature, which results in market damages, such as changes in net agricultural productivity, energy use, and property damage from increased flood risk, as well as nonmarket damages, such as those to human health and to the services that natural ecosystems provide to society.[19]

According to the AESC 2021 Study, the cost of GHG emissions reductions can be determined based on estimating either carbon damage costs or marginal abatement costs. Damage costs in the AESC are sourced from the December 2020 SCC Guidance published by the State of New York. This guidance recommended a 15 year levelized price of $128 per short ton. Due to the many uncertainties in climate damage cost estimates, the AESC study concluded that the marginal abatement cost method should be used instead. This method asserts that the value of damage avoided, at the margin, must be at least as great as the cost of the most expensive abatement technology used in a comprehensive strategy for emission reduction.[20]

The AESC 2021 Study developed three approaches for calculating the non-embedded cost of carbon based on marginal abatement costs. The first approach is an estimate for the global marginal carbon abatement cost based on carbon capture and sequestration technology, which yields a value of $92 per short ton of CO_2 equivalent and is lower than the prior AESC 2018 Study[21] value used. The second approach is based on a New England specific marginal abatement cost, where it is assumed that the marginal abatement technology is offshore wind. The third approach assumes a New England specific cost derived from multiple sectors, not just electric.

The New England specific marginal abatement costs assume a $125 per short ton of CO2 emissions. This is based on the future cost trajectories of offshore wind facilities along the east coast of the United States.

[19] National Academies of Sciences, Engineering, and Medicine 2017. Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide. Washington, DC: The National Academies Press. https://doi.org/10.17226/24651.

[20] "Avoided Energy Supply Components in New England: 2021 Report." *AESC 2021 Materials*, Synapse Energy Economics, Inc., 2021, https://www.synapse-energy.com/sites/default/files/AESC_2021_.pdf. Pages 171 to 182.

[21] "Avoided Energy Supply Components in New England: 2018 Report." *AESC 2018 Materials*, Synapse Energy Economics, Inc., 2018, https://www.synapse-energy.com/project/aesc-2018-materials

This aligns with New York Department of Environmental Conservation's 2020 valuation of $125 per ton. This value is used in this BCA model.

The AESC 2021 uses an assumed 117 pounds of CO2 per MMBtu for natural gas. This is derived from the U.S. Energy Information Administration's assumption of about 117 lbs/MMBtu across all sectors of natural gas use. The AESC 2021 also includes assumptions of other fuel emissions including fuel oil, gasoline, and electricity. In cases where the solution would have alternate fuel increases in the solution a net greenhouse gas reduction will be utilized.

Nominal annual benefits are then calculated using an average inflation rate to convert AESC's 2021 real dollar values to nominal values. Loss factors are applied to the natural gas supply to account for local lost and unaccounted for gas to the end-use customer. Nominal annual benefits are then calculated using an average inflation rate to convert AESC's 2018 real dollar values to nominal values.

The dollar value of annual benefits is therefore calculated as:

- GHG Reduction Benefit ($/yr) = NaturalGasEnergySavings MMBtu/yr * GHG Costs $/MMBtu * TechnologyCoincidence * TechnologyDerate * (1 + %LAUF) * (1 + %Inflation)^(year-2021)

Where:

- NaturalGasEnergySavings (MMBtu/yr) = Estimated annual natural gas energy savings based on Engineering models
- GHG Cost ($/MMBtu) = Cost of GHG emissions (AESC 2021, Table 159, "Marginal emission rates for non-electric sectors")[22]
- TechnologyCoincidence = Coincidence factor applied based on the solution technology type
- TechnologyDerate = Derating factor applied based on solution technology type
- %LAUF = 2.7% (National Grid RI, Gas Distribution Annual Report for DOT Pipeline and Hazardous Materials Safety Administration, 2021)
- %Inflation = 2% (AESC 2021, Appendix E, Page 327)

3.10.2 Non-Embedded NOx Reduction Benefits

Nitrogen oxide (NOx) emissions come from a variety of sources including heavy duty vehicles, industrial processes, and the combustion of natural gas. NOx contributes to the formation of fine particle matter (PM) and ground-level ozone that are associated with adverse health effects including heart and lung diseases, increased airways resistance, which can aggravate asthma and other underlying health issues, and respiratory tract infections. In addition to known health impacts, PM pollution and ozone are also likely to contribute to negative climate impacts.[23]

[22] "Avoided Energy Supply Components in New England: 2021 Report." *AESC 2021 Materials*, Synapse Energy Economics, Inc., 2021, https://www.synapse-energy.com/sites/default/files/AESC_2021_.pdf. Table 159

[23] "Our Nation's Air: Status and Trends through 2019." *Our Nation's Air: Trends Report*, United States Environmental Protection Agency, 2020, https://gispub.epa.gov/air/trendsreport/2020.

The AESC 2021 Study estimates avoided NOx emissions costs utilizing a continental U.S. average, non-embedded NOx emission wholesale cost of $14,700 per ton of NOx (2021 dollars).[24] This translates to a $0.71 per MMBtu in 2021. The RI NPA BCA model utilizes this AESC 2021.

Nominal annual benefits are then calculated using an average inflation rate to convert AESC's 2021 real dollar values to nominal values. Loss factors are applied to the natural gas supply to account for local lost and unaccounted for gas to the end-use customer. Nominal annual benefits are then calculated using an average inflation rate to convert AESC's 2018 real dollar values to nominal values.

The dollar value of annual benefits is therefore calculated as:

- NOx Reduction Benefit($/yr) = NaturalGasEnergySavings MMBtu/yr * NOxCosts $/MMBtu * TechnologyCoincidence * TechnologyDerate * (1 + %LAUF) * (1 + %Inflation)^(year-2021)

Where:

- NaturalGasEnergySavings (MMBtu/yr) = Estimated annual natural gas energy savings based on Engineering models
- NOxCosts = Projected annual values for NOx emissions (AESC 2021, Table 159, "Marginal emission rates for non-electric sectors")
- TechnologyCoincidence = Coincidence factor applied based on the solution technology type
- TechnologyDerate = Derating factor applied based on solution technology type
- %LAUF = 2.7% (National Grid RI, Gas Distribution Annual Report for DOT Pipeline and Hazardous Materials Safety Administration, 2021)
- %Inflation = 2% (AESC 2021, Appendix E, Page 327)

3.10.3 Non-Embedded SO_2 Reduction Benefits

Sulfur dioxide (SO_2) emissions come from a variety of sources including industrial processes and the combustion of coal (especially high-sulfur coal) and fuel oil for electricity generation and heating. SO_2 contributes to the formation of fine PM that are associated with adverse health effects including heart and lunch diseases and increased airways resistance, which can aggravate asthma and other underlying health issues. In addition to known health impacts, PM pollution is also likely to contribute to negative climate impacts.[25]

In February, 2018, the US EPA published a Technical Support Document for estimating the benefit of reducing PM2.5 precursors from 17 sectors.[26] The EPA document estimates national average values for

[24] "Avoided Energy Supply Components in New England: 2021 Report." *AESC 2021 Materials*, Synapse Energy Economics, Inc., 2021, https://www.synapse-energy.com/sites/default/files/AESC_2021_.pdf. Page 183

[25] "Our Nation's Air: Status and Trends through 2019." *Our Nation's Air: Trends Report*, United States Environmental Protection Agency, 2020, https://gispub.epa.gov/air/trendsreport/2020.

[26] "Estimating the Benefit per Ton of Reducing PM2.5 Precursors from 17 Sectors (February 2018)." *US EPA Benefits Mapping and Analysis Program (BenMAP)*, United States Environmental Protection Agency, Feb. 2018, www.epa.gov/benmap/estimating-benefit-ton-reducing-pm25-precursors-17-sectors.

mortality and morbidity per ton of directly-emitted SO_2 reduced for 2016, 2020, 2025, and 2030 based on the results from two other studies.[27,28] Using the average of the results from the two studies, the RI NWA BCA Model estimates the SO_2 emissions cost to be $69,000 per ton of SO_2 in 2020 (2015 dollars) increasing to $79,500 per ton of SO_2 in 2030 (2015 dollars). The EPA released its Natural Gas Combustion report in 2020.[29] This report stated that SO_2 emissions from natural gas typically has extremely low sulfur levels of 2,000 grains per million cubic feet (MCF). However, sulfur-containing odorants are added to natural gas leading to small amounts of SO_2 emissions. This results in a small SOx impact in natural gas of approximately 0.0006 lbs/MMBtu and a $0.02 impact per MMBtu. For cases where the solution includes distillate fuel used as a natural gas replacement the net emissions savings will include emissions from the distillate fuel.

Loss factors are applied to the emissions factor to account for lost and unaccounted for gas from supply to the end-use customer. Nominal annual benefits are then calculated using an average inflation rate to convert AESC's 2018 real dollar values to nominal values.

The dollar value of annual benefits is therefore calculated as:

- SO_2 Reduction Benefit ($/yr) = NaturalGasEnergySavings MMBtu/yr * SO_2EmissionsRate lb/MMBtu * SO_2Value $/ton* TechnologyCoincidence * TechnologyDerate * (1 + %LAUF) * (1 + %Inflation)^(year-2015)

Where:

- NaturalGasEnergySavings (MMBtu/yr) = Estimated annual natural gas savings based on Engineering models
- SO_2EmissionsRate (lb/MMBtu) = 0.00059 lb SO_2/MMBtu (EPA 1.4 Natural Gas Combustion, Table 1.4-2 "Emission Factors for Criteria Pollutants and Greenhouse Gases from Natural Gas Combustion" SO_2Value ($/ton) = $69,000-$79,500/ton (US EPA 2019, Tables 5-10, average of SO_2 from "Electricity Generation Units", 2015 dollars)
- TechnologyCoincidence = Coincidence factor applied based on the solution technology type
- TechnologyDerate = Derating factor applied based on solution technology type
- %LAUF = 2.7% (National Grid RI, Gas Distribution Annual Report for DOT Pipeline and Hazardous Materials Safety Administration, 2021)
- %Inflation = 2% (AESC 2021, Appendix E, Page 327)

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[27] Krewski, Daniel, et al. "Extended Follow-up and Spatial Analysis of the American Cancer Society Study Linking Particulate Air Pollution and Mortality." Health Effects Institute, Health Effects Institute, 26 May 2021, https://www.healtheffects.org/publication/extended-follow-and-spatial-analysis-american-cancer-society-study-linking-particulate.

[28] Lepeule, Johanna, et al. "Chronic Exposure to Fine Particles and Mortality: An Extended Follow-up of the Harvard Six Cities Study from 1974 to 2009." National Institute of Environmental Health Sciences, U.S. Department of Health and Human Services, 1 July 2012, https://ehp.niehs.nih.gov/doi/10.1289/ehp.1104660.

[29] "1.4 Natural Gas Combustion Final Section - Supplement D, July 1998." *EPA*, Environmental Protection Agency, https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-fifth-edition-volume-i-chapter-1-external-0.

Note that the AESC 2021 Study does not include estimates for avoided SO_2 emissions costs due to the Study's assertion that most of the available emission data is considered old and the impacts are very small.[30]

3.11 Economic Development Benefits

The Docket 4600 Framework includes consideration of societal economic development benefits and notes that such benefits can be reflected via a qualitative assessment or, alternatively, can be quantified through detailed economic modelling. Therefore, economic development impacts (e.g., economic growth, job creation) can be quantified using the Regional Economic Models, Inc. (REMI) model of the Rhode Island economy, which estimates the increased economic activity resulting from investments. The overall societal impact is measured by net Rhode Island gross domestic product (GDP), which encompasses job years, incomes, state tax revenues and the increased competitiveness of Rhode Island business firms.

National Grid agrees with Docket 4600 that economic development benefits are important. However, including these benefits in the base case BCA results can be problematic due to the relatively high uncertainty associated with these benefits, which can discredit other more precise components of the BCA. Additionally, because the benefits can be large, they create a "masking" effect. For these reasons, the RI NPA BCA Model did not consider economic development benefits in its BCA.

3.12 Contract/Solution Costs

The contract or solution cost is the direct cost for the NPA. This could be a payment schedule to a third party or for paid customer participation (e.g., targeted energy efficiency or demand response). These cost schedules are typically based on an annual, semi-annual, or monthly cadence. Additionally, these cost schedules may involve an annual escalator. In cases with a known, irregular cost schedule these costs can be entered manually in their respective years.

3.13 Administrative Costs

Administrative costs are related to the ongoing support of the NPA. Administrative costs can include evaluation, measurement, and verification (EM&V) costs, ongoing communications and information technology fees, or additional costs related to the post-implementation costs to keep the NPA viable. For each solution an annual expected administrative cost will be applied. In cases with a known, irregular admin cost schedule these costs can be entered manually in their respective years.

3.14 Utility Interconnection Costs

The interconnection cost is the cost for physically and digitally linking the solution to the gas system. Interconnection costs will be determined on a case-by-case basis regarding the specific system need and its respective targeted NPA. This cost will generally be a capital expenditure, initially borne by the utility, prior to the commercially viable date of the NPA solution.

[30] "Avoided Energy Supply Components in New England: 2021 Report." *AESC 2021 Materials*, Synapse Energy Economics, Inc., 2021, https://www.synapse-energy.com/sites/default/files/AESC_2021_.pdf Page 56.

4. Benefit-Cost Calculations

The RI NPA BCA Model is a comparison tool to be utilized to analyze multiple solutions with respective technologies to assess their cost-effectiveness. Currently two technology types are assessed: Energy Efficiency and Demand Response. The RI NPA BCA Model will be expanded as new technologies or solutions evolve. The RI NPA BCA Model is structured to allow for any given solution to utilize any, all, or a combination of these technologies on a per solution basis.

As prescribed by the Standards, the RI NPA BCA Model uses a "discount rate that appropriately reflects the risks of the investment". The Company maintains that the most reasonable rate at which to discount future year costs and benefits is the Company's after-tax Weighted Average Cost of Capital (WACC) (currently 6.97%)[31] since the NPA investments are utility investments, and after-tax WACC is the Company's effective discount rate.

The total benefits will equal the sum of the net present value (NPV) of each annual benefit component:

- [Electric Benefits + DRIPE Benefits + Natural Gas Energy Benefits + Natural Gas Supply Capacity Benefits + Natural Gas Distribution Capacity Benefits + Natural Gas Supply Infrastructure + Natural Gas Supply Infrastructure Site-Specific Benefits + Delivered Fuel Oil Benefits + Water & Sewer Benefits + Value of Improved Reliability + Non-Energy Impacts + Non-Embedded GHG Reduction Benefits + Non-Embedded NOx Reduction Benefits + Non-Embedded SO_2 Reduction Benefits + Economic Development Benefits]

The total costs will equal the sum of the NPV of each annual cost component:

- [Contract/Participant Costs + Program Administrative Costs + Utility Interconnection Costs]

The RI Test benefit-cost ratio (BCR) will then equal:

- Total NPV Benefits ÷ Total NPV Costs

The BCA can then financially compare multiple solutions, regardless of technology type.

The NPA investment will be considered cost-effective if the BCR for the resource is greater than 1.0.

[31] "Docket No. 4770." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, The Narragansett Electric Company d/b/a National Grid, 29 Nov. 2017, www.ripuc.ri.gov/eventsactions/docket/4770page.html.

5. Appendices

Appendix 1	AESC 2021 Materials Source Reference
Appendix 2	Table of Terms

Appendix 1: AESC 2021 Materials Source Reference

Please refer to the following citation for the Appendix B, C and D data tables of the AESC 2021 Study materials.

> "AESC 2021 Materials." *Avoided Energy Supply Components in New England: 2021 Report*, Synapse Energy Economics, Inc., 2021, https://www.synapse-energy.com/project/aesc-2021-materials.

Appendix 2: Table of Terms

Term	Definition
AESC	Avoided Energy Supply Components
AESC 2021 Study	Avoided Energy Supply Components in New England: 2021 Report
BCA	Benefit-Cost Analysis
BCR	Benefit-Cost Ratio
Capex	Capital expenditure
CO_2	Carbon dioxide
DER	Distributed Energy Resource
DR	Demand Response
DRIPE	Demand Reduction Induced Price Effect(s)
EE	Energy Efficiency
EE Plan	Energy Efficiency Program Plan
EEP	Energy Efficiency Program
EERMC	Energy Efficiency and Resource Management Council
EM&V	Evaluation, Measurement, and Verification
EPA	Environmental Protection Agency
ESS	Energy Storage System
FERC	Federal Energy Regulatory Commission
GAME	Gas Asset Management and Engineering
GDP	Gross Domestic Product
GHG	Greenhouse gas
ISO	Independent Systems Operator
LAUF	Lost and Unaccounted for Gas
LCP	Least-Cost Procurement
LCP Standards	Least-Cost Procurement Standards
LDC	Local Distribution Company
LMU	Locational Marginal Unit
MMBtu	Million British Thermal Unit
MW	Megawatt
MWh	Megawatt-hour
NERC	North American Energy Reliability Corporation
NOx	Nitrogen oxides (NO, NO_2)
NPV	Net Present Value
NPA	Non-Pipeline Alternative

Term	Definition
NWA	Non-Wires Alternative
O&M	Operations and Maintenance
Opex	Operational expenditure
PM	Particulate Matter
PTF	Pool Transmission Facilities
PTL	Pool Transmission Losses
PUC	Public Utilities Commission
RD&D	Research, Design, and Development
REC	Renewable Energy Credit
REMI	Regional Economic Models, Inc.
RGGI	Regional Greenhouse Gas Initiative
RI	Rhode Island
RI NPA BCA Model	Rhode Island Non-Pipeline Alternative Benefit-Cost Analysis Model
RI NWA BCA Model	Rhode Island Non-Wires Alternative Benefit-Cost Analysis Model
RI NWA BCA TRM	Rhode Island Non-Pipeline Alternative Benefit-Cost Analysis Technical Reference Manual
RI NWA BCA TRM	Rhode Island Non-Wires Alternative Benefit-Cost Analysis Technical Reference Manual
RI Test	Rhode Island Benefit-Cost Test
ROP	Rest of Pool
RPS	Renewable Portfolio Standards
SO_2	Sulfur dioxide
T&D	Transmission and Distribution
TRC Test	Total Resource Cost Test
TRM	Technical Reference Manual
US	United States of America
WACC	Weighted Average Cost of Capital

Appendix 7

Appendix 7 – SRP TWG Topics to Date

Table A7-1: SRP TWG Topics to Date

Year	Month	SRP TWG Topic
2019	March	Discussion of 2019 Marketing and Engagement Plan
2019	March	Discussion of 2019 SRP Portal Work
2019	March	Discussion of SRP Marketing Monthly Reports
2019	March	Discussion of Stakeholder Priorities
2019	March	Overview of 2019 SRP Report to Date
2019	March	Overview of 2020 SRP Report Draft to Date
2019	March	Presentation on System Reliability Procurement
2019	March	Summary of 2018 SRP Plan Results
2019	April	Discussion of Stakeholder Priorities
2019	April	Discussion on NPAs and SRP
2019	April	Discussion on Reason for SRP
2019	April	Discussion on the Enhancement Study
2019	May	Discussion on NWA Market Engagement
2019	May	Discussion on Open RFPs in the Portal
2019	May	Discussion on the Enhancement Study
2019	May	Recap Discussion on Stakeholder Priorities
2019	June	2020 SRP Report First Draft Discussion
2019	June	NWA Process Deep Dive
2019	July	2020 SRP Report First Draft Discussion
2019	July	Rhode Island System Data Portal Demo
2019	July	SRP Market Engagement Deep Dive
2019	August	2020 SRP Report Second Draft Discussion
2019	August	Update on South County East NWA Opportunities
2019	September	2020 SRP Report Third Draft Discussion
2019	September	Starting Discussion on the Standards
2019	November	Electric Forecasting Deep Dive
2020	January	2020 Stakeholder Priorities Discussion
2020	January	NWA Website Introduction
2020	January	SRP Standards Discussion
2020	February	2020 Stakeholder Priorities Discussion
2020	March	RI Test Transmission Capacity as it relates to NWA
2020	March	SRP Commitments
2020	April	Locational incentives
2020	April	SRP Accounting Error
2020	May	Proactive Targeted EE/DR (How can EE be a mitigating measure to reduce NWA/wires need)

Year	Month	SRP TWG Topic
2020	May	Increase stakeholder engagement
2020	May	SRP Locational Incentives, continued
2020	June	Comparison to NY (NWAs)
2020	June	Deferral Value
2020	June	Stakeholder Introductions
2020	July	Bristol 51 NWA Overview
2020	July	NWA RFP improvements Overview
2020	July	SRP 3YP First Draft Overview
2020	July	SRP Locational Incentives, continued
2020	August	NPAs and Gas Discussion
2020	August	SRP 3YP First Draft Discussion
2020	September	Long-Term Capacity Report for Aquidneck discussion
2020	September	Procurement process
2020	September	SRP 3YP Second Draft Discussion
2020	October	Gas considerations, how to use electric to improve gas reliability
2020	October	SRP 3YP Final Draft Presentation
2021	January	2020 SRP Commitments Review
2021	January	AI Long Term Capacity findings and next steps
2021	February	2021 SRP Commitments Preview
2021	February	Electric Forecasting
2021	March	NPA Program Development Update
2021	March	South Kingstown NWA Update
2021	April	2020 SRP Year-End Report Discussion
2021	April	NPA Program Development Update
2021	April	Stakeholder Priorities
2021	May	NPA Program Development Update
2021	May	OER presenting on Optionality
2021	June	NPA Program Development Update
2021	June	Portal Walkthrough
2021	June	SRP Vendor Feedback Survey Results for the Portal
2021	July	CLF's introduction and priorities presentation
2021	July	Locationally-Targeted Outreach for Proactive Targeted EE/DR, Touchbase
2021	July	NPA Program Development Update
2021	July	OER's Presentation on Locational Outreach for EE as an NWA
2021	August	Bonnet 42F1 and South Kingstown NWA Summary Dive
2021	August	NPA Program Development Update
2021	September	2021 SRP Commitments Milestone Review

Year	Month	SRP TWG Topic
2021	September	Rhode Island System Data Portal - Filters Update
2021	October	NPA Program Development Update
2021	October	Rhode Island System Data Portal - Hosting Capacity Nodal Update
2021	November	NPA Program Development Update
2021	November	CommerceRI Introduction
2021	November	RI System Data Portal Updates
2022	January	NPA Program Development Update
2022	January	Docket 5080 SRP Data Requests
2022	January	2021-2023 SPR Commitments Review
2022	February	RI NPA BCA Model Overview
2022	February	PPL Transition Update
2022	April	Stakeholder Priorities (Acadia Center, CLF, Division, NECEC, OER)
2022	May	2021 SRP Year-End Report Revisions Discussion

Appendix 8

Appendix 8 – Targeted EE-DR Assessments for South Kingstown and Bonnet 42F1 NWA Opportunities

Targeted Energy Efficiency and Demand Response Assessments for South Kingstown and Bonnet 42F1 NWA Opportunities

Please note that this document is for informational purposes only. Targeted Demand Response (DR) Assessments for the Bonnet 42F1 and South Kingstown NWA opportunities are provided by Paul Wassink of National Grid's Demand Response Program. Targeted Energy Efficiency (EE) Assessments for the Bonnet 42F1 and South Kingstown NWA opportunities are provided by National Grid's Energy Efficiency program managers in the Customer Energy Management (CEM) team. The assessments below were updated in November of 2021. Please do not circulate without permission.

Bonnet 42F1 NWA Opportunity (Narragansett, RI)

Overview

The Bonnet 42F1 NWA opportunity reflects a system need of 1.2 megawatts (MW) load reduction and 5.0 megawatt-hours (MWh) energy reduction. This NWA opportunity has a planned implementation timeframe of 12 years from 2023 to 2034.

The DR estimate for this NWA opportunity has identified 0.9 MW of curtailable load in the NWA area with an annual cost of about $238,589 and a total (12-year) cost of approximately $2,863,068. This is only 74% of the NWA goal of 1.2 MW of load reduction. In addition to helping meet the NWA needs, these measures would also result in other system benefits (deferred transmission, deferred capacity, and DRIPE).

The EE estimate for this NWA opportunity has identified 3.45 kilowatts (kW) of total potential incremental load reduction in the NWA area with a total (12-year) incremental cost of approximately $79,200 (additional total incentives of $31,200 with annual marketing costs of $4,000 over twelve years). In addition to helping meet the NWA needs, these measures would also result in other system benefits associated with standard energy efficiency program measures per Docket 4600.

Together, the DR and EE estimates represent approximately 0.9 MW of load reduction and an estimated total (12-year) cost of approximately $2,942,268. This contrasts with a distribution deferral value of $474,068 and an estimated Approximate Value of $1,190,000. Note that the Approximate Value for NWA opportunities includes the deferral value and any additional benefit value that is preliminarily applicable.

The energy efficiency and demand response measure assessments do not appear to effectively address the NWA need or to complement other portfolio solutions within the parameters of the opportunity requirements and economics.

Demand Response Measures Assessment

Commercial & Industrial Customer (C&I) Demand Response – Targeted Dispatch (TD)

There are 2 large C&I accounts on the Bonnet Substation feeder F1 with an annual peak load larger than 100kW. Please see the chart and table below for a breakdown of the largest C&I customer loads on the feeder. Note that second customer from the left has 4 accounts, though all accounts fall under the same specific C&I customer.

Figure 1. Large C&I Customer Load Demand Breakdown

Sum of Peak_Demand__c for each Name broken down by Gis Circuit and Gis Substation. Color shows details about Service Account Number. The data is filtered on minimum of Peak_Demand__c, which ranges from 1 to 195. The view is filtered on Gis Substation and Gis Circuit. The Gis Substation filter keeps BONNET. The Gis Circuit filter keeps 42F1.

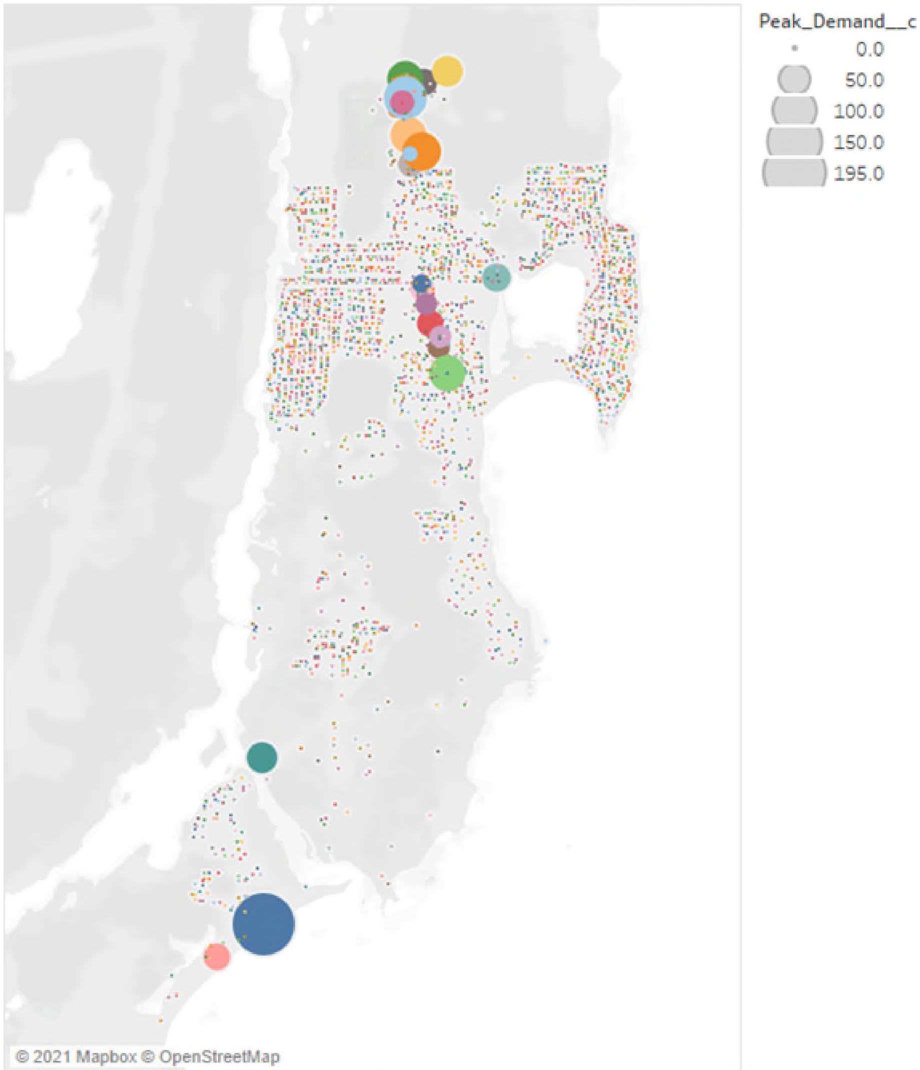
Table 1. Large C&I Customer Load Demand Breakdown, Table

Gis Substat..	Gis Circuit	Name	Service Acc..	
BONNET	42F1	Customer names and account numbers redacted	[redacted]	35.0
			[redacted]	17.0
			[redacted]	38.0
			[redacted]	11.0
			[redacted]	30.0
			[redacted]	69.0
			[redacted]	74.0
			[redacted]	195.0
			[redacted]	55.0
			[redacted]	9.0
			[redacted]	25.0
			[redacted]	19.0
			[redacted]	25.0
			[redacted]	32.0
			[redacted]	29.0
			[redacted]	93.0
			[redacted]	24.0
			[redacted]	47.0
			[redacted]	47.0
			[redacted]	40.0
			[redacted]	35.0
			[redacted]	9.0
			[redacted]	64.0
			[redacted]	65.0

Sum of Peak_Demand__c broken down by Gis Substation, Gis Circuit, Name and Service Account Number. The data is filtered on minimum of Peak_Demand__c, which ranges from 1 to 195. The view is filtered on Gis Substation and Gis Circuit. The Gis Substation filter keeps BONNET. The Gis Circuit filter keeps 42F1.

These customers account for 1.087 MW of peak demand. Our C&I customers can typically curtail ~30% of their peak load. So that would get us about 0.3MW of curtailment if we are able to sign up all these large customers/accounts.

Figure 2. Map View of Narragansett Customers



Map based on average of Long and average of Lat. Color shows details about Service Account Number. Size shows sum of Peak_Demand__c. The data is filtered on Gis Substation and Gis Circuit. The Gis Substation filter keeps BONNET. The Gis Circuit filter keeps 42F1.

The Targeted Dispatch incentive rate is $35/kW. In the summer of 2018, National Grid demonstrated that we can successfully target C&I customers in a constrained geographic location by doubling this incentive to $70/kW. The incremental cost of the added incentive for 0.3MW of load would be ($70/kW - $35/kW)*0.3MW*1000kW/MW = $11,414 per year in costs the NWA project would need to carry.

C&I Demand Response – Daily Dispatch (DD)

The Daily Dispatch incentive rate is $300/kW. With a larger incentive, some of the large accounts above may install batteries or other technologies to participate in Daily Dispatch. We have very few C&I

customers in the Daily Dispatch program so far. So, it is hard to estimate what the customer uptake would be. However, if we doubled the current incentive, I think we could at least get one C&I customer to install a 200kW battery. The incremental cost of the added incentive for a 0.2MW of load would be ($600 - $300/kW)*0.2MW*1000kW/MW = $60,00 per year in costs the NWA project would need to carry.

Electric Vehicle Demand Response

Rhode Island has elected not to enable the Connected Solutions EV or EVSE program until after the SmartCharge pilot ends.

Thermostat Demand Response

There are currently 35 thermostats enrolled in our demand response program on this feeder

The average curtailment per thermostat is 1 kW. So, this represents 0.04 MW of DR potential.

There are about 300 smart thermostats on this feeder that are not enrolled in our DR programs. If we could enroll all of them, this would represent 0.3 MW of DR potential. The best-in-class enrollment rates for thermostat-based residential DR programs is a about 45%. So, these additional thermostats represent and achievable curtailment of about 0.1 MW. Achieving this level of penetration would likely require additional marketing of about $15,000 per year an increased enrollment incentive rate of $50 per thermostat.

Residential Battery Demand Response

There are 2 residential accounts on the feeder that already have battery storage systems enrolled in Connected Solutions for a total of 0.01 MW.

There are 72 solar systems in Bristol, which can support battery installations, but are not yet enrolled in Connected Solutions. We could target marketing to these existing solar customers to increase participation in Connected Solutions in this area.

The average size curtailment per battery in our residential program is 6kW. So, the 74 solar customers represent a possible 0.4MW of curtailment. Assuming we could get 100% of customers enrolled is not realistic. However, we have not run this measure long enough to have a good estimate of our penetration potential. For this estimate, we will assume that we can enroll 30% of the market potential. This would give us 0.1 MW of achievable DR potential.

Achieving this DR potential would likely require about $15,000 per year in additional marketing and doubling the incentive in these zip codes from $400/kW-year to $800/kW-year. That would cost an additional ($800/kW-year - $400/kW-year) * 0.2 MW * 1000kW/MW = $103,800 per year.

Pool Pumps

Pool pumps will be a new measure in 2022. The Company does not yet have sufficient experience to estimate the customer uptake to estimate potential for this NWA.

Summary

This first estimate has identified 0.9 MW of curtailable load in the NWA area with an annual cost of about $238,589 and a total (12-year) cost of approximately $2,863,068. In addition to helping meet the NWA needs, these measures would also result in other system benefits (deferred transmission, deferred capacity, and DRIPE).

Table 2. DR Assessment Summary for Bonnet 42F1 NWA Opportunity

DR Type	MW Curtailed	Additional Annual Cost Borne by NWA	# Events Per Year	DR Scaling Factor	Additional Non-NWA System Benefits
C&I Targeted Dispatch	0.3	$11,414	8	10%	$18,979
C&I Daily Dispatch	0.2	$60,000	50	70%	$81,480
Thermostats	0.1	$18,375	15	40%	$31,428
Batteries	0.2	$103,800	40	70%	$90,443
NGrid Admin		$40,000			
Analytics		$5,000			
Total	**0.9**	**$238,589**			**$222,330**

At first approximation, it seems demand response alone cannot solve the NWA need of 1.2 MW and would need to be paired with other EE programs.

Energy Efficiency Measures Assessment

2. EE/DR Analysis Tables

Measure #1

Program	EnergyWise
Sector	Residential
Measure	Weatherization (elec heat and deliverable fuel)
EE/DR Program Manager	Mike Rossacci
Target Feeder	42F1

*Number of Participants should take into account the life of the measure.
**Values are considered Gross savings.
***Incremental costs additional to existing statewide incentive levels.

Potential Achievable Metrics for Weatherization (elec heat and deliverable fuel)							
	Incremental # of Participants*	New Load Relief (kW)**	New Energy Savings (kWh)**	Annual Load Relief (kW)**	Annual Energy Savings (kWh)**	Statewide Incentive Costs ($)	Targeted Customer Contribution ($)***
Year 1	2	0.23	323.89	0.23	324	$ 6,240	$ 2,080
Year 2	2	0.23	323.89	0.46	648	$ 6,240	$ 2,080
Year 3	2	0.23	323.89	0.69	972	$ 6,240	$ 2,080
Year 4	2	0.23	323.89	0.92	1,296	$ 6,240	$ 2,080
Year 5	2	0.23	323.89	1.15	1,619	$ 6,240	$ 2,080
Year 6	2	0.23	323.89	1.38	1,943	$ 6,240	$ 2,080
Year 7	3	0.35	485.84	1.73	2,429	$ 9,360	$ 3,120
Year 8	3	0.35	485.84	2.07	2,915	$ 9,360	$ 3,120
Year 9	3	0.35	485.84	2.42	3,401	$ 9,360	$ 3,120
Year 10	3	0.35	485.84	2.76	3,887	$ 9,360	$ 3,120
Year 11	3	0.35	485.84	3.11	4,373	$ 9,360	$ 3,120
Year 12	3	0.35	485.84	3.45	4,858	$ 9,360	$ 3,120
Total ꟷ	**30**	**3.45**	**4,858**	**3.45**	**4,858**	**$ 93,600**	**$ 31,200**

ꟷ Sum totals taken for all datapoints except for Annual Load Relief (kW), as power (kW) is an instantaneous value independent of time (additive vs cumulative). Max taken instead for kW. Max also taken for Annual Energy Savings (kWh) as it is already cumulatively summed.

Additional measure detail:

Incremental annual marketing costs of $4,000 per year. 10% lift in weatherization over EE levels in years 1-6 and 15% lift over 2019 year-end EE results.

Measure #2

Program	
Sector	Commercial and Industrial
Measure	C&I Measure Mix
EE/DR Program Manager	
Target Feeder	42F1

Additional measure detail:

The 5-year average kW reduction for the Bonnet 42F1 Feeder was 4.72 kW. The largest demand reduction occurred in 2013 and accounted for a 14.43 kW. The max achievable kW reduction was calculated as a 10 percent of the highest annual kW reduction. Therefore, the maximum incremental kW reduction was calculated to be 1.44 kW (10% of 14.43 kW), for a total kW reduction of 15.87 kW on the Bonnet 42F1 feeder. The maximum incremental reduction of 1.44 kW is not significant enough to warrant further analysis.

Summary

This EE estimate has identified 3.45 kW of total potential incremental load reduction in the NWA area with a total (12-year) incremental cost of approximately $79,200 (additional total incentives of $31,200 with annual marketing costs of $4,000 over twelve years). In addition to helping meet the NWA needs, these measures would also result in other system benefits associated with standard energy efficiency program measures per Docket 4600.

The energy efficiency measure assessment does not appear to effectively address the NWA need or complement other portfolio solutions within the parameters of the opportunity requirements and economics.

South Kingstown NWA Opportunity (South Kingstown, RI)

Overview

The South Kingstown NWA opportunity reflects a system need of 3.7 MW load reduction and 16.2 MWh energy reduction. This NWA opportunity has a planned implementation timeframe of 13 years from 2022 to 2034.

The DR estimate for this NWA opportunity has identified 1.3 MW of curtailable load in the NWA area with an annual cost of about $294,474 and a total (13-year) cost of approximately $3,828,162, as detailed below. This load relief is only 36% of the NWA goal of 3.7 MW. In addition to helping meet the NWA needs, these measures would also result in other system benefits (deferred transmission, deferred capacity, and DRIPE).

The EE estimate for this NWA opportunity has identified 37.3 kW of total potential incremental load reduction in the NWA area with a total (13-year) cost of approximately $263,380 (additional total incentives of $126,880 with annual marketing costs of $10,500 over thirteen years). In addition to helping meet the NWA needs, these measures would also result in other system benefits associated with standard energy efficiency program measures per Docket 4600.

Together, the DR and EE estimates represent approximately 1.3 MW of load reduction and an estimated total (13-year) cost of approximately $4,091,542. This contrasts with a distribution deferral value of $1,205,640 and an estimated Approximate Value of $4,560,000. Note that the Approximate Value for NWA opportunities includes the deferral value and any additional benefit value that is preliminarily applicable.

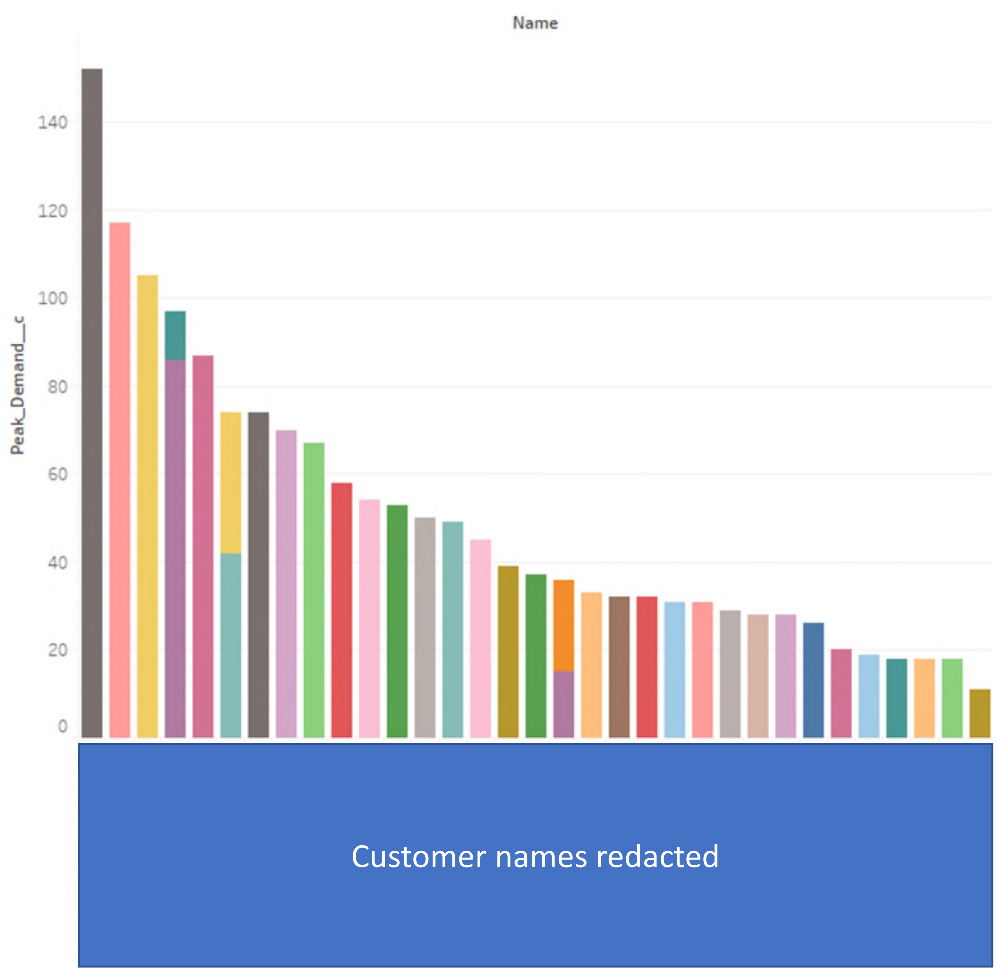
The energy efficiency and demand response measure assessments do not appear to effectively address the NWA need or complement other portfolio solutions within the parameters of the opportunity requirements and economics.

Demand Response Measures Assessment

C&I Demand Response – Targeted Dispatch

There are 3 large C&I customers and 36 accounts on the Peacedale 59F3 and Kenyon 68F2 feeders. The peak demand for these customers adds up to 1.6 MW. Three of these customers have a peak demand of greater than 100kW and would be great candidates for our C&I demand response programs.

Figure 3. Annual Peak Demand of Top Customers in South Kingstown



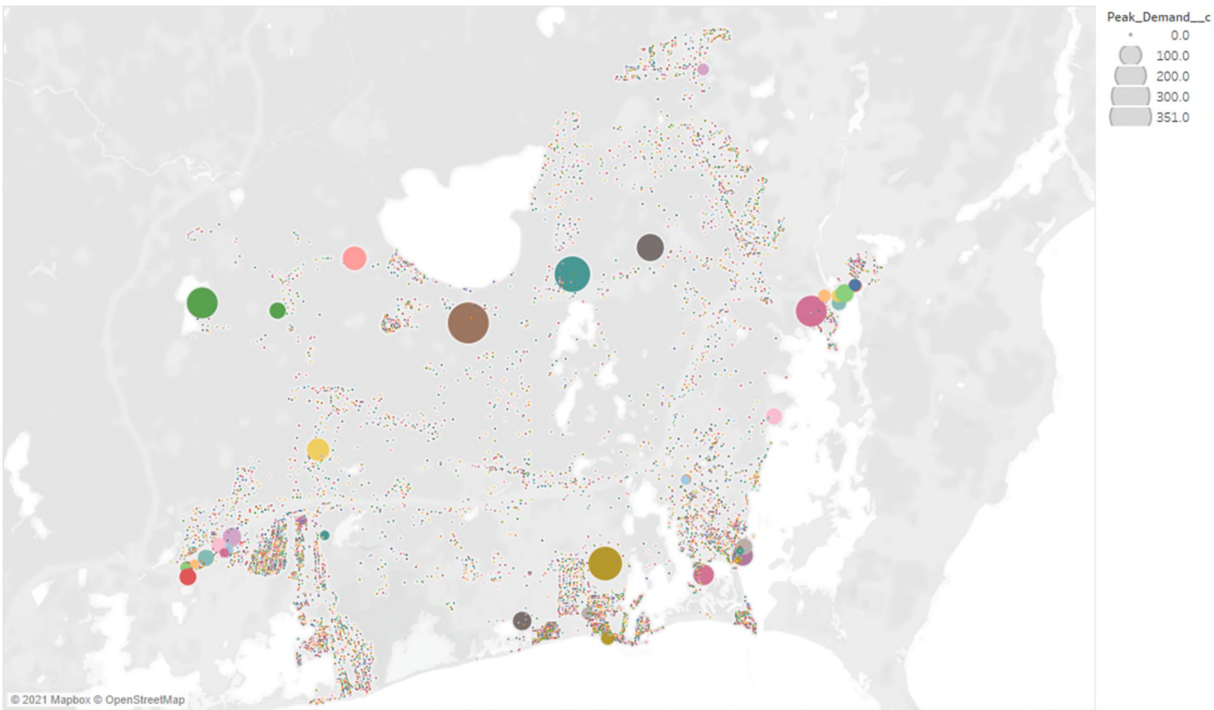
Sum of Peak_Demand__c for each Name. Color shows details about Service Account Number. The data is filtered on Gis Substation, Gis Circuit and minimum of Peak_Demand__c. The Gis Substation filter keeps KENYON and PEACEDALE. The Gis Circuit filter keeps 59F3 and 68F2. The minimum of Peak_Demand__c filter ranges from 1 to 195.

Figure 4. Demand Response Customer Load Demand Breakdown, Table

Gis Circuit	Gis Substation	Name	Service Account Number	Peak_Demand__c
59F3	PEACEDALE	[redacted]	[redacted]	19
59F3	PEACEDALE	[redacted]	[redacted]	54
59F3	PEACEDALE	[redacted]	[redacted]	87
59F3	PEACEDALE	[redacted]	[redacted]	67
59F3	PEACEDALE	[redacted]	[redacted]	31
59F3	PEACEDALE	[redacted]	[redacted]	11
59F3	PEACEDALE	[redacted]	[redacted]	86
59F3	PEACEDALE	[redacted]	[redacted]	50
59F3	PEACEDALE	[redacted]	[redacted]	32
59F3	PEACEDALE	[redacted]	[redacted]	42
59F3	PEACEDALE	[redacted]	[redacted]	33
59F3	PEACEDALE	[redacted]	[redacted]	11
59F3	PEACEDALE	[redacted]	[redacted]	37
59F3	PEACEDALE	[redacted]	[redacted]	32
59F3	PEACEDALE	[redacted]	[redacted]	26
59F3	PEACEDALE	[redacted]	[redacted]	28
59F3	PEACEDALE	[redacted]	[redacted]	152
59F3	PEACEDALE	[redacted]	[redacted]	21
68F2	KENYON	[redacted]	[redacted]	105
68F2	KENYON	[redacted]	[redacted]	20
68F2	KENYON	[redacted]	[redacted]	49
68F2	KENYON	[redacted]	[redacted]	53
68F2	KENYON	[redacted]	[redacted]	58
68F2	KENYON	[redacted]	[redacted]	45
68F2	KENYON	[redacted]	[redacted]	18
68F2	KENYON	[redacted]	[redacted]	18
68F2	KENYON	[redacted]	[redacted]	117
68F2	KENYON	[redacted]	[redacted]	74
68F2	KENYON	[redacted]	[redacted]	39
68F2	KENYON	[redacted]	[redacted]	31
68F2	KENYON	[redacted]	[redacted]	29
68F2	KENYON	[redacted]	[redacted]	18
68F2	KENYON	[redacted]	[redacted]	28
68F2	KENYON	[redacted]	[redacted]	15
68F2	KENYON	[redacted]	[redacted]	32
68F2	KENYON	[redacted]	[redacted]	70
				1,638

Customer names and account numbers redacted

Figure 5. Map View of South Kingstown Customers



Map based on average of Long and average of Lat. Color shows details about Service Account Number. Size shows sum of Peak_Demand__c. The data is filtered on Gis Substation and Gis Circuit. The Gis Substation filter keeps KENYON and PEACEDALE. The Gis Circuit filter keeps 59F3 and 68F2.

Customers in our C&I DR programs typically curtail about 30% of their annual peak demand. So, the customers above represent about 0.5MW of curtailable load.

Our typical C&I DR program pay an incentive of $35/kW. In the summer of 2018, National Grid demonstrated that we can successfully target C&I customers in a constrained geographic location by doubling this incentive to $70/kW. The incremental cost of the added incentive for 0.5MW of load would be ($70/kW - $35/kW)*0.5MW*1000kW/MW = $17,199 per year in costs the NWA project would need to carry.

Thermostat Demand Response

There are currently 70 thermostats enrolled in our demand response program on the target feeders.

The average curtailment per thermostat is 1 kW. So, this represents 0.01 MW of DR potential.

There are about 700 smart thermostats in these ZIP codes that are not enrolled in our DR programs. If we could enroll all of them, this would represent 0.7 MW of DR potential. The best-in-class enrollment rates for thermostat-based residential DR programs is a about 45%. So, these additional thermostats represent and achievable curtailment of about 0.3 MW. Achieving this level of penetration would likely require additional marketing of about $15,000 per year an increased enrollment incentive rate of $50 per thermostat.

Residential Battery Demand Response

There are 9 residential accounts on the feeder that already have battery storage systems enrolled in Connected Solutions for a total of 0.05 MW.

There are 112 solar systems on the target feeders, which can support battery installations, but are not yet enrolled in Connected Solutions. We could target marketing to these existing solar customers to increase participation in Connected Solutions in this area.

The average size curtailment per battery in our residential program is 6kW. So, the 112 solar customers represent a possible 0.7 MW of curtailment. Assuming we could get 100% of customers enrolled is not realistic. However, we have not run this measure long enough to have a good estimate of our penetration potential. For this estimate, we will assume that we can enroll 50% of the market potential. This would give us 0.3 MW of achievable DR potential.

Achieving this DR potential would likely require about $15,000 per year in additional marketing and doubling the incentive in these zip codes from $400/kW-year to $800/kW-year. That would cost an additional ($800/kW-year - $400/kW-year) * 0.3 MW * 1000kW/MW = $149,400 per year.

Summary

This estimate has identified 1.3 MW of curtailable load in the NWA area with an annual cost of about $294,474 and a total (13-year) cost of approximately $3,828,162. This is only 36% of the NWA goal of 3.7 MW of load reduction.

At first approximation, it seems the demand response alone cannot solve the NWA need and would need to be paired with other energy efficiency measures to reduce load in the NWA area.

Table 3. DR Assessment Summary for South Kingstown NWA Opportunity

DR Type	MW Curtailed	Additional Annual Cost Borne by NWA	# Events Per Year	DR Scaling Factor	Additional Non-NWA System Benefits
C&I Targeted Dispatch	0.5	$17,199	8	10%	$28,599
C&I Daily Dispatch	0.2	$60,000	50	70%	$81,480
Thermostats	0.3	$22,875	15	40%	$73,332
Batteries	0.3	$149,400	40	70%	$136,886
NGrid Admin		$40,000			
Analytics		$5,000			
Total	**1.3**	**$294,474**			**$320,298**

Energy Efficiency Measures Assessment

2. EE/DR Analysis Tables

Measure #1

Program	EnergyWise
Sector	Residential
Measure	Weatherization (elec heat and deliverable fuel)
EE/DR Program Manager	Mike Rossacci
Target Feeder	Peacedale 59F3

*Number of Participants should take into account the life of the measure.

**Values are considered Gross savings.

***Incremental costs additional to existing statewide incentive levels.

Potential Achievable Metrics for Weatherization (elec heat and deliverable fuel)							
	Incremental # of Participants*	New Load Relief (kW)**	New Energy Savings (kWh)**	Annual Load Relief (kW)**	Annual Energy Savings (kWh)**	Statewide Incentive Costs ($)	Targeted Customer Contribution ($)***
Year 1	3	0.34	486	0.34	486	$ 9,360	$ 3,120
Year 2	3	0.34	486	0.68	972	$ 9,360	$ 3,120
Year 3	3	0.34	486	1.02	1,457	$ 9,360	$ 3,120
Year 4	3	0.34	486	1.36	1,943	$ 9,360	$ 3,120
Year 5	3	0.34	486	1.70	2,429	$ 9,360	$ 3,120
Year 6	3	0.34	486	2.04	2,915	$ 9,360	$ 3,120
Year 7	3	0.34	486	2.38	3,401	$ 9,360	$ 3,120
Year 8	4	0.46	648	2.84	4,049	$ 12,480	$ 4,160
Year 9	4	0.46	648	3.30	4,696	$ 12,480	$ 4,160
Year 10	4	0.46	648	3.76	5,344	$ 12,480	$ 4,160
Year 11	4	0.46	648	4.22	5,992	$ 12,480	$ 4,160
Year 12	4	0.46	648	4.68	6,640	$ 12,480	$ 4,160
Year 13	4	0.46	648	5.14	7,287	$ 12,480	$ 4,160
Total †	**45**	**5.14**	**7,287**	**5.14**	**7,287**	**$ 140,400**	**$ 46,800**

† Sum totals taken for all datapoints except for Annual Load Relief (kW), as power (kW) is an instantaneous value independent of time (additive vs cumulative). Max taken instead for kW. Max also taken for Annual Energy Savings (kWh) as it is already cumulatively summed.

Additional measure detail:

Incremental annual marketing costs of $5,500 per year. 10% lift in weatherization over EE levels in years 1-5 and 15% lift over 2019 year-end EE results.

Measure #2

Program	EnergyWise
Sector	Residential
Measure	Weatherization (elec heat and deliverable fuel)
EE/DR Program Manager	Mike Rossacci
Target Feeder	Kenyon 68F2

*Number of Participants should take into account the life of the measure.
**Values are considered Gross savings.
***Incremental costs additional to existing statewide incentive levels.

Potential Achievable Metrics for Weatherization (elec heat and deliverable fuel)							
	Incremental # of Participants*	New Load Relief (kW)**	New Energy Savings (kWh)**	Annual Load Relief (kW)**	Annual Energy Savings (kWh)**	Statewide Incentive Costs ($)	Targeted Customer Contribution ($)***
Year 1	5	0.56	810	0.56	810	$ 15,600	$ 5,200
Year 2	5	0.56	810	1.12	1,619	$ 15,600	$ 5,200
Year 3	5	0.56	810	1.68	2,429	$ 15,600	$ 5,200
Year 4	5	0.56	810	2.24	3,239	$ 15,600	$ 5,200
Year 5	5	0.56	810	2.80	4,049	$ 15,600	$ 5,200
Year 6	5	0.56	810	3.36	4,858	$ 15,600	$ 5,200
Year 7	5	0.56	810	3.92	5,668	$ 15,600	$ 5,200
Year 8	7	0.79	1,134	4.71	6,802	$ 21,840	$ 7,280
Year 9	7	0.79	1,134	5.50	7,935	$ 21,840	$ 7,280
Year 10	7	0.79	1,134	6.29	9,069	$ 21,840	$ 7,280
Year 11	7	0.79	1,134	7.08	10,202	$ 21,840	$ 7,280
Year 12	7	0.79	1,134	7.87	11,336	$ 21,840	$ 7,280
Year 13	7	0.79	1,134	8.66	12,470	$ 21,840	$ 7,280
Total ↿	**77**	**8.66**	**12,470**	**8.66**	**12,470**	**$ 240,240**	**$ 80,080**

↿ Sum totals taken for all datapoints except for Annual Load Relief (kW), as power (kW) is an instantaneous value independent of time (additive vs cumulative). Max taken instead for kW. Max also taken for Annual Energy Savings (kWh) as it is already cumulatively summed.

Additional measure detail:

Incremental annual marketing costs of $5,000. 10% lift in weatherization over EE levels in years 1-5 and 15% lift over 2019 year-end EE results.

Measure #3

Program	Large Commercial Retrofit
Sector	Commercial & Industrial
Measure	C&I Measure Mix
EE/DR Program Manager	
Target Feeder	Peacedale 59F3

Additional measure detail:

The 5-year average kW reduction for the Peacedale 59 Feeder was 43.39 kW. The largest demand reduction occurred in 2014 and accounted for a 64.71 kW. The max achievable kW reduction was calculated as a 10 percent of the highest annual kW reduction. Therefore, the maximum incremental kW reduction was calculated to be 6.47 kW (10% of 64.71 kW), for a total kW reduction of 71.18 kW on the Peacedale 59 feeder. The maximum incremental reduction of 6.47 kW is not significant enough to warrant further analysis.

Measure #4

Program	Large Commercial Retrofit
Sector	Commercial & Industrial
Measure	C&I Measure Mix
EE/DR Program Manager	
Target Feeder	Kenyon 68F2

Additional measure detail:

The 5-year average kW reduction for the Kenyon 68 Feeder was 108.99 kW. The largest demand reduction occurred in 2013 and accounted for a 170.61 kW. The max achievable kW reduction was calculated as a 10 percent of the highest annual kW reduction. Therefore, the maximum incremental kW reduction was calculated to be 17.06 kW (10% of 170.61 kW), for a total kW reduction of 187.67 kW on the Kenyon 68 feeder. The maximum incremental reduction of 17.06 kW is not significant enough to warrant further analysis.

Summary

This EE estimate has identified 37.3 kW of total potential incremental load reduction in the NWA area with a total (13-year) cost of approximately $263,380 (additional total incentives of $126,880 with annual marketing costs of $10,500 over thirteen years). In addition to helping meet the NWA needs, these measures would also result in other system benefits associated with standard energy efficiency program measures per Docket 4600.

The energy efficiency measure assessment does not appear to effectively address the NWA need or complement other portfolio solutions within the parameters of the opportunity and economics.

Appendix 9

Appendix 9 – RI NWA BCA Model for the Bonnet 42F1 NWA Opportunity

The Company is seeking confidential treatment of Appendix 9.

The Company is providing Appendix 9 as an Excel file because it is too large to legibly produce as a PDF file.

Appendix 10

Appendix 10 – NWA Evaluation Results for the Bonnet 42F1 NWA Opportunity

The Company is seeking confidential treatment of Appendix 10.

The Company is providing Appendix 10 as an Excel file because it is too large to legibly produce as a PDF file.

Appendix 11

Appendix 11 – RI NWA BCA Model for the South Kingstown NWA Opportunity

The Company is seeking confidential treatment of Appendix 11.

The Company is providing Appendix 11 as an Excel file because it is too large to legibly produce as a PDF file.

Appendix 12

Appendix 12 – NWA Evaluation Results for the South Kingstown NWA Opportunity

The Company is seeking confidential treatment of Appendix 12.

The Company is providing Appendix 12 as an Excel file because it is too large to legibly produce as a PDF file.