The Narragansett Electric Company
d/b/a Rhode Island Energy

2022 System Reliability Procurement Plan Year-End Report

June 1, 2023

RIPUC Docket No. 5080

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:

Rhode Island Energy™
a PPL company

Filing Letter

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Rhode Island Energy™
a PPL company

June 1, 2023

VIA ELECTRONIC MAIL

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

RE: Docket No. 5080 – 2022 System Reliability Procurement Year-End Report

Dear Ms. Massaro:

On behalf of The Narragansett Electric Company d/b/a Rhode Island Energy (the "Company"), enclosed, please find the Company's *2022 System Reliability Procurement* ("SRP") *Year-End Report* (the "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.[1] At this time, the Company is not seeking any rulings from the Public Utilities Commission ("PUC") in connection with the Report nor is the Company proposing any incremental funding for SRP.

As detailed in the Report, the Company is on track to meet each of the commitments outlined in the 2021-2023 SRP Three-Year Plan. The Company also notes that, in the fourth quarter of 2022, it revitalized the SRP Technical Working Group ("TWG") and planned the SRP TWG's working calendar for 2023.

The Report contains a financial summary (Section 2), a comprehensive section on non-wires solutions (Section 3), a comprehensive section on non-pipes solutions (Section 4), and a comprehensive section on engagement (Section 5). Appendices include notes on terminology (Appendix 1), legal and regulatory basis (Appendix 2), screened wired projects (Appendix 3), non-wires solutions benefit-cost assessment model (Appendix 4), non-pipes solutions benefit-cost assessment model (Appendix 5), non-wires solutions technical reference model (Appendix 6), and non-pipes solutions technical reference model (Appendix 7) .

[1] 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

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 No. 5080 Service List

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.

______________________________ June 1, 2023
Joanne M. Scanlon Date

Docket No. 5080 – Rhode Island Energy – System Reliability Procurement 2021-2023 Plan
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Executive Summary

System Reliability Procurement (SRP) encompasses the activities conducted by The Narragansett Electric Company d/b/a Rhode Island Energy to meet or mitigate a gas or electric distribution system need or optimization that provides the need or optimization by employing diverse energy resources, distributed generation, or demand response.[1] In this *2022 SRP Year-End Report* ("Report"), Rhode Island Energy summarizes relevant activities that occurred in calendar year 2022 and describes these activities within the context of commitments made within the *2021-2023 SRP Three-Year Plan*.[2]

Generally, 2022 was a year of transition and revitalization for SRP. Some vital activities continued throughout transition: this included the core function of screening for opportunities for system reliability procurement for electric distribution system needs, continuing to develop a program for system reliability procurement for gas distribution system needs, and coordinating across functional teams internally. The SRP Technical Working Group (TWG) was revitalized in the fourth quarter after a hiatus in quarters two and three. In the fourth quarter, the SRP TWG regrouped and planned its working calendar for 2023. Further details about these activities and more are included throughout this Report.

Specifically, Rhode Island Energy is on track for each of the commitments outlined in the *2021-2023 SRP Three-Year Plan*. Table 1 summarizes efforts related to each commitment in calendar year (CY) 2022.

Table 1. Summary of status of commitments in *2021-2023 SRP Three-Year Plan*

Status	**Commitment**	**Notes**
On track	Continue to analyze current non-wires solution screening and development process	Rhode Island Energy completed the transition of SRP coordination and developed its workplan for specific analysis for CY 2023.
On track	Produce a detailed initial non-pipes solution program by end of CY 2023	Program components are described in *2021-2023 SRP Three-Year Report, 2021 SRP Year-End Report*, and herein. Rhode Island Energy did not identify a non-pipes pilot opportunity in CY 2022.
On track	Continue to analyze non-pipes solution screening and development processes	Rhode Island Energy began evaluating a "neighborhood" approach to identifying and screening non-pipes opportunities during gas distribution planning in CY 2022.
On track	Perform background research on non-pipes solutions	Rhode Island Energy began assessing the potential to broaden the scope of potential non-pipes solutions applicable to system needs in CY 2022.

[1] Per the Rhode Island Public Utilities Commission's Least-Cost Procurement Standards, 2020 version.
[2] Filed with the Rhode Island Public Utilities Commission in Docket No. 5080: https://ripuc.ri.gov/eventsactions/docket/5080page.html.

Status	Commitment	Notes
On track	Engage with stakeholders on opportunities and challenges regarding non-pipes solutions	Rhode Island Energy and stakeholders reviewed non-pipes solution program development to date and identified topics for further discussion with the System Reliability Procurement Technical Working Group during the December 2022 meeting.
On track	Engage stakeholders throughout non-pipes solutions program development	Rhode Island Energy and stakeholders reviewed non-pipes solution program development to date and identified topics for further discussion with the System Reliability Procurement Technical Working Group during the December 2022 meeting.
On track	Coordinate with grid modernization planning	Rhode Island Energy filed its *Grid Modernization Plan* ("GMP") with the Rhode Island Public Utilities Commission in December 2022. SRP and GMP are coordinated via overlapping staffing assignments. Areas of coordination include the assessment of potential grid modernization solutions (i.e., including SRP), understanding linkages between GMP and SRP, and planning for further coordination as appropriate following the conclusion of GMP and GMP-related regulatory proceedings.
On track	Improve coordination between SRP, Power Sector Transformation (PST), Energy Efficiency (EE), Infrastructure, Safety, and Reliability (ISR), GMP, and Advanced Metering Functionality (AMF)	Rhode Island Energy is improving coordination between SRP, PST, EE, ISR, GMP, and AMF through overlapping staffing assignments and internal topical working groups that span functional teams.
On track	Continue stakeholder engagement	Rhode Island Energy revitalized the System Reliability Procurement Technical Working Group in CY 2022 and worked with the System Reliability Procurement Technical Working Group to develop a calendar of specific discussions and deliverables for CY 2023.
On track	Avoid double-counting shareholder incentives	Rhode Island Energy is not proposing any shareholder incentive from activities in CY 2022, and therefore there cannot be any double counting.
Pending	Stakeholder engagement on electric forecasting process	Rhode Island Energy worked with the System Reliability Procurement Technical Working Group to develop a workplan for discussions in CY 2023;

Status	Commitment	Notes
		discussions related to electric forecasting scheduled throughout CY 2023.
On track	Develop and implement a data governance plan in coordination with AMF and GMP and with continued stakeholder engagement and discussion	Rhode Island Energy filed its *Grid Modernization Plan* ("GMP") with the Rhode Island Public Utilities Commission in December 2022; Attachment J of Book 2 contains the Data Governance Plan. SRP, GMP, and AMF are coordinated via overlapping staffing assignments. Areas of coordination include data availability, governance, and security.

Table 2 briefly summarizes each of the reporting requirements Rhode Island Energy committed to the *2021-2023 SRP Three-Year Plan*.

Table 2. Reporting requirements summary

Reporting Requirement	Summary
Screening results	Rhode Island Energy screened 100% of applicable wires investments for potential non-wires opportunities; zero opportunities were identified. A summary of screening results in included in Section 3.2 and Appendix A3.
Electric service projected load growth rates	Electric load is projected to remain fairly steady at the service territory level. Over the next five years, electric load is projected to increase slightly in the Newport and Western Narragansett power system areas and decrease slightly in the Blackstone Valley and Providence power system areas. A summary of projected load growth rates is included in Section 3.1.
Potential opportunities	There were zero opportunities in CY 2022.
Active and implemented projects	There were zero active or implemented projects in CY 2022.
System Data Portal	There were no changes or updates to the System Data Portal in CY 2022.
Market engagement	There were no market engagement activities in CY 2022.
Non-wires screening criteria	There are no proposals to update non-wires screening criteria.
Non-wires benefit-cost assessment model	There are no proposals to update the non-wires benefit-cost assessment model.

Rhode Island Energy files this Report as informative and does not request any rulings from the Rhode Island Public Utilities Commission nor propose any incremental funding request for SRP.

1. Introduction

System Reliability Procurement (SRP) encompasses the activities conducted by The Narragansett Electric Company d/b/a Rhode Island Energy to meet or mitigate a gas or electric distribution system need or optimization that provides the need or optimization by employing diverse energy resources, distributed generation, or demand response.[3] In this *2022 SRP Year-End Report* ("Report"), Rhode Island Energy summarizes relevant activities that occurred in calendar year (CY) 2022 and describes these activities within the context of commitments made within the *2021-2023 SRP Three-Year Plan*.[4] Rhode Island Energy has made slight modifications to this Report from prior reports. The objective of these modifications is to streamline the Report within the parameters set forth by the legal and regulatory basis (described in Appendix A2). There are four main sections of this Report: a financial summary, a comprehensive section on non-wires solutions, a comprehensive section on non-pipes solutions, and a comprehensive section on engagement.

The appendices to this Report provide additional details to aid in understanding of the Report and to comply with legal and regulatory reporting requirements. New for this year is an appendix that annotates key terminology used in this Report.

[3] Per the Rhode Island Public Utilities Commission's Least-Cost Procurement Standards, 2020 version.
[4] Filed with the Rhode Island Public Utilities Commission in Docket No. 5080: https://ripuc.ri.gov/eventsactions/docket/5080page.html.

2. Financials

Rhode Island Energy's *2021-2023 SRP Three-Year Report* anticipated $0 of cost recovery through the energy efficiency system benefit charge. Rhode Island Energy did not incur any costs in CY 2022; as such, Rhode Island Energy does not request any cost recovery through this *2022 SRP Year-End Report*. Budget and spending are summarized in Table 3.

Table 3. Budget and spending summary

2021-2023 SRP Three-Year Plan Funding Category	2021		2022		2023	
	Anticipated Funding Request	Actual Spending	Anticipated Funding Request	Actual Spending	Anticipated Funding Request	Actual Spending
Performance incentive	TBD	$0	TBD	$0	TBD	n/a
Non-wires solutions	TBD	$0	TBD	$0	TBD	n/a
Non-pipes solutions	TBD	$0	TBD	$0	TBD	n/a
System Data Portal	$0	$0	$0	$0	$0	n/a
Market engagement	$0	$3,092	$0	$0	$0	n/a
	$0	***$3,092***	***$0***	***$0***	***$0***	***n/a***

Notes: TBD is to be determined. Funding requests for a performance incentive, non-wires solutions, and non-pipes solutions in CY 2023 will be determined throughout the course of system planning in CY 2023; any funding request would go through the proper regulatory process pursuant to Least-Cost Procurement statute and Standards.

3. Non-Wires Solutions

This section describes non-wires solutions generally, identifies where readers can find more information, and includes specific detail about non-wires opportunities and active/implemented non-wires solutions.

A quick note on terminology: Rhode Island Energy is choosing to phase out the term ‘non-wires alternative’ in favor of ‘non-wires solution.’ Whereas ‘alternative’ denotes something that is ‘different from the usual or conventional,’[5] ‘solution’ connotes equal standing amongst all viable options. This change in terminology is intended to signal that consideration of non-wires solutions is part of the normal course of business for Rhode Island Energy, rather than an alternative that is unusual or unconventional.

[5] https://www.merriam-webster.com/dictionary/alternative

3.1 Projected Load Growth Rates

Rhode Island Energy conducts an annual electric load forecast (published in November of each year).[6] This load forecast informs electric distribution planning, operations, and programs, including projects as proposed in Rhode Island Energy's *Electric Infrastructure, Safety, and Reliability (ISR) Plans*, *SRP Investment Proposals*, and *Energy Efficiency Plans*.

The full electric load forecast methodology is described within each published annual forecast. The *2023 Electric Peak Forecast* (finalized November 2022) accounts for projected electricity consumption, solar PV production, electric vehicle consumption, electric heating consumption, energy storage, demand response, and energy efficiency.

Prior *SRP Year-End Reports* have shown electric load forecast by county; displaying forecast by county is a secondary step to the forecasting process and county-level forecasts are not used in planning. Beginning this year, Rhode Island Energy presents forecast data by power system area (PSA), which is the granularity of forecast applied in planning.

The table below, excerpted from the *2023 Electric Peak Forecast,* shows forecasted load growth for the four PSAs (Blackstone Valley, Newport, Providence, and Western Narragansett) from 2023-2027 (annual) and 2023-2037 (five-year average load growth). While load growth is anticipated to increase slightly over 2023-2027, growth is heterogenous with Blackstone Valley and Providence PSAs anticipating load reduction in 2024-2026.

Table 4. Annual Growth Percentages (Summer) by PSA

PSA	**Annual Growth Rates (%)**					**Five-year Growth Rates (%)**		
	2023	**2024**	**2025**	**2026**	**2027**	**2023-2027**	**2028-2032**	**2033-2037**
Blackstone Valley	1.0	-0.8	-0.4	-0.8	0.2	-0.2	0.1	0.1
Newport	2.0	0.1	0.5	-0.1	0.8	0.7	0.6	0.3
Providence	1.4	-0.4	-0.0	-0.5	0.4	0.2	0.3	0.2
Western Narragansett	2.1	0.2	0.6	-0.0	0.9	0.8	0.7	0.4

Notes: PSA is power system area. Growth rates include forecasted impacts of energy efficiency, solar PV production, electric vehicle consumption, electric heating consumption, demand response, and energy storage. Growth rates are relative to actual 2022 peak loads. Growth rates are rounded to the nearest tenth of a percent; -0.0% indicates forecasted load growth of -0.49 or less.

[6] Annual electric load forecasts are published on the System Data Portal: https://systemdataportal.nationalgrid.com/RI/

3.2 Screening Results Summary

The screening process and criteria are described in the *2021 SRP Year-End Report* within Section 7.[7] Rhode Island Energy did not identify any projects that passed the screening criteria for potential non-wires opportunities. Screening results are described in Appendix A3.

3.3 Status and Progress Updates on Potential Non-Wires Opportunities

There were zero potential non-wires opportunities identified in CY 2022.

3.4 Status and Progress Updates on Active and Implemented Non-Wires Projects

There were zero active or implemented non-wires projects in CY 2022.

3.5 Proposals to Update Non-Wires Screening Criteria

Rhode Island Energy does not propose any updates to non-wires screening criteria at this time. The current screening criteria in use are described in the *2021 SRP Year-End Report* within Section 7.

3.6 Proposals to Update Non-Wires Solution Benefit-Cost Assessment Model

Rhode Island Energy does not propose any updates to the benefit-cost assessment model for non-wires solutions. The current benefit-cost assessment model and technical reference manual are included as Appendix A4 and A6.

[7] RIPUC Docket No. 5080

4. Non-Pipes Solutions

This section describes non-pipes solutions generally, identifies where readers can find more information, and includes specific detail about the development of a non-pipes solution program.

A quick note on terminology: Rhode Island Energy is choosing to phase out the term 'non-pipes alternative' in favor of 'non-pipes solution.' Whereas 'alternative' denotes something that is 'different from the usual or conventional,'[8] 'solution' connotes equal standing amongst all viable options. This change in terminology is intended to signal that consideration of non-pipes solutions is part of the normal course of business for Rhode Island Energy, rather than an alternative that is unusual or unconventional.

4.1 General Information

Non-pipes solutions are essentially the gas system equivalent of non-wires solutions. Non-pipes solutions are a new aspect of system reliability procurement being developed to enable Rhode Island Energy to address natural gas system needs in alignment with Least-Cost Procurement statute.

A non-pipes solution can include any action, strategy, program, or technology that meets the following definition and requirements:

Non-Pipes Solutions Definition: Non-pipes solutions is the inclusive term for any targeted investment or activity that is intended to defer, reduce, or remove the need to construct or upgrade components of a natural gas system, or "pipeline investment."

Non-Pipes Solutions Requirements: These non-pipes investments are required to be cost-effective and are required to meet the specified gas pipeline need.

Rhode Island Energy is currently engaged in ongoing discussions with stakeholders about potential solution types in consideration of non-pipes solutions, proposals, and investment decisions.

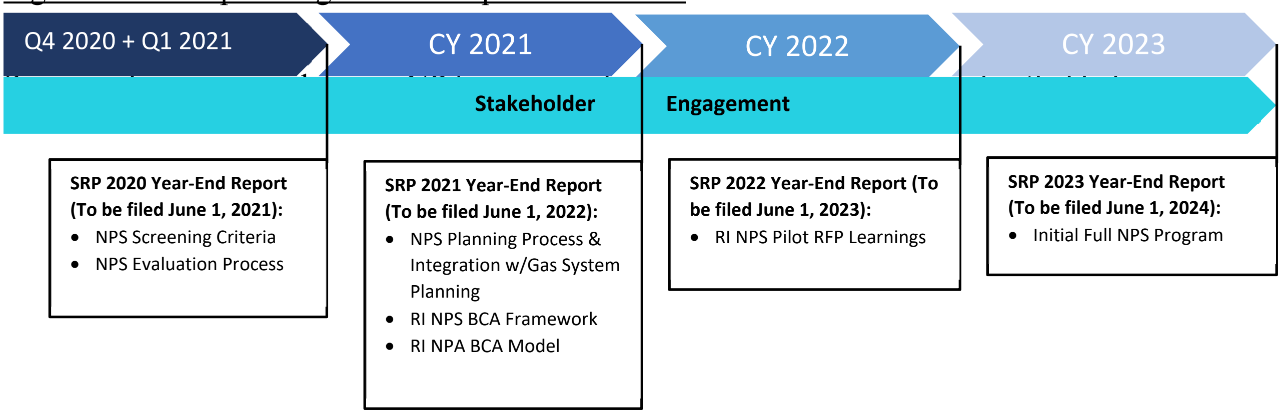
Some technologies and methodologies that can be applicable as a non-pipes investment include demand-side measures, such as demand response, conservation or energy efficiency, and electrification, and supply-side measures, such as renewable natural gas (RNG). This is not intended to be an exhaustive list of possible demand-side and supply-side solutions. NPA projects can include these and other investments individually or in combination to meet the specified need in a cost-effective manner.

[8] https://www.merriam-webster.com/dictionary/alternative

4.2 Program Development

In its *2021-2023 SRP Three-Year Plan*, Rhode Island Energy proposed to develop the non-pipes solutions program with screening criteria, a planning process integrated with gas system planning, a bid evaluation process, and a Non-Pipes Solution Benefit-Cost Assessment Model as constituent components over calendar years 2021 through 2023. The timeline for developing the Non-Pipes Program is detailed in Figure 1.

Figure 1: Non-Pipes Program Development Timeline



4.2.1 Non-Pipes Solutions Screening Criteria

Rhode Island Energy proposed non-pipes solutions screening criteria and an associated evaluation process in its *2020 SRP Year-End Report.*[9] Rhode Island Energy's intention is to apply the non-pipes solutions program screening criteria to all pipeline needs that arise through planning analysis and system assessment. As such, the screening criteria will be integrated into the gas system planning process. Table 5 contains the non-pipes solutions screening criteria proposed by Rhode Island Energy.

Table 5: Screening Criteria for Non-Pipes Solutions 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.
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.

[9] Filed within Docket No. 5080 with the Rhode Island Public Utilities Commission: https://ripuc.ri.gov/eventsactions/docket/5080-NGrid-2020%20SRP%20Year-End%20Plan%20(6-1-21).pdf

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. Additionally, at Rhode Island Energy's discretion, Rhode Island Energy 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 non-pipes solutions opportunity exists, assuming the benefits of doing so justify the costs.

Rhode Island Energy will continue analyzing its current non-pipes solutions screening process and criteria to capture the maximum number of projects eligible for consideration. No updates to the non-pipes solutions screening criteria are proposed at this time.

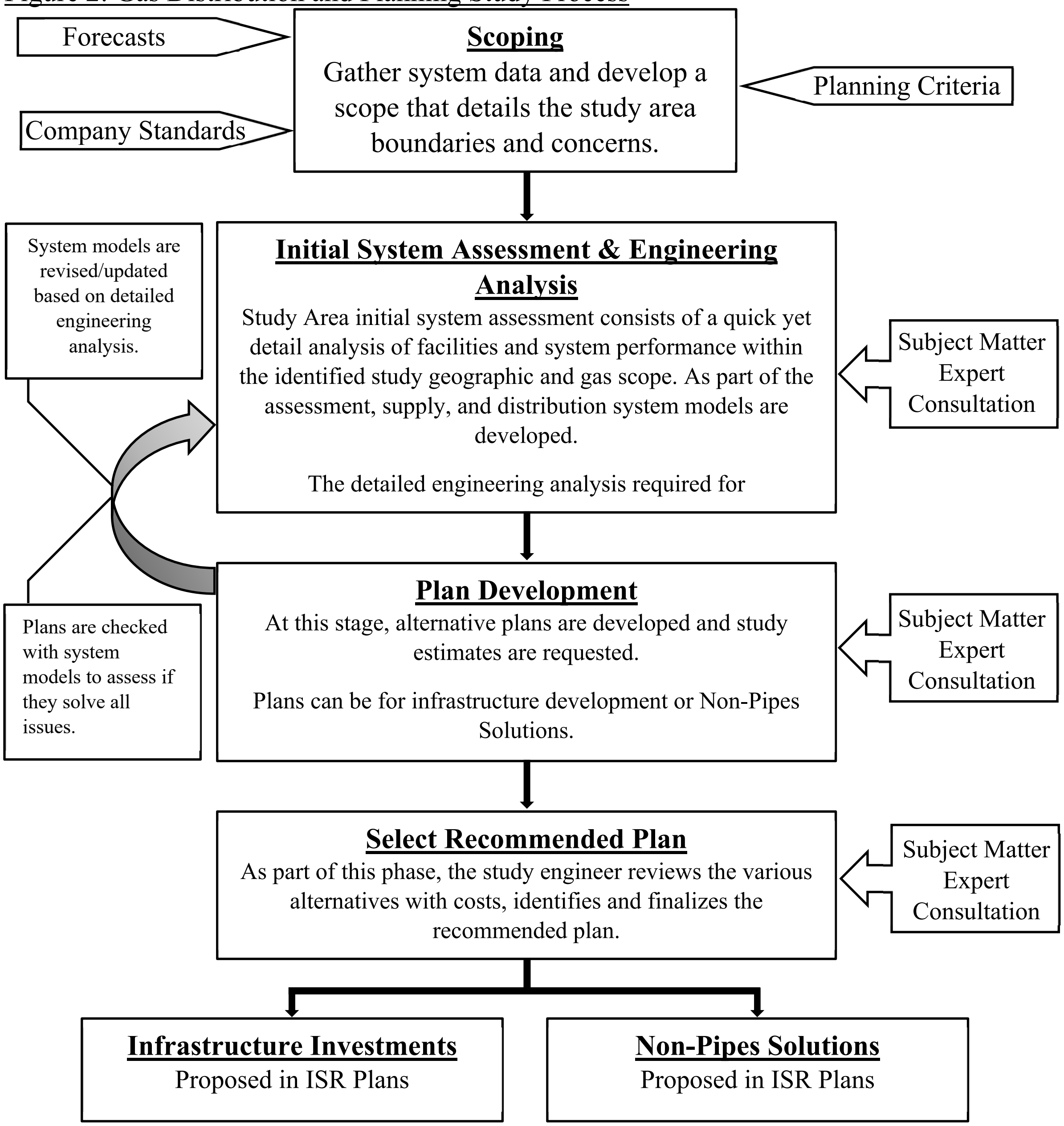
4.2.2. Non-Pipes Solutions Planning Process and Integration with Gas System Planning

Rhode Island Energy proposed non-pipes solutions planning process in its 2021 Year-End Report.[10] In Rhode Island Energy's program proposal, screening and analysis of potential non-pipes solutions 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 non-wires solutions program. The key difference is that Initial System Assessment and Engineering Analysis are combined as one step in the non-pipes solutions program, whereas these are two separate steps in the non-wires solutions 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.

Rhode Island Energy will identify and screen potential non-pipes solutions opportunities through the following high-level sequential process once a system need is identified or an area study is initiated:

[10] Filed within Docket No. 5080 with the Rhode Island Public Utilities Commission: https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2022-06/5080-NGrid-2021%20SRP%20Year-End%20Report%20%28PUC%205-23-22%29%20w-bates.pdf

Figure 2: Gas Distribution and Planning Study Process



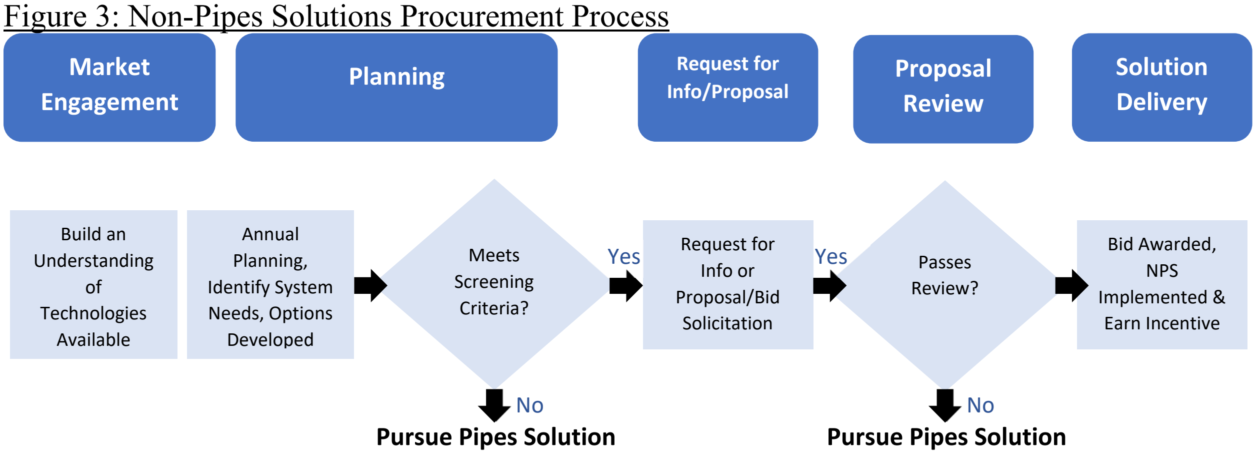
Rhode Island Energy plans to continue analyzing its current non-pipes solutions screening and development processes to determine how projects might be best considered as both complete and partial solutions. No updates to the non-pipes solutions planning process are proposed at this time.

4.2.3 Non-Pipes Solutions Evaluation and Procurement Process

If a non-pipes solution is selected as the solution for the gas system need through the planning study process the following procurement process is initiated:

- Identify system needs/opportunities
- Develop a Request for Proposals for the non-pipes opportunity(s)
- Issue the Request for Proposals to the market
- Receive, evaluate, and select bid proposals
- File a SRP Investment Proposal with the Rhode Island Public Utilities Commission for approval

Figure 3: Non-Pipes Solutions Procurement Process



The non-pipes solutions evaluation process was proposed by Rhode Island Energy in its *2020 SRP Year-End Report*.[11] The evaluation and review of submitted bid proposals is comprised of four rounds, 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.

[11] Filed within Docket No. 5080 with the Rhode Island Public Utilities Commission: https://ripuc.ri.gov/eventsactions/docket/5080-NGrid-2020%20SRP%20Year-End%20Plan%20(6-1-21).pdf

Table 6: Non-Pipes Solutions Evaluation Rounds and Description

Round	Evaluation Focus
Round 1	Go/No-Go: Preliminary benefit-cost assessment, 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 benefit-cost assessment, 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 factors that will be considered within non-pipes solutions 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 benefit-cost assessment. The non-pipes 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, the cost and cost-effectiveness are compared between the non-pipes solutions option and the pipes option, in alignment with Least-Cost Procurement Standards.
No updates to the non-pipes solutions evaluation and procurement process are proposed at this time.

4.2.4 Non-Pipes Solutions Benefit-Cost Assessment Model
Rhode Island Energy filed a Non-Pipes Solutions Benefit-Cost Assessment framework and a finalized Non-Pipes Solutions Benefit-Cost Assessment Model in its *2021 SRP Year-End Report*.[12] The Non-Pipes Solutions Benefit-Cost Assessment Model is a derivative of the RI Test and utilizes the same Docket 4600 Benefit-Cost Framework (Framework) to accurately assess non-pipes solutions benefits and costs. Please see Appendix A5 for the Non-Pipes Solutions Benefit-Cost Assessment Model and Appendix A7 for the Non-Pipes Solutions Technical Reference Manual.

Per the Least-Cost Procurement Standards, this specialized derivative of the RI Test is created using the RI Framework and accounts for applicable policy goals, Commission orders, regulations, guidelines, and other policy directives; accounts for all relevant, important aspects of the System Reliability Procurement and Non-Pipes Programs; is symmetrical by including both costs and benefits for each relevant type of impact; is forward-looking by capturing the benefit-

[12] Filed within Docket No. 5080 with the Rhode Island Public Utilities Commission: https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2022-06/5080-NGrid-2021%20SRP%20Year-End%20Report%20%28PUC%205-23-22%29%20w-bates.pdf

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 robust accounting of the societal benefits that non-pipes investments deliver to customers, the state, and society.

Project-specific supply and distribution capacity values are also included. Rhode Island Energy calculates a deferral value that utilizes the location-specific pipes solution expected cost, related operations and maintenance 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.

No updates to the Non-Pipes Solutions Benefit-Cost Assessment Model are proposed at this time.

4.2.5 Develop a Pilot for Learnings
The necessary components to identify, evaluate, and select non-pipes solutions have been proposed and filed in accordance with the development timeline laid out in Figure 1 above. With this framework established, Rhode Island Energy's next program development milestone is to develop a Request for Proposals and go to market for at least one eligible non-pipes opportunity so that the process can be tested and reviewed for efficacy and efficiency. If a proposal satisfies the Screening Criteria, Evaluation Process, is cost-effective, and is the least-cost option compared to an identified pipeline investment, then Rhode Island Energy will file the non-pipes project proposal for approval with the Rhode Island Public Utilities Commission. As per the Non-Pipes Solutions Program development timeline, details from this Request for Proposals effort, including the proposals and their evaluation results, were to be included in this *2022 SRP Year-End Report*. However, despite Rhode Island Energy actively screening gas distribution system needs for the potential to be served by non-pipe solutions, no viable non-pipes opportunities have been identified yet. Rhode Island Energy is continuing to look for non-pipes opportunities via gas long-term planning and infrastructure, safety, and reliability planning.

4.3 Next Steps
Rhode Island Energy committed to producing a detailed initial Non-Pipes Program by the end of CY 2023. Finalizing development of the Non-Pipes Program should prioritize identifying 1) non-pipes opportunities to pilot in 2023, and 2) the process and timing for engaging with the SRP Technical Working Group to complete development of the Non-Pipes Program in 2023 prior to submitting the *2024-2026 SRP Three-Year Plan*. Note that, as with Rhode Island Energy's Non-Wires Program, the Non-Pipes Program will continue to undergo program and process refinement and updates in the years following 2023 as the Rhode Island Energy team continues to learn and become experienced in non-pipes solutions.

5. Engagement

Rhode Island Energy focused its efforts on proactive stakeholder engagement with the SRP Technical Working Group in CY 2022. Rhode Island Energy did not conduct any proactive market engagement in CY 2022 but did maintain the System Data Portal for public use.

5.1 System Reliability Procurement Technical Working Group

The SRP Technical Working Group (TWG) is an external stakeholder group convened and administered by Rhode Island Energy for the sole purpose of advising Rhode Island Energy on matters related to System Reliability Procurement, as defined by Least-Cost Procurement Statute under RIGL 39-1-27.7. The SRP TWG is not a statutory or regulatory requirement, nor is the group public. Members of the SRP TWG include the Rhode Island Division of Public Utilities and Carriers, Rhode Island Office of Energy Resources, Energy Efficiency and Resource Management Council, Acadia Center, Green Energy Consumers Alliance, Northeast Clean Energy Coalition, and Conservation Law Foundation.[13]

Following the transition of the Company to Rhode Island Energy, the SRP TWG was revitalized in October 2022 and met in October, November, and December.

October and November's SRP TWG meetings focused on reintroducing SRP activities to members and developing a workplan for SRP TWG meetings in CY 2023. December's SRP TWG meeting reviewed progress to date and work to come related to developing a non-pipes program.

Table 7. summarizes meeting agendas and participation for each SRP TWG meeting.

Meeting	Agenda	SRP TWG Members Present
10/19/2022	• Introductions • RIE strategic vision • SRP TWG vision, mission, objectives • Discuss guidelines for participation • Review *2021-2023 SRP Three-Year Plan* commitments	• Division of Public Utilities and Carriers • Office of Energy Resources • Energy Efficiency and Resource Management Council • Acadia Center
11/16/2022	• October meeting recap • Discuss guidelines for participation • Workshop 2023 workplan • Looking ahead to December	• Division of Public Utilities and Carriers • Office of Energy Resources

[13] While Commerce RI, Rhode Island Office of the Attorney General, and Rhode Island Infrastructure Bank have been members and are welcome to continue to participate, there are currently no representatives from these organizations who are active in the SRP TWG.

Meeting	Agenda	SRP TWG Members Present
		• Energy Efficiency and Resource Management Council • Acadia Center • Green Energy Consumers Alliance • Northeast Clean Energy Coalition • Conservation Law Foundation
12/21/2022	• SRP and NPA background • NPA definition • NPA program development timeline • Gas system planning • NPA evaluation and procurement • NPA RFP pilot status and next steps • Finalizing NPA program and next steps	• Division of Public Utilities and Carriers • Office of Energy Resources • Energy Efficiency and Resource Management Council • Acadia Center • Green Energy Consumers Alliance

5.2 Market Engagement
Rhode Island Energy did not conduct any market engagement in CY 2022.

5.3 System Data Portal
Rhode Island Energy did not conduct any proactive engagement related to the System Data Portal in CY 2022.

Appendices

Appendix 1

A1. Notes on Terminology

Least-Cost Procurement Standards

The version of the Least-Cost Procurement Standards in effect for the entirety of CY 2022 is the version adopted by Order 23890 in Docket No. 5015: https://ripuc.ri.gov/eventsactions/docket/5015page.html.

The following definitions are excerpted from the Least-Cost Procurement Standards:

System Reliability Procurement

Procurement to meet or mitigate a gas or electric distribution system need or optimization from a party other than the gas or electric utility[14] that provides the need or optimization by employing diverse energy resources, distributed generation, or demand response.[15]

Utility Reliability Procurement

Procurement to meet or mitigate a gas or electric distribution system need or optimization that is not System Reliability Procurement and thus represents a utility-only investment or expenditure.[16]

Distribution System Needs

i. Electric Distribution System Needs: Needs to serve both customer load and customer generation, including, but not limited to, system capacity (normal and emergency), voltage performance, reliability performance, protection coordination, fault current management, reactive power compensation, asset condition assessment, distributed generation constraints, operational considerations, and customer requests.

ii. Gas Distribution System Needs: Needs to serve customers, including, but not limited to, system capacity (normal and emergency), pressure management, asset condition assessment, gas service that supports electric distributed generation, and operational considerations.

Optimization of Distribution System Performance

Improvement of the performance and efficiency[17] of the gas or electric distribution system that includes enhanced reliability, peak load reduction, improved utilization of both utility and non-utility assets, optimization of operations, and reduced system losses.

[14] A utility proposal to own and operate non-traditional investment or new operations and maintenance services, such as new voltage-regulation equipment, battery storage, or vegetation management, and any vendor services associated with such investment or service, shall not be considered System Reliability Procurement per this definition. Such investments and services are, however, still subject to the Guidance Document issued in Docket No. 4600A.

[15] Including, but not limited to, the resources named in R.I. Gen. Laws § 39-1-27.7(a)(1)(i)-(iii).

[16] For example, many such Utility Reliability Procurement investments and operations are proposed in annual Infrastructure, Safety, and Reliability Plans filed pursuant to R.I. Gen. Laws § 39-1-27.7.1(c)(2).

[17] Efficiency includes both long- and short-term cost efficiency.

Rhode Island Energy further annotates the following terminology to aid in understanding of this *2022 SRP Year-End Report*:

Non-Wires/Non-Pipes Alternative
Outdated terms referring to non-wires/non-pipes solution.

Non-Wires/Non-Pipes Solution
A solution that satisfies a Distribution System Need through means other than utility-owned infrastructure.

Non-Wires/Non-Pipes Opportunity
A Distribution System Need that may be satisfied via a Non-Wires/Non-Pipes Solution (i.e., the non-wires/non-pipes screening criteria has been met).

Non-Wires/Non-Pipes Project Proposal
A proposal for a specific Non-Wires/Non-Pipes Solution for a specific Non-Wires/Non-Pipes Opportunity (i.e., such as a proposal submitted in response to a Request for Proposals).

Non-Wires/Non-Pipes Project
A specific Non-Wires/Non-Pipes Solution for a specific Non-Wires/Non-Pipes Opportunity (i.e., such as a project in the process of being constructed, installed, or otherwise implemented).

Non-Wires/Non-Pipes Program
The process by which Rhode Island Energy identifies non-wires/non-pipes opportunities, solicits and evaluates non-wires/non-pipes project proposals, and submits funding requests with relevant justification and documentation for non-wires/non-pipes projects.

Wires/Pipes Solution
A solution that satisfies a Distribution System Need through utility-owned infrastructure.

SRP Investment Proposal
A filing describing a Non-Wires/Non-Pipes Project as per Chapter 5 of the Least-Cost Procurement Standards.

Appendix 2

A2. Legal and Regulatory Basis

A2.1 Least-Cost Procurement [18]

System reliability procurement is contemplated in Rhode Island's Least-Cost Procurement statute. Some key relevant excerpts from this statute are below for convenient reference.

"§ 39-1-27.7. System reliability and least-cost procurement.

(a) Least-cost procurement shall comprise system reliability and energy efficiency and conservation procurement, as provided for in this section, and supply procurement, as provided for in § 39-1-27.8, as complementary but distinct activities that have as common purpose meeting electrical and natural gas energy needs in Rhode Island, in a manner that is optimally cost-effective, reliable, prudent, and environmentally responsible.

(b) The commission shall establish not later than June 1, 2008, standards for system reliability and energy efficiency and conservation procurement that shall include standards and guidelines for:

(1) System reliability procurement, including but not limited to:

(i) Procurement of energy supply from diverse sources, including, but not limited to, renewable energy resources as defined in chapter 26 of this title;

(ii) Distributed generation, including, but not limited to, renewable energy resources and thermally leading combined heat and power systems, that is reliable and is cost-effective, with measurable, net system benefits;

(iii) Demand response, including, but not limited to, distributed generation, back-up generation, and on-demand usage reduction, that shall be designed to facilitate electric customer participation in regional demand response programs, including those administered by the independent service operator of New England ("ISO-NE"), and/or are designed to provide local system reliability benefits through load control or using on-site generating capability;

(iv) To effectuate the purposes of this division, the commission may establish standards and/or rates (A) For qualifying distributed generation, demand response, and renewable energy resources; (B) For net metering; (C) For back-up power and/or standby rates that reasonably facilitate the development of distributed generation; and (D) For such other matters as the commission may find necessary or appropriate.

(4) Each electrical and natural gas distribution company shall submit to the commission on or before September 1, 2008, and triennially on or before September 1 thereafter through September 1, 2028, a plan for system reliability and energy efficiency and conservation procurement…"

[18] RIGL 39-1-27.7 http://webserver.rilin.state.ri.us/Statutes/TITLE39/39-1/39-1-27.7.HTM

A2.2 Least-Cost Procurement Standards

Chapter 4.4.B of the Rhode Island Public Utilities Commission's revised "Least-Cost Procurement Standards," approved and adopted pursuant to Order No. 23890 in Docket No. 5015 (LCP Standards),[19] requires:

> "The Three-Year SRP Plan will include an annual reporting plan on the implementation of the Three-Year SRP Plan and investments made under System Reliability Procurement during the Three-Year SRP Plan period."

A2.3 Three-Year Plan

Section 12.3 of the *2021-2023 SRP Three-Year Plan*, filed in Docket 5080,[20] requires the following elements to be present in each year-end report:

a) "[The Company] will submit a Year-End Report to the EERMC and the SRP TWG for their review and comment annually at least three weeks before the EERMC's scheduled meeting prior to the filing date that year.
b) The EERMC shall vote whether to endorse the Annual Plan prior to the prescribed filing date, annually.
c) June 1, 2021 and annually thereafter: Submit the Year-End Report detailing plan implementation for the preceding calendar year.
d) The SRP Year-End Reports will contain content including, but not limited to:
    i. Screening results summary on all applicable wires and pipes investments for potential NWA or NPA opportunities.
    ii. Details on Rhode Island Company electric service projected load growth rates.
    iii. Status and progress updates on potential NWA or NPA opportunities.
    iv. Status and progress updates on active and implemented NWA or NPA projects.
    v. Status and progress updates on new enhancements for the Rhode Island System Data Portal, as applicable.
    vi. Status and progress updates on SRP market engagement efforts, as applicable.
    vii. Proposals to update the Company's NWA screening criteria for Rhode Island, as applicable.
    viii. Proposals to update the Company's RI NWA BCA Model, as applicable.

The Company proposes the annual reporting plan for *SRP Year-End Reports* as detailed above for calendar years 2021 through 2023."

[19] "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, https://ripuc.ri.gov/sites/g/files/xkgbur841/files/eventsactions/docket/5015_LCP_Standards_05_28_2020_8.21.2020-Clean-Copy-FINAL.pdf
[20] "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.

Appendix 3

A3. Screened Wires Projects
Table A3.1, below, summarizes all projects screened for potential non-wires opportunities.

Table A3.1. Screening Results Summary

Project ID	Location (Feeder ID, Street, Municipality, or other)	Project Description	Meets Screening Criteria to Consider Non-Wires Solution?	Explanation	Feasibility of Partial Non-Wires Solution	Capex Spending Rational	Date Initiated
CRI3038	Natick 29F1	Reconductor Distribution Line	No	<$1 million in cost	Not suitable	System Capacity & Performance	5/27/2021
CRI3039	2232 Panto Road	Engineering Reliability Review	No	<$1 million in cost	Not suitable	Reliability	5/27/2021
CRI3040	2232 Industrial Drive	Engineering Reliability Review	No	<$1 million in cost	Not suitable	Reliability	5/27/2021
CRI3042	155F8_63F6	Relocate Feeder Tie	No	<$1 million in cost	Not suitable	Asset Condition	5/27/2021
C091057	Lafayette Narrow Lane	Cable Replacement	No	<$1 million in cost	Not suitable	System Capacity & Performance	7/18/2022
C091120	155F8	Install Line Regulators and Smart Capacitors	No	<$1 million in cost	Not suitable	Reliability	7/25/2022
C091235	28F1 and 28F2	Underground Cable Replacement Program	No	Project driven by asset condition	Not suitable	Asset Condition	8/11/2022

Project ID	Location (Feeder ID, Street, Municipality, or other)	Project Description	Meets Screening Criteria to Consider Non-Wires Solution?	Explanation	Feasibility of Partial Non-Wires Solution	Capex Spending Rational	Date Initiated
C091285	Stone Ridge Acres	Underground Rural Development	No	Project driven by asset condition	Not suitable	Asset Condition	8/19/2022
C091395	Recloser Installation (Portfolio)		No	<$1 million in cost (each)	Not suitable	Reliability	9/7/2022
C091405	Manning Street	Underground Cable Replacement Program	No	Project driven by asset condition	Not suitable	Asset Condition	9/8/2022
C091408	1152	Underground Cable Replacement Program	No	Project driven by asset condition	Not suitable	Asset Condition	9/8/2022
C091409	1153	Underground Cable Replacement Program	No	Project driven by asset condition	Not suitable	Asset Condition	9/8/2022
C091411	2J7	Underground Cable Replacement Program	No	Project driven by asset condition	Not suitable	Asset Condition	9/8/2022
C091414	2J10	Underground Cable Replacement Program	No	Project driven by asset condition	Not suitable	Asset Condition	9/8/2022

Project ID	Location (Feeder ID, Street, Municipality, or other)	Project Description	Meets Screening Criteria to Consider Non-Wires Solution?	Explanation	Feasibility of Partial Non-Wires Solution	Capex Spending Rational	Date Initiated
C091491	1169	Underground Cable Replacement Program	No	Project driven by asset condition	Not suitable	Asset Condition	9/26/2022
C091493	105K1 and 102K22	Distribution Line Retirement	No	Project driven by asset condition	Not suitable	Reliability	9/26/2022
C091524	Water Street	CLX Cable Replacement	No	Project driven by asset condition	Not suitable	Asset Condition	9/30/2022
C091640	Providence and Pawtucket	Replace AC Network Vault Vent Blowers	No	Project driven by asset condition	Not suitable	Asset Condition	10/20/2022
C091975	Boston Store, Providence	Network Vault 19	No	Project driven by asset condition	Not suitable	Asset Condition	12/7/2022
CRI3004	33F6	Line Extension	No	Amount of load offset needed is greater than 20% of area loading	Not suitable	System Capacity & Performance	2/17/2023
CRI3027	Nasonville Substation	New Transformer and Bay	No	Amount of load offset needed is greater than 20% of area loading	Not suitable	System Capacity & Performance	3/9/2023

Project ID	Location (Feeder ID, Street, Municipality, or other)	Project Description	Meets Screening Criteria to Consider Non-Wires Solution?	Explanation	Feasibility of Partial Non-Wires Solution	Capex Spending Rational	Date Initiated
CRI3028	Nasonville Substation	Feeder Work	No	Amount of load offset needed is greater than 20% of area loading	Not suitable	System Capacity & Performance	3/9/2023
CRI3024	Kingston Substation	Distribution Line Work	No	<$1 million in cost	Not suitable	System Capacity & Performance	3/13/2023
CRI3026	Bicentennial Way, North Providence	Underground Rural Development	No	<$1 million in cost	Not suitable	Reliability	3/23/2023
CRI3013	Winchester Ave, North Smithfield	Underground Rural Development	No	<$1 million in cost	Not suitable	Reliability	3/24/2023

Appendix 4

A4. Non-Wires Solutions Benefit-Cost Assessment 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

A5. Non-Pipes Solutions Benefit-Cost Assessment Model

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

A6. Non-Wires Solutions Technical Reference Manual

A7. Non-Pipes Solutions Technical Reference Manual

Appendix 6

Rhode Island Energy's Technical Reference Manual

for the

Benefit-Cost Analysis

of

Non-Wires Alternatives

in

Rhode Island

For use by and prepared by

The Narragansett Electric Company
d/b/a Rhode Island Energy

Table of Contents

RHODE ISLAND ENERGY's NON-WIRES ALTERNATIVES BENEFIT-COST ANALYSIS TECHNICAL REFERENCE MANUAL

1. Introduction

Rhode Island Energy's[1] Rhode Island Non-Wires Alternatives Benefit-Cost Analysis Technical Reference Manual (RI NWA BCA TRM) details how the Company assesses cost-effectiveness of Non-Wires Alternative (NWA) opportunities planned in Rhode Island through the Rhode Island Non-Wires Alternative Benefit-Cost Analysis Model (RI NWA 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 NWA BCA Model.

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

I. Assess the cost-effectiveness of the NWA 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.
    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.

[1] The Narragansett Electric Company d/b/a Rhode Island Energy (Rhode Island Energy 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.

[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.

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 NWA 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 NWA 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.

[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 NWA 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., electric energy) supply and delivery 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, Rhode Island Energy adheres to the RI Test for all NWA investment proposals. Rhode Island Energy has developed the RI NWA BCA Model, which is a derivative of the RI Test and utilizes the same Docket 4600 Benefit-Cost Framework, to more accurately assess NWA opportunities benefits and costs. The benefit categories and formulas in the RI NWA 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 NWA BCA. Note that an "X" indicates that the category is quantified while an "O" indicates the category is unquantified, as applicable for RI NWAs. 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

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

[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	NWA	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	(3)
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
(1) These non-electric utility benefits are expected to be negligible for a site-specific targeted need (i.e., NWAs).
(2) Currently do not have data to claim benefits for a targeted need case.
(3) 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 NWA benefits are directly associated with the development of non-wires compared to a Reference Case with no NWA options. The source for many of the avoided cost value components is the "Avoided Energy Supply Components in New England: 221 Report" (AESC 2021 Study) prepared by Synapse Energy Economics for AESC 2021 Study Group, March, 2021.[9] This report was sponsored by the

[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

electric and gas EE program administrators of Rhode Island Energy 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. In the 2021 AESC study four counterfactual cases exist based upon the inclusion of energy efficiency, building electrification, and active demand management. For the purpose of this BCA counterfactual #2 was utilized. This is the most inclusive counterfactual including energy efficiency and active demand management being utilized in 2021 and later years. This counterfactual does not include future building electrification but due to the limitations of the various models it is determined to be the most applicable for NWAs.

The RI NWA BCA methodology is technology agnostic and should be broadly applicable to all anticipated project and portfolio types, with some adjustments as necessary. Specific technology's availability during the specified system need time may differ. This technology coincidence factor is based upon the association between the system, transmission, and distribution peak for the specified NWA need, as detailed in Section 5.2 of National Grid's New York BCA Handbook.[10] These generalized values are subject to change.

3.1 Electric Energy Benefits

Electric energy benefits due to NWA 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 in the RI NWA BCA Model. Electric energy benefits are valued using the avoided electric energy costs developed in the AESC 2021 Study, Appendix B.[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.

AESC's wholesale cost of electric energy includes pool transmission losses (PTL) incurred from the generator to the point of delivery to the distribution companies, while AESC's retail cost of electric energy includes the wholesale cost plus the cost of renewable energy credits (RECs) borne by generators (i.e.,

[10] "National Grid Version 2.0 Benefit-Cost Analysis (BCA) Handbook." *National Grid Non-Wires Alternatives: Additional Information*, Niagara Mohawk Corporation d/b/a National Grid, 31 July 2018, www.nationalgridus.com/media/pdfs/bus-partners/ny_bca_handbook_v2.0.pdf.

[11] "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

embedded GHG costs), wholesale risk premium (WRP) that captures market risk factors typically recovered by generators in their pricing,[12] and distribution losses incurred from the Independent System Operator (ISO) delivery point to the end-use customer. In the RI NWA BCA benefits calculation, energy savings are grossed up using factors that represent transmission and distribution losses, situation dependent, because a reduction in energy use at the end user means that amount of energy does not have to be generated, plus the extra generation that is needed to cover the losses that occur in the delivery.

AESC's avoided energy cost values also internalize the expected cost of complying with current or reasonably anticipated future regional or federal greenhouse gas reduction requirements, which are borne by generators and passed through in wholesale costs.

Both the wholesale and retail costs of electric energy in the AESC 2021 Study are provided in four different costing periods consistent with ISO New England Inc. (ISO-NE) definitions. Net energy savings are apportioned into these periods in the value calculation. The time periods are defined as follows:

- Winter Peak: October – May, 7:00 a.m. – 11:00 p.m., weekdays excluding holidays.
- Winter Off-Peak: October – May; 11:00 p.m. – 7:00 a.m., weekdays. Also, including all weekends and ISO defined holidays.
- Summer Peak: June – September, 7:00 a.m. – 11:00 p.m., weekdays excluding holidays.
- Summer Off-Peak: June – September; 11:00 p.m. – 7:00 a.m., weekdays. Also, including all weekends and ISO defined holidays.

NWA system needs have targeted time of use that fall within the above time periods. Each system need will therefore have a specific ratio of the four time periods. Energy savings for NWAs are allocated to the targeted times and multiplied by the appropriate avoided energy value. Generally, the system need is occurring during summer peak.

In cases where an energy use transfer occurs (e.g., battery storage) energy reductions and increases could occur across time periods. Each time period is calculated separately and then added together resulting in a net monetized energy reduction value. Furthermore, in solutions with energy losses as part of the technology solution (e.g., battery storage, solar) a round trip/efficiency loss modifier is utilized.

To account for the value of embedded CO_2 costs (i.e., RECs) separately in the RI NWA BCA Model, AESC's wholesale cost of electric energy values is used as the basis for electric energy savings benefits. Nominal annual benefits are then calculated using an average inflation rate to convert AESC's 2021 real dollar values to nominal values. These benefit values are then grossed up using the appropriate WRP that captures market risk factors typically recovered by generators in their pricing,[13] and distribution loss factors representing losses from the ISO delivery point to the end-use customer.

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[12] Wholesale risk premium represents the observed difference between wholesale costs and retail prices.
[13] Wholesale risk premium represents the observed difference between wholesale costs and retail prices.

The AESC 2021 Study assumes 9% for marginal system losses.[14] Marginal losses are more in line with the peaking nature of NWA use cases. This is similar to the Company's distribution loss estimate of 6.9% for "Secondary Voltage" customers, which are predominantly residential and small commercial customers (e.g., Rates A-16, A-60, C06, G02)[15], plus the Company's non-PTF transmission loss estimates of 0.07%.

Each technology then has a rating factor that is applied based on its system need coincidence.

The dollar value of annual benefits is therefore calculated as:

- Summer Peak Energy Benefit ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings $\text{ElectricEnergyCost}_{\text{SumPk}}$ $/kWh * TechnologyCoincidence * EfficiencyLoss * (1 + WRP) * (1 + %Losses) * (1 + %Inflation)^(year-2021)
- Summer Off-Peak Energy Benefit ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings * $\text{ElectricEnergyCost}_{\text{SumOffPk}}$ $/kWh * TechnologyCoincidence* EfficiencyLoss * (1 + WRP) * (1 + %Losses) * (1 + %Inflation)^(year-2021)
- Winter Peak Energy Benefit ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings * $\text{ElectricEnergyCost}_{\text{WinPk}}$ $/kWh * TechnologyCoincidence* EfficiencyLoss * (1 + WRP) * (1 + %Losses) * (1 + %Inflation)^(year-2021)
- Winter Off-Peak Energy Benefit ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings * $\text{ElectricEnergyCost}_{\text{WinOffPk}}$ $/kWh * TechnologyCoincidence * EfficiencyLoss * (1 + WRP) * (1 + %Losses) * (1 + %Inflation)^(year-2021)

Where:

- ElectricEnergySavings (kWh/yr) = Estimated annual electric energy savings based on Engineering models
- %ElectricEnergySavings = Estimated annual electric energy savings fraction for each time period based on Engineering models
- ElectricEnergyCost ($/kWh) = Projected annual values for each time period (AESC 2021, Appendix B, "Wholesale Cost of Electric Energy")
- TechnologyCoincidence = Coincidence factor applied based on the solution technology type
- EfficiencyLoss = modifier applied for energy inefficiencies based on the proposed solution
- WRP = 8% (AESC 2021, Appendix B, "WRP" AESC default value)
- %Losses = 9% (AESC 2021, Appendix B, "Marginal Loss" ISO-NE default value)
- %Inflation = 2% (AESC 2021, Appendix E, page 327)

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. These RPS and Clean Energy Policy compliance benefits due to NWAs are the results of the reduced energy usage as described in Section 3.1.

[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] "Tariff Provisions." *National Grid: Bills, Meters & Rates*, National Grid US, www.nationalgridus.com/RI-Business/Rates/Tariff-Provisions.

The resulting avoided RPS and Clean Energy Policy (i.e., RGGI) compliance costs are appropriate benefits for inclusion in the RI NWA BCA Model. When customers do not have to purchase electric energy because of an investment an avoided RPS and Clean Energy Policy compliance benefit is created. These compliance benefits are valued using the avoided wholesale REC costs developed in the AESC 2021 Study, Appendix B.[16] Due to the expanding geographical footprint of the RGGI initiative, and the electricity usage now being dominated by states outside of New England, the AESC treats the effects of RGGI as an exogenous price.

SO_2 emissions pricing is determined by the allowance under the Cross-State Air Pollution Rule (CASPR) and the Acid Rain Program (ARP). The 2020 SO_2 spot auction resulted in a price of $0.02 per short ton. No embedded NOx pricing is assumed.

Nominal annual benefits are calculated using an average inflation rate to convert AESC's 2021 real dollar values to nominal values. These benefit values are then grossed up using the appropriate WRP that captures market risk factors typically recovered by generators in their pricing,[17] and distribution loss factor representing losses from the ISO delivery point to the end-use customer. Each technology then has a rating factor that is applied based on its system need coincidence. Furthermore, in solutions with energy losses as part of the technology solution (e.g., battery storage, solar) a round trip/efficiency loss modifier is utilized.

The dollar value of the annual benefits is therefore calculated as:

- RPS and Clean Energy Policy Compliance Benefit ($/yr) = ElectricEnergySavings kWh/yr * (RGGICompliance $/kWh + SOx Embedded) * TechnologyCoincidence * EfficiencyLoss * (1 + %Inflation)^(year-2021) * (1 + WRP) * (1 + %Losses)

Where:

- ElectricEnergySavings (kWh/yr) = Estimated annual electric energy savings based on Engineering models
- RGGICompliance ($/kWh) = Projected annual values (AESC 2021, Appendix B, "REC Costs")
- SOx Embedded ($/kWh) = Projected annual values (AESC 2021, Page 107)[18]
- %Inflation = 2.00% (AESC 2021, Appendix E, Page 327)
- WRP = 8% (AESC 2021, Appendix B, "WRP" AESC default value)
- %Losses = 9% (AESC 20218, Appendix B, " Marginal Loss" ISO-NE default value)
- TechnologyCoincidence = Coincidence factor applied based on the solution technology type
- EfficiencyLoss = modifier applied for energy inefficiencies based on the proposed solution

3.3 Demand Reduction Induced Price Effects

[16] "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

[17] Wholesale risk premium represents the observed difference between wholesale costs and retail prices.

[18] "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 107

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 electric system investments can include NWAs. 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. This is observed in the New England market when ISO-NE activates its price response programs. When this price effect is a result of NWAs, it is appropriate to include the impact in the RI NWA 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 kWh and kW transacted in 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. AESC provides values for two types of DRIPE benefits, Intrastate and Rest of Pool (ROP). Intrastate DRIPE takes credit for the reduced clearing price for Rhode Island customers, while ROP DRIPE takes credit for the reduced clearing price for customers across New England. The base case BCA results exclude ROP DRIPE to align with standard industry practice.

Intrastate Energy, Capacity, and Cross DRIPE values developed for the AESC 2021 Study are used in the RI NWA BCA Model. Wholesale Energy DRIPE values in the AESC 2021 Study are provided in four different costing periods consistent with ISO-New England (ISO-NE) definitions. Net energy savings are split up into these periods in the value calculation. See Section 3.1 for time period definitions. Both wholesale and retail Capacity DRIPE values are provided in the AESC 2021 Study on an annual basis. AESC also provides annual wholesale Cross DRIPE values to account for natural gas price effects caused by a change in electricity generation demand. Each technology then has a rating factor that is applied based on its system need coincidence. Furthermore, in solutions with energy losses as part of the technology solution (e.g., battery storage, solar) a round trip/efficiency loss modifier is utilized.

Capacity DRIPE is valued differently in the AESC report depending upon whether the benefit results from resources that are bid into the Forward Capacity Market (FCM) (i.e., cleared resources) or reductions in peak demand that are not bid into the FCM (i.e., uncleared resources). For NWA solutions the DRIPE avoided cost forecast for uncleared resource values is used. AESC assumes a lag of 5 years between the appearance of the load reduction and the realization of the Capacity DRIPE benefits for uncleared resources (e.g., load reductions in 2021 results in benefits in 2026). To maintain that lag, DRIPE capacity benefits are shifted based on the commercial operating date of the NWA solution.

Energy and Cross DRIPE benefits are also shifted based on the commercial operating date, but the benefits are realized the year after installation, with the $/kWh avoided costs shifted forward one year and escalated by one year of inflation. Loss factors are applied to the wholesale Energy and Cross DRIPE values to account for local transmission and distribution (T&D) losses from the point of delivery to the distribution company's system to the ultimate customer's facility. Wholesale Capacity DRIPE values are used in the RI NWA BCA Model calculations and then T&D loss factors applied. Nominal annual benefits are then calculated using an average inflation rate to convert AESC's 2021 real dollar values to nominal values. Capacity DRIPE's demand savings are calculated to be coincident with the ISO-NE definition of the peak, which is in the summer.

The dollar value of annual benefits is therefore calculated as:

- Summer Peak Energy DRIPE Benefit ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings ElectricEnergyCost$_{SumPk}$ $/kWh * TechnologyCoincidence * EfficiencyLoss * (1 + WRP) * (1 + %Losses) * (1 + %Inflation)^(year-2021)
- Summer Off-Peak Energy DRIPE Benefit ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings * ElectricEnergyCost$_{SumOffPk}$ $/kWh * TechnologyCoincidence* EfficiencyLoss * (1 + WRP) * (1 + %Losses) * (1 + %Inflation)^(year-2021)
- Winter Peak Energy DRIPE Benefit ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings * ElectricEnergyCost$_{WinPk}$ $/kWh * TechnologyCoincidence* EfficiencyLoss * (1 + WRP) * (1 + %Losses) * (1 + %Inflation)^(year-2021)
- Winter Off-Peak Energy DRIPE Benefit ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings * ElectricEnergyCost$_{WinOffPk}$ $/kWh * TechnologyCoincidence * EfficiencyLoss * (1 + WRP) * (1 + %Losses) * (1 + %Inflation)^(year-2021)
- Cross DRIPE Benefit ($/yr) = ElectricEnergySavings kWh/yr * CrossDRIPE $/kWh * TechnologyCoincidence * EfficiencyLoss * (1 + WRP) * (1 + %Losses) * (1 + %Inflation)^(year-2021)
- Generation Capacity DRIPE Benefit ($/yr) = ElectricDemandSavings kW/yr$_{SumPk}$ * WholesaleCapDRIPE $/kW-yr * TechnologyCoincidence * (1 + WRP) * (1 + %Losses$_{Cap}$) * (1 + %Inflation)^(year-2021)

Where:

- ElectricEnergySavings (kWh/yr) = Estimated annual electric energy savings based on Engineering models
- %ElectricEnergySavings = Estimated annual electric energy savings fraction for each time period based on Engineering models
- ElectricDemandSavings (kW/yr) = Estimated peak electric demand savings based on Engineering models
- EnergyDRIPE ($/kWh) = Projected annual values (AESC 2021, Appendix B, "Intrastate - Wholesale Energy DRIPE")
- CrossDRIPE ($/kWh) = Projected annual values (AESC 2021, Appendix B, "Intrastate – Wholesale Cross DRIPE")
- RetailCapDRIPE ($/kW-yr) = Projected annual values (AESC 2021, Appendix B, "Intrastate – Capacity DRIPE – Uncleared")
- TechnologyCoincidence = Coincidence factor applied based on the solution technology type
- EfficiencyLoss = modifier applied for energy inefficiencies based on the proposed solution
- WRP = 8% (AESC 2021, Appendix B, "WRP" AESC default value)
- %Losses = 9% (AESC 2021, Appendix B, "Marginal Loss" ISO-NE default value)
- %Losses$_{Cap}$ = 16% (AESC 2021, Appendix B, "Marginal Loss Capacity" ISO-NE default value)
- %Inflation = 2% (AESC 2021, Appendix E, Page 327)

3.4 Electric Capacity Benefits

At the generation and transmission level, electric capacity benefits due to NWAs are a result of load reductions at summer peak. At the distribution and site-specific transmission level, electric 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.

3.4.1 Electric Generation Capacity Benefits

When generators do not have to build new generation facilities or when construction can be deferred because of NWAs, an avoided electric energy resource benefit is created. In the New England capacity market, capacity benefits accrue because demand reduction reduces ISO-NE's installed capacity requirement. The capacity requirement is based on avoided load's contribution to the system peak, which, for ISO-NE, is the summer peak. Generation capacity avoided costs are driven by load at the time of the ISO-NE peak, which has by convention associated with an hour ending at 3 PM or 5 PM on a hot summer day.[19] Therefore, capacity benefits accrue only from summer peak demand reduction; there is currently no winter generation capacity benefit for ISO-NE.

Peak demand savings created through NWAs are valued using the avoided wholesale capacity values from the 2021 AESC, Appendix B. The values are then grossed up to account for wholesale risk premium (WRP) and distribution losses. Nominal annual benefits are then calculated using an average inflation rate to convert AESC's 2021 real dollar values to nominal values. Demand savings are calculated to be coincident with the ISO-NE definition of peak, which is in the summer.

The dollar value of annual benefits is therefore calculated as:

- Generation Capacity Benefit ($/yr) = ElectricDemandSavings kW/yr$_{SumPk}$* CapCost $/kW-yr * %Summer Coincidence * TechnologyCoincidence * (1+WRP) * (1+%Losses$_{Cap}$) * (1 + %Inflation)^(year-2021)

Where:

- ElectricDemandSavings (kW/yr) = Estimated peak electric demand savings based on Engineering models
- WholesaleCapCost ($/kW-yr) = Projected annual values (AESC 2021, Appendix B, "Wholesale Electric Capacity – Uncleared")
- %Summer Coincidence: % of NWA peak capacity at ISO peak
- TechnologyCoincidence: Coincidence factor applied based on the solution technology type
- WRP = 8% (AESC 2021, Appendix B, "WRP" AESC default value)
- %Losses$_{Cap}$ = 16% (AESC 2021, Appendix B, "Marginal Loss Capacity" ISO-NE default value)
- %Inflation = 2% (AESC 2021, Appendix E, Page 327)

The AESC 2021 Study includes two types of wholesale capacity values: 1) cleared capacity (Forward Capacity Auction (FCA) price), which is the traditional valuation of electric generation capacity, and 2) uncleared capacity, which is a new approach to valuing the capacity of short duration measures that are

[19] "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 239.

not actively bid in the ISO-NE Forward Capacity Market (FCM). The AESC study provides these two values for avoided electric generation capacity, which are differentiated based on whether a load reduction is taken into account when bidding into the FCM (cleared capacity) or is not (uncleared capacity), and an overall weighted average avoided capacity value representing a weighted average of the cleared capacity and uncleared capacity values.

Given the three year forward nature of the FCM and the timing of the ISO-NE load forecast, it takes five years from the time of load reduction for uncleared capacity to begin impacting the FCM procurements. As a result, measures with a useful life less than five years (e.g., traditional demand response programs) would not produce any generation capacity benefits in years 1-5 under the traditional capacity modeling methodology.

NWAs will not be considered when bidding into the FCM, so the uncleared capacity values are used.

3.4.2 Electric Transmission Capacity Benefits

When transmission facilities do not have to be built or can be deferred because of NWAs, an avoided electric energy resource benefit is created. Electric transmission capacity benefits are valued in the RI Test based on the costs of Pool Transmission Facilities (PTF). The AESC 2021 Study calculates an avoided cost for PTF of $84/kW-year in 2021 dollars.

Capacity loss factors are applied to the avoided transmission capacity cost to account for local transmission and distribution (T&D) losses from the point of delivery to the distribution company's system to the ultimate customer's facility. Thus, T&D losses are accounted for from the generator to the end-use customer. Nominal annual benefits are then calculated using an average inflation rate to convert AESC's 2021 real dollar values to nominal values. Demand savings are calculated to be coincident with the ISO-NE definition of peak, which is in the summer.

The dollar value of annual benefits is therefore calculated as:

- Transmission Benefit ($/yr) = DemandSavings kW/yr$_{SumPk}$ * TransCapCost $/kW-yr * %Summer Coincidence * TechnologyCoincidence * (1 + %Losses$_{Avg}$) * (1 + %Inflation)^(year-2021) * TransmissionCoincidence

Where:

- DemandSavings (kW/yr) = Estimated peak electric demand savings based on Engineering models
- TransCapCost ($/kW-yr) = $84/kW-year (AESC 2021, Appendix B, "T&D Cost")
- %Summer Coincidence = % of NWA peak capacity at ISO peak
- TechnologyCoincidence = Coincidence factor applied based on the solution technology type
- %Losses$_{Avg}$ = 8% (AESC 2021, Page 333 "PTF Losses", "Average Loss Peak")
- %Inflation = 2% (AESC 2021, Appendix E, Page 327)
- TransmissionCoincidence (%)= System Need (MW)/RI Capacity (MW)

3.4.3 Electric Distribution Capacity Benefits

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

3.4.4 Electric Transmission Infrastructure Site-Specific Benefits

Transmission Infrastructure Site-Specific benefit is based on the direct deferred transmission infrastructure due to the implementation of the NWA. This value includes such inputs as deferred capital expenditure, deferred O&M, and deferred taxes over the expected contract timeframe of the NWA. This value will typically be null for NWAs.

3.5 Natural Gas Benefits

An avoided resource benefit is produced when a project, in which customers have invested, reduces natural gas usage. Natural Gas benefits are negligible for NWAs, so they are not included in the RI NWA BCA Model calculations.

3.6 Delivered Fuel Benefits

An avoided resource benefit is produced when a project, in which customers have invested, reduces delivered fuel usage. Avoided delivered fuel costs (natural gas, propane, or fuel oil) are negligible for NWAs, so they are not included in the RI NWA BCA Model calculations.

3.7 Water and Sewer Benefits

An avoided resource benefit is produced when a project, in which customers have invested to save electricity or fuel, 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 NWAs, so they are not included in the RI NWA 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 NWAs 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 NWA investments and are therefore appropriate for inclusion in the RI NWA 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. These benefits are currently seen to be negligible for NWAs.

3.10 Environmental and Public Health Impacts

Environmental benefits due to NWAs are a result of reduced energy use from the implemented solution. The resulting avoided environmental costs are appropriate benefits for inclusion in the RI NWA BCA Model. Reduction in the use of electricity generated at central power plants provides environmental benefits to Rhode Island and the region, including reduced greenhouse gas emissions and improved air quality.

3.10.1 Non-Embedded Greenhouse Gas Reduction Benefits

Carbon dioxide and other GHG emissions come from a variety 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.[20]

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 damages 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.[21]

The AESC 2021 Study developed three approaches for calculating the non-embedded cost of carbon based on marginal abatement costs. Note that "non-embedded" costs are not included in AESC's modeling of energy prices, as opposed to "embedded" costs, which include costs associated with RGGI, SO_2 regulation programs.[22] 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[23] 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. 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 costs of compliance with the RGGI are already included or "embedded" in the projected electric energy market prices. Therefore, the difference between the $125 per short ton societal cost and the RGGI compliance costs already embedded in the projected energy market prices represents the value of

[20] 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.

[21] "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.

[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. See *Chapter 4. Common Electric Assumptions* for a discussion of how these costs are modeled.

[23] "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

carbon emissions not included in the avoided energy costs. The AESC 2021 calculates this value at a $/kwh broken into winter/summer and peak/off-peak aligning with and not double counting the energy benefits calculated in section 3.1.

Loss factors are applied to the marginal emissions factor for ISO-NE generators to account for marginal losses from the generator to the end-use customer. Nominal annual benefits are then calculated using an average inflation rate to convert AESC's 2021 real dollar values to nominal values.

The dollar value of annual benefits is therefore calculated as:

- Non-Embedded GHG Reduction Benefit Summer Peak ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings * Non-Embedded GHG Costs$_{SumPk}$ $/kWh * TechnologyCoincidence * EfficiencyLoss * (1 + %Losses) * (1 + %Inflation)^(year-2021)
- Non-Embedded GHG Reduction Benefit Summer Off-peak ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings * Non-Embedded GHG Costs$_{SumOffPk}$ $/kWh * TechnologyCoincidence* EfficiencyLoss * (1 + %Losses) * (1 + %Inflation)^(year-2021)
- Non-Embedded GHG Reduction Benefit Winter Peak ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings * Non-Embedded GHG Costs$_{WinPk}$ $/kWh * TechnologyCoincidence* EfficiencyLoss * (1 + %Losses) * (1 + %Inflation)^(year-2021)
- Non-Embedded GHG Reduction Benefit Winter Off-Peak ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings * Non-Embedded GHG Costs$_{WinOffPk}$ $/kWh * TechnologyCoincidence * EfficiencyLoss * (1 + %Losses) * (1 + %Inflation)^(year-2021)

Where:

- ElectricEnergySavings (kWh/yr) = Estimated annual electric energy savings based on Engineering models
- %ElectricEnergySavings = Estimated annual electric energy savings fraction for each time period based on Engineering models
- Non-Embedded GHG Costs: Projected annual values for each time period (AESC 2021, Appendix B, "Non-Embedded GHG Costs")
- TechnologyCoincidence = Coincidence factor applied based on the solution technology type
- EfficiencyLoss = modifier applied for energy inefficiencies based on the proposed solution
- %Losses = 9% (AESC 2021, Appendix B, "Marginal Loss", ISO-NE default value) %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 for electricity generation. 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.[24]

In February, 2018, the US EPA published a Technical Support Document for estimating the benefit of reducing PM2.5 precursors from 17 sectors, including avoided NOx costs from "electricity generating units".[25] The EPA document estimates national average values for mortality and morbidity per ton of directly-emitted NOx reduced for 2016, 2020, 2025, and 2030 based on the results from two other studies.[26,27] Using the average results from the two studies the non-embedded NOx emissions cost to be $10,100 per ton in 2020 (2015 dollars). This translates into a $0.90 per MWh in 2020.
The AESC 2021 Study also 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).[28] This translates to a $0.77 per MWh in 2021. The RI NWA BCA model utilizes the AESC 2021 value broken down into a winter/summer and peak/off-peak kWh value.

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 marginal emissions factor for ISO-NE generators to account for local T&D losses from the generator 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:

- Non-Embedded NOx Reduction Benefit Summer Peak ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings * Non-Embedded NOx Costs$_{SumPk}$ $/kWh * TechnologyCoincidence * EfficiencyLoss * (1 + %Losses) * (1 + %Inflation)^(year-2021)
- Non-Embedded NOx Reduction Benefit Summer Off-peak ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings * Non-Embedded NOx Costs$_{SumOffPk}$ $/kWh * TechnologyCoincidence* EfficiencyLoss * (1 + %Losses) * (1 + %Inflation)^(year-2021)
- Non-Embedded NOx Reduction Benefit Winter Peak ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings * Non-Embedded NOx Costs$_{WinPk}$ $/kWh * TechnologyCoincidence* EfficiencyLoss * (1 + %Losses) * (1 + %Inflation)^(year-2021)
- Non-Embedded NOx Reduction Benefit Winter Off-Peak ($/yr) = ElectricEnergySavings kWh/yr * %ElectricEnergySavings * Non-Embedded NOx Costs$_{WinOffPk}$ $/kWh * TechnologyCoincidence * EfficiencyLoss * (1 + %Losses) * (1 + %Inflation)^(year-2021)

[24] "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.

[25] "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.

[26] Krewski D, Jerrett M, Burnett RT, Ma R, Hughes E, Shi Yet al., "Extended Follow-up and Spatial Analysis of the American Cancer Society Study Linking Particulate Air Pollution and Mortality", Boston Health Effects Institute, 2009.

[27] Lepeule J, Laden F, Dockery D, and Schwartz J, "Chronic Exposure to Fine Particles and Mortality: An Extended Follow-up of the Harvard Six Cities Study from 1974 to 2009", EHP Vol 120 No. 7, July 2012.

[28] "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

Where:

- ElectricEnergySavings (kWh/yr) = Estimated annual electric energy savings based on Engineering models
- %ElectricEnergySavings = Estimated annual electric energy savings fraction for each time period based on Engineering models
- Non-Embedded NOx Costs: Projected annual values for each time period (AESC 2021, Appendix B, "Non-Embedded NOx Costs")
- TechnologyCoincidence = Coincidence Factor based on the solution technology type
- EfficiencyLoss = modifier applied for energy inefficiencies based on the proposed solution
- %Losses = 9% (AESC 2021, Appendix B, "Marginal Loss", "ISO default")
- %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.[29]

In February, 2018, the US EPA published a Technical Support Document for estimating the benefit of reducing PM2.5 precursors from 17 sectors, including avoided SO_2 costs from "electricity generating units".[30] The EPA document estimates national average values for 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.[31,32] 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). These translate into $3.80 per MWh in 2020 and $4.6037 per MWh in 2030 (2015 dollars) using the ISO-NE 2019 marginal SO_2 emissions factor of 0.02 lb SO_2/MWh.[33] Nominal annual benefits are then calculated using an average inflation rate to convert the 2015 real dollar values to nominal values.

Loss factors are applied to the marginal emissions factor for ISO-NE generators to account for local transmission and distribution (T&D) losses from the generator to the end-use customer. Nominal annual

[29] "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.

[30] "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.

[31] Krewski D, Jerrett M, Burnett RT, Ma R, Hughes E, Shi Yet al., "Extended Follow-up and Spatial Analysis of the American Cancer Society Study Linking Particulate Air Pollution and Mortality", Boston Health Effects Institute, 2009.

[32] Lepeule J, Laden F, Dockery D, and Schwartz J, "Chronic Exposure to Fine Particles and Mortality: An Extended Follow-up of the Harvard Six Cities Study from 1974 to 2009", EHP Vol 120 No. 7, July 2012.

[33] "2019 ISO New England Electric Generator Air Emissions Report." *ISO New England*, ISO New England Inc., March 2021, https://www.iso-ne.com/static-assets/documents/2021/03/2019_air_emissions_report.pdf. Page 32, Table 5-3.

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:

- Non-Embedded SO_2 Reduction Benefit ($/yr) = ElectricEnergySavings kWh/yr * SO_2EmissionsRate ton/kWh * (NonEmbeddedSO_2Value $/ton - Embedded$SO_2$Value $/ton) * TechnologyCoincidence * EfficiencyLoss (1 + %Losses) * (1 + %Inflation)^(year-2015)

Where:

- ElectricEnergySavings (kWh/yr) = Estimated annual electric energy savings based on Engineering models
- SO_2EmissionsRate (ton/kWh) = 0.02 lb SO_2/MWh * 1/1,000 MWh/kWh ÷ 2,000 lb/ton (ISO-NE 2021,[34] Table 5-3, 2019 Time-Weighted LMU Marginal Emissions Rates-All LMUs, SO_2 "Annual Average (All Hours)")
- NonEmbeddedSO_2Value ($/ton) = $69,000-$79,500/ton (US EPA 2019, Tables 5-10, average of SO_2 from "Electricity Generation Units", 2015 dollars)
- EmbeddedSO_2Value ($/ton) = $0.02/ton (AESC 2021, Page 107, SO_2 "2021$")[35]
- TechnologyCoincidence = Coincidence Factor based on the solution technology type
- EfficiencyLoss = modifier applied for energy inefficiencies based on the proposed solution
- %Losses = 9% (AESC 2021, Appendix B, "Marginal Loss", "ISO default")
- %Inflation = 2% (AESC 2021, Appendix E, Page 327)

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 quite old and the impacts are very small.[36]

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.

RI Energy 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

[34] "2019 ISO New England Electric Generator Air Emissions Report." *ISO New England*, ISO New England Inc., March 2021, https://www.iso-ne.com/static-assets/documents/2021/03/2019_air_emissions_report.pdf. Page32.

[35] "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 107.

[36] "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.

BCA. Additionally, because the benefits can be large, they create a “masking” effect. For these reasons, the RI NWA 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 NWA. 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 NWA. 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 NWA 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 electric system. This can include upgrading the wires (e.g., with a battery storage or solar solution) or a telecommunications upgrade. Interconnection costs will be determined on a case-by-case basis regarding the specific system need and its respective targeted NWA. This cost will generally be a capital expenditure, initially borne by the utility, prior to the commercially viable date of the NWA solution.

4. Benefit-Cost Calculations

The RI NWA BCA Model is a comparison tool to be utilized to analyze multiple solutions with respective technologies to assess their cost-effectiveness. Currently four technology types are assessed: Battery Storage, Solar, Demand Response, and Energy Efficiency. The RI NWA BCA Model will be expanded as new technologies or solutions evolve. The RI NWA 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 NWA 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%)[37] since the NWA 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 Energy Benefits + Compliance Benefits + DRIPE Benefits + Electric Generation Capacity Benefits + Electric Transmission Capacity Benefits + Electric Distribution Capacity Benefits + Electric Transmission Infrastructure Site Specific + Natural Gas Benefits + Fuel 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 NWA investment will be considered cost-effective if the BCR for the resource is greater than 1.0.

[37] "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 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
DG	Distributed Generation
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
FCA	Forward Capacity Auction
FCM	Forward Capacity Market
FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
GHG	Greenhouse gas
ISO	Independent Systems Operator
ISO-NE	ISO New England Inc.
kW	Kilowatt
kWh	Kilowatt-hour
LCP	Least-Cost Procurement
LCP Standards	Least-Cost Procurement Standards
LMU	Locational Marginal Unit
MW	Megawatt
MWh	Megawatt-hour
NERC	North American Energy Reliability Corporation
NOx	Nitrogen oxides (NO, NO_2)

Term	Definition
NPV	Net Present Value
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 NWA BCA Model	Rhode Island Non-Wires Alternative Benefit-Cost Analysis Model
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
WCMA	West/Central Massachusetts
WRP	Wholesale Risk Premium

Appendix 7

Rhode Island Energy’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 Rhode Island Energy

Table of Contents

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 Rhode Island Energy (Rhode Island Energy 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, Rhode Island Energy adheres to the RI Test for all NPA investment proposals. Rhode Island Energy 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

RI Test Category	Docket 4600 Category	NPA	Notes
Electric Energy Benefits	Energy Supply & Transmission Operating Value of Energy Provided or Saved (Power System Level)	O	(1)
	Retail Supplier Risk Premium (Power System Level)	O	
	Criteria Air Pollutant and Other	O	
	Distribution System Performance (Power System Level)	O	
Renewable Portfolio Standards (RPS) and Clean Energy Policies Compliance Benefits	REC Value (Power System Level)	O	(1)
	GHG Compliance Costs (Power System Level)	O	
	Environmental Externality Costs (Power System Level)	O	
Demand Reduction Induced Price Effects	Energy DRIPE (Power System Level)	X	
Electric Generation Capacity Benefits	Forward Commitment Capacity Value (Power System Level)	O	(1)
Electric Transmission Capacity Benefits	Electric Transmission Capacity Value (Power System Level)	O	(1)
	Electric Transmission Infrastructure Costs for Site-Specific Resources	O	
Electric Distribution Capacity Benefits	Distribution Capacity Costs (Power System Level)	O	(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	

[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 Rhode Island Energy 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]

[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% (Rhode Island Energy 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% (Rhode Island Energy, 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% (Rhode Island Energy, 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 * $\text{RetailCost}_{\text{DistFuelOil}}$ $/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
- $\text{RetailCost}_{\text{DistFuelOil}}$ ($/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.

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[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% (Rhode Island Energy, 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% (Rhode Island Energy, 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

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[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% (Rhode Island Energy, Gas Distribution Annual Report for DOT Pipeline and Hazardous Materials Safety Administration, 2021)
- %Inflation = 2% (AESC 2021, Appendix E, Page 327)

[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.

Rhode Island Energy 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