2026 Rhode Island Test Description

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1. Introduction

This section has been prepared pursuant to Section 1.3(C) and 3.2(N) of the Least Cost Procurement Standards as approved and adopted pursuant to Rhode Island PUC Docket 23-07-EE[1] (referred to herein as the "LCP Standards"), and in alignment with the Rhode Island Benefit Cost Test (RI Test) as defined by the Standards and the Docket 4600A Benefit-Cost Framework and associated Guidance. The methods identified herein will be used for the calculation of benefits and costs associated with the 2026 Annual Energy Efficiency Plan.

Two key supporting documents for cost-effectiveness are the Rhode Island Technical Reference Manual (TRM) and the "Avoided Energy Supply Components in New England: 2024 Report" (AESC 2024) avoided cost study (see Section 3.1 for more details). For the 2026 Annual Plan, the Company developed the 2026 Rhode Island TRM, which documents the sources and derivation of savings estimates for proposed 2026 measures. Sources can be evaluation studies, engineering analyses, and/or other research. The TRM is a public document and was provided to the EERMC and its consultants to support and facilitate their determination of the Plan's cost-effectiveness. The TRM is reviewed and updated annually to reflect changes in technology, baselines, and evaluation results.

2. The RI Test Overview and Docket 4600 Benefit Cost Framework

The RI Test compares the present value of benefits associated with lifetime net savings of an energy efficiency measure or program to the total costs necessary to implement that measure or program. The RI Test may be applied to any energy efficiency measure or program independent of primary fuel type.

The RI Test captures the value created by efficiency measures installed in a particular program year across the programmatic useful life of the measure. The measure life is based on the technical life of the measure modified to reflect expected measure persistence and period of program influence. Because the RI Test captures the value associated with a stream of benefits over time, a measure's benefits are present-valued so that costs and benefits may be compared.

All savings included the calculation of RI Test benefits 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. The expected net savings also reflect market effects due to the program. The RI Test captures the combined effects of a program on both the participating customers and those not participating in a program. From a resource acquisition perspective, if the program induces participants or non-participants to acquire energy efficiency devices without program expenditures (i.e., outside of

[1] https://ripuc.ri.gov/sites/g/files/xkgbur841/files/2023-07/2307-LCP%20Standards_final.pdf

the program), these effects – known as spillover – are attributed as program benefits in the RI Test. The costs incurred by customers to acquire equipment on their own are also counted as costs in the RI Test.

On the other hand, if customers accept program funds to implement energy efficiency measures they would have installed anyway, the associated savings are known as free-ridership. From the perspective of resource acquisition through utility programs, it is important to distinguish whether a customer would have implemented the efficiency measure without the program. Therefore, savings associated with free-ridership are deducted from program savings.[2] The cumulative impact of realization rates and market effects on gross savings is known as net savings.

The primary assessment of cost-effectiveness in the RI Test captures all benefits and costs, including benefits shared between Rhode Island and other jurisdictions. Modifications made to the LCP Standards in 2023 specify an additional assessment of cost-effectiveness including only benefits that accrue inside Rhode Island. Rhode Island Energy has determined rest-of-pool DRIPE benefits (see Section 3.8) accrue outside of Rhode Island and are therefore excluded from the aforementioned additional assessment of cost-effectiveness. To the best of the Rhode Island Energy's knowledge, no costs accrue out of state.

The benefits and costs considered in the RI Test as applied to Energy Efficiency are detailed in the next section and are presented in Attachments 5 and 6.

3. Description of Program Benefits and Costs

The following benefits and costs are quantified and monetized in the RI Test.[3] Section 6 shows the alignment of each benefit and cost category to the Docket 4600 Benefit-Cost Matrix.

Benefits

- Electric Energy Benefits
- Electric Generation Capacity Benefits
- Electric Transmission and Distribution Capacity Benefits
- Natural Gas Benefits
- Delivered Fuel Benefits
- Water and Sewer Benefits
- Non-Energy Impacts
- Demand Reduction Induced Price Effects (DRIPE)
- Non-embedded Greenhouse Gas Reduction Benefits
- Non-embedded Nitrogen Oxides Reduction Benefits
- Value of Improved Reliability
- Combined Heat and Power Benefits

[2] Both free-ridership and spillover have been determined from evaluation, measurement, and verification studies of program participants, non-participants, and other market actors, such as developers and vendors.
[3] Economic Development Benefits are a recognized benefit in Rhode Island.Their monetized value, however, is not included in the RI Test calculation and is reported separately.

Costs

- Utility Costs
- Participant Costs

3.1 AESC 2024 and the AESC User Interface

The cost-effectiveness analyses of the proposed programs (specifically the calculation of benefits) use avoided costs developed by Synapse Energy Economics as part of AESC 2024.[4] The study is sponsored by the New England electric and gas efficiency program administrators and is used for cost-effectiveness screening in 2024 or later. The avoided costs reflect a view of market conditions over the full study horizon (2024-2038) at the time of the study and are highly influenced by the cost of fossil fuels and expectations about ISO-NE's forward capacity market. AESC 2024 introduced six counterfactual scenarios representing variations in demand-side measures offered in the future. For cost-effectiveness screening of the 2026 Rhode Island energy efficiency portfolio, the Company used Counterfactual #3. Counterfactual #3 models a scenario in which program administrators install no new energy efficiency resources in 2024 and beyond.[5]

The AESC 2024 User Interface Counterfactual #3 workbook contains a menu that allows users to set various parameters that affect results. Examples of these parameters are region (e.g., Rhode Island, Connecticut, or Vermont) and measure vintage (the install year of measures contained in the benefit-cost analysis). Figure 1 below details Rhode Island Energy's selections, in the blue cells, within the AESC 2024 User Interface Counterfactual #3 workbook for this 2026 Annual Plan:

[4] Avoided non-pool transmission and distribution capacity values and avoided water and sewer costs specific to Rhode Island Energy are developed separately by Rhode Island Energy and used in the RI Test.
[5] For more information on AESC 2024's Counterfactual #3, please the 2024 AESC Report, Table 40, page 73, https://www.synapse-energy.com/sites/default/files/inline-images/AESC%202024%20May%202024.pdf.

Figure 1. AESC 2024 User Interface Counterfactual #3 Selection Menu

Region	Rhode Island
Dollar type	2024 $
Measure vintage year	2026
GHG cost basis	New England MAC (electric sector)
Include non-CO2 GHGs?	Yes
Include upstream GHGs?	No
Include emissions from biomass?	No
Include non-emitting direct fuel costs?	No
Include state policy considerations for marginal emissions?	No
Summer Wholesale Risk Premium (WRP)	8.00%
Winter Wholesale Risk Premium (WRP)	8.00%
Energy losses	9.00%
Peak demand losses	16.00%
Assumed VOLL ($/kWh)	$61

For the "Include non-CO2 GHGs" toggle, the User Interface only includes non-CO_2 GHGs when the social cost of carbon is selected for the "GHG cost basis." However, even though Rhode Island Energy uses a marginal abatement cost, non-CO_2 GHGs are included using multipliers derived by Rhode Island Energy using emissions factors sourced from the AESC 2024 User Interface Counterfactual #3 workbook. Please see Section 3.10 for more details.

The "Include state policy considerations for marginal emissions?" toggle does not adjust Rhode Island specific outputs. Rhode Island Energy has instead used other custom modifications in the User Interface to consider Rhode Island specific state policy considerations. Please see Section 3.10 for more details.

The wholesale risk premium and energy / peak demand losses inputs are all default values provided by AESC 2024 based on Synapse's research. Similarly, the "Assumed VOLL" (assumed value of lost load) is from the AESC 2024 report and is used to calculate electricity reliability benefits (see Section 3.12).

The user interface workbook generates a set of tables consistent with those selections. Specifically, Rhode Island Energy sources avoided costs from the AESC 2024 User Interface Counterfactual #3 workbook[6], and the AESC 2024 Appendix C and Appendix D workbooks.[7] The Appendix C and Appendix D workbooks are separate from the User Interface and produce tables that are not controlled by a user selection menu. Table 1 summarizes the AESC sources and what avoided cost components they provide. Since the AESC 2024 User Interface outputs avoided costs in 2024 dollars, they are escalated for use in the 2026 benefit-cost model.

[6] https://drive.google.com/drive/folders/1yTRxpky3pt4vBaJZ33NFEC0Ize84nN15
[7] https://www.synapse-energy.com/aesc-2024-materials

Table 1. AESC Sources for Avoided Cost Components

User Interface "AppdxB"	Electric energy, electric energy DRIPE, PTF
User Interface "AppdxC"	Gas DRIPE
User Interface "AppdxG"	Non-embedded GHGs
User Interface "AppdxJ_O"	Electric capacity, capacity DRIPE, and reliability through 2027
User Interface "AppdxJ_S"	Summer electric capacity, capacity DRIPE, and reliability starting in 2028
User Interface "AppdxJ_W"	Winter electric capacity, capacity DRIPE, and reliability
Appendix C[8]	Gas energy
Appendix D[9]	Delivered fuels, delivered fuels DRIPE

3.2 Electric Energy Benefits

Avoided electric energy costs are appropriate benefits for inclusion in the RI Test. When consumers do not have to purchase electric energy because of their investment in energy efficiency, an avoided resource benefit is created.

Electric energy savings are valued using the retail avoided electric energy costs developed in the AESC 2024 User Interface, Counterfactual #3, Appendix B. These retail avoided costs internalize the expected cost of complying with current or reasonably anticipated future regional or federal greenhouse gas reduction requirements. The retail avoided electric energy costs sourced from the User Interface workbook also include energy losses of 9% and the wholesale risk premium of 8%. These embedded factors are the default values provided in the User Interface workbook (see Figure 1). In the calculation of benefits, energy savings are grossed-up using factors that represent transmission and distribution energy losses, because a reduction in energy use at the customer site means less energy needs to be generated and less extra generation is needed to cover losses that occur in delivery. The wholesale risk premium identified by Synapse captures the premium above wholesale costs that suppliers add to their pricing.

The avoided energy costs in the 2024 AESC Study are provided in four different costing periods consistent with ISO-NE definitions. Net energy savings are split up into these periods in the value calculation. The time periods are defined as follows:

- Summer on-peak: The 16-hour block from 7 a.m. till 11 p.m., Monday–Friday (except ISO holidays), in the months of June–September (1,344 Hours, 15.3 percent of 8,760)
- Summer off-peak: All other hours between 11 p.m. and 7 a.m., Monday–Friday, weekends, and ISO holidays in the months of June–September (1,582 Hours, 18.1 percent of 8,760)
- Winter on-peak: The 16-hour block from 7 a.m. till 11 p.m., Monday–Friday (except ISO holidays), in the eight months of January–May and October–December (2,736 Hours, 31.2 percent of 8,760)

[8] Separate workbook from the User Interface available here: https://www.synapse-energy.com/aesc-2024-materials.
[9] Ibid.

- Winter off-peak: All other hours between 11 p.m. and 7 a.m., Monday–Friday, all day on weekends, and ISO holidays–in the months of January–May and October–December (3,096 Hours, 35.3 percent of 8,760)[10], [11]

Measure-level net energy savings are allocated to each costing period and multiplied by the appropriate avoided energy value.[12]

- Summer Peak Energy Benefit ($) = Net Annual kWh * Summer Peak Energy % * Summer Peak Energy Value $\$/kWh_{@Life}$ * $(1 + \text{Energy Losses})_{\text{Already included in User Interface}}$ * $(1 + \text{Summer Wholesale Risk Premium})_{\text{Already included in User Interface}}$
- Summer Off Peak Energy Benefit ($) = Net Annual kWh * Summer Off Peak Energy % * Summer Off Peak Energy Value $\$/kWh_{@Life}$ * $(1 + \text{Energy Losses})_{\text{Already included in User Interface}}$ * $(1 + \text{Summer Wholesale Risk Premium})_{\text{Already included in User Interface}}$
- Winter Peak Energy Benefit ($) = Net Annual kWh * Winter Peak Energy % * Winter Peak Energy Value $\$/kWh_{@Life}$ * $(1 + \text{Energy Losses})_{\text{Already included in User Interface}}$ * $(1 + \text{Winter Wholesale Risk Premium})_{\text{Already included in User Interface}}$
- Winter Off Peak Energy Benefit ($) = Net Annual kWh * Winter Off Peak Energy % * Winter Off Peak Energy Value $\$/kWh_{@Life}$ * $(1 + \text{Energy Losses})_{\text{Already included in User Interface}}$ * $(1 + \text{Winter Wholesale Risk Premium})_{\text{Already included in User Interface}}$

3.3 Electric Generation Capacity Benefits

Avoided electric generation capacity values are appropriate for inclusion in the RI Test. When generators do not have to build new facilities or when construction can be deferred because of investments in energy efficiency, an avoided resource benefit is created. In New England, capacity benefits accrue because demand reduction reduces ISO-NE's installed capacity requirement. Notably, AESC 2024 monetizes winter peak demand reduction because of the regional growth of electric heat. Therefore, capacity benefits accrue from summer and winter peak demand reduction.

Demand savings are valued using the avoided capacity values from the AESC 2024 User Interface Counterfactual #3, Appendix J. There are avoided capacity values in Appendix B. However, the Appendix B values are based on a fixed measure life input in the User Interface's selection menu. Appendix J contains

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[10] https://www.synapse-energy.com/sites/default/files/inline-images/AESC%202024%20May%202024.pdf

[11] All equations in this an subsequent section show the inclusion of loss factors in the calculation of benefits. Notations ae used to further indicate whether the loss factors are included in the avoided costs through the user interface or whether they are included in the benefit-cost model.

[12] The notation "@Life" used in the benefit equations in this section and the sections that follow is an indication that the avoided value component for each benefit (e.g., electric energy, capacity, natural gas, etc.) is the cumulative net present value of avoided costs for each year of the planning horizon from the base year over the life of the measure. For example, the avoided value component for a measure with an expected life of ten years for any given benefit component is the sum of the net present value of the annual avoided costs for that component in Year 1, Year 2, Year 3, etc., through Year 10.

avoided capacity values for all measures with lifetimes between 1 and 35 years. Because the Rhode Island energy efficiency portfolio contains measures with a wide variety of expected lifetimes, Appendix J is used.

A loss factor of 16% (the AESC 2024 default) representing losses from the generator to the end-use customer is used as part of a multiplier. A wholesale risk premium of 8% (the AESC 2024 default) is also used in a multiplier for uncleared costs only.[13]

The dollar value of benefits is therefore calculated as:

- Cleared Generation Capacity Benefit ($) = Net Annual Summer kW * Summer Generation Cleared Capacity Value $\$/kW_{@Life}$ * (1 + Capacity Losses)$_{\text{Added at BCR model}}$ * + Net Annual Winter kW * Winter Generation Cleared Capacity Value $\$/kW_{@Life}$ * (1 + Capacity Losses)$_{\text{Added at BCR model}}$
- Uncleared Generation Capacity Benefit ($) = Net Annual Summer kW * Summer Generation Uncleared Capacity Value $\$/kW_{@Life}$ * (1 + Capacity Losses)$_{\text{Added at BCR model}}$ * (1 + Summer Wholesale Risk Premium)$_{\text{Added at BCR model}}$ + Net Annual Winter kW * Winter Generation Uncleared Capacity Value $\$/kW_{@Life}$ * (1 + Capacity Losses)$_{\text{Added at BCR model}}$ * (1 + Winter Wholesale Risk Premium)$_{\text{Added at BCR model}}$

AESC 2024 provides avoided electric generation capacity values that are differentiated based on whether a measure is bid into the FCM or not.[14] In this plan, capacity savings from all measures except for those from behavioral programs are assumed to be bid into the FCM.

New for the 2024 AESC study, because of anticipated changes in the ISO-New England's Forward Capacity Market, electric capacity, capacity DRIPE, and reliability avoided costs are split into three categories:

1. "Current capacity market structure," which goes through 2027.
2. "Future capacity market structure - Summer (June through September)," which starts in 2028.
3. "Future capacity market structure - Winter (October through May)," which starts in 2028.

Therefore, in the calculation of electric capacity, capacity DRIPE, and reliability benefits, all benefits accruing before 2028 will use the current capacity market structure avoided costs, and all benefits accruing in 2028 and later will use the seasonally separated summer and winter future capacity market structure avoided costs. The Rhode Island Test calculations include both summer and winter capacity benefits accruing in 2028 and beyond.

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[13] Both of these factors, while inputs in the AESC User Interface selection menu, are not specifically rolled into the User Interface Appendix J outputted avoided electric generation capacity values. Therefore the multipliers, while still consistent with the AESC 2024 defaults, must be applied separately in the benefit-cost model.
[14] Capacity bid into the FCM is known as cleared capacity. Capacity not bid into the FCM is known as uncleared capacity. Uncleared capacity passively reduces system load and subsequently reduces the ISO-NE load forecast and the resulting amount of capacity that is procured through the FCM.

3.4 Electric Transmission Capacity and Distribution Capacity Benefits

Avoided transmission and distribution capacity values are appropriate for inclusion in the RI Test. When transmission and distribution facilities do not have to be built or can be deferred because of lower loads because of consumers' investments in energy efficiency, an avoided resource benefit is created. Electric Pool Transmission Facilities (PTF) capacity benefits are valued in the RI Test based on avoided costs sourced from the AESC 2024 User Inface Counterfactual #3, Appendix B. AESC 2024 estimates the avoided cost for PTF at $81.53/kW-year in 2025 dollars.[15]

Electric non-PTF capacity benefits are valued in the RI Test using avoided non-PTF capacity values calculated in an Excel tool. The tool calculates an annualized value of statewide avoided non-PTF capacity values from company-specific inputs of historic and projected capital expenditures and loads, as well as a carrying charge calculated from applicable tax rates and Federal Energy Regulatory Commission (FERC) Form 1 accounting data. The calculations of the electric non-PTF capacity benefits were updated for the 2026 plan resulting in an avoided non-PTF capacity cost of $38.18/kW-year in 2025 dollars.

Electric distribution capacity benefits are valued in the RI Test using avoided distribution capacity values calculated in an Excel tool. The tool calculates an annualized value of statewide avoided distribution capacity values from company-specific inputs of historic and projected capital expenditures and loads, as well as a carrying charge calculated from applicable tax rates and Federal Energy Regulatory Commission (FERC) Form 1 accounting data. The calculations of the electric distribution capacity benefits were updated for the 2026 plan resulting in an avoided distribution capacity cost of $90.05/kW-year in 2025 dollars.

A capacity loss factor of 8% is applied in the calculation of non-PTF transmission and distribution capacity benefits. 8% is half of the AESC 2024 User Interface default total capacity loss factor of 16% (which accounts for all transmission and distribution losses from the point of delivery into the transmission system to the ultimate customer's facility).

It is forecast in AESC 2024 that ISO-NE's regional system will switch to winter peaking in 2035. There is no analogous information available regarding if or when Rhode Island Energy's non-PTF and distribution systems would similarly switch to winter peaking. Because of the degree of uncertainty, Rhode Island Energy's continued assumption is that non-PTF and distribution capacity values are based on avoiding summer kW. Therefore, the T&D benefits will be exclusively associated with summer demand reduction and the dollar value will be calculated as follows:

- Distribution Benefit ($) = Net Annual Summer kW * Distribution Value $\$/kW_{@Life}$ * (1 + Distribution Losses)$_{\text{Added at BCR model}}$

[15] In the 2024 AESC, PTF transmission avoided costs are separated by summer and winter. Combined, the avoided cost of PTF transmission is always $81.53/kW-year in 2025 dollars.

- PTF Benefit ($) = Net Annual Summer kW * Summer PTF Value $\$/kW_{@Life}$ * (1 + PTF Losses)$_{\text{Added at BCR model}}$ + Net Annual Winter kW * Winter PTF Value $\$/kW_{@Life}$ * (1 + PTF Losses)$_{\text{Added at BCR model}}$
- Non-PTF Benefit ($) = Net Annual Summer kW * Non-PTF Value $\$/kW_{@Life}$ * (1 + Non-PTF Losses)$_{\text{Added at BCR model}}$

3.5 Natural Gas Benefits

Avoided natural gas consumption is appropriate for inclusion in the RI Test. When an energy efficiency project saves natural gas, an avoided resource benefit is created.

Natural gas benefits in the RI Test are valued using avoided natural gas values from AESC 2024, Appendix C. Natural gas avoided costs include commodity costs, pipeline transportation costs, and retail distribution margin costs / delivery charges that would be avoided by fuels not consumed by end users. AESC 2024 presents avoided natural gas value components in end-use categories to match individual program characteristics. The natural gas categories are:

- Commercial and industrial, non-heating/hot water, applied where savings are constant over the year
- Commercial and industrial, heating, applied to heating savings
- Residential heating, applied to heating savings
- Residential water heating/residential non-heating, applied where savings are constant over the year
- All commercial and industrial, applied to behavioral savings, codes and standards, and custom measures
- All residential, applied to behavioral programs

Using each of these end-use value components as appropriate, the dollar value of fuel benefits is calculated as:

- Natural Gas Benefits ($) = Net Annual MMBtu Gas Savings * Gas Value$_{@EndUseCategory}$ $\$/MMBtu_{@Life}$

3.6 Delivered Fuel Benefits

Avoided delivered fuel costs (fuel oil and propane) are appropriate for inclusion in the RI Test. When a project saves delivered fuels, an avoided resource benefit is created.

Fuel benefits in the RI Test are valued using avoided fuel values from AESC 2024, Appendix D. The 2024 AESC Study developed estimates of avoided fuel costs for distillate fuel oil, residual fuel oil, B5 / B20 / B50 biofuels, and propane.

In 2021, the Rhode Island state senate approved an act titled, “Relating to Health and Safety – Biodiesel Products” that dictates “not later than July 1, 2025, all No. 2 distillate heating oil sold in the state shall at a minimum meet the standards for B20 biodiesel blend."[16] Therefore, the Company used the 2024 AESC Study's estimates of avoided fuel costs for B20 biofuels to calculate fuel oil benefits.

Using each of these end-use value components as appropriate, the dollar value of fuel benefits is calculated as:

- Delivered Fuel Benefits ($) = Net Annual MMBtu Delivered Fuel Savings * Delivered Fuel Value $/MMBtu$_{@Life}$

3.7 Water Benefits

Water savings created from energy efficiency projects are appropriate for inclusion in the RI Test. Water savings are valued using average water rates in Rhode Island. While there are no specific water efficiency measures, when an electricity or fuel efficiency project also affects water consumption – for example, a cooling tower project that reduces makeup water needed – a resource benefit is created. Depending on the project and metering configuration, changes in water consumption may also affect sewerage billings.

Water rates were estimated using a weighted average value. Specifically, rates for Providence County[17], Bristol County[18], Newport County[19], Kent County[20], and Washington County[21] were all sourced separately and weighted by population[22].

Residential and commercial rates were sourced and calculated separately. Where applicable, water benefits are counted for all residential and commercial projects and calculated as follows:

- Water Benefits ($) = Net Annual Water Savings * Water Value $/Gallon$_{@Life}$

3.8 Non-Energy Impacts

Other quantifiable non-resource or non-energy impacts may be created as a direct result of energy efficiency efforts and are therefore appropriate for inclusion in the RI Test.

Non-energy impacts are typically associated with the number of measures installed, and less typically with energy savings of the equipment. These impacts may be positive or negative, and they may be one-time

[16] http://webserver.rilin.state.ri.us/BillText21/SenateText21/S0357.pdf
[17] https://www.provwater.com/customers/current-water-rates, effective date 7/1/2021.
[18] https://bcwari.com/current-water-rates-and-fees/, effective date 3/1/2025.
[19] https://www.cityofnewport.com/CityOfNewport/media/City-Hall/Departments/Utilities/Water/Consumer%20Confidence%20Reports/RATE-SCHED2sides-Docket24-30-WW.pdf, effective date 3/1/2025.
[20] https://kentcountywater.org/rates-billing.aspx, effective date 7/1/2021.
[21] https://ripuc.ri.gov/utility-information/water/ri-regulated-water-suppliers-rates-updated-september-3-2020, effective date 9/3/2020.
[22] https://www.rhodeisland-demographics.com/counties_by_population

benefits or annually recurring. The effects of non-energy impacts will be included when they are a direct result of the measure and are quantifiable and avoidable.

The specific values of non-energy impacts used in the 2026 Annual Plan for prescriptive measures are documented in the 2026 RI TRM. Non-energy impacts may include – but are not limited to – labor, material, facility use, health and safety, materials handling, property values, and transportation. For income-eligible measures, non-energy impacts also include the impacts of having lower energy bills to pay, such as reduced arrearages or avoided utility shut off costs. Non-energy impacts for custom Commercial and Industrial measures are not included in program planning and benefit-cost analyses; they are counted on a case-by-case basis when supported by site-specific engineering calculations or other analyses.

The dollar value of non-resource benefits will be calculated as follows (units can be pieces of equipment or energy savings):

- One-time Non-energy impacts ($) = Non-energy impact ($)/unit * Number of units
- Annual Non-energy impacts ($) = Non-energy impact ($)/unit * Number of units * Present Worth Factor$_{@Life}$

3.9 Price Effects

The Demand-Reduction-Induced Price Effect (DRIPE) is the reduction in prices in energy and capacity markets resulting from the reduction in need for energy and capacity due to efficiency. Consumers' investments in energy efficiency lead to structural changes in the market due to lower demand, in addition to avoiding marginal energy production and capital investments. Over time, the market adjusts to lower demand. However, until the market adjustment, reduced demand leads to a reduction in the market price of electricity. This trend is observed in the New England market when ISO-NE activates its price response programs. When this price effect results from consumer investments in energy efficiency, it is appropriate to include the effect in the RI Test.

DRIPE effects are very small when expressed as an impact on market prices, i.e., reductions of a fraction of a percent. However, 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 to large absolute dollar amounts.

DRIPE values developed for energy efficiency installations in 2026 were sourced from the following locations:

- Summer and Winter Electric energy DRIPE: AESC 2024 User Interface Counterfactual #3, Appendix B

- Summer and Winter Electric capacity DRIPE: AESC 2024 User Interface Counterfactual #3, Appendix J
- Gas DRIPE: AESC 2024 User Interface Counterfactual #3, Appendix C
- Oil DRIPE: AESC 2024, Appendix D

The retail avoided DRIPE costs associated with electric measures sourced from the AESC 2024 User Interface Counterfactual #3 workbook include energy losses of 9% and a wholesale risk premium of 8%. These built-in factors are the default values provided in the user interface workbook (see Figure 1). The AESC 2024 User Interface Counterfactual #3 workbook also has a default electric capacity loss value of 16% that does not roll into the Appendix J avoided costs but is later added in the benefit-cost model. The Appendix J electric uncleared capacity avoided costs also require the wholesale risk premium of 8% to be added in the benefit-cost model.

The price effects are expressed as \$/kWh for summer and winter electric energy, \$/kW for summer and winter electric capacity, \$/MMBtu for natural gas, and \$/MMBtu for oil. For all DRIPE categories there are values for intrastate and rest-of-pool DRIPE. For electric energy DRIPE, there are values for all four costing periods and cross-fuel (electric-to-gas-to-electric) effects. There are also cross-fuel (electric-to-gas) effects associated with gas energy DRIPE. The DRIPE benefit is calculated as:

- Summer Peak Energy DRIPE Benefit (\$) = Net Annual kWh * Summer Peak Energy % * Summer Peak DRIPE Value $\$/\text{kWh}_{\text{@Life}}$ * (1 + Energy Losses)$_{\text{Already included in User Interface}}$ * (1 + Summer Wholesale Risk Premium)$_{\text{Already included in User Interface}}$
- Summer Off Peak Energy DRIPE Benefit (\$) = Net Annual kWh * Summer Off Peak Energy % * Summer Off Peak DRIPE Value $\$/\text{kWh}_{\text{@Life}}$ * (1 + Energy Losses)$_{\text{Already included in User Interface}}$ * (1 + Summer Wholesale Risk Premium)$_{\text{Already included in User Interface}}$
- Winter Peak Energy DRIPE Benefit (\$) = Net Annual kWh * Winter Peak Energy % * Winter Peak DRIPE Value $\$/\text{kWh}_{\text{@Life}}$ * (1 + Energy Losses)$_{\text{Already included in User Interface}}$ * (1 + Winter Wholesale Risk Premium)$_{\text{Already included in User Interface}}$
- Winter Off Peak Energy DRIPE Benefit (\$) = Net Annual kWh * Winter Off Peak Energy % * Winter Off Peak DRIPE Value $\$/\text{kWh}_{\text{@Life}}$ * (1 + Energy Losses)$_{\text{Already included in User Interface}}$ * (1 + Winter Wholesale Risk Premium)$_{\text{Already included in User Interface}}$
- Cross-DRIPE (\$) = Net Annual kWh * Electric-Gas-Electric Cross-DRIPE Value $\$/\text{kWh}_{\text{@Life}}$ * (1 + Energy Losses)$_{\text{Already included in User Interface}}$ * (1 + Average of Summer and Winter Wholesale Risk Premiums)$_{\text{Already included in User Interface}}$ + Net Annual MMBtu Gas Savings * Gas-Electric Cross-DRIPE Value $\$/\text{MMBtu}_{\text{@Life}}$
- Cleared Generation Capacity DRIPE Benefit (\$) = Net Annual Summer $\text{kW}_{\text{Summer}}$ * Summer Capacity Cleared DRIPE Value $\$/\text{kW}_{\text{@Life}}$ * (1 + Capacity Losses)$_{\text{Added at BCR model}}$ * + Net Annual Winter kW * Winter Capacity Cleared DRIPE Value $\$/\text{kW}_{\text{@Life}}$ * (1 + Capacity Losses)$_{\text{Added at BCR model}}$
- Uncleared Generation Capacity DRIPE Benefit (\$) = Net Annual Summer $\text{kW}_{\text{Summer}}$ * Summer Capacity Uncleared DRIPE Value $\$/\text{kW}_{\text{@Life}}$ * (1 + Capacity Losses)$_{\text{Added at BCR model}}$ * (1 + Summer

Wholesale Risk Premium)$_{\text{Added at BCR model}}$ + Net Annual Winter kW * Winter Capacity Uncleared DRIPE Value \$/kW$_{\text{@Life}}$ * (1 + Capacity Losses)$_{\text{Added at BCR model}}$ * (1 + Winter Wholesale Risk Premium)$_{\text{Added at BCR model}}$

- Natural Gas DRIPE Benefit (\$) = Net Annual MMBtu Gas Savings * Gas DRIPE Value \$/MMBtu$_{\text{@Life}}$
- Delivered Fuel DRIPE Benefit (\$) = Net Annual MMBtu Delivered Fuel Savings * Delivered Fuel DRIPE Value \$/MMBtu$_{\text{@Life}}$

3.10 Non-embedded Greenhouse Gas Reduction Benefits

In accordance with Section 1.3(C)(iv) of the LCP Standards and the Docket 4600 Benefit-Cost Framework, the RI Test includes the value of non-embedded greenhouse gas (GHG) reductions.[23] These reductions are valued using avoided costs from the AESC 2024 User Interface, Counterfactual #3, Appendix G.

AESC 2024 contains multiple approaches for calculating the non-embedded cost of greenhouse gases.[24] For the 2026 Annual Plan, Rhode Island Energy uses the New England-based marginal abatement cost, derived for the electric sector (electric sector MAC). The electric sector MAC specifically uses the costs of procuring offshore wind to value non-embedded GHG costs. The electric sector MAC was chosen because it is a reasonable and conservative estimate available in AESC 2024 for Rhode Island.[25] Rhode Island Energy is actively involved with the Executive Climate Change Coordinating Council (EC4) process, and in the future could potentially use updated values resulting from EC4.

In AESC 2024, avoided renewable portfolio standard (RPS) compliance costs are rolled into retail electric energy avoided costs as found in the AESC 2024 User Interface Counterfactual #3, Appendix B. As described above, the non-embedded value of GHGs is valued using the costs of procuring offshore wind. To ensure no potential double counting between RPS compliance costs and costs of other activities (such as procuring offshore wind) required to comply with the RI Act on Climate, Rhode Island Energy has netted-out the RPS compliance cost from the full value of non-embedded value GHGs associated with electric measures. The avoided non-embedded GHG costs associated with electric measures sourced from the User Interface Counterfactual #3 workbook also include energy losses of 9%. This embedded factor is the default value provided in the User Interface workbook (see Figure 1).

For reporting of GHG reductions in short tons associated with electric measures (presented in Attachments 5, Table E-6A), annual pounds-per-MWh emissions factors sourced from the AESC 2024 User Interface Counterfactual #3 workbook are scaled by one minus the annual RPS targets detailed in AESC

[23] Rhode Island Energy decided upon the described procedures following discussions with the Rhode Island Energy Efficiency Resources Management Council and the Rhode Island Division of Public Utilities and Carriers.

[24] For more details see Section 8 of the 2024 AESC Study: https://www.synapse-energy.com/sites/default/files/inline-images/AESC%202024%20May%202024.pdf

[25] Other options provided by AESC 2024 are the all-sector MAC (which values non-embedded GHGs at the cost of procuring renewable natural gas), and the social cost of carbon (a damage-based method that estimate future damages caused by GHG emissions).

2024, Tables 79 and 80.[26] Therefore, in 2033 when the Rhode Island RPS target reaches 100%, the avoided short tons of GHGs associated with electric measures reaches 0. This approach is consistent with state policy and avoids overestimating the short tons of GHG reductions associated with energy efficiency.

In summary, in 2033 when the Rhode Island RPS requirement goes to 100%, the monetary value of avoided non-embedded GHGs is non-zero but the number of avoided short tons of GHGs is zero. This is because, in 2033 and subsequent years, energy efficiency avoids activities not reflected in the embedded RPS compliance costs that are required to meet the 2021 Act on Climate. These activities (in this case, valued at the estimated cost of offshore wind) are non-emitting but still come at a non-zero cost.

For reporting of GHG reductions in short tons associated with non-electric measures, the following emissions factors are used (sourced from the AESC 2024 report Table 169[27]):

- Natural Gas emission factor: 0.0585 short tons/MMBtu
- B20 biofuel emission factor 0.0655 short tons/MMBtu
- Propane emission factor: 0.0680 short tons/MMBtu

Non-CO_2 (specifically CH_4 and N_2O) GHGs are factored into non-embedded GHG reduction benefits as a multiplier. The multiplier is calculated by dividing the sum of CO_2, CH_4, and N_2O marginal emissions (non-CO_2 GHG marginal emissions rates are converted to CO_2 equivalents) rates by the CO_2 marginal emissions rate (all marginal emissions rates are sourced from the AESC 2024 User Interface, "NonEmbedded_Calcs" tab).

The non-embedded GHG reduction benefit is calculated by multiplying the kWh and/or MMBtu fuel savings by the respective non-embedded cost of carbon specific to that fuel type and temporal category, if applicable (e.g., summer peak).

- Summer Peak Non-Embedded GHG Benefit ($) = Net Annual kWh * Summer Peak Energy % * Summer Peak Non-Embedded GHG Value $/kWh$_{@Life}$ * (1 + Energy Losses)$_{\text{Already included in User Interface}}$
- Summer Off Peak Non-Embedded GHG Benefit ($) = Net Annual kWh * Summer Off Peak Energy % * Summer Off Peak Non-Embedded GHG Value $/kWh$_{@Life}$ * (1 + Energy Losses)$_{\text{Already included in User Interface}}$
- Winter Peak Non-Embedded GHG Benefit ($) = Net Annual kWh * Winter Peak Energy % * Winter Peak Non-Embedded GHG Value $/kWh$_{@Life}$ * (1 + Energy Losses)$_{\text{Already included in User Interface}}$
- Winter Off Peak Non-Embedded GHG Benefit ($) = Net Annual kWh * Winter Off Peak Energy % * Winter Off Peak Non-Embedded GHG Value $/kWh$_{@Life}$ * (1 + Energy Losses)$_{\text{Already included in User Interface}}$
- Gas Non-Embedded GHG Benefit ($) = Net Annual MMBtu Gas Savings * Gas No-Embedded GHG Value $/MMBtu$_{@Life}$

[26] https://www.synapse-energy.com/sites/default/files/inline-images/AESC%202024%20May%202024.pdf
[27] Ibid.

- Delivered Fuel Non-Embedded GHG Benefits ($) = Net Annual MMBtu Delivered Fuel Savings * Fuel Non-Embedded GHG Value $/MMBtu$_{@Life}$

To quantify the short ton carbon reduction, the relevant emission factors (short tons per MWh or short tons per MMBtu) are multiplied by the relevant annual savings. For the electricity emission factor, the value used reflects an average across the summer/winter peak/off-peak periods.

3.11 Non-embedded Nitrogen Oxides Reductions Benefits

In accordance with Section 1.3(F)(ii) of the LCP Standards and the Docket 4600 Benefit-Cost Framework, the RI Test includes the value of non-embedded Nitrogen Oxide (NOx) reductions.

AESC 2024 does not provide avoided costs for non-embedded NOx. Therefore, for avoided non-embedded NOx costs for electric measures, Rhode Island Energy used the dollars per short ton NOx valuation from AESC 2021, a loss factor of 9% (the AESC 2024 default), and emissions rates sourced from the "2023 ISO New England Electric Generator Air Emissions Report: Appendix" workbook.[28] For avoided non-embedded NOx costs for non-electric measures, Rhode Island Energy used values from the 2021 Avoided Energy Supply Cost Study[29] Counterfactual #3 User Interface workbook.[30]

The non-embedded NOx reduction benefit is calculated by multiplying the kWh and/or MMBtu fuel savings by the respective non-embedded cost of NOx specific to that fuel type and temporal category, if applicable (e.g., summer peak).

- Summer Peak Non-Embedded NOx Benefit ($) = Net Annual kWh * Summer Peak Energy % * Summer Peak Non-Embedded NOx Value $/kWh$_{@Life}$ * (1 + Energy Losses)$_{\text{Already included in User Interface}}$
- Summer Off Peak Non-Embedded NOx Benefit ($) = Net Annual kWh * Summer Off Peak Energy % * Summer Off Peak Non-Embedded NOx Value $/kWh$_{@Life}$ * (1 + Energy Losses)$_{\text{Already included in User Interface}}$
- Winter Peak Non-Embedded NOx Benefit ($) = Net Annual kWh * Winter Peak Energy % * Winter Peak Non-Embedded NOx Value $/kWh$_{@Life}$ * (1 + Energy Losses)$_{\text{Already included in User Interface}}$
- Winter Off Peak Non-Embedded NOx Benefit ($) = Net Annual kWh * Winter Off Peak Energy % * Winter Off Peak Non-Embedded NOx Value $/kWh$_{@Life}$ * (1 + Energy Losses)$_{\text{Already included in User Interface}}$
- Natural Gas Non-Embedded NOx Benefit ($) = Net Annual MMBtu Gas Savings * Gas Non-Embedded NOx Value $/MMBtu$_{@Life}$
- Delivered Fuel Non-Embedded NOx Benefits ($) = Net Annual MMBtu Delivered Fuel Savings * Delivered Fuel Non-Embedded NOx Value $/MMBtu$_{@Life}$

[28] https://www.iso-ne.com/system-planning/system-plans-studies/emissions
[29] https://www.synapse-energy.com/sites/default/files/AESC%202021_20-068.pdf
[30] https://drive.google.com/drive/folders/1Oq2FKvmc0ufRxg56XoZc26z9mghIuG_h

3.12 Value of Improved Reliability

In accordance with the Docket 4600 Benefit-Cost Framework, the RI Test includes the value of improved reliability from energy efficiency investments.

Rhode Island Energy sourced improved reliability values from the AESC 2024 User Interface Counterfactual #3, Appendix J. One input used to calculate the reliability benefit is the value of lost load (VOLL) which is a user input in the 2024 AESC User Interface Counterfactual #3 workbook. As stated in Section 3.1, Rhode Island Energy used $61/kWh which is the default value. Rhode Island Energy applied the cleared reliability value to all summer kW savings (and winter kW savings starting in 2028) associated with cleared measures and the uncleared reliability value to all summer kW savings (and winter kW savings starting in 2028) associated with uncleared measures.

The reliability benefit is calculated as follows with the reliability value in $/kW changing whether a measure is assumed to be cleared or uncleared in the FCM auction.

- Cleared Reliability Value Benefit ($) = Net Annual Summer kW * Summer Reliability Cleared Value $\$/kW_{@Life}$ * $(1 + \text{Capacity Losses})_{\text{Added at BCR model}}$ * + Net Annual Winter kW * Winter Reliability Cleared Value $\$/kW_{@Life}$ * $(1 + \text{Capacity Losses})_{\text{Added at BCR model}}$
- Uncleared Reliability Value Benefit ($) = Net Annual Summer kW * Summer Reliability Uncleared Value $\$/kW_{@Life}$ * $(1 + \text{Capacity Losses})_{\text{Added at BCR model}}$ * $(1 + \text{Summer Wholesale Risk Premium})_{\text{Added at BCR model}}$ + Net Annual Winter kW * Winter Reliability Uncleared Value $\$/kW_{@Life}$ * $(1 + \text{Capacity Losses})_{\text{Added at BCR model}}$ * $(1 + \text{Winter Wholesale Risk Premium})_{\text{Added at BCR model}}$

3.13 Combined Heat and Power Benefits

R.I.Gen.Laws §39-1-27.7(c) (6) (iii) directs the Company to support the development of combined heat and power (CHP). The law requires that the following criteria be factored into the Company's CHP plan: (i) economic development benefits in Rhode Island; (ii) energy and cost savings for customers; (iii) energy supply costs; (iv) greenhouse gas emissions standards and air quality benefits; and (v) system reliability benefits.[31] Energy and cost savings and energy supply costs are captured in the energy benefits described above. The other three listed benefits – economic development, greenhouse gas, and system reliability benefits – are described below and will be applied to eligible CHP projects, should any be proposed.

Economic Development

As provided by the statute, for all CHP projects, net economic development benefits will be counted as Rhode Island Test benefits. The gross state product multipliers for the program in which it is implemented (e.g., C&I retrofit) presented in Figure 2 below will be used to calculate the benefits. The rate of economic

[31] See R.I. Gen.Laws § 39-1-27.7(c) (6) (iii).

development benefit of lifetime gross state product increases per dollar of program investment for CHP projects is based on the report, "Economic Impacts of Rhode Island Energy's 2023 Annual Energy Efficiency Plan" prepared for the Company by the Brattle Group. The multiplier reflects the present value of lifetime state gross domestic product (GDP) effects of program and participant spending that creates jobs in construction and other industries as the project is planned, and equipment is purchased and installed. Therefore, the CHP Economic Development benefits will be calculated as program and participant spending ($) x program multiplier.

Greenhouse gas emissions standards and air quality benefits

For all CHP projects, greenhouse gas mitigation and air quality benefits will be counted as benefits to the extent they are not already captured in the BCR screening values and to the extent that usable emissions data is available. The emissions profile of the CHP site facility prior to the installation of the retrofit (most likely a combination of grid supplied generation for electricity and an on-site boiler for thermal needs) will be compared to the emissions post-retrofit (most likely the CHP unit alone). The change in emissions in tons will be multiplied by a value of $/ton for each pollutant and the values will be summed over all pollutants and counted as a benefit in the benefit/cost calculation. This method is contingent on having emissions data for all pollutants. This information is often difficult to come by; for example, ISO-New England annually publishes emissions per kWh for only SOx, NOx, and CO_2. Similarly, the amount of emissions for all pollutants associated with a particular CHP unit is not always provided. Where locational information is not available, the value of net CO_2 emission reductions and NOx reductions will be calculated consistent with Section 3.9 above.

System Reliability

If a CHP project is proposed in a system reliability target area, the system reliability benefits from deferring a distribution system upgrade would be captured in the System Reliability Procurement report. In the context of CHP located elsewhere in the state, system reliability benefits are the local distribution benefits created by the introduction of the CHP unit in the local area. Notably, CHP projects do not produce the same level of deferred distribution investment savings described in Section (3) above, as traditional energy efficiency.[32] Accordingly, the distribution benefits are modified as follows:

- For CHP systems of less than 1 MW net capacity, the distribution deferral benefit value estimated by the Company based on system wide averages will be multiplied by 0.75 to

[32] With traditional energy efficiency projects, the installed measures permanently reduce load on the electric distribution system and, therefore, reduce the need to make distribution investments. CHP projects may not result in similar deferred distribution investment savings. A CHP unit may not be available at all peak times, and, absent any contractual or mechanical modification to ensure that the load does not reappear, the Company will still need to design and maintain the distribution system for when that unit goes off line during a peak hour on a peak day. This is particularly significant with larger CHP projects, in which a single host customer represents a significant percentage of the total load on a feeder. With multiple smaller units, some level of savings is possible, but these units are still not likely to produce distribution benefits in the same manner as traditional energy efficiency. Of note, for the 2026 Annual Plan, there are no planned CHP units.

incorporate an estimate of the reliability experience of discrete deployment of CHP units compared with end-use reduction efficiency measures which are spread across the state;[33]

- For CHP systems equal to or greater than 1 MW net capacity, the distribution benefit will consider location-specific distribution benefits, as opposed to average system-wide benefits. The results of this analysis will replace the adjusted 0.75 of average system-wide distribution benefit described for CHP projects of less than 1 MW. This may entail a detailed engineering analysis performed by the Company, and additional costs. This consideration will have two parts: 1) identification of foreseeable investments that the CHP installation could potentially help defer, and their value; and 2) whether the unit will be sufficiently reliable, or firmed through the provision of physical assurance by the customer, to enable such savings to be realized;
- For CHP projects of 1 net MW or greater, gas system benefits not paid out as incentives to the Customer via the AGT incentive or gas service contract terms will be counted as benefits.[34]

3.14 Utility Costs

Utility costs incurred to achieve implementation of energy efficiency measures and programs are appropriate for inclusion in the RI Test. These costs have been categorized as follows:

- **Program Planning and Administration (PP&A):** These costs are the administrative costs associated with the utility role in program delivery, including payroll, information technology, contract administration, and overhead expenses.
- **Marketing:** These are the costs of marketing and advertising to promote a program. The costs also include the payroll and expenses to manage marketing.
- **Cost of services and product rebates/incentives provided to customers:** These are the incentives (provided by the program) that customers use to install energy efficient equipment. Incentives include, but are not limited to, rebates to customers, copayments to vendors for direct installation of measures, payments to distributors to buy down the cost of their products for sale in retail stores, payments to vendors to create and deliver information, costs of an education course, or payments to lenders to buy down the interest in a loan. Customer incentives typically cover a portion of the equipment and installation costs directly associated

[33] As explained in footnote 10, *supra*, while multiple small CHP units may produce some level of savings, these units are still not likely to produce distribution benefits in the same manner as traditional energy efficiency. Therefore, the 0.75 factor is adopted as a planning assumption to represent the contingency that, when a single CHP unit on a feeder fails to perform, the load reappears on the system. As more CHP units, particularly smaller units, are deployed in the state, the diversity of operation may allow the adjustment factor to be increased. The Company intends to review this planning assumption based on actual experience for future EE Program Plan filings.

[34] For example, a 3 MW installation with an additional sales volume of approximately 150,000 Dth per year would generate approximately $130,000 of marginal revenue per year under current rates. Assuming $100,000 of capital costs, the project could qualify for up to $573,000 in AGT funding, subject to budget limitations.

with the energy-efficient equipment being installed.[35] For a retrofit project, the customer incentives cover a portion of the full cost of the efficiency project, as it is assumed that the alternative to the project is no customer action. For a failed equipment replacement/renovation/new construction project, these customer incentives cover a portion of the incremental additional costs associated with moving to a higher efficiency item or practice compared to what the customer would have done otherwise.

- **Sales, Technical Assistance, and Training (STAT):** These costs include the training and education of the trade ally community regarding the company's current energy efficiency programs. Examples of trade allies include but are not limited to: equipment vendors, heating contractors, lead vendors, project expediters, weatherization contractors, and equipment installers. These costs also include the tasks associated with internal and contractual delivery of programs. Tasks associated with this budget category include but are not limited to: lead intake, customer service, rebate application, quality assurance, technical assessments, engineering studies, plan reviews, payroll and expenses.
- **Evaluation:** These are the costs of evaluation or market research studies to support program direction and post-installation studies to study program effectiveness or verification of savings estimates. These costs also include the payroll and expenses to manage the research.
- **Performance Incentive:** This is the incentive received by the Company for meeting specified savings goals and/or performance targets (the Company would not implement energy efficiency programs to the extent it does without the incentive). The performance (shareholder) incentive is included in the cost of energy efficiency.

3.15 Customer Costs

Customer costs include the customer's contribution to the installation cost of the efficient measure. Typically, this is the portion of the equipment and installation cost not covered by the customer incentive. As noted above, it excludes the cost of equipment that might be part of the customer's construction project, but that is not related to the energy efficiency portion of the project.

In addition to the direct costs that customers face to purchase energy efficient equipment, they may have additional costs for participating in energy efficiency programs that are not quantified and monetized. For example, a customer participating in a home energy assessment may need to spend some amount of time at home to facilitate the assessment, creating some time cost for the customer to participate. The magnitude and value of these additional potential time costs are currently unknown. They would likely vary by sector, program, and possibly measure and are therefore challenging to estimate reliably.

[35] The full cost of the efficiency project is not necessarily the same as the full cost of the project being undertaken by the customer. For example, a customer may be renovating an HVAC project that includes a newly installed chiller and chilled water distribution system. While the new distribution system may be part of the construction project, if it does not contribute to energy savings, it will not be included in the efficiency project cost; only the incremental cost of the new efficient chiller will be considered.

4. Benefit Cost Calculations

The cost-effectiveness of a measure, program, or portfolio is determined by calculating whether the ratio of the net present value of the benefits to the net present value of the costs is greater than or equal to 1.

For the 2026 Annual Plan, all costs and benefits will be expressed in constant 2026 dollars. The avoided value component for each benefit (e.g., electric energy, capacity, natural gas, etc.) is the cumulative net present value (in 2026 dollars) of lifetime avoided costs for each year of the planning horizon from the base year up to the measure life of the equipment.

As prescribed by the Standards, all values in the 2026 Annual Plan and the benefit-cost model are stated in present value terms "using a discount rate that appropriately reflects the risks of the investment of customer funds in Least-Cost Procurement. Energy efficiency is a low-risk resource in terms of cost of capital risk, project risk, and portfolio risk." For the 2026 Annual Plan, the Company used the same approach used to calculate the discount rate in the 2025 Annual Plan. The approach is to source nominal[36] and real[37] discount rates equal to a twelve-month average of the historic yields from the ten-year United States Treasury note. For the 2026 Annual Plan, the twelve-month period starts on 5/14/2024 and ends on 5/14/2025. The calculations resulted in a nominal discount rate of 4.4% and real discount rate of 2.0% for the 2026 Annual Plan.

The total benefits will equal the sum of the NPV of each benefit component:

- [Energy Benefits + Generation Capacity Benefits + Avoided T&D Benefits + Natural Gas Benefits + Fuel Benefits + Water & Sewer Benefits + Non-Resource Benefits + Price Effects Benefits + Non-embedded Greenhouse Gas Reduction Benefits + Non-embedded NOx Reduction Benefits + Value of Improved Reliability + Economic Development Benefits (where counted; treatment as described above for CHP and below for other measures)]

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

- (Program Planning and Administration + Sales, Training, Technical assistance + Marketing + Rebates and Other Customer Incentives + Evaluation + Shareholder incentive + Customer Cost)

The RI Test benefit cost ratio will then equal:

- Total NPV Benefits / Total NPV Costs

[36] https://home.treasury.gov/resource-center/data-chart-center/interest-rates/TextView?type=daily_treasury_yield_curve&field_tdr_date_value=2024
[37] https://home.treasury.gov/resource-center/data-chart-center/interest-rates/TextView?type=daily_treasury_real_yield_curve&field_tdr_date_value=2024

Per the Standards, on a program level, all benefit categories are included in the benefit/cost calculation. All cost categories, except the shareholder incentive, are included at the program level because they are tracked at that level.[38]

On a sector level, the cost of pilots, demonstrations, assessments, community-based initiatives, sector financing, workforce development, and educational/outreach programs (which are not focused on producing savings), and the projected shareholder incentive, are included with the other costs in the determination of cost-effectiveness. The shareholder incentive is included at this level because it is designed to achieve savings targets by sector. At a portfolio level, the allocations to the Office of Energy Resources, EERMC, and the Rhode Island Infrastructure Bank are also included in the cost-effectiveness calculation.

Separate calculations of benefits and cost-effectiveness are provided for the electric energy efficiency programs and natural gas energy efficiency programs. Some electric energy efficiency programs are expected to produce natural gas savings in addition to electricity savings while some natural gas energy efficiency programs are expected to produce electricity savings in addition to natural gas savings. For example, an electric HVAC project that improves air distribution incentivized through the electric Large C&I Retrofit Program will also produce natural gas savings when natural gas is used by the participant for heating and heat is distributed through the same heating system. All resource benefits produced by a program are shown with that program.

5. Economic Impacts (Non-CHP Measures)

Per the practice first set for the 2022 Plan and with the agreement of stakeholders, economic impacts[39] are presented separately and not included in the estimation of the RI Test ratios. The Rhode Island PUC may consider the estimated value of these economic impacts in their determination of cost-effectiveness under the Least Cost Procurement standards.[40]

The macroeconomic multipliers for the economic growth and job creation benefits of investing in cost-effective energy efficiency are based on the report, “Economic Impacts of Rhode Island Energy’s 2023 Annual Energy Efficiency Plan” prepared for Rhode Island Energy by the Brattle Group in 2023. This study is an update to “Review of RI Test and Proposed Methodology” prepared for the Company by the Brattle Group in 2019. The updated study identified values for other categories of economic impact identified by the Division (i.e., business income, personal income, state income taxes) and gave attention to the

[38] Commitments, if any, of customer incentives made from one year to the next are excluded from the program costs used in the benefit/cost calculation. The costs are only counted in the year in which the incentive is paid and the savings are counted.
[39] This section details the methodology for applying economic benefits to non-CHP measures. Section 3.11 in this document refers to the application of economic benefits to CHP measures.
[40] LCP Standards, Section 3.2(N) states “qualitative benefits and costs may be considered in determining cost-effectiveness.” The exception to this would be for Combined Heat and Power facilities, since the inclusion of economic benefits is required by statute.

question of how double counting of economic benefits in cost-effectiveness testing can be avoided. The presentation of economic impacts in Attachments 5 and 6 includes gross domestic product associated with the proposed investment in energy efficiency in Rhode Island in 2026 using values derived from the Brattle study. The macroeconomic multipliers for job-years associated with proposed investments in energy efficiency are still sourced from the Brattle Group's 2019 report. The Brattle Group's 2023 report did not contain updated job-year multipliers.

The exclusion of economic benefits from cost-effectiveness calculations was motivated by the DPUC, via their consultant Synapse Energy Economics, who conducted a benefit cost analysis and assessment of the treatment of macroeconomic benefits of the RI Community Remote Net Metering (CRNM) program in early 2021.[41] This analysis recommended that, due to the challenges of fully separating all benefit streams within macroeconomic benefits from those already included in other benefit categories counted in the RI Test, the results of an economic impact assessment (EIA) should be shown separately from a BCA and that further discussion of the approach to including economic benefits in the RI Test are warranted to refine the estimation of macroeconomic benefits.

For the 2026 Annual Energy Efficiency Plan, the Company shows RI Test results without economic impacts. Omission of the macroeconomic benefits and other economic impacts lowers benefit cost ratios for all programs and the electric and gas portfolios as a whole. Because this is a conservative approach to addressing potential double counting and likely underestimates cost-effectiveness, the Company submits that the cost-effectiveness of its programs and portfolios is likely greater than what is shown for the RI Test and requests that the Commission take this into consideration when assessing the cost-effectiveness of the Plan.

[41] http://www.ripuc.ri.gov/generalinfo/Synapse-CRNM-Macroeconomic-Report-2021.pdf

Figure 2. Multipliers by Energy Efficiency Program Type

Program Type	GDP / $ Program Spending	Job Years / $M Program Spending
Electric Portfolio		
Residential Programs		
Residential New Construction	1.66	14.8
Residential HVAC	1.45	12.2
EnergyWise Single Family	1.17	12.3
EnergyWise Multifamily	1.97	14.8
Home Energy Reports	2.17	13.6
Residential Consumer Products	1.76	8.5
Income Eligible Single Family	1.67	10.9
Income Eligible Multifamily	2.37	13.4
C&I Programs		
Large C&I New Construction	4.76	19.0
Large C&I Retrofit	2.06	51.4
Small Business Direct Install	1.97	12.3
Gas Portfolio		
Residential Programs		
Residential New Construction	1.19	2.4
Residential HVAC	1.06	6.9
EnergyWise Single Family	0.87	11.9
EnergyWise Multifamily	2.30	16.5
Home Energy Reports	2.77	7.5
Income Eligible Single Family	1.53	12.1
Income Eligible Multifamily	2.31	16.0
C&I Programs		
Large C&I New Construction	5.28	1.2
Large C&I Retrofit	1.92	16.4
Small Business Direct Install	2.50	13.4
C&I Multifamily	3.46	11.0

6. Docket 4600 Benefit Cost Framework

Table 2. Alignment of RI Test to Docket 4600 Framework for 2026 Electric Energy Efficiency Portfolio

Docket 4600
Rhode Island Energy
Summary of 2026 Electric Cost-Effectiveness Framework

(a)	(b)	(c)	(d)	(e)	(f)
Level	**#**	**Mixed Benefit or Cost Category from Original Framework**	**Description of Benefit Versus Costs**	**Value**	**Notes**
Power Sector	1	Energy Supply & Transmission Operating Value of Energy Provided or Saved (Time- & Location-specific LMP)	Benefit: Reduced Energy Costs	$34,092,985	Benefit is monetized using retail avoided costs sourced from AESC 2024, Appendix B (counterfactual #3) and Appendix J (counterfactual #3).
	2	Renewable Energy Credit Cost / Value	Beneft: Reduced REC Costs	See Column (f)	Wholesale cost of RECs is embedded in the retail avoided costs described in row #1.
	3	Retail Supplier Risk Premium	Benefit: Reduced Energy Costs	See Column (f)	Wholesale risk premium is embedded in the retail avoided costs described in row #1.
	4	Forward Commitment: Capacity Value	Benefit: Reduced Generation Capacity Costs	See Column (f)	Forward commitment capacity avoided costs are included in the value on row #1.
	5	Forward Commitment: Avoided Ancillary Services Value	Benefit: Reduced Ancillary Services Costs	See Column (f)	Not applicable.
	6	Utility / Third Party Developer Renewable Energy, Efficiency, or DER costs	Cost: Utility Administration and Measure Costs Cost: Third Party Developer Costs	$67,815,170	Includes "Program Planning and Administration", "Rebates and Other Customer Incentives, "Sales, Technical Assistance, and Training", "Evaluation and Market Research", and the "Performance Incentive".
	7	Electric Transmission Capacity Costs / Value	Benefit: Reduced Transmission Costs	$7,648,808	Includes PTF and Non-PTF transmission benefits. PTF benefit is monetized using retail avoided costs sourced from AESC 2024, Appendix B (counterfactual #3). Non-PTF benefit is monetized using internal Company investment forecasts, FERC Form data, and Rhode Island ISR Plan data.
	8	Electric transmission infrastructure costs for Site Specific Resources	Cost: Increase Transmission Costs	See Column (f)	Currently no location-specific energy efficiency measures. All measures are offered across the service territory.
	9	Net risk benefits to utility system operations (generation, transmission, distribution) from DER flexibility and diversity.	Benefit: Reduced Risk	$24,946	Benefit is monetized using retail avoided costs sourced from AESC 2024, Appendix J (counterfactual #3).
	10	Option value of individual resources	Benefit: Reduced Risk	See Column (f)	Additional research necessary to determine applicability.
	11	Investment under Uncertainty: Real Options Cost / Value	Benefit: Reduced Risk	See Column (f)	Additional research necessary to determine applicability.
	12	Energy Demand Reduction Induced Price Effect	Benefit: Wholesale Market Price Suppression Effect	$22,663,798	Benefit is monetized using retail avoided costs sourced from AESC 2024, Appendix B (counterfactual #3), Appendix C, Appendix D, and Appendix J (counterfactual #3).
	13	Greenhouse gas (GHG) compliance costs	Benefit: Reduced GHG Compliance Costs	See Column (f)	Cost of compliance with GHG regulations is embedded in the retail avoided costs described in row #1.
	14	Criteria air pollutant and other envt'l compliance costs	Benefit: Reduced Environmental Compliance Costs	See Column (f)	Cost of compliance with criteria air pollutant regulations is embedded in the retail avoided costs described in row #1.
	15	Innovation and Learning by Doing	Benefit: Innovation and Market Transformation	See Column (f)	Additional research necessary to determine applicability. Possibly non-zero through pilots, demonstrations, and assessments. Likely of minimal value.
	16	Distribution capacity costs	Benefit: Reduced Distribution Costs Cost: Increased Distributions Costs	$6,259,766	Benefit is monetized using internal Company investment forecasts, FERC Form data, and Rhode Island ISR Plan data.
	17	Distribution delivery costs	Benefit: Reduced Distribution Costs Cost: Increased Distributions Costs	See Column (f)	Additional research necessary to determine applicability.
	18	Distribution system performance	Benefit: Reduced Distribution Costs Cost: Increased Distributions Costs	See Column (f)	Additional research necessary to determine applicability.
	19	Utility low income	Benefit: Utility Non-Energy Benefits	$105,424	Includes "reduced arrearages", "bad debt write-offs", "terminations and reconnections", "notices", "safety related emergency calls", and "customer calls and collections". Embedded in row #22.
	20	Distribution system and customer reliability / resilience impacts	Benefit: Reduced Distribution Costs Cost: Increased Distributions Costs	See Column (f)	See row #9.
	21	Distribution system safety loss/gain	Benefit: Reduced Distribution Costs Cost: Increased Distributions Costs	See Column (f)	Additional research necessary to determine applicability.
Customer	22	Program participant / prosumer benefits / costs	Benefit: Participant Non-Energy Benefits	$19,791,927	Non resource and 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. Includes utility non-energy benefits described in row #19.
			Cost: Participant Measure Costs Cost: Participant Non-Energy Costs	$14,886,754	Participant cost defined as the measure cost not covered by the rebates and other customer incentives described in row #6. Of note, participant cost nets out cost paid by free-riders for energy efficiency measures they would have installed regardless of the Company's programs.
	23	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	Cost: Increased Water and Other Fuel Use Benefit: Reduced Watter and Other Fuel Use	$17,593,493	Gas, Oil, and Propane benefit is monetized using retail avoided costs sourced from AESC 2024, Appendix C and Appendix D. Water benefit is monetized using data from "RI Regulated Water Suppliers – Rates Updated September 3, 2020".
	24	Low-Income Participant Benefits	Benefit: Low-Income Participant Non-Energy Benefits	See Column (f)	Embedded in row #22.
	25	Consumer Empowerment & Choice	Benefit: Customer Empowerment	See Column (f)	Additional research necessary to determine applicability.
	26	Non-participant (equity) rate and bill impacts	Not an input to the cost-effectiveness analysis	See Column (f)	See Attachment 5, Table E-9 and Attachment 6 Table G-9.
Societal	27	Greenhouse gas externality costs	Benefit: Reduced GHG Impacts	$24,406,697	Benefit is monetized using retail avoided costs sourced from AESC 2024, Appendix B (counterfactual #3), and Appendix G (counterfactual #3). Note, non-CO2 GHGs and state policy considerations were applied in the AESC 2024 User Interface.
	28	Criteria air pollutant and other envt'l externality costs	Benefit: Reduced Environmental Impacts (non-GHG)	$1,281,713	NOx benefit is monetized using retail avoided costs sourced from AESC 2021, Appendix B (counterfactual #3). AESC 2024 does not produce NOx avoided costs.
	29	Conservation and community benefits	Benefit: Reduced Environmental Impacts (non-GHG)	See Column (f)	Additional research necessary to determine applicability.
	30	Non-energy costs/benefits: Economic Development	Benefit: Economic Development Impacts	$116,066,189	Presented separate from the cost-effectiveness analysis. Economic benefits are calculated by applying multipliers developed by the Brattle Group in the report "Economic Impacts of Rhode Island Energy's 2023 Annual Energy Efficiency Plan" to program implementation expenses. See Attachment 5, Table E-6 and Attachment 6, Table G-6.
	31	Innovation and knowledge spillover (Related to demonstration projects and other RD&D)	Benefit: Innovation and Market Transformation (included in the Power Sector)	See Column (f)	Additional research necessary to determine applicability. Possibly non-zero through pilots, demonstrations, and assessments. Likely of minimal value.
	32	Societal Low-Income Impacts	Benefit: Societal Low-Income Benefits	See Column (f)	Embedded in row #22.
	33	Public Health	Benefit: Public Health Benefits	See Column (f)	Embedded in row #22.
	34	National Security and US international influence	Benefit: Energy Security Benefits	See Column (f)	Embedded in row #22.

Notes:
1) Columns (a), (c), and (d) sourced from "The Rhode Island Cost-Effectiveness Framework, Methodologies for Developing Inputs for Distributed Energy Resources", Page 6, Table 1.

Table 3. Alignment of RI Test to Docket 4600 Framework for 2026 Natural Gas Energy Efficiency Portfolio

Docket 4600
Rhode Island Energy
Summary of 2026 Gas Cost-Effectiveness Framework

(a)	(b)	(c)	(d)	(e)	(f)
Level	**#**	**Mixed Benefit or Cost Category from Original Framework**	**Description of Benefit Versus Costs**	**Value**	**Notes**
Power Sector	1	Energy Supply & Transmission Operating Value of Energy Provided or Saved (Time- & Location-specific LMP)	Benefit: Reduced Energy Costs	$308,009	Benefit is monetized using retail avoided costs sourced from AESC 2024, Appendix B (counterfactual #3) and Appendix J (counterfactual #3).
	2	Renewable Energy Credit Cost / Value	Beneft: Reduced REC Costs	See Column (f)	Wholesale cost of RECs is embedded in the retail avoided costs described in row #1.
	3	Retail Supplier Risk Premium	Benefit: Reduced Energy Costs	See Column (f)	Wholesale risk premium is embedded in the retail avoided costs described in row #1.
	4	Forward Commitment: Capacity Value	Benefit: Reduced Generation Capacity Costs	See Column (f)	Forward commitment capacity avoided costs are included in the value on row #1.
	5	Forward Commitment: Avoided Ancillary Services Value	Benefit: Reduced Ancillary Services Costs	See Column (f)	Not applicable.
	6	Utility / Third Party Developer Renewable Energy, Efficiency, or DER costs	Cost: Utility Administration and Measure Costs Cost: Third Party Developer Costs	$31,816,676	Includes "Program Planning and Administration", "Rebates and Other Customer Incentives, "Sales, Technical Assistance, and Training", "Evaluation and Market Research", and the "Performance Incentive".
	7	Electric Transmission Capacity Costs / Value	Benefit: Reduced Transmission Costs	$98,085	Includes PTF and Non-PTF transmission benefits. PTF benefit is monetized using retail avoided costs sourced from AESC 2024, Appendix B (counterfactual #3). Non-PTF benefit is monetized using internal Company investment forecasts, FERC Form data, and Rhode Island ISR Plan data.
	8	Electric transmission infrastructure costs for Site Specific Resources	Cost: Increase Transmission Costs	See Column (f)	Currently no location-specific energy efficiency measures. All measures are offered across the service territory.
	9	Net risk benefits to utility system operations (generation, transmission, distribution) from DER flexibility and diversity.	Benefit: Reduced Risk	$288	Benefit is monetized using retail avoided costs sourced from AESC 2024, Appendix J (counterfactual #3).
	10	Option value of individual resources	Benefit: Reduced Risk	See Column (f)	Additional research necessary to determine applicability.
	11	Investment under Uncertainty: Real Options Cost / Value	Benefit: Reduced Risk	See Column (f)	Additional research necessary to determine applicability.
	12	Energy Demand Reduction Induced Price Effect	Benefit: Wholesale Market Price Suppression Effect	$8,269,101	Benefit is monetized using retail avoided costs sourced from AESC 2024, Appendix B (counterfactual #3), Appendix C, Appendix D, and Appendix J (counterfactual #3).
	13	Greenhouse gas (GHG) compliance costs	Benefit: Reduced GHG Compliance Costs	See Column (f)	Cost of compliance with GHG regulations is embedded in the retail avoided costs described in row #1.
	14	Criteria air pollutant and other envt'l compliance costs	Benefit: Reduced Environmental Compliance Costs	See Column (f)	Cost of compliance with criteria air pollutant regulations is embedded in the retail avoided costs described in row #1.
	15	Innovation and Learning by Doing	Benefit: Innovation and Market Transformation	See Column (f)	Additional research necessary to determine applicability. Possibly non-zero through pilots, demonstrations, and assessments. Likely of minimal value.
	16	Distribution capacity costs	Benefit: Reduced Distribution Costs Cost: Increased Distributions Costs	$98,484	Benefit is monetized using internal Company investment forecasts, FERC Form data, and Rhode Island ISR Plan data.
	17	Distribution delivery costs	Benefit: Reduced Distribution Costs Cost: Increased Distributions Costs	See Column (f)	Additional research necessary to determine applicability.
	18	Distribution system performance	Benefit: Reduced Distribution Costs Cost: Increased Distributions Costs	See Column (f)	Additional research necessary to determine applicability.
	19	Utility low income	Benefit: Utility Non-Energy Benefits	$42,243	Includes "reduced arrearages", "bad debt write-offs", "terminations and reconnections", "notices", "safety related emergency calls", and "customer calls and collections". Embedded in row #22.
	20	Distribution system and customer reliability / resilience impacts	Benefit: Reduced Distribution Costs Cost: Increased Distributions Costs	See Column (f)	See row #9.
	21	Distribution system safety loss/gain	Benefit: Reduced Distribution Costs Cost: Increased Distributions Costs	See Column (f)	Additional research necessary to determine applicability.
Customer	22	Program participant / prosumer benefits / costs	Benefit: Participant Non-Energy Benefits	$13,380,472	Non resource and 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. Includes utility non-energy benefits described in row #19.
			Cost: Participant Measure Costs Cost: Participant Non-Energy Costs	$5,261,420	Participant cost defined as the measure cost not covered by the rebates and other customer incentives described in row #6. Of note, participant cost nets out cost paid by free-riders for energy efficiency measures they would have installed regardless of the Company's programs.
	23	Participant non-energy costs/benefits: Oil, Gas, Water, Waste Water	Cost: Increased Water and Other Fuel Use Benefit: Reduced Watter and Other Fuel Use	$22,605,325	Gas, Oil, and Propane benefit is monetized using retail avoided costs sourced from AESC 2024, Appendix C and Appendix D. Water benefit is monetized using data from "RI Regulated Water Suppliers – Rates Updated September 3, 2020".
	24	Low-Income Participant Benefits	Benefit: Low-Income Participant Non-Energy Benefits	See Column (f)	Embedded in row #22.
	25	Consumer Empowerment & Choice	Benefit: Customer Empowerment	See Column (f)	Additional research necessary to determine applicability.
	26	Non-participant (equity) rate and bill impacts	Not an input to the cost-effectiveness analysis	See Column (f)	See Attachment 5, Table E-9 and Attachment 6 Table G-9.
Societal	27	Greenhouse gas externality costs	Benefit: Reduced GHG Impacts	$30,627,994	Benefit is monetized using retail avoided costs sourced from AESC 2024, Appendix B (counterfactual #3), and Appendix G (counterfactual #3). Note, non-CO2 GHGs and state policy considerations were applied in the AESC 2024 User Interface.
	28	Criteria air pollutant and other envt'l externality costs	Benefit: Reduced Environmental Impacts (non-GHG)	$1,983,102	NOx benefit is monetized using retail avoided costs sourced from AESC 2021, Appendix B (counterfactual #3). AESC 2024 does not produce NOx avoided costs.
	29	Conservation and community benefits	Benefit: Reduced Environmental Impacts (non-GHG)	See Column (f)	Additional research necessary to determine applicability.
	30	Non-energy costs/benefits: Economic Development	Benefit: Economic Development Impacts	$44,093,443	Presented separate from the cost-effectiveness analysis. Economic benefits are calculated by applying multipliers developed by the Brattle Group in the report "Economic Impacts of Rhode Island Energy's 2023 Annual Energy Efficiency Plan" to program implementation expenses. See Attachment 5, Table E-6 and Attachment 6, Table G-6.
	31	Innovation and knowledge spillover (Related to demonstration projects and other RD&D)	Benefit: Innovation and Market Transformation (included in the Power Sector)	See Column (f)	Additional research necessary to determine applicability. Possibly non-zero through pilots, demonstrations, and assessments. Likely of minimal value.
	32	Societal Low-Income Impacts	Benefit: Societal Low-Income Benefits	See Column (f)	Embedded in row #22.
	33	Public Health	Benefit: Public Health Benefits	See Column (f)	Embedded in row #22.
	34	National Security and US international influence	Benefit: Energy Security Benefits	See Column (f)	Embedded in row #22.

Notes:
1) Columns (a), (c), and (d) sourced from "The Rhode Island Cost-Effectiveness Framework, Methodologies for Developing Inputs for Distributed Energy Resources", Page 6, Table 1.