National Grid'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 National Grid

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

1. Introduction

National Grid'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 National Grid (National Grid or Company).
[2] "Docket No. 4600 and Docket No. 4600-A." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, Rhode Island Public Utilities Commission, 2 Nov. 2018, www.ripuc.ri.gov/eventsactions/docket/4600page.html.
[3] "Least Cost Procurement Standards." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, Energy Efficiency and Resource Management Council, 21 Aug. 2020, http://www.ripuc.ri.gov/eventsactions/docket/5015_LCP_Standards_05_28_2020_8.21.2020%20Clean%20Copy%20FINAL.pdf.
[4] "RIPUC." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, State of Rhode Island, www.ripuc.ri.gov/.
[5] "Docket No. 4443." *State of Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers*, Energy Efficiency and Resource Management Council, 17 Sept. 2013, www.ripuc.ri.gov/eventsactions/docket/4443page.html.
[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, National Grid adheres to the RI Test for all NWA investment proposals. National Grid 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 National Grid in New England and is designed to be used for cost-effectiveness screening in 2019 through 2021.

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

The AESC Study provides projections of avoided costs of energy in each New England state for a hypothetical future in which a myriad of EE and DER opportunities exist. 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., embedded GHG costs), wholesale risk premium (WRP) that captures market risk factors typically

[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

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.

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

[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.
[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

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

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

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

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 NO_x 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

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

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[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

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) * (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) %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) * (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 = 9% (AESC 2021, Appendix B, "Marginal Loss" 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 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.

[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.

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) * (1 + %Inflation)^(year-2021) * TransmissionsCoincidence

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 = 0% (AESC 2018, Appendix B, "Marginal Loss", ISO-NE default value) %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.

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 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.

[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

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]

[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.

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:

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

Where:

- ElectricEnergySavings (kWh/yr) = Estimated annual electric energy savings based on Engineering models

[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

- %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 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:

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[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.

- 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.

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

3.12 Contract/Solution Costs

[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.

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