Rhode Island Energy Efficiency Market Potential Study (Volume II: Appendices)

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STATE OF RHODE ISLAND
ENERGY EFFICIENCY & RESOURCE MANAGEMENT COUNCIL

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Preface

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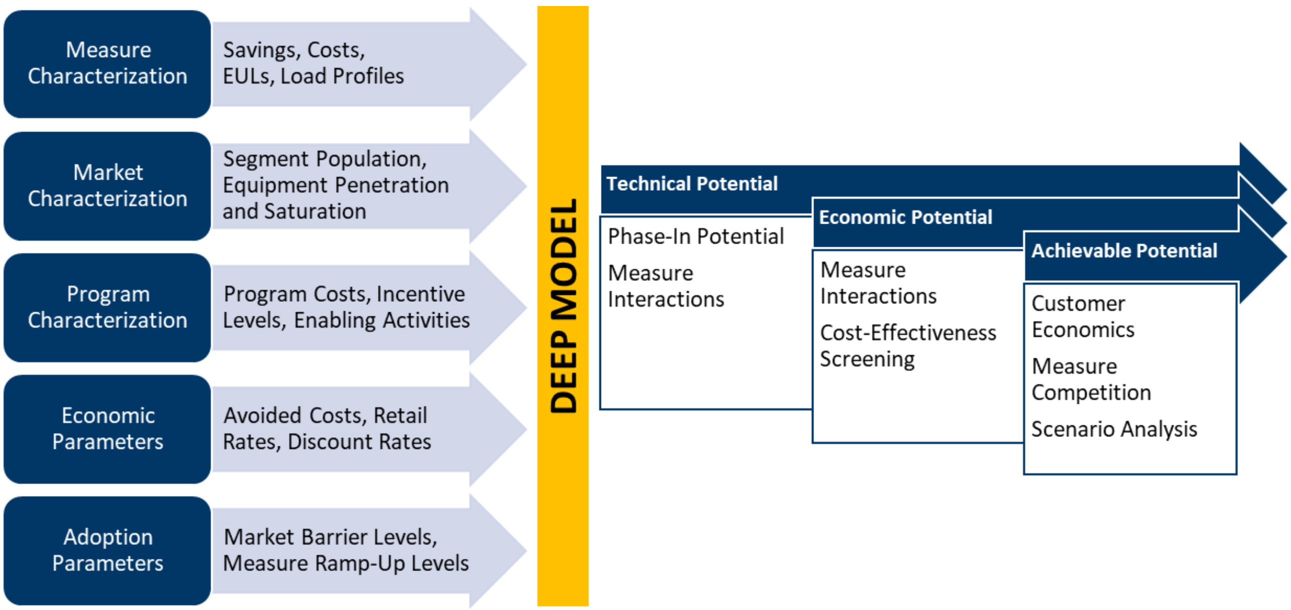
A. Energy Efficiency Methodology

A.1 Overview

The market potential for energy efficiency was estimated using the Dunsky Energy Efficiency Potential (DEEP) model. DEEP employs a multi-step process to develop a bottom-up assessment of the technical, economic and achievable potentials. This appendix describes DEEP's modeling approach, the process of developing DEEP model inputs and the underlying calculations employed to assess energy efficiency potential.



A.2 The Dunsky Energy Efficiency Potential Model

DEEP's bottom-up modelling approach assesses thousands of "measure-market" combinations, applying program impacts (e.g. incentives and barrier reducing enabling activities) to assess energy savings potentials across multiple scenarios. Rather than estimating potentials based on the portion of each end-use that can be reduced by energy saving measures and strategies (often referred to as a "top-down" analysis), the DEEP's approach applies a highly granular calculation methodology to assess the energy savings opportunity for each measure-market segment opportunity in each year. Key features of this assessment include:

- **Measure-Market Combinations:** Energy saving measures are applied on a segment-by-segment basis using segment-specific equipment saturations, utility customer counts, and demographic data to create unique segment-specific "markets" for each individual measure. The measure's impact and market size are unique for each measure-market segment combination, which increases the accuracy of the results.

- Phase-In Potential: DEEP assesses the phase-in technical, economic, and achievable potential by applying a measure's expected useful life (EUL) and market growth factors to determine the number of energy savings opportunities for each measure-market combination each year. This provides an important time series for each energy savings measure upon which estimated annual achievable program volumes (measure counts and savings) can be calculated in the model, as well as phase-in technical and economic potentials.

- Annual and Cumulative Savings: For each measure-market combination in each year, DEEP calculates the annual and cumulative savings accounting for mid-life baseline adjustments and program re-participation where appropriate.[1] This provides a read on the cumulative savings (above and beyond natural uptake), as well as the annual savings that will pass through DSM portfolios.

Key Limitations

The key limitations for estimating energy efficiency potential in this study are the availability of market data and the complexity of estimating costs and benefits under the RI Test.

The ability to forecast results is connected to the availability of market data and past market behavior. Where this data is not available, secondary sources and professional judgement must be employed. As discussed in more detail in Appendix F, this study utilizes Rhode Island specific information wherever possible, but in many cases alternative data sources were used to fill data gaps.

The RI Test incorporates many different avoided cost streams for efficiency measures. Some of these avoided cost streams are specific and unique to the measure installation year (e.g. reliability avoided costs). The DEEP model uses a single stream of avoided costs and does not create avoided cost streams according to install year. For this reason, special treatment of installation year specific avoided costs was required to convert them into a single value stream as described in Appendix F. This approach loses some of the granularity in estimating measure costs and benefits inherent within the RI Test.

A.3 DEEP Model Inputs

DEEP requires an extensive set of model inputs related to energy savings measures, markets, economic factors, and adoption parameters to accurately assess energy efficiency potential. These inputs are developed through several concurrent processes that include measure characterization, market characterization, program characterization, economic parameter development and adoption parameter development. The remainder of this section outlines each process.

[1] Mid-life baseline adjustments are required for early retirement measures after the useful life of the existing equipment expires and new equipment (at a more efficient baseline) would have been purchased. Program re-participation occurs when a customer may receive an incentive for a new efficient measure to replace an efficient measure previously received through the program at the end of its life, which results in *program* savings but no additional *cumulative* savings.

A.3.1 Measure Characterization

Measure characterization is the process of determining the costs, savings, and lifetimes of potential energy-saving technologies and services and their baseline equivalents that will then be used as inputs to the DEEP model. The measure characterization process begins by developing a comprehensive list of energy saving measures.

In this study, an initial measure list was proposed based on the full range of existing measures in National Grid's Energy Efficiency programs as well as a number of emerging opportunities. Measures were limited to currently commercially viable options, and those that may become commercially viable over the study period (based on Dunsky's professional experience). In some cases, Dunsky excluded measures that were highly unlikely to pass RI's Cost-Effectiveness Test in the study period due to relatively low savings and/or high incremental costs or measures that have extremely low market penetration due to existing baselines. The measure list was vetted and approved by the Market Potential Study Management Team (MPSMT) and National Grid and finalized prior to measure characterization. The final measure list represents more than 2,200 measure-market combinations, representing the full range of commercially available technologies (current and emerging). Appendix F provides the full measure list.

Measure characterization is accomplished by compiling primary and secondary data (as available) on the efficient and baseline (e.g. non-efficient) energy-consuming equipment available in a given jurisdiction. Measures are characterized using segment-specific inputs when available yielding segment specific characterizations for each measure-market combination.

Measures are characterized in terms of their **market unit** such as savings per widget, savings per square foot, or savings per ton of cooling capacity. Each measure in the measure list was characterized by defining a range of specific parameters. Table A-1 describes these parameters.

Table A-1. DEEP Measure Characterization Parameters

Parameter	Description
Market unit	The unit in which the measure is characterized and applied to the market (e.g. per widget, per building, per square foot, etc.)
Measure type	The measure type, which can be at least one of the following: • Replace on Burnout • Early Replacement • Additional Measures • New Construction/Installation
Annual gross savings	The annual gross savings of the measure per market unit in terms of both energy (e.g. kWh, MMBtu), demand (e.g. kW) and other factors (e.g. water) as applicable
Measure costs	The incremental cost of the measure (e.g. the difference in cost between the baseline technology and the efficient technology)
Measure life	The effective useful life (EUL) and/or remaining useful life (RUL) of both the efficient measure and the baseline technology
Impact factors	Any factors affecting the attribution of gross savings including net-to-gross adjustments, in-service factors, persistence factors and realization rates.
Load factors	Any factors affecting modulating gross savings including summer and winter peak coincidence factors as well as seasonal savings distributions.
Program allocation	The program(s) to which the measure applies – in some instances, measures will be allocated to multiple programs on a pro-rated basis if the measure is offered through multiple programs

This study characterized measures using inputs from National Grid's Rhode Island Technical Resource Manual (TRM) when supporting entries were present and deemed applicable to the study. In cases where RI TRM entries were not available, judged to be less accurate than alternative approaches, or did not account for segment by segment variations, measures were characterized using other best in class TRMs from other jurisdictions. See Appendix F for the complete measure list and accompanying TRM sources used in this study.

Measure Types

DEEP incorporates four types of measures – replace on burnout, early replacement, addition, and new construction/installation. DEEP treats each of these measure types differently in determining the maximum annual market available for phase-in potential. Table A-2 provides a guide as to how each measure type is defined and how the replacement or installation schedule is applied within the study to assess the phase-in potentials each year.

Table A-2. DEEP Measure Type Descriptions

Measure Type	Description	Yearly Units Calculation
Replace on Burnout (ROB)	An existing unit is replaced by an efficient unit after the existing unit fails. *Example: Replacing burned out bulbs with LEDs*	The eligible market is the number of existing units divided by EUL.[2]
Early Replacement (ER)[3]	An existing unit is replaced by an efficient unit before the existing unit fails. These measures are generally limited to measures where savings are sufficient enough to motivate a customer to replace existing equipment earlier than its expected lifespan. *Example: Replacing a functional, but inefficient, furnace*	The eligible market is assumed to be a subset of the number of existing units based on a function of the equipment's EUL and remaining useful life (RUL)
Addition (ADD)	A measure is applied to existing equipment or structures and treated as a discretionary decision that can be implemented at any moment in time. *Example: Adding controls to existing lighting systems, adding insulation to existing buildings*	The eligible market is distributed over the estimated useful life of the measure using an S-curve function.
New Construction/ Installation (NEW)	A measure that is not related to existing equipment. *Example: Installing a heat-pump in a newly constructed building.*	The eligible market is measure-specific and defined as new units per year.

In this study, only a small number of measures were characterized as early replacement measures. In general, early replacement measures are limited to those where energy savings are sufficient to motivate a customer to replace existing equipment significantly before the end of its expected useful life. This is generally limited to measures with long EULs and a large difference between existing installed efficiency and baseline efficiencies for new equipment (e.g. furnaces and boilers) as the early replacement of these measures will create significant additional savings through the early retirement of particularly inefficient equipment. While current National Grid programs may incentivize customers to replace equipment before it actually ceases to function or maintenance costs become excessive, the exclusion of these measures in the model will not impact overall savings estimates as the model is calibrated to the savings currently procured by existing programs.

A.3.2 Market Characterization

Market characterization is the process of defining the size of the **market** available for each characterized measure. Primary and secondary data are compiled to establish a **market multiplier**, which is an assessment of the market baseline that details the current penetration (e.g. the number of lightbulbs) of energy-using equipment and saturation of energy efficiency equipment (e.g. the percentage of lightbulbs that are LEDs) in each market sector and segment. The market multiplier is applied to each market segment's **population** to establish each measure's market. The market multiplier can be understood as the

[2] The EUL is set at a minimum of 3 years to spread installations over the potential study period. Note: Home Energy Reports are a special case with an EUL of one year.

[3] Early replacement measures are limited to measures where energy savings are sufficient enough to motivate a customer to replace existing equipment prior to the end of its expected lifespan.

average number of opportunities per customer within the market segment in terms of the measure's market unit.

This study characterized markets by leveraging anonymized National Grid customer data and Rhode Island specific baseline data. Residential baseline information was taken from the draft National Grid Rhode Island Residential Appliance Saturation Survey (Study RI2311) and accompanying Excel workbook dated October 20, 2018. Commercial and industrial baseline data was derived from preliminary data provided by National Grid as part of the Rhode Island C&I Market Characterization Data Collection Study on December 5, 2019. When Rhode Island specific baseline data was not available (or was based on a low number of observations), baseline data from neighboring jurisdictions in the Northeast United States were leveraged and adjusted for Rhode Island specific attributes wherever possible.

A.3.3 Program Characterization

Program characterization is the process of estimating the average administrative program costs in terms of fixed and variable costs, incentive levels, and enabling activity impacts of existing efficiency programs. Inputs generated through the program characterization process include:

- Fixed costs are the portion of non-incentive administrative costs that are independent of the amount of savings attributable to the program.
- Variable costs are the portion of non-incentive administrative costs that change in magnitude with the amount of savings attributable to the program.
- Incentives are the portion of the measure's incremental costs that are covered by the program. Incentive levels vary by program scenario.
- Enabling activities are strategies employed by programs to reduce market barriers (e.g. effective marketing and delivery processes, contractor training, etc.). For details on the enabling strategies considered in this study please refer to Appendix F.

This study characterized programs through an extensive review of National Grid's 2020 Energy Efficiency Plan and conversations with National Grid's program specialists to develop initial estimates of program costs, incentives, and enabling activities. To adhere to the RI Benefit-Cost Test, program characterization also included characterizing economic benefit multipliers for each program based on Attachment 4 of the 2020 Energy Efficiency Plan.[4] The initial program characterization was reviewed by National Grid and the

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[4] Economic Benefit Multipliers are the net-incremental benefits of Rhode Island's energy efficiency programs beyond what is already claimed in the RI Benefit-Cost Test.

MPSMT and subsequent updates were made. Appendix F provides more information on the specific inputs resulting from program characterization.

A.3.4 Economic Parameter Development

DEEP harnesses key economic parameters such as avoided costs, retail energy rates, and discount rates to assess measure cost-effectiveness and customer adoption. Appendix F outlines the development of these inputs, which were used across all modules of this study.

A.3.5 Adoption Parameter Development

DEEP requires several key inputs to determine achievable measure adoption including market barrier levels and measure ramp-up levels.

- **Market barrier levels** define maximum adoption rates and are assigned for each measure-market combination based on market research and professional experience. Different end-uses and segments exhibit different barriers. Barrier levels may change over time if market transformation effects are anticipated.

- **Measure ramp-up levels** modify the initial uptake of measures not offered by existing programs and/or offered at lower levels than expected given the market context to account for ramping up new programs and measure marketing. In this study, measures that represent significant savings and are not currently offered by existing programs have ramp rates of 33%, 66%, and 100% applied in the first three years of the study, respectively. For measures that are currently offered but at levels lower than expected, ramp rates of 50%, 75%, 100% were applied in the first three years, respectively.

A.4 Assess Potential

Using the comprehensive set of model inputs, DEEP assesses three levels of energy savings potential: technical, economic, and achievable. In each case, these levels are defined based on the governing regulations and practice in the modeled jurisdiction, such as applying the appropriate cost-effectiveness tests, and applying the relevant benefit streams and net-to-gross (NTG) ratios to ensure consistency with evaluated past program performance. Table A-3 provides a summary of how DEEP treats each potential type.

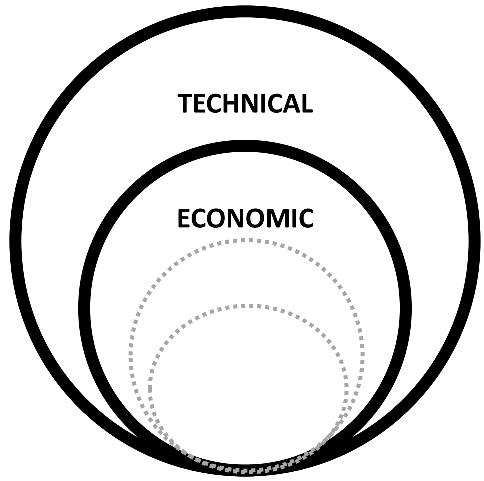
Table A-3. DEEP Treatment of Technical, Economic, and Achievable Potential

APPLIED CALCULATION	TECHNICAL POTENTIAL	ECONOMIC POTENTIAL	ACHIEVABLE POTENTIAL
1. ECONOMIC SCREENING	No Screen	Cost-Effectiveness (RI Benefit- Cost Test)	Cost-Effectiveness (RI Benefit-Cost Test and Participant Cost Test [PCT])
2. MARKET BARRIERS	No Barriers (100% Inclusion)	No Barriers (100% Inclusion)	Market Barriers (Adoption Curves)
3. COMPETING MEASURES	Winner takes all	Winner takes all	Competition Groups Applied
4. MEASURES INTERACTIONS	Chaining Adjustment	Chaining Adjustment	Chaining Adjustment
5. NET SAVINGS	Not Considered	Not Considered	Program Net-to-Gross Ratios (NTGR)

For each level of potential, DEEP calculates annual and cumulative potential:

- **Annual potential** is the incremental savings attributable to program activities in the study year. It includes re-participation in programs (e.g. when a customer may receive an incentive for a new LED lightbulb to replace a burnt-out LED lightbulb previously received through the program). DEEP expresses annual potential both in terms of incremental lifetime savings and incremental annual savings. This is the most appropriate measure for annual program planning and budgeting.
- **Cumulative potential** is the total savings attributable to program activities from the beginning of the study period to the relevant study year. It accounts for mid-life baseline adjustments to measures implemented in previous years, as well as the retirement of savings for measures reaching their end of life. As such it does not include new savings for re-participation in programs, thereby providing an assessment of the cumulative impact of the measure/program (e.g. the reduction in energy sales). This is the most appropriate measure for resource planning.

A.4.1 Technical and Economic Potential



Technical potential is all theoretically possible energy savings stemming from the applied measures. Technical potential is assessed by combining measure and market characterizations to determine the maximum amount of savings possible for each measure-market combination without any constraints such as cost-effectiveness screening, market barriers, or customer economics. This excludes early replacement and retirement opportunities, which are to be addressed in the subsequent achievable potential analysis. Technical potential is calculated for each year in the study period.

DEEP's calculation of technical potential accounts for markets where multiple measures compete. In these instances, the measure procuring the greatest energy savings is selected while all other measures are excluded to avoid double counting energy savings while maximizing overall technical energy savings (see description of measure competition below for additional detail).

Additionally, the calculation of technical potential also accounts for measures that interact and impact the savings potential of other measures (see description of measure interactions below for additional detail).

Mid-Life Baseline Adjustments

Where a new standard may alter the baseline of a measure before the end of its EUL, the model removes a portion of the savings for previously installed measures from the cumulative savings for that measure. The amount removed is equivalent to the difference between the baselines, which may represent all or just a portion of the previously installed measure's cumulative savings.

Economic potential is a subset of technical potential that only includes measures that pass cost-effectiveness screening. Economic screening is performed at the measure level and only includes costs related to the measure. All benefits and costs applied in the cost-effectiveness screening are multiplied by their corresponding cumulative discounted avoided costs to derive a present value ($) of lifetime benefits. All benefits and costs are adjusted to real dollars expressed in the first year of the study. Economic screening does not include general program costs. Like technical potential, the calculation of economic potential also accounts for measure competition and interaction.

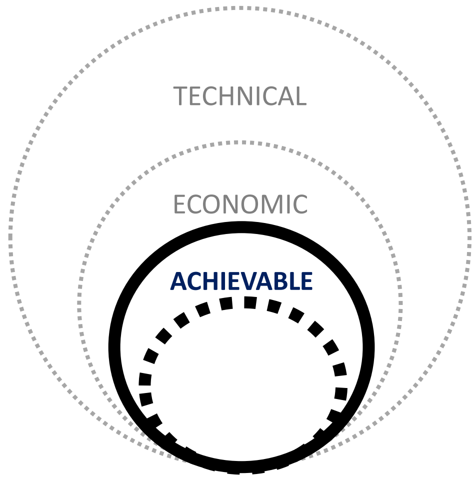
This study screened measures based on Rhode Island's societal benefit-cost framework ("RI Test") – a modified version of the Total Resource Cost test – as described in National Grid's 2020 Energy Efficiency Program Plan filing.[5] According to the filing, the RI benefit-cost test "compares the present value of a stream of net benefits associated with the net savings of an energy efficiency measure or program over

[5] For a full description of the RI Test, please see the Attachment 4 - 2020 Rhode Island Test Description as filed with National Grid's 2020 EEPP (Docket No. 4979) accessible at: http://www.ripuc.ri.gov/eventsactions/docket/4979-NGrid-EEPP2020%20(10-15-19).pdf

the life of that measure or program to the total costs necessary to implement the measure or program." The RI benefit-cost test consists of multiple benefit and cost streams, which were treated and aggregated for use in the DEEP model. The description of these inputs can be found in Appendix F. Measures that had a benefit-cost ratio below 0.75 were excluded from economic potential, while overall program and portfolio benefit cost ratios were held above 1. The 0.75 measure threshold was chosen to ensure measures were not erroneously excluded due to inherent uncertainties in model calculations, while the program and portfolio threshold was chosen to ensure overall cost-effectiveness at a higher scale.

A.4.2 Achievable Potential and Scenario Modeling

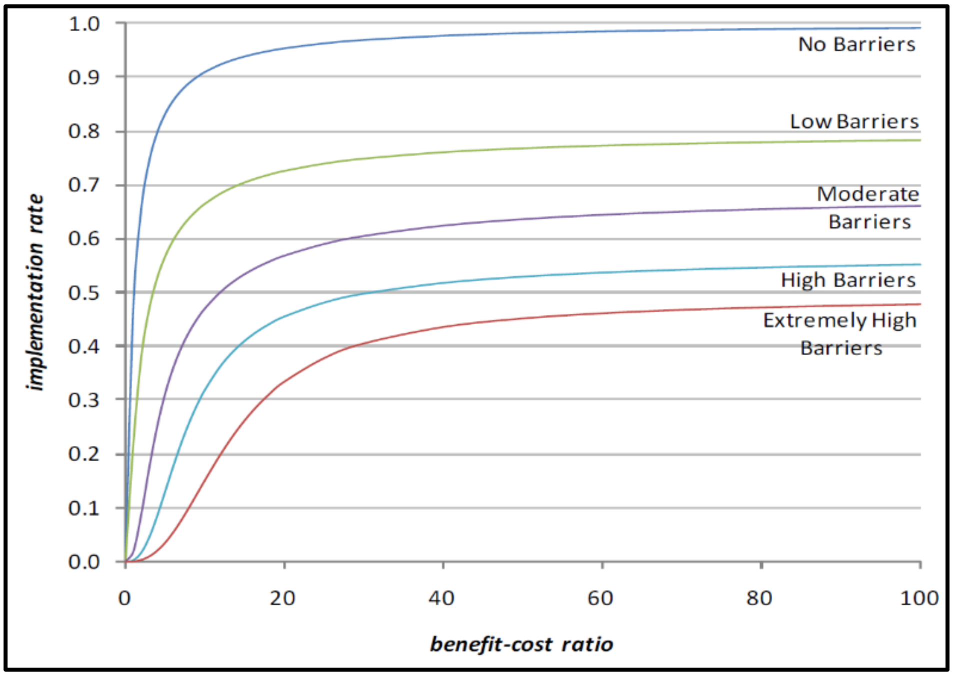
Achievable potential is the energy savings stemming from the customer adoption of energy-savings measures. Rooted in the United States' Department of Energy (U.S. DOE) adoption curves,[6] DEEP defines annual adoption rates based on a combination of customer cost-effectiveness and market barrier levels. Customer cost-effectiveness is calculated within the model based on inputs from measure and program characterization as well as economic and adoption parameters. Figure A-1 presents a representative example of the resulting adoption curves.



While this methodology is rooted in the U.S. DOE's extensive work on adoption curves, it applies two important refinements as described below:

[6] The USDOE uses this model in several regulatory impact analyses. An example can be found in http://www.regulations.gov/contentStreamer?objectId=090000648106c003&disposition=attachment&contentType=pdf, section 17-A.4.

Figure A-1. Representative Example of Adoption Curves



Refinement #1: Choice of the cost-benefit criteria. The DOE model assumes that participants make their decisions based on a benefit-cost ratio calculated using discounted values. While this may be true for a select number of large, more sophisticated customers, experience shows that most consumers use simpler estimates, including simple payback periods. This has implications for the choice and adoption of measures, since payback period ignores the time value of money as well as savings after the break-even point. The model converts DOE's discount rate-driven curves to equivalent curves for payback periods and applies simple and discounted payback periods based on sector. Generally, DEEP assumes residential customers assess cost-effectiveness by considering a measure's simple payback period, while commercial customers assess cost-effectiveness by considering a discounted payback period.

Refinement #2: Ramp-up. Two key factors – measure awareness and program delivery structure – can limit program participation, especially during the first few years after a program's launch or redesign and result in lower participation than DOE's achievable rates would suggest. For example, a new home retrofit program that requires the enrollment and training of skilled auditors and contractors by program vendors could take some time to achieve the uptake assumed using DOE's curves. As described under adoption parameter development, this study adjusts adoption rates on a case-by-base basis where appropriate.

Scenario Modeling

Multiple levels of achievable potential are modeled within DEEP by applying varying incentive and market barrier levels, which impact the degree of customer adoption. Additional details on parameters for each scenario can be found in Appendix F.

Varying levels of achievable adoption will also impact program spending by modulating incentive payments and variable program costs. As part of program characterization, variable program costs may be adjusted between scenarios to account for increased program expenses for providing additional enabling activities above current program levels.

It is important to note that program cost estimates are based on historical budgets and DEEP does not consider dynamic impacts on program budgets resulting from internal (to the program) and external factors impacting program and incremental costs. For example, the variable cost of delivering programs may decline overtime as program learnings are applied to future administrative and delivery practices within a program or incentive costs may decline if incremental costs decline over time. Likewise, program costs may increase if factors lead to increasing measure costs, for example, the lack of enough contractors to deploy high adoption measures leading to an increase in overall labor costs.

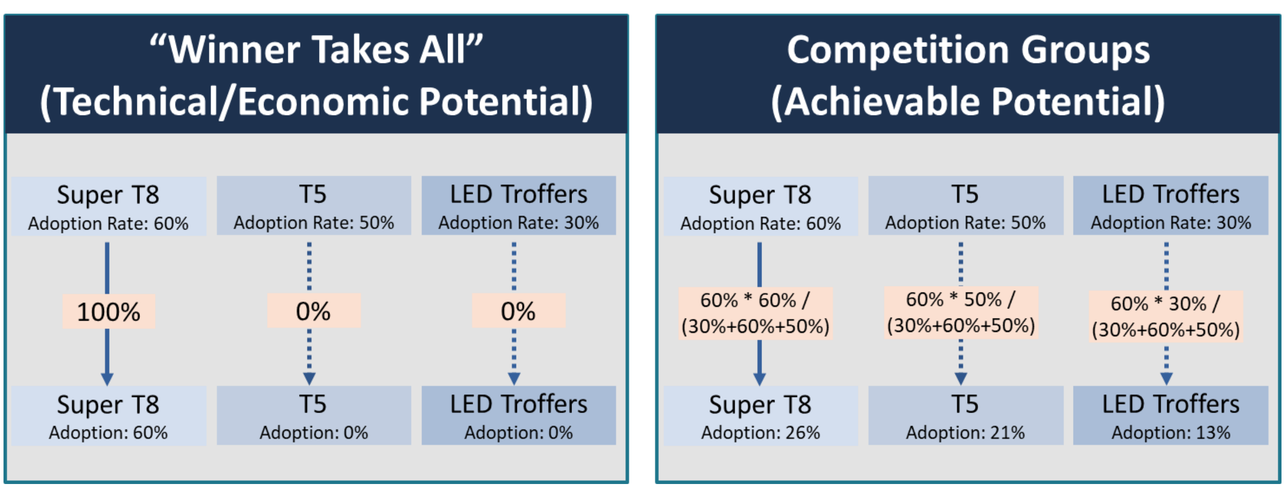
A.4.3 Measure Competition

Measure competition occurs when measures share the same market opportunity but are mutually exclusive. For example, LED troffers, T5 lamps and Super T8 lamps can all serve the same market opportunity but will not be simultaneously adopted. In these cases, DEEP assesses the market potential for each measure as follows:

- Technical Potential: 100% of the market is applied to the measure with the highest savings.
- Economic Potential: 100% of the market is applied to the measure with the highest savings that passes cost-effectiveness screening.
- Achievable Potential: The market is split between all cost-effective measures by pro-rating the achievable adoption rate based on the maximum adoption rate and each of the measures' respective adoption rates.

Figure A-2 presents an example where three measures compete: LED troffers, Super T8 and T5 lamps. First, the adoption rate is calculated for each measure independent of any competing measures, as outlined in the figure below. Based on this assessment, the maximum adoption rate is 60%, corresponding to the measure with the highest potential adoption. Next, the adoption of each measure is pro-rated based on their relative adoption rates to arrive at each measure's share of the 60% total adoption rate. As a result, the total adoption rate is still 60%, but it is shared by three different measures.

Figure A-2. Example of DEEP Measure Competition

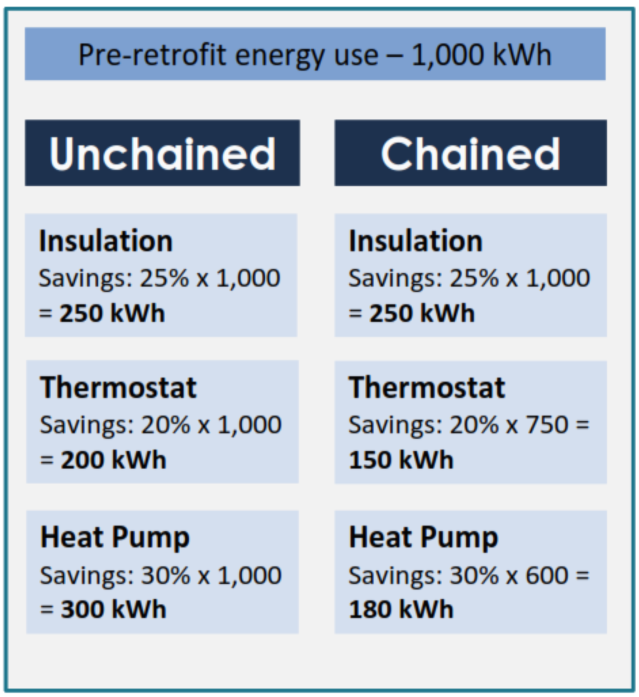


A.4.4 Measure Interactions (Chaining)

Measure interactions occur when the installation of one measure will impact the savings of another measure. For example, the installation of more efficient insulation will reduce the savings potential of subsequently installing a smart thermostat. In DEEP, measures that interact are "chained" together and their savings are adjusted when other chained measures are adopted in the same segment. Chaining is applied at all potential levels and these interactive effects are automatically calculated according to measure screening and uptake at each potential level.

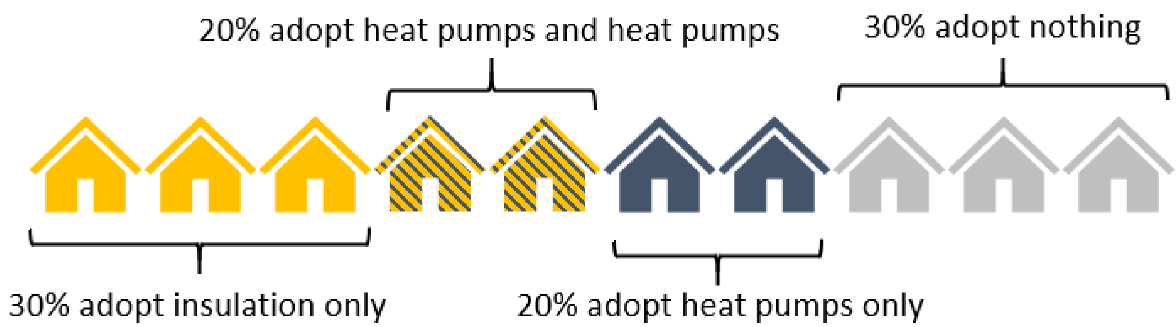
DEEP applies a hierarchy of measures in the chain reducing the savings from each measure that is lower down the chain. The model adjusts the chained measures' savings for each individual measure, with the final adjustment calculated based on the likelihood that measures will be chained together (determined by their respective adoption rates) and the collective interactive effects of all measures higher in the chain. Figure A-3 provides an example of the calculations used to determine the interactive savings effects for a customer where insulation is added in addition to a smart thermostat and a heat pump.

Figure A-3. Example of Savings Calculation for DEEP Chained Measures



The model estimates the number of customers adopting chained measures based on the relative adoption rates of each measure. In an example where insulation has a 50% adoption rate and heat pumps have a 40% adoption rate in isolation, when chaining is considered, the model might assume 40% of customers adopting insulation will also install a heat pump, which means 50% of customers adopting a heat pump will also improve their installation levels. This segments the market into customers adopting only one of the measures, customers adopting both measures, and customers adopting none of the measures as shown in Figure A-4.

Figure A-4. Representative Example of Adoption for DEEP Chained Measures



Note: The above figure is representative of the DEEP model's treatment of chained measures only and not representative of any actual program or measure inputs. In many cases, efficiency programs require weatherization prior to the incentivization of a heat pump.

B. Heating Electrification Methodology

B.1 Overview

The market potential for heating electrification is estimated using the DEEP model architecture as described in Appendix A. Like the energy efficiency methodology, the process begins by establishing a comprehensive set of inputs related to heating electrification measures, markets, equipment saturations, and economic factors, which are then applied in the model to assess heating electrification technical, economic, and achievable potential. Accordingly, DEEP calculation methodologies including estimating phase-in potential and accounting for measure competition and interactions are incorporated into the heating electrification model. The remainder of this appendix describes key inputs and assumptions employed in the heating electrification model.

B.2 Representative Use Cases

The heating electrification model estimates **the potential for replacing or retrofitting existing heating systems** with air source heat pumps (ASHP) to displace heating from existing fossil-fuel based (natural gas, oil, and propane) space and water heating systems over the study period. To avoid double-counting, new construction heating electrification is not considered in this model as it is implicitly captured in new construction measures within the EE measures. To accomplish this, the study is centered on defining representative heating electrification "use cases" that characterize the most common heating electrification opportunities for each sector within the study period. Table B-1 and Table B-2 list the use cases for the residential and commercial sectors included in this study, respectively.

Table B-1. Residential Heating Electrification Use Cases

Counter-Factual System	Heat Pump System
Gas/oil/propane boiler	DMSHP (partial replacement)
Gas/oil/propane furnace	Central ASHP (partial replacement)
	DMSHP (partial replacement)
	Central ASHP (full replacement)
Electric resistance baseboard / space heaters	DMSHP (partial replacement)
Gas/oil/propane storage hot water heaters	Heat pump water heater

Table B-2. Commercial Heating Electrification Use Cases

Counter-Factual System	Heat Pump System
Gas/oil boiler	DMSHP (partial replacement)
Gas/oil furnace	Central ASHP (partial replacement)
	DMSHP (partial replacement)
Electric resistance baseboard / space heaters	DMSHP (partial replacement)
Gas/oil storage hot water heaters	Heat pump water heater

Each use case consists of a fossil-fuel or electric resistance baseline system that is being displaced by a heat pump system.[7] The heat pump systems are segmented into either central ASHPs or ductless mini-split heat pumps (DMSHP). Ground source heat pumps are not included in this analysis due to the high cost of retrofitting these systems in the existing building stock, they are however captured as a replace on burnout measure in the energy efficiency model. Air to water heat pumps are also excluded from this analysis, due to their prohibitive costs which renders them largely commercially unviable over the study period.

For the residential sector, both full and partial replacements use cases are considered, while in commercial sector only partial heating load replacements are considered to reflect typical commercial retrofit behavior. The full replacement use cases are treated as a replace on burnout (ROB) measure where a customer replaces an existing system at the end of its life with a heat pump system instead of a new system of the same existing type. Full replacement scenarios are only considered for customers with existing furnaces as customers without furnaces will not have the requisite ductwork to cost-effectively host a central heat pump. Additionally, full replacement scenarios only consider the installation of central ASHPs as customers are more likely to retain existing equipment after the installation of a DMSHP for backup purposes (even if the DMSHP provides all or the vast majority of space heating needs). The partial replacement use cases are treated as retrofit addition (ADD) measures where the heat pump system is installed in addition to the existing heating system.[8]

B.3 Space Heating Assumptions and Inputs

For space heating electrification in this study, heating energy impacts (both in terms of fuel savings and electric consumption increases) were estimated using a modified version of the "RES21 Energy Optimization Study" Excel-based heat pump analysis tool developed on behalf of the Massachusetts

[7] Please note that the displacement of electric resistance baseboard heating with a DMSHP was characterized as part of the heating electrification module due to similarities between it and other electrification measures. However, this measure was reported as an energy efficiency measure since it does not technically resulting in fuel switching.

[8] For more detail on the difference between measure types (e.g. ROB and ADD), please see Table 2 in Appendix A.

Program Administrators utilizing Rhode Island specific climate inputs.[9] This tool estimates annual heat pump performance based on a bin analysis of the average number of hours each year at each degree Fahrenheit and heat pump coefficient of performance (COP) as a function of temperature. Climate data for Providence, RI was used in this study. COP as a function of temperature equations for cold climate heat pumps were derived based on performance metrics from the Northeast Energy Efficiency Partnership's (NEEP) cold climate heat pump database. COP as a function of temperature equations for standard heat pumps were calculated based on the specification sheets of representative standard heat pumps.

In addition to energy impacts related to space heating, this study assumes heat pumps adopted for space heating will also provide space cooling. To account for the energy and customer economic impacts of space cooling, the study separately models heating electrification use cases for homes that have air conditioning (AC) – either central AC or room AC – and for homes that do not have AC.[10] This study assumes that 82% of residential customers have some form of AC (see Figure B-1).

For **homes with AC**, this study assumes the addition of a heat pump provides more efficient space cooling than currently installed AC systems thus resulting in energy and summertime peak demand savings. For central ASHPs, the impacts are estimated assuming a pro-rated blend of central ACs and room ACs.[11] For DMSHPs, the impacts assume the heat pumps displace room ACs only. The study also assumes customers receive an additional benefit by way of deferring the future replacement cost of an AC system.

For **homes without AC**, this study assumes approximately 45% of these customer would have adopted AC in the absence of adopting a heat pump thus providing energy savings compared to a counterfactual AC system assumed to be at code efficiency as well as the avoided cost of the air conditioning system.[12] The study assumes the remaining 55% of customers without air conditioning would not have adopted AC in the absence of adopting a heat pump. For these customers, the adoption of a heat pump results in an increase in energy consumption for space cooling.

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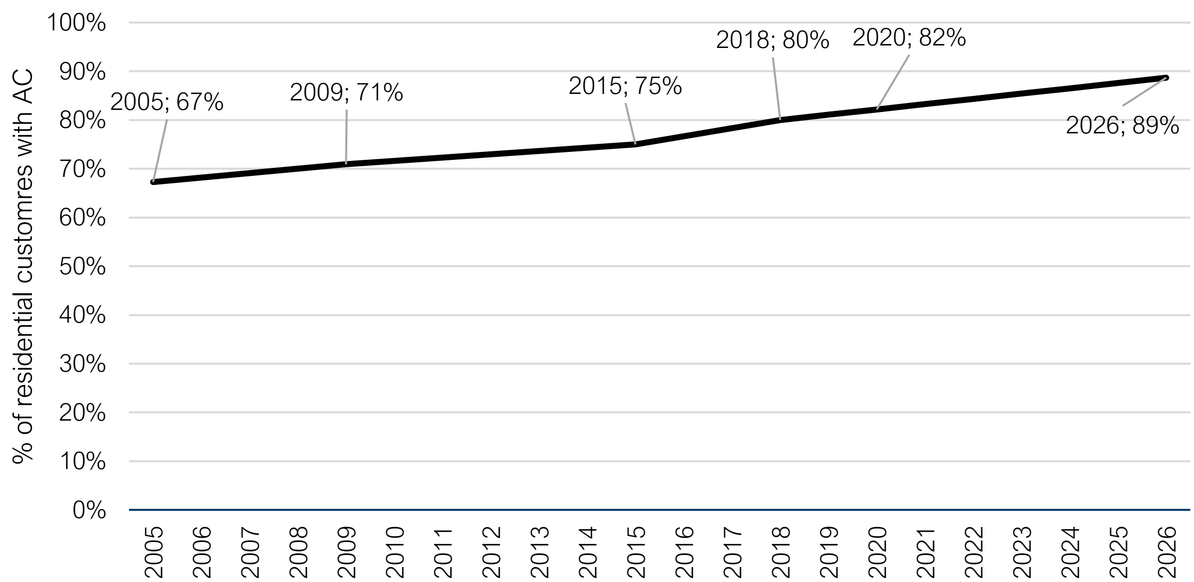
[9] For more information, please see the memorandum summarizing the Energy Optimization Study (RES21) accessible at: http://ma-eeac.org/wordpress/wp-content/uploads/RES21_Energy-Optimization-Study_09OCT2018.pdf

[10] The study assumes that all commercial customers have some portion of their floor space served by AC.

[11] According to the RI RASS report, approximately 69% of residential customers with AC have room or window units, while 31% have central AC systems.

[12] This assumption is derived from the expected increase in residential AC adoption between 2021 and 2026 from 82% to 89%, which represents approximately 45% of remaining customers without AC.

Figure B-1. Historical and projected adoption of residential air conditioning in Rhode Island



Note: Data for 2005, 2009 and 2015 are sourced from the EIA RECS Survey and data for 2018 are sourced from the RI RASS.

B.3.1 Additional Assumptions

Further assumptions were made to define representative use cases for space heating electrification, as presented in Table B-3 below.

Table B-3. Space Heating Electrification Assumptions

Assumption	Central HP (Full)	Central HP (Partial)	DMSHP (Partial)
Equipment Sizing	Sized to cover average heating load	Sized to cover average cooling load	Sized based on RI DMSHP Feasibility Assessment
HP Efficiency	High-tier efficiency, cold climate specs (18 SEER / 9.6 HSPF)	Low-tier efficiency (16 SEER / 8.5 HSPF)	Low-tier efficiency (18 SEER / 10 HSPF)
Backup heating	Electric resistance	Existing system	
Incremental Measure Costs (IMCs)	Incremental cost between HP system and replacing existing fueled system + deferred replacement cost of A/C system (blend of central AC and room ACs)	Total cost of HP system + deferred replacement cost of A/C system (blend of central AC and room ACs)	Total cost of HP system + deferred replacement cost of A/C system (room ACs only)

Equipment Sizing

For the residential sector, heat pump sizing for each use case is based on the type of heat pump (i.e. central ASHP versus DMSHP), the heat pump's use (i.e. partial versus full replacement), the segment's average heating and cooling load, and the average proportion of a home's floor area that can be feasibly served. Table B-4 below lists heat pump sizing assumptions for the residential sector.

For central ASHPs, this study assumes systems partially replacing existing heating systems are sized to meet the average cooling load for each segment, while systems fully replacing existing heating systems are sized to meet the average heating load for each segment.

This study assumes DMSHPs can serve up to 75% of the average home's heating load.[13] It is unlikely, however, that a single DMSHP will be able to serve this entire load due to barriers such as the layout of the home. Accordingly, this study assumes that approximately half of the average home's heating load can be served by a single DMSHP ("primary DMSHP"), with the remaining heating load (approximately 25%) served by a smaller DMSHP ("secondary DMSHP").[14]

Table B-4. Residential Heat Pump Sizing Assumptions

Heat Pump	Single Family Size (tons)	Multi-Family Size (tons)
DMSHP (Primary)	2	1
DMSHP (Secondary)	1	0.5
Central ASHP (Partial)	2	1.25
Central ASHP (Full)	4.25	2

The study does not make explicit assumptions regarding heat pump sizes for the commercial sector as measures are characterized on a per ton basis. The study assumes that commercial customers will size heat pump systems, at maximum, to meet the cooling load of the business, based on typical commercially viable practices in the market.

Heat Pump Efficiency

For space heating, the study assumes that heat pumps partially replacing existing heating systems meet low-tier efficiency standards (16 SEER / 8.5 HSPF for central ASHP and 18 SEER / 10 HSPF for DMSHP) that do not meet cold climate heat pump specifications as they will not be expected to serve the entire heating load. Heat pumps fully replacing existing heating systems are assumed to be more efficient and meet cold climate heat pump specifications (18 SEER / 9.6 HSPF for central ASHP) as these heat pumps will need to serve the entire heating load.

Backup heating

For standard heat pumps partially displacing existing heating systems, the study assumes the existing heating system remains in place and serves as a back-up with a switch over temperature of 23 degrees

[13] This assumption is based on data from the Mini-Split Heat Pump Technical Feasibility assessment included in the 2018 RASS. The study estimates that 75% of the average home's square footage is considered Tier 1 and Tier 2 floor space for DMSHP feasibility. We include Tier 2 floor space as it contains bedroom floorspace that is not heated by electric resistance heating or indicated as needed supplementing heating/cooling by the homeowner but can still be physically served by a DMSHP.
[14] The DMSHP feasibility assessment estimated that approximately 47% of the average home's square footage is contiguous Tier 1 floor space that can be served by a single DMSHP.

Fahrenheit (-5 degrees Celsius). For cold climate heat pumps fully replacing existing heating systems, the study assumes the heat pump includes built-in electric resistance backup heating with a switch over temperature of 14 degrees Fahrenheit (-10 degrees Celsius). Setpoints were determined based on a review of relevant studies in near-by jurisdictions (i.e. RES21 study) and Dunsky's professional judgement.[15] Cold climate heat pumps have a lower switch over temperature as they have better performance at lower temperatures.

Incremental Measure Costs

For full replacement measures, the incremental cost is determined as the difference between the cost of the heat pump system, compared to the cost of replacing the existing heating system with the same type of equipment (e.g. gas, oil or propane furnace) at federal standard efficiency. The heat pump system includes costs associated with electric backup heating and the removal/disposal of old equipment. For partial replacement measures, the incremental cost is the total cost of the system including additional labor costs to integrate the heat pump system with the existing system.

The study also assumes that heat pumps defer replacement costs for central and room air conditioning systems in homes that already contain these systems. Central ASHP defer replacement costs for both central and room air conditioning systems, while DMSHP only defer replacement costs for room air conditioning. Deferred replacement costs are pro-rated by the proportion of customers with each type of air conditioning system and the average age of existing equipment.

B.4 Water Heating Assumptions and Inputs

B.4.1 Sizing and Efficiency

The study assumes that some customers will opt to install a larger water heater when switching to a heat pump water heater due to the perception a heat pump will not be able to replenish hot water at the same rate as the previous/existing non heat pump hot water heater. The study assumes that the increase in standing loses from a larger water heater will be insignificant. However, the incremental cost will increase due to the installation of a larger water heater – for those customers that opt to do so. Accordingly, the incremental costs of switching to a heat pump hot water heater are increased by 10% based on professional adjustment to account for this factor. This value was decided in consideration of customers that will not opt for a larger water heater as well as efforts by utility programming to encourage the rightsizing of water heating systems.

For heat pump water heaters, the study assumes heat pumps meet energy star ratings (2.0 EUF). Heat pump water heaters are assumed to replace existing water heaters on burnout.

B.4.2 Applicability

For the residential sector, the study assumes that only a portion of homes can feasibly accommodate a HPWH based on data from the Heat Pump Water Heater Feasibility assessment included in the 2018

[15] For more information, please see the memorandum summarizing the Energy Optimization Study (RES21) accessible at: http://ma-eeac.org/wordpress/wp-content/uploads/RES21_Energy-Optimization-Study_09OCT2018.pdf

RASS. The study found that only 36% of homes with water heaters installed in spaces met the following conditions deemed suitable for HPWH:

- Greater than 750 cubic feet,
- Year-round temperature greater than 50F,
- Height of at least 6.5 feet, and
- Contain a drain

The study assumes this applicability factor also applies to smaller commercial customers (<5,000 square feet), while 100% of larger commercial customers (>5,000 square feet) are assumed to have space that is suitable for HPHW.

C. Demand Response Methodology

C.1 Overview

The following sections outline Dunsky's Demand Response Model methodology, used to assess the technical, economic and achievable peak-hour demand savings from electric demand response programs. The strength of Dunsky's approach to analyzing demand response (DR) potential, is that it takes into account two specific considerations that differentiate it from energy efficiency potential assessments.

DR Potential is Time-Sensitive

- DR measures are often subject to constraints based on when the affected demand can be reduced and for how long.
- DR measure "bounce-back" effects (caused by shifting loads to another time) can be significant, creating new peaks that limit the achievable potential.
- DR measures impact one another by modifying the System Load Shape – thus the entire pool of measures (at all sites) must be assessed together to capture these interactive effects and provide a true estimate of the achievable potential impact on the system peak.

Many DR Measures Offer Little or no Direct Economic Benefits to Customers

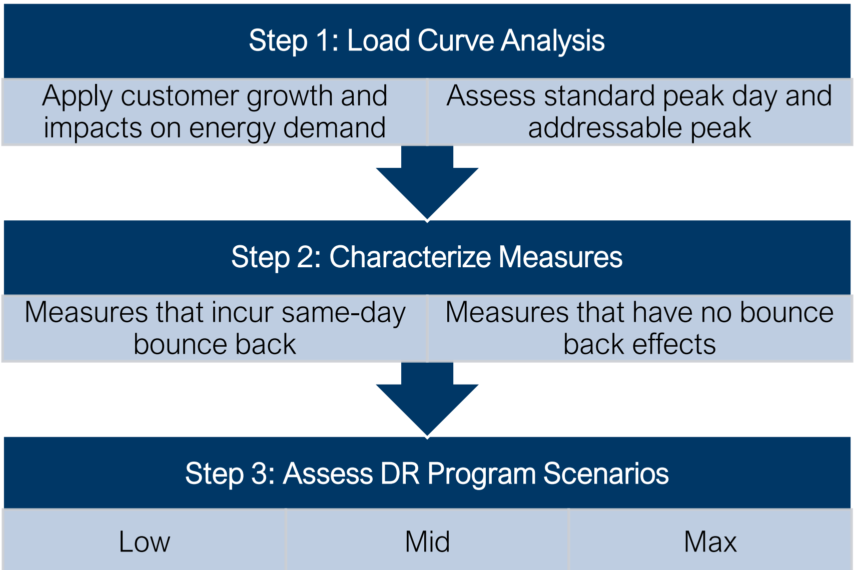
- Participants must receive an incentive over and above simply covering the incremental cost associated with installing the DR equipment.[16]
- Incentives can be based on an annual payment basis, a rebate/reduced rate based on a participant agreement to curtail load, or through time-dependent rates that send a price signal encouraging load reduction during anticipated system peak hours.
- Savings are expected to persist only as long as programs remain active.

A limitation of the methodology is that it may not be consistent with how utilities quantify their DR impacts, which may focus on reducing demand only at certain pre-determined peak hours, regardless of how load may vary at other hours, or if a new peak emerges outside of the targeted hours.

Figure C- 1 presents an overview of the analysis steps applied to assess the DR potential in this study. For each step, system-specific inputs are identified and incorporated into the model. Each step is described below.

[16] This study did not account for reductions in customer peak demand charges that may arise from DR program participation. Since DR events are typically called for a small number of days each month, the impact on commercial monthly peak demand charges is assumed to be minimal.

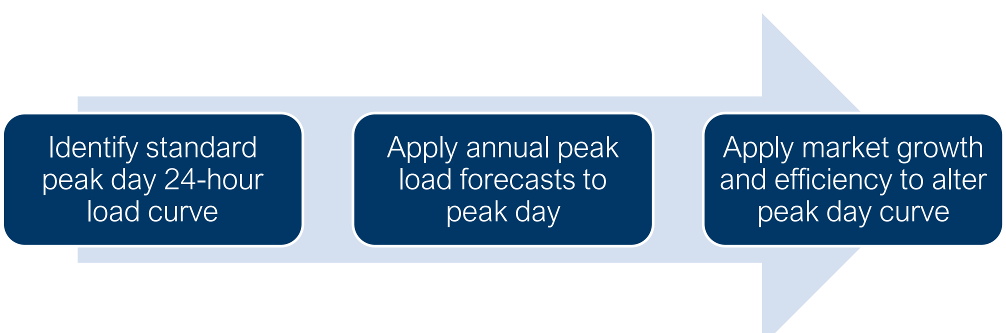
Figure C- 1. Demand Response Potential Assessment Steps



C.2 Load Curve Analysis

The first modelling step of Dunsky's approach is to define the baseline load forecast and determine the key parameters of the utility load curve that influence the DR potential. The process begins by conducting a statistical analysis of historical utility data to determine the 24-hour load curve for the "Standard Peak Day" against which DR measure impacts are assessed. The utility peak demand forecast period is then applied to adjust the amplitude of the standard peak day curve over the study period. Finally, relative market sector growth factors and efficiency and heating electrification program savings (as well as solar PV and EV adoption, where relevant)[17] are applied to further adjust the peak day load curve (growth factors used in the study can be referenced in Appendix F).

Figure C- 2. Load Curve Analysis Tasks



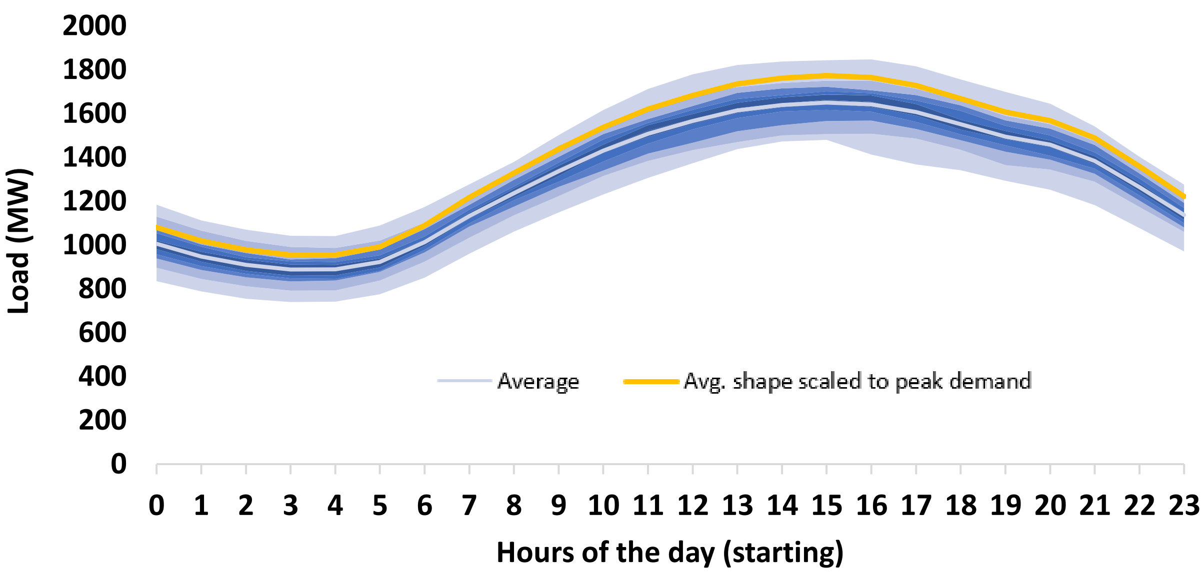
Once complete, the load curve analysis provides a tool which can assess the individual measure, and combined program impacts against a valid utility peak baseline curve that evolves to reflect market changes over the study period.

[17] Mid scenario results for EE, HE, and solar PV savings were applied to adjust the load curve.

C.2.1 Identify Standard Peak Day

The **Standard Peak Day** is assessed through an analysis of historical hourly annual load curves. For each year, a sample of the peak days are identified (e.g. 10 top peak demand days in each year that historical data is available) and a pool of peak days is established. From this the average peak day shape is established as from the pool of peak day hourly shapes. The standard peak day load curve is then defined by raising the average peak day load curve such that the peak moment matches the projected annual peak demand (keeping the shape consistent with the average curve), as shown in Figure C- 3 below.

Figure C- 3. Standard Peak Day Curve



Note: Each blue shading area represents a 10-percentile gradient.

From the standard peak day curve, a DR window was identified which represent the 6-hour time period that capture the highest demand hours.[18] These are assessed against the historical annual curves to ensure that 90% of DR peak events within a given year fall within the defined DR windows. These are used to characterize certain DR measures, providing guidance on which hours to target for time-of-use (TOU) high rate tiers, customer driven curtailment periods, and to create pre-charge/reduction/re-charge curves for equipment control measures, as described in the next step.

[18] A 6-hour peak period is applied as it is considered a reasonable maximum event duration for most DR measures.

C.3 DR Measures Characterization

DR potential is assessed drawing on Dunsky's database of specific demand reducing measures developed from a review of commonly applied approaches in DR programs across North America, and emerging opportunities such as battery storage.[19] Measures are characterized with respect to the local customer load profiles, and the technical and economic DR potentials are assessed for each individual measure.

Figure C- 4. DR Measure Characterization Tasks

Once complete, the measure-specific economic potential is loaded into the model to assess the achievable potential scenarios when all interactive load curve effects are considered.

C.3.1 Measure Specific Model Inputs

Measures are developed covering all customer segments and end-uses, and can be broadly categorized into two groups:

- Type 1 DR Measures (typically constrained by demand bounce-back and/or pre-charging):
    - These measures exhibit notable pre-charging or bounce-back demand profiles within the same day as the DR event is called. This can create new peaks outside of the DR window and may lead to significant interaction effects among measures when their combined impact on the utility peak day curve is assessed.
    - Typically, Type 1 measures can only be engaged for a limited number of hours before causing participant discomfort or inconvenience. This is reflected in the DR measure load curves developed for each measure-segment combination. (example: direct load control of a residential water heater)

[19] A detailed list of measures applied in this study is provided in Appendix E.

- **Type 2 DR Measures (unconstrained by load curve):**
  - These measures do not exhibit a demand bounce-back and are therefore not constrained by the addressable peak.
  - Some of them can be engaged at any time, for an unlimited duration. (example: back-up generator at a commercial facility)

Dunsky's existing library of applicable DR measure characterizations was applied and adjusted to reflect hourly end-use energy profiles for each applicable segment. Key metrics of the characterization are:

1. **Load Shape:** Each measure characterization relies on defined 24-hour load shape both before and after the demand response event. The load shapes are based on the population of measures within each market segment and are defined as the average aggregate load in each hour across the segment.

2. **Effective Useful Life (EUL):** Effective useful life of the installed equipment/control device. For behavioural measures with no equipment, a one-year EUL is applied.

3. **Costs:** At measure level, the costs include the initial cost of the installed equipment (i.e. controls devices and telemetry) and the annual operational cost (program administration, customer incentives etc.).

4. **Constraints:** Some measures are subject to specific constraints such as the number of hours per day or year, maximum number of events per year and event durations.

Once the measures are adapted to the utility customer load profiles and markets, the technical and economic potentials are assessed for each measure independently as outlined below. Because these are assessed independently (i.e. not considering interactions among measures), the technical and economic potentials are not considered to be additive, but instead provide important measure characterization inputs to assess the collective achievable potential when measures are analyzed together in step 3.

C.3.2 Technical Potential (Measure Specific)

The technical potential represents a theoretical assessment of the total universe of controllable loads that could be applicable to a DR program. It is defined as the technically feasible load (kW) impact for each DR measure considering the impact on the controlled equipment power draw coincident with the utility annual peak.

More specifically, the technical potential is calculated from the maximum hourly load impact during a DR event multiplied by the applicable market of the given measure. It is important to note that the technical potential assessment does not consider the utility load curve constraints, such as the impact that shifting load to another hour may have on the overall annual peak.

C.3.3 Economic Potential (Measure Specific)

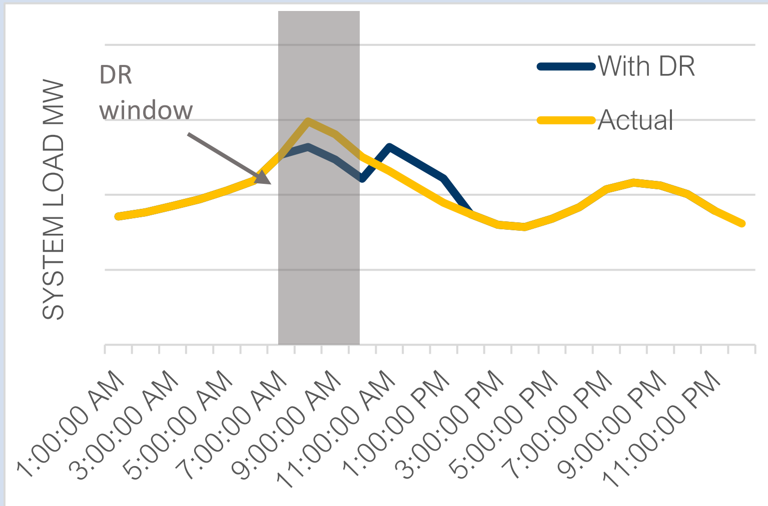
The assessment of each measure's economic potential is conducted in three key steps: adjustment of the technical potential, screening for cost-effectiveness, and adjusting for market adoption limitations.

1. **Net Technical Potential Adjustment:** The measure's hourly load curve impact is applied to the utility standard peak day load curve, to assess the net impact after pre-charge and bounce-back effects are accounted for. For each individual measure an optimization algorithm that assesses various control schemes and market portions is applied to arrive at the maximum number of participants and impact for the given measure, without creating a new system peak, either during the standard peak day, or over the sample annual hourly load profile.

Net Impact Determination:

By considering the bounce-back effect associated with water heaters recharging their reservoirs after the evening DR window has passed, Figure C- 5 illustrates how adding too many water heaters to the DR program would risk creating a new peak outside of the DR window. This new peak is used to assess the net impact of the measures, which is determined as the difference between the peak before the DHW controls were applied and the new peak after the DHW controls were applied.

Figure C- 5: Illustrative Domestic Hot Water (DHW) Bounce-Back Effect Example



2. **Cost-Effectiveness Screening:** Once each measure's net impact on the peak is assessed, measures are screened using the applicable cost-effectiveness test, considering installation costs and baseline incentive costs.[20] It is important to note the customer incentives are not treated as a pass through cost for DR programs because they typically do not cover a portion of the customers' own equipment incremental costs (i.e. customers typically have no direct equipment costs, unlike in efficiency programs where the incentives provided cover a portion of the participant's incremental costs for the efficiency upgrade).

   For measures that pass the cost-effectiveness screening, program incentives can then be set either as a fixed portion of the avoided costs net of measure costs (i.e. 50%) or at the level that maximizes the cost-effectiveness test value for the measure in question.

[20] Any measure that cannot achieve a RI Test > 0.75 is not retained for further consideration in the model. For customer curtailment measures RI Test screening may be assessed under a baseline incentive level (i.e. $20/kW). For equipment control measures the baseline incentive can be set to zero, and then adjusted for measures that return net benefits to the utility.

Table C- 1. DR Benefits and Costs Included in Determination of the PACT

Benefits	Costs
Avoided Capacity Costs Other ancillary benefits (as applicable)	Controls equipment installation Controls equipment Operations and Maintenance (O&M) (if required) Annual incentives ($/ participant) Peak reduction incentives ($/kW contracted)

3. **Market Adoption Adjustment**: The market for a given DR program or measure may be constrained either by the impact on the load curve, or by the expected participation (or adoption) among utility customers.

   In the first case, the economic potential assessment (described above) determines the number of devices needed to achieve the measure's maximum impact on the utility peak load. Adding any further participation will come at a cost to the utility, but with little or no DR impact benefits.

   In the second case, the model determines the expected maximum program participation based on the incentive offered, the need to install controls equipment, the level of marketing, and the total number of eligible customers, by applying DR program propensity curves (described in the call out box below) developed by the Lawrence Berkeley National Laboratory.[21]

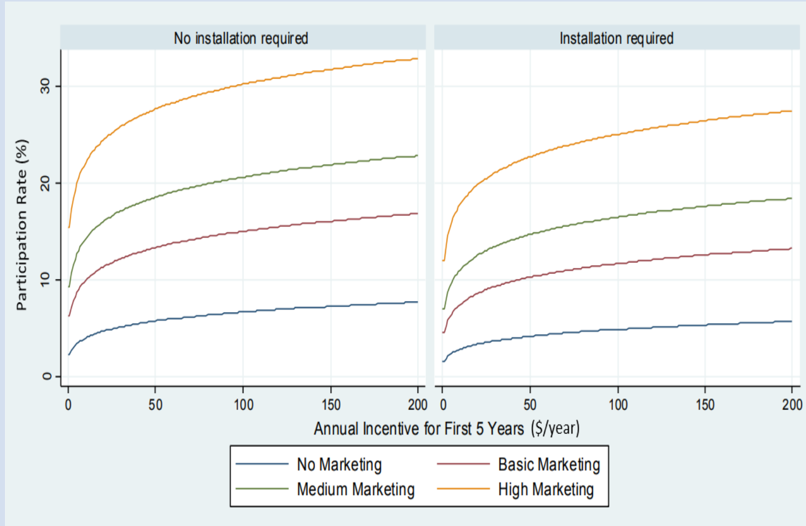
   The DR model assesses both the utility curve economic potential market and the maximum adoption at the resulting incentive levels, then constrains the market (maximum number of participants) to the lower of the two. This is then applied as a measure input for the achievable potential assessment described in the next step.

[21] Lawrence Berkeley National Laboratory, March 2017. 2025 California Demand Study Potential Study, Phase 2 Appendix F. Retrieved at: http://www.cpuc.ca.gov/General.aspx?id=10622

Demand Response Propensity Curves

For each measure the propensity curve methodology, as developed by the Lawrence Berkeley National Laboratory to assess market adoption under various program conditions, is applied. The curves represent achievable enrollment rates as a function of incentive levels, marketing strategy, number of DR calls per year, and the need for controls equipment. Their development is based on empirical studies, calibrated to actual enrollment from utility customer data. Specific curves are available for each sector.

Figure C- 6: Residential Adoption Curves used in the study



C.4 Assessment of Achievable Potential Scenarios

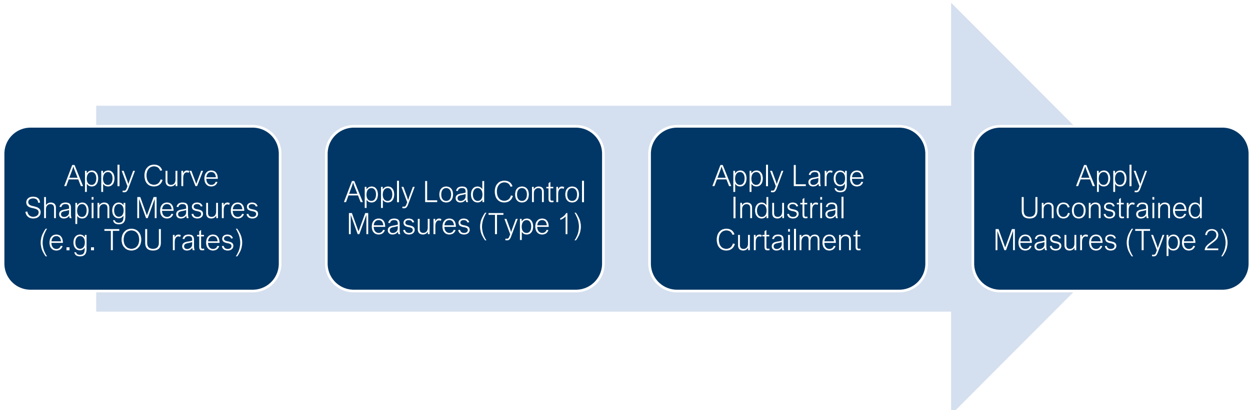
The achievable potential is determined through an optimization process that considers market adoption constraints, individual measure constraints, and the combined inter-measure impacts on the utility load curve.

Scenarios are developed to assess the combined impact of selected programs and measures. For example, one scenario may assess the achievable potential of the impact of applying TOU rates and industrial curtailment, while another may assess the combined potential from direct load control of customer equipment and industrial curtailment. This approach recognizes that there can be various strategies to access the DR potentials from the same pool of equipment (i.e. TOU rates can exert a reduction in residential water heating peak demand, thereby reducing or eliminating the potential from a water heater DLC program). The scenarios are assembled from logical combinations of programs and measures designed to test various strategies to maximize the achievable peak load reduction.

C.4.1 Assessing Achievable Potential

For each scenario, measures are applied in groups in order starting with the least flexible/most constrained measures and progressing to the measures/groups that are less and less constrained, as per the order illustrated in Figure C- 7 below.

Figure C- 7. Achievable Potential Assessment Tasks



- **Curve Shaping:** Rates Based Measures (such as time of use rates) are typically applied first as these are designed to alter customer behaviour with time, and are considered the least flexible (i.e. with the exception of critical peak pricing, they cannot be engaged by the utility to respond to a specific DR event, but must be set in place and exert a prolonged effect on the utility load curve shape). Curve shaping can also include passive demand reduction via increased adoption of efficiency measures.

- **Type 1 - Load Control Measures:** Direct control of connected loads such as water heaters and thermostats, and customer controlled shut-off or ramp down of commercial HVAC loads are applied next. These are typically constrained to specific times of day based on the utility peak load shape, and the controlled equipment load shape (i.e. turning of residential water heaters at midday may be feasible but deliver next to no savings as there is minimal hot water demand at that hour). These are assessed against the load curve altered by any shaping measures, and measures that may double count savings are eliminated. A new aggregate utility load curve is then created, applying the achievable load control peak reductions, and bounce-back effect.

- **Industrial / Commercial Curtailment:** Next customer curtailment is applied, which typically carries constraints related to the number of curtailment hours per day (consecutive and total), the number of events per year, and in some cases the time of day that curtailment can be applied (but does not carry same-day bounce-back effects). These are applied to the adjusted load curve to assess the potential impact of large industrial and commercial curtailment measures on the magnitude and timing of the overall annual peak .

- **Type 2 - Unconstrained Measures:** Finally, the remaining Type 2 measures that have no constraints on the duration, frequency or timing of their application are applied. These may include measures such as dual-fuel heating and back-up generators which can be engaged as needed and whose potential is not impacted by the shape of the utility load curve.

C.4.2 DR Programs and Scenarios

Dunsky has developed a set of best-in-class program archetypes based on a review of programs in other jurisdictions. For each program, development, marketing and operating costs are estimated and applicable measures are mapped to the corresponding program, applying key features from the program archetypes, and taking into account current programs offered by the utility.

The model first determines the achievable DR potential of the combined measures within all programs, and then assesses the program level cost-effectiveness, summing all program and measure costs, as well as applicable measure benefits. A 10-year delivery period is assumed for each program, except where the program is based on control devices with a longer EUL, in which case the program is assumed to cover the entire device life. In cases where DR device EULs are shorter than 10 years, preparticipation / re-installation costs are applied. This approach allows the model to fairly assess the programs costs and benefits for an on-going program.

New measure and program ramp-up: Where applicable, new programs and measures can be ramped up accounting for the time needed to enroll customers and install controls equipment to reach the full achievable potential. Ramp up trajectories applied to the achievable potential markets after all interactive effects (i.e. new peaks created or program interactions that affect the net impact of any other program) have been assessed. Typically, it is assumed that it takes three years for a new or expanded program or measure to reach full participation and roll out (i.e. a ramp rate of 33% per year was applied for adding new programs).

Based on these steps the Achievable DR potential for each measure, program and scenario are developed, along with an appropriate assessment of the measure, program and scenario level cost-effectiveness.

D. Combined Heat and Power Methodology

D.1 Overview

The technical and economic market potential for combined heat and power (CHP) in Rhode Island was estimated by Energy Resource Solutions, Inc. (ERS) using a bottom-up approach that analyzed monthly gas customer billing data as a proxy for thermal loading. The achievable market potential for CHP was then estimated by Dunsky based on the economic market potential using technology adoption and diffusion theory as captured through the Bass Diffusion curve. Unlike a top-down approach, this bottom-up approach using actual customer data provides a granular analysis that identifies individual customers with thermal loads amenable to CHP systems. This approach provides results that reflect the unique characteristics of natural gas customers in Rhode Island as observed through individual consumption data.

D.2 Technical and Economic Potential

Using anonymized gas customer billing data provided to ERS by National Grid, the study analyzed technical and economic CHP potential by segment using a CHP optimization model.[22]

Data set. The study leveraged the same customer data as described in Appendix F, which contained approximately 23,000 customer accounts covering 200 million therms of annual natural gas consumption within the commercial and industrial (C&I) sectors. Anonymized data was provided at the account level with pseudo-IDs masking the customer name and account number.

Locational data (such as address or zip code) was not provided due to customer privacy concerns, preventing manual inspection for accuracy of classifications or final results. Manual inspection would allow customer accounts with large estimated CHP potential to be checked for segment accuracy (if customer segment was previously unknown) as well as factors that may make CHP infeasible at the customer's particular site.

However, based on information provided by National Grid, customer accounts with existing CHP systems were removed from the analysis and not included in the technical or economic potential. Additionally, ERS provided the customer pseudo account IDs associated with the 10 largest estimated CHP systems to National Grid for feasibility review. Several additional existing CHP facilities were identified as well as several sites that were deemed not feasible due to site limitations (e.g. incompatible thermal distribution systems and/or load profiles) and not being an appropriate fit for CHP. These customers were also excluded from the technical and economic potential.

For the remaining accounts, the annual consumption was computed for each account along with minimum/maximum monthly values and the average summer load, which were used to develop the fraction of use that was considered to be baseload use. The magnitude of the thermal usage must be

[22] The segments used in this study can be found in Appendix F.

large enough to support the installation of a commercially viable CHP unit. For this reason, the analysis excludes customer accounts with annual consumption lower than 20,000 therms.

The customer accounts were assigned to business segments in the same manner as described in Appendix F.

Eligible thermal use. The methodology employed by ERS uses gas consumption as a proxy for facility thermal loads. CHP systems can generally offset only certain processes, such as space heating and domestic hot water loads. CHP heat cannot feasibly meet non-spacing heating load requirements for which gas is combusted directly (e.g., cooking and thermal oxidizers). To determine the fraction of gas used for space heating, base gas usage was derived from each customer's summer usage. The team then estimated the weather sensitive load (the fraction of gas used for space heating) as the difference between the annual consumption and the base usage.

The annual gas usage estimated for space heating was converted to a thermal load by accounting for an assumed boiler combustion efficiency of at the federal minimum standard of 80%. Additionally, the team utilized the US EIA Commercial Building Energy Consumption Survey (CBECS) end use consumption data to further refine the fraction of non-weather sensitive baseload energy use that cannot be displaced by CHP for each business segment (e.g., office, hospital). This is also a characteristic of the respective building type (i.e., office, hospital, etc.).

CHP system sizing. The ERS model utilizes an optimization algorithm to calculate a CHP unit size for each customer. CHP systems are unique in that systems can be sized to be electric or thermal following and can be sized to meet any fraction of those loads from 0–100%. For this study, systems were sized to operate as thermal load-following systems, since this optimizes long term economics of the systems.

For **technical potential**, the model sized systems to cover 100% of the customer's eligible thermal load regardless of customer economics. In this way, technical potential is a measure of the market size that is only constrained by technological limits – that is, the ability of the technology to match customer thermal needs and does not consider cost or site constraints.

In practice, however, system sizing is inherently an economic decision – the larger a system is sized (nameplate capacity), the larger the percentage of the load it can meet. However, the system's annual full load hours will decrease, resulting in a less economic system with longer customer payback. Therefore, for **economic potential**, the model sized systems to ensure a Rhode Island benefit-cost ratio greater than 1 and a reasonable customer payback of at least 9 years. Ultimately, sizing systems to a reasonable customer payback was the limiting factor for system sizes and resulted in systems with Rhode Island BCRs of approximately 1.5. Systems sized to achieve BCRs closer to 1.0 resulted in larger systems, but paybacks were considered prohibitive from the customer perspective. Any sites with modeled systems with paybacks of more than 9 years were excluded from economic potential.

Technical and economic potential as estimated by ERS included the following additional considerations/assumptions:

- Similarly, a minimum viable system size of 20 kW was identified by National Grid as a possible threshold for an upcoming program. However, only two systems were sized between 20 kW and 24 kW. All other estimated systems were larger than 24kW.

- In the original list of gas accounts provided by National Grid, a large number of buildings were classified under an "unknown" segment. Since consumption data was provided at a monthly timescale, it was not possible to accurately place customer accounts into segments (more granular data would be required for this analysis). Instead, ERS leveraged load profiles for other classified segments to calculate the percentage of base load that cannot be displaced by CHP for the "unknown" segment based on a weighted average of annual consumption (e.g. segments with a larger portion of annual natural gas consumption were weighted more heavily in the derivation of the "unknown" base load analysis). Technical and economic potential for "Unknown" customers was then assigned to classified segments on a pro-rated basis based on the segment's technical and economic installed capacity potential (e.g. segments with a greater portion of "known" CHP potential received a greater portion of the "unknown" potential).

- The study assumes a CHP unit cannot displace direct-fired uses such as for cooking or process, steam boilers, or unit heating systems. The model only presents a market potential for hot water-based applications in buildings. It is also assumed that some portion of the base usage cannot be displaced by CHP depending upon the building type and the results were de-rated to account for this.

- Additionally, technical and economic potential was de-rated to account for direct-fired heating systems (such as furnaces) where it would not be economically feasible to convert building distribution systems. This reduced capacity by 47%, which is the estimated portion of buildings with direct-fired heating systems.

Table D-1 describes additional inputs and assumptions used in this analysis.

Table D-1. CHP Module Inputs and Assumptions

Input/Assumption	Description
Costs	ERS leveraged equipment, installation, and operation and maintenance (O&M) costs from prior studies and industry experience in the region of upstate NY. These costs were used for the RI study due to the geographic and economic similarities of the two regions.
Climate data	The model used typical meteorological year (TMY3) hourly weather data from Providence, RI to simulate operation of the weather-dependent loads in the hourly analysis.
Peak hours	The model used RI peak hours of 1 – 5 pm on the hottest weekday when quantifying peak electric demand impacts.
Economic inputs	The model utilized the same retail customer rates, utility avoided costs, and other economic inputs like line losses and emission factors as the rest of the study as described in Appendix F. The retail customer pricing for both electricity and gas is used to compute the value of the electrical and gas benefits and customer payback. The model incorporates RI avoided costs (summer and winter energy, transmission and distribution, and natural gas) to calculate the BCRs.
Effective useful life (EUL)	The model assumed an estimated useful life of 16 years for CHP systems in RI, based on the "Guide to Submitting CHP Applications for Incentives in Rhode Island" document referenced by the RI Technical Reference Manual (TRM).

Finally, the estimation of technical and economic potential is subject to the following limitations and additional considerations:

- With anonymized customer data, ERS could not perform a manual sanity check on the largest screened CHP systems. It is possible that sites are misclassified or contain certain loads that could not be met by CHP.
- The study does not consider potential overlap between CHP savings potential and large-scale heat pump systems in the heating electrification (HE) module. However, this overlap is expected to be relatively minor as the HE module does not explicitly model large-scale heat pump systems that would be installed in place of a CHP system.
- Geographic gas constraints were not taken into account. Certain areas of RI are experiencing pipeline capacity limitations and may not be able to support additional CHP gas loads. Without locational data and the network areas experiencing constraints, ERS could not flag potential sites where this may be an issue. For potential sites where these constraints are an issue, technical/economic potential would need to be de-rated based on the fraction of the gas system that is constrained.
- Electric system constraints were also not taken into account. Certain areas of the electric grid may not be configured to support CHP interconnection. Without locational data and the network areas experiencing limitations, we could not flag sites where this may be an issue. For potential sites where these constraints are an issue, technical/economic potential would need to be de-rated based on the fraction of the grid that is constrained.

D.3 Achievable Potential

Achievable potential was estimated by Dunsky using technology adoption and diffusion theory as captured through the Bass Diffusion curve. The curve was calibrated to reflect historical adoption in Rhode Island since the inception of National Grid's CHP Incentive Program in 2013 using parameters tuned to historically observed CHP adoption in Rhode Island and that are representative of a technology that has been in the market for a significant period of time and has generally high barrier levels for market adoption. Adoption under each achievable scenario is then estimated by varying incentive levels, which impact customer economics and willingness to adopt, and adoption parameters to simulate non-incentive adoption barrier reductions.

Due to the relatively small size of the potential market for CHP in Rhode Island and the generally "lumpiness" of CHP investments (i.e. relatively few projects and large variances between project sizes), the application of technology adoption and diffusion theory is limited in estimating a given year's likely adoption. For this reason, the achievable potential for CHP is most appropriately interpreted as an annual average over the entire six-year study period instead of single year estimations.

E. Customer-Sited Solar PV Methodology

The scope of the study is to assess the technical, economic and achievable potential for customer-sited rooftop solar systems in Rhode Island. The study leverages Dunsky's Solar Adoption Model (SAM) and Rhode Island-specific inputs to forecast solar adoption and the corresponding load impacts under a number of scenarios reflecting different market and policy conditions. In this section, an overview of the approach used in the study is highlighted as well as an overview of the model's methodology.

E.1 Approach Overview

The following approach was used to assess the technical, economic and achievable potential for customer-sited solar in Rhode Island:

- Step 1 - Market Characterization: The segments developed in this study were used as the basis for the solar market characterization as described in Appendix F. The segments capture customers with similar building characteristics, energy consumption, energy pricing, decision-making thresholds, and other characteristics, and develop characteristics for an average customer in each segment. Individual units within multi-family residential buildings were assumed to have no potential for customer-sited solar adoption due to the lack of access to a dedicated rooftop.[23]
- Step 2 - Assess Technical Potential: Estimate technically feasible installations for distributed solar based on building stock, suitability for solar and roof space as well as the energy generation potential for each market segment.
    - Number of suitable sites for solar deployment, developed by estimating the appropriate building stock (i.e. stand-alone buildings) in each segment[24], percentage of technically feasible rooftops that are suitable for solar installation (i.e. shading, roof tilt, etc.)[25] and other constraints (i.e. low-income, renter-occupied).
    - Average system size for a typical customer in each segment based on customer's annual electricity consumption, available roof space[26], historically reported system sizes from interconnection data and other constraints (e.g. REG size caps if applicable)

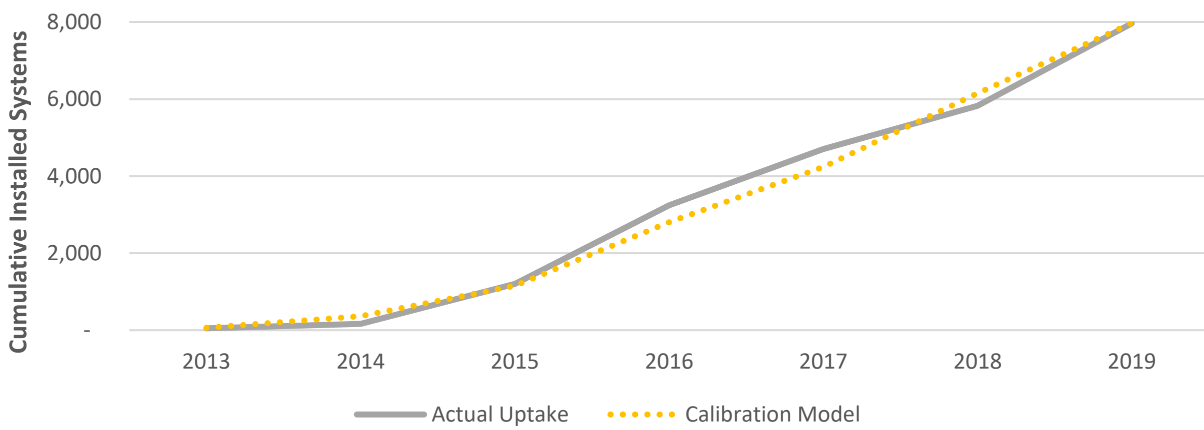
[23] While individual units in a multi-family building are assumed to have no potential for solar deployment, common areas and amenities of multi-family apartment buildings are usually metered as commercial spaces and would be captured within the potential of the non-residential segments.
[24] Customer population counts per segment were coupled with market data from Rhode Island and nearby jurisdictions (see discussion on market characterization in Appendix F) and data from the Energy Information Agency's (EIA) Commercial Buildings Energy Consumption Survey (CBECS) were used to estimate number of buildings per segment.
[25] Assumptions based on Dunsky's experience and data from a National Renewable Energy Laboratory study (*Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment*) and Google's Environmental Insights Explorer (EIE) tool were coupled to estimate the percentage of buildings suitable for rooftop deployment in each segment.
[26] Market archetypes and CBECS data used to estimate average rooftop area for a typical building in each segment using data on total building area and number of floors per building.

- Energy generation potential for a typical solar system is estimated (in the form a capacity factor or kWh/kW multiplier) based on solar irradiation data and reported system performance. A typical annual solar generation profile was generated using PVWatts and matched to the assumed capacity factor for each segment to estimate customers' net load and grid impacts of solar generation.

- **Step 3 - Model Calibration:** To capture the local characteristics of the solar market in Rhode Island, historical inputs (2010 to 2019[27]) on market size, electricity rates, PV costs and state/federal incentives were used to benchmark Dunsky's SAM model to historical adoption in Rhode Island and calibrate key model parameters. The calibration captures the degree to which the market adopts new technologies over time, accounting for local demographics and composition of market segments and their varying motivation for adoption (environmental, economic, etc.) as well as the local population's willingness-to-pay for BTM solar and expected levels of return that would encourage adoption. When calibrating the model, the focus is on obtaining the closest fit of cumulative uptake within the period under investigation as well as a representative trends of annual adoption and year-over-year growth trends, as illustrated in Figure E-1.

  Given the existence of two complementary programs for BTM solar; Renewable Energy Growth (REG) program and Net Energy Metering (NEM) coupled with the Renewable Energy Fund (REF) program, the calibration considered historical economics to adopters under both programs and competition between them. The model was first calibrated to historical NEM uptake to capture installations that took place prior to the REG program as well as incremental installs above and beyond REG during competition periods. A second instance of the model was then calibrated to historical REG adoption during competition years to capture adoption trends relative to NEM.

Figure E-1. Residential Model Calibration



- **Step 4 - Scenario Analysis:** The calibrated model was populated with state-specific inputs and assumptions on key market and technology factors (presented in Appendix F) to forecast adoption under different policy, and market scenarios (summarized below in Figure E-1). The scenario analysis reflects changes in factors related to the REG and REF programs as well as solar PV costs, which would impact the market's trajectory over the study period. Given that potential BTM adopters have access to

[27] Historical adoption was based on data from National Grid's interconnection database. Given that the study was initiated in Q3 2019, a full-year estimate for 2019 adoption was developed based on historical month-to-month trends.

both REG and NEM+REF programs, the competition between both programs is accounted for using the relative potential for each program. Uptake under both programs is first modeled separately, and the total market share in a given year is assumed to be the maximum of the two. A competition function is then applied to prorate the modeled adoption of each program in isolation to the maximum adoption potential. For illustration, if the REG model forecasts 10 MW and the Net Metering Model Forecasts 20 MW, then total adoption will be estimated as 20 MW (the maximum of the two), and the allocation of total adoption between the two programs would be calculated as the following percentages: NEM Adoption will represent 66.7% (i.e. 20 MW / 30 MW), and REG adoption will represent 33.3% (10 MW / 30 MW). In addition to the direct competition between both programs, the model also considers the REG program allocation caps and limits adoption in REG accordingly. The REF program was not constrained by budget availability.

Figure E-2. Solar Program Scenarios[28]

Low	**Reduced policy support for solar deployment** and unfavorable market conditions after the phase-out of Federal Investment Tax Credit (ITC). • REG program with constrained allocation • Net-Metering with no upfront incentives • High system costs post ITC phase-out
Mid	**Business-as-usual policy support and market conditions** for solar in Rhode Island that maintains the trajectory of current programs • REG program with existing allocation • Net-Metering with BAU incentives levels (stepped-down) • BAU system costs post ITC phase-out
Max	**More aggressive policy support and favorable market conditions** for solar deployment in Rhode Island to counteract the impacts of the phase-out of the ITC. • REG program with no allocation caps • Net-Metering with BAU incentives (stepped-down gradually to mitigate ITC Phase-out) • Low PV costs post ITC phase-out

- **Step 5 - Impacts Assessment:** For each policy/market scenario, we calculate key impact metrics, including
    - Load impacts (energy and demand) associated with forecasted solar uptake;
    - Greenhouse gas (GHG) emission reductions from the displaced electricity from the grid;
    - Program costs considering administrative cost, incentives and compensation paid to adopting customers over the lifetime of systems; and
    - Cost-effectiveness of the forecasted uptake considering benefit and cost streams captured through the Rhode Island test.
- **Step 6 - Storage Uptake:** For each segment, we estimate the portion of the forecasted solar PV uptake that will be storage-paired by adding the incremental benefits (e.g. Demand response revenue, peak demand savings) and the incremental costs (e.g. upfront and operational costs considering incentives under the Investment Tax Credit) of battery storage. Additionally, model parameters that capture

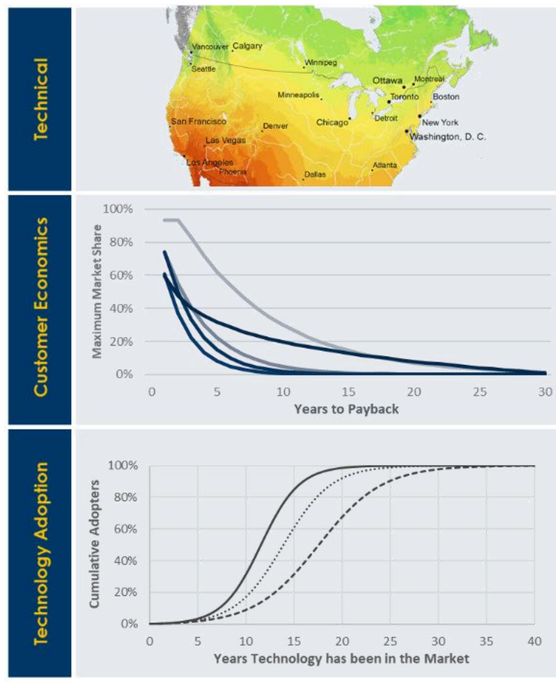
[28] Given that existing program support for solar in Rhode Island is significant, existing programs are modeled as the Mid scenario (Base Case). Additional scenarios featuring reduced (Low) and more aggressive (Max) programs as modeled described in Figure 1.

customers' willingness-to-pay and rate of adoption were adjusted based on observed historical distributed storage uptake in Rhode Island and other jurisdictions to forecast future adoption of storage-paired solar PV. Only NEM customers were assumed to be able to adopt storage-paired systems[29].

E.2 Solar Adoption Model (SAM)

Dunsky's proprietary Solar Adoption Model (SAM) is used in this study to assess the potential uptake of residential and non-residential solar PV. The model is based on a methodology developed by the National Renewable Energy Laboratory (NREL) for its Distributed Generation Model and is complemented with rigorous research and survey data from academia and industry, as well as Dunsky's own knowledge base and experience modeling the uptake of clean energy technologies. To date, the model has been leveraged for client projects in California, New York, Ontario, Alberta and other jurisdictions across North America, and cross segments (residential, commercial, industrial and institutional) to project market demand under business-as-usual conditions as well as under alternative policy and market scenarios, and support incentive and financing program design and optimization.

Figure E-3. Overview of Solar Adoption Model (SAM)



Using jurisdiction-specific inputs, the model forecasts demand for solar PV based on three factors described below and summarized in Figure E-3:

- Technical potential: The estimated theoretical maximum deployment potential for solar PV is estimated based on local building stock, the assumed portion of roof tops considered suitable for solar deployment and generation potential.
- Customer Economics: Economic potential for adoption is captured through calculating expected solar uptake driven by customer economics relative to willingness-to-pay of different customer groups for solar PV. Based on PV system costs, energy rates, estimated solar generation, incentive levels and other key scenario inputs, annual customer cash-flows for customers are developed and used to compute a financial metric (e.g. payback) for each segment for each year in the study period. Due to differences in perception, decision-making criteria and economic threshold, simple payback (years) is assumed to be used by residential customers in considering solar adoption, while Internal Rate of Return (IRR) is assumed to be used by more sophisticated commercial and industrial customers. The financial metrics are then used to estimate the portion of each segment that is willing to adopt solar at different return levels based on multiple standard curves integrated in the model (as shown in Figure E-3) that are adjusted based on the model calibration to the local market.

[29] Changes to REG initiated after the start of this study allow energy storage system to be build in conjunction with a generation system under REG under certain circumstances.

- **Technology adoption:** To estimate the rate of adoption of customer-sited solar given local barriers and market characteristics, technology adoption and diffusion theory captured through a Bass Diffusion curve is used to estimate the local deployment of solar over time. The Bass diffusion curve is used to determine the maximum achievable market size given the technology and market maturity in a given year. The diffusion curve parameters are set based on calibration to historical uptake trends and use in forward-looking scenario projections.

The three factors combined provide an estimate of the annual solar PV uptake using jurisdiction-specific inputs.

F. Study Inputs and Assumptions

The following appendix describes the key inputs used in this study and how they were derived.

F.1 Measure Characterization

F.1.1 Energy Efficiency Measure List

The following tables lists the energy efficiency measures and characterization sources used in this study. Table F-1 lists the various Technical Resource Manuals (TRM) and other sources used to characterize measures.

Table F-1. Measure Characterization Sources

Key	Source
IA	Iowa Statewide Technical Reference Manual - Version 2.0
IL-1	2020 Illinois Statewide Technical Reference Manual for Energy Efficiency, Version 8.0
MA-1	Massachusetts Technical Reference Manual for Estimating Savings from Energy Efficiency Measures, 2016-2018 - Plan Version.
MA-2	Massachusetts Technical Reference Manual for Estimating Savings from Energy Efficiency Measures, 2019-2021 - Plan Version.
MA-3	MA RES21, Energy Optimization Study
ME	Efficiency Maine Technical Resource Manual - Version 2018.3
MI	2017 Michigan Energy Measures Database
MN	State of Minnesota Technical Resource Manual for Energy Conservation Improvement Programs - Version 3.0
NB	Energie NB Power Technical Resource Manual - September 2017
NEEP	Mid-Atlantic Technical Reference Manual - Version 8
NY	New York Standard Approach for Estimating Energy Savings from Energy Efficiency Programs - Version 7
OEB	Ontario Natural Gas Demand Side Management Technical Resource Manual - Version 3.0
PSEG-LI	PSEG Long Island - Technical Reference Manual - 2019
RI-1	Rhode Island Technical Reference Manual, 2020 Program Year, Electronic Version
RI-2	Rhode Island and Massachusetts Custom Projects Database
RI-3	Rhode Island Home Energy Report Program Impact and Process Evaluation, 2017.
VT	Efficiency Vermont Technical Reference User Manual - 2015
WI	Wisconsin Focus on Energy - 2018 Technical Reference Manual

Table F-2 and Table F-3 lists each residential and commercial and industrial (C&I) energy efficiency measure included in this study along with the TRM source from which the measure was characterized.

These typically reference the source of the algorithms used to determine the measures savings and impacts, which were then applied to the RI specific market, equipment saturations, climate, and customer consumption data used as inputs to the study.

Table F-2. Residential Energy Efficiency Measures

Class	Measure	Source
Appliance	Air Purifier	RI-1
Appliance	Clothes Dryer	RI-1
Appliance	Clothes Washer	RI-1
Appliance	Dehumidifier	RI-1
Appliance	Dehumidifier Recycle	RI-1
Appliance	Dishwasher	RI-1
Appliance	Freezer	RI-1
Appliance	Freezer Recycle	RI-1
Appliance	Refrigerator Recycle	RI-1
Appliance	Heat Pump Clothes Dryers	RI-1
Appliance	Refrigerator	RI-1
Behavioral	Home Energy Report	RI-1
Envelope	New Home Construction	Custom
Envelope	Air Sealing	IA
Envelope	Attic Insulation	IL-1
Envelope	Basement Insulation	IL-1
Envelope	Wall Insulation	IL-1
Hot Water	Solar Water Heater	Custom
Hot Water	Storage Water Heater	IL-1
Hot Water	Tankless Water Heater	IL-1
Hot Water	Faucet Aerator	RI-1
Hot Water	Heat Pump Water Heater (HPWH)	RI-1
Hot Water	Low Flow Shower Head	RI-1
Hot Water	Thermostatic Restrictor Shower Valve	RI-1
HVAC	Air Source Heat Pump (ASHP) Tune Up	IA
HVAC	Central Air Conditioning Tune Up	IA
HVAC	Duct Sealing	IA
HVAC	Whole House Fan	IA
HVAC	Boiler	IL-1
HVAC	Boiler Reset Control	IL-1
HVAC	Furnace	IL-1
HVAC	Thermostat Programmable	IL-1

Class	Measure	Source
HVAC	Thermostat Wi-Fi	IL-1
HVAC	Air Source Heat Pump (ASHP)	MA-2
HVAC	Mini-split Ductless Heat Pump (DMSHP)	MA-2
HVAC	Duct Insulation	ME
HVAC	Ceiling Fan	NEEP
HVAC	Central Air Conditioning (CAC)	NEEP
HVAC	Ground Source Heat Pump (GSHP)	NEEP
HVAC	Electric Resistance to DMSHP	MA-3
HVAC	Heat Recovery Ventilator (HRV)	RI-1
HVAC	Room Air Conditioner (RAC)	RI-1
Lighting	LED Linear Tube	NEEP
Lighting	LED Specialty - Candelabras, Globes (Interior)	RI-1
Lighting	LED Specialty - Reflectors (Exterior)	RI-1
Lighting	LED Specialty - Reflectors (Interior)	RI-1
Other	Advanced Smart Strips	RI-1
Other	Pool Pump	RI-1

Table F-3. C&I Energy Efficiency Measures

Class	Measure	Source
Behavioral	Building Operator Certification	MA-2
Compressed Air	Zero Loss Condensate Drain	IL-1
Compressed Air	Air Entrainment Nozzle	IL-1
Compressed Air	High Efficiency Air Compressor	IL-1
Compressed Air	Low Pressure Drop Filters	IL-1
Compressed Air	Refrigerated Air Dryer	IL-1
Compressed Air	Compressed Air Leak Repair	MN
Compressed Air	Custom VFD	RI-2
Compressed Air	Air Receiver for Load/No Load Compressor	VT
Envelope	LEED Certified	Custom
Envelope	Net-Zero Ready	Custom
Envelope	Building Shell Air Sealing	IA
Envelope	Attic/Roof Insulation	IL-1
Envelope	Cool Roof	NY
Hot Water	Low Flow Shower Head	IL-1
Hot Water	Recirculation Pump with Demand Controls	IL-1
Hot Water	Storage Water Heater	IL-1

Class	Measure	Source
Hot Water	Condensing Water Heater	IL-1
Hot Water	Faucet Aerator	IL-1
Hot Water	Pre-Rinse Spray Valve	IL-1
Hot Water	Circulator Pump EC Motor	ME
Hot Water	Heat Pump Water Heater (HPWH)	NEEP
Hot Water	Thermostatic Restrictor Shower Valve	NEEP
HVAC	Condensing RTU	Custom
HVAC	Energy Management System (EMS)	Custom
HVAC	Refrigeration Heat Recovery	Custom
HVAC	Retro-commissioning Strategic Energy Manager (RCx SEM)	Custom
HVAC	Waste Heat Recovery	Custom
HVAC	Waste Heat Recovery	Custom
HVAC	Guest Room Energy Management	IA
HVAC	Room/Wall-Mounted Air Conditioner (RAC)	IA
HVAC	Chiller, Air Cooled	IL-1
HVAC	Chiller, Water Cooler, Centrifugal	IL-1
HVAC	Boiler Reset Control	IL-1
HVAC	Demand Control Ventilation (DCV)	IL-1
HVAC	Destratification Fan - High Efficiency	IL-1
HVAC	Energy Recovery Ventilator (ERV)	IL-1
HVAC	Furnace	IL-1
HVAC	Ground Source Heat Pump (GSHP)	IL-1
HVAC	Infrared Heater	IL-1
HVAC	Kitchen Demand Control Ventilation	IL-1
HVAC	Package Terminal Air Conditioner (PTAC)	IL-1
HVAC	Package Terminal Heat Pump (PTHP)	IL-1
HVAC	Steam Boiler Stack Economizer	IL-1
HVAC	Steam Pipe Insulation	IL-1
HVAC	Water Boiler Stack Economizer	IL-1
HVAC	Advanced Thermostat (Wi-Fi Thermostat)	MA-2
HVAC	Dual Enthalpy Economizer Controls	MA-2
HVAC	Steam Boiler	MI
HVAC	Computer Room Air Conditioner (CRAC)	MN
HVAC	High Efficiency Unit Heaters	MN
HVAC	Air Source Heat Pumps (ASHP)	NEEP
HVAC	Boiler	NEEP
HVAC	Mini-split Ductless Heat Pump (DMSHP)	NEEP

Class	Measure	Source
HVAC	Unitary Air Conditioner	NEEP
HVAC	Electric resistance and RAC blend to DMSHP (Partial)	NEEP
HVAC	Condensing Make Up Air Unit	OEB
HVAC	Combo Condensing Boiler/Water Heater	RI-1
HVAC	Custom HVAC	RI-2
HVAC	Steam Trap	WI
HVAC Motors	HVAC EC Motor	MA-2
HVAC Motors	HVAC VFD - Cooling Tower	NB
HVAC Motors	HVAC VFD - Fan	NB
HVAC Motors	HVAC VFD - Pump	NB
Kitchen	Infrared Broiler	IA
Kitchen	Fryer	IL-1
Kitchen	Griddle	IL-1
Kitchen	Oven	IL-1
Kitchen	Dishwasher	IL-1
Kitchen	Hot Food Holding Cabinet	IL-1
Kitchen	Steamer	IL-1
Lighting	LED Exit Sign	IL-1
Lighting	Lighting Controls (Interior), Daylighting	IL-1
Lighting	Lighting Controls (Interior), Occupancy	IL-1
Lighting	LED Parking Garage (Exterior)	ME
Lighting	LED High Bay	NB
Lighting	LED Pole Mounted (Exterior)	NB
Lighting	LED Specialty - Reflectors (Exterior)	NB
Lighting	LED Specialty - Reflectors (Interior)	NB
Lighting	Linear LED Tube	NB
Lighting	LED Luminaire	PSEG-LI
Lighting	LED Refrigerated Case Lighting	PSEG-LI
Lighting	Advanced Network Lighting Controls	WI
Office Equipment	Advanced Smart Strips	MN
Process	Motor Controls - Conveyors	Custom
Process	Motor Controls - Pumps	Custom
Process	Motor Controls - Process	NB
Process	Custom Processes	RI-2
Refrigeration	Refrigerated Vending Machines	IA
Refrigeration	Refrigerated Case Anti-Sweat Door Heaters	IL-1
Refrigeration	Refrigerated Walk-ins Evaporator Fan Control	IL-1

Class	Measure	Source
Refrigeration	Door Closers	IL-1
Refrigeration	ENERGY STAR Ice Maker	MA-1
Refrigeration	Refrigerated Case Night Cover	MA-1
Refrigeration	Refrigerated Case Door Gaskets	NEEP
Refrigeration	Refrigerated Case EC Motor	PSEG-LI
Refrigeration	Refrigerated Walk-ins EC Motor	PSEG-LI
Refrigeration	Custom Refrigeration	RI-2
Refrigeration	Refrigeration Defrost Control	VT

Note: Many measures were characterized using technical resource manuals (TRM) and other resources from jurisdictions other than Rhode Island in order to obtain more granular and segment specific savings estimates. However, in most cases, Rhode Island specific jurisdictional data from the Rhode Island TRM was used to populate algorithms sourced from other jurisdictions' TRMs.

Measure Ramp-Up

As described in Appendix A, measures that represent significant savings and are not currently offered by existing programs have ramp rates of 33%, 66%, and 100% applied in the first three years of the study, respectively. For measures that are currently offered but at levels lower than expected, ramp rates of 50%, 75%, 100% were applied in the first three years, respectively. Table F-4 lists the measures and ramp rates where they are applied. Measures needing ramp rates were identified by comparing measure-level potential results to measure-level assumptions in the 2020 Energy Efficiency Program Plan Benefit-Cost Ratio workbook and through feedback provided by National Grid after their review of measure-level draft results. [30]

[30] National Grid's 2020 EEPP (Docket No. 4979) is accessible at: http://www.ripuc.ri.gov/eventsactions/docket/4979page.html. The Excel workbook used for this study is not publicly available.

Table F-4. List of Measures with Ramp Rates

Sector	Measure	Ramp Rate
Residential and Residential Low-Income	Clothes Washer	33% / 66% / 100%
	Electric Resistance to DMSHP	50% / 75% / 100%
	Freezer	33% / 66% / 100%
	Heat Pump Clothes Dryers	33% / 66% / 100%
	LED Specialty - Candelabras, Globes (Interior)	50% / 75% / 100%
	Mini-split Ductless Heat Pump (DMSHP)	50% / 75% / 100%
	Pool Pump	50% / 75% / 100%
	Refrigerator	33% / 66% / 100%
Commercial and Industrial	Faucet Aerator	50% / 75% / 100%
	Boiler Reset Control	50% / 75% / 100%
	Condensing Make Up Air Unit	50% / 75% / 100%
	Infrared Heater	50% / 75% / 100%
	Fryer	50% / 75% / 100%

F.1.2 Appliance and Equipment Standards

Updates to US Federal appliance and equipment standards will impact the claimable savings for measures that incorporate the relevant appliances and equipment. This study accounts for updates to standards that will occur during the study period. The study only considers published final standards updates with compliance dates within the study period as draft standards are subject to revisions and revocations. Standards that will be updated before the study period are applied for entire study period – impacting the baseline efficiency of the applicable efficiency measures.

Updates to Rhode Island state standards were not considered in this study as there were no finalized updates at the time of the study's initiation. While proposed state legislation existed to increase efficiency standards beyond federal regulations. there was too much uncertainty in whether and when standards would come into force to include in the study.

Table F-5 lists the final published updates to federal U.S. standards with compliance dates within the study period. Each of these updated standards will increase the efficiency of baseline equipment beginning in the compliance year, which results in less claimable savings from efficiency measures for these technologies.

Table F-5. Federal U.S. standard updates within study period

Product	Compliance Date
Residential – Central Air Conditioners and Heat Pumps	2023
Commercial – Warm Air Furnaces	2023

F.1.3 EISA Lighting Standards

At the time of this study, federal efficiency standards for lighting were in flux due to uncertainty regarding the triggering of the "backstop" mechanism for specialty lighting in the 2007 Energy Independence and Security Act (EISA). To understand the impact of this uncertainty, the study incorporates two scenarios regarding specialty and reflector light bulbs:

- The **baseline scenario** assumes the backstop provision is delayed and/or the market naturally transforms beginning on January 1st, 2023 (nearly halfway through the study period). Under this scenario, sub 45 lumen per watt reflector and speciality lamp sales end the year of compliance/transformation.

- The **alternative scenario** assumes the backstop provision begins in 2020 before the study period begins. Under this scenario, savings from reflectors and speciality lamp measures are not included.

At the beginning of the study, the underlying assumption was that EISA standards for General-Service Lamps (GSL) would come into force in 2020. Under this assumption, and allowing for a 1-year sell-through period of existing halogen bulb stocks, the study stakeholders agreed that A-Lamp savings would not be included in the study for 2021 and beyond. Moreover, given the relative advantage that LED lighting has over CFL bulbs in the market, the study assumes that LEDs are the baseline for GSL applications throughout the study period in both the residential and commercial markets.

Claimable Savings: The study treats claimable savings from bulbs purchased pre-enforcement as follows. Because residential halogen bulbs have an EUL of 3 years[31], while commercial halogen bulbs have an EUL of 1 year based on typical annual operating hours of these bulbs, the study assumes bulb savings are claimable beyond the date of enforcement to account for halogen bulbs that would be in-service after the enforcement date. Although savings from new bulbs are not attributed to programs after January 1, 2023, savings from bulbs purchased prior to this time are claimed post-enforcement dependant on the install year *(see Table F-6 and Table F-7).*

[31] Assuming the rated lifetime of a Halogen bulb is 2,000-4,000 hours and the average hours of use a residential application is approximately 1,000 hours per year

Table F-6. Residential Persistence of Bulb Savings by Install Year

Install year	Years of claimable savings	Notes
2021	3	First year of study
2022	3	
2023	0	Begin backstop enforcement / assume market transformation Claimable savings from 2021 – 2022 installs First year with no new program sales
2024-2025	0	Claimable savings from 2021 – 2022 installs
2026	0	No claimable savings

Table F-7. Commercial Persistence of Bulb Savings by Install Year

Install year	Years of claimable savings	Notes
2021	2	First year of study
2022	1	
2023	0	Begin backstop enforcement / assume market transformation Claimable savings from 2021 – 2022 installs for this year only First year with no new program sales
2024-2026	0	No claimable savings

F.1.4 Building Codes

Updates to applicable building codes – to the extent they increase the energy efficiency of buildings built to code – will impact the claimable savings for new construction energy efficiency measures.

The State of Rhode Island intends to implement 2018 IECC standards by September 1^{st}, 2020. This study assumes that new buildings will be built to this standard in 2021 and beyond, thus making 2018 IECC the baseline for NC measures. The State of Rhode Island intends to update buildings codes twice during the study period by implementing IECC updates (scheduled for 2021 and 2024) in the summer of the year after they are published (i.e. September 1^{st}, 2022 and September 1^{st}, 2025, respectively).

Based on information provided by National Grid and making an adjustment to the applicability of the 2018 IECC to mitigate model complexity, this study uses the following IECC code impacts to baseline energy consumption for new construction measures.

Table F-8. Assumed RI New Building Energy Codes in Study

Rhode Island's Energy Code	Years Applies to in Study	Sector	Efficiency improvement estimate[32][33]
2018 IECC	2021-2024	Residential	3%
		Non-Residential	8%
2021 IECC	2025-2026	Residential	5%
		Non-Residential	10%

F.1.5 Enabling infrastructure

Advanced metering functionality (AMF) is a key piece of enabling infrastructure considered in this study. To explore the potential impact of AMF deployment, the study considers three scenarios regarding AMF as described in Table F-9.

Table F-9. AMF Scenarios

Scenario	Description
No AMF	AMF is not available during study period.
AMF	AMF is available during the study period beginning in 2024. AMF data sharing is treated as described in National Grid's AMF Business Case, i.e. default data sharing with customers, but 3rd parties cannot directly access this data unless explicitly shared by the customer. Additionally, AMF does not enable time varying rates under this scenario to stay consistent with the AMF Business Case.
AMF+	AMF is available during the study period beginning in 2024. AMF data sharing is more liberal than described in National Grid's AMF Business Case, i.e. default data sharing with both customers and 3rd parties. Additionally, AMF does enable time varying rates under this scenario.

AMF deployment impact energy efficiency and demand response as follows:

- EE Impacts: The study assumes AMF leads to barrier reductions for EE measures (**AMF+** will lead to greater barrier reductions than **AMF** due to enhanced 3rd party data accessibility).
- DR Impacts: For demand response, the study assumes **AMF+** enables time-variable pricing. For both AMF scenarios, the study assumes that AMF reduces direct load control equipment costs, which an impact the cost-effectiveness of some active DR measures.

The study assumes the AMF scenario assumptions impact only the second three-year period of the study from 2024 to 2026, as no AMF infrastructure will be in place prior to this time period. This assumption is consistent with National Grid's AMF Business Case.

[32] Improvement estimates are approximately at the mid-point of National Grid's low-end and high-end improvement estimates for each code update.
[33] Improvement estimate percentages are relative to building code being replaced.

F.2 Market Characterization

F.2.1 Customer Population Counts

Customer population counts are a key parameter for defining market opportunities. Population counts were estimated using anonymized monthly customer meter data provided by National Grid. The final population counts for each sector and segment are presented in Table F-10.

Table F-10. Customer Sector and Segment Population Counts.

Sector / Segment	Population
Residential	364,494
Single Family	*318,737*
Multi-Family[34]	*45,757*
Residential Low Income	29,883
Commercial	38,821
Office	14,761
Retail	7,028
Food Service	3,321
Healthcare/ Hospitals	3,308
Campus/ Education	1,472
Warehouse	1,405
Lodging	3,321
Other Commercial	2,909
Food Sales	1,296
Industrial	2,373

To arrive at these population estimates, National Grid's customer data was treated with the following approach.

F.2.1.1 Low consumption accounts

Accounts with low levels of consumption were dropped under the assumption that these accounts are not active and/or use such little energy that they will not be applicable to energy efficiency and other measures. Approximately 4,500 residential accounts below an annual consumption of 50 kWh were removed, and approximately 17,500 commercial/industrial accounts below an annual consumption threshold of 2,000 kWh were removed from the analysis.[35] Low consumption residential accounts removed from the analysis represented <0.1% of residential electric consumption, and low

[34] The multi-family population count represents individual residential units within multi-family buildings.
[35] The 2,000 kWh threshold for commercial/industrial accounts was chosen to conform with the threshold used in the Rhode Island C&I Market Characterization Data Collection Study as many other model inputs are based on this study.

consumption commercial/industrial accounts removed from the analysis represented 0.3% of commercial/industrial electric consumption.

F.2.1.2 Accounts without a full year of meter data

Approximately 68,000 residential accounts and 3,000 commercial/industrial accounts had only a partial year of meter data. Accounts with less than 350 days of meter data were excluded from the calculation of other metrics (e.g. mean consumption) to avoid skewing these parameters. However, most of these accounts likely represent actual customer that are eligible for efficiency measures. Accordingly, these accounts were included in population counts on a pro-rated basis based on the number of metering days associated with each account. For example, a customer account with 6 months of metering data would be equivalent to 0.5 customers. This approach accounts for customers that may have switched accounts during the data's time frame and other issues that would reduce continuous customer data.

F.2.1.3 Sector and segment assignments

Customer accounts were assigned to sectors and segments based on multiple criteria.

Residential and low-income accounts

Residential accounts were classified based their rate class, dwelling type, and a multi-family indicator included in the monthly customer meter data received by Dunsky. Accounts with a multi-family flag and/or a dwelling type indicating an account within a building with 4+ units were assigned to the residential sector and multi-family segment.[36] Accounts with a low-income rate classification were assigned to the residential low-income sector.[37] The remaining accounts were assigned to the residential sector and single family segment.

Finally, there were many accounts with residential rate classifications with extremely high levels of consumption that are unlikely to be single residential customers and more likely to be master-metered multi-family accounts. Accordingly, accounts above a consumption threshold were assigned to the commercial sector and lodging segment, as measures for this segment will be more applicable to these accounts. The consumption threshold was set at six standard deviations above the mean annual consumption for all residential accounts – making the threshold approximately 48,000 kWh. This threshold is high enough to avoid misclassifying significant numbers of high consuming non-master metered multi-family accounts, while still capturing a significant portion of master metered multi-family accounts and assigning a correct segment label. Under this threshold, 897 accounts were deemed as master metered multi-family buildings.

[36] Some accounts with commercial rate classifications were flagged as multi-family accounts. These accounts were assumed to signify a multi-use building and/or master metered multi-family building. Of these accounts, ones with NAICS code classifications were assigned to a commercial segment based on the NAICS code. Accounts without NAICS codes were assigned to the commercial sector and lodging segment.
[37] Accounts flagged as multi-family with a low-income rate classification were included in the residential sector and multi-family segment. The vast majority (91%) of low-income accounts were not flagged as multi-family.

Commercial and industrial accounts

Commercial and industrial accounts were classified based on NAICS codes associated with accounts as included in the customer data. Approximately 35% of accounts representing 22.5% of consumption did not have NAICS codes associated with them. These "unknown" customer accounts were assigned to sectors and segments on a pro-rated basis based on known segment populations and rate class distributions (e.g. segments with more known accounts receive a higher proportion of the unknown accounts). Metrics derived from customer data were adjusted to reflect the addition of unknown accounts (e.g. unknown accounts typically had lower average annual consumption, thus reducing the average annual consumption metric for most segments). Table F-11 shows the customer population counts for commercial and industrial accounts before and after the reassignment of unknown accounts.

Table F-11. C&I Customer Sector and Segment Population Counts Before and After Reassignment of Unknown Accounts.

Sector / Segment	Population Prior to Prorating Unknown Accounts	Prorated Population
Commercial	25,596	38,821
Office	9,610	14,761
Retail	4,583	7,028
Food Service	2,245	3,321
Healthcare/ Hospitals	2,156	3,308
Campus/ Education	1,008	1,472
Warehouse	936	1,405
Lodging	2,265	3,321
Other Commercial	1,900	2,909
Food Sales	892	1,296
Industrial	1,609	2,373
UNKNOWN ACCOUNTS	*13,983*	*N/A*

F.2.1.4 Block Island Utility District and Pascoag Utility District

Electric customer population counts were derived using National Grid data only. The data did not include customer information for non-National Grid electric utilities operating in Rhode Island – namely Block Island Utility District ("Block Island") and Pascoag Utility District ("PUD"). In order to derive savings estimates for Block Island and PUD, this study simply scales estimates savings based on the ratio of National Grid customer populations to Block Island and PUD customer populations. Residential and non-residential customer counts for Block Island and PUD were provided by the Rhode Island Public Utilities Commission.

Overall, non-National Grid utilities serve 5,619 residential and 1,164 non-residential customers – representing approximately 1.4% and 2.8% of National Grid's customer populations, respectively.

Therefore, residential and non-residential savings estimates for non-National Grid utilities can be estimated by multiplying National Grid's savings estimates by 1.4% and 2.8%, respectively. Table F-12 shows the residential and non-residential customer counts for each utility and their respective savings scaling factors.

Table F-12. PUD and Block Island customer counts and savings scaling factors

Utility	Residential Customers	Residential Scaling Factor	Non-Residential Customers	Non-Residential Scaling Factor
PUD	4,278	1.070%	595	1.413%
Block Island	1,341	0.335%	569	1.351%
Total	*5,619*	*1.405%*	*1,164*	*2.764%*

F.2.2 Market Baseline Data

The study uses residential baseline information from the draft National Grid Rhode Island Residential Appliance Saturation Survey (Study RI2311) and accompanying Excel workbook dated October 20, 2018. Commercial and industrial baseline data was derived from preliminary data provided by National Grid as part of the Rhode Island C&I Market Characterization Data Collection Study on December 5, 2019. For many commercial and industrial segments, there were not enough observations to produce reasonably significant results at the segment level. For these segments, overall metrics computed from all observations were used instead. The only segments with enough observations to produce reasonably significant results were the office, retail, and manufacturing / industrial segments.

Where Rhode Island specific baseline data was not available (or was based on a low number of observations), baseline data from neighboring jurisdictions in the Northeast United States was leveraged and adjusted for Rhode Island specific attributes wherever possible.

F.2.3 Growth Factors

Table F-13 lists the growth factors used in this study. Growth factors are based on the statewide growth in existing housing stock determined by the issuance of housing construction permits in 2018.[38] Unique growth factors are applied to residential single family and multi-family segments due to data available. The growth of commercial and industrial sectors is assumed to be equivalent to the overall growth in housing stock in Rhode Island.

Table F-13. New growth factors

Sector	Growth Factor
Residential – Single Family and Low Income	0.37%
Residential – Multi-Family	0.67%
Commercial and Industrial	0.5%

[38] HousingWorksRI. "2019 Housing Fact Book". Accessed at: https://www.housingworksri.org/Portals/0/Uploads/Documents/2019%20Pages/HFB2019_compressed.pdf

F.3 Program Characterization

Program characterization was performed by reviewing past EE program investments and savings, as well as the 2020 EE Plan investments and savings. These were then compared to Dunsky's internal database of program incentive levels from other potential studies and program design work and the program costs, incentive levels and measure barrier reductions resulting from enabling activities in each program were set for each of the program scenarios.

F.3.1 Residential Programs

Table F-14 describes each residential program characterized for this study and the default barrier reductions applied based on existing enabling activities.

Table F-14. Residential Energy Efficiency Program Enabling Activity Descriptions

Program	Description	Barrier reductions
Residential New Construction	Promotes the construction of high-performing energy efficient single family, multifamily, and low-income homes, as well as the education of builders, tradesmen, designers, and code officials.	Half step reduction for contractor training and design support.
EnergyWise	Offers single-family customers home energy assessments (site visit and on-line) and information regarding their actual energy usage. The program also includes finance opportunities to customers such as the HEAT Loan. In addition, a 100% landlord incentive will be offered to address the split incentive barrier.	Half step barrier reduction for energy audit, technical assistance, split incentive assistance, and financing.
Multifamily Programs	Comprehensive energy services for multifamily customers include energy assessments and incentives. Coordinated services will be offered for all types of multifamily properties, including alignment with refinance cycles.	Half step barrier reduction for energy audits and financing.
Residential Home Energy Report	The Home Energy Reports (HER) program achieves energy savings through changes in customer behavior.	No barriers applied for this program in model
EnergyStar Lighting	This initiative provides discounts to customers for the purchase of ENERGY STAR® lighting through instant rebates, special promotions at retail stores, pop-up retailer, and social marketing campaigns.	No barrier reduction as it is assumed that strategic marketing would be reflected in past sales.
ENERGY STAR® Appliances	This program promotes the purchase of high efficiency household appliances, including kitchen appliances and electronics. These appliances carry an ENERGY STAR® label. The program also offers refrigerator recycling, which promotes more efficient refrigerators while removing non-efficient units from the market.	No barrier reduction as it is assumed that strategic marketing would be reflected in past sales.

Program	Description	Barrier reductions
ENERGY STAR® HVAC Program	This program promotes the installation of high efficiency central air conditioners and new energy efficient natural gas related equipment. The program provides training for contractors.	Half step barrier reduction to account for contractor training and outreach.
Low-Income Single Family	For income eligible customers, includes free assessments, direct install of low-cost measures, assesses appliances determining if they qualify for no-cost replacement & replaces as applicable, full free weatherization. If equipment qualifies, provides full HVAC replacement (for all heating fuel except natural gas) with ASHP (that also provides cooling).	Full-step barrier reduction to account for the range of assessment and outreach activities.
Low-Income Multi Family		
Other programs	A range of other programs run by National Grid do not claim savings directly and are therefore not characterized in the model. These include Community Based Initiatives, Residential Pilots, and Education Programs.	Program costs added to totals in the model.

Low Scenario: Current Programs

The Low Scenario applies current program parameters as per National Grid's 2020 EE Plan.

Table F-15. Residential Energy Efficiency Program Inputs (Low Scenario)

Program	Fixed Costs	Variable Costs ($/MMBTU)	Average Incentive Level	Barrier Level Impact
New Construction	$114,231	75.1	41%	-0.5
EnergyStar HVAC	$58,621	28.0	36%	-0.5
EnergyWise	$151,271	66.5	84%	-0.5
EnergyWise Multi Family	$29,878	35.3	79%	-0.5
Behavior Feedback[39]	$9,842	1.1	100%	n/a
EnergyStar Lighting	$90,537	10.0	58%	None
EnergyStar Appliances	$74,117	60.1	39%	None
Low-Income SF	$505,319	155.8	100%	-1.0
Low-Income MF	$208,564	27.7	100%	-1.0

Note: Incentives are expressed as the portion of efficient equipment incremental costs covered by the program.

Mid Scenario: Best in class incentives with increased investments in enabling strategies

The Mid Scenario increases incentives to 75% except where they already exceeded this level. Where feasible, a ½ step barrier reduction was added to represent additional enabling activities and the fixed costs increased by 25% and variable costs by 15% to account for increased program investments. The ratio of incentives to non-incentive costs in the 2020 EE Plan is 4.7 across National Grid's

[39] *Dunsky's understanding is that the HER program is already rolled out over maximum coverage, so no program level scenarios are proposed. Because HER are pushed directly to clients, no adoption curves or barriers are applied.*

residential portfolio, indicating there is room for further enabling strategies investments to have an impact on customer barriers.

Table F-16. Residential Energy Efficiency Program Inputs (Mid Scenario)

Program	Fixed Costs	Variable Costs ($/MMBTU)	Average Incentive Level	Barrier Level Impact
New Construction	$142,790	86.4	75%	-1.0
EnergyStar HVAC	$73,277	32.3	75%	-1.0
EnergyWise	$189,089	76.5	84%	-1.0
EnergyWise Multi Family	$37,348	40.6	79%	-1.0
Behavior Feedback	$12,303	1.8	100%	n/a
EnergyStar Lighting	$113,172	11.5	75%	-0.5
EnergyStar Appliances	$92,647	69.1	75%	-0.5
Low-Income SF	631,650	179.1	100%	-1.5
Low-Income MF	260,705	31.9	100%	-1.5

Note: Incentives are expressed as the portion of efficient equipment incremental costs covered by the program.

Max Scenario: 100% Incentives

Under the Max scenario, all incentives are increased to 100% and the same barrier reductions are applied as in the Mid Scenario. This scenario assumes that best in class barrier reducing effort was applied and that with full incentives that program budgets were not constrained to pursue all cost-effective savings.

Table F-17. Residential Energy Efficiency Program Inputs (Max Scenario)

Program	Fixed Costs	Variable Costs ($/MMBTU)	Average Incentive Level	Barrier Level Impact
New Construction	$142,790	86.4	100%	-1.0
EnergyStar HVAC	$73,277	32.3	100%	-1.0
EnergyWise	$189,089	76.5	100%	-1.0
EnergyWise Multi Family	$37,348	40.6	100%	-1.0
Behavior Feedback	$12,303	1.8	100%	n/a
EnergyStar Lighting	$113,172	11.5	100%	-0.5
EnergyStar Appliances	$92,647	69.1	100%	-0.5
Low-Income SF	631,650	179.1	100%	-1.5
Low-Income MF	260,705	31.9	100%	-1.5

Note: Incentives are expressed as the portion of efficient equipment incremental costs covered by the program.

F.3.2 Commercial Programs

Table F-18 describes each non-residential program characterized for this study and the default barrier reductions applied based on existing enabling activities.

Table F-18. Non-Residential Energy Efficiency Program Enabling Activity Descriptions

Program	Description	Barrier reductions
Large Commercial New Construction and Building Energy Code and Appliance Standards	This program promotes energy efficient design and construction practices in new and renovated commercial, industrial, and institutional buildings. The program promotes and incentivizes the installation of high efficiency equipment in existing facilities during building remodeling and at the time of equipment failure and replacement. program provides both technical and design assistance. Incentives are also offered to owner's design teams for their time and effort to meet program requirements. The program also promotes compliance with the building energy code and increased use of the Stretch Code to support the State's goals and objectives.	Half step reduction for Contractor training, and design support.
Large Commercial Retrofit	Large Commercial Retrofit is a comprehensive retrofit program designed to promote the installation of energy efficient equipment such as lighting, motors, and heating, ventilation and air conditioning (HVAC) systems, thermal envelope measures, and custom measures in existing buildings. The Company offers technical assistance to customers to help them identify cost-effective efficiency opportunities and pays incentives to assist in defraying part of the material and labor costs associated with the energy efficient measures. The Company also offers education and training, such as the building operator certification (BOC) training.	Half step barrier reduction for energy audit recommendations, technical assistance, training, and financing.
Small Business Direct Install	The Small Business Direct Install Program provides direct installation of energy efficient lighting, non-lighting retrofit measures, and gas efficiency measures. The Customer share of the total project cost of a retrofit is discounted 15% for a lump sum payment or the customer has the option of spreading the payments over a two-year period, interest free.	Half step barrier reduction for direct install and deferred payment option.
C&I Multifamily	The Multifamily program provides joint residential and commercial energy services to condominiums and apartment complexes for energy efficiency upgrades with no cost audits. The multifamily C&I program also serves customers like non-profits, group homes and houses of worship that traditionally do not fit within the predefined program structure.	Half-step barrier reduction as per other large C&I program areas.
Commercial Pilots	This program does not claim savings directly.	Program costs added to totals in the model.
Financing	The financing program costs are rolled into the Large and Small/Med commercial programs.	Incentive equivalent to 15% added to the retrofit programs.[40]

[40] Financing incentives were calculated by taking the net present value of the interest buy-down based on the maximum repayment duration.

Low Scenario: Current Programs

The Low Scenario applies current program parameters as per National Grid's 2020 EE Plan.

Table F-19. Non-Residential Energy Efficiency Program Inputs (Low Scenario)

Program	Fixed Costs	Variable Costs ($/MMBTU)	Average Incentive Level	Barrier Level Impact
New Construction	$859,254	32.1	65%	-0.5
Large Commercial Retrofit	$2,769,200	13.4	65%*	-0.5
Small Business Direct Install	$928,150	14.5	85%*	-0.5
C&I Multifamily	$51,758	13.6	90%	-0.5

Note: Incentives are expressed as the portion of efficient equipment incremental costs covered by the program.
* Includes 15% additional incentive to capture impact and costs for OBR financing.

Mid Scenario: Best in class incentives with increased investments in enabling strategies

The Mid Scenario increases incentives to 75% except where they already exceeded this level. Where feasible, a ½ step barrier reduction was added to represent additional investment in enabling activities and the fixed costs increased by 25% and variable costs by 15% to account for increased program investments based on professional judgement. The ratio of incentives to non-incentive costs in the 2020 EE Plan is 2.0 across National Grid's commercial portfolio, indicating there is some room for further enabling strategies investments to have an impact on customer barriers.

Table F-20. Non-Residential Energy Efficiency Program Inputs (Mid Scenario)

Program	Fixed Costs	Variable Costs ($/MMBTU)	Average Incentive Level	Barrier Level Impact
New Construction	$1,074,067	36.9	75%	-1.0
Large Commercial Retrofit	$3,461,500	15.4	75%*	-1.0
Small Business Direct Install	$1,160,187	16.7	85%*	-1.0
C&I Multifamily	$64,698	15.7	90%	-1.0

Note: Incentives are expressed as the portion of efficient equipment incremental costs covered by the program.
* Includes 15% additional incentive to capture impact and costs for OBR financing.

Max Scenario: 100% Incentives

Under the Max Scenario, all incentives are increased to 100% and the same barrier reductions are applied as in the Mid Scenario. This scenario assumes that best in class barrier reducing effort was applied and that with full incentives that program budgets were not constrained to pursue all cost-effective savings.

Table F-21. Non-Residential Energy Efficiency Program Inputs (Max Scenario)

Program	Fixed Costs	Variable Costs ($/MMBTU)	Average Incentive Level	Barrier Level Impact
New Construction	$1,074,067	36.9	100%	-1.0
Large Commercial Retrofit	$3,461,500	15.4	100%	-1.0
Small Business Direct Install	$1,160,187	16.7	100%	-1.0
C&I Multifamily	$64,698	15.7	100%	-1.0

Note: Incentives are expressed as the portion of efficient equipment incremental costs covered by the program.

F.4 Economic and other parameters

F.4.1 Discount and Inflation Rates

The discount and inflation rates were sourced from National Grid's Rhode Island 2020 BCR Model as filed with the Annual Energy Efficiency Plan for 2020. As per the BCR Model, they were calculated by the National Grid using the RI Standards formula on April 22, 2019. The rate values as shown in Table F-22 were used across the study as necessary.

Table F-22. Discount and inflation rates

Rate Name	Rate Value
Nominal Discount	2.911%
Real Discount	0.835%
Inflation	2.059%

F.4.2 Avoided Costs

Avoided costs were sourced from National Grid's Rhode Island 2020 BCR Model as filed with the Annual Energy Efficiency Plan for 2020. The majority of avoided costs within National Grid's BCR Model were sourced from the *Avoided Energy Supply Components (AESC) in New England: 2018* report. Dunsky's DEEP model uses aggregated inputs for avoided costs based on the unit of value (e.g. $/kWh, $/kW, $/MMBTU); therefore, value stream components of the Rhode Island Test with the same unit of value were generally aggregated to fit the model input structure. For years beyond those covered by the BCR Model (2051-2067), avoided costs were calculated using a simple linear forecast.

The aggregated avoided cost inputs used in this study are available in a separate workbook accompanying this report. The values are reported in 2021 real-dollar terms.

Measure Vintage Year Specific Value Streams

There are several avoided cost value streams included in the RI Test that are dependent on the measure's year of installation. These values streams include energy and capacity DRIPE values and capacity-based reliability benefit values. Dunsky's DEEP model does not incorporate specific vintage year avoided cost value streams. Therefore, simplifications of these values streams were necessary. In these cases, a single stream of values was derived for the each year in the study period by:

1) First assuming the 2020 value stream as contained in the 2020 BCR Model applies to measures installed in each study year, then

2) Taking a weighted average across each study year with weights based on the proportion of each study year's resources still in existence (i.e. the measure's effective useful life has not been surpassed).

Due to significant differences in the EUL and treatment in forward capacity markets for energy efficiency, demand response and CHP measures, individual value streams were derived for each resource type (i.e. EE, DR, CHP, etc.).

For energy efficiency measures (including and heating electrification measures), avoided costs were derived under the assumption that 100% of resources are cleared in terms of capacity, capacity DRIPE, and reliability benefits.[41] Weights for measure year dependent values are derived from the energy savings persistence by year from a previous energy efficiency potential study conducted by Dunsky.

For demand response measures, avoided cost values assume measures are uncleared in terms of capacity, capacity DRIPE, and reliability benefits. Weights for measure year dependent values assume an average EUL of 10 years.

For CHP measures, avoided cost values assume 100% of CHP measures are cleared in terms of capacity, capacity DRIPE, and reliability benefits. Weights for measure year dependent values assume an average EUL of 16 years.

F.4.3 Retail Rates

The study uses marginal retail rates to estimate customer bill impacts – one component of calculating achievable potential – for energy savings measures. Marginal electric and gas retail consumption and demand rates were developed by reviewing National Grid Home and Business service electric and gas rates issued on September 26, 2019. To estimate the marginal rates by segment, Dunsky aggregated

[41] "Cleared" capacity refers to capacity resources that are successfully bid into ISO-NE capacity markets and "uncleared" capacity refers to capacity resources that reduce summer peak loads without being successfully bid into capacity markets. For a more thorough explanation of cleared and unclear capacity and their avoided cost value, please see the *AESC 2018* report accessible at: https://www.synapse-energy.com/project/aesc-2018-materials

the rate variable costs by rate classes (e.g. residential market, residential low-income, small C&I, general C&I and large C&I). Using consumption data by size and segment, Dunsky then blended the C&I rates to create general C&I segment rates.

The electricity rates were then forecasted through 2050 using their corresponding AESC retail energy and capacity rates forecasts yearly percent increases as a rate escalator. For years beyond the AESC data (2051-2067), avoided costs were calculated using a simple linear forecast. Natural gas, delivered fuels and water retail rates utilize their corresponding avoided cost values.

The retail rate inputs used in this study are available in a separate workbook accompanying this report. The values are reported in 2021 real-dollar terms.

F.4.4 Emission Factors

Marginal emission factors were sourced from the *Avoided Energy Supply Components (AESC) in New England: 2018* report as shown in Table F-23. These are the same emission factors utilized in National Grid's 2020 Energy Efficiency Program Plan (EEPP).

Table F-23. Marginal emission factors

Rate Name	Value
Electricity	0.4700 tCO2/MWh
Natural Gas	0.0585 tCO2/MMBtu
Oil	0.0805 tCO2/MMBtu
Propane	0.0695 tCO2,MMBtu

F.4.5 Baseline Energy and Demand Forecasts

To help discern the impact of the various measures analyzed in the MPS on overall energy consumption and demand in Rhode Island, the study establishes baseline energy and demand forecasts for the study period. Electric and natural gas consumption and electric demand forecasts provided by National Grid and delivered fuel forecasts developed by the Energy Information Agency were adjusted to remove the projected impacts of existing and planned energy efficiency programs and customer-sited solar adoption during the study period to avoid double counting impacts estimated throughout the MPS.

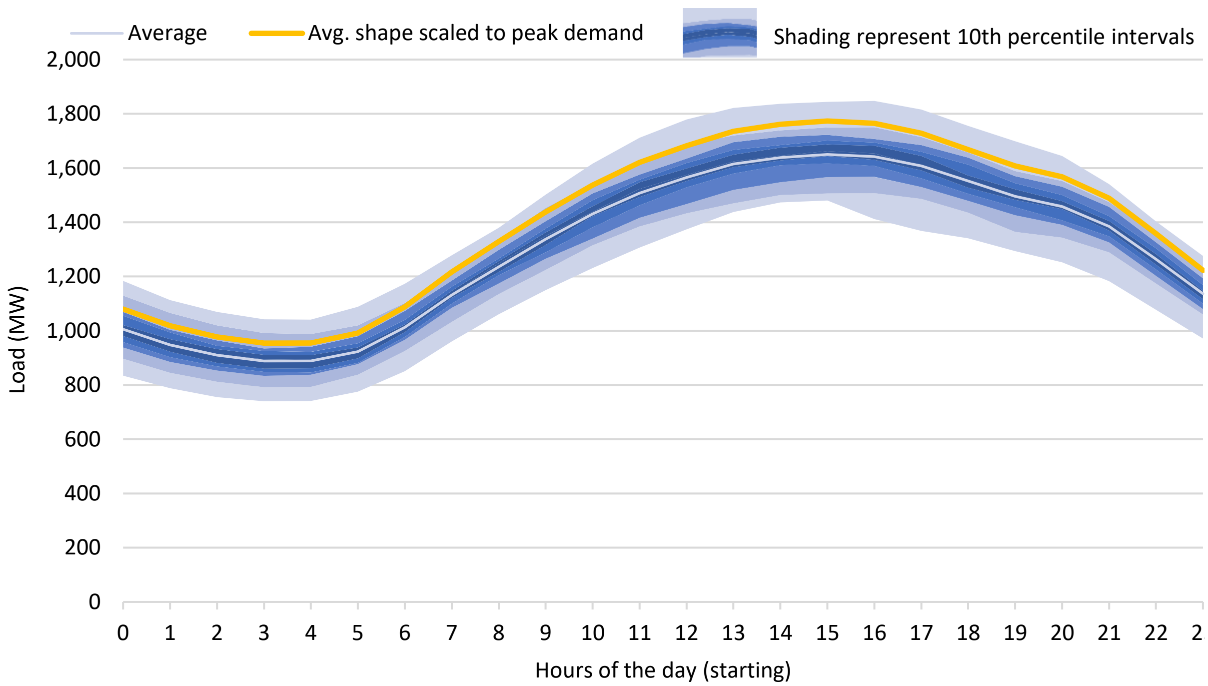
F.5 Demand Response Input

In addition to data described in this appendix, a number of other inputs were used in the demand response potential assessment.

F.5.1 Standard Peak Day

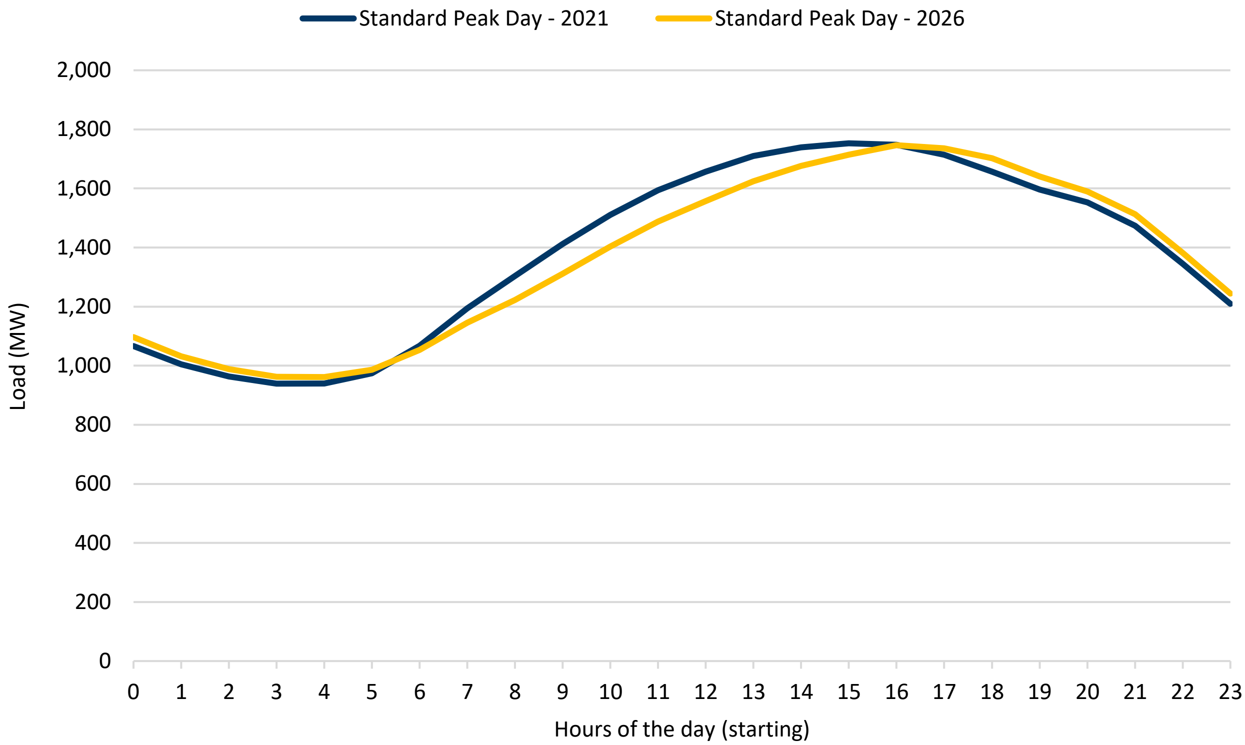
National Grid provided Dunsky with hourly historical load data. The data covered January 1st, 2014 to April 30th, 2019 (46,704 data points). This historical data was used to create standard peak day for the system.

Figure F-1. Standard Peak Day – National Grid, Rhode Island



When considering all the impacts on peak demand, such as energy efficiency, electrification and distributed energy, the initial effects are small. However, towards the end of the study period, the impact, mainly due to solar generation, starts to shift the time of peak demand to later at night. Peak shape is an important factor for DR potential.

Figure F-2. Evolution of the Standard Peak Day



F.5.2 End-Use Breakdowns

Dunsky developed end-use load curves for each market sector and end-use and where relevant, for individual segments. **Note that these breakdowns are for the electric consumption only, not the whole building (all fuel) energy use.** These provide a basis for three study processes:

1. They were used to assess standard peak day adjustments for DR addressable peak determination.
2. They were used to develop savings for custom measures, which are expressed as the potential savings as a portion of the associated end-use consumption.
3. They were used to benchmark savings when calibrating the model

The end-use load curves were developed from the following sources:

- US Department of Energy (US DOE) published load curves, taken from buildings in the Rhode Island climate zones, and adjusted to account for heating energy source.
- Engineered load profiles and Dunsky's in-house developed sample consumption profiles

In this study, the industrial sector was grouped into one segment “Manufacturing / Industrial”. The segment was modeled using one industrial end-use (“Industrial”), as seen in Figure F-3. Industrials were evaluated using Dunsky’s internal datasets.

Using this breakdown, an annual (hourly – 8670 hours) building energy consumption simulation from the US DOE (*Commercial Reference Buildings & Building America House Simulation Protocols*) allowed for the recreation of the end-use breakdown for a standard peak day. The figure below presents the end-use and sector breakdown of the electric system.

Figure F-3. Standard peak day – Sector breakdown

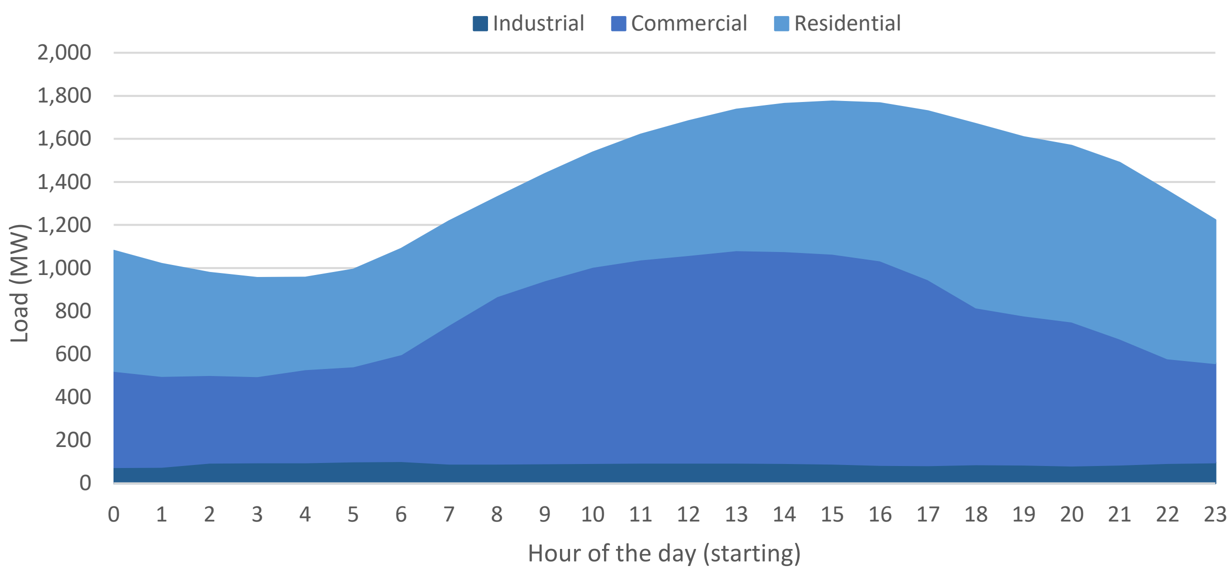
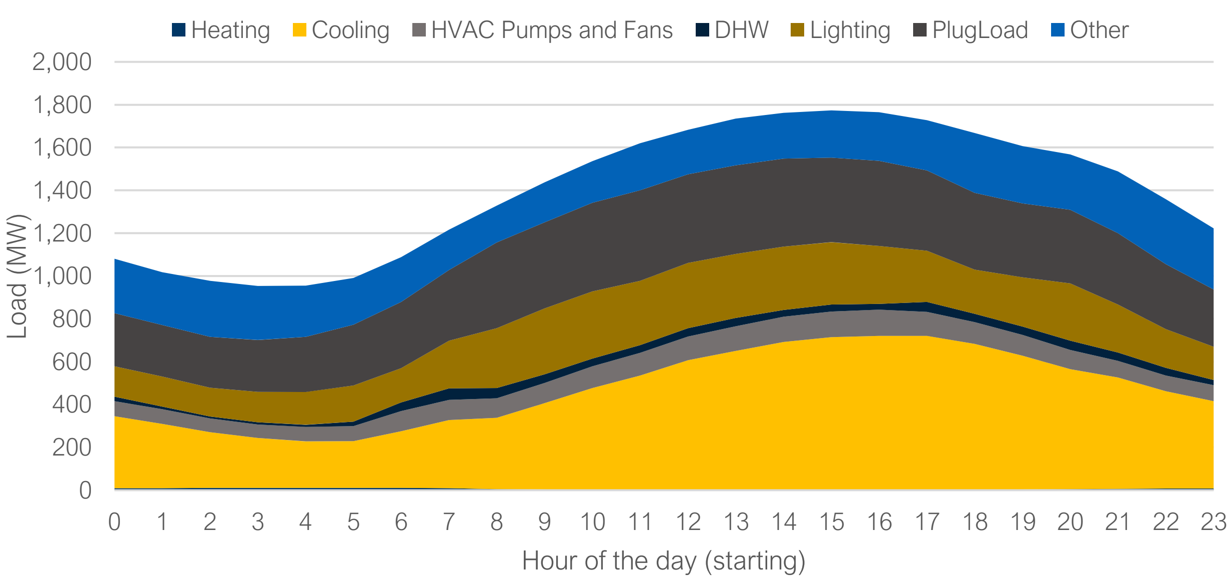


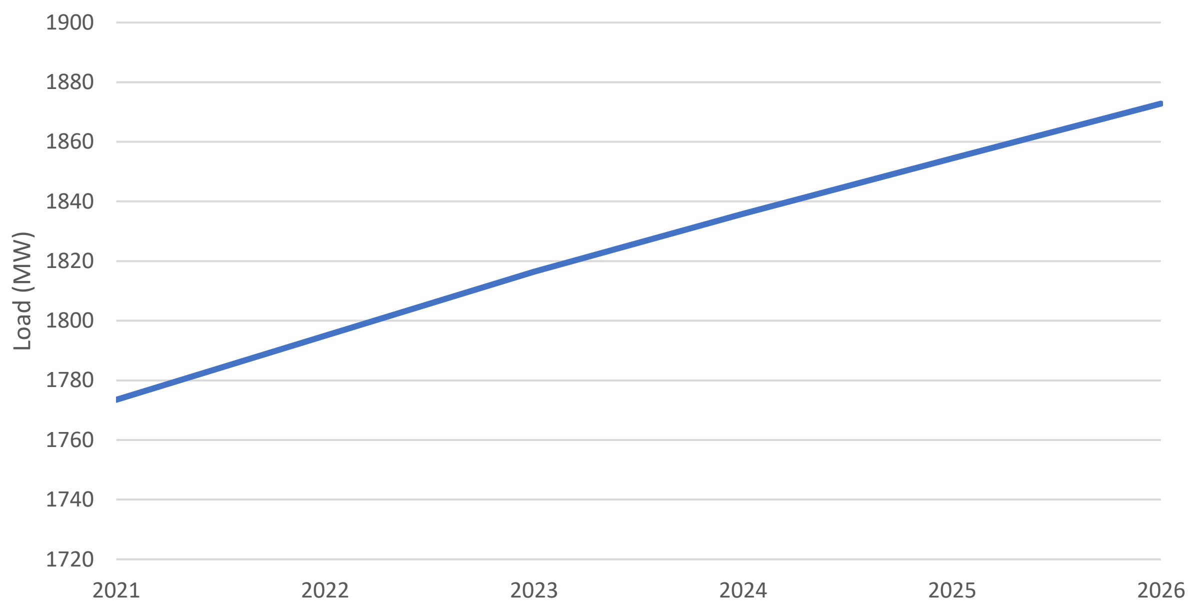
Figure F-4. Standard peak day – End-use breakdown



F.5.3 Future impacts

The standard peak day was forecasted using the same peak demand forecast as the rest of the potential study. It is presented in the figure below.

Figure 1. National Grid load forecasting (before EE)



Furthermore, results (baseline scenarios) for energy efficiency and distributed generation, as well as National Grid EV forecast were combined with the forecast in order to have a better grasp at the future load shape.

Table F-24. Impact of energy efficiency, solar and EV on Key Demand Response Factors (2026)

Average hourly reduction	Peak reduction	Peak-to-average difference
111 MW	126 MW	- 15 MW

F.5.4 Measures

To assess the DR potential in the jurisdiction, Dunsky characterized over 25 specific demand reducing measures, based on commonly applied approaches in DR programs across North America, and emerging opportunities such as battery storage. As defined in Appendix C, the measures are covering all customer segments and can be categorized into two groups: Type 1 (constrained by the addressable peak) and type 2 (unconstrained by the addressable peak). Measures of all types have the following key metrics:

- Load shape of the measure
- Constraints

- Measure Effective Useful Life (EUL)
- Costs

Dunsky applied our existing library of applicable DR measure characterizations and adjusted them to reflect end-use energy use profiles in Rhode Island's climate. Each measure was evaluated independently for each segment of the study. Table F-25 and Table F-26 provide an overview of each measure characterization and approach.

Table F-25. Residential Demand Response Measures

MEASURE BY END USE	DEMAND RESPONSE STRATEGY	ENABLING DEVICE	MARKET SIZE	INITIAL MEASURE COST	RI Test[42]	ADOPTION LIMIT[43]
Appliances						
Clothes Dryer - DLC	Appliance shut off during event	Smart Plug	Number of non-smart clothes dryers in the jurisdiction	Smart Plug	Fail	Not cost-effective
Clothes Dryer - BYOD	Appliance shut off during event	Smart Appliance	Number of smart clothes dryers in the jurisdiction	Incentive upon program inscription	Pass	Market size & Incentives[44]
Dehumidifier - BYOD	Appliance shut off during event	Smart Appliance	Number of smart dehumidifiers in the jurisdiction	Incentive upon program inscription	Pass	Market size & Incentives
Pool Pumps – Timer or Smart Switch – DLC	Postponing filtering and cleaning work of the pump	Simple Timer Switch or Smart Switch	Number of non-smart pool pumps in the jurisdiction	Timer or Smart Switch	Pass	Market size & Incentives
Pool Pumps – BYOD	Postponing filtering and cleaning work of the pump	Smart Appliance	Number of smart pool pumps in the jurisdiction	Incentive upon program inscription	Pass	Market size & Incentives
Hot Water						
Resistance Storage Water Heater - DLC	Appliance shut off during event	Smart Switch	Non-smart electric water heater (excl. heat pump water heater)	Smart Switch	Pass	Market size & Incentives
Resistance Storage Water Heater - BYOD	Appliance shut off during event	Smart Water Heater	Smart electric water heater (excl. heat pump water heater)	Incentive upon program inscription	Pass	Market size & Incentives

[42] Main results from RI Test: Some specific segments in a given measure may not pass.
[43] Main limiting factor: Some specific segments could have different adoption limits.
[44] The number of participants is a function of both market size and incentives. Increasing any of them could enhance adoption, as long as the new potential is not in competition with another measure.

MEASURE BY END USE	DEMAND RESPONSE STRATEGY	ENABLING DEVICE	MARKET SIZE	INITIAL MEASURE COST	RI Test[42]	ADOPTION LIMIT[43]
Heat Pump Storage Water Heater – BYOD	Appliance shut off during event	Smart Heat Pump Water Heater	Smart heat pump water heater	Incentive upon program inscription	Pass	Market size & Incentives
HVAC						
Central Air-Conditioner (AC) – DLC	Temperature setback (including pre-cooling strategies)	Wi-Fi Thermostat	Households with central AC and with manual or programmable thermostat	Installation of a WiFi thermostat	Pass	Potential filled by more cost-effective measures
Central Air-Conditioner – BYOD	Temperature setback (including pre-cooling strategies)	Wi-Fi Thermostat	Households with central AC and with Wi-Fi Thermostat	Incentive upon program inscription	Pass	Market size & Incentives
Ductless HP/AC – DLC	Temperature setback (including pre-cooling strategies)	Wi-Fi Thermostat	Households with a Ductless HP/AC	Installation of a WiFi thermostat	Pass	Potential partially filled by more cost-effective measures
Ductless HP/AC – BYOD	Temperature setback (including pre-cooling strategies)	Wi-Fi Thermostat	Households with a Ductless HP/AC a smart thermostat	Incentive upon program inscription	Pass	Potential partially filled by more cost-effective measures
Room AC – BYOD	Temperature setback (including pre-cooling strategies)	Smart Appliance	Smart room AC in the jurisdiction	Incentive upon program inscription	Fail	Not cost-effective
Other						
Electrical Vehicle (EV)	Shut off during event	Smart Electric Vehicle Supply Equipment (EVSE) or Smart Plug (such as	Number of EVs in the jurisdiction x % charged at home	Smart EVSE or Smart Plug	Pass	Market size & Incentives

MEASURE BY END USE	DEMAND RESPONSE STRATEGY	ENABLING DEVICE	MARKET SIZE	INITIAL MEASURE COST	RI Test[42]	ADOPTION LIMIT[43]
		FloCarma Plug)				
Battery Energy Storage – With Solar - BYOD	Battery discharges during event and extra power is send back into the grid	Battery	Households with solar panels and battery	None	Pass	Potential partially filled by more cost-effective measures
Battery Energy Storage – Without Solar - BYOD	Battery discharges during event to cover the house loads only	Battery	All households with a battery, excluding households with solar panels	None	Pass	Market size & Incentives
Energy Storage- DLC	Battery Energy Storage (BES) or Thermal Energy Storage (TES) discharges during event	BES or TES	BES: All households without BES TES: All households with central AC but no TES.	Full cost of the storage unit	Fail	Not cost-effective

Table F-26. Non-Residential Demand Response Measures

MEASURE BY END USE	DEMAND RESPONSE STRATEGY	ENABLING DEVICE	MARKET SIZE	INITIAL MEASURE COST	RI Test [45]	ADOPTION LIMIT[46]
Appliances						
Commercial Refrigeration	Refrigeration loads shed	Auto-DR	Refrigeration load per building with low-temperature cases x number of buildings (Grocery only)	Automated demand response	Fail	Not cost-effective
Hot Water						
Resistance Storage Water Heater - DLC	Appliance shut off during event	Smart Switch	Non-smart electric water heaters (excl. heat pump water heater)	Smart Switch	Pass	Potential partially filled by more cost-effective measures
Resistance Storage Water Heater - BYOD	Appliance shut off during event	Smart Water Heater	Smart electric water heaters (excl. heat pump water heater)	Incentive upon program inscription	Pass	Potential partially filled by more cost-effective measures
HVAC						
WiFi Thermostat – DLC	Temperature setback (including pre-cooling strategies)	Wi-Fi Thermostat	Small C&I buildings with central AC and with manual or programmable thermostat	Wi-Fi Thermostat	Pass	Utility-wide load curve constraints
WiFi Thermostat – BYOD	Temperature setback (including pre-cooling	Wi-Fi Thermostat	Small C&I buildings with central AC and with Wi-Fi	Incentive upon program inscription	Pass	Utility-wide load curve

[45] Main results from RI Test: Some specific segments in a given measure may not pass.
[46] Main limiting factor: Some specific segments could have different adoption limits

MEASURE BY END USE	DEMAND RESPONSE STRATEGY	ENABLING DEVICE	MARKET SIZE	INITIAL MEASURE COST	RI Test 45	ADOPTION LIMIT[46]
	strategies)		thermostat			constraints
Medium Commercial – HVAC Curtailment	HVAC demand curtailment (fresh airflow reduction, temperature adjustment, interruption of dehumidification, etc.)	Manual, BAS or Auto-DR	All medium-sized C&I buildings	None	Pass	Market size & Incentives
Medium Commercial – HVAC Curtailment (Auto-DR)	HVAC demand curtailment (fresh airflow reduction, temperature adjustment, interruption of dehumidification, etc.)	Auto-DR	All medium-sized C&I buildings	Auto-DR system	Pass	Market size & Incentives
Large Commercial – HVAC Curtailment	HVAC demand curtailment (fresh airflow reduction, temperature adjustment, interruption of dehumidification, etc.)	Manual, BAS or Auto-DR	All medium-sized C&I buildings	None	Pass	Market size & Incentives
Large Commercial – HVAC Curtailment (Auto-DR)	HVAC demand curtailment (fresh airflow reduction, temperature adjustment, interruption of dehumidification, etc.)	Auto-DR	All medium-sized C&I buildings	Auto-DR system	Pass	Market size & Incentives
Lighting						
Medium Commercial – Lighting Controls	Turning off some of the fixtures	Manual, BAS or Auto-DR	All medium-sized C&I buildings	None	Pass	Market size & Incentives
Medium Commercial –	Reduce level by 30% during peak events	Manual, BAS or Auto-DR	All medium-sized C&I buildings	Modulating system	Pass	Market size & Incentives

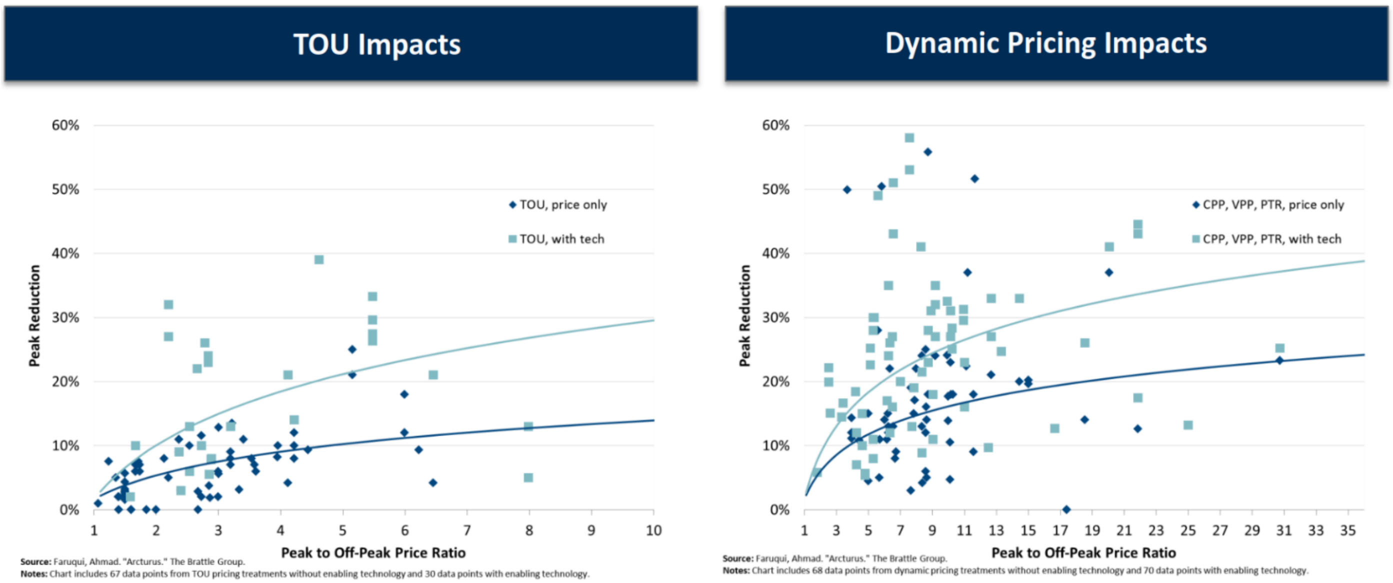
MEASURE BY END USE	DEMAND RESPONSE STRATEGY	ENABLING DEVICE	MARKET SIZE	INITIAL MEASURE COST	RI Test[45]	ADOPTION LIMIT[46]
Lighting Dimming						
Large Commercial – Lighting Controls	Turning off some of the fixtures	Manual, BAS or Auto-DR	All large-sized C&I buildings	None	Pass	Market size & Incentives
Large Commercial – Lighting Dimming	Reduce level by 30% during peak events	Manual, BAS or Auto-DR	All large-sized C&I buildings	Modulating system	Pass	Market size & Incentives
Other						
Electrical Vehicle (EV)	Shut off during event	Smart Electric Vehicle Supply Equipment (EVSE) or Smart Plug	Number of EVs in the jurisdiction x % charged at the office	Smart EVSE or Smart Plug	Fail	Not cost-effective
Emergency Generator (Gas)	Use of emergency generator during event	Manual, BAS or Auto-DR	Number of gas emergency generator in the jurisdiction	Costs of EPA stationary nonemergency compliance	Pass	Market size & Incentives
Combined Heat and Power	Use of CHP system during event	Manual, BAS or Auto-DR	Number of CHPs in the jurisdiction (non already involved with C&I program)	None	Pass	Market size & Incentives
Battery Energy Storage – With Solar	Battery discharges during event and extra power is send back into the grid	Battery	C&I buildings with solar panels and battery	None	Pass	Market size & Incentives
Battery Energy Storage – Without Solar	Battery discharges during event to cover the building loads only	Battery	C&I buildings with a battery, excluding households with solar	None	Fail	Not cost-effective

MEASURE BY END USE	DEMAND RESPONSE STRATEGY	ENABLING DEVICE	MARKET SIZE	INITIAL MEASURE COST	RI Test[45]	ADOPTION LIMIT[46]
			panels			
Energy Storage	Battery Energy Storage (BES) or Thermal Energy Storage (TES) discharges during event	BES or TES	All C&I buildings with central AC but no BES or TES.	Cost of the storage unit	Pass	Market size & Incentives
Medium Commercial – Other	Turning off or reducing some devices, appliances or processes	Manual, BAS or Auto-DR	All medium-sized C&I buildings	None	Pass	Market size & Incentives
Medium Commercial – Other (Auto-DR)	Turning off or reducing some devices, appliances or processes	Auto-DR	All medium-sized C&I buildings	Auto-DR system	Pass	Market size & Incentives
Large Commercial – Other	Turning off or reducing some devices, appliances or processes	Manual, BAS or Auto-DR	All large-sized C&I buildings	None	Pass	Market size & Incentives
Large Commercial – Other (Auto-DR)	Turning off or reducing some devices, appliances or processes	Auto-DR	All large-sized C&I buildings	Auto-DR system	Pass	Market size & Incentives
Large Industrial Curtailment	Load shifting with no intraday rebound, via expansion of existing programs or interruptible rates	Manual, BAS or Auto-DR	All large-sized Industrial buildings	None	Pass	Market size & Incentives
Medium Industrial Curtailment	Load shifting with no intraday rebound, via expansion of existing programs or interruptible rates	Manual, BAS or Auto-DR	All medium-sized Industrial buildings	None	Pass	Market size & Incentives

F.5.5 Dynamic Rates

Dynamic rates impacts were assessed using a peak to off-peak ratio. Figure F-5 presents this relationship that was established in a meta-analysis of TOU and dynamic rates by the Brattle Group[47]. This relationship is used to estimate peak savings and the energy shifted outside of the peak hours. Finally, based on Ontario's TOU roll-out, little to no energy conservation was reported when implementing TOU rates. For this reason, the study assumes a small 2% savings on the energy displaced over peak hours.

Figure F-5. Dynamic Rate Peak Reduction

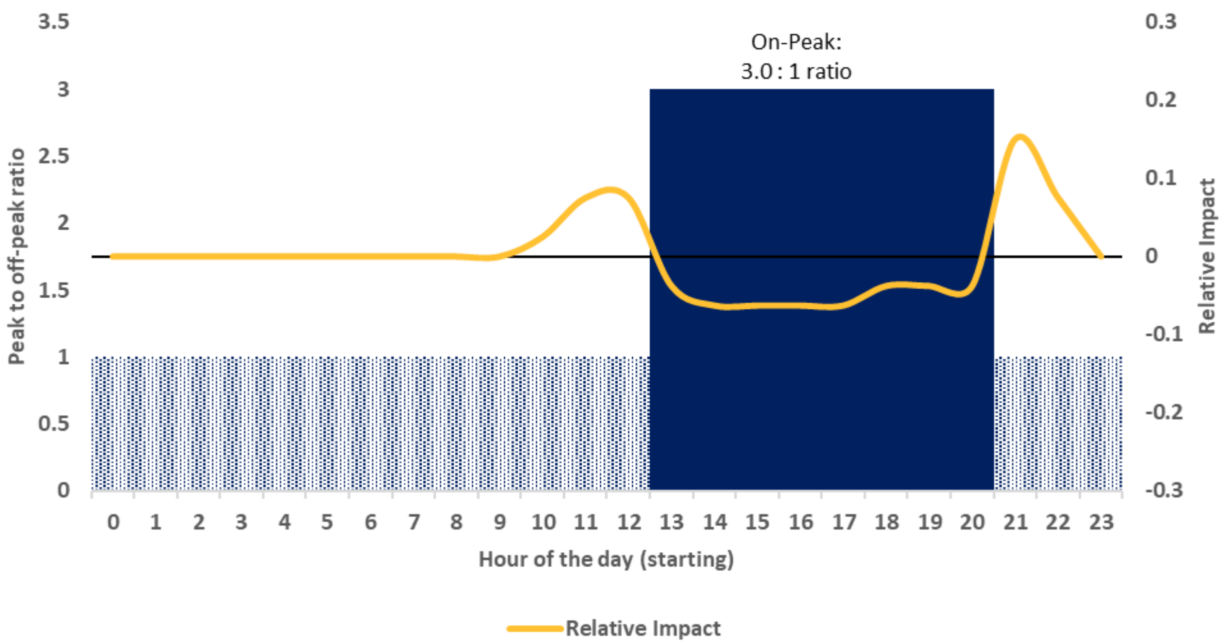


As of today, National grid, in Rhode Island, is currently offering an opt-out TOU for C&I customers exceeding 200kW of demand (can be opt-in for customers below that demand[48]). The peak hours cover the whole day, from 8:00 a.m. to 9:00 p.m. daily on Monday through Friday. To better target the demand peak described in the report, TOU rates were designed to reduce the standard peak day load and were tested over 5 years of historical hourly load data to determine the net impact. Ultimately a two-tier, 3:1 peak to off-peak TOU rate design, applied to residential customers, was found to deliver the highest peak demand reduction potential on the system, when applied in the absence of other DR programs and measures. Figure 3 presents this TOU rate structure as well as the normalized energy redistribution profiles from the TOU demand savings.

[47] Peak reduction from dynamic rates was assessed from "Arcturus: International Evidence on Dynamic Pricing", A. Faruqui and S. Sergici. 2013.

[48] See Nantucket Electric Company G-3 rate for more details: https://www.nationalgridus.com/media/pdfs/billing-payments/tariffs/mae/nant_g3.pdf

Figure F-6. Dynamic Rate Peak Reduction



The two-tier 3:1 TOU Rate design was applied to the system peak day, and it reduced the peak demand by 56 MW in 2026. Overall, the day load shape was an important factor that limited the TOU rates potential, as new peaks arise at noon and in the evening.

F.5.6 Programs

Table F-27 below presents the program costs for each major program type applied in the DR potential model, which were developed based on historical program information provided by National Grid. Program costs account for program development (set up), annual management costs, and customer engagement costs. These are added over and above any equipment installation and customer incentive costs to assess the overall program cost-effectiveness. In some cases, a program's constituent measures may be cost-effective, but the program may not pass cost-effectiveness testing due to the additional program costs. Under those scenarios, the measures in the underperforming program are eliminated from the achievable potential measure mix, and the DR potential steps are recalculated to reassess the potential and cost-effectiveness of each measure and program.

Table F-27. DR Program Administration Costs Applied in Study (excluding DR equipment costs)

Program Name	Development Complexity	Admin Complexity	Development Costs	Program Fixed Annual Costs	Other Costs ($/customers) for marketing, IT, admin	Program Adoption Ramp-up
Residential DLC	Small/Medium	High	$100,000	$84,760	$20	Yes
Residential BYOD	Small/Medium	High	$0	$84,760	$16	No
Small Commercial BYOD	Small/Medium	High	$100,000	$84,760	$40	Yes
Small Commercial DLC	Small/Medium	High	$100,000	$84,760	$40	Yes
Medium & Large Commercial Curtailment	Medium	Med	$0	$167,453	$480	No
Medium & Large Industrial Curtailment	Medium	Med	$0	$167,453	$480	No
Residential Behavioral DR	Small	Low	$0	$21,190		No

F.6 Customer-Sited Solar PV Inputs

F.6.1 Market and Measure Inputs

In addition to the inputs highlighted above, a number of specific inputs were developed and used for the customer-sited solar PV potential assessment, as shown in Table F-28. Specifically, the inputs include:

- **Suitable Market Size:** An estimate of the number of buildings in every segment with suitable roof conditions for solar deployment based on National Grid customer data and the developed market segments as described in Section F.2.1 Customer Population Counts.
- **Solar System Size:** Average installed capacity within each segment developed based on historical installed systems (National Grid's distributed generation interconnection database), customer's annual electricity consumption (National Grid customer data) and estimated rooftop size (Energy Information Agency's Commercial Building Energy Consumption Survey)
- **Annual Energy Production:** Estimated production from the installed system in 2020 developed through estimating capacity factors from reported installations
- **Solar System Costs:** Average unit installation cost ($/W) of systems installed in year 1 estimated using historical costing trends from program database and cost estimates provided by stakheolders in the Public Utilles Commission (PUC) Renewable Energy Growth program dockets[49].
- **Solar O&M Costs:** Annual unit operations and maintenance (O&M) costs incurred in year 1 based on industry standards and cost estimates provided by stakheolders in the PUC Renewable Energy Growth program dockets.
- **Storage System Power:** Assumed average battery power, developed based on an assumption of 100% solar-to-storage sizing for residential customers and 30% solar-to-storage sizing for non-residential customers.
- **Storage System Capacity:** Assumed battery capacity developed using an estimate of average 2-hour storage capacity
- **Storage System Cost:** Average unit installation cost ($/kWh) of battery storage system installed in 2020 based on the equipment and installation costs of a Tesla Powerwall and cost estimates from the National Renewable Energy Laboratory (NREL).
- **Storage O&M:** Average operations and maintenance (O&M) costs incurred in 2020 for battery storage system was pegged at 1.5% of the Storage System Costs, consistent with cost estimates from the Pacific Northwest National Laboratory.

In addition to segment-specific inputs, the following additional assumptions were applied in the study:

- Solar system lifetime: 30 years
- Battery storage system lifetime: 10 years

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[49] Sustainable Energy Advantage and Mondre Energy (2019), Rhode Island Renewable Energy Growth Program:2020 Ceiling Price Recommendations to DG Board (Available Online)

- Annual solar system degradation factor: 0.5%
- Battery roundtrip efficiency: 90%

Table F-28. Key Solar PV Inputs

Customer Segment	Technical Potential	Solar				Energy Storage			
	Suitable Market Size (2020)	System Size (kW)	Annual Energy Production (kWh/year)	System Costs - 2020 ($/W)	O&M Costs - 2020 ($/kW-yr)	Battery Power (kW)	Capacity (kWh)	CAPEX - 2020 ($/kWh)	OPEX - 2020 ($/kW-yr)
Single Family	231,072	6	7,838	$2.88	$32.80	6	12	$559	$8.38
Multi-Family		N/A							
Low Income									
Office	28,250	116	155,695	$2.28	$23.94	35	70	$450	$6.74
Retail	19,917	91	122,644	$2.35	$24.58	27	55	$456	$6.85
Food Service	3,499	24	32,043	$2.69	$28.67	7	14	$559	$8.38
Healthcare	4,706	484	650,506	$1.92	$21.00	145	290	$429	$6.43
Education	1,430	144	193,873	$2.23	$20.87	43	86	$442	$6.63
Warehouse	1,842	126	169,436	$2.26	$21.15	38	76	$445	$6.68
Lodging	3,025	157	210,901	$2.21	$23.95	47	94	$442	$6.63
Other Commercial	3,651	341	458,276	$2.01	$23.97	102	205	$431	$6.46
Food Sales	1,370	61	82,516	$2.45	$25.28	18	37	$468	$7.02
Manufacturing	2,059	144	193,483	$2.23	$19.77	43	86	$442	$6.63

F.6.2 Scenario Assumptions

The modeled scenarios for customer-sited solar deployment vary three factors:

- Renewable Energy Fund (REF) Incentives
- Renewable Energy Growth (REG) program allocation
- PV System costs

Assumptions for each under the three developed scenarios are summarized in the tables below. The Mid REF program incentive assumptions were developed based on historical program incentive decline trends, whereas the High Scenario was developed assuming a slower decline trajectory to counteract the decline in the Federal Incentive Tax Credit (ITC). REG price caps ($/kWh) and program allocations (MW) were developed based on historical program trends and 2020 announcements.

Table F-29. Renewable Energy Fund (REF) program incentive levels

Scenario	Sector		2021	2022	2023	2024	2025	2026
Low	Residential	$/W	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
		Max $	N/A					
	Non-Residential	$/W	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
		Max $	N/A					
Mid (Base)	Residential	$/W	$0.69	$0.58	$0.48	$0.38	$0.28	$0.17
		Max $	$7,000					
	Non-Residential	$/W	$0.56	$0.45	$0.35	$0.25	$0.14	$0.10
		Max $	$75,000					
Max	Residential	$/W	$0.78	$0.78	$0.78	$0.69	$0.58	$0.48
		Max $	$7,000					
	Non-Residential	$/W	$0.67	$0.67	$0.67	$0.56	$0.45	$0.35
		Max $	*$75,000*					

Table F-30. Renewable Energy Growth (REG) program parameters

	Scenario	Class[50]	2021	2022	2023	2024	2025	2026
Price Cap ($/kWh)	All Scenarios	Small Solar I *(1 – 10 kW)*	$0.26	$0.25	$0.23	$0.22	$0.19	$0.19
		Small Solar II *(11 – 25 kW)*	$0.26	$0.25	$0.24	$0.23	$0.23	$0.23
		Medium Solar *(26 – 250 kW)*	$0.21	$0.21	$0.20	$0.19	$0.18	$0.17
		Commercial Solar *(251 – 999 kW)*	$0.15	$0.17	$0.14	$0.14	$0.12	$0.13
Contract Duration (years)[51]	All Scenarios	Small Solar I *(1 – 10 kW)*	15	15	15	15	15	15
		Small Solar II *(11 – 25 kW)*	20	20	20	20	20	20
		Medium Solar *(26 – 250 kW)*	20	20	20	20	20	20
		Commercial Solar *(251 – 999 kW)*	20	20	20	20	20	20
Program Allocation (MW)	Low	Small Solar I & II	3.5	3.5	3.5	3.5	3.5	3.5
		Medium Solar	1.5	1.5	1.5	1.5	1.5	1.5
		Commercial Solar	4	4	4	4	4	4
	Mid (Base)	Small Solar I & II	7	7	7	7	7	7
		Medium Solar	3	3	3	3	3	3
		Commercial Solar	8	8	8	8	8	8
	Max	Small Solar I & II	No cap					
		Medium Solar						
		Commercial Solar						

[50] Each study segment was matched to a given REG class based on the assumed system size.
[51] To account for the full life-time benefits of systems, REG adopters were assumed to be grand-fathered into net metering contracts after the end of their Renewable Energy Growth Program contract.

Table F-31. Distributed Solar PV cost scenarios[52]

Scenario	Sector	Average Annual Cost Decline
Low	Residential	2.5%
	Non-Residential	0.5%
Mid (Base)	Residential	4.5%
	Non-Residential	2.5%
Max	Residential	6.5%
	Non-Residential	4.5%

[52] Scenarios are based on data from the National Renewable Energy Laboratory's (NREL) Annual Technology Baseline (ATB) dataset

G. Detailed Results Tables

Appendix G contains additional detailed results tables for each module of the MPS as needed and is provided in an Excel Workbook format that is accessible on the Rhode Island Energy Efficiency & Resource Management Council (EERMC) website located at www.rieermc.ri.gov.