Utility 2.0 Long Range Plan & Energy Efficiency Plan

2023 Annual Update

Prepared for Long Island Power Authority

July 1, 2023

Amended and updated as of August 25, 2023

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Executive Summary

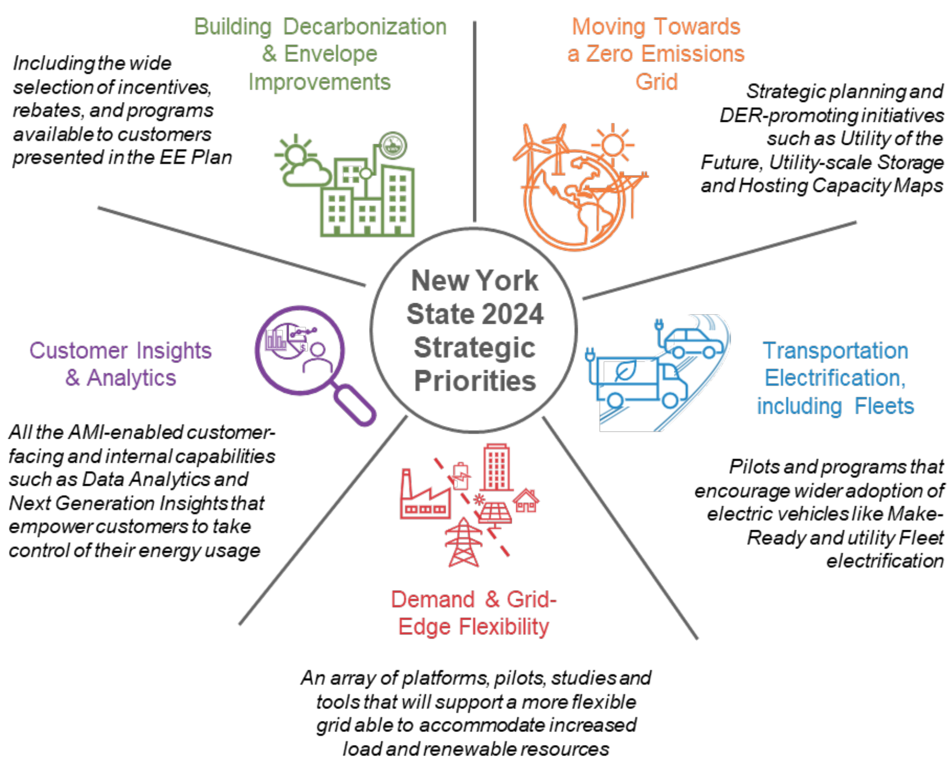
PSEG Long Island (the Utility) is submitting this ***Utility 2.0 Long Range Plan (Utility 2.0 Plan)*** for review by the Long Island Power Authority (LIPA) and the New York State Department of Public Service (DPS). This submittal is in accordance with Public Authorities Law Section 1020-f(ee) and the Amended and Restated Operations Services Agreement dated December 31, 2013, and updated November 30, 2022. This Utility 2.0 Plan Filing provides updates on 23 initiatives previously reviewed by DPS and approved by the LIPA Board of Trustees. PSEG Long Island seeks a positive recommendation on the Utility 2.0 Plan from DPS and incremental funding approval from LIPA for the additional scope of two of these previously approved initiatives (EV Make-Ready and EV Program).

This Utility 2.0 Plan also includes the 2024 update to PSEG Long Island's ***Energy Efficiency (EE) Plan*** (included as Appendix A). PSEG Long Island's EE programs make a wide selection of incentives, rebates, and programs available to residential and commercial customers on Long Island to assist them in reducing their energy usage, thereby lowering their energy bills. Promotion of electric heat pumps to reduce the use of fossil fuels is also an important component of the 2024 EE Plan.

PSEG Long Island's Evolved Utility 2.0 Vision

New York State and Long Island are committed to prioritizing efforts that are in line with the dynamic changes of the energy industry and support the NY State Climate Leadership and Community Protection Act ("Climate Act"). PSEG Long Island's Utility 2.0 vision and framework, in concert with the EE Plan, is aligned with New York State's five strategic priority areas, as presented in Figure ES-1, and support the Climate Act's focus on benefits to disadvantaged communities (DACs).

Figure ES-1. New York State 2024 Strategic Priorities and PSEG Long Island's Utility 2.0 & EE Plan

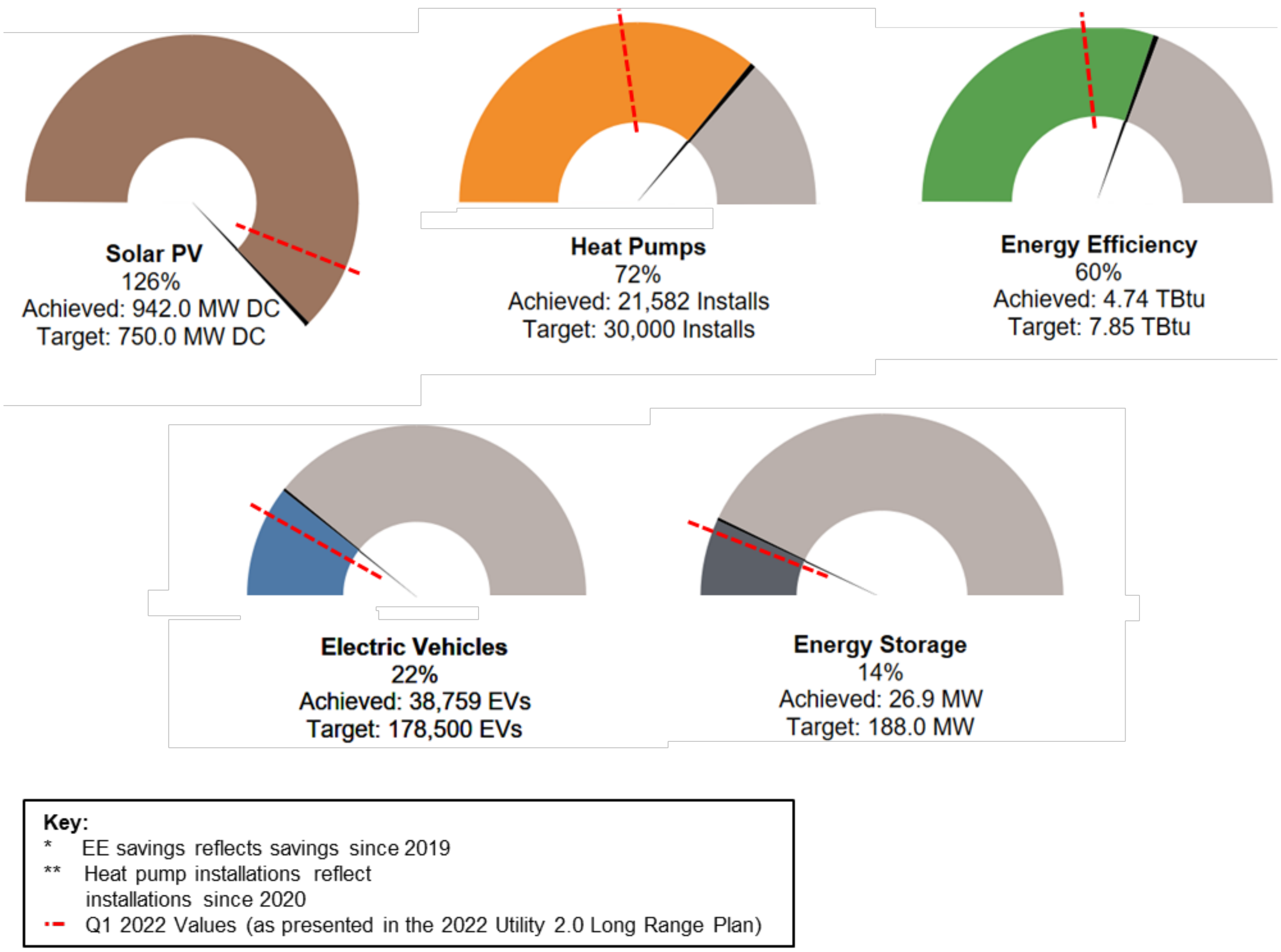


Long Island Supports the Achievement of Statewide Clean Energy Goals

Utility 2.0 initiatives that are underway are directly contributing to achieving goals in areas such as energy storage and electric vehicles (EVs). In addition, PSEG Long Island has several long running EE programs and customer offerings that contribute to EE and heat pump targets that are included in the 2024 EE Plan (Appendix A). LIPA and PSEG Long Island are also supporting state clean energy goals in several ways that go beyond the initiatives included in the Utility 2.0 and EE Plans including utility scale solar, wind, and battery storage (Section 1.3.2).

PSEG Long Island's progress towards Long Island's portion of the State's Clean Energy Goals as of Q1 2023 is presented in Figure ES-2.

Figure ES-2. Progress Towards Long Island's Portion of New York State's 2025 Clean Energy Goals



Note: Values are current as of March (EE, Heat Pumps, and EVs) and February (Energy Storage and Solar PV) 2023 based on data availability. Actual savings values for EE include 0.66 TBtu heating penalty for 2020-2022 and about 0.06 TBtu heating penalty for 2023. Including the heating penalty does not align with practices across the rest of the state, where heating penalties are not applied.

PSEG Long Island's 2023 Utility 2.0 Plan

PSEG Long Island's 2023 Utility 2.0 Plan represents a one-year outlook. PSEG Long Island has developed preliminary roadmaps for each of the priority areas by assessing the projected needs, gaps, and existing plans. Since many of the external plans and studies that are required to inform PSEG Long Island's future planning (detailed in Section 1) are still awaiting finalization, anything presented beyond 2024 in this plan is subject to change and therefore not requesting funding at this time.

PSEG Long Island uses a variety of qualitative criteria to determine which projects to fund through Utility 2.0 including but not limited to:

- **New York State priorities** as presented in the Climate Act and provided through additional guidance and feedback from the DPS via the Utility 2.0 Plan annual filing process,
- **LIPA priorities, commitments and metrics** as defined in the Operations Services Agreement (OSA) and provided through additional guidance from LIPA via the Utility 2.0 Plan annual filing process and,
- **Similar projects across the Joint Utilities (JU)** as identified through coordinated communication and planning. Please see Sections 3.1, 4.1.1.1, and 6.1 for examples on how coordination with the JU is addressed in applicable Utility 2.0 initiatives.

PSEG Long Island requires a total Utility 2.0 funding request of $24.94 million ($10.11M in capital and $14.83M in operations and maintenance (O&M)) for active initiatives, including initiatives with requested scope expansions, in 2024. Full details on projects costs and variances by year can be found in Section 7.2 with project-specific details in the sections identified in Table ES-1 below.

Table ES-1. 2024 Total Funding Request

Initiative	Document Section	Capital 2024 ($M)	O&M 2024 ($M)	Total 2024 ($M)
Connected Buildings Pilot	*5.1*	0.00	0.13	**0.13**
Electric Vehicle Program	*4.2*	0.00	1.75	**1.75**
EV Make-Ready Program[1]	*4.1*	3.96	8.89	**12.85**
IEDR Platform	*6.1*	4.08	0.50	**4.58**
Residential Energy Storage Program	*5.3*	0.00	1.54	**1.54**
Suffolk County Bus Make-Ready Pilot	*4.3*	0.00	0.04	**0.04**
Super Savers - Patchogue	*5.4*	0.00	0.04	**0.04**
Funding Request Subtotal for Active Projects		**8.04**	**12.89**	**20.92**
Fleet Make-Ready Program*	*4.1*	0.81	0.73	**1.54**
Residential Charger Rebate Program*	*4.2*	0.00	1.21	**1.21**
EV Phase-In Rate[2]*	*4.2*	1.27	0.00	**1.27**
Funding Request Subtotal for Expanded Scope		**2.08**	**1.94**	**4.02**
Total Funding Request		**10.11**	**14.83**	**24.94**

**Proposed scope expansions to currently Active Utility 2.0 initiatives.*

[1] Since the submission of the 2023 Utility 2.0 Long Range Plan on July 1, 2023, information regarding loan aggregator fees for 2023 (O&M costs) and third-party IT aggregator data collection (O&M costs) for 2024-2025 for this program has become available. O&M forecasts are updated accordingly as of August 25, 2023.

[2] Since the submission of the 2023 Utility 2.0 Long Range Plan on July 1, 2023, more information regarding third-party contracting support (Capital costs) for this program extension for 2024 has become available. Capital forecasts are updated accordingly as of August 25, 2023.

PSEG Long Island's 2024 EE Plan

PSEG Long Island's EE programs provide a wide array of incentives and rebates to residential, including Low and Moderate Income (LMI), and commercial customers to assist them in reducing their energy usage, thereby lowering energy bills. The Utility's proposed 2024 EE Plan (included as Appendix A of this document) consists of the six programs for residential customers and two multifaceted programs for commercial customers. It also provides the funding to support the tariff-based Dynamic Load Management offerings as well as some remaining supplementary support for Community Based Solar development remaining from a LIPA pledge of support in prior years. Proposed programs within the EE Plan are summarized in Table ES-2 below.

Table ES-2. Summary of Proposed Programs and Budgets in the 2024 EE Plan

Program	Sector	Savings (MMBtu)	Savings (MWh)	Program Budget ($M)
Energy Efficient Products	Residential	148,847	16,107	8.82
Home Comfort	Residential	111,645	1,587	17.91
Residential Energy Affordability Partnership (Low-Income)	Residential	10,475	1,862	3.37
Home Performance	Residential	29,236	2,245	7.58
Multifamily	Commercial	46,382	3,672	6.53
All Electric Homes	Residential	574	22	0.50
Commercial Efficiency	Commercial	237,533	71,126	32.09
Customer Insights & Home Energy Management (HEM) (Behavioral)	Residential	177,816	52,115	3.04
Total, Budget Components with Programmatic Savings		**762,509**	**148,736**	**79.83**
Dynamic Load Management (DLM) Program		-	-	2.40
PSEG Long Island Labor		-	-	3.37
Outside Services		-	-	2.66
Advertising		-	-	2.60
G&A		-	-	0.90
Community Solar		-	-	0.25
Home Comfort Market Development Fund		-	-	1.00
REAP Thermostats (TRC)		-	-	0.70
Total, Budget Components Not Associated with Programmatic Savings		**-**	**-**	**13.88**
Total		**762,509**	**148,736**	**93.71**

Income-eligible customer goals for programs within the EE plan are summarized in Table ES-3 below.

Table ES-3. 2024 Income-Eligible Customer Goals in the EE Plan

Program	Savings (MMBtu)	Program Budget ($M)
Home Comfort – Whole House LMI	21,363	4.50
REAP	10,475	4.07
Home Performance - LMI	11,284	3.62
Marketing & Outreach	-	0.50
Total	**43,122**	**12.69**

PSEG Long Island's 2024 EE Plan identifies opportunities to advance energy affordability for LMI consumers such as heat pump rebates and programmatic changes designed to enhance the Home Comfort, Home Performance and Residential Energy Affordability Partnership (REAP) programs that will total about $12.69 million in spending in 2024. The 2024 EE Plan also outlines how the Utility is consulting with its strategic marketing and advertising agency to support targeted outreach and increased awareness of EE programs to residential and business customers in DACs.

Structure of the Document

This annual update of the Utility 2.0 Plan includes reporting around the status, performance, and spend for previously approved initiatives. PSEG Long Island expects that performance and budget spend will fluctuate year-to-year throughout the duration of the various initiatives. Unless otherwise noted in this Plan, PSEG Long Island intends to deliver the scope of the approved initiatives within the overall approved funding and schedule.[3]

The reporting of updates to approved initiatives and the proposals for new initiatives are included in Chapters 3 through 6. Key figures, such as quantifiable benefits and spend, are summarized at the portfolio level in Chapter 1.

Overall, the 2023 Utility 2.0 Plan filing is organized as follows:

- **Chapter 1** outlines how PSEG Long Island continues to deliver on its evolving Utility 2.0 vision and strategy around New York State's strategic priorities, the annual Utility 2.0 filing process, and initiatives in and outside of Utility 2.0 that support the achievement of state goals.
- **Chapters 2 through 6** describe the design, justification, and funding request for scope that will start in 2024 and progress updates, performance reporting, and budget reconciliation for approved initiatives that are in active in 2023 for the five New York State 2024 priorities.
- **Chapter 7** provides an overview of the overall Utility 2.0 portfolio benefits, spend, and budgets. This chapter also outlines the expected rate impacts from the overall portfolio based on the expected spend and benefits.

[3] The duration of the approved funding for each initiative will vary depending on when they were originally filed and whether the schedule for the initiative has been subsequently updated to reflect a change in the end date. For clarity, the duration of each initiative has been noted separately and individually for each initiative in Chapters 3 through 6.

- **Appendix A** contains PSEG Long Island's 2024 EE Plan.
- **Appendix B** contains PSEG Long Island's revised BCA Handbook.
- **Appendix C** contains the full Electric Medium- and Heavy-Duty Make-Ready Study conducted by Gable Associates.
- **Appendix D** provides a list of the operationalized and completed Utility 2.0 initiatives.
- **Appendix E** provides a summary of the way LIPA and PSEG Long Island are organized.
- **Appendix F** includes a listing of acronyms and abbreviations used in this document.

1. Introduction

PSEG Long Island (the Utility) is submitting this ***Utility 2.0 Long Range Plan (Utility 2.0 Plan)***, which includes an update to the ***Energy Efficiency (EE) Plan***, for review by the LIPA and the New York State DPS. This submittal is in accordance with Public Authorities Law Section 1020-f(ee) and the Amended and Restated Operations Services Agreement dated December 31, 2013, and updated November 30, 2022.

1.1 PSEG Long Island's Evolved Utility 2.0 Vision

The global energy industry is actively undergoing critical transformation in many facets that impact customers and energy distribution. New York State and Long Island continue to stay committed to prioritizing goals and projects that are in line with the dynamic changes of the energy industry. July 2023 marks four years since New York State's Climate Leadership and Community Protection Act (Climate Act), one of the most ambitious climate laws in the world, was signed into law.

As the State evaluates progress to date and plans for increasing targets over the next three decades, PSEG Long Island recognizes the need to maintain flexibility and adaptability in response to shifting priorities. In collaboration with DPS, LIPA, and New York State Energy Research and Development Authority (NYSERDA), PSEG Long Island evolved its Utility 2.0 vision and framework, in concert with the EE Plan, to align with the following six strategic priority areas.

- Building Decarbonization and Envelope Improvements
- Moving Towards a Zero Emissions Grid
- Transportation Electrification, including Fleets
- Delivering Benefits to DACs
- Demand and Grid Edge Flexibility
- Customer Insights and Analytics

Last year, PSEG Long Island introduced the Utility's updated vision which focuses on decarbonization outcomes and technologies that enable them (Figure 1-1). PSEG Long Island now enters its second year with this vision and continues to execute and ideate for projects and programs that further enable decarbonization on Long Island.

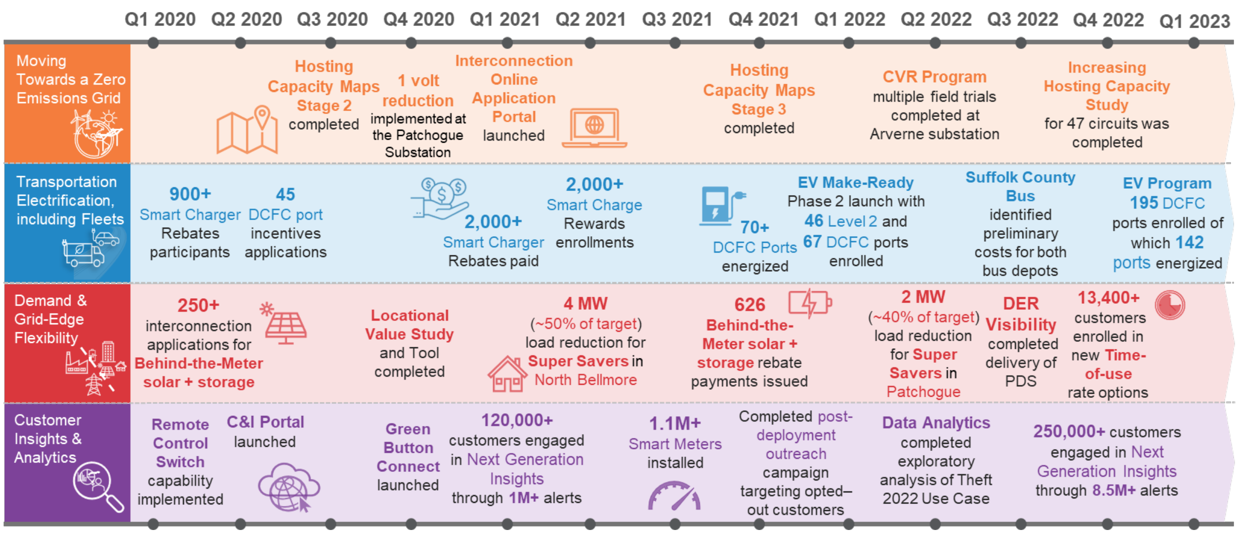
Figure 1-1. PSEG Long Island's Utility 2.0 Vision (Updated 2022)

PSEG Long Island's Utility 2.0 vision is to be a customer-centric, innovative, and forward-looking utility that is dedicated to driving a decarbonized future. PSEG Long Island will achieve this vision by enabling building decarbonization solutions, moving towards a zero-emissions grid, enabling transportation electrification, delivering benefits to disadvantaged communities, implementing demand and grid-edge flexibility, and offering customer insights.

Nex year, PSEG Long Island intends to use the building blocks laid by the Utility's updated vision and Utility 2.0 program history to develop a multi-year filing with additional detail on the projects and timeline for achieving Long Island's allocation of New York State goals. Current progress toward a longer-term view can be found under the 'Priority Area Future Need Assessment' subsection for each DPS priority area chapter (Chapters 3, 4, 5 and 6).

Figure 1-2 below highlights some of the major accomplishments of the Utility 2.0 Program from Q1 2020 to Q1 2023 based on the DPS Priority Areas in which the projects are aligned.

Figure 1-2. Success of Utility 2.0 Initiatives from Quarter 1 2020 to Quarter 1 2023[4]



PSEG Long Island, working with DPS and LIPA, continuously seeks ways to evolve its solutions and services to support its customers and their needs. In 2023, many of the projects and initiatives borne out of the Utility 2.0 program transitioned into PSEG Long Island's core operations (Appendix D). The successful integration of projects into PSEG Long Island's core operational activities makes way for the next evolution of Utility 2.0.

1.2 Managing the Utility 2.0 Program and Annual Filing Process

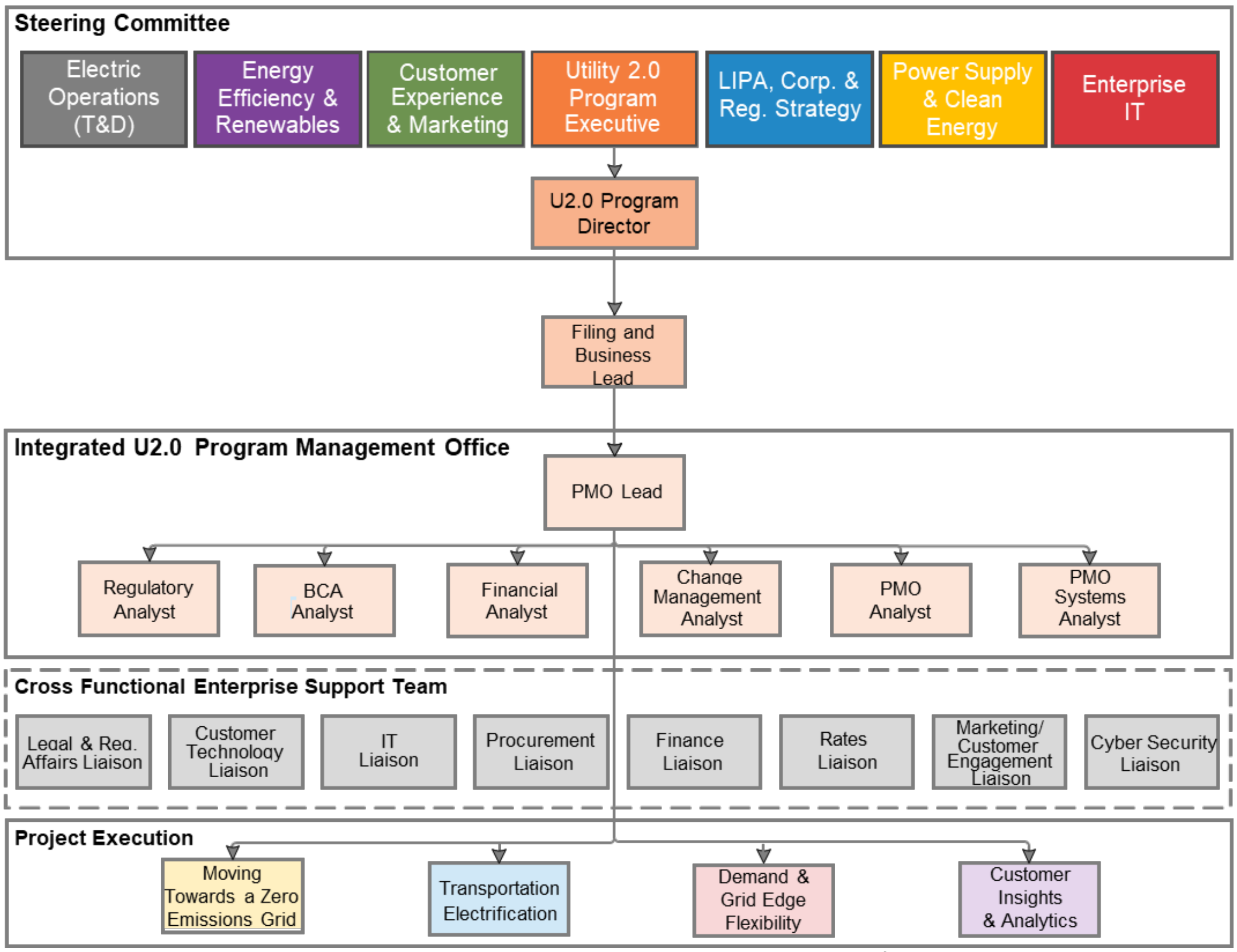
PSEG Long Island's Utility 2.0 vision is realized through an enterprise-wide program that currently includes 10 active initiatives with a projected spend of approximately $15.2 million in 2023. These initiatives span multiple functional groups with considerable departmental interdependencies and regulatory oversight and impact the organization, its processes, and its technology. The Utility 2.0 Program is managed by a Program Management Office (PMO) that was established in 2020 and was operationalized in 2023 along with 11 other Utility 2.0 initiatives. The Utility 2.0 PMO develops the annual Filing, manages responses to interrogatories, and oversees the execution and reporting of approved projects including the development of project implementation plans and associated requirements documentation, implementation of projects, and achievement of deliverables and project outcomes. The PMO is also responsible for internal and external reporting and associated meetings with stakeholders including the DPS, LIPA, and other community interest groups.

The Utility 2.0 portfolio of projects is overseen by a cross-functional Steering Committee that assists in the resolution of critical project issues and provides guidance to ensure projects meet defined goals and objectives within budget. Additionally, the Steering Committee provides executive oversight on various

[4] As noted in Figure ES-2, the Building Decarbonization and Envelope Improvement goals are the target of the incentives, rebates and programs available to customers presented in and progress updates are provided in the EE Plan (Appendix A) and are reported separately from the U2.0 program.

projects and initiatives as well as enables the exchange of information across customer service, transmission and distribution (T&D), information technology (IT), and other key stakeholders (Figure 1-3).

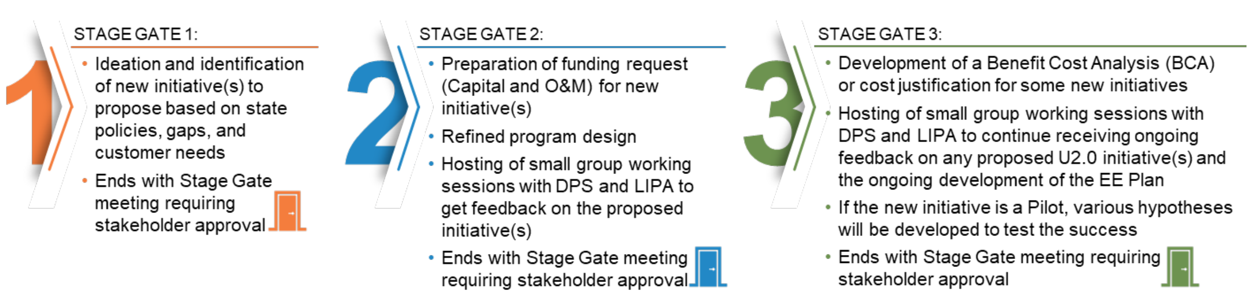
Figure 1-3. Utility 2.0 Governance Structure



Note: Building Decarbonization and Envelope Improvements initiatives are managed outside of the Utility 2.0 Program and Delivering Benefits to DACs is addressed at a program-wide level

To complete the Utility 2.0 Plan each year, the PSEG Long Island team uses a stage gate process with DPS and LIPA to communicate its proposed initiatives. Each initiative that is proposed in the annual Utility 2.0 Plan must be approved by stakeholders at all three stage gates. Small group work sessions with stakeholders are added in-between stage gates to supplement development of each initiative. A summary of the stage gate process is provided in Figure 1-4.

Figure 1-4. Annual Utility 2.0 Filing Stage Gate Process



Once an initiative completes stage gate 3, the PMO coordinates with project owners to compile the narrative for its proposal in the Utility 2.0 Plan. After the Utility 2.0 Plan is submitted on July 1st, DPS or LIPA can submit Interrogatory Requests (IRs) to understand specific details and impacts about a proposed initiative and corresponding budgets. PSEG Long Island has 10 days from the submission of an IR to respond and the PMO team is responsible for communicating IRs to the proper individuals and coordinating their response(s).

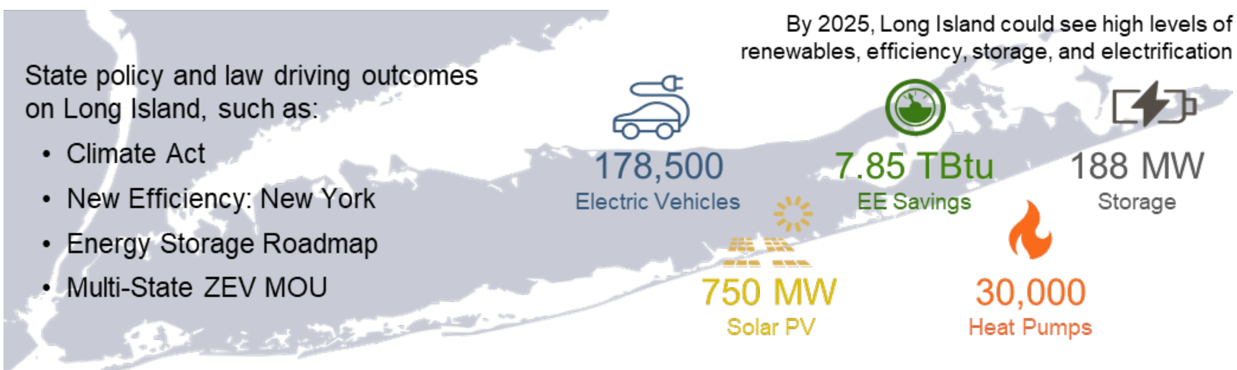
Beginning in 2022, preliminary IRs (prior to the submission of the Utility 2.0 Plan) were requested by DPS and LIPA. This preliminary process provides stakeholders with an opportunity to influence the content in the Utility 2.0 Plan and weigh-in on proposed projects. Also, it enables PSEG Long Island to increase transparency with LIPA throughout the filing process.

The PMO develops and maintains a standardized Project Charter Template that is used for new Utility 2.0 initiative proposals. During the Stage Gate process, the project teams (with support from the PMO) fill out this document for projects that are being proposed in the Utility 2.0 Plan. If the initiative is approved by DPS and LIPA, the PMO is responsible for updating the Project Charter before kicking-off implementation.

1.3 Long Island Supports the Achievement of Statewide Clean Energy Goals

Long Island has a significant role to play in New York State meeting its Climate Act goals and additional policies that shape the State's energy and sustainability landscape. PSEG Long Island is contributing towards its share of these goals both in and outside of the Utility 2.0 program including through many of its long running EE programs (see Appendix A). Figure 1-5 shows Long Island's share of the statewide clean energy goals for 2025 based on PSEG Long Island's analysis.

Figure 1-5. Long Island's Share of the Statewide Clean Energy Goals for 2025[5]



Long Island's share of the statewide goals is based on the assumptions listed in Table 1-1.

[5] 2014 Multi-State ZEV Memorandum of Understanding (MOU)

Table 1-1. Assumptions used to estimate Long Island's share of the Statewide Clean Energy Goals

Statewide Clean Energy Goal	2025	2030	Assumption(s)
Electric Vehicles	178,500 EVs	100% of new vehicles*	Based on Long Island's share of vehicle registrations in New York (approximately 21%)
Energy Efficiency	7.85 TBtu Savings	TBD**	Of the incremental target of 31 TBtu of reduction by utilities toward achieving the statewide goal, LIPA was assigned a proportional share of increased EE savings of at least 3 TBtu over the period of 2019-2025, or 7.85 TBtu when combining base-level electric savings and the incremental amount established in the December 2018 Order[6]
Energy Storage	188 MW†	750 MW	Based on Long Island's share of statewide peak load (approximately 12.5%)
Heat Pumps	30,000 Installs (1.15 TBtu Savings)	150,000 Installs***	The basis for this was the 2020 annual EEDR Plan for that year's heat pump categories, with a reasonable growth rate across categories
Solar PV	750 MW DC	1,300 MW DC	Based on Long Island's share of statewide peak load (approximately 12.5%)

†This value reflects a target rather than an official goal for Long Island's portion of the 2025 Energy Storage Climate Act Goal.
**This statewide clean energy goal is for 2035 rather than for 2030 and reflects only newly sold EVs. The 2025 statewide clean energy goal captures EVs currently on the road.*
***The statewide goals for 2030 for EE still to be determined by the state of New York.*
****The statewide goal for heat pumps based off Governor's Hochul's 2022 State of the State address is 1,000,000 homes by the end of 2030 – LIPA has indicated that its share of this goal is established at 150,000, as reflected in detail in page XX in Appendix A*

1.3.1 Achievement of Statewide Goals Within Utility 2.0

The Utility 2.0 initiatives underway or planned for the near future that directly contribute to the Climate Act targets for EE, energy storage, beneficial electrification (heating and transport), and renewable energy are identified in Table 1-2. Initiatives that yield prospective benefits for DACs (discussed in further detail in Section 1.4) are listed in orange.

Table 1-2. PSEG Long Island Initiatives Contributing to New York State Clean Energy Goals

Category	Energy Efficiency	Heat Pumps	Energy Storage	Electric Vehicles	Solar PV
Statewide Goal for 2025	185 TBtu	5 TBtu	1,500 MW	850,000	6,000 MW DC
Long Island Portion of 2025 Goals	7.85 TBtu	30,000 installations (1.15 TBtu)	188 MW	178,500	750 MW DC

[6] Order Adopting Accelerated EE Targets, CASE 18-M-0084 In the Matter of a Comprehensive EE Initiative, December 13, 2018.

Category	Energy Efficiency	Heat Pumps	Energy Storage	Electric Vehicles	Solar PV
Actuals on Long Island (Q1 2023)	~4.74 TBtu	~21,582 installations (~0.70 TBtu)	~27 MW (4.5 MW queued)	~36,760	942 MW DC
Statewide Goal for 2030	TBD	1,000,000	6,000 MW[7]	TBD	10,000 MW DC[8]
Active & Approved Initiatives	• EE Programs (EE Plan) • Super Savers	• EE Programs (EE Plan)	• Energy Storage Bulk Solicitation • Connected Buildings Pilot • Storage Hosting Capacity Maps • Residential Energy Storage System Incentive	• EV Program • EV Make-Ready (EVMR) Program[9] • Suffolk County Make-Ready Pilot • EV Load Serving Capacity Maps	• DER Visibility Platform

Orange Text: Prospective Benefits for DACs. DACs and goals will be tracked in the future.

1.3.2 Achievement of Statewide Goals Outside of Utility 2.0

LIPA and PSEG Long Island are also supporting state clean energy goals in several ways that go beyond the initiatives included in the Utility 2.0 and EE Plans including utility-scale solar, wind and battery storage.

The Climate Act includes, among other mandates, a requirement that 70% of electricity consumed in the state by 2030 be produced with renewable energy (i.e., the 70 x 30 mandate), the development and commercial operation of 9,000 MW of offshore wind by 2035, 3,000 MW of energy storage by 2030, 6,000 MW of distributed solar by 2025, and 100% zero-carbon electricity production by 2040 (i.e., the 100 x 40 mandate). In addition, the Governor announced increases to some of those targets, although not formally adopted.

In alignment with *Moving Towards a Zero Emissions Grid* priority area, efforts external to Utility 2.0 that achieve state goals include Utility-scale Battery Storage, Solar and Wind. Information on PSEG Long Island and LIPA's Integrated Resource Planning[10] and Long-Term Transmission Planning efforts can be found outside of the Utility 2.0 and EE Plans presented herein.

Additionally, PSEG Long Island engages in efforts in *Transportation Electrification* external to Utility 2.0 including investigating purchasing an electric bucket truck to inform future programs aimed at electrifying the broader population of Medium- and Heavy-Duty Vehicles (MHDVs).

Lastly, the Utility's *Time of Day (TOD) Rates* is an effort outside of Utility 2.0 that advances statewide goals.

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[7] Governor Hochul's 2022 State of the State Book [governor.ny.gov] (page 146)

[8] Governor Hochul Announces Expanded NY-Sun Program to Achieve at Least 10 Gigawatts of Solar Energy by 2030

[9] The EV Make-Ready Program will be renamed as the Make-Ready Program and cover both the current EV Make-Ready Program and the proposed Fleet Make-Ready Program.

[10] Further details regarding IRP can be found at https://www.lipower.org/irp/.

Utility Battery Storage

The Climate Act targets include a 3,000-MW statewide energy storage goal by 2030. In the April 2022 State of the State address, the Governor proposed doubling of the State's energy storage goal to 6,000 MW by 2030. On December 28, 2022, the New York State Public Service Commission adopted the 6,000 MW Energy Storage goal for New York State. To date, LIPA has approximately 27 MW of energy storage connected to the system from installed utility scale and residential applications (~17 MW of residential and 10 MW of Behind-the-Meter (BTM) storage). It is expected that 4.5 MW of additional energy storage will be added to the system on the residential side by the end of 2023.

LIPA intends to continue to contribute to New York State energy storage targets through existing energy storage projects under contracts with LIPA and new projects being procured by the 2021 Bulk Energy Storage System (BESS) request for proposals (RFP). The BESS RFP had a goal to obtain minimum 175 MW of new bulk energy storage projects by 2025. This RFP was open to all energy storage technologies provided they are commercially viable and meet the required technical criteria, with a minimum size of 20 MW. In August 2022, five (5) Energy Storage projects totaling 329 MWs were selected for competitive contract negotiations. These negotiations are currently underway.

Utility Scale Solar and Wind

PSEG Long Island has been actively involved in the development of the first major offshore wind farm in the United States (US). Originally known as Deepwater Wind, this project, selected in the 2015 South Fork RFP, has been subsequently named South Fork Wind after the purchase of the project by a consortium of Orsted and EverSource. The project will deliver 132 MWs of renewable energy to the Long Island System. The target commercial operation date is December 31, 2023.

There is 198.6 MW of Utility Scale Solar now operating. In response to the 2015 Renewable RFP, PSEG Long Island recommended the selection of two utility scale solar projects. The first is the Long Island Solar Calverton project, a 22.9 MW solar generation facility which reached commercial operation in August 2022. For the second, the LIPA Board authorized execution of the 36 MW Riverhead Solar 2 project power purchase agreement on September 22, 2021, and discussions are ongoing for the project.

To further support commercial solar development on Long Island, PSEG Long Island implemented four Solar Feed-in-Tariff (FIT) programs which have 83.5 MW in operation, 5.3 MW in construction and 14 MW in award. This consists of: (i) FIT I starting in 2012, with 38.8 MW in operation, (ii) FIT II in 2013 with 30.3 MW in operation and 1.6 MW in construction, (iii) FIT III in 2016 with 14.4 MW in operation and 3.7 MW pending and (iv) In May of 2020 LIPA and PSEG Long Island launched a new Feed in Tariff program, termed Solar Communities or FIT V, two PPA's signed for 3 MW and three awards made for 11 MW.

Solar Communities is a new program to deliver affordable clean energy to income-eligible households, which have traditionally been underserved in the solar market.[11] The 20 MW Solar Communities program plans to double the amount of community solar on Long Island. As of March 31, 2023, two Power Purchase Agreements (PPA's) have been executed, totaling 3 MW. Awards have been made for an additional 11 MW, such that the program has a 14 MW with the price cap remaining at $0.1463 per kWh. There are also 17 projects representing 17.2 MW on the Waiting List. Applicants who are on the Waiting List may submit a revised application with no modifications other than price. The FIT V program is now closed and no longer accepting new applications.

Behind-the-Meter (BTM) Solar

[11] Solar Communities Feed-In Tariff V

The residential rooftop solar program accounts for over 500 MW of BTM solar generation. Because the New York Sun funding extended from 2019 through 2022, PSEG Long Island has consistently received and approved approximately 6,000 new BTM solar projects each year and interconnected over 8,000 solar projects in 2022. Since the inception of the Net Energy Metering in the early 2000s, which continues today, the Utility has completed and installed a total of over 70,000 solar projects, reflecting about 7% of the customer base.

Transportation Electrification

PSEG Long Island explored the potential for fleet electrification with internal experts, and found the following factors that impact the progress for converting internal utility fleet vehicles:

- **Nascent Market:** PSEG Long Island met with several bucket truck and chassis manufacturers to discuss potential available EVs and found that the technology is still in the preliminary stages and is not expected to be available until at least late 2024 or 2025. PSEG Long Island will be evaluating light duty pick-up truck and SUV availability for 2025 and forward, as well as evaluating plug-in electric tractor and straight truck for warehouse delivery applications.
- **Existing Vehicles**: PSEG Long Island's existing fleet has not yet reached the end of their useful life. Typically, PSEG Long Island utilizes vehicles per the defined replacement program life cycles or the point where they are at or past the point of economic repair. PSEG Long Island will continue to monitor vehicle condition and operation to identify vehicles for electrification.
- **Suitability**: PSEG Long Island found that range and cycle time and weight studies have not yet met operational needs for MHDVs, and plans on electrifying light-duty vehicles (LDVs) first given their range and duty cycle.
- **Charging Infrastructure Planning**: As with all EVs, charging infrastructure is required to allow charging of the vehicles when they're not being used. While a limited number of charging stations have been installed, a full-scale infrastructure campaign would be required to support any large-scale vehicle acquisitions. PSEG Long Island continues to monitor progress of the electric bucket truck technology and is in the early stages of developing a Fleet Electrification Strategy for LDVs and MHDVs.

PSEG Long Island will continue to monitor progress of the electric bucket truck technology and plans to reassess suitability for its needs once technology has matured.

PSEG Long Island's Fleet Transportation group is following the LIPA recommendations from a recent fleet assessment and is currently working with a consultant to identify opportunities to electrify its fleet. In the coming months, the group plans to identify which vehicle classes will be ready to electrify and develops strategies for each vehicle class. The group expects that most LDVs will electrify first with MHDVs electrifying in later years.

Additionally, PSEG Long Island has held discussions with National Grid who owns the yards that PSEG Long Island rents from to identify where charging stations would be located and what type of service upgrades are required.

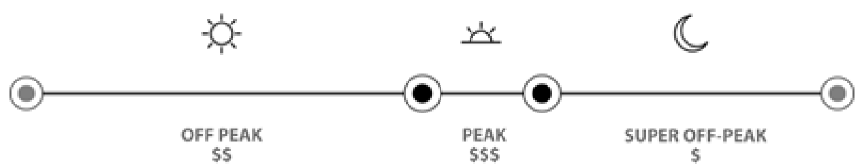
Time of Day (TOD) Rates

On March 29, 2023, the LIPA Board of trustees voted to implement a new residential TOD rate. This rate will become the standard rate for residential customers in January 2024, although customers can voluntarily opt into the TOD rate starting September 15, 2023. Residential customers currently on the flat rate will be transitioned to the new TOD rate in waves starting in February of 2024 through 2025. Customers can opt out of the rate at any time and switch back to a flat rate or other optional eligible rates.

The new TOD rate charges customers a different price per kWh depending on the time that energy is used. This is a pricing incentive that will encourage customers to shift usage from peak to off peak hours. By reducing usage during peak periods, PSEG Long Island can reduce the capacity and runtime of less efficient power plants. The rate is expected to save customers money as well as reduce carbon emissions on Long Island.

PSEG Long Island is implementing both the standard 2-block period TOD rate as well as a new optional 3-block period “Super Off Peak” rate. The super off-peak period offers additional incentives for individuals to use electricity at night, when overall energy usage is low, and is expected to benefit EV owners who charge their vehicles at night. This is depicted in Figure 1-6 below.

Figure 1-6. Off Peak, Peak, and Super Off-Peak Periods



To increase confidence in the program and reduce any risk to customers, PSEG Long Island is making bill protection available to flat rate customers that either opt-in or are migrated to TOD. A customer who has a higher bill on TOD than they would have on the flat rate will receive a bill credit for the difference. Customers will receive this bill credit after they have spent 12 months on the TOD rate or after they opt out. Customers will be provided high level awareness marketing communication starting October 2023. The public website will be updated with information on TOD specifics by the go-live date in September 2023. Personalized direct communications will be sent approximately 90, 60, and 30 days before each migrated group transitions to the new standard TOD rate. These targeted communications will begin in November 2023.

1.4 Delivering Benefits to Disadvantaged Communities

The Climate Act also commits to supporting an equitable and just clean energy transition in New York recognizing that climate change impacts can disproportionately burden traditionally underserved communities. To ensure that New York State’s clean energy policies deliver equitable benefits, the Climate Justice Working Group (CJWG) was formed to develop criteria for identifying these DACs.

In March 2023, the CJWG voted to approve and adopt the final DAC criteria to advance climate justice. The CJWG used 45 indicators to identify 35% of NYS census tracts as DACs. Beyond the geographic criteria, one other criterion that was considered specifically for clean energy policy was total household income at or below 60% of State Median Income (SMI). This allows investments for individual households outside of census tracts identified as DACs making at or below 60% SMI to be included.

PSEG Long Island is committed to developing programs, services, and other offerings to support and include LMI and DAC customers and will continue to monitor Climate Act working groups. As the criteria for DACs is being finalized, PSEG Long Island has begun to identify enhanced incentives for EE, heat pump and EV that will target these customers and communities.

PSEG Long Island is presently developing the capability to report upon customer program participation by census tract and expects to have that capability during the 3rd quarter of 2023. In the development of this capability, the Utility is also focusing on how to easily identify customers by census in order to support more specific identification of DAC customers prospectively in addition to the required DAC reporting retrospectively. Once PSEG Long Island has the ability to determine existing DAC customer participation in its non-income qualified program offerings, work will begin to ensure that overall, 2024 DAC customer program participation is in line with the target established for the Long Island electric service territory.

PSEG Long Island's 2024 EE Plan (Appendix A) identifies opportunities to advance energy affordability for LMI consumers such as heat pump rebates and programmatic changes designed to enhance the Home Comfort, Home Performance and REAP programs that will total about $12.69 million in spending in 2024. The 2024 EE Plan also outlines how the Utility is consulting with its strategic marketing and advertising agency to support targeted outreach and increased awareness of EE programs to residential and business customers in DACs.

1.5 Looking Ahead to the Future

PSEG Long Island's 2023 Utility 2.0 Plan represents a one-year outlook. In late 2022, PSEG Long Island began road mapping efforts by assessing the projected needs, gaps, and existing plans within each DPS priority area. Since many of the plans and studies listed below were not finalized until recently or are still awaiting finalization, anything presented beyond 2024 in this plan is subject to change and therefore not requesting additional funds at the time of this filing.

Current progress toward a long-term view can be found under the 'Priority Area Future Need Assessment' subsection for each DPS priority area chapter (Chapters 3, 4, 5, and 6).

Disadvantaged Communities

As noted in the previous section (Section 1.5), the CJWG voted to approve and adopt the final DAC criteria to advance climate justice in March 2023. As the set of criteria is being finalized, PSEG Long Island has begun developing a marketing and outreach plan for DACs as discussed further in the EE Plan in Appendix A. The final criteria will enable PSEG Long Island to better understand the needs of customers located within each DAC.

Climate Action Council Scoping Plan

The Climate Action Council developed a Scoping Plan to serve as a framework for how New York State will reduce greenhouse gas (GHG) emissions, increase renewable energy usage, progress climate justice, and achieve net-zero emissions. The finalized Scoping Plan was approved and released in December 2022 and discusses strategies to meet Climate Act directives and recommends sector-specific and economy wide actions the State should undertake. All these strategies are guided by pillars of climate justice, just transition, economic opportunity, long-term job opportunities, and public health.

Foundational recommendations to reduce GHG emissions include transition to zero-emission vehicles (ZEVs), enhancement of public transportation, mobility alternatives, private low-cost financing for building decarbonization, power generation transformation and grid enhancements, increased focus on energy management and efficiency opportunities through industry, carbon storage and sequestration in forestland, circular economy approach for materials management, and more efficient waste and agricultural management to reduce methane emissions.

Ultimately, the Scoping Plan lays out policies, programs, legislation, regulation, and funding opportunities for New York to meet the GHG emission limits established in the Climate Act; these actions will be taken across all levels of government and organizations. PSEG Long Island works closely with LIPA, DPS, and NYSERDA on its development of the Utility 2.0 plan to align its initiatives with the latest guidance, regulators, and State-led programs. Please see the following link for more information on the Climate Action Council Scoping Plan.

Mid-term Review of New Efficiency: New York

The New Efficiency: New York (NENY) report recommends a comprehensive mix of strategies to support building developers, commercial and industrial (C&I) business owners, industrial facilities, and residential households to pursue improvements that reduce energy consumption across the State. These efficiency improvements will allow New York to meet ambitious Climate Act goals and help catalyze innovation across multiple sectors in EE. Another priority documented in this report is to ensure that a substantial portion of new activities in EE benefit New Yorkers with low-to-moderate incomes.

In 2022, the DPS pledged to carry out a conventional interim evaluation of the NENY report. However, given the close association between NENY and the EE and building electrification facets of NYSERDA's Clean Energy Fund (CEF), the DPS chose to evaluate both simultaneously. This review effort began in September 2022 and consists of various review phases to evaluate the state's progress toward EE initiatives.

In 2022, the DPS Staff conducted a formal interim review of the programs, budgets, and targets authorized for New Efficiency: New York for consideration by the Public Service Commission in 2023. The report recommends a comprehensive mix of strategies to support building developers, C&I business owners, industrial facilities, and residential households to pursue improvements that reduce energy consumption across the State. These efficiency improvements will allow New York to meet ambitious Climate Act goals and help catalyze innovation across multiple sectors in EE. Another priority documented in this report is to ensure that a substantial portion of new activities in EE benefit New Yorkers with low-to-moderate incomes. Please see the following link for more information on the New Efficiency: New York (NENY) Report.

Assessment of EE and Electrification Potential in Buildings[12]

NYSERDA, in consultation with the JU, Staff, PSEG Long Island, and LIPA, developed an Assessment of EE and Electrification Potential in New York State Residential and Commercial Buildings, which was published in April 2023 with additional information being issued in May. This study estimates the EE and electrification savings potential over a 20-year period, from 2023 to 2042. The primary objectives of the study are to identify potential electrification and EE opportunities within the statewide building sector and inform potential design and planning intervention opportunities. The study spans the most prominent fuel types (electricity, natural gas, oil, and propane), building sectors (small residential, multifamily, commercial, industrial), and customer segments. Though the study reviews current building standards and codes, it does not set forth a specific building electrification plan for New York utilities. Therefore, it is important to note that this study is not comparable to PSEG Long Island building electrification initiatives described in the EE Plan in Appendix A but will be leveraged in the 5-year outlook provided next year.

Energy Storage

New York State has some of the most aggressive energy and climate goals in the country, and energy storage will play a crucial role in meeting these goals. Energy storage helps integrate clean energy into the grid, increases system efficiency, provides hosting capacity to support integration of more renewables and DER, provides resiliency to keep critical systems online during an outage, and reliability where energy storage is used in place of traditional T&D investments. In 2018, New York State set a nation-leading goal of 1,500 MW of energy storage by 2025. Later that year, the New York Public Service Commission issued a landmark energy storage order establishing a goal of 3,000 MW of energy storage by 2030, and the deployment mechanisms needed to achieve the 2025 and 2030 energy storage targets. Based on the proportion of peak load compared to the entire State, approximately 188 MW should be

[12] Assessment of Energy Efficiency and Electrification Potential in New York State Residential and Commercial Buildings

installed in Long Island by 2025. In January 2022, Governor Kathy Hochul called for New York to double its energy storage target to at least 6,000 MW by 2030 to help integrate significant new volumes of variable renewable energy resources.

PSEG Long Island supports the recommendations set in the New York Energy Storage Roadmap ("Storage Roadmap"), specifically addressing the following areas: retail rate actions and utility programs, direct procurement approaches through NWAs, market acceleration incentive, and "clean peak" actions. At present, PSEG Long Island has a portfolio of energy storage initiatives that directly support the achievement of these statewide energy storage targets. As outlined in the Storage Roadmap, each of PSEG Long Island's initiatives addresses different use cases: distribution system, bulk system, and customer sited.

Presently, PSEG Long Island is using two storage systems with a total capacity of 10 MW/80 MWh on the South Fork and is consistently soliciting for bulk energy storage to support the electric system in Long Island. In 2022, PSEG Long Island issued an RFP for Bulk Energy Storage to be in service by December 31, 2025. PSEG Long Island is currently in contract negotiations with selected developers.

Beyond utility-scale storage, customer-sited energy storage can support meeting the State's goals. PSEG Long Island completed its BTM Storage with Solar in 2021 and will make storage incentives available for Long Island residential customers beginning sometime in Q3 2023 through the Residential Energy Storage System Incentive Program (Section 5.4). These projects directly support the Storage Roadmap's recommendation of leveraging market acceleration incentives to accelerate adoption of customer-sited storage, including pairing with solar PV.

PSEG Long Island will aim to pursue a least-cost storage portfolio, which will be informed by PSEG Long Island's Bulk Energy Storage RFP, 2022 LIPA IRP, and any other updates to the Storage Roadmap.

2. Building Decarbonization and Envelope Improvements

The Climate Act puts the state on the path to reaching 100% zero emission electricity by 2040 and aims to reduce statewide GHG emissions by 85% by 2050 relative to 1990 levels. Given that buildings contribute about a third of the state's total direct carbon emissions, electrification, and EE upgrades in both new construction and existing buildings is key to achieving the decarbonization goals. Examples of key decarbonization strategies include high-performance building envelopes, energy-efficient technologies for heating and cooling buildings, and smart equipment promoting load flexibility.

Statewide, over 200,000 homes per year must be upgraded to be all-electric and energy efficient from 2030 and over 600,000 commercial, institutional, and multifamily buildings must rely on renewables by 2050.[13] To directly support building decarbonization, Governor Hochul committed to achieving a minimum of 1 million electrified homes and up to 1 million electrification-ready homes by 2030.[14] Of the 2 million, 800,000 of the homes are expected to be LMI households.

PSEG Long Island has been actively engaged in rolling out utility-leading residential and commercial savings programs for customers outside of U2.0. Building decarbonization and envelope improvements are addressed by the programs in the EE Plan. Additionally, the 2024 EE Plan (Appendix A) focuses on continuing to deliver EE savings programs to residential and commercial customers, while expanding the Utility's efforts to include beneficial electrification initiatives. Adopting fuel-neutral savings targets allows PSEG Long Island to aggregate efficiency achievements across electricity, natural gas, and delivered fuels such as oil and propane, which requires a shift toward investments in non-lighting opportunities, especially an expanded focus on heat pumps and other beneficial electrification opportunities.

Chapter Contents

[13] NYSERDA Carbon Neutral Buildings Roadmap: Achieving a carbon neutral building stock in New York State by 2050. June 2021.
[14] 2022 New York State of the State Book

3. Moving Towards a Zero Emissions Grid

Moving Towards a Zero Emissions Grid requires strategic planning to ensure customer energy demands are continuously met in parallel to deploying more renewables and battery storage to expand capacity. PSEG Long Island is moving towards a zero emissions grid through efforts and investments both within and outside of the Utility 2.0 program. Efforts focus on deployment of utility-scale renewables and storage, improving information available for developers to interconnect distributed energy resources (DER) to the grid, and planning activities to ensure success in this trajectory towards a zero emissions grid in future years.

The active Storage and EV Hosting Capacity Maps initiative supports *Transportation Electrification* in addition to *Moving Towards a Zero Emissions Grid*. The EV maps provide developers with insight on the optimal locations to build EV charging locations and, in turn, increase the accessibility of EV charging for customers. The storage maps similarly enable developers to understand optimal locations for additional storage and facilitate additional storage capacity.

To ensure a Distributed System Platform (DSP) capable of moving towards zero emissions, it is important to plan and operate a dynamic grid that encompasses DER and associated capabilities. The Utility of the Future team is foundational to supporting the overall advancement and management of the DSP, which enables proliferation of beneficial electrification, EVs, and Energy Storage across PSEG Long Island's service territory.

Both the Hosting Capacity Maps and the Increasing Hosting Capacity Study provided guidance on how to enable higher DER interconnection within the LIPA service territory. The completed Increasing Hosting Capacity Study studied ways to enable higher DER penetration specifically for locations that are currently or will be constrained, to ultimately yield more interconnection of zero emissions resources. Discussion on the Hosting Capacity Maps and other projects previously aligned to this priority area can be found in Section 1.3.

Priority Area Future Needs Assessment

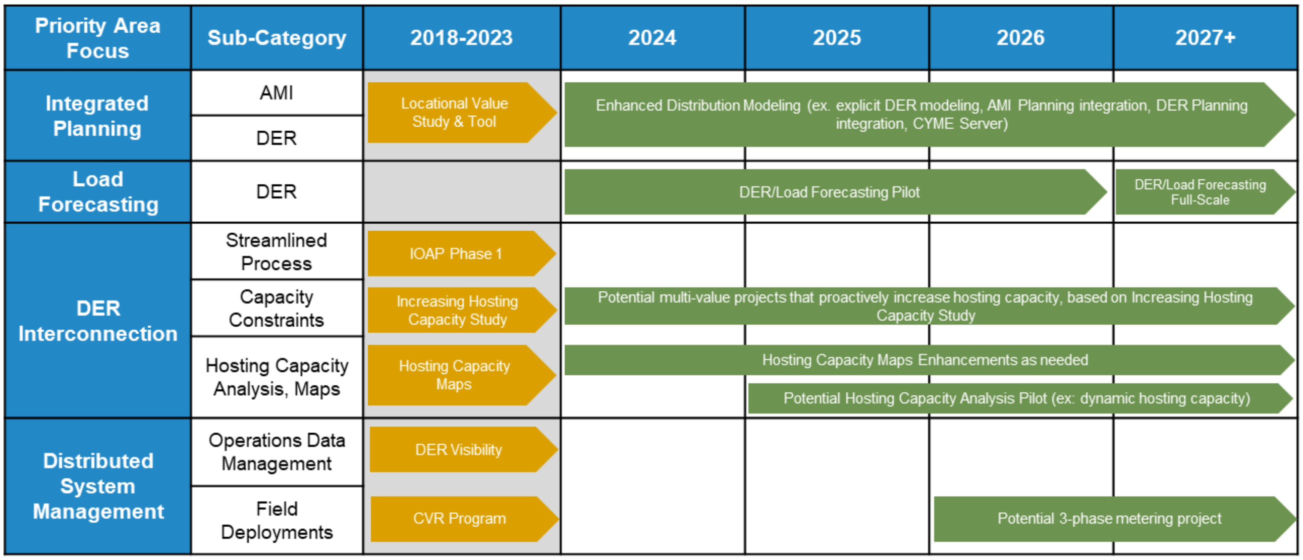
Since the Utility 2.0 Filing in 2018, PSEG Long Island has completed a diverse portfolio of projects that align with the current *Moving Towards a Zero Emissions Grid priority* area. In particular, the Utility 2.0 program established the Utility of the Future team, which has since become integrated in the Utility's everyday grid planning and operations. The Utility of the Future team has, in turn, completed a variety of projects that enable efficient advancement of the Distributed System Platform including project such as the Hosting Capacity Maps and Increasing Hosting Capacity Study.

The Utility of the Future team will continue to pursue projects that build on the Utility's successes and learnings over the years that the current *Moving Towards a Zero Emissions Grid* priority area had been built upon. Future projects will pursue more advanced analysis of DER related constraints on the distribution system which will be utilized to provide more accurate and useful information for DER interconnection. Another potential effort includes advanced analysis of EV Load Capacity, utilizing granular data to project potential constraints on critical feeders and assess potential solutions for addressing expected constraints ahead of need.

The Utility of the Future team may also pursue pilots to enhance distribution models for granular analysis and to identify necessary requirements for assessing wider implementation of new initiatives. The exact timeline and focus for future projects that align with this priority area is subject to future guidance and direction for PSEG Long Island.

Figure 3-1 provides a summary of potential future efforts within the *Moving Towards a Zero Emissions Grid* priority area. Future filings will provide additional detail to the Utility's multi-year outlook.

Figure 3-1. Moving Towards a Zero Emissions Grid Future Outlook



This chapter is organized into six subsections that provide an update for Utility 2.0 initiatives that directly align with the *Moving Towards a Zero Emissions Grid* priority area. PSEG Long Island notes that the initiatives in this chapter are not limited to only supporting this priority area and likely contribute to others.

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3.1 Storage and EV Hosting Capacity Maps

2023 Status	Active
2024 Status	Operational
Start Year	2023
Funding Approved Through	2023
Description and Justification	Building off Hosting Capacity Maps – Phase 3, the Storage and EV Hosting Capacity Maps will provide information to customers on favorable locations to interconnect storage resources and EV charging stations. This project aims to be implemented in 2023, with applicable updates ongoing thereafter.

The *Storage and EV* Hosting Capacity Maps will be hosted on the same platform as the previous Hosting Capacity Maps project. This project will offer a high-level overview to developers on optimal locations for installing energy storage and siting EV charging stations on LIPA's primary distribution system.

The Storage Capacity Maps will provide information on favorable locations for interconnecting energy storage thus enabling the cost-effective integration of energy storage resources to the distribution grid.

The EV Capacity Maps will be published on PSEG Long Island's website as an informational tool for EV customers. These maps will help facilitate EV charging equipment deployment throughout the utility's service territory. PSEG Long Island plans to integrate the EV maps such that developers and customers can log into a single platform to see all available hosting capacity maps. All hosting capacity maps will be hosted on the same platform with users going through the clear check process to gain access to the maps on the PSEG Long Island website.

3.1.1 Implementation Update

PSEG Long Island plans to leverage the best practices of the JU as applicable to develop storage hosting capacity maps. PSEG Long Island expects that a third-party consultant will be contracted to support development of the storage hosting capacity maps. The technical analysis will be conducted by PSEG Long Island's internal Utility of the Future (UoF) team. The maps will be made available on PSEG Long Island's website using the same portal as the existing hosting capacity Stage 3 Maps. See additional scope and schedule updates below for the Storage and EV Hosting Capacity Maps.

Scope Update

PSEG Long Island will collect relevant data and conduct hosting capacity analyses for energy storage systems and EV charging locations. PSEG Long Island will develop storage-specific hosting capacity maps by utilizing the EPRI Drive software tool. Maps will be updated on a quarterly basis, consistent with the existing hosting capacity maps. PSEG Long Island will develop EV load serving capacity maps based upon the analysis conducted, which will be updated on an annual basis.

Schedule Update

In Q1 2023, PSEG Long Island developed and submitted a Functional Design Methodology Document to the LIPA Smartsheet Portal that outlined the process for identifying energy storage hosting capacity on a given feeder, calculating EV headroom, and the data/line items that will be shared on the maps. In Q2 2023, PSEG Long Island will work with additional third-party support to begin data collection for the Storage and EV Hosting Capacity Maps, which will be connected to the straw model developed by the IT team. In Q3 2023, PSEG Long Island will engage in internal user acceptance testing (UAT) to validate the representation of EV load serving and storage hosting capacity data in the maps. By the end of 2023, the Storage and EV Hosting Capacity Maps will be published on the PSEG Long Island website and will be updated on an ongoing basis.

Risks and Mitigations

Table 3-1 outlines the potential risks and proposed mitigation steps for this initiative.

Table 3-1. Risk and Mitigation Assessment – Storage and EV Hosting Capacity Maps

Category	Risk	Mitigation
Project Scope	Need for communication with JU on the current practices in building EV load serving capacity maps, to ensure alignment in the development of PSEG Long Island's EV load serving capacity maps	Gain understanding of the scope of existing maps developed by JU before beginning development of PSEG Long Island's EV load serving capacity maps.

3.1.2 Funding Reconciliation

Starting in 2024, O&M costs for the Storage and EV Hosting Capacity Maps will be drawn from the PSEG Long Island core operations to support ongoing updates to the maps. Other future O&M costs will be conducted by internal IT and Utility of the Future teams and the project will no longer require Utility 2.0 budget beginning in 2024. Storage and EV Hosting Capacity Maps Budget and Forecast is detailed in Table 3-2.

Table 3-2. Storage and EV Hosting Capacity Maps Capital and Operating Expense Budget and Forecast

	Updated Forecast	
	2023	Total
Capital	0.94	**0.94**
O&M	-	**-**
Total	**0.94**	**0.94**

3.1.3 Performance Reporting

As a foundational customer-facing tool, the Storage and EV Hosting Capacity Maps are expected to provide value to Long Island customers or developers. The success is measured by ensuring relevant information is available to applicable customers and by ensuring the project stays on schedule and delivered by end of 2023. The maps will provide guidance to the interconnection customers of the locations on the circuit for potential cost-effective storage and EV charging infrastructure deployment.

Lessons Learned

Previous Utility 2.0 hosting capacity projects and studies (i.e., Hosting Capacity Maps Phases II, and III and Increasing Hosting Capacity Study) served as lessons learned for the Storage and EV Hosting Capacity Maps project. Learnings from these projects identified distinctions between types of hosting capacity within intersecting and different locations across Long Island.

To ensure delivery of the Storage and EV Hosting Capacity maps by the end of 2023, the project team will adhere to the proposed schedule and continually communicate with the PSEG Long Island IT team.

Next Steps

The Storage and EV Hosting Capacity Maps will go live on the PSEG Long Island website by the end of 2023. Beginning in 2024, the project will transition into Operational status as no activity or budgetary requirements are expected for this project within the Utility 2.0 Program moving forward.

3.2 Utility Scale Storage – Miller Place

2023 Status	Canceled
Start Year	2019
Funding Approved Through	Q1 2023
Description and Justification	In late 2019, PSEG Long Island issued a competitive solicitation for third-party support to deliver a 2.5 MW/12.5 MWh system at Miller Place Substation that will potentially defer the need for costly grid infrastructure investments. In Q1 2023, PSEG Long Island met with LIPA, and they jointly agreed to pursue a traditional T&D solution rather than the utility-scale battery storage system to resolve load growth at the Miller Place substation, leading to the project's cancellation.

The Utility-Scale Storage Miller Place project offered an opportunity for third-party developers to develop, procure, install, maintain, and potentially operate utility-scale storage on Long Island. This project would have contributed to the Climate Act goals of 1,500 MW of storage installed by 2025 and 6,000 MW by 2030.

The Utility-Scale Storage Miller Place project was intended to provide grid flexibility required to transition an electric grid with high renewable energy penetration, supporting the Governor's goals of supplying 70% of the state's energy needs with renewable energy by 2030. The main objective of the project was to defer the need for traditional T&D grid infrastructure investment at Miller Place substation.

3.2.1 Accomplishments & Outcomes

In 2022, the UoF team continued to engage with stakeholders to progress towards awarding a bid to a vendor for the Miller Place utility-scale battery system. A third-party vendor was identified and EPC contracting began, however, due to supply chain issues and installation uncertainties, the estimated contract cost with this vendor increased significantly from December 2022 to March 2023 resulting in traditional solution being more cost effective than the storage project

In Q1 2023, PSEG Long Island and LIPA jointly decided to pursue a traditional T&D solution rather than implement the utility-scale battery system to resolve load growth at the Miller Place substation. Cancellation of the utility-scale battery system at Miller Place can be attributed to contract and price uncertainty as well as the lower comparative cost of the traditional T&D solution.

3.2.2 Funding Reconciliation

Delays in contracting and procurement led to significant underspend in the overall 2022 budget for the Utility-Scale Storage Miller Place project. Since the project has recently been canceled, no additional funds will be requested for 2023 and beyond (see Table 3-3).

Table 3-3. Utility Scale Storage – Miller Place Capital and Operating Expense Budget, Forecast, and Variance

	Actual 2019	Actual 2020	Actual 2021	Actual 2022	Total	Variance 2022
Capital	0.09	0.14	0.02	0.03	**0.29**	**(6.79)**
O&M	-	-	-	-	**-**	**-**
Total	**0.09**	**0.14**	**0.02**	**0.03**	**0.29**	**(6.79)**

3.2.3 Lessons Learned

The primary lesson learned from this project is that the integration of new technology requires detailed review and learning from various subject matter experts and could result in a significantly longer project time frame as compared to an established traditional project. Also, any delays due to procurement processes can lead to increases in vendor estimates because of market conditions and economic supply constraints. Another lesson learned was that to properly reflect changing marketing conditions and to understand the cost effectiveness of projects with ongoing rising costs, the team needed to reevaluate the BCA. Lastly, the project team learned that constant communication with both external and internal stakeholders is critical to better facilitate the integration of a new technology to the system.

4. Transportation Electrification, Including Fleets

The transportation sector is the second biggest contributor of GHG emissions in New York State[15]. To achieve GHG reduction goals by 2050, the state has committed to:

- 850,000 electric LDVs by 2025
- All new passenger cars and trucks sold in New York State (NYS) to be zero-emissions by 2035
- Electrifying the state's light duty fleet and 100% of electric school buses by 2035
- All new MHDV sales to be zero-emissions by 2045

These transportation electrification targets are supported by initiatives that encourage wider adoption of EVs. One key initiative is the statewide EV Make-Ready Program, which incentivizes greater deployment of electric vehicle supply equipment (EVSE) by providing funding to support Utility-Side Make-Ready (US-MR), and Customer-Side Make-Ready (CS-MR) infrastructure costs.

As detailed in Section 1.1, PSEG Long Island evolved its Utility 2.0 vision and framework to align with statewide priorities. All initiatives included in this chapter, including those implemented outside of the Utility 2.0 program, directly contribute to Transportation Electrification. The EV Make-Ready Program and the Suffolk County Bus Make-Ready Pilot support New York State goals to achieve a 40% reduction in GHG emissions from 1990 levels by 2030 and to deploy 850,000 ZEVs by 2025. PSEG Long Island's ongoing EV Program also promotes adoption of EVs to help achieve the target of 850,000 EVs by 2025 as well as the all-new passenger vehicles being electric by 2035 target.

PSEG Long Island targets supporting the adoption of 178,500 EVs on Long Island through various transportation electrification initiatives. Long Island's share of the State ZEV adoption goal (850,000 LDVs) is based on the ratio of vehicles registered on Long Island to those in the state, which is approximately 21%. Long Island continues to see more EVs on the road, around 41,000 EVs as of June 2023.[16]

Priority Area Future Needs Assessment

Since the inaugural Utility 2.0 Filing in 2018, PSEG Long Island has initiated a diverse portfolio of projects that align with the current *Transportation Electrification, including Fleets* priority area. The Utility 2.0 program established the Transportation Electrification Team in 2022 that plans and implements projects to meet the fast-growing needs to electrify the transportation sector. The Transportation Electrification Team is currently made of 4 Full Time Employees (FTEs) and is projected to grow to 6 FTEs by 2024, with an EV Program Manager leading the Team. A variety of projects have been introduced by the Team to support the increase in EV adoption and charging infrastructure deployment on Long Island.

The Transportation Electrification Team will continue to pursue projects that build on the Utility's successes and learnings over the years. PSEG Long Island offers rebates and affordable rates, develops make-ready infrastructure, and supports fleet electrification to lower the barriers to EV adoption and charging infrastructure development, while helping customers save on their electric bills.

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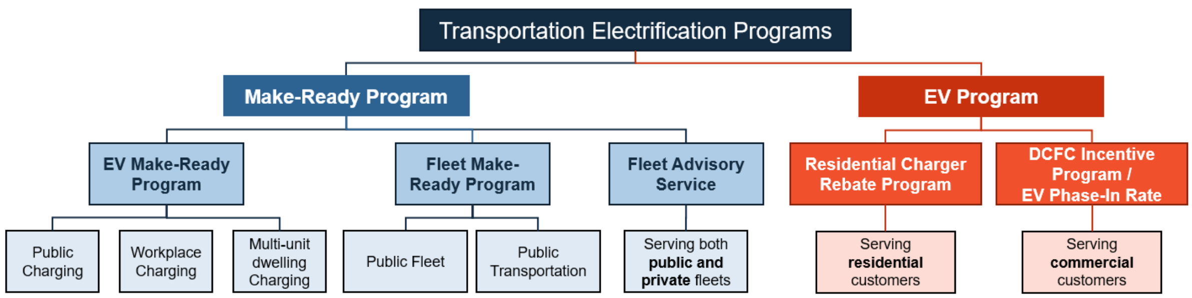
[15] New York State Department of Environmental Conservation. 2022 Statewide GHG Emissions Report.

[16] The "EVs on the Road" number was last updated on the NYSERDA website on June 2, 2023. https://www.nyserda.ny.gov/All-Programs/chargeny/support-electric/map-of-ev-registrations%20

Figure 4-1 illustrates an overview of the active and proposed programs on the *Transportation Electrification, including Fleets* priority area. The Make-Ready program aims to support the deployment of charging infrastructure in the commercial and multi-unit dwelling markets on Long Island and consists of the existing EV Make-Ready Program, the approved Fleet Advisory Service, and the proposed Fleet Make-Ready Program. More details on the Make-Ready Program can be found in Section 4.1.

The EV Program serves both residential and commercial customers through charger rebates and affordable rates and consists of the proposed Residential Charger Rebate Program and the existing DCFC Incentive Program, which will be replaced by EV Phase-In Rate in 2025. Section 4.2 provides details on the EV Program.

Figure 4-1. Transportation Electrification Program Structure



To ensure a sustainable and equitable transition to electrified transportation, the proposed Fleet Make-Ready Program will include a higher incentive tier for projects located in DACs, and the proposed Residential Charger Rebate Program will include a higher incentive tier for eligible LMI and DAC customers on Long Island.

Given the importance of customer awareness and collaboration among stakeholders in accelerating EV adoption, the Team aims to enhance its Marketing, Education, and Outreach (ME&O) efforts to improve customer experience, reinforce collaboration with EV ecosystem partners, and inform the development of future programs. The Team aims to build EV awareness and promote EV programs through a variety of efforts which may include:

1. **Conduct Customer Journey Mapping** to improve customer experience, and provide a clear and simple path to EV planning and adoption

2. **Update EV Program Webpages** that provide clear and trusted information on EVs and associated charging

3. **Deliver Targeted Education and Outreach** to commercial fleet customers and EV ecosystem partners, such as automakers, electricians, contractors, and charging service providers

4. **Conduct Market Research** to gauge customers' perception and interests towards EV and program participation through surveys, as well as gain insights into the quickly evolving EV market; and

5. **Expand and Strengthen Ecosystem Collaborations** by collaborating with the Edison Electric Institute major accounts and community-based organizations, sponsoring events and workshops, and presenting at industry forums.[17]

Additionally, the Transportation Electrification Team has been actively monitoring the state of the EV market and associated infrastructure and technologies. In addition to the programs proposed in this year's filing, the team will consider pursuing pilots and/or programs in areas that could further provide grid services and strengthen charging infrastructure reliability and grid resiliency in future years. Future initiatives may include:

- **Managed Charging:** Managed charging pilots/programs can be effective at incentivizing the behavior of EV drivers to charge their EVs during times of low peak demand and high renewable generation. A managed charging pilot could validate whether such programs could provide additional grid services such as peak shaving and increasing daytime electricity consumption, as well as evaluating whether such programs would be well received by customers. This can potentially be done either at the charger level, or at the vehicle level.
- **Vehicle-to-Everything (V2X):** New technologies, such as vehicle-to-grid (V2G) and vehicle-to-home/building (V2H/B) have the potential to be important grid resources (e.g., resiliency, non-wires alternative), and provide additional benefits to EV drivers and owners.
- **Microgrid Charging:** DER technologies such as battery storage and solar canopy could be used to enable EV charging during power outages.

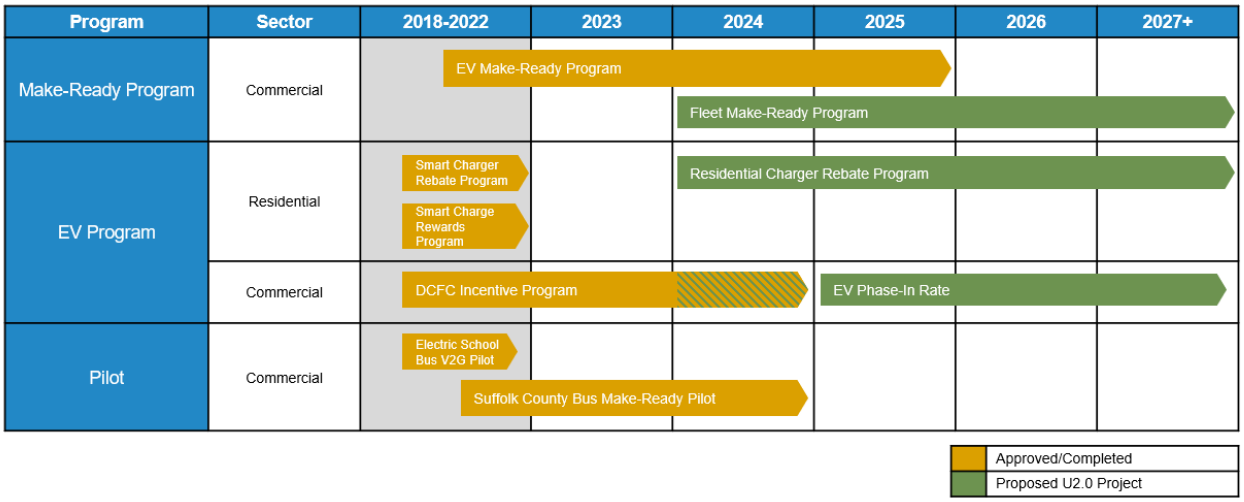
While the current focus of transportation electrification is on LDVs and MHDVs on road, the Transportation Electrification team will consider supporting non-road electrification.[18] in future years. The team plans to engage airports and ports to investigate their interests in installing charging stations at parking lots, their plans to electrify ground support vehicles (e.g., airport shuttles, service vehicles and equipment, forklifts, etc.), and stay informed on their future electrification plans.

Figure 4-2 provides a summary of approved and proposed efforts within the *Transportation Electrification, including Fleets* priority area. Future filings will provide additional detail to the Utility's multi-year outlook.

[17] The Transportation Electrification Team has participated in more than a dozen of events since the beginning of 2023. These activities include: "Working Safely Around Electric Vehicles" – an EV safety course at Suffolk County Community College in partnership with Clean Cities, New York Association for Student Transportation, NY Energy Summit, radio interviews to promote EVs at Connoisseur Media, TV commercials to promote EVs on Long Island, monthly committee meetings at Drive Electric Long Island, and many more.

[18] According to New York State Department of Environmental Conservation's 2022 NYS GHG Emissions Report, non-road transportation constitutes of around 16% of transportation emissions in New York State. Non-road transportation sources include aviation, marine, and rail as well as equipment used in agriculture, construction, landscaping, or recreation.

Figure 4-2. Transportation Electrification, including Fleets Future Outlook



This chapter is organized into three subsections that provide an update for Utility 2.0 initiatives that directly align with the *Transportation Electrification, including Fleets* priority area. PSEG Long Island notes that the initiatives in this chapter are not limited to only supporting this priority area and likely contribute to others.

Chapter Contents

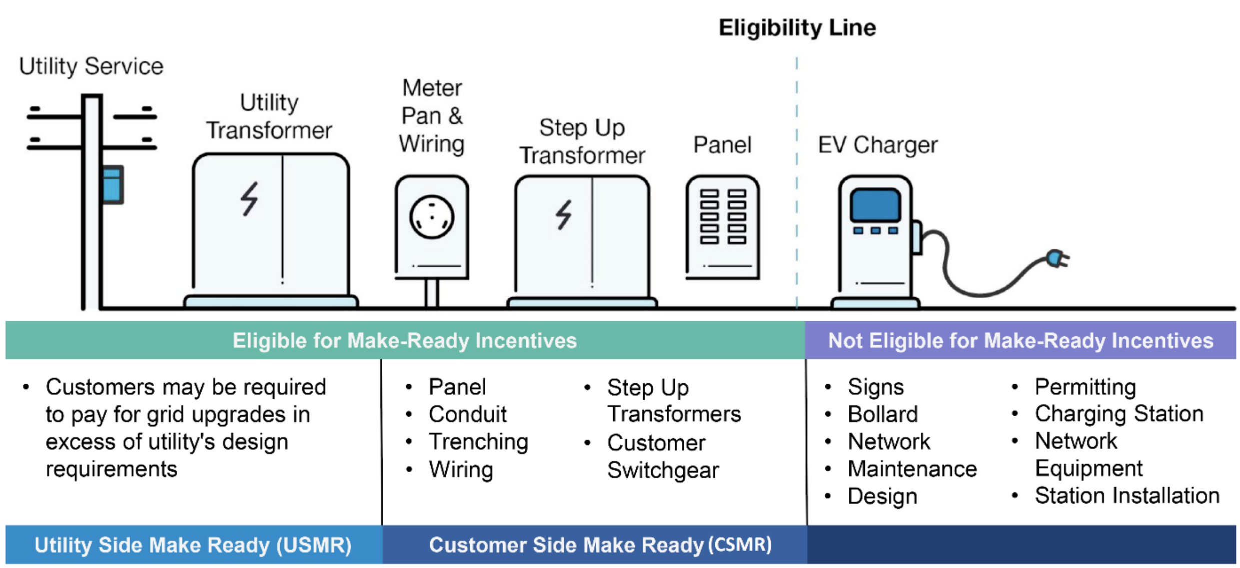
4.1 Make-Ready Program

2023 Status	Active
2024 Status	Active
Start Year	2021
Funding Approved Through	2025
Description and Justification	The EV Make-Ready Program was initially proposed in 2020 to support and accelerate EV adoption on Long Island. The scope and funding for make-ready infrastructure is revaluated in this filing to account for the expanded scope to support fleet electrification on Long Island. This program will be renamed as the Make-Ready Program and covers three programs and services: (1) the existing EV Make-Ready Program; (2) the approved Fleet Advisory Service; and (3) Fleet Make-Ready Program. The EV Make-Ready Program will be updated based off the DPS EV Make-Ready Program Midpoint Review and Recommendations Whitepaper. The Fleet Advisory Service was approved in 2022 and is being developed to launch in Q3 2023. Under the new Fleet Make-Ready Program, PSEG Long Island plans to provide Utility-Side and Customer-Side Make-Ready incentives to eligible fleet customers operating LDVs and MHDVs on Long Island for the next 5 years.

Definitions

Make-Ready refers to all infrastructure required to provide power to the physical point where chargers will be installed, but not including the chargers themselves. US-MR represents infrastructure on the utility side of the meter and includes any utility upgrades required to supply power from the distribution network, down to the meter. The US-MR is built, owned, and operated by the utility. CS-MR represents the infrastructure that supplies power from the meter, up to the connection of EVSE. The CS-MR is built, owned, and operated by the site host (see Figure 4-3).

Figure 4-3. Utility-Side and Customer-Side Make-Ready



EV Make-Ready Program

In July 2020, the NY PSC released the EV Make-Ready Program Order (Make-Ready Order) that established statewide goals for a utility supported EVSE Make-Ready program.[19] The Make-Ready Order recommends that major electric utilities should provide financial contributions for Make-Ready infrastructure to accelerate EVSE deployment, in turn enabling more rapid adoption of EVs.

In the 2020 Utility 2.0 Plan, PSEG Long Island proposed a Phase 1 Light-duty Make-Ready Program to support the deployment of make-ready infrastructure for new direct current fast charging (DCFC) and Level 2 (L2) charging stations. PSEG Long Island also proposed in its 2021 Utility 2.0 Plan a Phase 2 Light-duty Make-Ready Program to support EV Make-Ready (EVMR) investments from 2022 through 2025.

PSEG Long Island's EV Make-Ready Program is structured similarly to requirements set out in the Make-Ready Order. Due to accounting and financing nuances specific to LIPA's public power model, cash rebates are recovered through operating expenses and impact ratepayers in the year they occur. PSEG Long Island is therefore implementing a "lease-to-buy" model that will allow LIPA to capitalize on the customer-side make-ready (CS-MR) infrastructure for DCFC, as these charging stations have significant investment requirements compared to L2 charging, thus avoiding having to recover a significant amount of operating expenses (for rebates for CSMR infrastructure) from ratepayers. L2 charging stations utilize the rebate model given their lower investment requirements and therefore have less of an impact to operating expenses from ratepayers.

In March 2023, the NY DPS released the Electric Vehicle Make-Ready Program Midpoint Review and Recommendations Whitepaper. The Whitepaper recommended a higher program budget, updated plug projections for both L2 and DCFC, and added flexibility on program timeline. PSEG Long Island also observed that the market might mature at a slower pace than originally forecasted. In line with the recommendations made in the Midpoint Review Whitepaper and the Team's experience in administrating the program, PSEG Long Island proposes to extend the program by two years (to 2027), slightly decrease L2 port target, update the assumed make-ready costs, update the incentive tier to be 100%, 75%, and 50%, and update program budget to reflect these changes. These changes are discussed in detail in the next section.

Fleet Make-Ready Program

PSEG Long Island plans on further supporting the development of EV charging infrastructure through the proposed Fleet Make-Ready Program. While other NYS utilities have similar pilots, this will be the first program designed to serve fleets, which include both LDV and MHDV segments, in New York State.[20] The Fleet Make-Ready Program aims to serve two target markets that would most likely benefit customers in DACs: 1) public fleets which cover local government, public serving, and not-for-profit organizations; 2) public transportation (e.g., school buses, and transit buses). If approved, this program will provide US-MR and CS-MR incentives[21] from 2024 through 2028.

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[19] Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs, CASE 18-E-0138 Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure, July 16, 2020.

[20] Program guidelines will be further developed in H2 2023 based on DPS's MHD Make-Ready Whitepaper or Order (expected Q4 2023).

[21] The same US-MR and CS-MR definitions apply to both EV Make-Ready Program and Fleet Make-Ready Program.

PSEG Long Island views the Fleet Make-Ready Program as an expansion of the Make-Ready infrastructure development effort and achieving the same Climate Act goals as the EV Make-Ready Program. The Fleet Make-Ready Program will be a separate program offering, parallel to the EV Make-Ready Program under the Make-Ready Program (Figure 4-1). Eligible fleets may operate both LDVs or MHDVs, and there may be situations where a customer submits a load letter at one location that has both public and/or workplace charging along with fleet charging. While the Fleet Make Ready Program does serve less customer segments compared to the EV Make Ready Program, there are synergies among the two programs to make the application process as streamlined as possible for customers. Eligible customers will be able to apply for both programs through the Make-Ready Program application[22].

Fleet Advisory Service

The Make-Ready Program will also cover the approved Fleet Advisory Service[23]. The Service will be available to both public and private fleet customers, with anticipated launch in Q3 2023. Service offerings in this Program include:

1. Free **Fleet Advisory Online Tool** that provides personalized, self-service information on available EV options, the best time to charge, rate and eligible program recommendations, potential bill impact and cost savings, and GHG reductions; and
2. **Fleet Advisor** who provides additional advisory services to fleet customers through their electrification journey, as well as support on customer outreach and engagement.

To date, the Transportation Electrification Team has spoken with several school districts and coalitions/associations on Long Island to help them get started with their fleet electrification efforts. Below is a list of school districts, associations, and companies that the Team has connected with:

- Sewanhaka School District
- Long Beach School District
- New York Association for Pupil Transportation (NYAPT)
- New York School Bus Contractors Association (NYSBCA)
- Farmingdale School District
- Frito-Lay (a PepsiCo company)

The Team has also informed these organizations of the proposed Fleet Make-Ready Program and what type of incentives would be offered starting 2024.

4.1.1 Implementation Update

PSEG Long Island launched Phase 2 of the EV Make Ready Program in Q1 2022 and continued to enroll and energize L2 and DCFC ports in the Program. During the third quarter of 2022, PSEG Long Island engaged a third-party consultant to develop a MHD Make Ready Study[24] that informed what policies and trends are influencing the pace at which these vehicle segments will electrify, and their impact on the

[22] More details on Make-Ready Program application will be provided on the PSEG Long Island website once this program is approved.
[23] Additional details on the Fleet Advisory Service can be found in 2022 Utility 2.0 Long Range Plan & Energy Efficiency Plan.
[24] The MHD Make Ready Study can be found in Appendix C.

electrical grid. This study has helped with the development of the Fleet Make Ready Program, which is slated to start serving eligible fleet customers in 2024.

Scope Update

Overall, PSEG Long Island targets supporting the adoption of 178,500 EVs on Long Island through various transportation electrification initiatives. Long Island's share of the State ZEV adoption goal (850,000 LDVs) is based on the ratio of vehicles registered on Long Island to those in the state, which is approximately 21%.

To directly support this goal, PSEG Long Island proposed in the 2021 Utility 2.0 Plan to make incentives available for 498 new DCFC ports and 4,247 new L2 ports through 2025. PSEG Long Island has since reevaluated annual program enrollments and budget requirements, as detailed in the following sections.

4.1.1.1 EV Make-Ready Program

Ports

Based on progress since 2021 as shown in Table 4-1, PSEG Long Island expects enrollment in the EV Make-Ready Program will gradually increase over time and at a slightly slower pace than originally forecasted. Thus, PSEG Long Island plans on extending the program by two years (to 2027) to allow for additional market maturity and vehicle adoption for the utility to serve the market. Table 4-1 and Table 4-2 show the updated total number of ports estimated to be enrolled and energized, respectively, by year and port type[25]. In line with the Mid-term Review recommendation, overall L2 port target is slightly reduced. The overall DCFC port target will remain the same as previously proposed.

Table 4-1. EV Make-Ready Program Actual and Estimated Enrolled Ports by Type (2023 Update)[26]

Port Type	2021	2022	2023	2024	2025	2026	2027	Total
	Actual	*Actual*	*LIPA Target*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	
L2	8	185	450	500	731	929	1,249	**4,052**
DCFC	0	108	110	68[27]	68	72	72	**498**
Total	8	293	560	568	799	1,001	1,321	**4,550**

The expected number of energized ports as shown in Table 4-2 is based upon the assumption that L2 projects would take approximately six months on average from committing funds to construction and that

[25] Enrolled is defined as ports with committed funds or pre-approval letter. Energized is defined as the total population of DCFC and L2 ports that have meters set and put into service in a given year.

[26] Since the submission of the 2023 Utility 2.0 Long Range Plan on July 1, 2023, the actual and forecast port count were updated based on the most up-to-date information in the PSEG-LI Internal EV Make-Ready Program Database as of August 25, 2023, which is reflected in this table. Supporting documentation provided on July 1, 2023 will differ slightly from the updated forecast presented here.

[27] PSEG Long Island received approximately 90% less DCFC applications in the first half of 2023 compared to the first half of 2022. As a result, PSEG Long Island updated the DCFC port forecast to reflect the current market demand and planned for several marketing and outreach efforts to increase program participation in the latter half of 2023.

DCFC projects would take approximately 15 months. Thus, some of the projects are expected to be completed in 2028.[28]

Table 4-2. EV Make-Ready Program Actual and Estimated Energized Ports by Type (2023 Update)[29]

Port Type	2021	2022	2023	2024	2025	2026	2027	2028	Total
	Actual	*Actual*	*LIPA Target*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	*Forecast*	
L2	0	87	400	293[30]	558	774	1,007	933	**4,052**
DCFC	48	100	103	54	68	47	47	30	**498**
Total	48	187	503	347	626	821	1,054	964	**4,550**

The infrastructure targets are based on assumptions regarding the amount of infrastructure required to support NYS targets for EV adoption[31]. Recognizing that actual EV adoption may vary from forecasts based on multiple factors including but not limited to, available incentives to purchase EVs, price parity, and vehicle availability, PSEG Long Island monitors EV registrations monthly, and annual number of adoptions so that any deviations from forecasts can quickly be acknowledged and addressed. Depending on the types of deviation experienced (if any), PSEG Long Island would expect to identify the deviations and any resultant programmatic changes to address as part of the annual Utility 2.0 reconciliation process in future years.

Infrastructure Costs

The make-ready costs are divided into two categories: US-MR and CS-MR. The Team developed updated US-MR and CS-MR cost estimates based on the JU's actual project cost data as the PSEG Long Island actual program data is limited in certain cost components. Table 4-3 shows the infrastructure costs updated based upon actual average project cost data outlined in the Midpoint Review.

Table 4-3. EV Make-Ready Program Infrastructure Cost Estimates per Location (2023 Update)

Port Type	US-MR	CS-MR	Total
L2	$242	$27,770	$28,012
DCFC	$11,938	$357,031	$368,969

[28] All projects that enroll in the EV Make-Ready Program must commit to complete by 2028.

[29] Since the submission of the 2023 Utility 2.0 Long Range Plan on July 1, 2023, the actual and forecast port count were updated based on the most up-to-date information in the database as of August 25, 2023, which is reflected in this table. Supporting documentation provided on July 1, 2023 will differ slightly from the updated forecast presented here.

[30] PSEG Long Island refreshed the forecast for L2 ports based on the slight reduction in L2 target and extended program timeline.

[31] During the first quarter of 2021, PSEG Long Island engaged a third-party EV expert consultant to develop an implementation plan to identify target EVSE infrastructure levels, make-ready costs and associated incentives, and business models for make-ready and EVSE infrastructure deployment. The infrastructure targets were developed based on this third-party study.

To ensure equitable distribution of incentives, PSEG Long Island established incentive caps based on project type:

- L2: $30,366
- DCFC Corridor: $529,302[32]
- DCFC Community: $205,623[33]

Additionally, no more than 20% of the annual budget should go towards any one entity.

Business Model

PSEG Long Island implements the lease-to-buy model for all DCFC projects, and the rebate model for all L2 projects.[34]

In line with the model recommended by the DPS in its Make-Ready Order and its Midpoint Review Whitepaper, for both L2 and DCFC infrastructure, the incentive strategy is a three-tier structure based on the relative value of a given port. Projects will be eligible for an incentive tier of 100%, 75%, or 50% depending on specific requirements based on:

- whether it is available to the general public
- whether it utilizes standard charging port types
- power requirements
- whether it is located within a DAC
- whether it accepts universal forms of payment

PSEG Long Island includes a requirement on universal forms of payment to ensure that all EV drivers can pay for their charging session at any public charging station without the need to utilize a mobile app. This includes being able to utilize other forms of payment, such as cash, credit card, QR code, tap-to-pay, or calling a toll-free phone number to activate the charger and supply power to the EV.

The updated expected allocation of locations per incentive tier is shown in Table 4-4.

Table 4-4. EV Make-Ready Program Customer Incentive Breakdown 2024 – 2027 (by location)

Port Type	100% Incentive	75% Incentive	50% Incentive	Total
L2	343	628	171	**1,142**
DCFC	7	20	41	**68**
Total	**350**	**648**	**212**	**1,210**

4.1.1.2 The Fleet Make-Ready Program

The proposed Fleet Make-Ready Program targets fleet customers operating LDVs, MHDVs, or both. In this program, a fleet is defined as three or more vehicles operated by a non-residential entity with a meter on a

[32] The incentive cap for DCFC Corridor is based on costs of at least 4 ports per site.
[33] The incentive cap for DCFC Community is based on costs of at least 2 ports per site.
[34] Additional details can be found in 2022 Utility 2.0 Long Range Plan & Energy Efficiency, Beneficial Electrification, and Demand Response Plan.

commercial tariff, consisting of any vehicle-type or weight-class. The Program will focus on who operates the vehicle, not ownership, to allow for the common case where vehicles are financed by one entity and operated by another. This program is also designed to be technology-agnostic, and supports L2, DCFC, or mixed applications.

The program guidelines discussed in the following section is preliminary and will be updated and finalized before Q1 2024.

Projects

The Fleet Make-Ready Program aims to serve two target markets: 1) public fleets which cover local government, public serving, and not-for-profit organizations; 2) public transportation (e.g., school buses, and transit buses). These markets were identified for their ability to largely benefit customers in DACs.

Table 4-5 shows the total number of projects estimated to be enrolled, respectively, by year and project type. These estimates are not tied to the number of ports enrolled, while it will be tracked through this program.

Table 4-5. Fleet Make-Ready Program Estimated Enrolled Projects

Project Type	2024	2025	2026	2027	2028	Total
Public Fleets	**4**	**8**	**14**	**26**	**37**	**89**
Small/Medium (<1,000 kW)	3	6	11	21	30	71
Large (>1,000 kW)	1	2	3	5	7	18
Public Transportation	**4**	**7**	**11**	**12**	**12**	**46**
Small/Medium (<1,000 kW)	1	2	3	4	4	14
Large (>1,000 kW)	3	5	8	8	8	32
Total	**8**	**15**	**25**	**38**	**49**	**135**

Eligibility

The Fleet Make-Ready Program will have a Public Fleets Offering and a Public Transportation Offering.

The Public Fleets Offering provides incentives to support public entities through their fleet electrification journey. To be eligible for the Public Fleets offering:

- Applicant must be local government units, counties, municipalities, not-for-profit organizations, and public entities, such as schools, universities, fire houses, police authorities, sewage authorities, libraries, etc.
- Fleet vehicles must be operated by a public entity, or operated under contract to a public entity, and the vehicle may be used for any purpose.

The Public Transportation Offering aims to support entities providing public transportation services. To be eligible for the Public Transportation Offering:

- Applicant must be a fleet operator[35] providing transportation services to the public, such as transit, school, and public commuter and shuttle bus operators.
- Both for-profit and public entities that provide public transportation services are eligible to participate.

[35] For both offers, eligibility is focused on the entity that OPERATES the vehicles, not the entity that OWNS the vehicles. This allows for vehicle leasing by the operators, or other financing arrangements that might impact ownership status.

- Ride-hailing or car-sharing services are not eligible to participate in this program.

Vehicles operated by a public entity for vehicles used to provide transportation services to the public (for example, school buses) are ineligible under the Public Fleets Offering but would be eligible under the Public Transportation Offering.

Infrastructure Costs

The make-ready costs are divided into two categories: US-MR and Customer-Side Make-Ready (CS-MR). Table 4-6 shows the estimated infrastructure costs based upon multiple sources including actual average project cost data and various studies.[36] PSEG Long Island will plan to track and monitor what actual project costs will amount to by both US-MR and CS-MR, which would inform future cost estimates.

Table 4-6. Estimated Fleet Make-Ready Program Infrastructure Costs per Location

Project Type	US-MR	CS-MR	Total
Small/Medium (<1,000 kW)	$20,000	$112,974	$132,974
Large (>1,000 kW)	$200,000	$272,438	$472,438

Business Model

PSEG Long Island intends to cover 100% US-MR costs for both public fleets and public transportation projects, while covering up to 50% CS-MR costs (see Table 4-7). In contrary to the EV Make Ready Program, which has seen many projects utilize existing service and therefore US-MR costs are almost non-existent. The Fleet Make Ready Program anticipates that most locations such as bus depots or municipal buildings, which typically do not have large electrical services, will require extensive infrastructure upgrades to support the fleets that would be electrified.

Table 4-7. Fleet Make-Ready Program US-MR and CS-MR Cost Coverage (by project type)

Project Type	US-MR[37]	CS-MR
Public Fleets	100% coverage	no coverage
Public Transportation	100% coverage	50% coverage in DACs; 20% coverage for all other eligible customers[38]

Note: To qualify for the higher CSMR coverage under the public transportation offering, the project location needs to be within one mile of a DAC.

For both offerings summarized above, incentives will be applied up to a soft cap per location of:

- $400,000 for projects with capacity less than 1MW; and
- up to $1.4M for projects with capacity over 1MW.[39]

The soft-cap may be waived by the Utility on a case-by-case basis, if requested, based on both need and merit. The cap applies to both US-MR and CS-MR incentive in aggregate, including any applicable future-proofing costs, with the costs associated with the US-MR addressed first.

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[36] See more details in the MHD Make Ready Study which can be found in Appendix C.
[37] No customer deposit or CIAC is required.
[38] To be paid by the Utility as reimbursement at the end of construction, after final inspection.
[39] Additionally, no more than 50% of the annual budget should go towards any one entity.

Considering future-proofing the make-ready infrastructure in the initial construction plan can help customers save costs by reducing or eliminating the need to address additional infrastructure with each subsequent charger installation. Under the Public Transportation Offering, customers may future-proof the CS-MR up to 125% of current charger installation on a kW basis, while the utility may future-proof the US-MR at its discretion. A customer must declare both planned and projected number and charging capacity of chargers needed at the site, as well as anticipated timeline for future charger installation. This program feature could significantly reduce churn by the Utility in revisiting particular sites multiple times and allows customers to optimize their total project costs, while reducing the risk of stranded assets.

Other Grants and Incentives

The utility incentive program is focused on the make-ready component of an electrification project. These incentives are intended to be combined with (i.e., “stacked with”) additional incentives available from other sources, including incentives related to vehicle purchase, and charging equipment. These incentives are available on both state and federal level, and may include grants, rebates, and tax-based incentives. Applicants must disclose sources and amounts of other grants and/or incentives to the utility at the time of application, along with estimated total charging infrastructure costs. Incentive amount may be adjusted by the Utility so that the total amount of all incentives for the charging infrastructure project does not exceed 100% of eligible costs.

Schedule Update

Phase 1 of the EV Make-Ready Program launched in mid-2021, and Phase 2 launched in early 2022. PSEG Long Island proposes to extend the program by two years (to 2027) to allow for additional market maturity and vehicle adoption for the Utility to serve the market. All aspects of program management and data collection will span the full duration of infrastructure and incentive deployment.

The Fleet Make-Ready Program is expected to launch in Q1 2024 and run through 2028 (see Table 4-8).

Table 4-8. Make Ready Program Proposed Schedule

Program Name	2021	2022	2023	2024	2025	2026	2027+
Make Ready Program							
EV Make Ready Program							
Fleet Make Ready Program							
Fleet Advisory Service							

Risks and Mitigations

Table 4-9 outlines the potential risks and proposed mitigation steps for the implementation of the Fleet Make ready Program.

Table 4-9. Risk and Mitigation Assessment – Fleet Make Ready Program

Category	Risk	Mitigation
Participation	Fleet customers may adopt EVs at a slower pace, which would lead to lower participation rate in the beginning of the program.	Track program participation and revisit program targets annually. Engage with fleet customers early to help address their concerns and develop individualized plans.

	Some customers might want to only electrify a small portion of their fleet at the beginning to test out the practicality, while from an infrastructure standpoint, it's more cost-effective to electrify all at once for the customer.	Provide planning tools and advisory services for customers to strategically plan and future-proof their infrastructure deployment in the early stage of their electrification journey.
Procurement	Delays in procurement due to supply chain limitation can slow the progress of the program.	Build in flexibility in project timeline to accommodate delays and escalate timeline concerns to key stakeholders.
	The costs may be greater than currently estimated due to potential increase in material costs.	Revisit cost assumptions to accommodate shifts that may occur.

4.1.2 Funding Reconciliation and Request

The EV Make Ready Program spent approximately $1.28 million in 2022. The spending is less than what was planned for, largely due to less enrollment than expected. Most of the planned O&M activities associated with general project and data management were also slightly delayed due to changes in contracting and needs. The forecasted budget for 2023 is approximately $6.33 million, of which around $3.3 million is planned for EV Make-Ready US-MR and CS-MR incentives, and $1.95 million is for the NYSERDA Clean Transportation Prize.[40] The EV Make Ready Program further requires 1 additional FTE to start in Q3 2023 to help the program keep up with the growing demand.

PSEG Long Island requests additional funding to expand the Make-Ready Program to provide funding for the Fleet Make-Ready Program through 2028. The budget largely consists of the costs associated with the deployment of infrastructure and incentives but also includes incremental program management and IT costs (see Table 4-10 and Table 4-11). If approved, the Fleet Make Ready Program also requires one incremental FTE to start in 2024 to manage customer applications and enrollment, process incentives, and track program budget and performance.

The overall budget request in 2024 is lower than previously outlined due to proposed shifts in EV Make-Ready program schedule.[41] The incentives planned for 2024 and 2025 will now be distributed among 4 years (2024 through 2027). The total make-ready budget projection for the remaining of the EV Make-Ready Program (from 2024) is around $40.8 million.

Table 4-10. Make-Ready Program Capital and Operating Expense Actual, Forecast, and Projected

		Actual	Updated Forecast	Request	Projected (Not Requested)	
		2019-2022	2023	2024	2025	Total
Existing Program	Capital	0.35	0.85	3.96	3.98	**9.15**
	O&M[42]	1.00	5.48	8.89	10.33	**25.69**

[40] Activity updates will be provided through quarterly reports.

[41] The budget is updated based on a forecast developed by a third-party consultant who utilized cost estimates provided in the DPS Midpoint Review. As the Team will increase marketing efforts in H2 2023, there might be an uptake in enrollment, and thus the Team might need to provide additional incentives than forecasted.

[42] Since the submission of the 2023 Utility 2.0 Long Range Plan on July 1, 2023, information regarding loan aggregator fees for 2023 (O&M costs) and third-party IT aggregator data collection (O&M costs) for 2024-2025 for this program has become available. O&M forecasts are updated accordingly as of August 25, 2023.

(EVMR)	**Total**	**1.35**	**6.33**	**12.85**	**14.31**	**34.84**
Program Expansion (Fleet MR)	Capital	-	-	0.81	1.47	**2.28**
	O&M	-	-	0.73	0.75	**1.48**
	Total	**-**	**-**	**1.54**	**2.22**	**3.76**
Full Program (Make-Ready)	Capital	0.35	0.85	4.77	5.45	**11.42**
	O&M	1.00	5.48	9.62	11.08	**27.17**
	Total	**1.35**	**6.33**	**14.39**	**16.53**	**38.60**

Table 4-11.Make-Ready Program Capital and Operating Expense Budget, Forecast, and Variance

		2022	2023	2024	2025
Existing Program (EVMR)	Capital	(0.95)	(2.04)	0.42	(1.02)
	O&M[43]	(2.25)	(1.15)	(2.93)	(14.51)
	Total	**(3.19)**	**(3.19)**	**(2.51)**	**(15.53)**
Program Expansion (Fleet MR)	Capital	-	-	0.81	1.47
	O&M	-	-	0.73	0.75
	Total	**-**	**-**	**1.54**	**2.22**
Full Program (Make-Ready)	Capital	(0.95)	(2.04)	1.23	0.45
	O&M	(2.25)	(1.15)	(2.20)	(13.76)
	Total	**(3.19)**	**(3.19)**	**(0.97)**	**(13.31)**

4.1.3 Performance Reporting

Through Q4 2022, 185 L2 and 108 DCFC ports have enrolled in the EV Make-Ready Program. To calculate realized benefits and costs of the Fleet Make-Ready Program, PSEG Long Island will also track number of ports enrolled and energized, make-ready costs, utility funds committed, and overall EV adoption in Long Island once the program is approved.

Key performance indicators (KPIs) for EV Make-Ready are detailed in Table 4-12. The Fleet Make-Ready Program will track these KPIs separately.

Table 4-12. Make-Ready Program KPIs[44]

Benefit	LIPA Metric Target Through 2022	BCA Target Through 2022	Realized Through 2022	Realized %[45]
# of DCFC Ports Enrolled	75	100	108	108%
# of L2 Ports Enrolled	637	266	185	70%
# of DCFC Ports Energized	50	25	100	400%

[43] See previous footnote. The 2023-2025 O&M budget forecast updates for this program impacted O&M variances for 2023-2025.

[44] Since the submission of the 2023 Utility 2.0 Long Range Plan on July 1, 2023, the actual and forecast port count were updated based on the most up-to-date information in the PSEG-LI Internal EV Make-Ready Program Database as of August 25, 2023, which is reflected in this table. The support documentation submitted on July 1, 2023 is slightly different from the updated forecast.

[45] Percentage Realized is based on BCA Target.

# of L2 Ports Energized	450	204	87	43%

Additionally, PSEG Long Island is tracking and planning to report on the number of applications in DACs and how the programs benefit customers in DACs.

Business Case with Expanded Scope[46]

This year, the benefit-cost analysis (BCA) has been updated to reflect both EV Make-Ready and Fleet Make-Ready Programs and evaluate the impacts of make-ready infrastructure on LD and MHD vehicle adoption.

Benefit streams considered in the BCA include:

- Net avoided carbon emissions from reduced fossil fuel consumption
- Avoided fossil fuel consumption
- Added electricity as a benefit for the utility
- Vehicle O&M savings
- Gasoline/diesel security value

The benefits are largely driven by fuel switching, which accounts for avoided fossil fuel consumption from EV uptake, vehicle O&M savings from lower O&M costs associated with EVs, gasoline/diesel security value from a decreased need for imported oil, and federal tax credits for EVs.

Program costs considered in the BCA include:

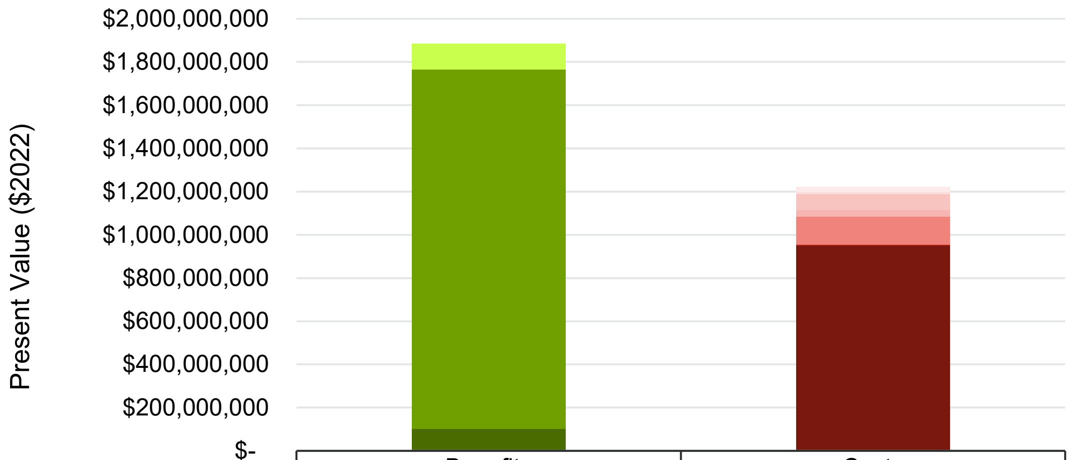
- Make-ready infrastructure costs
- EVSE costs
- Ongoing O&M, program management, and IT investment costs
- Added energy from increased electricity usage (utility cost)
- Increased electricity consumption (consumer cost)
- Added participant DER costs not rebated by the program
- Incremental vehicle cost
- Added capacity costs

PSEG Long Island's contributions to the NYSERDA EV Prize are also included in the costs through the original EV Make-Ready Program. Societal costs are driven primarily by participant DER costs, which include EVSE and O&M costs and the incremental costs of EVs, totaling over $1 billion.

The combined Make-Ready Program has a societal cost test (SCT) benefit-to-cost ratio of 1.54. The two components of the combined program, the EV Make-Ready Program and the Fleet Make-Ready Program, have SCT ratios of 1.70 and 1.31, respectively. The EV Make-Ready Program's SCT ratio has increased from the previously filed BCA due to an increase in gasoline prices, which have increased the benefits gained from fuel switching. The underlying assumptions regarding the number of vehicles have stayed the same during this period. This is detailed in Figure 4-3 and Table 4-13

[46] Since the submission of the 2023 Utility 2.0 Long Range Plan on July 1, 2023, information regarding loan aggregator fees for 2023 (O&M costs) and third-party IT aggregator data collection (O&M costs) for 2024-2025 for this program has become available. O&M forecasts and the subsequently impacted EV Make-Ready Portion of the Make-Ready Program BCA has been updated as of August 25, 2023. The SCT ratio slightly increased from 1.53 to 1.54.

Figure 4-3. Make-Ready Program Present Value Benefits and Costs of SCT[47]



	Benefits	Costs
Incremental T&D and DSP Costs	$-	$25,621,407
Added O&M	$-	$9,151,641
Net Non-Energy Benefits	$118,843,770	$-
Added T&D Capacity Infrastructure	$-	$74,165,492
Added Generation Capacity Cost	$-	$27,172,946
Added Energy (LBMP)	$-	$131,257,548
IT Infrastructure Costs (O&M)	$-	$1,236,128
Fuel Switching Benefits	$1,664,850,162	$-
Net Avoided CO2	$100,908,452	$-
Program Administration Costs	$-	$3,601,123
Participant DER Cost	$-	$950,060,794
Total	$1,884,602,384	$1,222,267,079

Table 4-13. Make-Ready Program Value Streams

#	Value Stream	Calculation Methodology	Benefits (NPV)	Costs (NPV)
1	**Net Avoided CO2**	Includes reduced carbon emissions from reduced gasoline consumption and increased emissions from increased electricity consumption.	100.91	
2	**Fuel Switching Benefits**	Benefits due to avoided gasoline consumption from EV adoption and gasoline security value. Avoided gasoline consumption is based on added EVs, vehicle miles traveled, and avoided gasoline consumption per vehicle as defined by Safer Affordable Fuel Efficient (SAFE) vehicle standards.	1,664.85	

[47] Since the submission of the 2023 Utility 2.0 Long Range Plan on July 1, 2023, information regarding loan aggregator fees for 2023 (O&M costs) and third-party IT aggregator data collection (O&M costs) for 2024-2025 for this program has become available. O&M forecasts and the subsequently impacted EV Make-Ready portion of the Make-Ready Program BCA has been updated as of August 25, 2023. The SCT ratio slightly increased from 1.53 to 1.54.

3	**Net Non-Energy Benefits**	Includes the federal tax credit for EVs.	118.84	
4	**Participant DER Cost**	Accounts for participant cost of make-ready not covered by rebates, cost of EVSE and respective ongoing O&M, incremental vehicle cost of added EVs, and make-ready lease payments		950.06
5	**Program Administration Costs**	Includes internal and external labor for program implementation lease management and user interface development.		3.60
6	**IT Infrastructure Costs (O&M)**	Includes IT integration costs for aggregating and ingesting data		1.24
7	**Added Energy (LBMP)**	Includes cost of added energy from increased electricity consumption. Based on marginal energy cost and estimated charging volume for added EVs		131.26
8	**Added Generation Capacity Cost**	Includes cost of added generation capacity. Based on marginal capacity costs and estimated capacity requirements due to charging during coincident peak.		27.17
9	**Added T&D Capacity Infrastructure**	Includes cost of added T&D capacity. Based on marginal capacity costs and estimated capacity requirements due to charging during coincident peak		74.17
10	**Added O&M**	Includes costs for customer engagement, loan originator fees, NYSERDA EV Prize incentives, and fleet advisory services		9.15
11	**Incremental T&D and DSP Costs**	Includes costs of US-MR under the rebate model for 2021 and US-MR and CS-MR under the lease model for 2022-2025		25.62
	Total Benefits		**1,884.60**	
	Total Costs			**1,222.27**
	SCT Ratio		**1.54**	

Performance Measurement and Reporting

To track the overall performance of the Make Ready Program, PSEG Long Island will continue to track the same metrics identified through the EV Make Ready Program. In addition, the Utility will capture and document data and metrics of each Fleet Make Ready project and continually evaluate and improve the approach, program design and budget assumptions to inform future program strategy. Such data may include[48]:

- Total US-MR, CS-MR, and EVSE costs
- Details about equipment installed, including charging port count, type, and nameplate capacity
- Incentive payments made for both US-MR and CS-MR
- Total Fleet size, vehicle classes and use-cases, fraction of fleet being electrified immediately (for the current project), and schedule for future electrification (estimated)
- Any managed charging or load reduction measures contemplated for the project.

[48] This list is still being developed and is subject to change.

- The Transportation Electrification Team has experienced some challenges around data quality and completeness with the EV Make-Ready Program. The Team aims to review the data collection and management process to standardize and streamline the reporting process.

Lessons Learned

PSEG Long Island has been continuing to make improvements to the EV program offerings and will continue to do so through staying up to date with industry trends, engaging EV ecosystem partners, and reflecting on customer feedback to ensure efficient and successful program implementation.

Table 4-14 shows feedback PSEG Long Island has received as well as improvement opportunities and actions that PSEG Long Island could take to better support customer needs and improve customer experience.

Table 4-14. Feedback from Customers on Program Improvement Opportunities

Category	Feedback Received	Improvement Opportunities
Program Participation	The application process takes longer than expected.	• The Transportation Electrification Team is planning to make significant improvements to existing application process. Such efforts include utilizing TRC Captures,[49] like the EE Program, where customers can submit applications through TRC Captures instead of manually processing. • The Team will also expand the resources that can review applications to speed up and streamline the process and provide better feedback to program applicants on the status of their application.
	Some customers are not clear if they are eligible to participate in the EV Make-Ready Program.	• The Team plans to update the EV webpages to include clear and simple clarification on eligibility criteria as well as FAQs. • Examples of eligibility criteria that were further refined and clarified are: ○ A multi-unit dwelling customer with more than one housing location and account is now allowed to submit multiple applications for the different location. ○ A car dealership is allowed to submit applications for make-ready infrastructure that support public and workplace charging applications, but not for charging their EV inventory.
	Customers need better insights into what the available capacity is on the grid.	PSEG Long Island is developing an EV hosting capacity map (Section 3.1) which will be available later this year.

[49] TRC Captures is an application processing software and database.

	Through monitoring program participation, PSEG Long Island has observed that there's a high interest in L2 adoption while the number of ports installed per project is on average three ports instead four ports as outlined in the original forecast.	The Team updated its forecast to project three ports would be installed per project and lowered the overall L2 port goals accordingly, which also aligns with the Midpoint Review recommendation.
Interest Area	Customers are eager to understand how to begin fleet electrification.	The Team recognizes the needs and interests from customers and aims to support them in the early stage of their electrification journey. Thus, PSEG Long Island offers Fleet Advisory Service which will be available to both public and private fleet customers, with anticipated launch in Q3 2023. The fleet advisor will also be able to further assist customers to help them get started with their fleet electrification efforts.
ME&O	Customers would like to know what program offerings are available for EVs in general.	The Team plans to further its ME&O efforts in H2 2023. For example, the Team will update the Make-Ready Program websites by conducting a customer journey mapping exercise to identify and provide simple, clear, and concise program instructions to assist customers through the enrollment process and improve customer experience.

The Transportation Electrification Team will continue to monitor adoption progress and assist customers with their electrification journey accordingly.

Next Steps

PSEG Long Island will continue to promote the Make-Ready Program in 2023 and beyond and continue to provide the approved Fleet Advisory Service to support fleet electrification on Long Island.

4.2 EV Program

2023 Status	Active
2024 Status	Active
Start Year	2019
Funding Approved Through	2025
Description and Justification	In 2022, the EV Program consisted of the Residential Smart Charger Rebate Program, Smart Charge Rewards Program, and the DCFC Incentive Program. The Residential Smart Charger Rebate Program, and the Smart Charge Rewards Program was discontinued at the end of 2022, but PSEG Long Island proposes to reintroduce the Rebate Program with a slight adjustment in scope and name change to the Residential Charger Rebate Program. The Residential Charger Rebate Program will run from 2024 to 2028. The DCFC Incentive Program will be modified in 2024 and discontinued when the new EV Phase-In Rate is implemented in 2025.

The EV Program aims to increase adoption of EVs on Long Island, align EV customer adoption strategy with reducing GHG emissions, empower customers, accelerate the EV charging infrastructure market, improve system efficiency, and encourage off-peak charging. The EV Programs will shift in scope and continue to serve EV customers in 2024 and beyond.

4.2.1 Implementation Update

In 2022, 3,135 Smart Charger rebates[50] were distributed to customers, and 186 DCFC ports[51] have been energized.

Scope Update

Residential Programs

The Smart Charger Rebate Program was removed at the direction of DPS in 2023. In 2024, PSEG Long Island plans to reintroduce the program with less limitation on eligible EVSE to help lower the upfront cost of purchasing EV associated charging equipment, as well as time required to charge.

The proposed Residential Charger Rebate Program plans to offer participants a cash rebate with the purchase of an Energy Star-rated L2 charger[52] instead of a limited selection of smart L2 chargers. To help promote more equitable access to EVs, this program will provide higher incentive for residential customers located within DACs. If approved, the rebate amount would be:

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[50] Smart Charger Rebate Program offers participants a cash rebate with the purchase of a L2 Smart Charger.

[51] Since the submission of the 2023 Utility 2.0 Long Range Plan on July 1, 2023, the energized port count was updated based on the most up-to-date information in the PSEG-LI Internal DCFC Incentive Program Tracker as of August 25, 2023, which is reflected here.

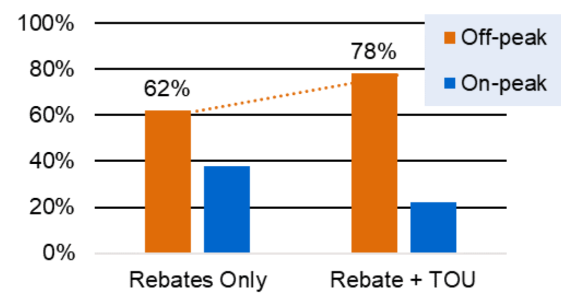
[52] Examples of Energy-Star Rated L2 chargers can be found here: https://www.energystar.gov/productfinder/product/certified-evse/results.

- $200 per charging port for non-DAC customers; and
- $300 per charging port for DAC customers.

The proposed Residential Charger Rebate Program aims to address customers' concerns about upfront cost and charging time needed, two of the top four reasons car shoppers in the U.S. have cited as reasons they would not purchase an EV.[53] Other utilities that have established charger rebate pilots or programs also made similar observations. For example, Portland General Electric describes their pilot program on their website as making "EV ownership more affordable with rebates on qualified chargers so you can charge faster."[54]

As 82% of Long Island residents live in single-family homes[55], having a Residential Charger Rebate Program that promotes L2 charging will allow these customers to charge at home during super off-peak hours under the TOU rate (10PM to 6AM) and save more on their energy bills, as compared to Level 1 (L1) charging. Through the former Smart Charger Rebate Program, PSEG Long Island has found that participating customers who are on TOU rates are more likely to charge during off-peak hours (see Figure 4-4).

Figure 4-4. EV Customer Charging Behavior Comparison



Source: PSEG Long Island Smart Charge Rebate Program

Additionally, based on a high-level analysis using average residential L1 and L2 charging profiles, L2 charging allows customers to charge 76% of their charging need during super off-peak hours, which is almost double the amount of L1 charging during super off-peak hours (40%). Therefore, incentivizing customers to charge at home using L2 charger would enable more charging during super off-peak hours, resulting in greater grid benefits.

This rebate is also meant to encourage the use of safe and tested equipment. Some auto manufacturers are no longer offering chargers to customers with the purchase of an EV.[56, 57, 58] The Residential Charger Rebate Program will only offer UL-tested, and Energy Star-rated chargers. Through the Program, PSEG Long Island can support and advance the adoption of safe charging equipment.

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[53] E-Vision Intelligence Report. April 2023. *J.D. Power*. EV Divide Grows in U.S. as More New-Vehicle Shoppers Dig in Their Heels on Internal Combustion | J.D. Power (jdpower.com)

[54] PGE Smart Charging Program and Rebates Frequently Asked Questions. Accessed June 22, 2023. Home EV Charging Rebates FAQ | PGE (portlandgeneral.com)

[55] See additional information on Long Island housing here. PSEG Long Island supports multi-family EV charging infrastructure upgrades through the EV Make-Ready Program.

[56] Tesla goes full Apple and stops delivering cars with included charging hardware, now sold separately (U). *Electrek*. URL: https://electrek.co/2022/04/16/tesla-goes-full-apple-stops-delivering-cars-with-included-charging-cable-now-sold-separately/ Accessed: June 25, 2023.

[57] "Home charging equipment is not included." URL: https://www.tesla.com/modely/design#overview Accessed: June 25, 2023.

[58] The Ford Mobile Power Cord is sold separately for $500 for Ford Mach-E. URL: https://shop.ford.com/configure/order/new/mach-e/config/paint/Config%5B%7CFord%7CMache%7C2023%7C1%7C1.%7C400A.K4S..PAE...AWD.18D.GTS.%5D?intcmp=vhp-360cta-fbc Accessed: June 25, 2023.

Commercial Programs

In January 2023, the NY PSC released an Order[59] establishing framework for alternatives to traditional demand-based rate structures for commercial EV charging. The Order recommends an immediate solution to implement a Demand Charge Rebate that provides 50 percent off-bill rebate against traditional demand charges for public DCFC sites, and a near-term solution to implement an EV Phase-In Rate that will replace the Demand Charge Rebate once it is available.

In line with the Order, PSEG Long Island plans on modifying the DCFC Incentive Program which currently offers per-plug incentives by launching a 50-percent demand charge rebate in 2024. Existing DCFC Incentive Program participants will be allowed to choose between:

1. Continuing with their existing per-plug incentive schedule and receiving their declining annual incentives until the EV Phase-In Rate becomes available; or
2. Make a one-time switch to begin participation in the 50-percent demand charge rebate in 2024.

Any new participants that enroll in the program after the beginning of 2024 will only be able to opt into the 50-percent demand charge rebate structure until the EV Phase-In Rate solution becomes available for customer participation. See Table 4-14 below for upcoming program offering shifts.

Table 4-14. EV Program Commercial Offering Updates

Type of Commercial Customer	2023 Offering	2024 Offering	2025 Offering
	DCFC Incentive Program		
New Customer	Per Plug Incentive	Demand Charge Rebate	**EV Phase-In Rate** ***Go-Live***
Existing Customer	Per Plug Incentive	Demand Charge Rebate *(one-time switch in Jan. 2024)* or stay on Per Plug Incentive	

PSEG Long Island reached out to current participants to inform them of the tentative new program offering and to understand whether they would choose to remain in the per-plug incentive or switch over to the demand charge rebate in Q2 2023. PSEG Long Island will also inform new customers the tentative deadline of 12/31/2023 for any new per-plug incentive applications and the upcoming shift in program offering. Program participants will have 60 days to respond once this plan is approved in Q4 2023.

EV Phase-In Rate

The EV Phase-In Rate is a commercial tariff specifically designed for public and commercial fleet charging. It consists of four graduation levels based on participants' annual load factor[60]. Within each graduation level, there would be a customer charge, a TOU energy charge, and a demand charge component with varying ratios.

Schedule Update

The Residential Smart Charger Rebate Program was discontinued in 2023 but is intended to be reintroduced as a Residential Charger Rebate Program in 2024. The DCFC Incentive Program will continue through the end of 2023 as a per-plug incentive and be modified to mainly provide 50% Demand

[59] CASE 22-E-0236 – Proceeding to Establish Alternatives to Traditional Demand-Based Rate Structures for Commercial Electric Vehicle Charging. January 19, 2023.

[60] Annual load factor computation: the ratio of annual energy consumption to the product of the simultaneous charging capacity (when available, otherwise nameplate capacity) and 8,760 hours (or 8,784 hours during a leap year).

Charge Rebate in 2024, followed by the EV Phase-In Rate in 2025. Table 4-15 details the proposed schedule for the EV Program.

Table 4-15. EV Program Proposed Schedule

Program Name	2022	2023	2024	2025	2026+
Residential Programs					
Charger Rebate Program					
Commercial Programs					
DCFC Incentive Program					
EV Phase-In Rate					

Risks and Mitigations

Table 4-16 outlines the potential risks and proposed mitigation steps for the implementation of the EV Phase-In Rate.

Table 4-16. Risk and Mitigation Assessment

Category	Risk	Mitigation
Schedule	Given the complexity of the EV Phase-In Rate and priority to implement the TOD rate, the schedule might be shifted to accommodate IT Team's availability.	Build flexibility into the project schedule to accommodate delays and escalate timeline concerns to key stakeholders (as necessary).
Customer Enrollment	Customers might be hesitant to enroll in the new EV Phase-In Rate due to lack of familiarity and complexity of the rate design.	Simplify the enrollment process and provide clear guidance on PSEG Long Island's website. Train relevant customer service representatives to better assist customers.

4.2.2 Funding Reconciliation and Request

The EV Program spent approximately $2.4 million in O&M in 2022. The spending aligns with what was planned for. The forecasted budget for 2023 is slightly less than the approved budget primarily due to decreased costs associated with data collection licensing, which is no longer needed.

The Residential Charger Rebate Program requests $1.17 million in O&M each year from 2024 to 2028 to offer participants cash rebates with the purchase of an Energy Star rated L2 Charger.

In 2024, the DCFC Incentive Program requests approximately $1.49 million in O&M to provide participating customers with 50 percent Demand Charge Rebate. The implementation of the EV Phase-In Rate requires approximately $1.27 million in 2024 to account for incremental IT development costs, as well as a third-party consultant to assist the implementation of the rate in 2024 (see Table 4-17 and Table 4-18).

Table 4-17. EV Program Capital and Operating Expense Actual, Forecast, and Projected

		Actual	Updated Forecast	Request	Projected (Not Requested)	
		2019-2022	2023	2024	2025	Total
	Capital	-	-	-	-	-

Existing Program	O&M	5.47	1.29	1.75	2.61	**11.12**
	Total	**5.47**	**1.29**	**1.75**	**2.61**	**11.12**
Program Expansion	Capital[61]	-	-	1.27	0.82	**2.09**
	O&M	-	-	1.21	1.21	**2.42**
	Total	**-**	**-**	**2.48**	**2.03**	**4.51**
Full Program	Capital	-	-	1.27	0.82	**2.09**
	O&M	5.47	1.29	2.96	3.82	**13.54**
	Total	**5.47**	**1.29**	**4.23**	**4.64**	**15.63**

Table 4-18. Capital and Operating Expense Budget, Forecast, and Variance

		2022	2023	2024	2025
Existing Program	Capital	-	-	-	-
	O&M	(0.05)	(0.51)	0.51	1.32
	Total	**(0.05)**	**(0.51)**	**0.51**	**1.32**
Program Expansion	Capital[62]	-	-	1.27	0.82
	O&M	-	-	1.21	1.21
	Total	**-**	**-**	**2.48**	**2.03**
Full Program	Capital	-	-	1.27	0.82
	O&M	(0.05)	(0.51)	1.71	2.53
	Total	**(0.05)**	**(0.51)**	**2.99**	**3.35**

4.2.3 Performance Reporting

The metrics for the EV Program track the participation rates in the residential and public charging programs. For the Residential Smart Charger Rebate Program, the number of participants was tracked via the number of Smart Charger rebates paid to customers. The participation in the DCFC Incentive program is tracked as the number of DCFC ports committed and energized. The take-rate is a key metric that combines the program participation with the total expected number of EVs sold and offers insight into the success of participant acquisition. The take-rate through 2022 exceed the target of 14%. Similarly, the total number of participants in the residential programs was higher than expected (Table 4-19).

Table 4-19. EV Program KPIs

Benefit	Target Through 2022	Realized Through 2022	Realized %
Incremental Smart Charger Rebates Paid	4,162	6,901	166%
Incremental EVs Sold on Long Island	29,177	30,943	106%

[61] Since the submission of the 2023 Utility 2.0 Long Range Plan on July 1, 2023, more information regarding third-party contracting support and the associated Capital costs for this program extension for 2024 has become available. Capital forecasts are updated accordingly as of August 25, 2023.

[62] See previous footnote. The 2024 capital budget forecast update for this program expansion impacted the capital variance for 2024.

Program Take-Rate	14%	22%	156%
Incremental DCFC Program Ports Committed	360[63]	202[64]	56%

Participation in the Smart Charger Rebate Program exceeded expectations, and as a result allowing for all benefits to exceed targets through 2022, as shown in Table 4-20.

Table 4-20. EV Program Benefit Reporting

Benefit	Target Through 2022 ($M)	Realized Through 2022 ($M)	Realized %
Customer O&M Savings	3,912,397.52	6,775,585.29	173%
Additional Energy Sales	5,960,401.58	12,121,129.23	203%
Reduced Fuel Emissions	1,376,954.80	2,639,994.22	192%

Performance Measurement and Reporting for Expanded Scope

PSEG Long Island plans to track the aforementioned metrics for the Residential Charger Rebate Program in 2024.

For Demand Charge Rebate and EV Phase-In Rate, PSEG Long Island will also track the following metrics on a semi-annual basis:

- Number of accounts participating in solution
- Participants' average peak demand (kW)
- Participants average monthly kWh consumption
- Participants' average annual load factor on a year-to-date basis
- Number and type of each charger participating
- And the following data on an aggregated basis:
- Percentage of charging occurring during off-peak periods
- Percentage of charging occurring during on-peak periods
- Percentage of charging occurring during super-peak periods

Additionally, PSEG Long Island plans to report the following metrics on an annual basis:

- Year-over-year growth rate in number of accounts participating in solutions
- An assessment of whether incremental EV charging load has resulted in local grid impacts
- An assessment of the extent to which incremental EV charging load has resulted in upward or downward rate pressure on non-participating customer rates
- An assessment on the impacts of solutions on LMI customers and DAC residents

Lessons Learned

PSEG Long Island can collect valuable feedback from customers to better promote the programs and provide clarity where needed to further enable EV adoption. For example, due to the high demand in the Smart Charger Rebate Program, PSEG Long Island plans to bring back the program and broaden

[63] Target here was established in 2019 and represents five-year target (2019-2023). Since the DCFC Incentive Program is proposed to be extended through 2025, the target was updated in 2023 based on historical program growth rate to be 470 through 2025.

[64] Since the submission of the 2023 Utility 2.0 Long Range Plan on July 1, 2023, the realized port count was updated based on the most up-to-date information in the PSEG-LI Internal DCFC Incentive Program Tracker as of August 25, 2023, which is reflected in this table.

equipment eligibility to cover a broad range of Energy Star rated L2 chargers, as well as offering additional incentives for customers in DACs. PSEG Long Island also informs customers of available tax credits from the Inflation Reduction Act to install an EV charger at their home in lieu of the Smart Charger Rebate Program in 2023 on the EV Program website.

The DCFC Incentive Program data provides insights into customer load factor, and the design and implementation of the EV Phase-In Rate, enabling PSEG Long Island to develop a solution that better serves the needs of customers.

Next Steps

PSEG Long Island will continue to promote the DCFC Incentive Program in 2023, look to roll out the Residential Charger Rebate Program (pending approval) in 2024, and will work to plan for a successful implementation of the EV Phase-In Rate in 2025.

4.3 Suffolk County Bus Make-Ready Pilot

2023 Status	Active
2024 Status	Active
Start Year	2022
Funding Approved Through	2025
Description and Justification	PSEG Long Island is supporting the EV Make-Ready infrastructure for Suffolk County's electric buses to better understand the needs, costs, and challenges of electrifying public MHDV transit fleets. The lessons learned through this initiative will be utilized to support and scale up future programs related to electrifying transit fleets in PSEG Long Island's service territory.

The proposed pilot goes beyond the scope of the EV Make-Ready Program, which is focused on electric charging infrastructure for LDVs, to explore Make-Ready infrastructure requirements for MHDVs. Through this pilot, PSEG Long Island works with Suffolk County to construct and contribute funds to Make-Ready infrastructure for two charging sites. The Make-Ready infrastructure deployed is expected to support the charging requirements of approximately 40 buses by 2025.

4.3.1 Implementation Update

See the scope and schedule updates below for the Suffolk County Bus Make-Ready Pilot.

Scope Update
The scope remains as previously proposed in the 2021 Utility 2.0 Plan.

Schedule Update
PSEG Long Island expects the pilot to be completed by the end of 2024 instead of 2023. The pilot schedule is delayed due to a malware attack that Suffolk County experienced in September 2022, delays in the Suffolk County RFP process which resulted in later-than-expected delivery of electric buses. Suffolk County issued an RFP in December of 2022 for operators of its transit system and plans to issue awards by mid-2023. One of the locations is expected to be completed in Q3 2023 while a second location will be expected late Q4 2023 or early 2024. Suffolk County also issued RFPs for electric buses and EVSE which will be finalized around Q3 2023. Buses are expected to be delivered in 2024.

Risks and Mitigations
Table 4-21 outlines the potential risks and proposed mitigation steps for this initiative.

Table 4-21. Suffolk County Bus Make-Ready Pilot Risk and Mitigation Assessment

Category	Risk	Mitigation
Technical	Charging equipment could be unavailable or not compatible. Equipment replacement could lead to change in system infrastructure configuration.	Coordinate with Suffolk County to confirm assumptions around charging needs and infrastructure requirements.
Schedule	Significant delays in delivery of the electric buses would lead to project delays and underutilization of the make-ready infrastructure.	Build flexibility into the project schedule to accommodate delays.

Category	Risk	Mitigation
	Significant delays in awarding the bid to a bus operating company could lead to delays in the overall project schedule.	Build flexibility into the project schedule to accommodate delays and escalate timeline concerns to key stakeholders (as necessary).
Costs	The costs may be significantly greater than currently estimated.	Establish contribution caps so PSEG Long Island's costs do not exceed a certain limit.

4.3.2 Funding Reconciliation

There was no budgetary spend for the Suffolk County Bus Make Ready Pilot in 2022 due to project delays. Thus, the projected US-MR and CS-MR costs and EM&V costs are shifted by one year, from 2022 and 2023 to 2023 and 2024, respectively. The updated annual budget is shown in Table 4-22 and variance is shown in Table 4-23.

Table 4-22. Suffolk County Bus Make-Ready Pilot Capital and Operating Expense Budget, Forecast

	Updated Forecast 2023	Request 2024	Projected (Not Requested) 2025	Total
Capital	0.01	-	-	**0.01**
O&M	0.65	0.04	-	**0.69**
Total	**0.66**	**0.04**	**-**	**0.70**

Table 4-23. Suffolk County Bus Make-Ready Pilot Capital and Operating Expense Variance

	2022	2023	2024	2025
Capital	(0.10)	0.01	-	-
O&M	(0.71)	0.61	0.04	-
Total	**(0.81)**	**0.62**	**0.04**	**-**

4.3.3 Performance Reporting

Once completed, PSEG Long Island will assess the pilot hypotheses as proposed in the 2021 Utility 2.0 Plan. The following metrics will be tracked to gain insights from the pilot:

- **Make-ready costs:** Track the total make-ready costs of each site. This will provide insight into the costs PSEG Long Island transit owners and operators can expect for similar public transit fleet electrification efforts.
- **Ratio of US-MR to CS-MR costs:** Track the portion of the total make-ready costs that are utility-side versus customer-side. This data will support the determination of how public transit make-ready costs are allocated and how they may vary from light duty.
- **Analysis of daily consumption patterns once chargers are installed and buses deployed:** Analyze Advanced Metering Infrastructure (AMI) data from each site once operational to better understand equipment utilization, grid impacts and future planning considerations.
- **Identification of future customer support needs:** Utilize experience gained during this effort to better support future MD/HD fleet conversions, especially in the municipal transit area.

Lessons Learned

This initiative is delayed due to the Suffolk County malware issue in September 2022. PSEG Long Island cannot move forward with this effort until the County completes their efforts. As such, PSEG Long Island has continued to initiate contact with the County to monitor schedules, issues, and progress. In projects such as this, when customers experience project delays, it's important for PSEG Long Island to be able to maintain flexibility to support the customers' needs as the project develops.

Next Steps

This initiative heavily relies on engagement with Suffolk County and its 'to-be' awarded operators. PSEG Long Island will work with Suffolk County to coordinate project details, such as cost, schedule, roles, and responsibilities. The PSEG Long Island team will also coordinate regular internal meetings with the team and external work sessions with third-party partners to help facilitate project delivery.

5. Demand and Grid-Edge Flexibility

Driven by the electrification of buildings and transportation, New York's clean energy future will see gradual increases in load on the electric system. These load increases, in addition to increased renewable energy integration, will ultimately require the electric system to be more flexible to accommodate 100% carbon-free electricity. Historically, demand response (DR) programs required customers to make active behavior changes in response to peak events. Demand flexibility, on the other hand, allows for real-time shifting of BTM resources.

Some examples of demand and grid-edge flexibility initiatives include energy storage and non-wires alternatives (NWA). Energy storage helps integrate clean energy into the grid, increases system efficiency, provides hosting capacity to support integration of more renewables and DER, and provides resiliency to keep critical systems online during an outage. NWAs allow for avoiding or deferring traditional T&D investments by using alternative solutions such as energy storage, renewable energy, EE, and DR. They can deliver cost savings to customers and achieve system-wide and localized benefits (e.g., environmental).

As detailed in Section 1.1, PSEG Long Island evolved its Utility 2.0 vision and framework to align with statewide priorities. Initiatives included in this chapter contribute to *Demand and Grid-Edge Flexibility* in different ways. For example, the Residential Energy Storage System Incentive Program promotes adoption of storage solutions and is uniquely capable to support DERs by storing solar generation and utilizing it during critical peak demand periods.

The Connected Buildings Pilot aims to deploy smart electric panels within residential buildings for ease of integrating energy storage and solar PV, as well as insight into circuit-load energy usage, resulting in contributions to the state's solar and storage goals. The DER Visibility Platform increases distribution system operational capabilities as DER are added to the distribution grid, which in turn enables the safe and effective addition of DER. And the Locational Value Tool estimates the value that is used to defer T&D capital investment, which is needed to incentivize the interconnection of DER within PSEG Long Island's service territory. The values derived from the tool are used as inputs to NWA Planning Tool to assess NWA solutions for the traditional proposed capital projects.

The NWA Process Development program and Planning Tool promote NWAs which animate customer measures and markets as an alternative to traditional utility construction. These initiatives promote the identification, selection and procurement of NWAs and enable PSEG Long Island to calculate system benefits and costs more comprehensively. The Super Savers program in North Bellmore and Patchogue is an example of an NWA already deployed in PSEG Long Island's territory.

The Rate Modernization initiative included in this chapter is foundational to all priority areas, specifically grid-edge flexibility, by encouraging customer energy patterns that are beneficial to load balancing efforts and by providing customers with greater choice and convenience. By promoting load shifting through TOD rates, PSEG Long Island can encourage lasting customer behavioral changes that can reduce overall supply and delivery costs to all customers and protect the integrity of existing infrastructure by reducing peak load usage. Rate Modernization provides additional incentives for customers to purchase EVs, energy storage, heat pumps, solar PV as well as participation in other EE and DR programs.

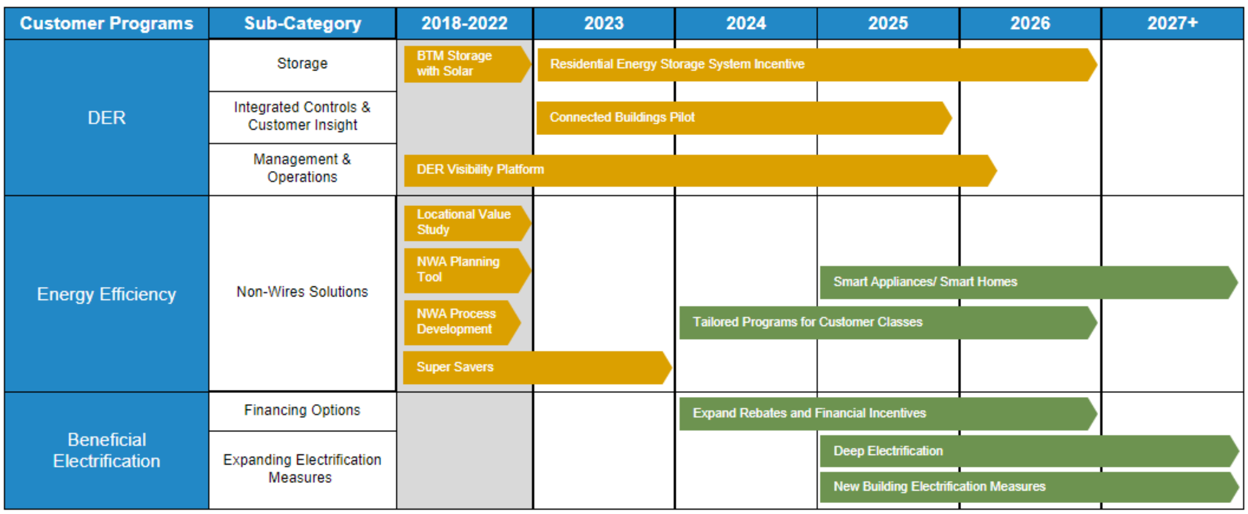
Priority Area Future Needs Assessment

Since the inaugural Utility 2.0 Filing in 2018, PSEG Long Island has completed a diverse portfolio of projects that align with the current *Demand and Grid-Edge Flexibility* priority areas. In particular, the Super Savers project in North Bellmore was completed in 2022, which achieved a total of 56% of its 4MW target, and enabled PSEG Long Island to successfully defer upgrades to the North Bellmore substation until 2025.

PSEG Long Island will continue to pursue projects that build on the current *Demand and Grid-Edge Flexibility* priority areas. Future projects will focus on advanced forecasting and proactive investments in DER integration. Future efforts will also aim to promote deep weatherization and deep electrification measures for existing buildings, in addition to electrification measures for new buildings. Furthermore, PSEG Long Island will work towards expanding rebates and financial incentives for customers that will be necessary to reach the TBtu savings goals as well as the DAC benefits goals. To this end, PSEG Long Island will potentially launch tailored programs for customer classes. The exact timeline and focus for future projects that align with this priority area is subject to future guidance and direction for PSEG Long Island.

Figure 5-1 provides a summary of potential future efforts within the *Demand and Grid-Edge Flexibility* priority area. Future filings will provide additional detail to the Utility's multi-year outlook

Figure 5-1. Demand and Grid-Edge Flexibility Future Outlook



This chapter is organized into eight subsections that provide an update for Utility 2.0 initiatives that directly align with the *Demand and Grid-Edge Flexibility* priority area. PSEG Long Island notes that the initiatives in this chapter are not limited to only supporting this priority area and likely contribute to others.

Chapter Contents

5.1 Connected Buildings Pilot

2023 Status	Active
2024 Status	Active
Start Year	2022
Funding Approved Through	2025
Description and Justification	The Connected Buildings Pilot demonstrates insights into how the control of consumption helps provide customers with bill savings, adds grid value through reduced supply and infrastructure costs, and supports beneficial electrification. This initiative is expected to launch in 2023 and run through 2024.

The Connected Buildings Pilot aims to demonstrate the benefits of integrated controls by enabling customer devices to respond directly and autonomously to utility price and dispatch signals. Insight into and control of consumption can lead to more efficient and optimal energy management, provide customers with bill savings, add grid value through reduced supply and infrastructure costs, and support beneficial electrification.

Within the Pilot, a smart electric panel is used to integrate and control end-use devices. The pilot is conducted with PSEG Long Island residential customers (the device is only designed for residential homes), beginning with single-family homes seeking to add significant new DERs such as solar, storage, EVSE, and heat pumps. The smart panel enables breaker-level monitoring, better insight into customer loads, and more granular control of certain DER (e.g., storage). In addition to providing value through response to utility price and dispatch signals, the panel can reduce the cost of interconnecting new DER's and improve customer and utility understanding of end-use consumption. Lastly, the panel can improve customer resiliency through customized interoperability between the panel, DER's, and dynamically designated customer critical loads.

5.1.1 Implementation Update

Due to delays in the contracting stage of the Connected Buildings Pilot, the pilot is projected to be completed by the end of 2024 rather than by then end of 2023. See the scope and schedule updates below for Connected Buildings Pilot.

Scope Update
The pilot is limited to 75 Smart Panel installations at approximately 75 (or slightly fewer) residential single-family homeowners. Minimal activity for the project occurred in 2022 due to contracting delays with the third-party contractor and vendor. Through April 2023, seven panels have been installed and rebated, five applications were pre-approved. In early 2023, PSEG Long Island was notified by the panel manufacturer that a data sharing agreement would be required in addition to customer authorization. Work on the data sharing agreement remains underway.

Schedule Update
Initial plans were to have all 75 panels installed by the end of the second quarter of 2023. To exercise the capability of the panels, customers generally are sought who have at least 2 or more of the following equipment: photovoltaics, EV charger, on-site storage or heat pump. While using this criterion seemed reasonable for having 75 panels installed during the first 6 months of 2023, PSEG Long Island was informed by the partnered photovoltaic contractor that market conditions have changed uptake patterns. Specifically, changes in interest rates, coupled with changing in lending patterns resulting from bank

failures early this year, coupled with continued price increases has resulted in a dampening of customer uptake of multiple measures. This has been the major contributing factor to the delayed progress on planned installations. The current estimate is that all panels will be installed by the end of 2023. Preliminary data acquisition and analysis is expected to begin in Q3 2023. Development of testing scenarios (e.g., metering and demand flexibility) are expected to begin in the third quarter of and will be completed by the end of 2024. The operation and testing phase of the pilot will occur for two years with a mid-term report to be issued at the end of 2023 providing initial findings from the summer of 2023. After completion of the two-year demonstration, a final report will be issued in Q1 2025.

Risks and Mitigations

Table 5-1 outlines the potential risks and proposed mitigation steps for this initiative.

Table 5-1. Connected Buildings Pilot Risk and Mitigation Assessment

Category	Risk	Mitigation
Project Management	Inability to secure 75 SPAN installations by end of Q2 2023 due to customer uptake.	Work with installers to try to improve uptake. However, impact provided all units are installed by end 2023 may result in less information being available for the mid-term report but should still result in the final report having data coming from at least one year of activity of all panels.

5.1.2 Funding Reconciliation

The Connected Buildings Pilot had no budgetary spend in 2022 due to contractual delays with a third-party contractor and vendor. Because of these delays, the pilot completion date has shifted from the end of 2023 to the end of 2024. Thus, there is projected O&M spend for this pilot in 2023 and 2024. Please see the adjustments listed below:

- **Rebates:** Identified and recruited customers will be offered the opportunity to participate in the Connected Buildings Pilot through a rebate that covers the cost of the Smart Panel in exchange for sharing breaker-level data with PSEG Long Island.
  - Estimated \$3,500 rebate/Smart Panel x 75 Smart Panels = \$262,500 in 2023
- **Evaluation:** Two Pilot Assessment Reports will be required per the 2023 LIPA OSA Metric for this pilot. Third-Party support will be required to aid in the development of the reports.
  - Estimated \$20,000/report for 2023 and 2024
- **Customer Incentives:** Participating customers will be offered various opportunities throughout the pilot period to participate in incentive offerings which will be offered by PSEG Long Island to test the different capabilities of the third-party vendor's Smart Panels.
  - Estimated \$30,000 in 2023 and \$40,000 in 2024
- **IT:** Internal and existing IT support related to accessing, collecting, and analyzing data.
  - Estimated \$75,000 in 2023

The updated annual budget for the Connected Buildings Pilot is shown in Table 5-2 and variance is shown in Table 5-3.

Table 5-2. Capital and Operating Expense Budget, Forecast

	Updated Forecast 2023	Request 2024	Projected (Not Requested) 2025	Total
Capital	-	-	-	**-**
O&M	0.29	0.13	-	**0.42**
Total	**0.29**	**0.13**	**-**	**0.42**

Table 5-3. Connected Buildings Pilot Capital and Operating Expense Variance

	2022	2023	2024	2025
Capital	-	-	-	-
O&M	(0.56)	0.21	0.13	-
Total	**(0.56)**	**0.21**	**0.13**	**-**

5.1.3 Performance Reporting

To evaluate the hypothesis of the pilot, PSEG Long Island will track the following metrics and KPIs:

- **Peak demand reduction:** Compare the demand (kW) of the participating customers on a regular basis to the demand during DR events. The panel data will be continuously collected and provided to PSEG Long Island to support evaluation and verification of this hypothesis.
- **Energy savings:** Compare the baseline energy consumption (kWh) of the participating customers to the energy consumption using the smart panel. PSEG Long Island will also be able to track the addition or removal of electric loads to determine the specific impact of the smart panel on customers' consumption volumes and patterns.
- **DER installation cost:** Gather data and survey responses from participating customers and 3rd Party vendors about the cost of installation and compare the costs to those for customers with traditional electric panels to identify the avoided costs to customers installing DER with the smart panel.
- **Avoided service upgrades:** Track the number of service upgrades avoided due to the smart panel.
- **Meter data accuracy:** Compare the data from the smart panel to the smart meter data to determine the percent difference between the data sources. This calculation will determine if the smart panel data may be reliably used for billing purposes (e.g., device-level rates and incentives).
- **Reduction in consumption during outages:** Compare the consumption data of the participating customers with storage on a regular basis to the consumption during outages to determine if the panel adjusted customers' consumption to prolong the duration of the storage during an outage.

Lessons Learned

Through the process of contracting with third-party vendors for the Connected Buildings Pilot, PSEG Long Island has learned that it can be very difficult to for a utility to finalize a contract with new, small, start-up companies. Additionally, changes in consumer spending patterns due to changes in lending economics can have unplanned impacts on programs such as these which rely on consumer purchasing habits.

Next Steps

In 2023, the Connected Buildings Team will continue receiving rebate applications and work with the third-party vendor to develop a verification process. Once the data sharing agreement with the third-party vendor is complete, the Team will determine how to retrieve data from the panels and begin collecting the data for testing scenarios (e.g., metering and demand flexibility). Additionally, the Team will establish a target installation schedule with the other third-party contractor to ensure a timely and successful installation of the 75 Smart Panels by the end of 2023.

5.2 DER Visibility Platform

2023 Status	Active
2024 Status	Operational
Start Year	2021
Funding Approved Through	2023
Description and Justification	The DER Visibility Platform enables PSEG Long Island's distribution operators to better manage DER under various system conditions. Implementation of the platform began in mid-May 2022 and is expected to continue as scheduled with the platform going live in late 2023.

The DER Visibility Platform is a platform that enables PSEG Long Island's distribution operators to monitor and manage DER under different system conditions.

The platform supports the increase of DER penetration and interconnection to the PSEG Long Island distribution system by providing visibility to T&D operators so that decisions can be made under different system conditions considering the impact of DER connected onto the circuit. The platform is envisioned to provide additional capabilities such as visualizing the output and status of the DER, displaying custom aggregated Supervisory Control and Data Acquisition (SCADA) data, and delivering basic forecasting of DER output based on weather conditions and historical DER output.

The platform will initially focus on integrating DER locations that have capacity greater than 1 MW; there are at least 27 such locations on Long Island. In addition to the 27 existing locations, PSEG Long Island expects that approximately 30 new large-scale DER sites will be interconnected in each of the first 2 years of implementation, and approximately 50 new sites annually in later years. Once it is fully implemented and the data from all existing sites is migrated, PSEG Long Island will continue to connect new DER locations with SCADA data to the new platform.

5.2.1 Implementation Update

See the scope and schedule updates below for DER Visibility Platform.

Scope Update

The test environment was set up with the DERMS and Forecast software to enable Pre-Functional Testing & Functional Testing to verify basic capabilities of the platform. The team has developed the Geographic Information System (GIS), Weather and SCADA interfaces that the DERMS platform requires for functionality. Some of the remaining current scope of the project, includes integrating all the DERs, training the Distribution Operators, performance & cybersecurity testing, and cutover planning & execution.

Schedule Update

Change to the integration software led the team to re-work the system interface development enabling the team to complete the preliminary interface testing in March 2023. Additionally, the vendor's recommendation to have a parallel communications path established between the subset of DERs with the vendor's existing DSCADA (also known as 'listen-only mode') module to obtain & process live data for DER testing necessitated procurement of specific hardware that was impacted by supply chain issues. Testing & Distribution Operator training is expected to be completed by mid-2023 and the project is expected to "go live" in late 2023. "Go live" here means that the DER are fully integrated into the existing DSCADA platform to display feeder connectivity, SCADA data & alarms, and DER output forecast. At least 27 existing DER over 1 MW with available SCADA data, considered "distribution-type DER," will be integrated.

Risks and Mitigations

Table 5-4 outlines the potential risks and proposed mitigation steps for this initiative.

Table 5-4. DER Visibility Platform Risk and Mitigation Assessment

Category	Risk	Mitigation
Timeline	Independent Power Producer (IPP) ownership of SCADA equipment may lead to configuration delays	PSEG Long Island will manage communications with IPPs to ensure configuration change requests are responded to with urgency.
Timeline	Distribution and Transmission Operator availability might be limited during summer peak times and any unforeseen storm events, which could pose possible delays to the project timeline	The project plan is set up to minimize dependencies on Transmission and Distribution Operator participation during. summer peak and storm seasons (June - September).
Timeline	Identifying an IT security vulnerability during solution implementation could delay project delivery	Vulnerability scans will be scheduled early in the project implementation phase to identify and mitigate potential issues such that it does not impact go-live.

5.2.2 Funding Reconciliation

Separate contracts with the system integrator and the product vendor were finalized in 2022. The need for GIS interface re-engineering to support DER Visibility was identified in pre-planning and contract discussions with the product vendor. A GIS interface to import DER data into the Distribution Supervisory Control and Data Acquisition (DSCADA) eMap will be designed and implemented to display the DER in the eMap. The product vendor has proposed a more direct and automated GIS data connection into DSCADA than currently exists to improve the import process. The system integrator will provide project management and subject matter expertise to ensure the project can be successfully delivered. The system integrator brings product knowledge as well as industry experience in deploying Distributed Energy Resources Management System (DERMS) solutions, which PSEG Long Island does not currently have. Additional IT EPMO schedule, project controls and project management resources were added to support successful implementation of the project.

The initiative's 2023 capital budget includes IT system integration costs, such as product vendor software design and configuration, engineering and implementation services, cybersecurity network architecture reviews and testing, interface design and integration services, user and system testing, and product licenses. In 2023 capital funding includes cost for the product vendor to complete the re-engineering of the GIS interface for DER. The project kickoff delay in 2022 shifted milestone payments for the product vendor and the system integrator work into 2023 and increased ongoing O&M costs due to cost escalations.

Capital underspend in 2022 was primarily due to the shift in milestone payments, lower Long Island assessments and shifting of labor charges into 2023. PSEG Long Island is not expecting any O&M labor charges to the project. Ultimately, the additional identified scope, shifting vendor costs and additional IT EPMO resources described above led to an increase in required budget for 2023.

Ongoing O&M expenditure will be required to cover annual IT maintenance of the platform, but these costs will be drawn from the PSEG Long Island Core Operating Budget starting in 2024 and beyond.

The updated annual budget for the DER Visibility Pilot is shown in Table 5-5 and variance is shown in Table 5-6.

Table 5-5. DER Visibility Platform Capital and Operating Expense Budget, Forecast

	Actual 2022	Updated Forecast 2023	Request 2024	Projected (Not Requested) 2025	Total
Capital	2.79	2.90	-	-	**5.69**
O&M	0.01	-	0.07	0.08	**0.16**
Total	**2.80**	**2.90**	**0.07**	**0.08**	**5.85**

Table 5-6. DER Visibility Platform Capital and Operating Expense Variance

	2022	2023	2024	2025
Capital	(1.62)	0.00	(0.16)	(0.16)
O&M	0.01	(0.06)	-	-
Total	**(1.61)**	**(0.06)**	**(0.16)**	**(0.16)**

5.2.3 Performance Reporting

Once implemented, the DER Visibility Platform is expected to:

- Monitor and enable increased DER penetration levels on PSEG Long Island's system
- Help achieve New York State climate and energy goals
- Better inform related projects proposed in the Utility 2.0 Plan and other DSP-related projects

Lessons Learned

Through the DER Visibility Platform, PSEG Long Island has learned that the System Integrator, product vendor and core PSEG Long Island core team will need to coordinate demos, feedback sessions and training with representatives of the Distribution Operations Teams for all 4 divisions. DER owners (IPPs) will be needed for all DERs being migrated to reconfigure SCADA equipment.

Next Steps

The PSEG Long Island team plans to conduct the Preliminary Functional Test as well as the Functional Test of the system. The team also will continue to develop and configure custom dashboards, reports, and alarms. Later, the team will complete the vulnerability scan and mitigation, as well as Site

Acceptance Testing (SAT), Performance Testing, and User Acceptance Testing (UAT) of the platform. The platform is due to go live in late 2023.

5.3 Residential Energy Storage System Incentive Program

2023 Status	Active
2024 Status	Active
Start Year	2023
Funding Approved Through	2025
Description and Justification	The Residential Energy Storage System Incentive Program represents an extension of the BTM Solar plus Storage program proposed and approved in the 2018 Utility 2.0 Plan and proposes to continue leveraging the existing Long Island Single-Family Residential Incentive program. PSEG Long Island expects to make available the additional funding once the current NYSERDA incentive block expires.

PSEG Long Island initiated an incentive program to provide customers with financial support for purchasing and installing energy storage systems (ESS). The upfront incentives will be available for PSEG Long Island residential customers (including LMI/DAC[65] customers) installing an Energy Storage System paired with new or existing solar.

This program represents an extension of the BTM Solar plus Storage program that was proposed and approved in the 2018 Utility 2.0 Plan and plans to continue leveraging the existing Long Island Single-Family Residential Incentive program. PSEG Long Island expects to make available the additional funding once the current NYSERDA incentive block expires.

PSEG Long Island proposes to make available an additional $1.8 million in incentives through this program. The funding is expected to be placed in a declining block incentive structure based upon a per kWh of usable installed storage.

5.3.1 Implementation Update

See the scope and schedule updates below for the Residential Energy Storage Program.

Scope Update
A detailed funding approach will be taken in order to provide incentives to residential customers to install storage systems. As mentioned above, PSEG Long Island will make an additional $1.8 million in funding for incentives available through this program starting in Q3 2023. The funding will be placed in a declining Block incentives structure based on a per kWh of usable installed storage capacity. For this program, PSEG Long Island proposes two blocks with each block consisting of $0.9 million. The incentives will be available to PSEG Long Island single-family residential customers, with higher incentives proposed for LMI/DAC customers.

The first Block will offer $200 per kWh installed capacity (capped at $5,000 per project with a 25-kWh limit) for non-LMI/DAC customers and $400 per kWh for LMI/DAC (capped at $10,000 per project). The second Block will offer lower incentives: $150 per kWh and $300/kWh for non-LMI/DAC and LMI/DAC customers, respectively. Table 5-9 shows the proposed incentives by block.

[65] NYSERDA's definition on LMI and DAC will be used. See additional information on the definition of a DAC.

Table 5-9. Incentive Rates by Block

Block	Available Funding	Non-LMI/DAC	LMI/DAC
1	$900,000	$200/kWh	$400/kWh
2	$900,000	$150/kWh	$300/kWh

Based on the declining Block incentive structure, PSEG Long Island now expects to enroll a total of approximately 760 systems through the program, assuming a battery capacity of 5kW/13.5kWh. Table 5-10 outlines expected systems by customer segment and block.

Table 5-10. Expected System Enrollment by Block

Segment	Block 1	Block 2	Total
Non- LMI/DAC	315	422	737
LMI/DAC	10	12	22
Total	**325**	**434**	**759**

In order to be eligible for the incentive, storage systems must be paired with PV solar and meet the following requirements:

- Be permanently installed
- Be new and commercially available
- Be certified to UL 1973 and UL 9540 specifications by the time of installation
- Meet all AHJ requirements
- Be warrantied for at least 10 years
- Maintain a minimum 70% round-trip efficiency during the system life

Additionally, customers must also enroll their systems in the PSEG Long Island DLM Tariff program to be eligible for the upfront incentive. PSEG Long Island will encourage these participants to enroll in the TOD rates but will not be required as a condition of being eligible for the upfront incentive. DLM participants receive performance incentive payments every year based upon the average measured load relief the battery contributes to the grid during critical periods.

As with NYSERDA's Incentive Blocks 1 and 2, PSEG Long Island will work directly with NYSERDA-participating solar contractors and developers to help offset the cost for installing ESS. Customers will need to work with a NYSERDA-approved participating contractor in order to receive the incentives, which is provided directly to the contractors. Contractors will install the system and must work with a participating aggregator to enroll the systems in the PSEG Long Island's DLM Tariff program. Customers must commit to actively participate for a minimum of five years. Systems must also have at least 80% of usable capacities available for dispatch during the PSEG Long Island Energy Storage Rewards program capability period.

Schedule Update

The Residential Energy Storage System Incentive Program is on track to make funding available by Q3 2023, when the current NYSERDA Incentive Block 2 is expected to expire. Although projected to expire by mid-2023, it is possible that the NYSERDA funding remains available for a longer period than expected. PSEG Long Island, therefore, plans to make the additional funding available once the current incentive block expires. Marketing and outreach, as well as enrolling customers, is expected to begin in Q4 2023 rather than in Q3 2023 and will continue through the end of Q4 2024. Payments on the allocated block will be made throughout 2025 (if necessary).

Risks and Mitigations

Table 5-11 outlines the potential risks and proposed mitigation steps for this initiative.

Table 5-11. Residential Energy Storage System Incentive Program Risk and Mitigation Assessment

Category	Risk	Mitigation
Schedule	Although PSEG Long Island anticipates the current NYSERDA Incentive Block 2 to be available until Q3 2023, it is possible that the Block 2 incentive will be fully subscribed earlier, leading to delays in making available the proposed additional funding.	Track progress of NYSERDA Incentive Block closely to update projections and coordinate with NYSERDA on a regular basis ahead of launch. Extend NYSERDA funding by decreasing the incentive level ($/kWh) to increase the number of customers participating.
Enrollment	After receiving the upfront incentive and being enrolled in the DR program, customers may un-enroll from the program.	Eligibility requirement that customers must remain in the program for 5 years. Track enrollments and if determined that customers are un-enrolling, the associated contractor/aggregator may be removed from participating in the program.

5.3.2 Funding Reconciliation

In 2022, PSEG Long Island proposed an additional $2 million in incentives to be available through the program. Since the planned launch of the incentives would not occur until Q3 2023, the DPS recommended an overall downward adjustment of $200,000 in O&M funding.

Marketing and outreach O&M funding is projected for the creation of a website, downloadable brochures, and direct and/or mail outreach to existing battery storage customers which have installed and not enrolled in the PSEG Long Island Battery Storage Program. Table 5-12 shows the annual forecast for the Residential Energy Storage Incentive Budget.

The Reason for the variance, as shown in Table 5-13 is twofold: (1) There is a decrease in the number of battery storage customer applications being submitted for the current NYSERDA Long Island Residential Energy Storage Incentive. This is delaying the start date of the PSEG Long Island Residential Energy Storage incentive as the PSEG Long Island incentive is set to begin immediately when the current NYSERDA incentive closes. (2) There is an approximate three-month lag in the time a contractor submits their customers application for the incentive, to the time the project is installed, and PSEG Long Island issues the incentive. Therefore, this reduces the forecasted budget for 2023 and increases the forecasted budget for 2024 and 2025.

Table 5-12. Residential Energy Storage System Incentive Program Capital and Operating Expense Budget, Forecast

	Updated Forecast	Request	Projected (Not Requested)	
	2023	2024	2025	Total
Capital	-	-	-	**-**
O&M	0.31	1.54	0.15	**2.00**
Total	**0.31**	**1.54**	**0.15**	**2.00**

Table 5-13. Residential Energy Storage System Incentive Program Capital and Operating Expense Variance

	2023	2024	2025
Capital	-	-	-
O&M	(0.69)	0.54	0.15
Total	**(0.69)**	**0.54**	**0.15**

5.3.3 Performance Reporting

To calculate the realized benefits and costs of the Residential Energy Storage System Incentive Program, PSEG Long Island will track the following metrics:

- **Number of Systems Enrolled –** Measure the level of participation in the incentive program, broken out by LMI/DAC and non-LMI/DAC. PSEG Long Island will use this information to determine whether a 200% increase in incentives[66] for LMI/DAC customers are effective in increasing participation for ESS.
- **Utility Funds Committed –** Track the funds committed to assess the total program costs.

Lessons Learned

Because the start date of this incentive program is dependent on when the current NYSERDA incentive program expires, the team learned that it is important to communicate with aggregators frequently and notify contractors through both NYSERDA and PSEG Long Island websites when this change occurs.

Next Steps

In Q2 2023, PSEG Long Island will develop and finalize a draft of the program design and inform external stakeholders of its completion. Marketing and outreach as well as the enrollment of participating customers is expected to begin in Q3 2023 and will continue until the end of 2024. PSEG Long Island will continue ongoing program administration such as managing incentives through 2024 and distributing payments on the allocated block through 2025 (if necessary).

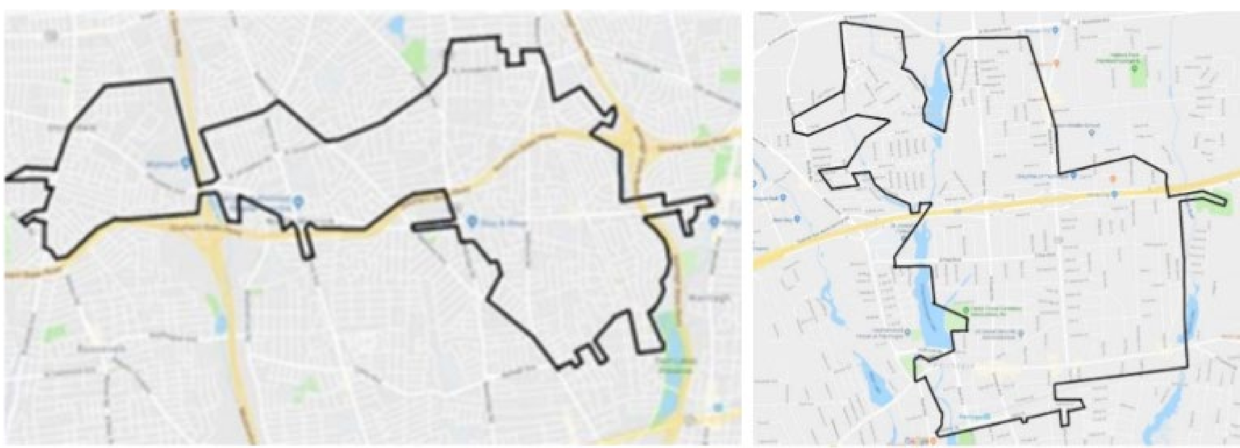
[66] For example, Block 1 Non-LMI/DAC incentive: $200/kWh; Block 1 LMI/DAC incentive: $400/kWh. See additional information in the 'Scope Update' Section above.

5.4 Super Savers

2023 Status	Patchogue = Active and North Bellmore = Complete
2024 Status	Patchogue = Active and North Bellmore = N/A
Start Year	2019
Funding Approved Through	2023
Description and Justification	Super Savers is an NWA seeking to reduce peak by 4 MW in North Bellmore and 2 MW in Patchogue to defer traditional capital investment. Through the initial pilot in North Bellmore, PSEG Long Island learned how to encourage the community adoption of EE and DER measures and whether they can shed enough load to defer infrastructure upgrades. The Super Savers program in North Bellmore was extended to 2022 and expanded to Patchogue, which will run through 2023 with payments to the implementation contractor being made through 2025.

Super Savers is an NWA seeking to reduce peak demand to defer traditional capital investment. Through this pilot, PSEG Long Island is learning how to encourage community adoption of EE and DER measures and whether they can shed enough load to defer infrastructure upgrades. The Super Savers program was completed on the North Bellmore (4 MW reduction) circuit in 2022 and is active on the Patchogue (2 MW reduction) circuit. Figure 5-2 illustrates the testing areas.

Figure 5-2. North Bellmore (Left) and Patchogue (Right) Super Saver Areas



5.4.1 Implementation Update

By the end of 2022, the North Bellmore Super Savers Program achieved a 2.3 MW peak demand reduction, representing 56% of the 4 MW peak reduction goal. The Patchogue Super Savers Program launched in late 2020 and has so far achieved 52% of its 2 MW goal. Increased marketing efforts in both N. Bellmore and Patchogue through emails, mailings, door to door and telecommunications have helped to achieve demand reduction by both residential and commercial customers through commercial lighting upgrades and DR measures.

Scope Update
The scope remains as previously reported in the 2021 and 2022 Utility 2.0 Plans.

Schedule Update

The Super Savers program in Patchogue will be completed in 2023, but DR payments to the implementation contractor for provided load relief will occur through 2025.

Risks and Mitigations

Table 5-14 outlines the potential risks and proposed mitigation steps for this initiative.

Table 5-14. Super Savers - Patchogue Risk and Mitigation Assessment

Category	Risk	Mitigation
Customer Engagement	Low rate of participation, even with nearly or completely free measures could impact program benefits	Build more targeted marketing strategies and higher incentives to build customer engagement
Customer Engagement	Marketing/targeting challenges; difficult to target customers on specific circuit vs geographic area	More door-to-door marketing to target customers on specific circuits

5.4.2 Funding Reconciliation

Although the marketing of the Super Savers program in Patchogue will be completed by the end of 2023, previously approved O&M funding will be used through 2025 ($900/kW/3 years).

The Super Savers Program previously relied heavily on door-to-door marketing to target specific customers, but this marketing strategy was difficult to implement over the last couple of years.

Although the peak demand reduction targets have not been met, all incremental reduction helps in assessing whether capital expenditure deferral is possible. The demand reduction and the insights gained from this program ultimately save or postpone investments that otherwise may have occurred. The updated annual budget and variance are shown in Table 5-15**,** Table 5-16, and Table 5-17.

Table 5-15. Super Savers Patchogue Capital and Operating Expense Budget, Forecast, and Request

	Actual 2019	Actual 2020	Actual 2021	Actual 2022	Updated Forecast 2023	Request 2024	Projected (Not Requested) 2025	Total
Capital	-	-	-	-	-	-	-	**-**
O&M	-	0.02	0.62	0.09	0.24	0.04	0.02	**1.02**
Total	**-**	**0.02**	**0.62**	**0.09**	**0.24**	**0.04**	**0.02**	**1.02**

Table 5-16. Super Savers Patchogue Capital and Operating Expense Variance

	2022	2023	2024	2025
Capital	-	-	-	-
O&M	(0.67)	(0.55)	0.04	0.02
Total	**(0.67)**	**(0.55)**	**0.04**	**0.02**

Table 5-17. Super Savers North Bellmore Capital and Operating Expense Budget, and Variance

	Actual 2019	Actual 2020	Actual 2021	Actual 2022	Total	Variance 2022
Capital	-	-	-	-	**-**	**-**
O&M	0.48	0.27	0.25	0.10	**1.10**	**(0.17)**
Total	**0.48**	**0.27**	**0.25**	**0.10**	**1.10**	**(0.17)**

5.4.3 Performance Reporting

The North Bellmore Super Savers Program achieved 56% of its peak demand reduction target of 4 MW and the Patchogue Super Savers Program achieved 49% of its peak demand reduction target of 2 MW through 2022. Super Savers North Bellmore and Patchogue KPIs and benefits are detailed in Table 5-18, Table 5-19, Table 5-20, and Table 5-21

Table 5-18. Super Savers North Bellmore KPIs

Benefit	Target Through 2022	Realized Through 2022	Realized %
Cumulative Peak Demand Reduced (Annual Average)	2,398	2,111	88%
Cumulative Energy Savings	4,470,725	3,220,111	72%

Table 5-19. Super Savers Patchogue KPIs

Benefit	Target Through 2022	Realized Through 2022	Realized %
Cumulative Peak Demand Reduced (Annual Average)	1,327	813	61%
Cumulative Energy Savings	2,643,393	3,725,721	141%

Table 5-20. Super Savers North Bellmore Benefits

Benefit	Target Through 2022 ($M)	Realized Through 2022 ($M)	Realized %
Super Savers: Avoided Generation Capacity Cost (AGCC)	651,625.80	289,221.97	44%
Super Savers: Avoided Energy (LBMP)	776,302.31	423,909.05	55%
Super Savers: Avoided Transmission Capacity Infrastructure	371,301.07	188,482.55	51%
Super Savers: Avoided Distribution Capacity Infrastructure	589,852.38	2,455,216.58	416%
Super Savers: Net Avoided CO2	377,696.00	307,099.50	81%

Table 5-21. Super Savers Patchogue Benefits

Benefit	Target Through 2022 ($M)	Realized Through 2022 ($M)	Realized %
Super Savers: Avoided Generation Capacity Cost (AGCC)	178,071.03	57,206.29	32%
Super Savers: Avoided Energy (LBMP)	265,737.60	159,943.04	60%
Super Savers: Avoided Transmission Capacity Infrastructure	112,259.30	30,724.65	27%
Super Savers: Avoided Distribution Capacity Infrastructure	1,062,350.41	204,288.59	19%
Super Savers: Net Avoided CO2	122,386.32	141,691.24	116%

Lessons Learned

As many of the Utility 2.0 programs, Super Savers was particularly impacted by the COVID-19 pandemic. Given that door-to-door marketing was not feasible during the pandemic, PSEG Long Island shifted their approach to digital and mail campaign outreach to small-to-medium businesses, resulting in an enrollment increase. The team also launched specific email outreach campaigns targeting specific technologies, like smart thermostats, to entice customers who were spending more time at home.

Because the Super Saver Program participant area is based on circuit boundaries that do not align with community boundaries, the program team learned that repeated and varied marketing touchpoints, such as email, telemarketing, postcards, and door-to-door outreach were successful in building customer trust and participation. Despite these efforts, along with nearly or completely free measures, there was still less than forecast rate of customer participation.

Due to the Super Savers program, PSEG Long Island successfully deferred substation upgrades to the North Bellmore substation until 2025 as well as captured learnings that continue to inform the program in Patchogue.

Next Steps
The Super Savers program in North Bellmore was competed in Q4 2022, and no activity, external reporting, or budgetary requirements are expected for this program in 2023 and beyond.

The Super Savers program in Patchogue is expected to continue the ongoing promotion and installation of smart thermostats and commercial efficiency upgrades through 2023. The program will also initiate and carry-on coordination with measurement and verification staff through 2023. Additionally, payments for this project to the implementation contractor will continue through 2025.

6. Customer Insights and Analytics

PSEG Long Island is committed to providing customers with greater access to data and information, enabling them to better manage their energy use. The *Customer Insights and Analytics* priority area highlights the significance of AMI deployment and the benefits and capabilities it enabled across the program and towards achieving the Utility 2.0 vision.

The development and deployment of AMI technology and systems is foundational to integrating clean energy options for customers. PSEG Long Island completed 98% of the planned AMI deployment by December 2022 which enables increased customer benefits and operational savings. By utilizing individual and aggregate time interval usage insights and other data provided by the AMI system, PSEG Long Island has implemented customer-facing and internal capabilities such as Data Analytics and Next Generation Insights to empower customers to take control of their energy usage more effectively and support efficient management of the electric grid. See Appendix D for the list of Utility 2.0 initiatives driven by the deployment of AMI that were operationalized as of 2023.

The Integrated Energy Data Resource (IEDR) platform will have the necessary information for DER providers to identify areas with high locational value for future interconnection planning through the availability of hosting capacity, solar siting, and aggregated customer usage data in a common platform. Promoting access to this data will support increased penetration of DERs and contribute to several New York State priorities.[67]

Priority Area Future Needs Assessment

The foundation of *Customer Insights and Analytics* priority area has been the prolific deployment of AMI across the PSEG Long Island service territory and utilization of data derived from AMI to drive customer access to data and information that improves their understanding and management of energy usage. Over the years of the Utility 2.0 program, the Utility has also deployed several customer experience pilots such as *Next Generation Insights* and *Energy Concierge.*

Future initiatives that fall under the *Customer Insights and Analytics* priority area will continue to capitalize on the widespread deployment of AMI technology and systems to drive customer access and increased choice in energy usage and savings. This will include advanced use cases for the data collected through AMI. PSEG Long Island will also seek to continuously update and improve its management of customer data with a focus on improving the customer experience when it comes to accessing and managing their energy information.

This chapter is organized into six subsections that provide an update for Utility 2.0 initiatives that directly align with the *Customer Insights and Analytics* priority area. PSEG Long Island notes that the initiatives in this chapter are not limited to only supporting this priority area and likely contribute to others.

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[67] The Data Access Framework adopted in this Order will serve as a single source for data access policies and provide uniform and consistent guidance on what is needed for access to, and the availability of, energy-related data. Moreover, the Framework will promote data access, while preserving all the necessary protections, to facilitate New York State's policy goals, Case 20-M-0082.

6.1 Integrated Energy Data Resource (IEDR) Platform

2023 Status	Active
2024 Status	Active
Start Year	2023
Funding Approved Through	2025
Description and Justification	The New York PSC issued an Order in 2021 for the implementation of an IEDR platform that would securely collect, integrate, and provide broad and appropriate access to large and diverse energy-related information on one statewide data platform. PSC assigned NYSERDA to coordinate with other state agencies that will also have a role in implementing the IEDR platform, including DPS, the New York Power Authority (NYPA), LIPA, the New York Independent System Operator, Inc. (NYISO), and the New York State investor-owned electric and gas utilities (IOUs). PSEG Long Island will be participating in the IEDR platform initiative led by NYSERDA. The objective of this New York state-wide centralized energy data platform is to inform investment decisions, promote innovation, encourage new business models, and enable better policy making and operational efficiency.

NYSERDA is leading the effort to develop an IEDR platform to satisfy the New York State PSC and deliver upon requested data access use cases. This project requires coordination with the NYSERDA project team, who is leading the effort in establishing the business requirements for all use cases. The NYSERDA project team includes their selected vendors; Pecan Street, the utility data advisor; E Source Companies, LLC, the solution architect and platform provider; and additional development and project management support from UtilityAPI, Flux Tailor, TRC Companies, and HumanLogic.

The project will be delivered in two phases. Phase 1 consists of producing an Initial Public Version (IPV) and a Minimum Viable Product (MVP). The scope and scale of Phase 2 has not yet been finalized and will be determined through a proposal scheduled to be filed on May 1, 2023. The project scope for Phase 1 and Phase 2 will be determined iteratively by the NYSERDA project team based on the feedback they receive from the utilities and other stakeholders. Therefore, the use case requirements and delivery timelines set by the NYSERDA project team are subject to change and are highly dependent on the use cases ultimately selected.

6.1.1 Implementation Update

The IPV scope of the project, which was due by Q1 2023, has been completed. The IPV phase provides NYSERDA with information they requested from all utilities on the format of certain data elements they wanted to understand in detail. The primary scope of the remainder of Phase 1 includes delivery of the five Use Cases NYSERDA decides to pursue for the IEDR platform this year. The use cases will help to drive the technology solution PSEG Long Island plans to design and deliver. Therefore, these use case will represent most of the scope of the project. As of yet, NYSERDA has only released the names of the use cases, but no further details and requirements are known. The final delivery schedule and level of execution complexity will be highly dependent on the pace at which the NYSERDA IEDR team progresses in defining business requirements and signing a data sharing agreement with the NYSERDA IEDR Platform Provider.

To support NYSERDA's IEDR requirements, PSEG Long Island will need to design a technology solution that enables data sharing with a third party hosted vendor solution. The design of the solution is dependent on receiving requirements from NYSERDA which have yet to be provided. At this stage, it is known that the use case requirements will likely include sensitive data elements to be delivered to the IEDR Platform. Therefore, PSEG Long Island has begun its internal security process of engaging Cybersecurity and Legal teams for evaluating and approving the third-party vendor solution (NYSERDA's IEDR platform provided by vendor ESource). Cybersecurity and Legal will also be required to review and approve the entire technology design of the NYSERDA IEDR platform including the IEDR requirement of having PSEG Long Island sensitive data hosted on a third-party platform for the public. To get started with all these required approvals, ESource is in the process of completing a vendor security questionnaire required by PSEG Long Island Cybersecurity team.

Scope Update

The scope of the project, as defined by NYSERDA, is a multi-year phased delivery that will eventually deliver over 50 use cases. For this year, Phase 1 includes delivery of IPV and MVP scope as outlined below.

NYSERDA envisions that the completion of the first five MVP use cases will be completed by 2023 year-end. However, this timeline is in jeopardy as requirements are still pending and NYSERDA still needs to resolve many pending issues related to security and other concerns from other utilities. These issues and concerns are described in *Schedule Update* section below.

Phase 1 descriptions

IPV: The IPV ("Initial Public Version"), which was launched on March 31st, 2023, refers to a set of initial use cases for public use intended to get users into the system and collect early feedback. This release focused on identifying, defining, and mapping the data fields and data sources for each use case. The desired outcome is the build, test, and delivery of the IPV data file(s) for each use case below.

- Hosting capacity maps
- Installed DER
- Planned DER

MVP: The MVP ("Minimum Viable Product") release includes five high priority use cases based on learnings from the IPV data gathering and from stakeholder input. The NYSERDA IEDR team selected the following five use cases for the MVP:

- DER Siting – Environmental, Community, Terrain, Land, and Property assessment
- EIAT Hosting Capacity & DER Map Enhancement
- Efficient and Effective Access to Existing Customer Billing Data
- Find and Filter Rate Options Across NYS IOU Utilities
- Access to Basic Rate Data and Tariff Book for Priority Rates

Schedule Update

NYSERDA's IEDR team shifted the release date of the first three use cases in the IPV from end of Q4 2022 to the end of Q1 2023. For the next part of the phase, NYSERDA's original plan includes year end 2023 delivery of the five MVP related used cases. However this timeline is in jeopardy due to the following factors: 1) the NYSERDA team has not released the data requirements for the MVP use cases; 2) the data sharing agreement with the platform provider is still pending and nothing can get started until this has been completed; 3) data security concerns are being raised from all Utilities including PSEG Long Island; and 4) and the risk/issue the Utilities have raised regarding sharing customer data with the vendor E Source without customer consent.

In May 2022, the JU of New York filed a petition[68] to modify the data security agreement self-attestation requirements and implement a governance review process for regular self-attestation updates. This petition would modify the Commission's October 2019 Order Establishing Minimum Cyber Security and Privacy Protections and Making Other Findings[69], resulting in six updated and three new requirements in the current Self Attestation of the commission-approved Data Security Agreement and establish a governance process for regular Self-Attestation review and recommend further updates. These changes will require stricter guideline around how data is handled by the IEDR team.

In December 2022, the JU filed a second petition[70] seeking direction from the Commission regarding the direct sharing of protected customer data with the NYSERDA IEDR platform provider. It is the JU's position that there is no explicit requirement in the IEDR Implementation Order[71] or the April 2021 Data Access Framework[72] for utilities to share data without customer consent. This petition requests that the Commission explicitly direct the JU to provide non-anonymized, non-aggregated customer specific data (Protected Customer Data) to the NYSERDA IEDR Solution Architect and Development Team (IEDR Administrator) without customer consent. Should this be directed, the JU also requests that the Commission clarify that the IEDR Platform Provider not share Protected Data with third parties until customer consent is obtained. Lastly, as the JU were not participants in the selection of the IEDR Administrator, nor do they have any role in overseeing the activities or operations of the IEDR Administrator or IEDR and, therefore, have no ability to protect the data stored in the IEDR, it is the JU's position that they should not be held liable for any disclosures and have clear liability limitations in their electric and gas tariffs to protect against any potential legal actions.

When the Commission responds to these two petitions, PSEG Long Island Legal will review and determine the impact on PSEG Long Island's participation in the IEDR program.

Risks and Mitigations

Table 6-1 outlines the potential risks and proposed mitigation steps for this initiative.

Table 6-1. Risk and Mitigation Assessment

Category	Risk	Mitigation
Technical	Unknown IEDR platform technology may result in integration issues and timeline delays.	Stay connected with the IEDR Team by attending workshops and meetings to remain informed of technology decisions and raise concerns as needed.

[68] Cases 20-M-0082 and 18-M-0376 Joint Utility Petition to Modify Self Attestation, May 2022

[69] October 2019 Order Establishing Minimum Cyber Security and Privacy Protections and Making Other Findings

[70] Case 20-M-0082: Joint Utility Petition Regarding Sharing Data with the Integrated Energy Data Resource December 1, 2022

[71] Strategic Use of Energy Data Proceeding, Order Implementing an Integrated Energy Data Resource (issued February 11, 2021) (IEDR Implementation Order).

[72] Case 20-M-0082, In the Matter of the Strategic Use of Energy Related Data (Strategic Use of Energy Data Proceeding), Order Adopting a Data Access Framework and Establishing Further Process (issued April 15, 2021) (Data Access Framework Order).

Project Schedule	This project will require coordination with NYSERDA's requirements and timelines, which are subject to change. NYSERDA's requirements for IEDR are being iteratively developed with input from the JU and PSEG Long Island. Therefore, the timelines for the remainder of Phase 1 (MVP) are draft only and have not been finalized. This could delay the schedule.	The baseline schedule for the IPV and MVP rollout is provided in this document as it is currently known. This schedule is subject to change based on the NYSERDA IEDR team confirmation of use cases and schedules.
Data Sensitivity	NYSERDA and the IEDR Development Team require sharing of sensitive data fields that PSEG Long Island does not currently make publicly available. Not providing these data may result in a non-optimal solution.	Review data elements with cybersecurity and include requirements in the Utility Data sharing agreement, as applicable.
Customer Consent	NYSERDA and the IEDR Development Team require all data fields to be shared to the Platform regardless of existing customer consent captured by the Utilities and Customer Consent will be applied after the data is received into the IEDR platform. Without appropriate safeguards, sensitive information will not be protected.	Work through any concerns with PSEG Cybersecurity, the NYSERDA UCG, and the NYSERDA Development Team. Provide inputs into the development of the Utility Data Sharing agreement where relevant. Customer data will not be shared until a data sharing agreement with the platform provider is approved.
Data Access Framework	NYSERDA expects all utilities to build their technology solutions engaging customer consent through their data access framework. This customer authentication process may require the use of Green Button Connect. This represents a technology risk in implementation. This technology risk could impact the cost of the solution as well as the implementation schedule.	Currently, PSEG Long Island does not use Green Button Connect technology. PSEG Long Island Business SMEs, Legal, and cybersecurity teams will need to be engaged to vet the process and potentially build the needed solution.
Storm Response	Storm duty takes priority over everything, including project work. PSEG Long Island labor availability may be impacted, and project deliverables/tasks may be delayed due to storm duty.	Plan and anticipate schedule impact due to storm duty. Notify relevant stakeholders (i.e., the DPS, LIPA) when storm duty will impact the submittal of deliverables.
Data availability	The use cases and data requirements for the MVP have not been finalized. As such, PSEG Long Island is unable to determine if the data required is available to be delivered according to the schedule.	Coordinate with the project teams for projects that will be collecting relevant data in the future. Share possible data fields needed and gather the timeline for implementation.

6.1.2 Funding Reconciliation

The previously submitted budget estimates were based on the best-known schedule of activities provided by NYSERDA at the time of submittal. However, NYSERDA's proposed timelines for the IEDR platform and delivery of subsequent phases have continually seen delays due to a variety of factors.

The original 2023 capital budget for IEDR project of $3.12M has been reforecast to reflect the updated project timelines. Therefore, the new 2023 forecast will be $775,000 for this year, reflecting the shifting of $2.25 million to next year (2024). In addition, the $0.10M in O&M originally planned for 2023 has also been shifted from 2023 to 2024.

The updated capital forecast for 2023 will no longer include the $1.58 million attributable to LIPA for the NYSERDA platform and its development costs.[73] This cost will be paid by LIPA directly and does not come out of a Utility 2.0 budget.

The updated annual budget and variance are shown in Table 6-2 and Table 6-3.

Table 6-2. Capital and Operating Expense Budget, Forecast*

	Updated Forecast	Request	Projected (Not Requested)	
	2023	2024	2025	Total
Capital	0.78	4.08	1.83	**6.69**
O&M[74]	-	0.50	0.60	**1.10**
Total	**0.78**	**4.58**	**2.43**	**7.79**

Table 6-3. Capital and Operating Expense Variance*

	2023	2024	2025
Capital	(3.83)	2.25	-
O&M[75]	(0.10)	0.10	-
Total	**(3.93)**	**2.35**	**-**

6.1.3 Performance Reporting

PSEG Long Island's IEDR project does not have specific KPIs or benefits. PSEG Long Island's goal is to provide data to NYSERDA's IEDR platform.

Next Steps

PSEG Long Island is providing sample data sets for the IPV release. The team is working with NYSERDA and their vendors to get cybersecurity approvals for data sharing. In addition, the PSEG Long Island legal team is working with the JU to draft a data sharing agreement which is needed prior to any sensitive data being shared.

[73] As agreed in the Memorandum of Understanding between LIPA and NYSERDA, from March 31st, 2021.

[74] In the 2023 Utility 2.0 Long Range Plan that was submitted on July 1, 2023, the IEDR Platform 2023 O&M Budget was properly reflected in the Section 6.1.2 narrative above but was improperly reflected in Table 6-2 and Table 6-3. O&M forecasts are updated accordingly as of August 9, 2023.

[75] See previous footnote. O&M budget forecast for 2023 impacted the O&M variance for 2023.

7. Utility 2.0 Portfolio-Level Summary Tables

7.1 Funding Requested for New and Active Utility 2.0 Initiatives

Table 7-1 summarizes the updated funding request for proposed and active projects, broken out by Capital and O&M expenditures. As this Filing is representative of a one-year outlook only, funding requests reflect 2024 only. Estimated spending forecasts are provided for 2025, however, this outer year will be revisited in next year's filing. Detailed budgets for each initiative with costs organized by funding subcategory (for new projects only) can be found in Chapters 3 through 6. Note – 2023 spending is estimated through year end and includes YTD spending.

Table 7-1. Funding Request for Active and Proposed Projects

		Capital Expenditure ($M)			O&M Expenditure ($M)			
		Request	Projected		Request	Projected		
	Funding Subcategory	2024	2025	2-Year Total	2024	2025	2-Year Total	2-Year Total Request
Proposed	Fleet Make-Ready Program	0.81	1.47	**2.28**	0.73	0.75	**1.48**	**3.76**
	Residential Charger Rebate Program	0.00	0.00	**0.00**	1.21	1.21	**2.42**	**2.42**
	EV Phase-In Rate[76]	1.27	0.82	**2.09**	0.00	0.00	**0.00**	**2.09**
Active	EV Make-Ready Program[77]	3.96	3.98	**7.94**	8.89	10.33	**19.22**	**27.16**
	Electric Vehicle Program	0.00	0.00	**0.00**	1.75	2.61	**4.36**	**4.36**
	Suffolk County Bus Make-Ready Pilot	0.00	0.00	**0.00**	0.04	0.00	**0.04**	**0.04**
	Connected Buildings Pilot	0.00	0.00	**0.00**	0.13	0.00	**0.13**	**0.13**
	Residential Energy Storage Program	0.00	0.00	**0.00**	1.54	0.15	**1.69**	**1.69**
	Super Savers - Patchogue	0.00	0.00	**0.00**	0.04	0.02	**0.06**	**0.06**
	IEDR Platform	4.08	1.83	**5.91**	0.50	0.60	**1.10**	**7.01**
	Total	**10.11**	**8.09**	**18.22**	**14.83**	**15.67**	**30.50**	**48.72**

[76] Since the submission of the 2023 Utility 2.0 Long Range Plan on July 1, 2023, more information regarding third-party contracting support and the associated Capital costs for this program extension for 2024 has become available. Capital forecasts are updated accordingly as of August 25, 2023.

[77] Since the submission of the 2023 Utility 2.0 Long Range Plan on July 1, 2023, information regarding loan aggregator fees for 2023 (O&M costs) and third-party IT aggregator data collection (O&M costs) for 2024-2025 for this program has become available. O&M forecasts are updated accordingly as of August 25, 2023.

7.2 Budget Variance for Ongoing Utility 2.0 Initiatives

PSEG Long Island reconciled actual spend in 2022 with the approved budget that was filed for each of the approved initiatives through the 2022 Utility 2.0 Plan. The Utility also re-forecasted the budget for all ongoing initiatives for the period between 2023 and 2025 except for operationalized initiatives, which were only reforecast to 2023.

Table 7-2 shows the variance between the approved budget and the actual and updated projected spending from 2022-2025 and Table 7-3 shows the variance by project broken out by year. Initiative-level details for the actual spend and the forecast are included in Chapters 3-6. Please note, as in other variance tables throughout this document, negative values reflect an actual or projected overspend of the previously filed budget.

Table 7-2. Variance Between Approved Budget and Updated Project Spending

		Capital ($M)			O&M ($M)			
2023 Status	Project	2022 Budget 2022-2025	Updated Forecast 2022-2025	Total Capital Variance	2022 Budget 2022-2025	Updated Forecast 2022-2025	Total O&M Variance	Total Variance
Active	**Connected Buildings Pilot**	0.00	0.00	**0.00**	0.64	0.42	**(0.21)**	**(0.21)**
	Electric Vehicle Program[78]	0.00	2.09	**2.09**	6.82	10.51	**3.69**	**6.78**
	EV Make-Ready Program[79]	9.01	11.36	**2.35**	50.19	27.17	**(23.01)**	**(20.66)**
	IEDR Platform[80]	8.25	6.68	**(1.58)**	1.10	1.10	**0.00**	**(1.58)**
	Residential Energy Storage Program	0.00	0.00	**0.00**	2.00	2.00	**0.00**	**0.00**
	Suffolk County Bus Make-Ready Pilot	0.10	0.01	**(0.10)**	0.75	0.69	**(0.06)**	**(0.16)**
	Super Savers - Patchogue	0.00	0.00	**0.00**	1.54	0.39	**(1.16)**	**(1.16)**
	DER Visibility Platform	7.62	5.69	**(1.94)**	0.20	0.16	**(0.04)**	**(1.98)**
	Storage/EV Hosting Capacity Maps	1.93	0.94	**(0.99)**	0.20	0.20	**0.00**	**(0.99)**

[78] Since the submission of the 2023 Utility 2.0 Long Range Plan on July 1, 2023, more information regarding third-party contracting support and the associated Capital costs for the EV Phase-In Rate (EV Program Extension) for 2024 has become available. Capital forecasts are updated accordingly as of August 25, 2023.

[79] Since the submission of the 2023 Utility 2.0 Long Range Plan on July 1, 2023, information regarding loan aggregator fees for 2023 (O&M costs) and third-party IT aggregator data collection (O&M costs) for 2024-2025 for this program has become available. O&M forecasts are updated accordingly as of August 25, 2023.

[80] Since the submission of the 2023 Utility 2.0 Long Range Plan on July 1, 2023, a correction has been made regarding third-party support costs for 2023 (O&M) for the IEDR Platform. O&M forecasts are updated as of August 9, 2023.

	NWA Process Development	0.00	0.00	**0.00**	0.50	0.09	**(0.41)**	**(0.41)**
Canceled	**Grid Storage Miller Place**	15.35	0.04	**(15.31)**	1.11	0.00	**(1.11)**	**(16.42)**
	Total	**42.26**	**26.80**	**(15.46)**	**65.04**	**42.73**	**(22.32)**	**(37.78)**

Table 7-3. Annual Variance Between Approved Budget and Updated Project Spending

		Total Variance from 2021 Filed Plan				
2023 Status	**Project**	**2022**	**2023**	**2024**	**2025**	**Total**
Active	**Connected Buildings Pilot**	(0.56)	0.21	0.13	0.00	**(0.21)**
	Electric Vehicle Program[81]	(0.05)	(0.51)	2.99	3.35	**6.78**
	EV Make-Ready Program[82]	(3.19)	(3.19)	(0.97)	(13.31)	**(20.66)**
	IEDR Platform[83]	0.00	(3.93)	2.35	0.00	**(1.58)**
	Residential Energy Storage Program	0.00	(0.69)	0.54	0.15	**0.00**
	Suffolk County Bus Make-Ready Pilot	(0.81)	0.62	0.04	0.00	**(0.16)**
	Super Savers - Patchogue	(0.67)	(0.55)	0.04	0.02	**(1.16)**
	DER Visibility Platform	(1.61)	(0.06)	(0.16)	(0.16)	**(1.98)**
	Storage/EV Hosting Capacity Maps	0.00	(0.99)	0.00	0.00	**(0.99)**
	NWA Process Development	(0.41)	0.00	0.00	0.00	**(0.41)**
Canceled	**Grid Storage Miller Place**	(6.79)	(6.29)	(3.15)	(0.19)	**(16.42)**
	Total	**(14.08)**	**(15.38)**	**1.81**	**(10.14)**	**(37.78)**

[81] Since the submission of the 2023 Utility 2.0 Long Range Plan on July 1, 2023, more information regarding third-party contracting support and the associated Capital costs for the EV Phase-In Rate (EV Program Extension) for 2024 has become available. Capital variances are updated accordingly as of August 25, 2023.

[82] Since the submission of the 2023 Utility 2.0 Long Range Plan on July 1, 2023, information regarding loan aggregator fees for 2023 (O&M costs) and third-party IT aggregator data collection (O&M costs) for 2024-2025 for this program has become available. O&M variances are updated accordingly as of August 25, 2023.

[83] Since the submission of the 2023 Utility 2.0 Long Range Plan on July 1, 2023, a correction has been made regarding third-party support costs for 2023 (O&M) for the IEDR Platform. O&M variances are updated accordingly as of August 9, 2023.

7.3 Rate Impact Analysis

The rate impact on residential customers from both ongoing Utility 2.0 initiatives and the initiatives proposed for funding in the 2023 Utility 2.0 Plan is illustrated in Figure 7-1. PSEG Long Island expects on average a moderate net increase in residential bills through 2025 as a result of Utility 2.0 initiatives. This net increase is driven primarily by the Residential Energy Storage Incentive Program and the EV Program.

Figure 7-1. Residential Customer Bill Impacts from Utility 2.0 Initiatives

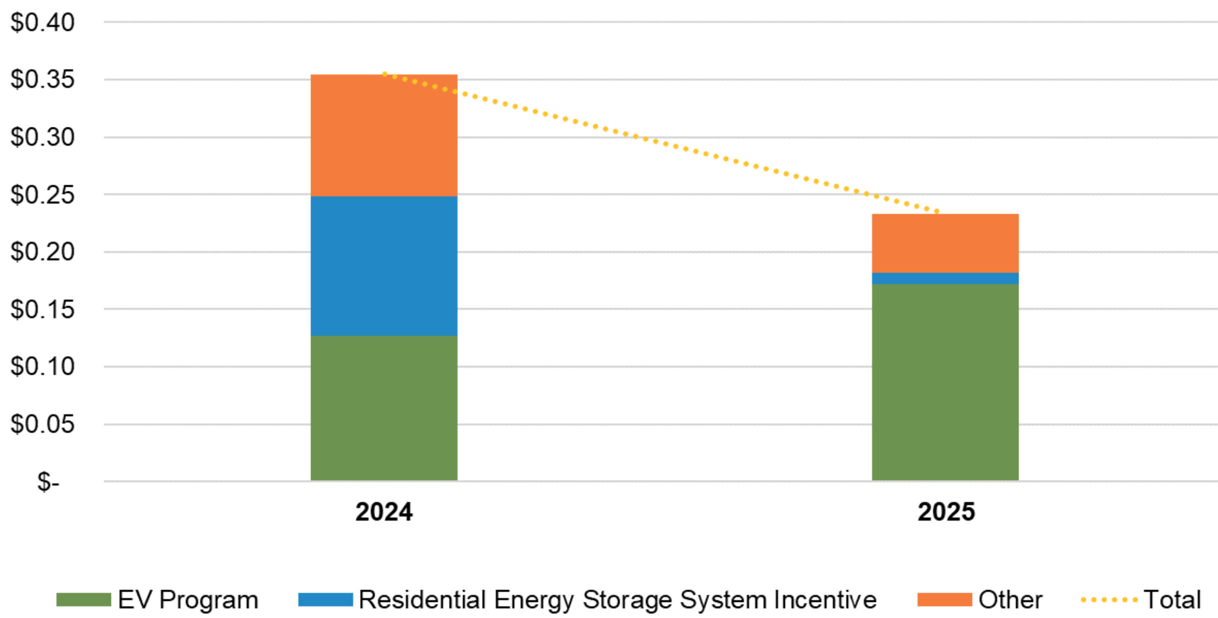


Table 7-4 and Table 7-5 illustrate the estimated rate impact on residential and commercial customers, respectively. These rate impacts reflect the capital, O&M, net revenue change, and power supply costs for each program, initiative and project included in the 2023 Utility 2.0 Plan's funding requirements, including both ongoing initiatives and new initiatives proposed in the 2023 Plan. Positive impact indicates an increase and negative impact a decrease in the rates.

Table 7-4. Residential Rate Impacts

Initiative	2024 ($)	2025 ($)
EV Program	0.13	0.17
Super Savers	0.02	0.02
Make-Ready Program	0.00	0.00
Connected Buildings Pilot	0.02	0.01
Suffolk County Bus Make-Ready Pilot	0.00	0.00
IEDR Platform	0.06	0.02
Residential Energy Storage System Incentive	0.12	0.01
Total	**0.35**	**0.23**

Table 7-5. Commercial Rate Impacts

Initiative	2024 ($)	2025 ($)
EV Program	0.99	1.21
Super Savers	0.01	0.01
Make-Ready Program	(10.80)	(22.49)
Connected Buildings Pilot	0.00	0.00
Suffolk County Bus Make-Ready Pilot	0.47	0.03
IEDR Platform	0.56	0.18
Residential Energy Storage System Incentive	0.00	0.00
Total	**(8.77)**	**(21.06)**

Appendix A. Energy Efficiency Plan

2024 Annual Update

Contents

A.1 Introduction

PSEG Long Island (the Utility) is a subsidiary of Public Service Enterprise Group Incorporated (PSEG), a publicly traded diversified energy company with annual revenue of $26.4 billion and operates LIPA's transmission and distribution (T&D) system under a 12-year contract.

PSEG Long Island is submitting this EE Plan for review by LIPA and the DPS. This submittal is in accordance with Public Authorities Law Section 1020-f(ee) and the Amended and Restated Operations Services Agreement dated November 9, 2021. PSEG Long Island seeks a positive recommendation on the Plan from DPS and funding approval from LIPA for 2024.

A.1.1 Portfolio Budget and Target Summary

PSEG Long Island's EE program makes a wide array of incentives, rebates, and programs available to their residential and commercial customers to assist them in reducing their energy usage and lowering their bills. PSEG Long Island has partnered with TRC Companies (TRC) to deliver the EE programs to the public. The proposed 2024 EE initiatives consist of programs for residential customers and multifaceted programs for commercial customers.

Two recently introduced programs will continue as standalone programs in 2024: All Electric Homes and Multifamily. The Behavioral Initiative/Home Energy Management (HEM) program will also continue. PSEG Long Island is proposing a restructured low-income offering in the Home Comfort program, which the Utility believes will better serve the bulk of low-income customers. Further information can be found in the Home Comfort section.

PSEG Long Island will continue working with NYSERDA to coordinate programs with IRA funding with the goal of leveraging such funding to support the Home Comfort and Home Performance programs. As NYSERDA is still working on their plans for administering such funding, PSEG Long Island is not able to incorporate detailed plans into this filing. Similarly, with respect to the Climate Act, PSEG Long Island has incorporated the guidance received to date into this planning effort. Additional guidance is expected and may be received subsequent to this submission, which will then be incorporated into PSEG Long Island's actual implementation of the 2024 plan.

As part of its overall goal of reducing GHG emissions by 40% by 2030, New York State set new statewide EE strategy in the New Efficiency: New York Order that was issued in 2018. In the Order, New York State establishes savings targets on an energy basis (Btu) for the state as a whole and specifically for Long Island and establishes estimated reductions in forecasted sales by 2025 that would be the result of the actions described in the Order. New Efficiency: New York established fuel-neutral targets to accommodate beneficial electrification of buildings because increased electrification in the building and transportation sectors is necessary to achieve the State's carbon reduction goals.

PSEG Long Island has been actively engaged in rolling out utility-leading residential and commercial savings programs for customers. The 2024 EE Plan focuses on continuing to deliver EE savings programs to residential and commercial customers, while expanding efforts to include building decarbonization initiatives. The plan has been impacted by the finalization of the EISA of 2007, which effectively results in lighting no longer being a program measure. As a result, the portfolio is transitioning into higher cost EE items, with continued trends of beneficial electrification growing while EE declines. Adopting fuel-neutral savings targets allows PSEG Long Island to aggregate efficiency achievements across electricity, natural gas, and delivered fuels such as oil and propane, which requires a shift toward investments in non-lighting opportunities, especially an expanded focus on heat pumps and other building decarbonization opportunities. PSEG Long Island has taken a different approach to reporting lower levels of MMBtus by including the heating penalty associated with lighting upgrades, an approach that does not align with the rest of the state. In this filing, PSEG Long Island has sought to provide a comparison by setting forth MMBtu achievements using both the method that is consistent with the rest of the state, as well as the method which PSEG used in prior reports.

Early in program implementation efforts, PSEG Long Island recognized the importance of aligning the business trades with its program offerings. The residential portfolio promotes the ENERGY STAR message through its media campaigns, website, marketing materials, and outreach. In addition, collaboration with trade allies, state agencies, local utilities, and municipalities supports a coordinated effort to reach goals. These stakeholder partnerships facilitate attractive incentives and services to be offered through the residential programs, which make participants' homes energy efficient, safe, and comfortable.

PSEG Long Island's program philosophy and delivery is structured to respond to market changes and cost-effective EE opportunities during any given year. The Plan targets **762,509 total MMBtu savings** (which includes 148,736 MWh of EE savings), which are similarly reflected on a gross basis at site.

The proposed 2024 budget of $93.71 million for the EE Plan reflects an increase compared to 2023's budget request of $90.52 million. PSEG Long Island has budgeted for some initiatives that will not have any MMBtu savings associated with them in 2024—e.g., the DLM Program at $2.4 million. Additionally, the Home Comfort budget, as well as the Marketing and Outreach budget, include incremental funding to support additional efforts aimed at addressing the barriers set forth in LIPA's UCS-44 Next Level Heat Pump Deployment Final Report, issued in March of this year.

Given the increased emphasis on advancing energy affordability by developing initiatives focused on energy solutions for LMI consumers, enhanced heat pump rebates and programmatic changes designed to enhance the Home Performance and REAP programs will total about $7.0 million in spending in 2024. This includes substantial programmatic fund investments in income-qualified whole house heat pump rebates with the anticipation that current enhanced rebates from Attorney General Settlement funds will be exhausted prior to the end of 2023. These energy affordability initiatives are screened to ensure that energy burden impacts, such as the cost of running heat pumps, for LMI customers have been factored into any economics analysis as part of the decision to provide enhanced rebates towards these measures or programs.

In her 2022 State of the State address, Governor Hochul announced the below goal to: Achieve 2 million Electrified or Electrification-Ready Homes by 2030

> Building electrification and related upgrades improve interior comfort, reduce exposure to air pollution, and support local jobs. But right now, only about 20,000 New York homes install modern heat pumps for heating and cooling each year.
>
> While New York is making progress through programs like NYS Clean Heat, more must be done to cut emissions in buildings.
>
> To accelerate green buildings in New York, Governor Hochul is setting an unprecedented commitment of a minimum 1 million electrified homes and up to 1 million electrification-ready homes by 2030 and ensuring that more than 800,000 of these homes will be LMI households. This target will be anchored by a robust legislative and policy agenda, including:

- Raising the current rate of electrification of approximately 20,000 homes per year more than tenfold by the end of the decade.
- Electrifying LMI homes supported through the housing capital plan.

- Requiring zero on-site GHG emissions for new construction no later than 2027 (see below).
- Upgrading New York's appliance efficiency standards, reducing energy use while saving New Yorkers billions of dollars in utility costs.
- Mandating energy benchmarking for large buildings, making it easier to track energy-efficiency improvements over time.
- Convening the finance, mortgage and banking industries to help align private capital with this important housing sustainability goal.
- Providing the training programs necessary to ensure that New York has a skilled workforce to deliver these services.
- Proposing legislation to level the playing field for clean energy alternatives and end the obligation to serve customers with natural gas that currently exists in state law, tailored to maintain affordability for New York's most vulnerable customers.
- Directing NYSERDA, Housing and Community Renewal (HCR), DPS, and DOS to deliver an executable plan in 2022, with a funding proposal and strategies to leverage private capital.

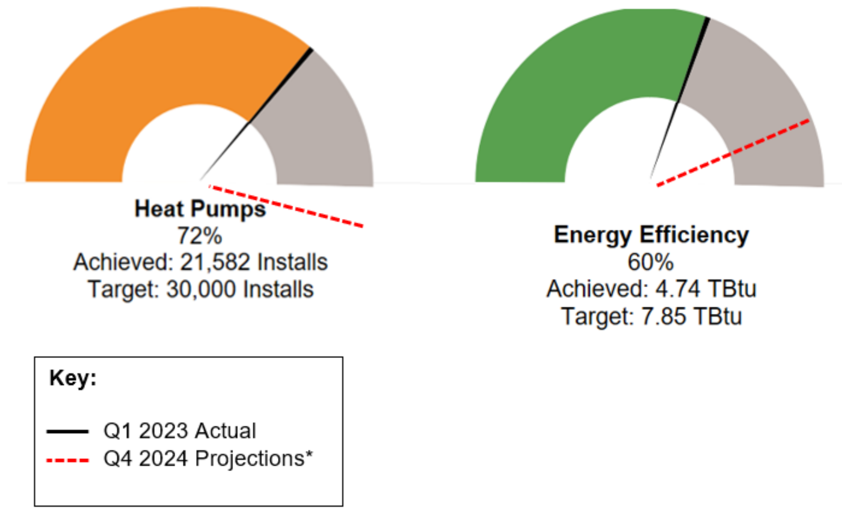
PSEG Long Island believes that the Governor's goal is one of the most ambitious in the nation and looks forward to being a part of this historic effort aimed at meaningful carbon reduction in the built environment. While offering rebates for geothermal heat pumps since 2014, starting in 2019 PSEG Long Island began promoting heat pumps under the Cool Homes Program. In 2020, the program name was changed to Home Comfort to reflect the changing focus to the promotion of heat pumps and beginning in 2021, the Home Comfort only promoted and incentivized heat pump technology. PSEG Long Island recognizes the level of effort and focus it will take to reach this goal and believes the pathway to success will not be all that different than the pathway photovoltaic installations on Long Island chartered in reaching success.

Long Island's proportional share of the electrification goal would yield a target of 125,000 to 150,000 homes heated with heat pumps by the end of the decade. PSEG Long Island is committed to working with all the heat pump industry stakeholders including the various State agencies fostering the development of the Governor's vision into a deployed plan and leveraging its strengths to ensure that Long Island once again leads the State in activity like it has done in both photovoltaics and EV registrations.

In 2024 PSEG Long Island plans a greater level of stress on whole house heat pumps (including for income-qualified customers) and an increasing emphasis on pushing customers towards cold climate models while continuing to deemphasize non-cold climate offerings. Figure A-1 below depicts the actual progress for heat pump installs[84] and EE savings through Q1 of 2023, as well as forecasted achievements through 2024 as a result of successful plan deployment.

[84] 2020 Planned Heat Pump Pool Heaters: 100 Units. 2020 Actuals: 1,635 Units
2021 Planned Heat Pump Pool Heaters: 150 Units. 2021 Actuals: 1,867 Units
2022 Planned Heat Pump Pool Heaters: 2,000 Units. 2022 Actuals: 1,217 Units
2023 Planned Heat Pump Pool Heaters: 1,000 Units. 2023 YTD June Actuals: 455 Units
2024 Planned Heat Pump Pool Heaters: 1,200 Units

Figure A-1 Heat Pump and EE Actual for 2023 Q1 and Forecasted for 2024 Q4



In Figure A-1, the 2024 forecasted savings value of 7.63 TBtu reflects savings calculated in the same manner used by the New York State electric utilities. This represents a change from prior year calculations used by PSEG Long Island, in that it reflects an incremental 0.78 TBtu of savings from not including the lighting waste heat factor heating penalties from 2020 through 2023. Including these penalties, would result in 6.92 TBtu of energy savings. Heat pump projections in alignment with plans equate to 33,278 installations by Q4 of 2024.

The proposed 2024 EE budget also reflects a small carryover of community solar projects that are expected to receive an incentive in 2024. PSEG Long Island continues to lead New York State in ongoing solar PV deployments. PSEG Long Island also continues to locally administer the NY-Sun Incentive Program for projects that receive Green Jobs – Green New York financing and Affordable Solar incentives for income-eligible households. Incentives are available for new residential and commercial projects that pair solar PV with energy storage, and those customers are also afforded enrollment opportunities in the DLM tariff to allow for capacity-based payments for system or local relief. PSEG Long Island expects that this is the last year funding to support photovoltaics will be included in the EE Plan.

PSEG Long Island monitors program performance and consumer uptake on a continual basis. By doing this, the Utility can respond to changes in market conditions in a timely and efficient manner, which allows for the revision of offerings throughout the year in response to changing market conditions. Depending on the program, PSEG Long Island does an annual, quarterly, or monthly review to help respond to market conditions.

A.1.2 Portfolio Summary

Table A-1 summarizes the expected EE savings (on a MMBtu and MWh basis), along with the associated budgets, for the various residential and commercial components that comprise PSEG Long Island's portfolio of EE programs.

Table A-1. 2024 EE Goals

Program	Savings (MMBtu)	Savings (MWh)	Program Budget ($M)
Energy Efficient Products	148,847	16,107	8.82
Home Comfort	111,645	1,587	17.91
REAP (Low-Income)	10,475	1,862	3.37
Home Performance	29,236	2,245	7.58
Multifamily	46,382	3,672	6.53
All Electric Homes	574	22	0.50
Commercial Efficiency	237,533	71,126	32.09
HEM (Behavioral)[85]	177,816	52,115	3.04
Total, Budget Components with Programmatic Savings	**762,509**	**148,736**	**79.82**
DLM Program	-	-	2.40
PSEG Long Island Labor	-	-	3.37
Outside Services	-	-	2.66
Advertising	-	-	2.60
G&A	-	-	0.90
Community Solar	-	-	0.25
Home Comfort Market Development Fund	-	-	1.00
REAP Thermostats (TRC)	-	-	0.70
Total, Budget Components Not Associated with Programmatic Savings	**-**	**-**	**13.88**
Total	**762,509**	**148,736**	**93.71**

Table A-2 summarizes the expected budgets, participation, and savings (on a MMBtu basis) for the various residential and commercial heat pumps across PSEG Long Island's portfolio of programs. Full details on unit types and associated rebates and incentives can be found in the program sections that follow. Note that the savings and budgets listed below are subsets of the overall goals outlined in Table A-1.

Table A-2. 2024 Heat Pump Goals

Program	Savings (MMBtu)	Participation (Units)	Rebates & Incentives Budget ($M)
Heat Pump Water Heaters (EE Products only)	5,038	500	0.55
Heat Pump Pool Heaters (EEP)	35,326	1,200	1.32
Home Comfort Program – Whole House ASHPs	94,397	2,710	10.9
Home Comfort Program – Partial House ASHPs	13,859	1,075	1.25

[85] Reflects uptake to serve 700,000 customers next year

Program	Savings (MMBtu)	Participation (Units)	Rebates & Incentives Budget ($M)
Home Comfort Program - GSHPs	11,277	228	1.28
Home Comfort Program – Water Heaters	1,170	116	0.14
Heat Pumps (All Electric Homes Program)	572	20	0.06
Commercial Heat Pumps (Commercial Efficiency Program and Multifamily)	9,000	1,700	-
Total	**170,639**	**7,549**	**15.50**

Plans for 2024 also include additional investments in energy affordability for customers through increased investments for LMI customers in EE programs and heat pump offerings. These investments in customer programs offer broad benefits, including permanently lowering household energy bills, reducing carbon emissions, supporting Climate Justice, and reducing bill impacts on all customers. In the proposed 2024 budget and shown below in Table A-3, PSEG Long Island plans on spending $12.69 Million on LMI Customers.

Table A-3 summarizes the expected budgets, participation, and savings (on a MMBtu basis) for the various programs focused on income-eligible customers across PSEG Long Island's portfolio of programs. An additional $1M is included to support incremental work and efforts, resulting from the LIPA heat pump barriers report. Full details on unit types and associated rebates and incentives can be found in the program sections that follow. Note that the savings and budgets listed below are subsets of the overall goals outlined in Table A-1.

Table A-3. 2024 Income-Eligible Customer Goals

Program	Savings (MMBtu)	Program Budget ($M)
Home Comfort – Whole House LMI	21,363	4.50
REAP[86]	10,475	4.07
Home Performance - LMI	11,284	3.62
Marketing & Outreach	-	0.50
Total	**43,122**	**12.69**

A.1.3 Benefit-Cost Analysis

While PSEG Long Island's EE planning is done on a gross basis at the customer meter to align with state objectives, the cost-effectiveness screening is still done on a net basis that considers potential free riders and spillover effects as a result of the program offerings.

[86] Includes 700,000 for REAP thermostats and 3.37 that is the delivery of service

PSEG Long Island has historically used two separate tests to screen each program and for the overall portfolio: the utility cost test (UCT) and the SCT. The tests are similar but consider slightly different benefits and costs in determining the benefit-to-cost ratios.

- The UCT includes the net costs of an EE or renewable program as a resource option based on the costs incurred by the program administrator, including all program costs and any rebate and incentive costs, but excludes costs incurred by the participant.
- The SCT considers costs to the participant but excludes rebate costs because these are viewed as transfer payments at the societal level. The SCT also includes the benefits of non-electric (i.e., gas and fuel oil) energy savings where applicable, resulting in different benefit totals than the UCT test.

To be consistent with the Benefit-Cost Analysis (BCA) Order that was issued in 2016, the rate impact measure (RIM) test is also conducted for each EE and renewable program and for the overall portfolio. The RIM test provides an assessment of the preliminary impact on customer rates and compares utility costs and utility bill reductions with avoided costs and other supply-side resource costs.

PSEG Long Island now uses the SCT as the primary method and has applied the June 2023 BCA Handbook, including the avoided capacity and energy costs from including the carbon costs, to screen its 2024 EE programs and portfolio. The UCT and RIM tests are used as secondary reference points to assess the impact on utility costs and ratepayer bills from the benefits and costs that pass the SCT.

Table A-4 presents the benefit-to-cost ratios for the SCT, UCT, and RIM tests for each program and for the overall EE portfolios. This includes LMI components that are part of various programs.

Table A-4. BCA for 2024 EE Portfolio

Program/Sector	SCT	UCT	RIM
Commercial Efficiency Program (CEP)	**1.69**	**1.58**	**0.29**
Multifamily	**0.40**	**(0.05)**	**0.07**
Commercial	**1.32**	**1.30**	**0.28**
Efficient Products	1.91	0.31	0.17
Home Comfort	1.09	(0.15)	1.94
REAP	0.52	0.16	0.09
Home Performance	0.06	0.02	0.02
All Electric Homes	0.29	0.00	0.23
HEM	0.75	0.38	0.10
Residential	**0.96**	**0.06**	**0.57**
Overall Portfolio	**1.12**	**0.64**	**0.36**

Table A-5 presents the benefit-to-cost ratios for the SCT, UCT, and RIM tests for each program and for the overall EE portfolios without the inclusion of the income qualified spending.

Table A-5. BCA for 2024 EE Portfolio without inclusion of Income Qualified Spending

Program/Sector	SCT	UCT	RIM

Commercial Efficiency Program (CEP)	1.70	1.59	0.29
Multifamily	0.40	(0.05)	0.07
Commercial	**1.32**	**1.31**	**0.28**
Efficient Products	1.94	0.32	0.17
Home Comfort	1.14	(0.19)	2.44
Home Performance	0.11	0.04	0.04
All Electric Homes	0.29	0.00	0.23
HEM	0.79	0.40	0.10
Residential	**1.21**	**0.10**	**0.62**
Overall Portfolio	**1.26**	**0.79**	**0.36**

Table A-6 presents the benefit-to-costs ratios for the income qualified portions of the portfolio.

Table A-6. BCA for 2024 EE Portfolio – Income Qualified Programs

Program/Sector	SCT	UCT	RIM
Home Comfort	0.89	(0.09)	1.01
REAP	0.50	0.15	0.09
Home Performance	0.03	0.02	0.01
Residential	**0.43**	**0.01**	**0.41**

Table A-7 outlines the levelized costs on a MMBtu-basis for each program.

Table A-7. Levelized Cost Comparisons for 2024 EE Portfolio

Program/Sector	$/MMBtu
Commercial	$27.82
Multifamily	***$50.42***
Efficient Products	$13.27
Home Comfort	$28.53
REAP	$51.69
Home Performance	$508.55
All Electric Homes	$106.37
HEM	$24.69

Levelized cost reflects the total incentive divided by the total savings over the measure life.

A.1.4 TRC Companies Implementation

PSEG Long Island has partnered with TRC to deliver the Utility's EE and beneficial electrification programs. This partnership is governed by a master services agreement that has been effective since 2015 with Lockheed Martin, whose Distributed Energy Solutions group was acquired by TRC Companies in November 2019. TRC is a global consulting, engineering, and construction management firm that provides technology-enabled solutions to the power, oil & gas, environmental, and infrastructure markets. The scope of the master services agreement includes design and implementation of residential and commercial EE. TRC implements and manages most of the EE programs offered under the PSEG Long Island brand. PSEG Long Island retains overall planning, budgeting, and advertising functions.

Program implementation includes ongoing analysis and continuous improvement of implementation methods, market conditions, and measure mix. Implementation also includes activities such as qualifying products, qualifying projects, validating project scopes, conducting pre- and post-inspections, processing rebates, issuing payments, engaging contractors, and training stakeholders. TRC provides customer service and technical assistance, including customer consultations, design collaboration, and customer support in developing energy plans and customized engineering studies. TRC is responsible for program analytics, including pipeline, product, and results reporting. TRC works in collaboration with the PSEG Long Island's program planning and evaluation team, participating in annual program evaluation and ensuring best practices are established and followed throughout the programs. In 2024, TRC will support incremental work and efforts aimed at increased support for and development of heat pump contractors in accordance with recommendations from LIPA's UCS-44.

A.1.5 New Efficiency: New York

As part of its overall goal of reducing GHG emissions by 40% by 2030, New York set a new statewide EE target of 185 TBtu by 2025. Of the 185 TBtu goal by 2025, the New Efficiency: New York December 2018 Order established an incremental target of 31 TBtu of reduction by the State's utilities toward the achievement of the goal. Of the incremental target of 31 TBtu, LIPA was assigned a proportional share of increased EE savings of at least 3 TBtu over the 2019-2025 period, or 7.85 TBtu when combining base-level electric savings and the incremental amount established in the December 2018 Order.

Beginning with PSEG Long Island's 2020 EEDR Plan, offerings were expanded to include rebates and incentives for installing EE measures that supply beneficial electrification to the grid and allow customers to save on their fossil fuel-based costs. As such, Long Island became the first region in New York State to convert all electric savings metrics to a MMBtu basis to better conform with the New Efficiency: New York goals. Over the past several filings, PSEG Long Island's approach to reporting progress and achieving these goals was not being calculated in the same manner as the rest of the NYS electric utilities. In this year's filing, PSEG Long Island has revised its approach to calculate savings in the same way that the rest of the electric utilities in New York have reported savings. The difference is that year's reporting converts overall MWH savings to MMBTU's rather than calculating net overall MMBTU's in which heat loss resultant from the installation of light-emitting diodes (LEDs) was offset by higher fossil fuel MMBTU consumption. This effort was supported by converting the entire PSEG Long Island Technical Resource Manual to calculate MMBtu for all measures offered.

Adopting fuel-neutral savings targets allows PSEG Long Island to aggregate efficiency achievements across electricity, natural gas, and delivered fuels such as oil and propane, which requires a shift toward investments in heat pumps and other beneficial electrification opportunities. Shifting rebate and incentive opportunities to a fuel-neutral basis de-emphasizes electric (kWh) savings and, by consequence, EE savings as a percentage of overall load in pursuit of the primary target of reducing overall energy use on a TBtu basis. As PSEG Long Island and the market gain greater insights from implementing fuel-neutral programs, programs can be modified to target Btu savings rather than electric consumption or demand savings more effectively, which served as prior metrics.

A.1.6 Energy Savings Portfolio of Programs

Table A-8 lists the programs offered under this Plan that are administered by TRC and PSEG Long Island.

Table A-8. Summary of EE Programs Offered by TRC and PSEG Long Island

Programs Administered by TRC	Programs Administered by PSEG Long Island
• Energy Efficient Products (EEP) Program	• Behavioral Initiative (HEM Program)
• Home Comfort Program	• DLM Tariffs
• REAP	
• Home Performance Weatherization Program	
• All Electric Homes	
• Multifamily	
• Commercial Efficiency Program (CEP)	

A.1.7 Evaluation, Measurement, and Verification

PSEG Long Island has a third-party consulting firm to conduct annual program and portfolio evaluations of the EE programs as well as any ad hoc evaluation studies deemed necessary.

As part of the annual evaluation cycle, the third-party evaluator produces two volumes: Volumes I and II. Together, these volumes comprise the entire Annual Evaluation report. Volume I provides an overview of evaluation findings, including impact and process results for 2022. Volume II of the 2022 Annual Evaluation Report, the Program Guidance Document, provides detailed program-by-program review of gross and net impacts of the EE portfolios along with process evaluation findings and a discussion of data collection and analytic methods. The program guidance document is developed to provide PSEG Long Island and its implementation contractor, TRC, with data-driven planning actions moving forward and full transparency for the methods employed to calculate energy and demand savings. Annual evaluation reports consist of the following four overarching categories:

Verified Ex-Ante

- Independently calculate program impacts using the methods and assumptions approved by PSEG Long Island. Determine energy, demand, and environmental impacts achieved from each EE program.
- Compare the results to the ex-ante gross values submitted by the implementation contractors to determine ex-ante realization rates

Impact Evaluation

- Determine energy, demand, and environmental impacts achieved from each EE program.
- Conduct cost-effectiveness analysis for each EE program.

Process Evaluation

- Assess how efficiently a program is being implemented by evaluating the operational efficiency of program administrators and contractors.

- Gap analysis conducted to identify strengths, opportunities, and improvements in program tracking data collections necessary for savings calculations and other evaluation processes and studies.

Economic Impact Analysis

- As part of their annual evaluation efforts, the evaluation team assesses the economic impacts of the EE portfolios' investments on the economy of Long Island.
- The third-party evaluator will provide 1-year and 10-year economic impacts estimates associated with the 2022 EE portfolio investments, where the 10-year economic impacts accrue from measures installed in 2022 over their remaining measure life.

A.1.8 Coordination with National Grid

The NENY Order that codified the EE and heat pump goals for New York also allows for greater opportunities for alignment around shared goals between utilities. PSEG Long Island and KEDLI are in the process of developing a memorandum of understanding to support a more holistic and coordinated approach to deliver EE and beneficial electrification opportunities to shared customers on Long Island. As KEDLI expands their own offerings to customers, particularly around market rate residential weatherization programs, PSEG Long Island has been working with KEDLI to pursue opportunities to align the customer journey where possible. Beyond a smoother customer journey, the benefits to customers may also include the ability to provide coordinated incentives for defined measures or programs.

To date, PSEG Long Island and KEDLI have executed a Memorandum of Understanding and are finalizing a non-disclosure agreement aimed at providing for the exchange of customer information between the parties to ease coordination of efforts on common customers. Beginning in 2022, all weatherization efforts for market-rate customers heating with natural gas have been referred to KEDLI's residential weatherization program rather than treated through PSEG Long Island's HPwES program. In this coordination effort, kWh energy savings was attributed to PSEG Long Island and anonymized customer data was provided allowing for PSEG Long Island's third-party evaluation firm to evaluate claimed kWh savings. Results for 2022 found that actual kWh savings per customer were lower than planned for and KEDLI and PSEG Long Island have been meeting in 2023 to identify strategies which might be able to be introduced in KEDLI's weatherization program to increase kWh savings.

Additionally, beginning in latter 2022 and continuing in 2023, KEDLI and PSEG Long Island met to discuss strategies to increase coordination on Commercial weatherization as well as low-income offerings. On Commercial weatherization it will not be as easy as it was in the residential sector to refer gas heat customers to KEDLI due to greater breadth of the offerings in PSEG Long Island's Commercial Efficiency Program (CEP), especially for larger customers where more than weatherization is generally undertaken in a more comprehensive project. Instead, beginning to coordinate joint KEDLI and PSEG Long Island meetings with the customer where a comprehensive view of the project can be understood by all, and program offerings coordinated seems to be the more likely pathway. PSEG Long Island expects more opportunities for this coordination to be organized during the second half of 2023.

Lastly, PSEG Long Island and KEDLI have been discussing opportunities for increased coordination on income eligible programs (KEDLI – HEAT and AMEEP, PSEG Long Island (REAP, Assisted Home Performance, Assisted Home Comfort, MultiFamily). These discussions are expected to continue throughout 2023. This may be the most challenging effort to coordinate. There are numerous income qualified programs, and the intensity and offerings differ between the two companies. Additionally, the programs rely upon third party implementation contractors who are presently in the middle of contract terms. Due to the complexity of issues to be addressed, PSEG Long Island expects that initial efforts may be focused on coordinating messaging and referrals while discussions continue whether an integrated offering might be possible at some future point.

A.1.9 Marketing and Outreach

PSEG Long Island markets and advertises its EE programs with the goal of increasing:

- Awareness about the programs offered by PSEG Long Island.
- Participation in PSEG Long Island's EE programs.
- Customer satisfaction, ultimately leading to driving up J.D. Power scores.

Research by J.D. Power suggests that customers who are aware and participate in PSEG Long Island's programs tend to trust and think of the Utility more favorably. As part of its strategy to increase awareness of the Utility's EE programs, PSEG Long Island uses J.D. Power and its own demographic data to target media messaging through select channels aimed specifically at demographic segments including:

- Mass media (print, radio, TV)
- Tactical (emails, direct mails, newsletters)
- Targeted (digital, social media, Online Energy Analyzer)

These combined tactics help transmit a broad message about EE but also communicate the benefits of EE to niche sectors of the audience, such as age, income level, homeowner versus renter, and those more inclined to embrace green technology.

PSEG Long Island continues to push the message of "save energy and money." Research conducted by PSEG Long Island indicated that customers want to hear from them most about how to save energy and money on their bill. Explaining to them that they have a choice when it comes to lowering their bill makes customer opinions toward PSEG Long Island more favorable.

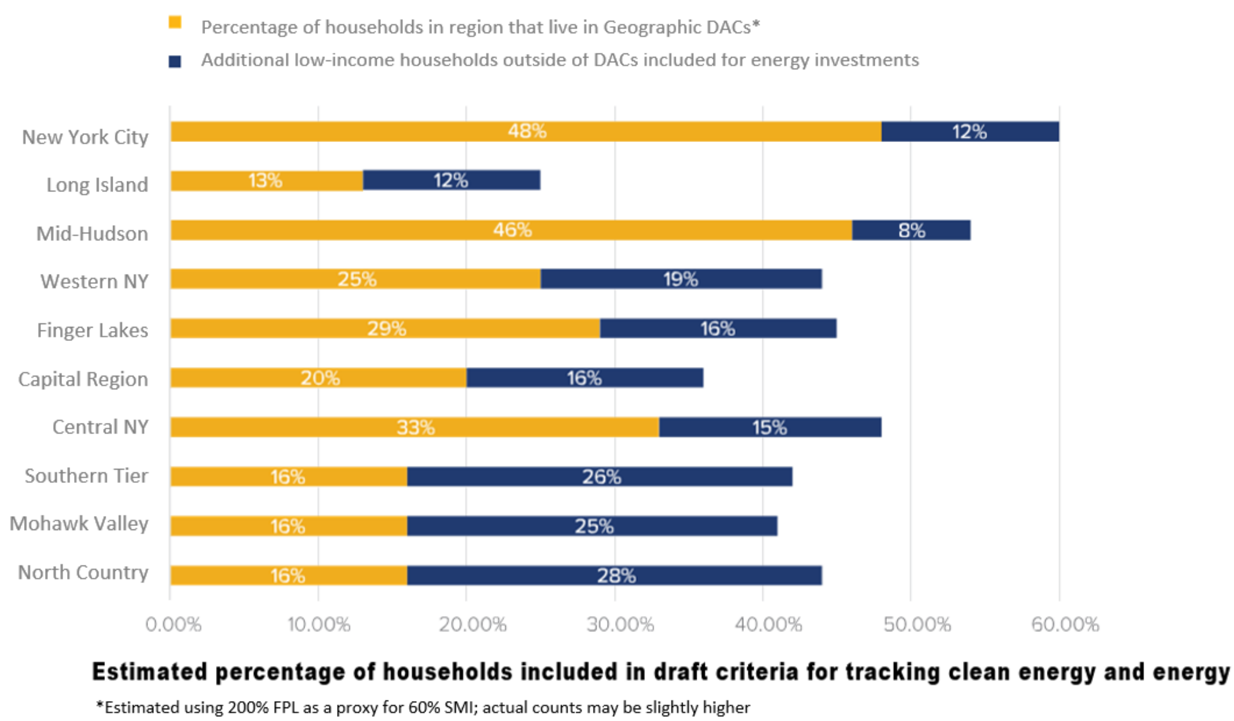
PSEG Long Island believes the right media mix and frequency is important to enforce the message of EE. To reach households in Nassau, Suffolk, and the Rockaways, a mix of TV, radio, newsprint, digital banners, and occasional billboards on trains and buses are used. This mix ensures that a broad audience is being reached. When it comes to marketing actual programs such as Home Comfort, Geothermal, or Home Performance, PSEG Long Island uses a more tactical approach with targeted emails, direct mail, and digital ads.
Efforts promoting EE continue to achieve positive results. Customers who are aware of EE programs/services rank PSEG Long Island 111 points higher in the J.D. Power. Over the last 10years, PSEG Long Island has successfully implemented multiple campaigns into the market on the Home Comfort (formerly Cool Homes) and Geothermal programs, as well as overall EE awareness. So far in 2023, the EE paid advertising campaign has delivered nearly 30,000,000 impressions across social media, digital display, SEM, Out Of Home, door hangers, and connected TV. We've executed 41 unique deliverables to drive awareness of general EE rebates, heat pump rebates, smart thermostat rebates, Google Nest Thermostat rebates, home energy assessments, and the MySmartEnergy portal.

A.1.10 Disadvantaged Communities[87]

PSEG Long Island is formulating a plan in consultation with its strategic marketing and advertising agency to support the state's goal of delivering at least 35% of EE benefits to residential and business customers in DACs or in income-qualified households. While the benefits accruing to DACs are expected to be economy-wide investments that are broader in scope than just clean energy and EE programs, this Appendix is primarily concerned with the EE benefits. This Plan focuses on the delivery of EE and beneficial electrification to DAC and LMI customers. While the Climate Act DAC taskforce voted to accept criteria on March 27,2023, presently, reporting on the DAC effort is based upon expenditures as opposed to benefits, which are yet to be determined. Final fact sheets are expected to be issued by the Climate Act task force subsequent to this filing, resulting in lack of explicit details included in the filing. Additionally, PSEG Long Island has not yet been able to confirm whether statewide goal of 35% of spending will be allotted to all electric utility service territories at the singular 35% level or if it may be modified based upon the DAC qualified percentage of census tracts within each service territory.

PSEG Long Island will be the most challenged of any New York State utility in reaching a 35% goal based upon the initial analysis released by the Climate Act task force (see Figure A- 2). As can be seen, PSEG Long Island's meeting the DAC and LMI criteria totaled 25% whereas the rest of utilities spanned between 36% - 60%.

Figure A-2. Percentage of census tracts in each region designated a draft DAC[88]



[87] See additional detail regarding LMI targeting in "Delivering Benefits to Disadvantaged Communities" on page xii of this docuement

[88] New York States Draft Disadvantaged Communities Criteria, 5/22, https://climate.ny.gov/-/media/Project/Climate/Files/Disadvantaged-Communities-Criteria/Technical-Documentation-on-Disadvantaged-Community-Criteria.pdf

The onboarding of ICF Next in 2021 as the utility's agency of record affords new options in promoting EE. In addition to the mass media advertising that PSEG Long Island uses to communicate the multiple benefits of its EE programs across Long Island and the Rockaways, in 2024 the plan will be to utilize ICF's Sightline analytical tool.

Sightline is a centralized customer intelligence platform that provides customer data enrichment and segmentation, advanced energy use analytics and propensity modeling, identification of critical customer groups for ongoing customer research and message testing.

These insights can maximize efficient marketing and outreach to DACs. Communications may take the form of emails, digital channels, and social media and targeted print ads. In addition, PSEG Long Island will look for opportunities to create Spanish ads in those communities identified with a large Hispanic population.

The effectiveness of the campaigns will be monitored, measured, and optimized by engagements such as site traffic, sales, EE conversions and any other KPIs that are established to help us meet goal.

In addition to marketing and advertising, communications, public affairs, and PSEG Long Island's business customer advocates will also help in the ongoing outreach and awareness of the Utility's EE programs.

PSEG Long Island is presently developing the capability to report upon customer program participation by census tract and expects to have that capability during the 3rd quarter of 2023. In the development of this capability, the Utility is also focusing on how to easily identify customers by census in order to support more specific identification of DAC customers prospectively in addition to the required DAC reporting retrospectively. Once PSEG Long Island has the ability to determine existing DAC customer participation in its non-income qualified program offerings, work will begin to ensure that overall, 2024 DAC customer program participation is in line with the target established for the Long Island electric service territory.

A.2 Products and Programs

The following sections provide details on the programs that are being offered in 2024. Each section includes an outline of the program delivery channels, the target market, and the list of measures and incentives. Where applicable, details on outreach efforts and the cost-effectiveness of the program are also provided.

A.2.1 Energy Efficiency Products

The objective of the Energy Efficiency Products (EEP) program is to increase the purchase and use of energy efficient appliances, beneficial electrification equipment, and lighting among PSEG Long Island residential customers. The EEP strives for market transformation, increasing the market penetration of efficient products primarily by financially incentivizing consumers. These rebates and incentives are distributed either through direct consumer rebates in a downstream program or to manufacturers or retailers in up-stream/mid-stream models. The loss of lighting savings due to the finalization of the EISA of 2007 greatly decreased associated program savings for not only PSEG Long Island, but for EE administrators across the county and the industry has acknowledged acknowledges that at this time, there is no new measure that can replace this savings at the scale and cost it represented.

The program provides rebates or incentives for energy efficient measures like ENERGY STAR-certified linear LED lighting, ENERGY STAR appliances, heat pump pool heaters, advanced power strips, and water heating equipment. Rebates and incentives are offered through upstream and downstream promotions. ENERGY STAR certified products meet the EE standards set by the US Environmental Protection Agency (EPA) and US Department of Energy (DOE). ENERGY STAR provides the program an independent third-party review and vetting of measures. As ENERGY STAR specifications change, PSEG Long Island adjusts its program offerings to remain in alignment, ensuring that program offerings meet the latest efficiency standards. In 2023, in recognition of the Energy Independence and Security Act (EISA) lighting standards, ENERGY STAR LED common lamps and specialty lamps were only incentivized for the first six months of 2023. ENERGY STAR Linear LED fixtures will be rebated in 2024. The rebate and promotion of battery-operated lawn care equipment was also phased out in 2023 and will not be re-introduced in 2024.

In addition to financial incentives, the program educates customers about the benefits of using energy efficient products and beneficial electrification equipment in their homes and outdoor spaces through a variety of marketing channels. The PSEG Long Island EEP program supports the stocking, sale, and promotion of efficient residential products at retail locations within its service territory. To support New York State's GHG reduction goals, PSEG Long Island's metrics shifted to MMBTU reduction. Resultantly, in 2020 the EEP began promoting and incentivizing beneficial electrification equipment, along with the more traditional electric energy saving ENERGY STAR offerings. The program uses a variety of mechanisms, most notably financial incentives, to increase the market penetration of these energy efficient products and beneficial electrification equipment in their homes. These incentives are distributed either through direct consumer rebates or up-stream/mid-stream incentives paid directly to manufacturers or retailers.

PSEG Long Island reviews and adjusts EEP program offerings to maximize customer engagement, incorporate new technologies trending in the industry, and to retire other measures from the portfolio when the market is saturated.

A.2.1.1 Program Delivery

The EEP program is delivered through partnerships between TRC, subcontractors, retailers, distributors/installers, and product manufacturers. Customers who purchase qualifying ENERGY STAR appliances and beneficial electrification equipment are eligible for rebates or point-of-sale incentives.

Upstream Incentives

Upstream incentives are payments to manufacturers or retailers to stock, promote, and sell ENERGY STAR-certified linear lighting products. PSEG Long Island is able to buy-down the wholesale price rather than the retail product price by directing the incentive to the retailer or manufacturer. This typically results in a greater reduction of the retail price. Retailer and manufacturer reimbursement is based on the submission and verification of sales data.

Markdowns focus on working directly with manufacturers and retailers to reduce the final retail price of specified products. A markdown is structured to provide a participating retailer a per-unit incentive for all sales of a particular product sold during a specified period.

In order to implement an upstream program, Program Agreements (PA) are required between appropriate parties, including the retailers and manufacturers. Several program agreements have been negotiated with lighting manufacturers and retailers to support the EEP. PA's provide a budget cap and number of products to be sold during a specified period. For each upstream promotion a PA is established that identifies:

- Model numbers and quantity of products to be promoted

- PSEG Long Island per-unit incentive
- Total allocated funding for the promotion
- Retail price for each specific product model during the promotional period
- Promotion duration including start and end dates
- Location of each retail store participating in the promotion
- Sales data reporting requirements
- Frequency of sales data submissions
- Marketing requirements, e.g., placement of PSEG Long Island-branded point of purchase (POP) materials

Processing Upstream Incentives
TRC's subcontractor partner is responsible for the following upstream rebate processing procedures:

- Obtaining point-of-sale (POS) data from retailers to confirm appropriate measures were incentivized and to track quantities, etc.
- Maintaining a database that can track sales data. Data must include fields like product name, store/retailer, date/time, promotional PA numbers, manufacturer. Data must be exportable to reports.
- Ensuring that incentives are paid only for eligible products sold through participating stores during an active promotional period
- Standardizing various sales reports supplied by different industry partners and into a central program database and, after reviewing and subjecting inputted data to various quality assurance checks, distribute funds to industry partners
- Issue incentive payment to manufacturers and retailers
- Payments are issued twice a month
- Host an online catalog or marketplace where customers can purchase energy efficient products through the PSEG Long Island website

Twice monthly sales data is communicated to the EEP team who validates that the sales data accurately reflects program participation and requirements. On validation, the subcontractor is paid the sum of incentives.

Downstream Rebates

Downstream rebates are payments paid to end-use customers who purchased qualifying equipment and applied for a rebate. TRC processes all rebates but engages with an Implementation Contractor to support the program by developing marketing collateral and promotions and establishing relationships and engaging with a large number of retailers to support the program. That engagement includes providing training to retailer and distributor sales staff on program participation and product eligibility, providing staffing for instore promotions and seeking opportunities for upstream promotion.

Processing Online Application and Mail-In Rebates
TRC provides a user-friendly Online Application (OLA) portal that allows customers to complete their rebate applications in a digital format. The OLA is integrated with the ENERGY STAR Qualified Product List which validates product eligibility that the customer is applying for. The OLA is also integrated with the Captures database which allows for the instant verification of a customer's CIS account number. After customer submittal of the OLA, the OLA migrates directly to Captures for review by the TRC processing team.

Under the umbrella of the EEP program, PSEG Long Island offers an Appliance Recycling program that is planned to continue through 2025. The goal of the program is to promote the removal of older, but operable and in use, inefficient appliances from the customer home/business. The program provides checks to residential and commercial customers who participate in the refrigerator/freezer recycling program, and vouchers for customers who participate in the dehumidifier recycling program. Vouchers can be used on the PSEG Long Island marketplace (Online Energy Efficient Products Catalog). The EEP program engages an appliance recycling subcontractor who is responsible for the removal and proper disposal of the recycled equipment.

Customers receive a $50 incentive for each refrigerator or freezer recycled. Customers can also earn an additional $35 voucher per unit for recycling up to three working room dehumidifiers in conjunction with a qualifying refrigerator or freezer pickup.

On behalf of PSEG Long Island, TRC subcontracts appliance recycling. Subcontractors have been vetted to ensure that they have experience providing the services offered and responsibly disposing of the appliances. Responsibilities include:

- Scheduling pickups from customer homes or businesses
- Verifying appliance qualifies for program
- Appliance removal from customer homes or businesses
- Rebate processing and payment (check/voucher)
- Program tracking and reporting against goals
- Identifying opportunities for improvement

The Program Manager engages the subcontractor to develop innovative and creative marketing strategies and materials. Marketing may include, but not be limited to, mailers, bill inserts, direct mail, e-blasts, flyers, website, print ads, and giveaway promotions.

The EEP model described above is intended to remain in place through 2025.

A.2.1.2 Target Market

All PSEG Long Island residential customers.

A.2.1.3 Measures and Incentives

Table A-9 lists the measures offered in the EEP program. Pool pumps will no longer be incentivized beginning in 2022 because of new DOE regulations that will go into effect in 2021. Battery operated lawn equipment was removed from the 2023 program year plan due to feedback from the DPS. Specialty and Standard LED Lighting were phased out in June of 2023 as a result of the updates to the Energy Independence and Security Act (EISA). The DOE ruling goes went effect in June 2023. ENERGY STAR Linear LED lighting is not impacted by the EISA standard and is included in the 2024 plan.

Table A-9. EEP: List of Measures

Measure	2024 Planned Units	Measure Incentives	Measure Rebates
Advanced Power Strips (Tier II)	300	$25	-
Most Efficient Clothes Washers	2,300	-	$50
Heat Pump Water Heater $\leq$ 55 gallons	300	$100	$1,000

Measure	2024 Planned Units	Measure Incentives	Measure Rebates
Heat Pump Water Heater > 55 gallons	200	$100	$1,000
ES Dehumidifiers – Mid-stream	13,000	$30	-
ES Room Air Purifiers (<150 CADR) - Upstream	2,000	$30	-
ES Room Air Purifiers (>150 CADR) - Upstream	1,800	$40	-
ES Dryer - Electric Resistance	2,500	-	$25
Advanced Power Strips (Tier I) - Mid-stream/Upstream	1,600	$15	-
Most Efficient Dryers- Heat Pumps	60	$50	-
Smart Thermostats - Connected (Wi-Fi Enabled)- Mid-stream	8,000	-	$70
Smart Thermostats - Learning – Mid-stream	6,000	-	$100
Heat Pump Pool Heaters	1,200	$100	$1,000
LED Linear Fixtures – Mid-stream	120,000	$6	-
Dehumidifier Recycle	190		$35
Refrigerator & Freezer Recycle Post 2001 & Pre 2014	2,000		$50
Refrigerator & Freezer Recycle Pre 2001	500		$50

A.2.1.4 Outreach

The EEP program for PSEG Long Island employs a variety of outreach strategies to ensure that customers are aware of the rebates/incentives available for ENERGY STAR appliances and beneficial electrification equipment and provides informative collateral on them. Strategies include broad brush and marketing via:

- Limited-time offer e-blast promotions
- Bill inserts
- Digital display ads
- Social media posts
- Point-of-purchase material at retailers
- Online Application
- PSEG Long Island website
- Online Marketplace

In addition, the program employs in-person outreach strategies including:

- Food Bank events
- In-store presentations
- Community partner outreach events
- Home shows in Nassau and Suffolk counties

These outreach strategies have proven effective in engaging and educating customers on the benefits of adopting ENERGY STAR and beneficial electrification products and they are planned to continue through 2025. Understanding the importance of digital transformation, the EEP program intends to increase social media presence to engage customers and promote the program.

Throughout the 2023 program year, the EEP program coordinated with several Food Banks to provide LED Bulbs to customers in need. 4-Pack LED bulbs were given to LMI customers, along with literature about PSEG Long Island's REAP. Since this initiative supports the low-income community and low-income program awareness, PSEG Long Island continued the initiative after June 2023, due to the positive impacts on the low-income community. This was the only exception the EEP Program made in relation to the June 2023 EISA update. In 2024, PSEG Long Island will continue to engage with Food Banks to provide program materials.

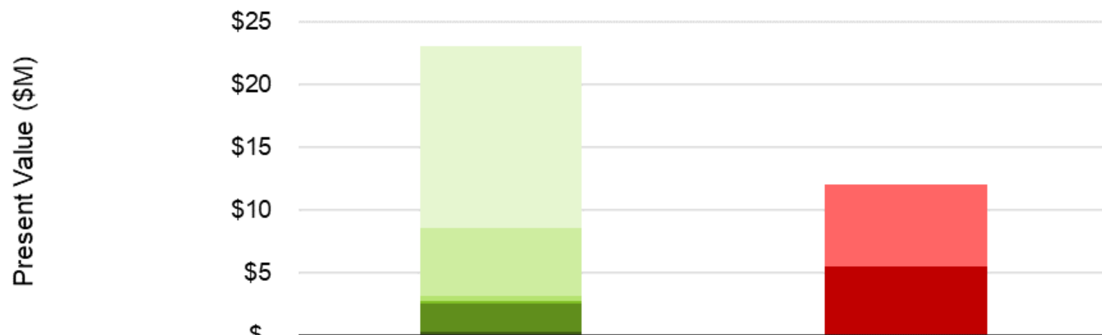
The TRC Program Manager works with the appliance recycling subcontractor to develop marketing collateral. The program uses palm cards to promote the program. They contain program details for TRC to distribute to customers at all public events and through other residential programs, such as REAP and Home Performance.

TRC and PSEG Long Island collaborate on social media posts and postcard mailings that educate the customer on proper recycling methods. TRC may also launch giveaway promotions to effectively increase participation.

A.2.1.5 Business Case

The EEP program has a SCT benefit-to-cost ratio of 1.91 and RIM benefit-to-cost ratio of 0.17. A list of the value streams considered in the BCA is detailed in Figure A-3 and Table A-10.

Figure A-3. Energy Efficiency Products Present Value Benefits and Costs of SCT



	Benefit	Cost
Fuel Switching Benefits	14.36	-
Net Avoided SO2 and NOx	0.000166	-
Net Avoided CO2	5.44	-
Avoided Distribution Capacity Infrastructure	0.41	-
Avoided Transmission Capacity Infrastructure	0.17	-
Avoided Energy (LBMP)	2.26	-
Avoided Generation Capacity Cost (AGCC)	0.36	-
Participant DER Cost	-	6.47
Program Administration Costs	-	5.55
Total	22.99	12.02

Table A-10. Energy Efficiency Products Value Streams

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
1	**Fuel Switching Benefits**	Considers participant fuel cost savings associated with switching from oil, gas, and propane to electricity.	14.36	
2	**Net Avoided SO_2 and NOx**	Reduced SO_2 and NOx from reduced energy consumption.	0.000166	
3	**Net Avoided CO_2**	Reduced carbon emissions from reduced energy consumption and beneficial electrification.	5.44	
4	**Avoided Distribution Capacity Infrastructure**	Based on demand savings and marginal distribution capacity cost.	0.41	
5	**Avoided Transmission Capacity Infrastructure**	Based on demand savings and marginal transmission capacity cost.	0.17	
6	**Avoided Energy (LBMP)**	Energy savings based on both on-peak and off-peak periods.	2.26	
7	**Avoided Generation Capacity Cost (AGCC)**	Based on demand savings and marginal capacity cost.	0.36	
8	**Participant DER Cost**	Includes cost of incremental equipment and installation.		6.47
9	**Program Administration Costs**	Includes contractors fee, labor, evaluation, and advertising costs.		5.55
	Total Benefits		**22.99**	
	Total Costs			**12.02**
	SCT Ratio		**1.91**	

A.2.2 Residential Home Comfort Program

PSEG Long Island's Home Comfort Residential Heating and Cooling Program provides PSEG Long Island residential customers rebates for the purchase and installation of efficient and clean Air Source Heat Pumps (ASHP). ASHPs are typically two to three times more efficient than traditional fossil fuel space heating. The Home Comfort Program rebates efficient cold climate and non-cold climate ducted and ductless systems. In addition, the program offers rebates for system controls to ensure the ASHP is operating as the primary heating source.

Since 2019, the Home Comfort program has evolved each year to align more closely with New York State's aggressive GHG reduction goals, found in the Climate Act. The Climate Act calls for an 85% reduction of GHG emissions by 2050. In the spring of 2019, PSEG Long Island rebranded the Cool Homes program to the Home Comfort program. The rebranding of the program was coincident with shifting the focus from cooling systems, like central air conditioning systems, to ASHPs and the proper use of them as a combined primary heating and cooling system. To promote ASHP technology, the Home Comfort Program launched an ASHP Pilot program that targeted electric resistance heating communities. The pilot boasted impressive engagement and installation results and laid the foundation for the Whole

House ASHP offering, which hit the market in 2020. The whole house rebate offering was available to new construction customers and customers with existing fossil fuel heating systems. In 2020, central air conditioning systems were removed from the Home Comfort program offering. This program change increased the promotion of whole house and partial house ASHP solutions and better aligned the Home Comfort program with New York State's goals.

On March 7, 2023, LIPA issued the UCS-44 Next Level Heat Pump Deployment Final Report – Barriers and Actions, which sought to identify current barriers and obstacles which would need to be overcome in order for Long Island to reach its share of New York State goals for transforming heating from fossil fuels to heat pumps by 2030. PSEG Long Island is currently working with LIPA and its consultants on the development of new and innovative tactics to address these barriers. Current efforts are focused on customer tools, outreach and broader manufacturer, distributor and contractor engagement and interaction in the Long Island marketplace and are expected to result in an iterative learning and refinement of the program. Additionally, in the ensuing year, PSEG Long Island, LIPA and its consultants are expecting to develop a broader roadmap with additional initiatives aimed at setting forth a comprehensive approach to addressing all barriers. In support of these expected efforts, there is an incremental $1 million earmarked in the Home Comfort budget to provide for undertaking these efforts.

A whole house installation occurs when a customer sizes the ASHP to meet the heating and cooling needs of their entire home. A partial house installation occurs when a customer sizes the ASHP to meet a portion of the heating and cooling needs of their home. Customers with existing fossil-fuel heating who participate in the whole house offering are permitted to keep the existing system as a secondary heating source. To ensure the ASHP is the primary heating source, the Home Comfort program rebates, and requires, the installation of integrated controls. Integrated controls connect to both the ASHP and fossil fuel system and are programmed to default to the ASHP unless the temperature dips below a certain temperature, causing engagement of the fossil fuel heating system. Except for customers replacing electric resistance or an old heat pump, all other heat pumps are expected to provide fuel switching benefits to customers.

The Home Comfort program provides a participation pathway for all customers by offering market-rate and income eligible rebates for holistic energy efficient whole house solutions and partial house solutions. In April 2021, PSEG Long Island began promoting a new component of the Home Comfort program called "Home Comfort Plus". The Home Comfort Plus program provides income eligible customers with enhanced rebates intended to cover a generous portion of a Whole House cold climate heat pump installation. To ease the path to participation for the public, the Home Comfort/Home Comfort Plus and HPwES weatherization program are offered in one application. Customers can participate in Home Comfort, HPwES or both programs at once. For low to moderate income participants, there is an enhanced rebate offer. Enhanced rebates are available for income eligible customers who install whole-house heat pumps and weatherization measures.

From initial program inception, and legacy Cool Homes program, the Home Comfort team has worked directly with partners, distributors, and manufacturers to educate and train them on program offerings and requirements. This level of engagement and collaboration ensures that all customers who interact with a member of the Home Comfort team or a trusted partner are educated on the benefits of ASHP technology and have the support to make energy efficient decisions for their home and family. ASHP technology can provide clean heating and cooling in a customer's home for 10-25 years. Because of this, it is critical for members of the Home Comfort team and the partners to positively influence the customer on the benefits of program participation. PSEG Long Island works with Energy Finance Solutions (EFS) to qualify income eligible customers. Income verification documents like letters from the Home Energy Assistance Program (HEAP) or Social Security will continue to be accepted. EFS also offers low-interest on-bill recovery loans and smart energy loans for qualified market-rate and income eligible customers.

In 2024-2025, to continue supporting New York State initiatives, the Home Comfort program will update program requirements to remain in alignment with the state and NYSERDA. As the requirements around heat pumps are rapidly evolving as the market adjusts, rebate values, contractor incentives, and program guidelines will be re-evaluated quarterly to ensure offerings remain engaging and promote state objectives and program participation.

A.2.2.1 Notable Changes

In 2024, the Home Comfort application continues to offer rebates for a number of measures that support holistic whole house solutions. Measures in the Home Comfort application include, Whole House Cold Climate Air Source Heat Pumps, Smart Thermostats and Controls, Weatherization (Air Sealing, Duct Sealing, Insulation), Tune-Ups, and Heat Pump Water Heaters. Historically, measures like Heat Pump Water Heaters were rebated through the EEP Program. To promote a seamless participation process, they were added to the Home Comfort application to allow the Home Comfort partner and participant to consider a whole-house solution. To further promote a holistic whole-house solution, rebates for windows will become available in 2024. Participants who install a Whole House Cold Climate Air Source Heat Pump, Insulation, and Air Sealing, will be eligible to participate in the windows offering. Income eligible rebates are available for Whole House Cold Climate Heat Pumps, Weatherization, Controls, Heat Pump Water Heaters, and Windows.

In May of 2022, to further streamline participation, the Home Comfort program re-evaluated existing rebates for both market and income eligible customers, as well as equipment eligibility requirements. As a part of the evaluation process, the Home Comfort team also met with high volume participating contractors to understand the current market. As a result, the Home Comfort/Home Comfort Plus offering was updated as follows:

- To allow more cold climate models to be eligible for the program, the Home Comfort program aligned efficiency requirements with NEEP
- To standardize the customer experience, equipment categories and rebates were reduced to one category for Market customers and one category for income eligible customers
- Rebates were also increased for both categories to stimulate the market
- Additional program funds, outside of the Home Comfort budget, allowed for a generous increase to the Income Eligible rebate
- All Non-Cold Climate Equipment was removed from the application to promote holistic whole house cold climate air source heat pump solutions
- Non-cold climate equipment is available for rebate through the Residential Online Application

In 2024, similar to 2023, the Home Comfort program will continue to engage the market through a robust Whole House Cold Climate Air Source Heat Pump Program. To align with New York State's heat pump goals, the 2024 Whole House Cold Climate Air Source Heat Pump planned unit count is approximately 89% higher than the 2023 planned unit count. The number of Whole House Cold Climate Air Source Heat Pumps increased by 211% for Income Eligible units and 69% for non-Income Eligible units. The Whole House Cold Climate Air Source Heat Pump unit count in the 2023 Plan was 1,436 units. The Whole House Cold Climate Air Source Heat Pump unit count in the 2024 Plan is 2,710 units.

All rebates continue to be based on the heating capacity of the equipment and calculated based on the 17°F rated heating capacity. Integrated controls continue to be required for all whole house and partial house cold climate systems where supplemental fossil fuel heating exists. The requirement for Manual J load calculations also remains constant with previous years and includes partial house cold climate ASHPs. A Manual J is required to ensure all equipment is properly sized for the home. These additional program requirements were included to better align the Home Comfort program with the rest of New York State.

An Equipment Only offering was launched in 2021 and continues to be available in 2024. TRC built a digital Equipment Only participation method through the already established Residential Online Application. Customers who wish to use a non-participating Home Comfort partner or who installed their own equipment, can apply for system rebates once every 5 years, for eligible non-cold climate ductless mini-split ASHPs and ducted ASHPs. The ducted ASHPs offering was added in May 2022. Through this equipment-only style offering, customers are not required to install smart thermostats, integrated controls, or provide a Manual J. The customer must provide an invoice and an AHRI certificate.

The Home Comfort program's income eligible offering continues to be available in 2024. Eligible customers can receive enhanced rebates for installing whole house cold climate ASHPs and weatherization measures. In April 2021, the program launched the Home Comfort Plus component of the low-income ASHP offering when it received $4.5M of one-time incremental funding from the New York Attorney General's office to be dedicated for income eligible customers installing whole house cold climate heat pumps. While the initial offering saw some uptake, it was found that the goal of providing for 80% of the cost for the heat pump was often not being met due to other incremental costs which were being identified once the contractor was on site (electric panel and service upgrades, duct work, etc. In recognition of this issue and in consultation with the Attorney General office, in May of 2022, this offering was further enhanced to provide even larger rebates to cover 70%-100% of the total project costs. To accommodate this robust offering, the Home Comfort program enrolled additional Home Comfort Plus Partners to engage with the income eligible community. In February of 2023, the $4.5M in AG funding was exhausted, therefore rebates were decreased to ensure an income eligible offering would still be available for the remainder of 2023 and into the 2024 program year. However, for 2024 the rebate for income eligible customers is proposed to be restructured from the current offering of $2,000 per ton, to a declining rebate which starts at $4,000 for the first ton and then declines by $1,000 for each incremental ton until such time that it equals the standard program offering of $1,000 per ton. Based upon analysis, for the average income eligible customer whose system need is 3.6 tons, the effective rebate will be approximately $2,700/ton.

As in previous years, income eligibility will continue to be based on 60% of the State Median Income. Extending into subsequent years, PSEG Long Island plans to increase the adoption of heat pumps (along with home performance projects) in the single-family residential sector by establishing a partnership with Sealed, a New York-based company that finances key home improvements using the money homeowners currently waste on energy. For more details on the Sealed Partnership, see Section A.2.4.1.

A.2.2.2 Program Delivery

Home Comfort program participation is primarily driven through partnerships with installation contractors who, with vetting and training, become Home Comfort partners. Home Comfort partners promote the benefits of participation in the Home Comfort program and have positively impacted the ASHP market by adhering to PSEG Long Island's quality installation verification (QIV) of ASHP equipment. Home Comfort partners are given the opportunity to collaborate with the Home Comfort team and receive education and training on program requirements regularly. TRC also hosts weekly contractor meetings, in-person and virtual, to assist partners with all aspects of program participation through initial application review, equipment review, and technical requirements.

To further assist and engage with partners, PSEG Long Island provides Home Comfort partners with incentives to offset costs associated with equipment testing, like Manual J Load Calculation software.

Providing incentives for equipment like software ensures partners will properly perform QIV installations and continue to participate in the Home Comfort program.

A Manual J is necessary for a QIV installation. Contractors perform Manual J calculations to ensure appropriately sized energy efficient units are installed. In addition to right-sizing equipment, the Home Comfort partners will ensure that the refrigerant charge and airflow are checked using prescribed tests. In 2024-2025, all heat pump projects will require installation by a QIV Home Comfort partner, with the exception of the equipment only offering.

Geothermal heat pumps are a component of the Home Comfort Program; however, geothermal projects are completed on the standalone Geothermal Rebate Application. The standalone application accommodates both Residential and Commercial projects. This is because most often, geothermal market partners service both residential and commercial customers. Rebate levels and contractor incentives are the same for both project types, but savings are driven by the selection of a residential or commercial installation. When an application is received, the customer type is validated by rate code and a site inspection. In 2021, geothermal water heating was added to the program offering. This allows a customer to install a whole house or whole site geothermal space heating and water heating system solution.

In May of 2022, like Home Comfort, the Geothermal rebate offering was also re-evaluated. The program launched an income eligible offering to reach those qualified customers who wish to pursue a Geothermal heat pump installation. The offering continues to be available in 2024, with the addition of an income eligible geothermal water heating offering.

A.2.2.3 Target Market

The Home Comfort program, inclusive of Geothermal, is offered to all residential customers in the PSEG Long Island service territory. Enhanced LMI rebates are offered to all eligible customers.

A.2.2.4 Measures and Incentives

A list of measures that are offered in the Residential Home Comfort program is included in Table A-11.

Table A-11. Residential Home Comfort Program: List of Measures

Measure	2024 Planned Units	Measure Incentives	Measure Rebates
Smart Thermostats - Learning - ASHP	100	-	$100
Smart Thermostats (Connected WI-FI enabled) – ASHP	30	-	$70
Integrated Controls	1,750	-	$500
Integrated Controls - LMI	550	-	$750
ASHP Tune Up	25	-	$50
CAC Tune Up	25	-	$40
ccASHP (QI) – Whole House Electric Baseline	25	$500	$2,544
ccASHP (QI) – Whole House Electric Baseline (LMI)	8	$500	$6,870
ccASHP (QI) – Whole House Fossil Fuel Baseline	2,000	$500	$2,544
ccASHP (QI) – Whole House Fossil Fuel Baseline (LMI)	600	$500	$6,870

Measure	2024 Planned Units	Measure Incentives	Measure Rebates
ccASHP (QI) – Whole House New Construction	75	$500	$2,544
ccASHP (QI) – Whole House New Construction LMI	2	$500	$6,870
Ducted ccASHP (QI) – Partial House	75	$250	$555
Ductless ccASHP (QI) - Partial House	1,000	$250	$360
Ductless ASHP – Equipment Only ≥18 SEER & ≥8.5 HSPF	500	-	$150
GSHP De-Superheaters	20	-	$250
GSHP Tier I	15	$200	$3,000
GSHP Tier II	150	$200	$6,000
GSHP Tier I LMI	5	$200	$6,000
GSHP Tier II LMI	20	$200	$12,000
GSHP Water Heater	15	-	$1,000
GSHP Water Heater LMI	3	-	$1,500
Heat Pump Water Heater ≤ 55 Gallons	60	$100	$1,000
Heat Pump Water Heater > 55 Gallons	40	$100	$1,000
Heat Pump Water Heater ≤ 55 Gallons LMI	10	$100	$1,500
Heat Pump Water Heater > 55 Gallons LMI	6	$100	$1,500
Tankless Water Heater <12 kW	10	$60	$100
Tankless Water Heater >12 kW	10	$100	$300

A.2.2.5 Outreach

The Home Comfort program outreach strategy, aside from contractor word of mouth, includes a variety of public platforms:

- Internet keyword searches
- Banners on high traffic webpages, such as Newsday.com, Facebook.com, etc.
- Radio advertisements
- Newspaper advertisements
- Industry networking events and speaking engagements, such as AIA Peconic, AIA Long Island, Passive House New York
- Partnering with New York State's Clean Heat marketing and advertising
- Promotion on the PSEG Long Island webpage

The Home Comfort team will continue to implement the above listed outreach strategies to promote the installation of efficient heat pumps and leverage success to expand existing strategies.

Beginning in 2023, and extending through 2025, the Home Comfort team will launch several new outreach strategies aimed at increasing the number of heat pump installations in the PSEG Long Island territory. The outreach strategies include, but are not limited to, the below opportunities:

- Survey existing Home Comfort Partners on program implementation, tools, partner list on website

- Provide education and training opportunities on emerging technologies, tools, and program initiatives
- Engage with prominent heat pump manufacturers and distributors to discuss pathway to increased heat pump installations and participation mechanisms
- Host round-table supply chain meetings with Home Comfort Partners
- Host Heat Pump and emerging technology Expo/mini-conference
- Develop “Case Studies” for website publication to highlight unique projects
- Develop “Case Studies” for website publication to highlight high-performing Home Comfort Partners
- Conduct post-installation customer surveys
- Survey results to be used for Home Comfort Partner Case Study selection
- Collaborate with NYSERDA and the Long Island Clean Energy Hub to develop training, heat pump promotion, and workforce development initiatives, which are currently not available on Long Island
- Launch “Pilot” opportunities for emerging technologies like air to water heat pumps

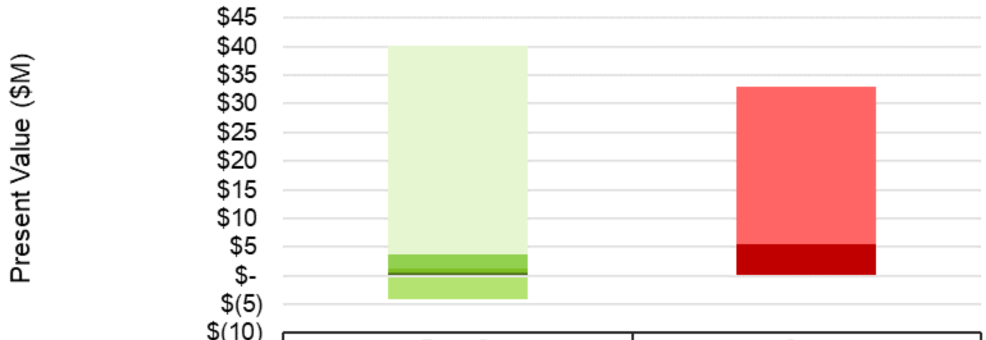
Additionally, an incremental $300,000 of funding has been requested in the 2024 to further support outreach and marketing for the Home Comfort program. The dollars would help support such initiatives such as ICF’s Sightline propensity and analytics tool, enhancements to the PSEG Long Island Home Comfort website including the creation of a contractor look up site on the PSEGLINY.com website, and assistance with testimonials/case studies of customer air source heat pumps success stories.

It should be noted that during the 2020 pandemic period, the Home Comfort team, along with the Home Performance team, began offering virtual training sessions to maintain contractor engagement. The Home Comfort subject matter experts hosted open houses and webinars, providing a platform for contractors to learn more about important program components such as the methodologies behind Manual J Load Calculation and best practices. These types of trainings maintain high level of contractor engagement and ensure the contractors have the tools necessary to reach and engage customers. Due to very positive response from the market and partners, these virtual methods of engagement continue to be utilized as well as in-person.

A.2.2.6 Business Case

The Home Comfort program has a SCT benefit-to-cost ratio of 1.09 and RIM benefit-to-cost ratio of 1.94. A list of the value streams considered in the BCA is detailed in Figure A-4 and Table A-12.

Figure A-4. Residential Home Comfort Program Present Value Benefits and Costs of SCT



	Benefit	Cost
Fuel Switching Benefits	36.50	-
Net Avoided SO2 and NOx	0.000414	-
Net Avoided CO2	2.47	-
Avoided Distribution Capacity Infrastructure	0.54	-
Avoided Transmission Capacity Infrastructure	0.22	-
Avoided Energy (LBMP)	(4.05)	-
Avoided Generation Capacity Cost (AGCC)	0.41	-
Participant DER Cost	-	27.54
Program Administration Costs	-	5.51
Total	36.09	33.05

Table A-12. Residential Home Comfort Program Value Streams

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
1	**Fuel Switching Benefits**	Considers participant fuel cost savings associated with switching from oil, gas, and propane to electricity.	36.50	
2	**Net Avoided SO_2 and NOx**	Reduced SO_2 and NOx from reduced energy consumption.	0.000414	
3	**Net Avoided CO_2**	Reduced carbon emissions from reduced energy consumption and beneficial electrification.	2.47	
4	**Avoided Distribution Capacity Infrastructure**	Based on demand savings and marginal distribution capacity cost.	0.54	
5	**Avoided Transmission Capacity Infrastructure**	Based on demand savings and marginal transmission capacity cost.	0.22	
6	**Avoided Energy (LBMP)**	Energy savings based on both on-peak and off-peak periods.	(4.05)	
7	**Avoided Generation Capacity Cost (AGCC)**	Based on demand savings and marginal capacity cost.	0.41	

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
8	**Participant DER Cost**	Includes cost of incremental equipment and installation.		27.54
9	**Program Administration Costs**	Includes contractors fee, labor, evaluation, and advertising costs.		5.51
	Total Benefits		**36.09**	
	Total Costs			**33.05**
	SCT Ratio		**1.09**	

A.2.3 Residential Energy Affordability Partnership Program

The REAP program is a free program for income eligible customers that includes a home energy survey conducted by a certified Building Performance Institute (BPI) field technician, energy savings education and tips, and the direct install of EE measures. The REAP program encourages whole house improvements and provides customer support throughout the entire EE journey. Homeowners and renters are eligible for the REAP program. Key components of the REAP program are:

- Achieving persistent energy savings
- Encouraging energy saving behavior and whole house improvements
- Helping residential customers reduce their electricity bills
- Developing partnerships with contractors to bring efficient systems to market
- Marketing and cross-promoting other PSEG Long Island program offerings

A.2.3.1 Notable Changes

In the 2023 program year, and continued into the 2024 program year, notable changes include offering Smart Thermostat installations to customers, as well as an adjustment to the income eligibility qualification. In 2024, the installation of refrigerators will also be discontinued, and the measure no longer offered.

To provide more benefits to REAP participants, Smart Thermostats will be offered to customers as a direct install measure. The inclusion of this measure will enable REAP participants to better control their heating and cooling systems and influence their heating and cooling behaviors. The Smart Thermostats will also be enrolled in PSEG Long Island's Smart Savers program for customers with Central Air Conditioning systems.

The income eligibility was updated in 2023 to reflect 80% of the State Median income, as opposed to the 80% Median Area Income. The purpose of this approach is to move towards the statewide income eligibility threshold while still addressing the higher cost of living in Nassau and Suffolk counties in comparison to New York State.

A.2.3.2 Program Delivery

PSEG Long Island and TRC engage a third-party implementation contractor to work with the REAP program team and eligible customers to efficiently meet energy saving goals while adhering to the program's budget. The REAP team and implementation contractor develop a targeted marketing plan for specific homes and areas. Factors included in identifying these customers are, high intensity usage, underserved regions or populations and specific need profiles such as income eligible. Customers who are identified through these efforts are offered a free comprehensive home energy survey and energy savings educational materials. These materials and free energy survey are intended to influence the customer in REAP program participation.

Customers who are interested in REAP participation can work with the dedicated REAP customer call center. The representatives in the call center are responsible for scheduling home energy surveys directly with the customers. Prior to the date of the scheduled survey, customers receive an email notification and pre-survey communications to highlight the key characteristics of the home.

Upon REAP program enrollment, the implementation contractor conducts a comprehensive home energy survey, performs health and safety tests, installs EE measures, and has a kitchen table talk with the customer. The kitchen table talk allows the customer to speak one on one with a program representative about energy savings behaviors and their monthly electric bills. The implementation contractor also provides the customer a folder that contains information about other PSEG Long Island programs, neighboring utility assistance programs, and PSEG Long Island brochures that contain information aiming to increase energy education and awareness on managing energy usage.

In 2020 and 2021, in response to the pandemic, the REAP program pivoted traditional in-person participation methods to virtual. Customers were offered remote energy surveys and a curbside delivery option for direct install measures. In 2022 and 2023, remote energy surveys were still offered to customers who feel more comfortable participating virtually. In 2023 customers participated mainly through the traditional REAP “in-person” survey. To ensure all customers have a participation pathway, remote energy surveys will be available upon customer request for 2024.

The REAP implementation contractor is responsible for:

- Hiring local staff to perform home energy surveys and direct measure installation
- Engaging with customers to schedule home energy survey appointments
- Providing customer service and support
- Tracking program performance, including customer participation as well as quality assurance/quality control.
- Reporting monthly on progress toward program goals

PSEG Long Island and the implementation contractor work together to market REAP using the following approaches:

- Utilizing bill inserts to raise awareness of the REAP program
- Delivering targeted direct mail pieces to further inform the customer of program benefits, home energy survey, and call center information
- Calling and door to door canvassing for potential REAP participants
- Participant is provided opportunity to schedule survey over the phone or in-person during site visit
- Emailing program information to eligible customers
- Hosting open houses at community central locations, like Town Hall offices

To increase referrals and productivity, Program management coordinates with different populations:

- Nonprofit, non-governmental organizations
- Government

- Senior citizens
- Financial/debt counseling organizations
- Faith-based institutions
- Apartment and multifamily dwellings
- Public libraries
- Food Banks

Energy Education

A fundamental precept of the REAP program design is extensive customer energy education and support throughout the customer's EE journey. Education and support for the customer are critical to ensure the customer uses the installed EE measures appropriately. This is achieved by creating a partnership between the REAP program and the customer. The partnership allows the REAP team member to work with their new partner in identifying energy savings behaviors that will lead to lower monthly electric bills and maximize the benefits of the newly installed EE measures. Once the energy savings behaviors are identified, they become the partners' Action Commitments and the partner agrees to implement the identified behaviors. Some examples of the energy savings behaviors are lowering the water heater temperature, checking furnace filters, turning off lamps, and utilizing energy saving settings on clothes washers and other appliances.

The partnership concept puts the customer in charge of their energy savings and their experience. Customers who participate in REAP, should agree to become partners, and accept their responsibility through the Action Commitments. The Action Commitments, once agreed on, are included in a formal written agreement, and signed by the new partner and a REAP representative.

Other key focuses of energy education include:

- Use and value of installed high efficiency lighting retrofits
- Set-back thermostat operation and management
- Appliance use and management
- Water conservation measures
- Water heater temperature setting

Referrals

During a home energy survey, the field technician provides the customer, either verbally or tangibly, information about other appropriate EE programs and assistance programs implemented by PSEG Long Island or other organizations, per PSEG Long Island approval. This is known as a referral. Providing the customer with information about other programs allows them to explore participation in other programs that will benefit them. The field technician is educated on the other programs to assist the customer.

Some of the assistance programs are:

- PSEG Long Island Home Comfort and Home Performance Programs
- New York State Home Energy Assistance Program
- New York State Weatherization Assistance Program
- Other relevant programs including town- or county-specific programs and social support programs to meet special needs

The field technician also leaves behind a REAP customer folder that includes informative PSEG Long Island brochures and information such as the Energy Saving Guide, "PSEG Long Island 66 Ways to Save On Your Electric Bill, "Household Assistance Rate," and "Financial Assistance."

Lead Generation
PSEG Long Island participates in a multitude of residential events throughout the year to distribute brochures that promote the benefits of the REAP program. In addition, customers can apply through the PSEGLINY.com website by completing a REAP Online Form; REAP Eblasts are emailed to income-eligible customers; Program information is included in PSEG Long Island bill inserts and on Home Energy Reports; REAP postcard mailings are sent on a monthly basis.

Energy Forum for Advocates
PSEG Long Island hosts an annual Energy Forum for Advocates, which is organized and hosted by the REAP program manager. The Energy Forum provides a platform for advocates to learn about services that can positively impact the lives of the income eligible families they work with. The REAP program manager invites a number of speakers from different assistance programs to speak to the advocates and answer any questions the advocate may have.

Speakers invited to the Energy Forum represent assistance programs including, but not limited to:

- PSEG Long Island's Household Assistance Rate
- Consumer Advocates from PSEG Long Island
- CDC Long Island's Weatherization Assistance Program
- National Grid Home Energy Affordability (HEAT) Program and Energy Affordability Program (EAP)
- Home Energy Assistance Program (HEAP)
- United Way of Long Island's Project Warmth
- DSS Emergency Energy Assistance

The Energy Forum is typically held in the fall prior to the heating season. This ensures the advocates are receiving the latest information on programs that help with heating for their clients. In 2022, the Energy Forum was held in-person person and boasted over 115 attendees.

A.2.3.3 Target Market

The program is offered to all residential customers who:

- Have a PSEG Long Island account
- Own or rent in the service territory
- Have not participated in REAP in the previous 5 years
- Comply with income guidelines and size of household and meet the qualifying criteria below.

REAP Income Guidelines are summarized in Table A-13 below.

Table A-13. 2023-2024 REAP Income Guidelines

Size of Family	Maximum Gross Monthly Income	Maximum Gross Annual Income
1	$3,803	$45,632
2	$4,973	$59,680
3	$6,144	$73,728
4	$7,313	$87,760
5	$8,484	$101,808
6	$9,655	$115,856
7	$9,873	$118,840
8	$10,093	$121,120
9	$10,312	$123,744
10	$10.532	$126,384

*Based on 80% of State Median Income

Customer Qualification

Verification of REAP program income eligibility for each PSEG Long Island customer is initially performed by the TRC's customer call center during the initial intake call. The customer must provide proof of income documentation prior to the start of the home energy survey. REAP eligibility is based on number of persons living in the home, total household income, and the inclusion of income from alternate sources.

The implementation contractor's field technician is responsible for the review of customer documentation to ensure eligibility for participation. In addition, the field technician is responsible for the recording of household member's name, annual income, source(s) of income and verification code of documents (VCD) code on the participation agreement form.

Historically, REAP income eligibility was based on 80% of the Median Area Income, as established by the U.S. Department of Housing and Urban Development. Beginning in 2023, income eligibility is based on 80% of the State Median Income. This criteria exceed the 60% of State Median Income required for CLCPA DAC income compliance. Act The income guidelines in the Climate Act align with the NYSERDA EmPower income guidelines which reflect 60% of the State Median Income. The Microsoft Dynamics CRM platform that PSEG Long Island utilizes for all reporting, includes new fields that are used to identify if a customer meets the 60% State Median Income threshold or the 80% State Median Income threshold.

Although the REAP income eligibility has changed, the PSEG Long Island Team is still working to serve as many low-income participants as possible. In some instances, not all participants can be served, due to the updated income eligibility requirements. In those instances, participants are directed towards other PSEG Long Island EEP.

Based on data from the first four months of 2023, approximately 83% of all REAP customers meet the income criteria of 60% of State median income while the remaining 17% of customers fall into the "moderate" income bracket of 80% State Median Income.

Verification Codes for Documents

- CSO – Child Support/Court Order
- DSS – Department of Social Services
- EVL – Employer Verification Letter
- PS2 – Pay Stubs, previous two months

- SSD – Social Security Disability
- SSI – Supplemental Security Income Award Letter
- SSR – Social Security Retirement
- SSS – Social Security Survivor's Benefit
- UAL – Unemployment Award Letter
- VBA – Veteran's Benefits Award Letter
- W-2 – Previous Year W-2 or 1040 SSE Form
- WCA – Workman's Compensation Award Letter
- Other ______________________________

A.2.3.4 Measures and Incentives

Measures offered through the REAP program are summarized in Table A-14 below.

Table A-14. REAP: List of Measures

Measure	2024 Planned Units	Measure Incentives	Measure Rebates
Advanced Power Strips (Tier II)	1,850	-	-
Dehumidifiers 25-50 Pints/Day	130	-	-
Dehumidifiers >50 Pints/Day	150	-	-
ES Room Air Purifiers (<200 CADR)	80	-	-
ES Room Air Purifiers (>200 CADR)	200	-	-
Water Temperature Turndown/HH	60	-	-
Faucet Aerators/unit	350	-	-
Low Flow Showerheads/unit	180	-	-
Thermostatic Valve	175	-	-
10,000 Btu RAC 1 Unit/HH	60	-	-
12,000 Btu RAC 1 Unit/HH	60	-	-
6,000 Btu RAC 1 Unit/HH	500	-	-
8,000 Btu RAC 1 Unit/HH	150	-	-
Pipe Insulation/ln ft	220	-	-
Nightlight	1,800	-	-
LED Bulbs	25,000	-	-
Smart Thermostats – Learning – Direct Install	1,000	-	-

It is estimated that 2,000 REAP visits will be conducted in the 2024 program year for customers who meet the income eligibility threshold. An estimated, additional, 500 REAP visits will be planned for customers who live in an area designated a DAC. The numbers of visits per year is expected to remain constant through the 2025 program year. A variety of the above-mentioned energy saving measures will be installed during the visit.

Offered measures are divided into core measures and major efficiency measures (see Table A-15).

- **Core Measures:** Measures that are typically directly installed regardless of the space heating fuel used by the PSEG Long Island residential customer.

- **Major Efficiency Measures:** Those measures that will cost-effectively reduce the energy consumption of high-use or seasonal appliances but typically require more extensive treatment. All energy-efficient measures are installed at no cost to the customer or building owner, if cost-effective, given site specifics. In the case of partners who occupy rental property, core efficiency measures involving building owner property, such as non-tenant-owned appliances, may not be installed without the prior written approval of the building owner.

Table A-15. Core and Major Efficiency Measures Offered through REAP

Typical Core Measures	Major Efficiency Measures
Installation of high-efficiency lighting Pipe Insulation* High-efficiency showerheads* Faucet Aerators* Reducing electric water heater temperature settings* Thermostatic Shower Valves* Smart Strips Smart Thermostats	Replacement of inefficient room air conditioners (RACs), dehumidifiers, room air purifiers

** Pipe insulation, low flow shower heads, faucet aerators, water temp turndown and thermostatic shower valve are provided to customers with electric domestic hot water heaters only.*

At the completion of a REAP home energy survey, follow up work may be identified in which the customer can utilize income eligible enhanced incentives through the Home Comfort and Home Performance program.

A.2.3.5 Outreach

The REAP program reaches customers and advocates in a variety of ways. The program coordinator and/or program manager communicates directly with PSEG Long Island customers, homeowners, and renters, and indirectly through related social agencies. Overall, PSEG Long Island works with over 200 entities in outreach and referrals.

In the 2022/2023 calendar year, the REAP team attended over 50 events at central community locations, such as libraries, churches, fairs. At these events, the REAP program coordinator and/or program manager conducted presentations, distributed program information, and made connections with customers and advocates.

The REAP program also focuses on building relationships with other organizations that can serve REAP-eligible customers. The goal is to not only collaborate with other organizations but to build even larger referral potentials and relationships with community liaisons, community councils and board members, housing authorities, departments of social services, and other government organizations that serve income eligible and senior citizen communities. To build these relationships, the REAP program provides workshops and presentations for agency staff meetings, support/consumer groups, and large-scale community events.

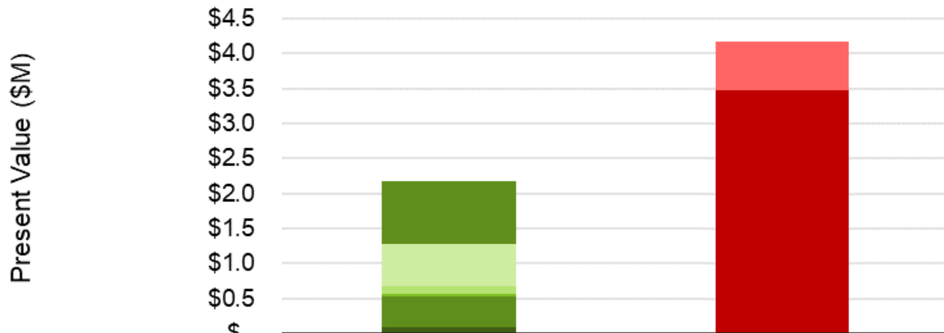
Customers can also reach the REAP program directly through the PSEG Long Island website or through E-blasts that are sent out periodically. Both avenues refer the customer to a REAP mini-application that is sent directly to the REAP team once completed. The E-blast response to the mini-app has resulted in a 24% scheduling rate.

Other forms of outreach used by the REAP team are monthly post-card mailings targeting income eligible areas, door hangers, and brochures delivered to foodbanks. In 2024-2025, these effective and engaging outreach strategies will continue to be implemented.

A.2.3.6 Business Case

REAP has a SCT benefit-to-cost ratio of 0.52 and RIM benefit-to-cost ratio of 0.09. A list of the value streams considered in the BCA is detailed in Figure A-5 and Table A-16.

Figure A-5. REAP Present Value Benefits and Costs of SCT



	Benefit	Cost
Fuel Switching Benefits	0.89	-
Net Avoided SO2 and NOx	0.000010	-
Net Avoided CO2	0.61	-
Avoided Distribution Capacity Infrastructure	0.10	-
Avoided Transmission Capacity Infrastructure	0.04	-
Avoided Energy (LBMP)	0.44	-
Avoided Generation Capacity Cost (AGCC)	0.09	-
Participant DER Cost	-	0.70
Program Administration Costs	-	3.47
Total	2.17	4.17

Table A-16. REAP Value Streams

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
1	**Fuel Switching Benefits**	Considers participant fuel cost savings associated with switching from oil, gas, and propane to electricity.	0.89	
2	**Net Avoided SO_2 and NOx**	Reduced SO_2 and NOx from reduced energy consumption.	0.000010	
3	**Net Avoided CO_2**	Reduced carbon emissions from reduced energy consumption and beneficial electrification.	0.61	

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
4	**Avoided Distribution Capacity Infrastructure**	Based on demand savings and marginal distribution capacity cost.	0.10	
5	**Avoided Transmission Capacity Infrastructure**	Based on demand savings and marginal transmission capacity cost.	0.04	
6	**Avoided Energy (LBMP)**	Energy savings based on both on-peak and off-peak periods.	0.44	
7	**Avoided Generation Capacity Cost (AGCC)**	Based on demand savings and marginal capacity cost.	0.09	
8	**Participant DER Cost**	Includes cost of incremental equipment and installation.		0.70
9	**Program Administration Costs**	Includes contractors fee, labor, evaluation, and advertising costs.		3.47
	Total Benefits		**2.17**	
	Total Costs			**4.17**
	SCT Ratio		**0.52**	

A.2.4 Home Performance

The primary objective of the Home Performance program is to support residential customers in making high efficiency choices when considering updates to their homes envelope and heating systems. This is achieved through utilizing a comprehensive whole house approach that identifies areas for improved efficiency, safety, and comfort of the home. Newly installed weatherization measures and heating equipment operate in a customer's home for 10 to 25 years. It is paramount to reach customers and influence their choices to ensure their decisions are energy efficient. This objective aligns with the overall goal of reducing the carbon footprint of customers who utilize electric, oil, or propane as their primary heating source. Income eligible customers who heat their homes with natural gas and utilize Central Air Conditioning systems to service 50% or more of their cooling load are also eligible for weatherization rebates through the Home Performance program. All other natural gas heating customers are referred to National Grid's weatherization program. This became effective in 2022 in response to the Memorandum of Understanding signed between National Grid and PSEG Long Island.

The Home Performance program provides a participation pathway for all customers by offering whole house solutions to income eligible and market-rate customers. Enhanced rebates are available for income eligible customers for whole-house heat pumps and weatherization measures. PSEG Long Island works with EFS to qualify income eligible customers. Income eligibility will continue to be based on 60% of the State Median Income. Participating Home Performance partners may also offer low-interest on-bill recovery loans and smart energy loans for qualified market rate and income eligible customers.

Historically, the US DOE administered HPwES Program. Beginning in 2024, the DOE will sunset the HPwES program. The DOE acknowledges all of the accomplishments partners and have contractors have achieved since program inception in 2002, but ultimately decided that the "HPwES Program is no longer needed to encourage whole home retrofits." PSEG Long Island will still continue to offer a Home Performance Weatherization Program. TRC will continue to administer the program and provide support to PSEG Long Island, Home Performance partners (trained and vetted contractors), and customers. TRC will provide design and implementation strategies through innovative program design and management, quality assurance and quality control, technical training for Home Performance partners, and Home Performance partner support to ensure the promotion of quality installation of energy efficient measures.

The Home Performance program has built a robust partner network. The program has built strong working business partnerships with the existing PSEG Long Island Home Performance contractor base, as well as various trade allies and constituent-based organizations like NYSERDA, Long Island Green Homes, BPI, BPCA, and Efficiency First.

Program Leads

PSEG Long Island Home Energy Assessments: PSEG Long Island Home Energy Assessments (HEA) are free energy audits available to eligible single-family homeowners in the PSEG Long Island service territory. Customers who are interested in receiving a free HEA complete a Home Energy Assessment Online Application, found on the PSEG Long Island website. The customer answers questions about their home, like heating and cooling equipment type and the age of the home and selects a qualified contractor to conduct the HEA. The selected contractor is notified of the HEA, through the Lead Partner Portal, and promptly schedules the audit with the customer. During the HEA, the contractor conducts a comprehensive audit of the home, utilizing a PSEG Long Island branded audit tool built by TRC, and educates the homeowner on the different energy savings opportunities offered by PSEG Long Island, ranging from duct sealing to air source heat pumps. At the conclusion of the HEA the customer will receive a PDF of the completed audit and recommendations. The PDF is also stored in the Captures database. Please note, although not all natural gas customers qualify for the PSEG Long Island Home Performance rebates, all natural gas customers are still eligible to receive a free Home Energy Assessment.

A.2.4.1 Notable Changes

In 2024, the Home Performance rebate offerings continue to be available through the Home Comfort/Home Performance application. The Home Comfort/Home Performance application provides customers with holistic whole-house solutions through the promotion, and rebate, of cold climate air source heat pumps, Home Performance weatherization measures, integrated controls, smart thermostats, electric hot water heating equipment, and Tune-Ups. Electric hot water heating equipment (ENERGY STAR Heat Pump Water Heaters and Electric Tankless Water Heaters) has typically been offered through the EEP program but including it in the program offering allows the Home Performance partner and participant to consider going all-electric to meet their space heating and water heating needs through one central application. To further promote a holistic whole-house solution, rebates for windows will become available in 2024. Participants who install a Whole House Cold Climate Air Source Heat Pump, Insulation, and Air Sealing, will be eligible to participate in the windows offering.

Notable changes, beginning in 2024, include the discontinuation of the direct install portion of the Home Performance program. The direct install program targeted residential electric heat customers. Many of the participants were in planned senior communities which had poor building shell insulation which when coupled with electric resistance heat resulted in very high winter bills. While initially there was significant demand for the program, as the years have passed, program interest and participation has continued to diminish as many of these units were treated. Also, as mentioned above, the US DOE will no longer be administering the HPwES program in 2024. Lastly, overall program savings and budget have been reduced from prior years to reflect a level of effort that is more in-line with actual program experience over the past few years.

In 2023, and continuing in the 2024 program year, natural gas customers who are income eligible and heat their homes with natural gas and utilize Central Air Conditioning systems to service 50% or more of their cooling load are eligible for weatherization rebates through the Home Performance program. All other natural gas heating customers are referred to National Grid's weatherization program. This became effective in 2022 pursuant to an MOU between National Grid and PSEG Long Island.

The Home Performance program offering for market-rate customers was increased from $1,000 per project to $1,200 per project, in mid-2022, to engage more market-rate customers and contractors and assist with out-of-pocket expenses. In 2024, the market-rate offering will be adjusted to $1,050 per project.

The Home Performance program's income eligible offering continues to be available in 2024. Historically, the income eligible offering was $4,000 per project where duct sealing, insulation, and air sealing were installed. In 2023, the income eligible offering was increased to reflect $6,000 per project. In 2024, the income eligible offering will be adjusted to $5,000 per project. The adjustment in the per project rebate is to ensure the Home Performance program remains cost-effective, while still providing an increased per project rebate, compared to historical offerings.

To increase accessibility and participation in the income eligible community, it was determined an increase in the offering would allow the program to impact more customers and provide the pathway to that holistic, whole-house solution. A whole-house solution begins with proper weatherization of the home. The enhanced rebates make this achievable. Income eligible customers may receive enhanced rebates for Whole House Cold Climate Heat Pumps, Heat Pump Water Heaters, and Windows. The enhanced rebates also achieve another PSEG Long Island objective; providing the income eligible customer with enough support through rebates to ensure the customer has little to no out of pocket costs, realize significant energy savings, and overall monthly bill savings.

Also continuing in 2024, participants who complete projects containing both whole house air source heat pumps and weatherization will be eligible for a participation bonus. Income eligible and market rate customers can receive an additional $500 for these projects. The addition of the participation bonus should influence the customer to explore the benefits associated with completing weatherization and installing a whole house air source heat pump as one project. The bonus should also assist in reducing the financial burden on the participant.

As discussed in the Home Comfort section, PSEG Long Island plans to explore increasing the adoption of home energy retrofits and residential heat pumps in the single-family residential sector through a partnership with a company that can help customers finance key home improvements using the money homeowners currently spend on wasted energy. PSEG Long Island will continue to offer smart energy loans and On-Bill Financing options for weatherization, heat pumps, and geothermal projects.

In April 2021, PSEG Long Island launched a partnership with Sealed, a New York-based company that finances key home improvements using the money homeowners currently waste on energy. The goal of the partnership is to increase the adoption of home energy retrofits and potentially residential heat pumps in the single-family residential sector by allowing for those customers to pay for energy-saving home improvements with the value of their expected energy savings. Sealed invests in home improvements that save energy and customers pay back based on the actual energy that is saved. If customers don't save energy, Sealed does not get paid back. This partnership is market-based relationship and does not require any dedicated program budget from PSEG Long Island. Sealed provides all the necessary capital for customer acquisition, operations, and project finance. In addition, Sealed provides upfront education and engagement on comfort and other non-energy customer pain points, and provides customers with a proposal and/or recommendations on how they can solve these problems. Customers will receive this education and engagement over phone and web and will be connected to local contractors once they have determined the project that will best meet their needs.

A.2.4.2 Program Delivery

PSEG Long Island's Home Performance program provides customer rebates and contractor incentives for the installation of weatherization measures and building shell upgrades like insulation, air sealing, and duct sealing. Customers and Home Performance partners must meet the minimum efficiency requirements for each measure installed to qualify for the rebates and incentives.

All Home Performance projects are reviewed for quality control and accuracy. In 2023, all projects required pre-approval. This practice will continue in the 2024 program year.

A significant amount of the Home Performance program participation is driven by the partnership between the Home Performance program and Home Performance partners. Prospective Home Performance contractors must submit a signed PSEG Long Island Home Performance Contractor Participation Agreement and provide documentation showing proof of business identification, financial condition, insurance, licensing, satisfactory customer relationships, and Building Performance Institute (BPI) Gold Star Status. On approval, the contractor is deemed a Provisional Participating Contractor until they successfully complete five Home Performance projects. As of May 2023, 12 participating Home Performance partners were enrolled in the program. On a monthly basis all electric (kW and kWh) savings are reported to PSEG Long Island. Fossil fuel (oil/propane, other non-natural gas heating fuels) savings are converted to MMBtu and reported to PSEG Long Island; PSEG Long Island reports the necessary savings metrics to LIPA and NYSERDA.

A.2.4.3 Target Market

The Home Performance Home Energy Assessment (HEA) is available to all eligible PSEG Long Island single-family home residential customers. Based on historical data collected from the Home Energy Assessment Tool and Online Application, 7% of customers utilize electric heat, 39% of customers utilize natural gas heat, 51% of customers utilize oil heat, and 3% of customers utilize propane heat. The Home Performance Direct Install program is available to eligible residential customers with electric heat.

Home Performance rebates are available to all customers, except those who heat their homes primarily with gas and do not have a central air conditioning system. Enhanced rebates are available for customers who qualify as income eligible. The Home Performance program utilizes 60% of the State Median Income to qualify homeowners as income eligible. Loans are available from EFS for both market and income eligible projects.

It is estimated that 4,000 HEAs and 1,250 Home Performance projects will be completed in the 2024 program year.

PSEG Long Island intends to offer the 2024 program in keeping with prior years, except for the program modifications made in 2022 to support the partnership with National Grid.

A.2.4.4 Measures and Incentives

A list of measures that are offered in the Home Performance program is included in Table A-17 and Table A-18.

Table A-17. PSEG Long Island Home Performance-Eligible Measures List

Eligible Measure	Minimum Efficiency Requirements
Duct Sealing	UL 181B mastic or tape; use of duct tape is disallowed
Duct Insulation	Installed in accordance with all applicable state and local codes

Building Shell	Insulation (attic, wall, floor, band joist, basement, crawl space)	Must be accompanied by blower door assisted air sealing per BPI standards
	Air Sealing	Blower door assisted per BPI standards
Windows		Installed with Whole House Heat Pump, Insulation, and Air Sealing

Table A-18. Home Performance: List of Measures

Measure	2024 Planned Units	Measure Incentives	Measure Rebates
Windows -- Market	12	-	$3,000
Windows – LMI	7	-	$4,500
HEA Audit Giveaway (Smart Strip Tier I)	4,000	-	$31
HEA Audits	4,000	-	-
LMI Projects	700	-	$5,000
Market Projects – Non-Gas Customers	380	-	$1,050
Market Projects – Gas Customers	170	-	$150

A.2.4.5 Outreach

The Home Performance program focuses on promoting the free Home Energy Assessment component of the Program. Home Energy Assessments are available to all eligible PSEG Long Island single-family home residential customers. The Home Energy Assessment (HEA) provides the customer with a comprehensive whole-house energy review including, but not limited to, weatherization measures, heating and cooling systems, appliances, domestic hot water. The Home Energy Assessment is promoted at PSEG Long Island sponsored events, such as home shows and street fairs, direct mailings, the PSEG Long Island website, and by the Home Performance partners.

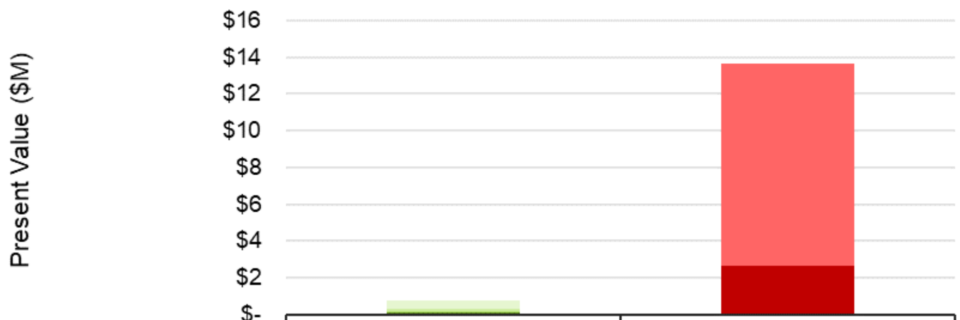
The HEA is a critical outreach effort, as the Home Performance partner can engage directly with the customer about the benefits of participation in the Home Performance program. The results of the HEA identify where the customer can make improvements in the home through the Home Performance program.

Beginning in 2020, to maintain contractor engagement during the pandemic, the Home Performance team, along with the Home Comfort team, started offering contractors virtual training sessions. The sessions focused on topics like financing, application submittals, technology deep dives, and general program updates. Contractors were also invited to speak directly with TRC subject matter experts during Friday morning Virtual Open House meetings. In 2023, the TRC team began hosting the Friday morning Open House meetings in person, as well. In 2024, engagement methods will continue to be a blend of in-person and virtual.

A.2.4.6 Business Case

Home Performance has a SCT benefit-to-cost ratio of 0.06 and RIM benefit-to-cost ratio of 0.02. A list of the value streams considered in the BCA is detailed in Figure A-6 and Table A-19.

Figure A-6. Home Performance Present Value Benefits and Costs of SCT



	Benefit	Cost
Fuel Switching Benefits	0.43	-
Net Avoided SO2 and NOx	0.000005	-
Net Avoided CO2	0.14	-
Avoided Distribution Capacity Infrastructure	0.04	-
Avoided Transmission Capacity Infrastructure	0.02	-
Avoided Energy (LBMP)	0.07	-
Avoided Generation Capacity Cost (AGCC)	0.06	-
Participant DER Cost	-	10.97
Program Administration Costs	-	2.66
Total	0.76	13.64

Table A-19. Home Performance Value Streams

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
1	**Fuel Switching Benefits**	Considers participant fuel cost savings associated with switching from oil, gas, and propane to electricity.	0.43	
2	**Net Avoided SO_2 and NOx**	Reduced SO_2 and NOx from reduced energy consumption.	0.000005	
3	**Net Avoided CO_2**	Reduced carbon emissions from reduced energy consumption and beneficial electrification.	0.14	
4	**Avoided Distribution Capacity Infrastructure**	Based on demand savings and marginal distribution capacity cost.	0.04	
5	**Avoided Transmission Capacity Infrastructure**	Based on demand savings and marginal transmission capacity cost.	0.02	
6	**Avoided Energy (LBMP)**	Energy savings based on both on-peak and off-peak periods.	0.07	
7	**Avoided Generation Capacity Cost (AGCC)**	Based on demand savings and marginal capacity cost.	0.06	

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
8	**Participant DER Cost**	Includes cost of incremental equipment and installation.		10.97
9	**Program Administration Costs**	Includes contractors fee, labor, evaluation, and advertising costs.		2.66
	Total Benefits		**0.76**	
	Total Costs			**13.64**
	SCT Ratio		**0.06**	

A.2.5 All Electric Homes Program

The All Electric Homes program was launched in April 2021 to support residential customers and residential developers who want to build or retrofit a single-family home as “All Electric”. To be eligible for the All Electric Homes program, customers must install electric-end use equipment in a New Construction residence or convert all existing fossil fuel equipment in an existing residence. Customers who wish to convert their existing propane, oil, or natural gas equipment are eligible. A backup fossil fuel connection is not permissible for New Construction. All existing fossil fuel connections, in existing residences, must be disconnected. Although a fossil-fuel connection is not permissible on site, a connection for a backup generator is allowable in the event of a power-outage.[89] This exception is implemented as an optional safety and resiliency measure in order to ease participation for customers with existing generators and to reassure customers that they can have a backup in the event of a power outage. This is consistent with our Whole House Heat Pump offering, which still allows fossil fuel secondary heating for the coldest days of the year.

The All Electric Homes program offers two pathways to participation. The “Tier I” pathway includes cold climate air source heat pumps, tankless water heaters, and ENERGY STAR labeled appliances. The “Tier II” pathway includes cold climate air source heat pumps, heat pump water heaters, and ENERGY STAR Most Efficient labeled appliances. All participants who participate in the Tier I offering will receive a 10% bonus on all required rebated measures. All participants who participate in the Tier II offering will receive a 25% bonus on all required rebated measures. The participation bonuses are intended to offset the costs associated with ENERGY STAR and ENERGY STAR Most Efficient appliances, as well as the costs associated with electric cooking equipment. In 2022, the electric cooking equipment requirement was waived in order to engage with more customers. Participating All Electric Homes customers may install either electric cooking equipment or propane cooking equipment. Similar to 2021 and 2022, the cooking equipment will not be rebated, nor will savings be claimed. Additionally in 2022, to stimulate the market, a $2,000 per project contractor incentive was introduced.

The All Electric Homes application contains required and optional measures, such as Cold Climate Air Source Heat Pumps, Geothermal Heat Pumps, Water Heating, Electric Appliances, Weatherization measures, and other equipment like Heat Pump Pool Heaters. The measures included in the All Electric Homes application were previously screened for program offerings like Home Comfort, HPwES, and the EEP Program.

[89] The fossil fuel source can hold be connected to the generator or, if the customer has one, a gas stove.

All measures found in the All Electric Homes application are not required for participation, however a base set of measures must be installed in order to qualify for All Electric Homes rebates and receive participation bonuses. The intent of including non-required measures in the application is to provide the customer a one-stop “all electric” shop for their project. Including all appropriate measures in the application also promotes a holistic whole house solution for the participant. Throughout the application, there are indicators informing the customer which measures are required and which measures are optional.

Measures that are required to be eligible for the All Electric Homes Program are captured in Table A-20 below.

Table A-20. Required Measures for All Electric Homes Program Eligibility

All Electric Homes – Tier I	All Electric Homes – Tier II
Cold Climate Air Source Heat Pump*	Cold Climate Air Source Heat Pump*
Smart Thermostat*	Smart Thermostat*
Tankless Water Heater*	Heat Pump Water Heater*
ENERGY STAR Electric Dryer*	Most Efficient Heat Pump Dryer*
ENERGY STAR Clothes Washer	Most Efficient Clothes Washer*
ENERGY STAR Dishwasher	Most Efficient Dishwasher
ENERGY STAR Refrigerator	Most Efficient Refrigerator
ENERGY STAR LED Lighting**	ENERGY STAR LED Lighting**
Standard Electric/Propane Cooking Range	Most Efficient Induction/Propane Cooktop/Oven

*Indicates a rebate is available
**Savings will be claimed for existing building only

Measures that are optional for the All Electric Homes Program are captured in Table A-21 below.

Table A-21. Optional Measures for All Electric Homes Program Eligibility

Geothermal Ground Source Heat Pump**	ENERGY STAR Dehumidifier
Heat Pump Pool Heater	ENERGY STAR Room Air Purifier
	Weatherization

** Customers can elect to install a Geothermal Ground Source Heat Pump in place of a Cold Climate Air Source Heat Pump and still qualify for the All Electric Homes Program and bonuses

The All Electric Homes program collaborates with developers and PSEG Long Island Lead Partners to promote the All Electric Home offering to the public.

The promotion of the All Electric Homes program will continue in 2024-2025.

A.2.5.1 Notable Changes

In Mid-2022, the All Electric Homes program launched two significant changes. To alleviate customer concerns related to preferred cooking equipment, the program added an option for Propane Cooking. This allowance is commensurate with the SMUD All-Electric Homes Program, which permits mixed-fuel homes to participate under certain circumstances. To stimulate the market and engage Partners and developers, a per project contractor incentive was introduced. Eligible contractors can receive a $2,000 participation bonus for completing an All-Electric New Construction project or an Existing Building conversion project.

The inclusion of propane cooking equipment and the $2,000 per project contractor incentive will remain a part of the offering in 2024.

In 2023, to remain consistent with the Energy Efficient Products program, the battery-operated lawn care equipment was removed from the All Electric Homes program.

A.2.5.2 Program Delivery

The All Electric Homes participation will primarily be driven through partnerships with developers and existing relationships with Home Comfort Partners, Home Performance Partners, and Multi-Family Partners and Developers. Leveraging relationships with existing partners and developers, and also promoting the program at industry events will result in creating program awareness and participation.

All partners who will participate in this offering have already been trained and vetted by the PSEG Long Island program. This ensures customers will have a positive “All Electric” participation experience.

TRC also holds weekly open-house meetings for all participating Lead Partners. Interested Lead Partners and developers will have the opportunity to speak one-on-one with a member of the Residential team to learn more about the program and navigate the application.

A.2.5.3 Target Market

The program is offered to all residential customers in the PSEG Long Island service territory. All qualified Residential developers with eligible projects and previously vetted lead partners may also participate.

A.2.5.4 Measures and Incentives

The measures available in the All Electric Homes program include equipment found in the current Home Comfort program, Home Performance, and the EEP program. The incentives for the All Electric Homes program are consistent with the rebates offered through Home Comfort, Home Performance, and EEP.

Customers are eligible for a Tier I or Tier II participation bonus. Contractors are eligible for a $2,000 per project contractor incentive.

The full list of required and optional measures for the All Electric Homes Program are listed in Table A-20 and Table A-20.

A.2.5.5 Outreach

The All Electric Homes program outreach strategy, aside from developer/lead partner/customer word of mouth, includes a variety of public platforms:

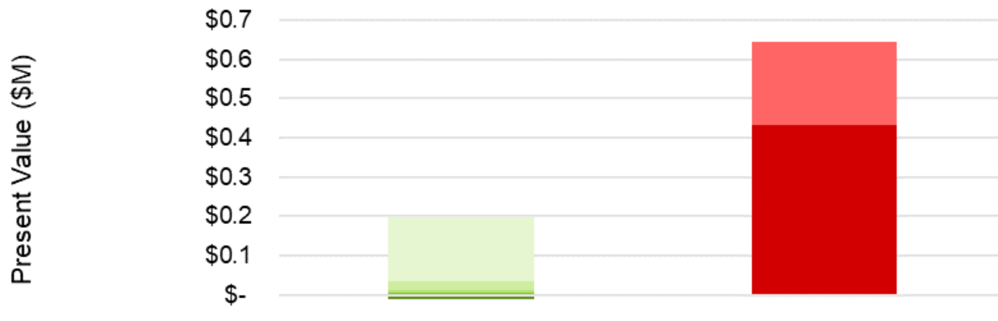
- PSEG Long Island Website page
- Industry networking events and speaking engagements, such as HIA, LIBI, and the US Green Building Council

In 2024-2025, the Residential team will continue to implement the above listed outreach strategies and work with participating developers and lead partners on tools to promote the installation of all electric equipment. In addition, the Residential team will develop educational materials to provide developers, lead partners, and customers to ensure they have a better understanding of the energy and non-energy benefits associated with an All Electric Home.

A.2.5.6 Business Case

The All Electric Homes program has a SCT benefit-to-cost ratio of 0.29 and RIM benefit-to-cost ratio of 0.23. A list of the value streams considered in the BCA is detailed in Figure A-7 and Table A-22.

Figure A-7. All Electric Homes Program Present Value Benefits and Costs



	Benefit	Cost
Fuel Switching Benefits	0.16	-
Net Avoided SO2 and NOx	0.000002	-
Net Avoided CO2	0.02	-
Avoided Distribution Capacity Infrastructure	0.01	-
Avoided Transmission Capacity Infrastructure	0.0022	-
Avoided Energy (LBMP)	(0.01)	-
Avoided Generation Capacity Cost (AGCC)	0.00	-
Participant DER Cost	-	0.21
Program Administration Costs	-	0.43
Total	0.19	0.64

Table A-22. All Electric Homes Program Value Streams

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
1	**Fuel Switching Benefits**	Considers participant fuel cost savings associated with switching from oil, gas, and propane to electricity.	0.16	
2	**Net Avoided SO_2 and NOx**	Reduced SO_2 and NOx from reduced energy consumption.	0.000002	
3	**Net Avoided CO_2**	Reduced carbon emissions from reduced energy consumption and beneficial electrification.	0.02	
4	**Avoided Distribution Capacity Infrastructure**	Based on demand savings and marginal distribution capacity cost.	0.01	
5	**Avoided Transmission Capacity Infrastructure**	Based on demand savings and marginal transmission capacity cost.	0.00	
6	**Avoided Energy (LBMP)**	Energy savings based on both on-peak and off-peak periods.	(0.01)	
7	**Avoided Generation Capacity Cost (AGCC)**	Based on demand savings and marginal capacity cost.	0.00	
8	**Participant DER Cost**	Includes cost of incremental equipment and installation.		0.21
9	**Program Administration Costs**	Includes contractors fee, labor, evaluation, and advertising costs.		0.43
	Total Benefits		**0.19**	
	Total Costs			**0.64**
	SCT Ratio		**0.29**	

A.2.6 Multifamily Program

In 2021, the Multifamily program offering expanded to include Existing Building scenarios. In 2022, ENERGY STAR rebates were included for Clothes Washer, and for the bundling of ENERGY STAR measures. The measures are required to be “bundled” to ensure cost effectiveness. Eligible measures for the bunding approach include ENERGY STAR Clothes Washers, ENERGY STAR Refrigerators, and ENERGY STAR Dishwashers. Elevator Modernization was also added to the offering. These offerings will continue to be available in 2024.

It should be noted that in the 2024 program year, the plan for the Multifamily program is much greater than in previous years. After the launch of the Multi-Family Program in 2021, word of the program began to spread, and each year, more developers have become engaged in the program. A number of developers have installed “in-unit” air source heat pumps, as well as Custom Heat Pumps and Variable Refrigerant Flow (VRF) systems. In 2023, Common Area HVAC measures, which include VRF systems, were projected to represent 27% of Multifamily savings. For 2024, Common Area HVAC is projected to represent 86% of savings. This will support the broader heat pump goal but will also result in a higher $/MMBtu for the Multi-Family program, which is driving an increased budget for next year. Last year, 62%

of savings were expected from low $/MMBtu lighting measures but this decreases to 5% in 2024. The budget projection also reflects the goal having 50 multi-family buildings participate in the program, most of which are expected to be heat pump projects. PSEG Long Island is in the middle of assessing what component units within buildings presently enrolled in the Multifamily meet DAC income criteria. This information once in hand will be used to help develop strategies for DAC spending compliance in the 2024 program year.

In the Summer of 2022, the CEP enhanced the Custom Heat Pump and VRF offering to align with neighboring utilities. Resultantly, the number of Custom Heat Pumps and VRFs installed through the multi-family program increased.

Based on 2023 data, the target for the number of 2024 closed multi-family projects is 50 buildings.

A.2.6.1 Notable Changes

In 2021, the Multifamily program offering expanded to include Existing Building scenarios. In 2022, ENERGY STAR rebates were included for Clothes Washer, and for the bundling of ENERGY STAR measures. The measures are required to be “bundled” to ensure cost effectiveness. Eligible measures for the bunding approach include ENERGY STAR Clothes Washers, ENERGY STAR Refrigerators, and ENERGY STAR Dishwashers. Elevator Modernization was also added to the offering. These offerings will continue to be available in 2024.

A.2.6.2 Program Delivery

The Multifamily program participation is driven through partnerships with developers and industry associations. Developer relationships are an integral part of the growing Multifamily program.

TRC also holds weekly open-house meetings for all participant Lead Partners and Developers. Interested Lead Partners and Developers can speak one-on-one with a member of the Commercial or Residential team to learn more about the program and navigate the application.

A.2.6.3 Target Market

The Multifamily program is offered to developers and building owners who install efficient equipment in low-rise or high-rise multi-family buildings consisting of five or more units.

A.2.6.4 Measures and Incentives

The Multifamily program offers rebates for measures found in the following programs:

- Residential Home Comfort Program
  - Partial and Whole Unit Air Source Heat Pumps
  - Smart Thermostats and Integrated Controls
- Residential EEP Program
  - ENERGY STAR/Most Efficient Appliances
  - ENERGY STAR Appliance Bundles
  - ENERGY STAR Lamps
  - Water Heating Equipment
  - Advanced Power Strips
  - Smart Thermostats
- Geothermal Program

  - Vertical Stack Heat Pumps
  - Water to Air Heat Pumps
  - Water to Water Heat Pumps
  - DGX
- Commercial HVAC Program
- Custom HVAC Program
  - VRFs
  - Cold Climate Air Source Heat Pumps
- Commercial Prescriptive Program
  - VFDs
  - Pool Equipment
  - Elevator Modernization
    - Existing Building Only
- Commercial Lighting Program
  - Interior Lighting
  - Exterior Lighting

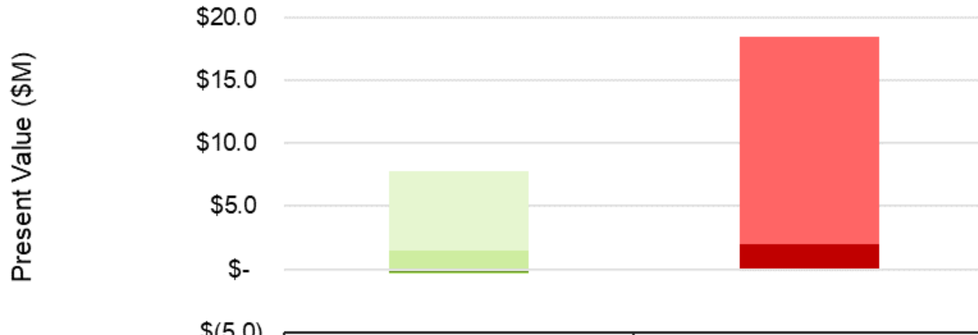
A.2.6.5 Outreach

The CEP engages with Multifamily developers and building owners by working with PSEG Long Island Major Account Executives (MAEs) to send out email blasts, and meeting with industry associations like the Building Owners and Management Association (BOMA) and the Long Island Building Institute (LIBI).

A.2.6.6 Business Case

The Multifamily program has a SCT benefit-to-cost ratio of 0.40 and RIM benefit-to-cost ratio of 0.07. A list of the value streams considered in the BCA is detailed in Figure A-8 and Table A-23.

Figure A-8. Multifamily Program Present Value Benefits and Costs



	Benefit	Cost
Fuel Switching Benefits	6.32	-
Net Avoided SO2 and NOx	0.000056	-
Net Avoided CO2	1.50	-
Avoided Distribution Capacity Infrastructure	(0.12)	-
Avoided Transmission Capacity Infrastructure	(0.05)	-
Avoided Energy (LBMP)	(0.10)	-
Avoided Generation Capacity Cost (AGCC)	(0.10)	-
Participant DER Cost	-	16.44
Program Administration Costs	-	2.01
Total	7.44	18.45

Table A-23. Multifamily Program Value Streams

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
1	**Fuel Switching Benefits**	Considers participant fuel cost savings associated with switching from oil, gas, and propane to electricity.	6.32	
2	**Net Avoided SO_2 and NOx**	Reduced SO_2 and NOx from reduced energy consumption.	0.000056	
3	**Net Avoided CO_2**	Reduced carbon emissions from reduced energy consumption and beneficial electrification.	1.50	
4	**Avoided Distribution Capacity Infrastructure**	Based on demand savings and marginal distribution capacity cost.	(0.12)	
5	**Avoided Transmission Capacity Infrastructure**	Based on demand savings and marginal transmission capacity cost.	(0.05)	
6	**Avoided Energy (LBMP)**	Energy savings based on both on-peak and off-peak periods.	(0.10)	
7	**Avoided Generation Capacity Cost (AGCC)**	Based on demand savings and marginal capacity cost.	(0.10)	

8	**Participant DER Cost**	Includes cost of incremental equipment and installation.		16.44
9	**Program Administration Costs**	Includes contractors fee, labor, evaluation, and advertising costs.		2.01
	Total Benefits		**7.44**	
	Total Costs			**18.45**
	SCT Ratio		**0.40**	

A.2.7 Commercial Efficiency Program

PSEG Long Island's CEP offers eligible nonresidential customers rebates for a number of energy savings conversation measures and engineering and design services. The rebates are intended to offset installation costs and costs associated with projects that go through the Technical Assistance program.

In 2024, and through program year 2025, PSEG Long Island's CEP proposes providing customer rebates for the following EE measures:

- Lighting
  - Indoor Lighting
    - Performance Based
    - Prescriptive (Fast Track)
  - Outdoor Lighting
- HVAC
  - Performance Based
- Geothermal
- Standard Application
  - Variable Frequency Drives
  - Compressed Air
  - Kitchen Equipment
  - Elevator Modernization
- Refrigeration
- Water Heating and Conservation
- Commercial Weatherization
  - Duct Sealing
  - Air Sealing
  - Envelope Insulation
  - Air Curtains
  - Pipe Insulation
- Custom and Custom Retrofit
  - Data Collection forms for Chillers, Data Centers, Measurement and Verification (M&V), Heat Pumps & Variable Refrigerant Flow (VRFs)
- Beneficial Electrification
  - Non-Road EVs
  - Battery Operated Lawn Care Equipment
  - Pool Equipment
  - Electric Kitchen Equipment
- Technical Assistance (TA) Program:
  - LEED Certification and Points

- ENERGY STAR Labeled Buildings
- Energy Engineering Study
- Whole Building (Energy Modeling)

The CEP strives to deliver a positive customer experience through the diverse portfolio of measures and rebates. The CEP also provides participating lead partners with equipment training, program education, and other tools to deliver a first-class participation experience for the customer. Similar to previous years, the CEP continues to implement the Prime Efficiency Partner Program. All lead partners who have been certified as Prime Efficiency Partners (PEPs) are vetted, trained, and tested on CEP guidelines and program requirements. All PEPs must re-apply for certification each year.

A.2.7.1 Notable Changes

In 2024, the CEP continues to offer the performance based interior lighting program that incentivizes customers and contractors to install the most energy efficient equipment available. In past years, the CEP lighting rebates were more in line with a prescriptive rebate approach and rebated per fixture. The 2024 rebate is based on energy savings. As LED lighting programs begin to phase out between 2024-2025, LED lighting will be rebated using an approach best in line with market conditions.

To prepare for a future beyond lighting, in 2022 the CEP launched two new Programs and adjusted the existing Custom Performance Rebate program offering.

The Commercial Water Heating and Conservation application was launched in January 2022. The application offers rebates to all Commercial customers who utilize electric water heating equipment or install electric water heating equipment through the offering. Other measures in the application include, Pre-Rinse Spray Valves, Low-Flow Faucets, Low Flow Showerheads, Pipe Insulation, Low Flow Salon Valves, ENERGY STAR Clothes Washers and ENERGY STAR Dryers.

In the summer of 2022, the CEP removed the Small-Medium Business Whole Building Heat Pump offering from the HVAC application and moved the offering to the Custom Performance Program. The Custom Performance Program application was updated to include Heat Pumps and VRFs. The rebate was also increased to align with neighboring utilities. All commercial customers may participate in the Custom Heat Pump/VRF offering. The shift in the offering has already demonstrated positive impacts on customer engagement, increased number of Heat Pump and VRF project submittals, and electrifying more commercial buildings.

In the fourth quarter of 2022, the CEP launched a Small Business Commercial Weatherization application. The application offers rebates to small business commercial customers who have an existing building, and the building is 10,000 square feet or less. New Construction buildings are not eligible. Buildings over 10,000 square feet are not eligible. The following measures are included in the application, duct sealing, air sealing, envelope insulation, air curtains, and pipe insulation (electric water heating system only). To qualify for rebates, air sealing and insulation must be installed.

In 2020, PSEG Long Island's EEDR programs' main goal metric was adjusted from kWh to MMBtu. The adjustment in the program's metric was necessary to better align the portfolio with New York State's GHG reduction goals. Adjusting the metric paved the way for the CEP to develop a fuel agnostic methodology for fuel switching measures like air source heat pumps and variable frequency drives. The adjustment in metric also allowed the CEP to explore other fuel switching, or beneficial electrification, measures. The CEP launched a prescriptive beneficial electrification program to target those necessary MMBtu savings. Equipment offered under this program component includes battery-operated non-road EVs (golf carts and forklifts), heat pump pool heaters and solar covers, and kitchen equipment.

In 2024-2025, the CEP will continue to incorporate measures and programs that support the MMBtu savings goal.

A.2.7.2 Program Delivery

The CEP participation is driven through partnerships with installation contractors, or Lead Partners. Customers may opt to participate as a self-install, but participation is primarily driven through lead partners. The CEP collaborates with lead partners and provides a platform for lead partners to work directly with representatives from the CEP at weekly open-house meetings. The weekly open house meetings allow contractors to talk about program requirements, applications, and to provide feedback on the participant experience. The CEP also offers training sessions on new technologies and new programs. In-person contractor meetings and trainings were suspended in 2020 due to the pandemic, however, the EE Programs pivoted traditional meeting methods to virtual. The CEP continues to utilize the virtual meetings to keep the lead partners engaged and supported. In 2023, TRC began hosting the Friday Open House Meetings In-Person, as well as virtual. This practice will continue in 2024.

In addition to the weekly contractor meetings and trainings, TRC hosts several contractor breakfasts, new technology expos, and regularly participates in industry events such as USGBC, ASHRAE, HIA, and AIA. TRC, on behalf of PSEG Long Island, coordinates and hosts an EE conference that now occurs on a biannual basis. The conference is open to all customers and contractors and provides networking opportunities, informative seminars with industry leaders, market trends, emerging technologies, and highlights project successes. In 2019, attendance reached over 600, with nearly half attendees being customers. The event is well regarded throughout Long Island as the EE event of the year. It is an excellent platform for the CEP to build camaraderie with participating lead partners and customers, as well as an opportunity for customers and lead partners to stay abreast on industry trends. The EE conference resumed, in-person, in November 2022 and reached close to 500 in attendance. The next conference is scheduled to be held on November 7, 2024.

PSEG Long Island continues to promote contractors who have been certified as Prime Efficiency Partners. The PEPs drive small business participation, making it paramount to train, vet, and promote these contractors. The introduction of the Prime Efficiency Partner network in 2017 has enabled the program to touch more small business customers and bring awareness to the programs. Contractors wishing to participate in the Fast Track program and be designated Prime must meet specific business criteria, complete trainings, and meet the strict program requirements. The launch of the Prime Efficiency Partner program has also played a crucial role in maintaining customer satisfaction. Lead partners who wish to achieve the prime designation can attend scheduled trainings to learn more about the program and become closer to achieve the designation.

The Fast Track Program is a prescriptive rebate program available to all customers who wish to participate in the CEP lighting program through an engaging and speedy solution. All commercial customers may participate in this offering, regardless of rate code or building size. The total rebate for a Fast Track project may not exceed $7,500. The Fast Track Program is unique in that only Prime Efficiency Partners may participate, and pre-approvals and pre-inspections are not required. Allowing Prime Efficiency Partners only in the Fast Track offering ensures the customer has a positive program experience with a PSEG Long Island trained and vetted contractor.

All lead partners, including PEPs, are subject to Quality Control Evaluation procedures as necessary, in an effort to ensure continued quality installations for commercial customers.

A.2.7.3 Target Market

All nonresidential customers in the PSEG Long Island service territory.

A.2.7.4 Measures and Incentives

Custom and Custom Retrofit project rebates are calculated by the PSEG Long Island CEP Project Screening Tool. Rebates are calculated based on four primary inputs: kW, kWh, incremental cost, and fossil fuel impacts, with overall $/MMBtu and percentage of project cost as caps. The default rebate calculation methodology in the tool is set at $/MMBtu, however, the tool allows $/kW, $/kWh, Simple Payback, %Incremental cost and weighted as selections that require project specific approval. For all other measures, rebates are set per market conditions, and may adjust during the year as the market changes. All measures are subject to cost/benefit screening prior to launch.

A.2.7.5 Outreach

The CEP team offers free energy assessments to all eligible PSEG Long Island commercial customers. Customers who request an assessment are contacted by a CEP Energy Consultant (EC) to arrange a site visit or virtual site visit. During the assessment, the EC conducts an audit of the facility, provides the customer with program information and recommendations, and leaves behind program collateral like a checklist complete with energy saving tips. The checklist covers the four core measure groups Lighting, HVAC, Compressed Air, and Refrigeration.

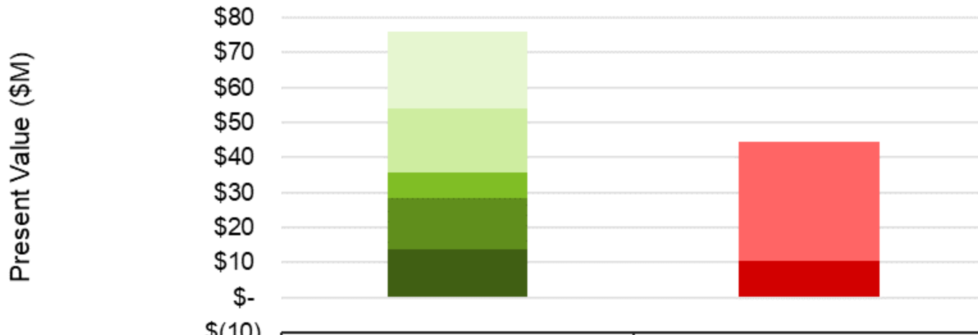
The CEP team also works closely with participating lead partners to drive program awareness and interacts with customers at Community Partnership Program (CPP) events to promote different program offerings and connect one on one with PSEG Long Island customers.

New in 2023, PSEG Long Island launched a new outreach initiative called “Counter Days”. Counter Days bring together PSEG Long Island ECs and Prime Efficiency Partners (PEP) who are also distributors. The EC coordinates with the PEP in advance and delivers program banners to the distributor’s location and spends the day at the counter. This initiative connects ECs with the PEP and electricians who are stopping at the counter to pay for/pick-up materials for commercial installations.

A.2.7.6 Business Case

The Commercial programs have a SCT benefit-to-cost ratio of 1.69 and RIM benefit-to-cost ratio of 0.29. A list of the value streams considered in the societal benefit-cost analysis is detailed in Figure A-9 and Table A-24.

Figure A-9. Commercial Efficiency Program Value Present Value Benefits and Costs of SCT



	Benefit	Cost
Fuel Switching Benefits	(0.37)	-
Net Avoided SO2 and NOx	(0.000006)	-
Net Avoided CO2	21.96	-
Avoided Distribution Capacity Infrastructure	18.11	-
Avoided Transmission Capacity Infrastructure	7.45	-
Avoided Energy (LBMP)	14.78	-
Avoided Generation Capacity Cost (AGCC)	13.70	-
Participant DER Cost	-	34.22
Program Administration Costs	-	10.47
Total	75.62	44.68

Table A-24. Commercial Efficiency Program Value Streams

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
1	**Fuel Switching Benefits**	Considers participant fuel cost savings associated with switching from oil, gas, and propane to electricity.	(0.37)	
2	**Net Avoided SO_2 and NOx**	Reduced SO_2 and NOx from reduced energy consumption.	(0.000006)	
3	**Net Avoided CO_2**	Reduced carbon emissions from reduced energy consumption and beneficial electrification.	21.96	
4	**Avoided Distribution Capacity Infrastructure**	Based on demand savings and marginal distribution capacity cost.	18.11	
5	**Avoided Transmission Capacity Infrastructure**	Based on demand savings and marginal transmission capacity cost.	7.45	
6	**Avoided Energy (LBMP)**	Energy savings based on both on-peak and off-peak periods.	14.78	
7	**Avoided Generation Capacity Cost (AGCC)**	Based on demand savings and marginal capacity cost.	13.70	

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
8	**Participant DER Cost**	Includes cost of incremental equipment and installation.		34.22
9	**Program Administration Costs**	Includes contractors fee, labor, evaluation, and advertising costs.		10.47
	Total Benefits		**75.62**	
	Total Costs			**44.68**
	SCT Ratio		**1.69**	

A.2.8 Clean Green Schools

PSEG Long Island is not proposing any funding to the Clean Green Schools Initiative in 2024. No schools in PSEG Long Island's service territory were selected by NSYERDA for the program in its most recent offering, which will result in no expenditures taking place for Long Island schools next year. PSEG Long Island expects to remain in contact with NYSERDA and the initiative, but no budgetary requirements will be reflected in the plan.

A.2.9 Dynamic Load Management Programs

LIPA introduced three DLM programs to the electric tariff effective April 1, 2016. The DLM Tariff was designed to be consistent with the objectives of REV by providing innovative market-based solutions to T&D system needs. The program is effective during the capability period, which is May 1-September 30.

The DLM Tariff consists of a direct load control (DLC) tariff program and a DR tariff program. The Bring Your Own Device Smart Savers Program allows residential and small commercial customers who have smart thermostats to provide PSEG Long Island with control of their thermostats during times of high electric demand periods to curtail overall electric demand. In exchange for this control, participating customers will receive a one-time $85 enrollment payment. In subsequent years, the customer will receive an annual $25 performance payment linked to their actual curtailment usage, when customers fully participate in a minimum of 50% of the curtailment events during the capability period.

The second part of the DLM tariff is a more traditional DR tariff, which emulates the New York Independent System Operator's Emergency DR and Special Case Resource programs. Under this tariff, medium-to-large size commercial customers or residential and small commercial customers in aggregation would sign up and be obligated to the Company to reduce their load by a specified amount when called on either through a day-ahead notification or in reliability need times two hours ahead.

For the DLC Smart Savers Program, PSEG Long Island will communicate with each participating customer's individual thermostat; and for the Commercial System Relief Program (CSRP)/ Distribution Load Relief Program (DLRP), PSEG Long Island will instruct aggregators and/or customers to curtail during a DR event one day or two hours in advance dependent on whether the CSRP or DLRP is initiated.

A.2.9.1 Notable Changes

Effective June 1, 2019, LIPA approved the use of battery storage (whether standalone or paired with other DER) for both residential and commercial customers as part of the DLM tariff program. Eligible customers enrolled in the DLM tariff program with qualifying battery storage and battery storage systems paired with solar equipment will receive a reservation payment locked in for up to 10 years from the date of initial enrollment.

A.2.9.2 Program Delivery

To implement the DLM Tariffs, EnergyHub was contracted to administer the tariff requirements and implement the program.

Direct Load Control Smart Savers Program

The Smart Savers Program will pay customers $85 to enroll their smart thermostat in the program. The thermostat will allow PSEG Long Island to curtail usage of central air conditioning systems in the home or small business. In addition, the customer will receive a $25 payment for each subsequent year they remain in the program and fully participate in a minimum of 50% of the curtailment events during the capability period. The customer must utilize an approved thermostat provider and install the device in their home or business. Approved thermostat providers market and promote the program to potential customers, and customers enroll in the Smart Savers Program through the smart thermostat electronic application. The device is an internet-connected thermostat that is registered with the program enrollment administrator and is linked to PSEG Long Island through an enrollment portal. PSEG Long Island initiates a load reduction curtailment day when appropriate, during the program capability period.

Commercial System Relief Program

The CSRP creates the opportunity for market forces to identify and implement load relief measures that would allow PSEG Long Island to avoid building new distribution capacity at specific locations along the T&D system. The goal of the program is to have the market provide such solutions and for PSEG Long Island to spend less on T&D upgrades and projects.

The CSRP offers several features to both individual customers and aggregators of customers in the program. The program scope consists of:

- Monthly reservation payments per kW for commitments to reduce load on 21 hours' notice. The current reservation payment is $5/kW/month.
- Performance payments for each kWh of energy curtailed during a called event, lasting up to 4 hours. The current performance payment is $0.25 per kWh reduced during a curtailment event.

Customers and aggregators may participate by reducing or deferring load, or utilizing dispatchable onsite generation options, to meet the commitment to reduce their load on the system. Generation options must meet strict emissions criteria to be eligible for the program. AMI metering is also required of all customers enrolled in the program. All load reduction provided during a called curtailment event will be quantified using a Customer Base Load methodology, which requires detailed usage information made available on a timely basis.

Distribution Load Relief Program

The DLRP creates the opportunity to reduce electric load in certain designated zones or "load pockets" on the PSEG Long Island system. These load pockets will be identified, when necessary, by PSEG Long Island and posted to the PSEG Long Island website. The DLRP offers:

- Monthly reservation payments per kW for commitments to reduce load on two-hours' notice. The current reservation payment is $3/kW/month of enrolled load reduction.

- Performance payments for each kWh of energy curtailed during a called event lasting up to 4 hours. The current performance payment for load reduced during a called event is $0.25 per kWh.

Customers and aggregators may participate by reducing or deferring load, or utilizing dispatchable onsite generation options, to meet the commitment to reduce their load on the system. Generation options must meet strict emissions criteria to be eligible for the program. AMI metering is also required of all customers enrolled in the program. All load reduction provided during a called curtailment event will be quantified using a Customer Base Load methodology, which requires detailed usage information made available on a timely basis.

A.2.9.3 Customer Enrollment/Financial Impacts

The financial impacts of the three proposed programs are expected to be favorable to ratepayers on a net present value basis. Each of the three programs involves payments that are less than the costs that can be avoided from their implementation, producing a net benefit to ratepayers; the Benefit-Cost Analysis is included in the DLM Annual Report. Table A-25 shows the enrollment activity as of January 1, 2023.

Table A-25. DLM Tariff Results as of January 1, 2023

Program	2022 Customers	2022 Measured Load Reduction (MW)	2022 Curtailment Events	Curtailment Events (2016-2022)
Smart Savers Program*	43,862	37.7***	2	26
CSRP/DLRP**	397	21.6****	6	37

*Enrollment is cumulative
**Customers enrolled for the 2022 season, May 1 – September 30
***Number of devices multiplied by the average load shed per device
****Contracted load relief

In 2022, most customers enrolled in CSRP were also enrolled in DLRP. The MW reductions shown in Table A-26 reflects the performance from both programs combined and are not additive.

Table A-26. DLM Tariff 5 Year Forecast

Associated Capacity (MW)	2024	2025	2026	2027	2028
DLC	54.8	60.8	66.8	72.8	78.8
CSRP	24.5	26.2	28.1	30.0	32.1
DLRP	24.5	26.2	28.1	30.0	32.1
Total	**79.3**	**87.0**	**94.9**	**132.8**	**143.0**
DLC Customer Payment	$1,730,175	$1,880,175	$2,030,175	$2,180,175	$2,330,175
CSRP Reservation Payment	$612,522	$655,398	$701,276	$750,365	$802,891
DLRP Reservation Payment	$367,513	$393,239	$420,766	$450,219	$481,734
CSRP/DLRP Performance Payment	$98,003	$104,864	$112,204	$120,058	$128,463
Total Payments	**$2,808,213**	**$3,033,675**	**$3,264,421**	**$3,500,818**	**$3,743,263**

*All DLM payments are collected through the Power Supply Charge and therefore do not impact the operating budget.

A.2.10 Behavioral Initiative (HEM)

This HEM Program that was launched in the third quarter of 2017 supports statewide goals under REV to create a cleaner, more resilient, and affordable energy system for all New Yorkers. Through regulatory overhaul, REV encourages the cleanest, most advanced, and efficient power system operation. State programs supporting clean energy are being redesigned to accelerate market growth and unlock private investment. This program will advance progress toward New York State's goals of achieving a 40% reduction in GHG levels and a 185 TBtu increase in statewide EE by 2030.

A.2.10.1 Program Delivery

PSEG Long Island's overarching objective of this program is to motivate and inspire PSEG Long Island customers to increase their understanding of all aspects of their energy needs and take active control of their energy usage. Indications are that this program has resulted in increased customer satisfaction, increased customers' understanding and ability to manage their energy usage, increased customer adoption of existing EE offerings, improved customer access to energy efficient products and clean energy service providers (i.e. EE, residential solar, community solar, DR and related services), and has fostered the development of marketplace solutions such as smart thermostats which will induce deeper clean energy penetration and leverage greater private investments in such efforts. Outcomes undergoing evaluation include:

- Customer bill savings
- Reduction in GHGs
- Clean energy penetration including increased use of renewable and low carbon sources,
- Demand and capacity reductions
- Greater private sector investment in clean energy solutions,
- Customer satisfaction

This HEM program enables residential customers to realize cost-effective verifiable EE savings, while also increasing awareness and adoption of applicable programs, products and services, and increases customer satisfaction.

A.2.10.2 Notable Changes

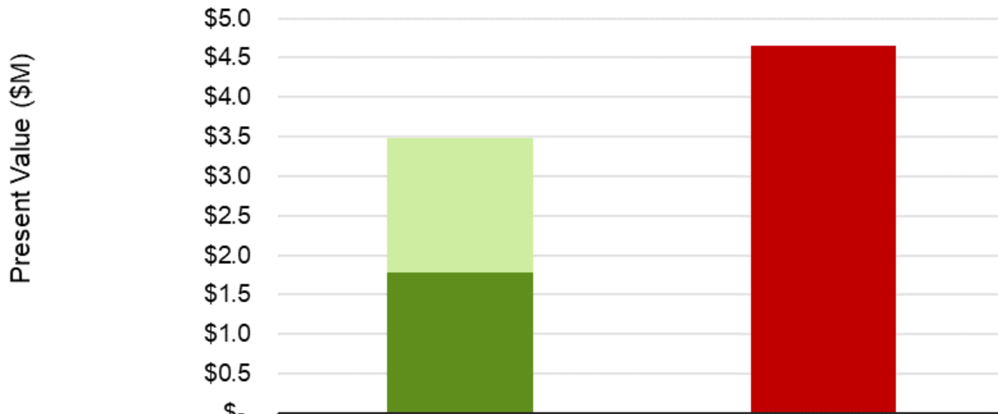
PSEG Long Island expects to increase distribution of the Home Energy Report treatment group to number approximately 700.000 residential customers in 2024. All residential customers will have access to the HEM MyEnergy engagement portal and online Home Energy Assessment function. The main reasons for the increase in customers are as follows:

- Given the shift to TOD for most residential customers, educating customers with reports on energy usage and time is an additional opportunity to market to them to save money by shifting usage time.
- To reach the energy savings goals without LEF lighting, PSEG Long Island plans to send out more energy reports to entice alternative program savings.

A.2.10.3 Business Case

HEM has a SCT benefit-to-cost ratio of 0.72 and RIM benefit-to-cost ratio of 0.10. A list of the value streams considered in the BCA is detailed in Figure A-10.

Figure A-10. Present Value Benefits and Costs of SCT – HEM



	Benefit	Cost
Net Avoided CO2	1.72	-
Avoided Distribution Capacity Infrastructure	-	-
Avoided Transmission Capacity Infrastructure	-	-
Avoided Energy (LBMP)	1.78	-
Avoided Generation Capacity Cost (AGCC)	-	-
Program Administration Costs	-	4.65
Total	3.49	4.65

Table A-27. HEM Value Streams

#	Value Stream	Calculation Methodology	Benefits (NPV, $M)	Costs (NPV, $M)
1	**Fuel Switching Benefits**	Considers participant fuel cost savings associated with switching from oil, gas, and propane to electricity.	0.00	
2	**Net Avoided SO_2 and NOx**	Reduced SO_2 and NOx from reduced energy consumption.	0.00	
3	**Net Avoided CO_2**	Reduced carbon emissions from reduced energy consumption and beneficial electrification.	1.72	
4	**Avoided Distribution Capacity Infrastructure**	Based on demand savings and marginal distribution capacity cost.	0.00	
5	**Avoided Transmission Capacity Infrastructure**	Based on demand savings and marginal transmission capacity cost.	0.00	
6	**Avoided Energy (LBMP)**	Energy savings based on both on-peak and off-peak periods.	1.78	
7	**Avoided Generation Capacity Cost (AGCC)**	Based on demand savings and marginal capacity cost.	0.00	

8	**Participant DER Cost**	Includes cost of incremental equipment and installation.		0.00
9	**Program Administration Costs**	Includes contractors fee, labor, evaluation, and advertising costs.		4.65
	Total Benefits		**3.49**	
	Total Costs			**4.65**
	SCT Ratio		**0.75**	

Appendix B. Benefit-Cost Analysis Handbook

This Benefit-Cost Analysis Handbook has been developed in conjunction with efforts undertaken by New York State Investor-owned Utilities in response to the State of New York Public Service Commission (NYPSC) direction to the JU[90] to develop and file Benefit-Cost Analysis (BCA) Handbooks by June 30, 2016, as a requirement of the Order Establishing the Benefit-Cost Analysis Framework (*BCA Order)*.[91]

This BCA Handbook is intended to set forth PSEG Long Island's approach to Benefit-Cost analysis for purposes of screening annual EE Portfolio Plans and will be updated in the future to reflect any approach used for the potential procurement of DER as NWA to planned Transmission and Distribution capital investments ("Non-Wire Solutions").

B.1 Introduction

The BCA Handbook provides methods and assumptions that will be used to inform BCA for the above types of expenditure and strives to be consistent with statewide methodologies adopted by the JU unless operational or procurement practices would require an alternative approach

The BCA Handbook endeavors to meet the following foundational goals

1. Be based on transparent assumptions and methodologies; list all benefits and costs including those that are localized and more granular.
2. Avoid combining or conflating different benefits and costs.
3. Assess portfolios rather than individual measures or investments (allowing for consideration of potential synergies and economies among measures).
4. Address the full lifetime of the investment while reflecting sensitivities on key assumptions.
5. Compare benefits and costs to traditional alternatives instead of valuing them in isolation

B.1.1 Application of the BCA Handbook

The evaluation of cost-effectiveness of programs and alternative solutions compared to traditional infrastructure investments and utility investments is a complex and sometime difficult analysis which requires the consideration of many factors – some which lend themselves to relatively clear quantification and some which are more challenging. Similarly, a like for like comparison cannot necessarily always be completed for each aspect of a potential solution.

The evaluation of cost-effectiveness of programs and alternative solutions compared to traditional infrastructure investments and utility investments is a complex and sometime difficult analysis which requires the consideration of many factors – some which lend themselves to relatively clear quantification and some which are more challenging. Similarly, a like for like comparison cannot necessarily always be completed for each aspect of a potential solution.

[90] For the purpose of this document, Joint Utilities includes Consolidated Edison Company of New York, Inc., Orange and Rockland Utilities, Inc., Central Hudson Gas & Electric Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, New York State Electric and Gas Corporation, and Rochester Gas & Electric Corporation.

[91] *BCA Order*: Case 14-M-0101, Order Establishing the Benefit Cost Analysis Framework (issued January 21, 2016).

In any such analysis it is important to recognize that the end results are highly dependent upon the forecasting, financial and framework assumptions which are used for both the base case and program and/or opportunity being compared to the base case.

This BCA Handbook includes key assumptions, data sources and overall approach methods which will be used for conducting a BCA for the EE Program Portfolio. Included are methodologies and descriptions of how benefits and costs are calculated as well as how different means of cost effectiveness testing can be conducted.

The BCA Handbook attempts to provide a common approach to conducting BCA across investments in programs, projects and portfolios while also noting instances where individual investment characteristics may need to be considered.

This BCA Handbook is envisioned to be a dynamic work which may be amended going forward as implementation of the BCA process reveals details or aberrations which may not have been foreseen in the initial drafting of the Handbook.

Lastly, the BCA Handbook will identify the source of data to be used based upon applicability of project. Table B-1 lists the statewide data and sources to be used for BCA and referenced in this Handbook.

Table B-1. New York Assumptions

New York Assumptions	Source
Energy and Demand Forecast	NYISO: Load & Capacity Data
Historical Ancillary Service Costs	NYISO: Markets & Operations Reports
Wholesale Energy Market Price Impacts	DPS Staff: To be provided
Allowance Prices (SO_2, and NO_X)	NYISO: CARIS Phase 2
Net Marginal Damage Cost of Carbon	DPS Staff: To be provided

Utility-specific assumptions include data embedded in various utility published documents such as rate cases. Table B-2 lists the suggested utility-specific assumptions for the BCA Handbook.

Table B-2. Utility-Specific Assumptions

Utility-Specific Assumptions	Source
Weighted Average Cost of Capital	[Utility-specific] Rate Case
Losses	[Utility-specific] Electric Loss Report
Marginal Cost of Service	[Utility-specific] Marginal Cost of Electric Delivery Service Study
Reliability Statistics	DPS: Electric Service Reliability Reports[92]
Restoration Costs	[Utility-specific]
Avoided Generation Capacity Cost (AGCC)	Utility-specific

[92] The 2020 Annual Electric Service Reliability Report is available at: https://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/d82a200687d96d3985257687006f39ca/$FILE/2020%20Electric%20Reliability%20Report.pdf.

Utility-Specific Assumptions	Source
Avoided Cost of Energy (ACE)	Utility-specific

The New York general and utility-specific assumptions that are included in this first version of the BCA Handbook (as listed in Table B-1 and Table B-2) are typically values by zone or utility system averages. In subsequent versions, application of the BCA Handbook may be enhanced by including more granular data, for example with respect to location (e.g., zone, substation, or circuit) or time (e.g., seasonal, monthly, or hourly) if available.

The BCA methodology underlying the BCA Handbook is technology-agnostic and should be broadly applicable to all anticipated project and portfolio types with some adjustments as necessary. BCA development will require the standard inputs provided in the BCA Handbook as well as project-specific information that captures locational and temporal aspects of the investment under analysis.
The BCA Handbook is anticipated to be revisited for updates every two years. However, it is anticipated that Utility Provided Data for energy and capacity will updated annually. Additionally, during the two-year interim, the Handbook and associated appendices may be updated at any time such changes are deemed to be necessary.

B.1.2 BCA Handbook Version

This 2022 BCA Handbook v4.0 provides techniques for quantifying the benefits and costs identified in the BCA Order. Interim revisions will be limited to material changes to input assumptions and/or new guidance or orders.

B.1.3 Structure of the Handbook

The four remaining sections of the Handbook explain the methodology and assumptions to be applied under the BCA Framework:

- **Section B.2. General Methodological Considerations** describes key issues and challenges to be considered when developing project-specific BCA models and tools based on this BCA Handbook.
- **Section B.3 Relevant Cost-Effectiveness Tests** defines each cost-effectiveness test included in the BCA Framework. These include the Societal Cost Test (SCT), the UCT, and the Rate Impact Measure (RIM). The *BCA Order* specifies the SCT as the primary measure of cost-effectiveness.
- **Section B.4 Benefits and Costs Methodology** provides detailed definitions, calculation methods, and general considerations for each benefit and cost.
- **Section B.5 Characterization of DER profiles** discusses which benefits and costs are likely to apply to different types of DER and provides examples for a sample selection of DERs.
- **Section 0 Utility-Specific Assumptions** includes value assumptions to be applied to the quantifiable energy and non-energy impacts of projects and portfolios.

B.2 General Methodological Considerations

This section describes key issues and challenges that that must be considered when developing project- or portfolio-specific BCAs. These considerations are incorporated into the benefit and cost calculation methods presented in Section B.4.

B.2.1 Avoiding Double Counting

A BCA must be designed to avoid double counting of benefits and costs. Double counting can be avoided by 1) careful tracking of the value streams resulting from multiple investment elements in a project, program, or portfolio and 2) clear definition and differentiation between the benefits and costs included in the analysis.

Sections B.2.1.1 and B.2.1.2 discuss these considerations in more detail.

B.2.1.1 Accounting of Benefits and Costs Across Multiple Value Streams

The BCA Handbook provides a methodology for calculating the benefits and costs resulting from utility investments as portfolios of projects and programs or as individual projects or programs. A project or program will typically involve multiple technologies, each associated with specific costs. Each technology also provides one or more functions that result in quantified impacts, which are valued as monetized benefits.

Investments may be made in technologies that do not result in direct benefits but instead function to enable or facilitate the realization of benefits from additional measures or technologies. Some technologies may both enable or enhance the benefits of other technologies and result in direct benefits though a parallel function. It is important not to double-count benefits resulting from multiple measures or technologies functioning together to achieve an impact. Determination of which impacts and benefits are derived from which investment elements will often depend on how and/or in what order the elements are implemented.

Enabling technologies such as an advanced distribution management system or a communications infrastructure are often crucial in achieving the impact and benefits of grid modernization projects. These infrastructure investments may be necessary for the implementation of other technologies, projects, or programs, and in some cases the same investments could also enable a given asset to achieve additional benefits beyond what that asset may have been able to achieve on its own. Over time, investments made as part of previous projects or portfolios may also enable or enhance new projects.

Multiple technologies may result in impacts that produce the same benefits. For example, there are many ways in which distribution grid modernization investments could affect the frequency and duration of sustained outages. Advanced meters equipped with an outage notification feature, an outage management system, automated distribution feeder switches or reclosers, and remote fault indicators are some examples of technologies that could all reduce the frequency or duration of outages on a utility's distribution network and result in Avoided Outage Cost or Avoided Restoration Cost benefits.

The utility BCA must also address the non-linear nature of grid and DER project benefits. For example, impact on Avoided Distribution Capacity Infrastructure of an energy storage project may be capped based on the interconnected load on the given feeder. If there is 1 MW of potentially deferrable capacity on a feeder with a new battery storage system, installation of a 5-MW storage unit will not result in a full 5 MW-worth of capacity deferral credit for that feeder. As another example, the incremental improvement on reliability indices may diminish as more automated switching projects are in place.

B.2.1.2 Benefit Definitions and Differentiation

A key consideration identified in performing a BCA is to avoid double counting of benefits and costs by appropriately defining each benefit and cost.

As discussed in Section B.3, the *BCA Order* identified 16 benefits to be included in the cost-effectiveness tests. The calculation methodology for each of these benefits is provided in Section B.4. Two bulk system benefits, Avoided Generation Capacity Costs (AGCC) and Avoided ACE, result from system coincident peak demand reduction and energy reduction impacts respectively, with avoided cost values derived from multiple components. These impacts and embedded component values included in the AGCC and Avoided ACE benefits may be confused with other benefits identified in the *BCA Order* that must be calculated separately.

Defined below are the avoided transmission and distribution loss impacts resulting from energy and demand reductions that should be included in the calculations of the AGCC and Avoided ACE and differentiate them from the impacts that should be counted as separate Avoided Transmission Losses and Avoided Distribution Losses benefits. Also provided below is the differentiation between the transmission capacity values embedded as components of the AGCC and Avoided ACE values, as well as differentiation between the CO_2, SO_2, and NO_x values embedded in Avoided ACE values and those values that must be applied separately in the Net Avoided CO_2 and Net Avoided SO_2, and NO_x benefits calculations.

Table B-3 provides a list of potentially overlapping AGCC and Avoided ACE benefits.

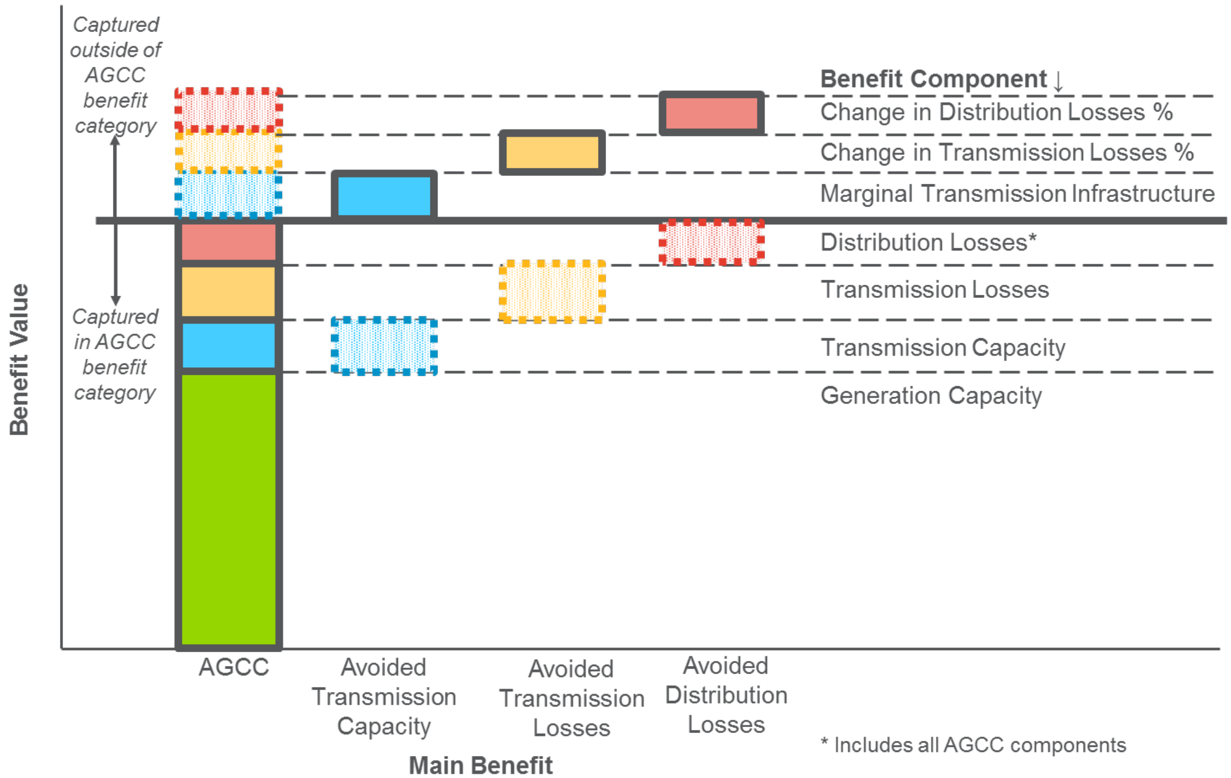
Table B-3. Benefits with Potential Overlaps

Main Benefits	Potentially Overlapping Benefits
Avoided Generation Capacity Costs (AGCC)	Avoided Transmission Capacity Avoided Transmission Losses Avoided Distribution Losses
Avoided ACE (analogous to LBMP)	Net Avoided CO_2 Net Avoided SO_2 and NO_x Avoided Transmission Losses Avoided Transmission Capacity Avoided Distribution Losses

Benefits Overlapping with Avoided Generation Capacity Costs

Figure B-1 graphically illustrates potential overlaps of benefits pertaining to the AGCC.

Figure B-1. Benefits Potentially Overlapping with AGCC (Illustrative)



Source: Guidehouse (formerly Navigant Consulting)

In this stacked column chart, the boxes with solid borders represent impacts and embedded values included in the calculation of the main benefit, while boxes with dotted borders represent impacts excluded from the main benefit but included in calculation of a separate benefit. The benefit shown above, AGCC, includes multiple components that are captured in the AGCC value. These include – ICAP including reserve margin, transmission capacity, and transmission tosses.[93] Additionally, distribution losses can affect the calculation of AGCC, depending on the project location on the system.[94] The AGCC calculation accounts for these distribution losses.

If a project changes the electrical topology and therefore changes the transmission loss percent itself, the incremental changes in transmission losses would be allocated to the Avoided Transmission Losses benefit. Similarly, any incremental changes to distribution loss percent as a result of the project would be included in the Avoided Distribution Losses benefit. These benefits are calculated separately from the AGCC benefit.

Benefits Overlapping with Avoided ACE

Figure B-2 graphically illustrates potential overlaps of benefits pertaining to Avoided ACE.

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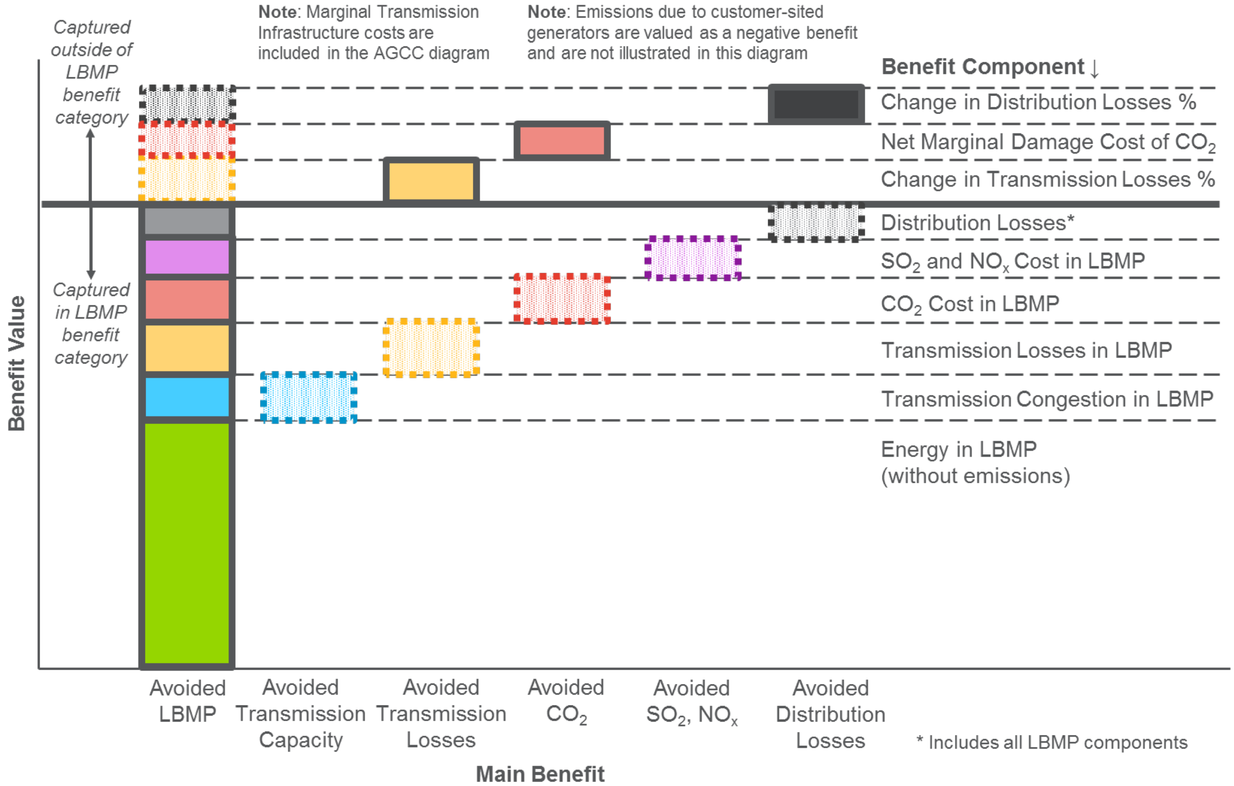
[93] The AGCC includes a portion of avoided transmission capacity infrastructure costs as zonal differences in the ICAP clearing price.

[94] For example, an impact on the secondary distribution system compared to the primary system will have a higher impact on the AGCC due to higher losses.

Figure B-2. Benefits Potentially Overlapping with Avoided ACE Benefit (Illustrative)



Source: Guidehouse (formerly Navigant Consulting)

In this stacked column chart, the boxes with solid borders represent impacts and embedded values included in the calculation of the main benefit, while boxes with dotted borders represent impacts excluded from the main benefit but included in calculation of a separate benefit. As seen in the figure, the stacked solid boxes in the Avoided ACE benefit include costs for factors beyond simple energy cost per megawatt-hour (MWh) of the electricity traded in the wholesale energy market. The following are included in the Avoided ACE benefit:

- Avoided transmission capacity infrastructure costs built into the transmission congestion charge which are embedded in the ACE
- Transmission-level loss costs which are embedded in the ACE
- Compliance costs of various air pollutant emissions regulations including the value of CO2 via the Regional Greenhouse Gas Initiative (RGGI) and the values of SO2 and NOx via cap-and-trade markets which are embedded in the ACE

Additionally, distribution losses can affect ACE purchases, depending on the project location on the system, and should gross up the calculated ACE benefits.[95] To the extent a project changes the electrical topology and changes the distribution loss percent itself, the incremental changes in distribution losses would be allocated to the Avoided Distribution Losses benefit. Similarly, there may be projects that would

[95] For example, an impact on the secondary distribution system compared to the primary system will have a higher impact on the ACE purchases due to higher losses.

specifically impact Avoided Transmission Capacity or change the transmission loss percent. In these instances, the impacts would be captured outside of the Avoided ACE benefit.

B.2.2 Incorporating Losses into Benefits

Many of the benefit equations provided in Section B.4 include a parameter to account for losses. In calculating a benefit or cost resulting from load impacts, the variable losses occurring upstream from the load impact must be accounted for to arrive at the total energy or demand impact. Losses can be accounted for either by adjusting the impact parameter or the valuation parameter. For consistency, all equations in Section B.4 are shown with a loss adjustment to the impact parameter.

The following losses-related nomenclature is used in the BCA Handbook:

- **Losses (MWh or MW)** are the difference between the total electricity send-out and the total output as measured by revenue meters. This difference includes technical and non-technical losses. Technical losses are the losses associated with the delivery of electricity of energy and have fixed (no load) and variable (load) components. Non-technical losses represent electricity that is delivered, but not measured by revenue meters.
- **Loss Percent (%)** are the total fixed and/or variable[96] quantity of losses between relevant voltage levels divided by total electricity send-out unless otherwise specified.
- **Loss Factor (dimensionless)** is a conversion factor derived from “loss percent”. The loss factor is 1 / (1 - Loss Percent).

For consistency, the equations in Section B.4 follow the same notation to represent various locations on the system:

- “r” subscript represents the retail delivery point or point of connection of a DER, for example distribution secondary, distribution primary, or transmission[97]
- “i” subscript represents the interface of the distribution and transmission systems.
- “b” subscript represents the bulk system which is the level at which the values for AGCC and ACE are provided.

Based on the notation described above, if a residential customer is connected to distribution secondary the loss percent parameter called $\mathrm{Loss\%}_{\mathrm{b \to r}}$ would represent the loss percent between the bulk system (“b”) and the retail delivery or connection point (“r”). In this example, the loss percent would be the sum of the distribution secondary, distribution primary and transmission loss percentages. If a large commercial customer is connected to primary distribution the appropriate loss percent would be the sum of distribution primary and transmission loss percentages.

[96] In the BCA equations outlined in Section **Error! Reference source not found.** below, project-specific energy and demand impacts at the retail delivery point are adjusted to the bulk system (or other relevant system location) based on *only* the variable component of the loss percent. In cases where the transmission or distribution loss percent is altered due to a project, the fixed and/or variable loss percent impacts are considered.

[97] Transmission in this context refers to the distribution utility’s sub-transmission and internal transmission.

B.2.3 Establishing Credible Baselines

One of the most significant challenges associated with evaluating the benefit of a grid or DER project or program is establishing baseline data that illustrates the performance of the system without the project or program. The utility may derive baseline estimates from recent historical data, forecasts, statistical or model-based projections, or comparison/control groups (e.g., similar feeders and households) during the course of the project.

Sound baseline data is crucial in measuring the incremental impact of the technology deployment. Because benefits of grid modernization projects accrue over many years, baselines must be valid across the same time horizon. This introduces a few points that merit consideration:

- **Forecasting market conditions**: Project impacts as well as benefit and cost values are affected by market conditions. For example, in the rest of the State, the Commission has directed that Avoided ACE should be calculated based on NYISO's CARIS Phase 2 economic planning process base case ACE forecast. However, the observed benefit of a project will be different if the wholesale energy market behaves differently from the forecasted trends. *Note – in PSEG Long Island's case unless the project was of significant size (~ 100 kW) there generally is no wholesale market implication.*
- **Forecasting operational conditions**: Many impacts and benefits are tied to how the generation, transmission, and distribution infrastructure are operated. In this example, the Commission indicated that benefits associated with avoided CO_2 emissions shall be based on the change in the tons of CO_2 produced by the bulk system when system load levels are reduced by 1%. It is important to note that this impact calculation is an approximation, and it is still very difficult to determine the actual CO_2 reductions at the bulk system level from the impacts of projects implemented at the distribution system level. Project-specific reductions are tied to dispatch protocols based on the optimized operation of the bulk system given a set of preventive post-contingency settings. In addition, the carbon intensity of the generation mix will inevitably change over time independent of any investment at the distribution level.
- **Predicting asset management activities**: Some impacts and benefits, such as Avoided Distribution Capacity Infrastructure, are affected by distribution-level capital investments that may take place independent of the projects being evaluated. In this example, the amount of available excess capacity may change if key distribution assets are replaced and uprated.

There are significant uncertainties surrounding the benefits and costs. Regulatory approvals, technological advances, operational budgets, and other business conditions all affect the cost of deployment, expected system performance, or both. As such, the utility may re-evaluate and revise its baseline data as significant events or developments alter the assumed or implied conditions underlying the existing baseline.

B.2.4 Normalizing Impacts

In addition to establishing an appropriate baseline, normalizing impact data presents similar challenges. This is particularly true for distribution-level projects, where system performance is significantly affected by external conditions beyond that which occurs on the distribution system. For instance, quantifying the impact of technology investment on reliability indices would require the baseline data to be representative of expected feeder reliability performance. This is a challenging task, as historical data would require weather adjustments and contemporaneous data would be drawn from different, but similar, feeders.

A distribution feeder may go through changes that could influence feeder performance independent of the technologies implemented. For instance, planned outages due to routine maintenance activities or outages due to damages from a major storm could impact reliability indices and changes in the mix of customer load type (e.g., residential vs. C&I), which may impact feeder peak load.

B.2.5 Establishing Appropriate Analysis Time Horizon

The duration over which the impact and benefits of new grid and DER investments accrue varies significantly. The time horizon for the analysis must consider several factors, including differences among the lengths of expected useful life of various hardware and software across multiple projects and how to reconcile the differences in these lengths of expected useful lives. The analysis timeframe should be based on the longest asset life included in the portfolio/solution under consideration.[98]

B.2.6 Granularity of Data for Analysis

The most accurate assumptions to use for assessing a BCA would leverage suitable location or temporal information. When the more granular data is not available, an appropriate annual average or system average may be used, if applicable in reflecting the expected savings from use of DER.

More granular locational or temporal assumptions are always preferred to capture the savings more accurately from use of a resource. However, the methodology included in the BCA Handbook would accommodate appropriate system averages in cases where their use is required.

B.3 Relevant Cost-Effectiveness Tests

The *BCA Order* indicates the BCA Handbook shall include "description of the sensitivity analysis that will be applied to key assumptions."[99] As Section B.4 presents, there is a discussion of each of the benefits and costs, and a sensitivity analysis can be performed by changing selected parameters.

The largest benefits for DER are typically the bulk system benefits of Avoided ACE or AGCC. A sensitivity of ACE, $/MWh, could be assessed by adjusting the ACE by +/-10%. Relevant Cost-Effectiveness Tests The *BCA Order* states that the SCT, UCT, and the Rate Impact Measure (RIM) make up the relevant cost-effectiveness tests to be used in the BCA. These cost-effectiveness tests are summarized in Table B-4.

[98] *BCA Order*, pg. 2
[99] *BCA Order*, Appendix C, pg. 31.

Table B-4. Cost-Effectiveness Tests

Cost Test	Perspective	Key Question Answered	Calculation Approach
SCT	Society	Is the State of New York better off as a whole?	Compares the costs incurred to design and deliver projects, and customer costs with avoided electricity and other supply-side resource costs (e.g., generation, transmission, and natural gas); also includes the cost of externalities (e.g., carbon emissions and other net non-energy benefits)
UCT	Utility	How will utility costs be affected?	Compares the costs incurred to design, deliver, and manage projects by the utility with avoided electricity supply-side resource costs
RIM	Ratepayer	How will utility rates be affected?	Compares utility costs and utility bill reductions with avoided electricity and other supply-side resource costs

The *BCA Order* positions the SCT as the primary cost-effectiveness measure because it evaluates impact on society as a whole.

The role of the UCT and RIM is to assess the preliminary impact on utility costs and ratepayer bills from the benefits and costs that pass the SCT. The results of the UCT and RIM test are critical in identifying projects that may require a more detailed analysis of their impact to the utility and ratepayers. Some projects may not provide benefits to the utility and ratepayers, even if it is beneficial to society as a whole. It is important to note, however, that if a measure passes the SCT but its results do not satisfy the UCT and RIM tests, the measure would not be rejected unless a complete bill impact analysis determines that the impact is of a “magnitude that is unacceptable”.[100]

Each cost-effectiveness test included in the BCA Framework is defined in greater detail in the following subsections. Which of the various benefits and costs to include in analysis of individual projects or investment portfolios requires careful consideration, as discussed in Section B.2.

Table B-5 summarizes which cost-effectiveness tests can be applied to the benefits and costs included in the *BCA Order*. The subsections below provide further context for each cost-effectiveness test. The Benefit Costs considered in the screening of the EE Program Portfolio are bolded in the below table.

Table B-5. Summary of Cost-Effectiveness Tests by Benefit and Cost

Section #	Benefit/Cost	SCT	UCT	RIM
	Benefit			
B.4.1.1	Avoided Generation Capacity Costs (AGCC)†	✓	✓	✓
B.4.1.2	Avoided ACE‡	✓	✓	✓
B.4.1.3	Avoided Transmission Capacity Infrastructure†‡	✓	✓	✓

[100] *BCA Order*, pg. 13.

Section #	Benefit/Cost	SCT	UCT	RIM
B.4.1.4	Avoided Transmission Losses†‡	✓	✓	✓
B.4.1.5	Avoided Ancillary Services	✓	✓	✓
B.4.1.6	Wholesale Market Price Impacts**		✓	✓
B.4.2.1	Avoided Distribution Capacity Infrastructure	✓	✓	✓
B.4.2.2	Avoided O&M	✓	✓	✓
B.4.2.3	Avoided Distribution Losses†‡	✓	✓	✓
B.4.3.1	Net Avoided Restoration Costs	✓	✓	✓
B.4.3.2	Net Avoided Outage Costs	✓		
B.4.4.1	Net Avoided CO_2‡	✓		
B.4.4.2	Net Avoided SO_2 and NO_x‡	✓		
B.4.4.3	Avoided Water Impacts	✓		
B.4.4.4	Avoided Land Impacts	✓		
B.4.4.5	Net Non-Energy Benefits***	✓	✓	✓
	Cost			
B.4.5.1	Program Administration Costs	✓	✓	✓
B.4.5.2	Added Ancillary Service Costs	✓	✓	✓
B.4.5.3	Incremental T&D and DSP Costs	✓	✓	✓
B.4.5.4	Participant DER Cost	✓		
B.4.5.5	Lost Utility Revenue			✓
B.4.5.6	Net Non-Energy Costs**	✓	✓	✓

† See Section 0 for discussion of potential overlaps in accounting for these benefits.
‡ See Section 0 for discussion of potential overlaps in accounting for these benefits.
*** The Wholesale Market Price Impacts in the UCT and RIM would be assessed as a sensitivity.*
**** It is necessary to identify which cost-effectiveness test should include the specific benefit or cost in the Net Non-Energy Benefit or Net Non-Energy Cost as it may apply to the SCT, UCT and/or RIM.*

Performing a cost-effectiveness test for a specific project or a portfolio of projects requires the following steps:

- **Select the relevant benefits** for the investment.
- **Determine the relevant costs** from each cost included over the life of the investment.
- **Estimate the impact** the investment will have in each of the relevant benefits in each year of the analysis period (i.e., how much will it change the underlying physical operation of the electric system to produce the benefits).
- **Apply the benefit values** associated with the project impacts as described in Section B.4.
- **Apply the appropriate discount** rate to perform a cost-effectiveness test for a specific project or portfolio. The discount rate is the utility weighted average cost of capital to determine the present value of all benefits and costs.
- **Treat inflation consistently** by discounting real cash flow by real discount rates and nominal cash flows by nominal discount rates. A 2% annual inflation rate should be assumed unless otherwise specified.

B.3.1 Societal Cost Test

Table B-6. Societal Cost Test

Cost Test	Perspective	Key Question Answered	Calculation Approach
SCT	Society	Is the State of New York better off as a whole?	Compares the costs incurred to design and deliver projects, and customer costs with avoided electricity and other supply-side resource costs (e.g., generation, transmission, and natural gas); also includes the cost of externalities (e.g., carbon emissions, and net non-energy benefits)

A majority of the benefits included in the *BCA Order* can be evaluated under the SCT because their impact can be applied to society as a whole. This includes all distribution system benefits, all reliability/resiliency benefits, and all external benefits.

Lost Utility Revenue and Shareholder Incentives do not apply to the SCT, as these are considered transfers between stakeholder groups that have no net impact on society as a whole.

Similarly, the Wholesale Market Price Impact sensitivity is not performed for the SCT because the price suppression is also considered a transfer from large generators to market participants. in the *BCA Order*:

“Wholesale markets already adjust to changes in demand and supply resources, and any resource cost savings that result are reflected in the SCT. Any price suppression over and above those market adjustments is essentially a transfer payment -- simply a shift of monetary gains and losses from one group of economic constituents to another. No efficiency gain results if, for example, generators are paid more or less while consumers experience equal and offsetting impacts. Therefore, the price suppression benefit is not properly included in the SCT beyond the savings already reflected there.”[101]

B.3.2 Utility Cost Test

Table B-7. Utility Cost Test

Cost Test	Perspective	Key Question Answered	Calculation Approach
UCT	Utility	How will utility costs be affected?	Compares the costs incurred to design, deliver, and manage projects by the utility with avoided electricity supply-side resource costs

The UCT looks at impact to utility costs associated with energy, capacity, generation, T&D, overhead, and general and administrative. For this reason, external benefits such as Avoided CO_2, Avoided SO_2 and NO_X, and Avoided Water and Land Impacts do not apply to the UCT. Utilities in New York do not currently

[101] *BCA Order*, pg. 24

receive incentives for decreased CO_2 or other environmental impacts. Benefits related to avoided outages would go to customers and not utilities, so this benefit also does not apply to the UCT.

Participant DER Cost and Lost Utility Revenue are not considered in the UCT because the cost of the DER is not a utility cost and any reduced revenues from DER are made-up by non-participating DER customers through the utility's revenue decoupling mechanism or other means.

B.3.3 Rate Impact Measure

Table B-8. Rate Impact Measure

Cost Test	Perspective	Key Question Answered	Calculation Approach
RIM	Ratepayer	How will utility rates be affected?	Compares utility costs and utility bill reductions with avoided electricity and other supply-side resource costs

The RIM test can address rate impacts to non-participants. External benefits such as Avoided CO_2, Avoided SO_2 and NO_X, and Avoided Water and Land Impacts do not apply to the RIM as they do not directly affect customer rates. Benefits related to avoided outages go to customers but, again, would have no effect on rates.

Participant DER cost does not apply to the RIM because the cost of the DER is not a utility cost. However, any reduced revenues from DER are included as increased costs to other ratepayers as Lost Utility Revenue because of revenue decoupling or other means that transfer costs from participants to non-participants.

B.4 Benefits and Costs Methodology

Each subsection below aligns with a benefit or cost listed in the *BCA Order*. Each benefit and cost includes a definition, equation, and general considerations.

There are four types of benefits which are further explained in the subsections below:

- Bulk System: Larger system responsible for the generation, transmission and control of electricity that is passed on to the local distribution system.
- Distribution System: System responsible for the local distribution of electricity to end use consumers.
- Reliability/Resiliency: Efforts made to reduce duration and frequency of outages.
- External: Consideration of social values for incorporation in the SCT.

Additionally, there are four types of costs that are also considered in the BCA Framework and explained in the subsections below. They are:

- Program Administration: Includes the cost of state incentives, measurement and verification, and other program administration costs to start, and maintain a specific program
- Utility-related: Those incurred by the utility such as incremental T&D, DSP, lost revenues, and shareholder incentives
- Participant-related: Those incurred to achieve project or program objectives

- Societal: External costs for incorporation in the SCT

In this version of the Handbook, for energy, operational, and reliability-related benefits and costs,[102] it is assumed that impacts generate benefits/costs in the same year as the impact. In other words, there is no time delay between impacts and benefits/costs. However, for capacity and infrastructure benefits and costs,[103] it is assumed that impacts generate benefits/costs in the following year of the impact. For example, if a project reduces system peak load in 2020, the AGCC benefit would not be realized until 2021.

B.4.1 Bulk System Benefits

B.4.1.1 Avoided Generation Capacity Costs (AGCC)

AGCC are due to reduced coincident system peak demand. This benefit is calculated by NYISO zone, which is the most granular level for which AGCC are currently available.[104] It is assumed that the benefit is realized in the year following the peak load reduction impact.

The avoided capacity, in $/kw-yr, is calculated using Market Manager, a sophisticated and proprietary PSEG Long Island software program that calculates forward market prices for both Long Island and Rest of State (ROS) as well as the net market capacity costs to LIPA. The calculations are based on the NYISO demand curves, NYISO Gold Book forecasted loads, forecasted installed capacity levels in Long Island and New York State, as well as the estimated values for locational requirements and installed reserve margin as established by NYS Reliability Council and NYISO.

For the purpose of quantifying the net market capacity costs, two Market Manager scenarios are analyzed. The first scenario assumes the current load forecast, the second scenario is based upon a load forecast decrease of 100 MW relative to the first scenario. The difference in the net market capacity costs to LIPA is then calculated. The results are shown on an annual unitized basis. This methodology captures both the decremental cost of supply for the reduction in needed capacity that results from the change in load as well as the overall change to LIPA's base capacity purchases.

Benefit Equation, Variables, and Subscripts

Equation B-1 presents the benefit equation for AGCC. This equation follows "Variant 1" of the Demand Curve savings estimation described in the 2015 Congestion Assessment and Resource Integration Study (CARIS) Appendix. Each NYISO zone is mapped to one of the four NYISO localities as follows: ROS = A-F, LHV = G-I, NYC = J, LI= K.

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[102] Energy, operational, and reliability-related benefits and costs include: **Error! Reference source not found.**ACE, the energy component of **Error! Reference source not found.**, **Error! Reference source not found.**, the energy portion of **Error! Reference source not found.**, **Error! Reference source not found.**, **Error! Reference source not found.**, **Error! Reference source not found.**, **Error! Reference source not found.** , the energy component of **Error! Reference source not found.**, **Error! Reference source not found.**, **Error! Reference source not found.**, **Error! Reference source not found.**, **Error! Reference source not found.**, **Error! Reference source not found.**, **Error! Reference source not found.**, **Error! Reference source not found.**, **Error! Reference source not found.**, and **Error! Reference source not found.**.

[103] Capacity, infrastructure, and market price-related benefits and costs include: **Error! Reference source not found.**, the capacity component of **Error! Reference source not found.**, **Error! Reference source not found.**, the capacity component of **Error! Reference source not found.**, **Error! Reference source not found.**, the capacity portion of the **Error! Reference source not found.**, **Error! Reference source not found.**, and **Error! Reference source not found.**.

[104] For a portfolio of projects located within multiple NYISO zones, it may be necessary to calculate weighted average across zones to obtain a benefit value.

Equation B-1. Avoided Generation Capacity Costs (AGCC)

$$\mathrm{Benefit}_{Y+1} = \sum_{Z} \frac{\Delta\mathrm{PeakLoad}_{Z,Y,r}}{1\text{-}\mathrm{Loss\%}_{Z,Y,b\rightarrow r}} * \mathrm{SystemCoincidenceFactor}_{Z,Y} * \mathrm{DeratingFactor}_{Z,Y} * \mathrm{AGCC}_{Z,Y,b}$$

The indices of the parameters in Equation B-1 include:

- Z = NYISO zone (A → K)
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

ΔPeakLoad$_{Z,Y,r}$ (ΔMW) is the project's expected maximum demand reduction capability, or "nameplate" impact at the retail delivery or connection point ("r"), by zone if applicable. This input is project or program specific. A positive value represents a reduction in peak load.

$\mathrm{Loss\%}_{Z,b\rightarrow r}$ (%) is the variable loss percent between bulk system ("b") and the retail delivery or connection point ("r"). The loss percentages by system level are found in Table B-25.

$\mathrm{SystemCoincidenceFactor}_{Z,Y}$ (dimensionless) captures a project or program's contribution to reducing bulk system peak demand relative to its expected maximum demand reduction capability. For example, a nameplate demand reduction capacity of 100 kW with a system coincidence factor of 0.8 would reduce the bulk system peak demand by 80 kW. This input is project specific.

$\mathrm{DeratingFactor}_{Z,Y}$ (dimensionless) is presented here as a factor to de-rate the coincident peak load reduction based on the availability of a resource during system peak hours. For example, a DR program may only be allowed to dispatch a maximum of 10 events per year, which could limit the availability of the resource during peak hours. Another example is the variability and intermittence (e.g., due to clouds) of a solar array which could limit its contribution to system peak load reduction. This input is project specific.

$AGCC_{Z,Y,b}$ ($/MW-yr) represents the annual AGCCs at the bulk system ("b") based on forecast of capacity prices for the wholesale market provided by DPS Staff. This data can be found in Staff's ICAP Spreadsheet Model in the "AGCC Annual" tab in the "Avoided GCC at Transmission Level" table. This spreadsheet converts "Generator ICAP Prices" to "Avoided GCC at Transmission Level" based on capacity obligations for the wholesale market. Note that the AGCC values provided in this spreadsheet are in the units of $/kW-mo, which must be converted to $/MW-yr to match the peak load impact in MW. To convert units, the summer and winter $/kW-mo values are multiplied by six months each and added together, and then multiplied by 1,000 to convert to $/MW-yr. AGCC costs are calculated based on the NYISO's capacity market demand curves, using supply and demand by NYISO zone, Minimum Locational Capacity Requirements (LCR), and the Reserve Margin.

General Considerations

The AGCC forecast provided by Staff is based on capacity market demand curves using the demand forecasts and available supply from NYISO's Load & Capacity Data report. CARIS can be used for guidance on how demand curves are applied to the AGCC forecast.[105] The Reserve Margin is determined annually by New York State Reliability Council. Minimum LCR, set by NYISO, are applicable to several localities (NYC, LI, "G-J" Region) and account for transmission losses. See NYISO Installed Capacity Manual[106] for more details on ICAP.

Any wholesale market capacity price suppression effects are not accounted for here and instead are captured in Wholesale Price Impacts, described in Section B.4.1.6.

Impacts from a measure, project, or portfolio must be coincident with the system peak and accounted for losses prior to applying the AGCC valuation parameter. The "nameplate" impact (i.e. $\Delta PeakLoad_{Z,Y,r}$) should also be multiplied by a coincidence factor and derating factor to properly match the planning impact to the system peak. The coincident factor quantifies a project's contribution to system peak relative to its nameplate impact.

It is also important to consider the persistence of impacts in future years after a project's implementation. For example, participation in a DR program may change over time. Also, a peak load reduction impact will not be realized as a monetized AGCC benefit until the year following the peak load reduction, as capacity requirements are set by annual peak demand and paid for in the following year.

The AGCC values provided in Staff's ICAP Spreadsheet Model account for the value of transmission losses and infrastructure upgrades. In instances where projects change the transmission topology, incremental infrastructure and loss benefits not captured in the AGCC values should be modeled and quantified in the Avoided T&D Losses and Avoided T&D Infrastructure benefits, below.

B.4.1.2 Avoided ACEs

Avoided ACE is avoided energy purchased.
Due to past practices with respect to the procurement of capacity and energy, certain impacts and costs are not applicable to PSEG Long Island. Unlike the remainder of the Investor-Owned Utilities, PSEG Long Island is generally "long" on capacity and has contracts in place for the bulk of its capacity requirements. Similarly, PSEG Long Island has contracts in place for the bulk of its energy requirements. As a result of this, the impact of location-based marginal pricing (LBMP) is significantly dampened compared to the rest of the New York electric utilities.

The avoided energy cost, in $/MWh, is calculated using GE MAPS (Multi-area Production Software) program. The MAPS program is used to calculate production costs given most up to date load forecasts, existing and future generation, and transmission network. The model used by PSEG Long Island consists of the 4-pool system: NY, NE, PJM Classic, and parts of Ontario, Canada.

For the purpose of quantifying the avoided energy costs, two MAPS scenarios are analyzed. The first scenario assumes the current load forecast, the second scenario is based upon a 100 MW peak and corresponding energy requirement decrease relative to the first scenario. The difference in LIPA's production cost between the two scenarios is divided by the change in energy to obtain the unitized avoided energy in $/MWh.

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[105] 2019 CARIS Phase 1 Study Appendix. https://www.nyiso.com/documents/20142/2226108/2019-CARIS-Phase1-Appendix-Final.pdf/7d061d58-85c5-6319-2407-3e2bdddcee71. The study is performed bi-annually and the most recent can be found under Planning Reports, Economic Planning Studies at: https://www.nyiso.com/library

[106] The NYISO Installed Capacity Manual is available at: https://www.nyiso.com/documents/20142/2923301/icap_mnl.pdf/234db95c-9a91-66fe-7306-2900ef905338

Benefit Equation, Variables, and Subscripts

Equation B-2 presents the benefit equation for Avoided ACE:

Equation B-2. Avoided ACE

$$\mathrm{Benefit_Y} = \sum_{Z}\sum_{P} \frac{\Delta \mathrm{Energy_{Z,P,Y,r}}}{1 - \mathrm{Loss\%_{Z,b \rightarrow r}}} * \mathrm{ACE_{Z,P,Y,b}}$$

The indices of the parameters in Equation B-2 include:

- Z = zone (A → K)
- P = period (e.g., year, season, month, and hour)
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

ΔEnergy$_{Z,P,Y,r}$ (ΔMWh) is the difference in energy purchased at the retail delivery or connection point ("r") before and after project implementation, by NYISO zone and by year with by time-differentiated periods, for example, annual, seasonal, monthly, or hourly as appropriate. This parameter represents the energy impact at the project location and is **not** yet grossed up to the ACE location based on the losses between those two points on the system. This adjustment is performed based on the $Loss\%_{Z,b\rightarrow r}$ parameter. This input is project- or program-specific. A positive value represents a reduction in energy.

$\mathbf{Loss\%_{Z,b\rightarrow r}}$ (%) is the variable loss percent between bulk system ("b") and the retail delivery or connection point ("r"). The loss percentages by system level are found in Table B-1.

ACE$_{Z,P,Y,b}$ ($/MWh) is the Avoided Cost of Energy, which is the sum of energy, congestion, and losses components by NYISO zone at the bulk system level ("b"). NYISO forecasts 20-year annual and hourly ACEs by zone. To determine time-differentiated ACEs, for example, annual, seasonal, monthly, or hourly, leverage NYISO's hourly ACE forecast by zone rather than developing an alternative forecast of time-differentiated ACEs based on shaping annual averages by zone from historical data. The NYISO hourly ACE forecast is a direct output from the CARIS Phase 2 modeling. To extend the ACE forecast beyond the CARIS planning period, if necessary, assume that the last year of the ACEs stay constant in real (inflation adjusted) $/MWh.

General Considerations

Avoided ACE benefits are calculated using a static forecast of ACE. Any wholesale market price changes as a result of the project or program are not accounted for in this benefit, and are instead captured in Wholesale Market Price Impacts, described in Section B.4.1.6.

The time differential for subscript P (period) will depend on the type of project, and could be season, month, day, hour, or any other interval. The user must ensure that the time-differentiation is appropriate for the project being analyzed. For example, it may be appropriate to use an annual average price and impact for a DER that has a consistent load reduction at all hours of the year. However, using the annual average may not be appropriate for energy storage which may be charging during non-peak hours and discharging during peak hours. In that case, it may be appropriate to multiply an average on-peak (or super-peak) and off-peak ACE by the on-peak (or super-peak) and off-peak energy impacts, respectively.

It is important to consider the trend (i.e., system degradation) of impacts in future years after a project's implementation. For example, a PV system's output may decline over time. It is assumed that the benefit is realized in the year of the energy impact.

B.4.1.3 Avoided Transmission Capacity Infrastructure and Related O&M

Avoided Transmission Capacity Infrastructure and Related O&M benefits result from location-specific load reduction that are valued at the marginal cost of equipment that is avoided or deferred by a DER project or program. A portion of Avoided Transmission Capacity is already captured in the congestion charge of the ACE and the AGCC prices. Because static forecasts of ACEs and AGCC values are used, this benefit will be quantified only in cases where a measure, project, or portfolio alters the planned transmission system investments from that level embedded in those static forecasts.

Benefit Equation, Variables, and Subscripts

Equation B-3 presents the benefit equation for Avoided Transmission Capacity Infrastructure and Related O&M:

Equation B-3. Avoided Transmission Capacity Infrastructure and Related O&M

$$\mathrm{Benefit}_{Y+1} = \sum_{C} \frac{\Delta \mathrm{PeakLoad}_{Y,r}}{\mathrm{Loss\%}_{Y,b\to r}} * \mathrm{TransCoincidentFactor}_{C,Y} * \mathrm{DeratingFactor}_{Y} * \mathrm{MarginalTransCost}_{C,Y,b}$$

The indices[107] of the parameters in Equation B-3 include:

- C = constraint on an element of transmission system[108]
- Y = Year
- b = Bulk System
- r = Retail Delivery or Connection Point

$\Delta \mathrm{PeakLoad}_{Y,r}$ (ΔMW) is the project's expected maximum demand reduction capability, or "nameplate" impact at the retail delivery or connection point ("r"). This input is project specific. A positive value represents a reduction in peak load.

$\mathrm{Loss\%}_{Y,b\to r}$ (%) is the variable loss percent between the bulk system ("b") and the retail delivery point ("r"). Thus, this reflects the sum of the transmission and distribution system loss percent values, both found in Table B-25.

$\mathrm{TransCoincidentFactor}_{C,Y}$ (dimensionless) quantifies a project's contribution to reducing transmission system peak demand relative to its expected maximum demand reduction capability. For example, an expected maximum demand reduction capability of 100 kW with a coincidence factor of 0.8 will reduce the transmission system peak by 80 kW (without considering $DeratingFactor_Y$). This input is project specific.

$\mathrm{DeratingFactor}_{Y}$ (dimensionless) is presented here as a generic factor to de-rate the transmission system coincident peak load based on the availability of the load during peak hours. For example, a DR

[107] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.

[108] If system-wide marginal costs are used, this is not an applicable subscript.

program may only be allowed to dispatch a maximum of 10 events per year, which could limit the availability of the resource during peak hours. Another example is the variability and intermittence (e.g., due to clouds) of a solar array which could limit its contribution to peak load reduction on the transmission system. This input is project specific.

MarginalTransCost$_{C,Y,b}$ ($/MW-yr) is the marginal cost of the transmission equipment from which the load is being relieved. It is assumed that the marginal cost of service is based on the bulk system ("b"). If the available marginal cost of service value is based on a different basis, then this parameter must first be converted to represent load at the bulk system prior to using in the equation above. Localized or equipment-specific marginal costs of service should be used in most cases. In some limited circumstances use of the system average marginal cost have been accepted, for example, for evaluation of EE programs. System average marginal cost of service values are provided in Table B-26.

General Considerations

In order to find the impact of the measure, project, or portfolio on the transmission system peak load, the "nameplate" capability or load impact must be multiplied by the transmission system coincidence factor and derating factor. Coincidence factors and derating factors would need to be determined by a project-specific engineering study. Where the coincidence factor is in the control of the operator (e.g., Conservation Voltage Reduction (CVR), utility-controlled batteries), an engineering study may not be needed.

Some transmission capacity costs are already embedded in both ACE and AGCC. Both the AGCC and transmission congestion charges could be decreased in the event that additional transmission assets are built or load is reduced. To the extent that deferred or avoided transmission upgrades are incremental to the value captured in ACE and AGCC and can be modeled or calculated, these benefits would be reported in this benefit. This value would need to be project-specific based on the specific deferral and/or change to the system topology rather than through generic utility marginal cost of service studies. Using system average marginal costs to estimate avoided transmission and infrastructure need may result in significant over- or under-valuation of the benefits or costs and may result in no savings in utility costs for customers.

The use of project-specific values helps ensure that the calculated impact is applicable to the specific impact of the project both on a temporal and locational basis, adjusting for losses (i.e., locational alignment) and coincidence with the transmission peak (i.e., temporal alignment). In other words, the load reduction ultimately used to value this benefit must be coincident with the load on the relieved equipment. It is important to distinguish between system and local constraints in order to match the impact with the avoided cost. It is assumed that the marginal cost of service is based on the load at the bulk system. If the available marginal cost of service value is based on a different location in the system (e.g., interface between transmission and distribution), then this parameter must first be converted to represent load at the bulk system prior to using in the equation above.

Avoided transmission infrastructure cost benefits are realized only if the project improves load profiles that would otherwise create a need for incremental infrastructure. Benefits are only accrued when a transmission constraint is relieved due to coincident peak load reduction from DER. Under constrained conditions, it is assumed that a peak load reduction impact will produce benefits in the following year as the impact. Once the peak load reduction is less than that necessary to avoid or defer the transmission investment and infrastructure must be built, or the constraint is relieved, this benefit would not be realized from that point forward.

The marginal cost of transmission capacity values provided in Table B-26 include both capital and O&M, and cannot be split between the two benefits. Therefore, care should be taken to avoid double counting of any O&M values included in this benefit and in the Avoided O&M benefit described in Section B.4.2.2.

B.4.1.4 Avoided Transmission Losses

Avoided Transmission Losses is the benefit that is realized when a project changes the topology of the transmission system and results in a change to the transmission system loss percent. Reductions in end use consumption and demand that result in reduced losses are included in Avoided ACE and AGCC benefits as described above in Sections B.4.1.2 and B.4.1.1. In actuality, both the ACE and AGCC would adjust to a change in system losses in future years; however, the static forecast used in this methodology does not capture these effects.

Benefit Equation, Variables, and Subscripts

Equation B-4 presents the benefit equation for Avoided Transmission Losses:

Equation B-4. Avoided Transmission Losses

$$\mathrm{Benefit}_{Y+1} = \sum_{Z} \mathrm{SystemEnergy}_{Z,Y+1,b} * \mathrm{ACE}_{Z,Y+1,b} * \Delta\mathrm{Loss\%}_{Z,Y+1,b\rightarrow i} + \mathrm{SystemDemand}_{Z,Y,b} * \mathrm{AGCC}_{Z,Y,b} * \Delta\mathrm{Loss\%}_{Z,Y,b\rightarrow i}$$

Where,

$$\Delta\mathrm{Loss\%}_{Z,Y,b\rightarrow i} = \mathrm{Loss\%}_{Z,Y,b\rightarrow i,baseline} - \mathrm{Loss\%}_{Z,Y,b\rightarrow i,post}$$

The indices[109] of the parameters in Equation B-4 include:

- Z = NYISO zone (for ACE: A → K; for AGCC: NYC, LHV, LI, ROS[110])
- Y = Year
- b = Bulk System
- i = Interface of the transmission and distribution systems

$\mathrm{SystemEnergy}_{Z,Y+1,b}$ (MWh) is the annual energy forecast by NYISO in the Load & Capacity Report at the bulk system ("b"), which includes transmission and distribution losses. Note that total system energy is used for this input, not the project-specific energy, because this benefit is only included in the BCA when the system topology is changed resulting in a change in the transmission loss percent, which affects all load in the relevant area.

$\mathrm{ACE}_{Z,Y+1,b}$ ($/MWh) is the ACE, which is the sum of energy, congestion, and losses components by NYISO zone at the bulk system level ("b"). To determine time-differentiated ACEs, for example, annual, seasonal, monthly, or hourly, leverage NYISO's hourly ACE forecast by zone rather than developing an alternative forecast of time-differentiated ACEs based on shaping annual averages by zone from historical data. The NYISO hourly ACE forecast is a direct output from the CARIS Phase 2 modeling. To

[109] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.

[110] Mapping NYISO localities to NYISO zones: ROS = A-F, LHV = G-I, NYC = J, LI = K

extend the ACE forecast beyond the CARIS planning period, if necessary, assume that the last year of the ACEs stay constant in real (inflation adjusted) $/MWh.

$\mathbf{SystemDemand_{Z,Y,b}}$ (MW) is the system peak demand forecast by NYISO at the bulk system level (“b”), which includes transmission and distribution losses by zone. Note that the system demand is used in this evaluation, not the project-specific demand, because this benefit is only quantified when the system topology is changed resulting in a change in transmission losses percent, which affects all load in the relevant zone.

$\mathbf{AGCC_{Z,Y,b}}$ ($/MW-yr) represents the annual AGCCs based on forecast of capacity prices for the wholesale market provided by Staff. This data can be found in Staff’s ICAP Spreadsheet Model in the “AGCC Annual” tab in the “Avoided GCC at Transmission Level” table. This spreadsheet converts “Generator ICAP Prices” to “Avoided GCC at Transmission Level”[111] based on capacity obligations at the forecast of capacity prices for the wholesale market. Note that the AGCC values provided in this spreadsheet are in the units of $/kW-mo, which must be converted to $/MW-yr to match the peak load impact in MW. To convert units, the summer and winter $/kW-mo values are multiplied by six months each and added together, and then multiplied by 1,000 to convert to $/MW-yr.

$\mathbf{\Delta Loss\%_{Z,Y,b\rightarrow i}}$ (Δ%) is the change in fixed and variable loss percent between the bulk system (“b”) and the interface of the transmission and distribution systems (“i”) resulting from a project that changes the topology of the transmission system. This value would typically be determined in a project-specific engineering study. Two parameters are provided in the equations above: one with a “Y” subscript to represent the current year, and one with a “Y+1” subscript to represent the following year.

$\mathbf{Loss\%_{Z,Y,b\rightarrow i,baseline}}$ (%) is the baseline fixed and variable loss percent between bulk system (“b”) and the interface of the transmission and distribution systems (“i”). Thus, this reflects the sub-transmission and internal transmission losses pre-project, which is found in Table B-25.

$\mathbf{Loss\%_{Z,Y,b\rightarrow i,post}}$ (%) is the post-project fixed and variable loss percent between bulk system (“b”) and the interface of the transmission and distribution systems (“i”). Thus, this reflects the sub-transmission and internal transmission losses post-project.

General Considerations

Transmission losses are already embedded in the ACE. This benefit is incremental to what is included in ACE and is only quantified when the transmission loss percent is changed (e.g., from 3% to 2.9%). For most projects, this benefit will be zero unless an engineering study determines otherwise.

The energy and demand impacts are based on system-wide energy and demand, not project-specific, because this benefit is only quantified when the losses percentage is changed which affects all customers in the affected area. Transmission losses will not affect downstream distribution losses.

It is assumed that the ACE component of the avoided losses benefit is accrued in the same year as the impact, and the AGCC component of the benefit is accrued in the following year of the benefit. This is reflected in the equation above with “Y” and “Y+1” subscripts to indicate the timing of the benefits relative to the impacts.

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[111] “Transmission level” represents the bulk system level (“b”).

B.4.1.5 Avoided Ancillary Services (Spinning Reserves, and Frequency Regulation)

Avoided Ancillary Services benefits may accrue to selected DERs that are willing and qualify to provide ancillary services to NYISO. NYISO could purchase ancillary services from these DERs in lieu of conventional generators at a lower cost without sacrificing reliability. This benefit will only be quantified in cases where a measure, project, or portfolio is qualified to, or has the ability and willingness to provide ancillary services to NYISO.

DER causes a reduction in load but will not directly result in a reduction in NYISO requirements for regulation and reserves since these requirements are not based on existing load levels but instead are based on available generating resource characteristics. Regulation requirements are periodically set by NYISO to maintain frequency, and reserve requirements are set to cover the loss of the largest supply element(s) on the bulk power system.

Some DERs may have the potential to provide a new distribution-level ancillary service such as the voltage support and power quality. However, it is uncertain whether such attributes can be cost-effectively provided by dispersed DERs. The infrastructure costs required to monitor the applicable system conditions (voltage, flicker, etc.) and individual DERs as well as the operations and communications system to communicate with and effectively dispatch those DER attributes are also uncertain. It is premature to include any value in the BCA for such services unless and until the utilities can cost-effectively build the systems to monitor and dispatch DERs to capture net distribution benefits.

Benefit Equation, Variables, and Subscripts

The benefits of each of two ancillary services (spinning reserves, and frequency regulation) are described in the equations below. The quantification and inclusion of this benefit is project specific.

<u>Frequency Regulation</u>

Equation B-5 presents the benefit equation for frequency regulation:

Equation B-5. Frequency Regulation

$$\mathrm{Benefit_Y} = \mathrm{Capacity_Y} * \mathrm{n} * (\mathrm{CapPrice_Y} + \mathrm{MovePrice_Y} * \mathrm{RMM_Y})$$

The indices of the parameters in Equation B-5 include:

- Y = Year

$\mathbf{Capacity_Y}$ **(MW)** is the amount of annual average frequency regulation capacity when provided to NYISO by the project. The amount is difficult to forecast.

$\mathbf{n}$ **(hr)** is the number of hours in a year that the resource is expected to provide the service.

$\mathbf{CapPrice_Y}$ **($/MW·hr)** is the average hourly frequency regulation capacity price. The default value is the two-year historical average for day-ahead regulation capacity prices from NYISO.

$\mathbf{MovePrice_Y}$ **($/ΔMW)**: is the average hourly frequency regulation movement price. The default value is the two-year historical average for real-time dispatch of regulation movement prices from NYISO.

$\mathbf{RMM_Y}$ **(ΔMW/MW·hr)**: is the Regulation Movement Multiplier (RMM) used for regulation bids and accounts for the ratio between movement and capacity. It is assumed to be 13 ΔMW/MW-hr.

Spinning Reserves

Equation B-6 presents the benefit equation for spinning reserves:

Equation B-6. Spinning Reserves

$$\text{Benefit}_Y = \text{Capacity}_Y * n * \text{CapPrice}_Y$$

The indices of the parameters in Equation B-6 include:

- Y = Year

$\textbf{Capacity}_\textbf{Y}$ **(MW)** is the change in the amount of annual average spinning reserve capacity when provided to the NYISO by the project. The amount is difficult to forecast.

$\mathbf{n}$ **(hr)**: is the number of hours in a year that the resource is expected to provide the service.

$\textbf{CapPrice}_\textbf{Y}$ **($/MW·hr)** is the average hourly spinning reserve capacity price. Default value uses the two-year historical average spinning reserve pricing by region.

General Considerations

There are no reductions in annual average frequency regulation, and spinning reserve, because those are set by the NYISO independent of load levels and DER penetration.

NYISO in late 2015 changed the number of regions for Ancillary Services from two to three and two-year historical data is not available for all three regions. Thus, assume that EAST and SENY are equal to the historical data for EAST. The corresponding NYISO zones for EAST are F – K, and the corresponding zones for WEST are A – E.

The average hourly prices for frequency regulation capacity, frequency regulation movement, and spinning reserve capacity can be calculated from historical pricing data posted by NYISO. The recommended basis is a historical average of interval pricing over the prior two-year period. To avoid the complication of the change in regions, the two-year historical average is based on November 1, 2013 through October 31, 2015.

The NYISO Ancillary Services Manual suggests that the day-ahead market is the predominant market for regulation capacity and spinning reserves; regulation movement is only available in real-time.
The RMM is fixed by NYISO at a value of 13 ΔMW/MW per hour. While NYISO does not publish historical interval volume data to calculate actual movement, this value can be considered a reasonable proxy for actual movement.

B.4.1.6 Wholesale Market Price Impact

Wholesale Market Price Impact includes the benefit from reduced wholesale market prices on both energy (i.e., ACE) and capacity (i.e., AGCC) due to a measure, project, or portfolio. ACE impacts will be provided by Staff and are determined using the first year of the most recent CARIS database to calculate the static impact on wholesale ACE of a 1% change in the level of load that must be met.[112] ACE impact

[112] *BCA Order*, Appendix C, pg. 8.

will be calculated for each NYISO zone. AGCC price impacts are characterized using Staff's ICAP Spreadsheet Model.

Benefit Equation, Variables, and Subscripts

Equation B-7 presents the benefit equation for Wholesale Market Price Impact:

Equation B-7. Wholesale Market Price Impact

$$\mathrm{Benefit}_{Y+1} = \sum_{Z} (1 - \mathrm{Hedging\%}) * \left(\Delta\mathrm{ACEImpact}_{Z,Y+1,b} * \frac{\Delta\mathrm{Energy}_{Z,Y+1,r}}{1 - \mathrm{Loss\%}_{Z,b\rightarrow r}} + \Delta\mathrm{AGCC}_{Z,Y,b} * \mathrm{ProjectedAvailableCapacity}_{Z,Y,b}\right)$$

The indices of the parameters in Equation B-7 include:

- Z = NYISO zone (A → K[113])
- Y = Year
- b = Bulk System

$\mathrm{Hedging\%}$ (%) is the fraction of energy or capacity hedged via fixed price or multi-year agreements or other mechanisms. Price hedging via long term purchase contracts should be considered when assessing wholesale market price impacts. The JU have generally assumed that the percent of purchases hedged is 50% and equal for both energy and capacity.

$\Delta\mathrm{ACEImpact}_{Z,Y+1,b}$ (Δ$/MWh) is the change in average annual ACE at the bulk system ("b") before and after the project(s); requires wholesale market modeling to determine impact. This will be provided by DPS Staff.

$\Delta\mathrm{Energy}_{Z,Y+1,r}$ (ΔMWh) is the change in energy purchased at the retail delivery or connection point ("r") as a result of the project. This parameter considers the energy impact at the project location, which is then grossed up to the bulk system level based on the $Loss\%_{Z,b\rightarrow r}$ parameter. A positive value represents a reduction in energy.

$\mathrm{Loss\%}_{Y,b\rightarrow r}$ (%) is the variable loss percent from the bulk system level ("b") to the retail delivery or connection point ("r"). These values can be found in Table B-25.

$\mathrm{WholesaleEnergy}_{Z,Y,b}$ (MWh) is the total annual wholesale market energy purchased by zone at the bulk system level ("b"). This must represent the energy at the ACE.

$\Delta\mathrm{AGCC}_{Z,Y,b}$ (Δ$/MW-yr) is the change in AGCC price by ICAP zone calculated from Staff's ICAP Spreadsheet Model before and after the project is implemented. This value is determined based on the difference in zonal prices in Staff's ICAP Spreadsheet Model, "AGCC Annual" tab, based on a change in the supply or demand forecast (i.e., "Supply" tab and "Demand" tab, respectively) due to the project.[114] The price impacts are based on the size and location of the project. A positive value represents a reduction in price.

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[113] Mapping NYISO localities to NYISO zones: ROS = A-F, LHV = G-I, NYC = J, LI = K

[114] As in the AGCC benefit equation, System Coincidence Factors and Derating Factors adjust the maximum load reduction of the project.

$\text{ProjectedAvailableCapacity}_{Z,Y,b}$ **(MW)** is the projected available supply capacity by ICAP zone at the bulk system level ("b") based on Staff's ICAP Spreadsheet Model, "Supply" tab, which is the baseline before the project is implemented.

General Considerations

Wholesale market price impacts or demand reduction induced price effects are project specific based on the size and shape of the demand reduction. ACE market price impacts will be provided by Staff and will be determined using the first year of the most recent CARIS database to calculate the static impact on ACE of a 1% change in the level of load that must be met in the utility area where the DER is located. These impacts must be considered in the benefit calculation once available. The capacity market price impacts can be calculated using Staff's ICAP Spreadsheet Model. The resultant price effects are not included in SCT but would be included in RIM and UCT as a sensitivity.

It is assumed that Wholesale Market Price Impacts do not result in benefits for more than one year, as these markets will respond quickly to the reduced demand, quickly reducing the benefit. It is also assumed that the capacity portion of Wholesale Market Price Impacts will produce benefits in the year following the impact, and the energy portion of Wholesale Market Price Impacts will produce benefits in the same year as the impact.

B.4.2 Distribution System Benefits

B.4.2.1 Avoided Distribution Capacity Infrastructure

Avoided Distribution Capacity Infrastructure benefit results from location-specific distribution load reductions that are valued at the marginal cost of distribution system infrastructure that is avoided or deferred by a DER project or program. The load reduction impact must be coincident with the distribution equipment peak or otherwise defer or avoid the need for incremental distribution infrastructure based on the characteristics of the specific load and the design criteria of the specific equipment that serves it.

Benefit Equation, Variables, and Subscripts

Equation B-8 presents the benefit equation for Avoided Distribution Capacity Infrastructure:

Equation B-8. Avoided Distribution Capacity Infrastructure

$$\text{Benefit}_{\text{Y}} = \sum_{\text{V}} \sum_{\text{C}} \frac{\Delta\text{PeakLoad}_{\text{Y,r}}}{1 - \text{Loss\%}_{\text{Y,b}\rightarrow\text{r}}} * \text{DistCoincidentFactor}_{\text{C,V,Y}} * \text{DeratingFactor}_{\text{Y}} * \text{MarginalDistCost}_{\text{C,V,Y,b}}$$

The indices of the parameters in Equation B-8 include:

- C = Constraint on an element (e.g., pole-mounted transformer, distribution line, etc.) of the distribution system.[115]
- V = Voltage level (e.g., primary, and secondary)
- Y = Year
- b = Bulk System

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[115] In limited cases where use of system-wide marginal cost values is required, this subscript is not applicable.

- r = Retail Delivery or Connection Point

$\mathbf{\Delta PeakLoad_{Y,r}}$ **(ΔMW)** is the nameplate demand reduction of the project at the retail delivery or connection point ("r"). This input is project specific. A positive value represents a reduction in peak load.

$\mathbf{Loss\%_{Y,b\rightarrow r}}$ **(%)** is the variable loss percent between the bulk system ("b") and the retail delivery point ("r"). Thus, this reflects the sum of the transmission and distribution system loss percent values, both found in Table B-25. This parameter to used to adjust the $\Delta\mathrm{PeakLoad}_{Y,r}$ parameter to the bulk system level.

$\mathbf{DistCoincidentFactor_{C,V,Y}}$ **(dimensionless) is a project specific input that** captures the contribution to the distribution element's peak relative to the project's nameplate demand reduction. For example, a nameplate demand reduction of 100 kW on the distribution feeder with a coincidence factor of 0.8 would contribute an 80 kW reduction to peak load on an element of the distribution system. This input is project specific.

$\mathbf{DeratingFactor_{Y}}$ **(dimensionless) is a project specific input that** is presented here as a generic factor to de-rate the distribution coincident peak load based on the availability of the load during peak hours. For example, a DR program may only be allowed to dispatch a maximum of 10 events per year, which could limit the availability of the resource during peak hours. Another example is the variability and intermittence (e.g., due to clouds) of a solar array which could limit its peak load reduction contribution on an element of the distribution system. This input is project specific.

$\mathbf{MarginalDistCost_{C,V,Y,b}}$ **($/MW-yr)** is the marginal cost of the distribution equipment from which the load is being relieved. It is assumed that the marginal cost of service is based on the bulk system ("b"). If the available marginal cost of service value is based on a different basis, then this parameter must first be converted to represent load at the bulk system prior to using in the equation above. Localized or equipment-specific marginal costs of service should be used in most cases. In some limited circumstances use of the system average marginal cost have been accepted, for example, for evaluation of EE programs. System average marginal cost of service values are provided in Table B-26.

General Considerations

Project- and location- specific avoided distribution costs and deferral values should be used when and wherever possible. Using system average marginal costs to estimate avoided transmission and distribution infrastructure need may result in significant over- or under-valuation of the benefits or costs, and may result in no savings in utility costs for customers. Coincidence and derating factors would be determined by a project-specific engineering study.

Avoided distribution infrastructure benefits for a specific location are realized only if a DER project or portfolio of DER projects meets the engineering requirements for functional equivalence (i.e., DER reliably reduces coincident load to a level that allows the deferral or avoidance of the distribution project. The DSIP identifies specific areas where a distribution upgrade need exists and where DERs could potentially provide this benefit.

Use of system average avoided cost assumptions may be required in some situations, such as system-wide programs or tariffs. These values are provided in Table B-26.

The timing of benefits realized from peak load reductions are project and/ or program specific. It is assumed that a peak load reduction impact will produce benefits in the year of the impact. Once the peak load reduction is no longer enough to avoid or defer investment and infrastructure must be built, the constraint is relieved, and benefits should not be realized from that point forward.

The marginal cost of distribution capacity values provided in Table B-26. include both capital and O&M and cannot be split between the two benefits. Therefore, whenever these system average values are used, care should be taken to avoid double counting of any O&M values included in this benefit and in the Avoided O&M benefit described in Section B.4.2.2.

B.4.2.2 Avoided O&M

Avoided O&M includes any benefits incremental to the value captured in the Avoided Distribution Capacity Infrastructure benefit (Section B.4.2.1). As discussed above, marginal cost studies include O&M and that O&M is not separately included in this benefit. Therefore, this benefit includes reduced expenses not tied to avoided or deferred distribution system investment from DER. This benefit may capture O&M savings from investments to improve customer service that reduces phone calls to the call center or O&M savings from migrating toward advanced meter functionality reducing meter reading costs. At this time, for most DER projects this benefit will be zero. For example, DER may reduce equipment loading, which reduces failure rates, but somewhat higher equipment loading may have led to the installation of new equipment with lower O&M costs. Further analysis is required to understand how DER would impact O&M.

Benefit Equation, Variables, and Subscripts

Equation B-9 presents the benefit equation for Avoided O&M Costs:

Equation B-9. Avoided O&M

$$\mathrm{Benefit}_{\mathrm{Y}} = \sum_{\mathrm{AT}} \Delta \mathrm{Expenses}_{\mathrm{AT,Y}}$$

The indices of the parameters in Equation B-9 include:

- AT = activity type (e.g., line crews to replace equipment, engineering review of DER interconnection applications, responding to calls received at call centers)
- Y = Year

$\Delta\mathrm{Expenses}_{\mathrm{AT,Y}}$ (Δ$): Change in O&M expenses due to a project, including an appropriate allocation of administrative and common costs. These costs would increase by inflation, where appropriate.

General Considerations

Distribution O&M benefits from DERs may be limited to instances where DERs can avoid or defer new distribution equipment, which is already captured in the Avoided Distribution Capacity Infrastructure benefit (Section B.4.2.1), where the O&M costs are embedded in the marginal cost of service values. DER interconnections could increase O&M costs, while lower equipment failure rates could decrease these costs. In general, these impacts are difficult to quantify for DER investments and may be zero for most cases.

Avoided O&M benefits would be quantifiable for some non-DER investments, such as utility investments in DSP capabilities. For example, a utility investment in advanced metering functionality may avoid truck rolls and other costs by collecting meter data remotely. Labor and crew rates can be sourced using the utility's activity-based costing system or work management system, if that information is available

B.4.2.3 Distribution Losses

Avoided Distribution Losses are the incremental benefit that is realized when a project changes distribution system losses, resulting in changes to both annual energy use and peak demand. Distribution losses are already accounted for in the ACE and AGCC when grossing impacts at the project location to the price locations. Because static forecasts of ACEs and AGCC are used, this benefit will be quantified only in cases where a measure, project, or portfolio alters the distribution system losses percentage (e.g., from 3% to 2.9%).

Benefit Equation, Variables, and Subscripts

Equation B-10 presents the benefit equation for Avoided Distribution Losses:

Equation B-10. Avoided Distribution Losses

$$\mathrm{Benefit}_{Y+1} = \sum_{Z} \mathrm{SystemEnergy}_{Z,Y+1,b} * \mathrm{ACE}_{Z,Y+1,b} * \Delta\mathrm{Loss\%}_{Z,Y+1,i\rightarrow r} + \mathrm{SystemDemand}_{Z,Y,b} * \mathrm{AGCC}_{Z,Y,b} * \Delta\mathrm{Loss\%}_{Z,Y,i\rightarrow r}$$

Where,

$$\Delta\mathrm{Loss\%}_{Z,Y,i\rightarrow r} = \mathrm{Loss\%}_{Z,Y,i\rightarrow r,\mathrm{baseline}} - \mathrm{Loss\%}_{Z,Y,i\rightarrow r,\mathrm{post}}$$

The indices[116] of the parameters in Equation B-10 include:

- Z = NYISO zone (for ACE: A → K; for AGCC: NYC, LHV, LI, ROS[117])
- Y = Year
- i = Interface Between Transmission and Distribution Systems
- b = Bulk System
- r = Retail Delivery or Connection Point

$\mathrm{SystemEnergy}_{Z,Y,b}$ **(MWh)** is the system energy purchased in the relevant area of the distribution system (i.e., the portion of the system where losses were impacted by the project) at the retail location by zone. Note that the system energy is used here, not the project-specific energy, because this benefit is only quantified when the distribution loss percent value is changed, which affects all load in the relevant part of the distribution system.

$\mathrm{ACE}_{Z,Y,b}$ **($/MWh)** is the ACE, which is the sum of energy, congestion, and losses components by NYISO zone at the bulk system level ("b"). To determine time-differentiated ACEs, for example, annual, seasonal, monthly, or hourly, leverage NYISO's hourly ACE forecast by zone rather than developing an alternative forecast of time-differentiated ACEs based on shaping annual averages by zone from historical data. The NYISO hourly ACE forecast is a direct output from the CARIS Phase 2 modeling. To extend the ACE forecast beyond the CARIS planning period, if necessary, assume that the last year of the ACEs stay constant in real (inflation adjusted) $/MWh.

$\mathrm{SystemDemand}_{Z,Y,b}$ **(MW)** is the system peak demand for the portion of the retail location on the distribution system(s) (i.e., the portion of the system where losses are impacted by the project) for the relevant NYISO capacity zone. This parameter is grossed up to the bulk system level (i.e., location of the AGCC) based on the $\mathrm{Loss\%}_{Z,b\rightarrow r}$ parameter. Note that the system demand is used in this evaluation, not the

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[116] In future versions of the Handbook, additional indices such as time period and voltage level can be included as this data becomes available.

[117] Mapping NYISO localities to NYISO zones: ROS = A-F, LHV = G-I, NYC = J, LI = K.

project-specific demand, because this benefit is only quantified when the system topology is changed resulting in a change in distribution loss percent, which affects all load in the relevant part of the distribution system.

$\mathbf{AGCC_{Z,Y,b}}$ **($/MW-yr)** represents the annual AGCCs at the bulk system level (“b”) based on forecast of capacity prices for the wholesale market provided by Staff. This data can be found in Staff’s ICAP Spreadsheet Model in the “AGCC Annual” tab in the “Avoided GCC at Transmission Level” table. This spreadsheet converts “Generator ICAP Prices” to “Avoided GCC at Transmission Level” based on capacity obligations at the forecast of capacity prices for the wholesale market. Note that the AGCC values provided in this spreadsheet are in the units of $/kW-mo, which must be converted to $/MW-yr to match the peak load impact in MW. To convert units, the summer and winter $/kW-mo values are multiplied by six months each and added together, and then multiplied by 1,000 to convert to $/MW-yr.

$\mathbf{\Delta Loss\%_{Z,Y,i\rightarrow r}}$ **(Δ%)** is the change in fixed and variable loss percent between the interface between the transmission and distribution systems (“i”) and the retail delivery point (“r”) resulting from a project that changes the topology of the distribution system. This value would typically be determined in a project-specific engineering study. Two parameters are provided in the equations above: one with a “Y” subscript to represent the current year, and one with a “Y+1” subscript to represent the following year.

$\mathbf{Loss\%_{Z,Y,i\rightarrow r,baseline}}$ **(%)** is the baseline fixed and variable loss percent between the interface of the transmission and distribution systems (“i”) and the retail delivery point (“r”). Thus, this reflects the distribution loss percent pre-project, which is found in Table B-25.

$\mathbf{Loss\%_{Z,Y,i\rightarrow r,post}}$ **(%)** is the post-project fixed and variable loss percent between the interface of the transmission and distribution systems (“i”) and the retail delivery point (“r”).

General Considerations

Distribution losses are already accounted for in the ACE and AGCC when grossing impacts at the project location to the price locations. Because static forecasts of ACEs and AGCC are used, this benefit will be quantified only in cases where a measure, project, or portfolio alters the distribution system losses percentage (e.g., from 3% to 2.9%). For most projects, this benefit will be zero unless an engineering study determines otherwise.

The energy and demand impacts are grossed up from retail impacts to transmission system impacts based on losses in the equations above. Impacts are based on system-wide energy and demand, not project-specific, because this benefit is only quantified when the loss percentage is changed which affects all load in the affected area. Note that distribution losses also affect upstream transmission losses. Because losses data is usually only available on an annual average basis, the energy and demand impacts should be on an annual average basis as well.

It is assumed that the ACE component of the avoided losses benefit is accrued in the same year as the impact, and the AGCC component of the benefit is accrued in the following year of the benefit. This is reflected in the equation above with “Y” and “Y+1” subscripts to indicate the time delay of benefits relative to the impacts.

B.4.3 Reliability/Resiliency Benefits

B.4.3.1 Net Avoided Restoration Costs

Avoided Restoration Costs accounts for avoided costs of restoring power during outages. For most DER investments, this benefit will not be quantified, as utilities will have to fix the cause of the outage regardless of whether the DER allows the customer to operate independently of the grid. For some non-DER investments such as automatic feeder switching, distribution automation and enhanced equipment monitoring, the utility may save time and other expenses dispatching restoration crews as a result of having improved visibility into the type and nature of the fault. Storm hardening and other resiliency investments can reduce the number of outage events, resulting in reduced restoration crew hours. Two methodologies to capture the potential value of programs or specific projects are identified below.

Benefit Equation, Variables, and Subscripts

Equation B-11 presents the benefit equation for Net Avoided Restoration Costs:

Equation B-11. Net Avoided Restoration Costs

$$\mathrm{Benefit}_{\mathrm{Y}} = -\Delta\mathrm{CrewTime}_{\mathrm{Y}} * \mathrm{CrewCost}_{\mathrm{Y}} + \Delta\mathrm{Expenses}_{\mathrm{Y}}$$

Where,

$$\Delta\mathrm{CrewTime}_{\mathrm{Y}} = \#\mathrm{Interruptions}_{\mathrm{base,Y}} * (\mathrm{CAIDI}_{\mathrm{base,Y}} - \mathrm{CAIDI}_{\mathrm{post,Y}} * (1 - \%\mathrm{ChangeSAIFI}_{\mathrm{Y}}))$$

$$\%\mathrm{ChangeSAIFI}_{\mathrm{Y}} = \frac{\mathrm{SAIFI}_{\mathrm{base,Y}} - \mathrm{SAIFI}_{\mathrm{post,Y}}}{\mathrm{SAIFI}_{\mathrm{base,Y}}}$$

SAIFI, CAIDI and SAIDI values could be utilized at the system level for projects/programs that are applicable across a total system basis but can and should be substituted with more granular data for more localized and geographic specific projects that have more localized impacts. Other reliability metrics if available and applicable may be utilized to better quantify certain reliability or resiliency benefits and costs.

There is no subscript to represent the type of outage in Equation B-11 because an average restoration crew cost that does not change based on the type of outage is assumed. However, the ability to reduce outages would be dependent on the outage type.

$\boldsymbol{\Delta\mathrm{CrewTime}_{\mathrm{Y}}}$ **(Δhours/yr)** is the change in crew time to restore outages based on an impact on frequency and duration of outages. A positive value represents a reduction in crew time.

$\boldsymbol{\mathrm{CrewCost}_{\mathrm{Y}}}$ **($/hr)** is the average hourly outage restoration crew cost for activities associated with the project under consideration.

$\boldsymbol{\Delta\mathrm{Expenses}_{\mathrm{Y}}}$ **(Δ$)** are the average expenses (e.g., equipment replacement) associated with outage restoration.

$\boldsymbol{\#\mathrm{Interruptions}_{\mathrm{base,Y}}}$ **(int/yr)** are the baseline (i.e., pre-project) number of sustained interruptions per year, excluding major storms. The system-wide five-year average number of interruptions excluding major storms is available from the annual Electric Service Reliability Reports.

$\mathbf{CAIDI_{base,Y}}$ **(hr/int)** is the baseline (i.e., pre-project) Customer Average Interruption Duration Index. It represents the average time to restore service, excluding major storms. The system-wide five-year average CAIDI excluding major storms is available from the annual Electric Service Reliability Reports. Note that this parameter is not necessarily a system-wide value. Rather, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

$\mathbf{CAIDI_{post,Y}}$ **(hr/int)** is the post-project Customer Average Interruption Duration Index. It represents the average time to restore service, excluding major storms. This parameter would require an engineering study or model to quantify. Note that this parameter is not necessarily a system-wide value. Rather, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

$\%\mathbf{ChangeSAIFI_Y}$ **(Δ%)** is the percent change in System Average Interruption Frequency Index. It represents the percent change in the average number of times that a customer experiences an outage per year.

$\mathbf{SAIFI_{base,Y}}$ **(int/cust/yr)** is the baseline (i.e., pre-project) System Average Interruption Frequency Index. It represents the average number of times that a customer experiences an outage per year, excluding major storms. The baseline system-wide value five-year average and excludes major storms. It is available from the annual Electric Service Reliability Reports. This parameter is not necessarily a system-wide value. Rather, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

$\mathbf{SAIFI_{post,Y}}$ **(int/cust/yr)** is the post-project System Average Interruption Frequency Index. It represents the average number of times that a customer experiences an outage per year in the post-project scenario. Note that this parameter is not necessarily a system-wide value. Rather, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

Equation B-12. Net Avoided Restoration Costs

$$\mathrm{Benefit_Y} = \mathrm{MarginalCost_{R,Y}}$$

The indices of the parameters in Equation B-12 include:

- R = Reliability constraint on an element (e.g., pole-mounted transformer, distribution line, etc.) of T&D system
- Y = Year

$\mathbf{MarginalDistCost_{R,Y}}$ **($/yr):** Marginal cost of the reliability investment. This value is very project- and location- and a system average value is not applicable.

This benefit only applies for an individual project or portfolio of DER which is able to provide functionally equivalent to the reliability provided by the traditional distribution reliability investment; otherwise, the value of this benefit for DER is zero. When an individual or portfolio of DER is able to defer a distribution reliability investment, the value of the Avoided Distribution Capacity Infrastructure would likely be zero to avoid double counting.

General Considerations

The impact on SAIFI or CAIDI is due to the implementation of the project relative to a baseline, not based on outside factors such as weather. The changes to these parameters should consider the appropriate context of the project, for example, impact to one feeder or impact to a portion of the distribution system. The baseline values should match the portion of the system impacted. In addition, one should consider the types of outage event and how the project may or may not address each type of outage event to inform the magnitude of impact.

In addition to being project-specific, calculation of avoided restoration costs is dependent on projection of the impact of specific investments affecting the facilitation of actual system restoration and the respective costs. It is unrealistic to expect that DER investments will limit or replace the need to repair field damage to the system, and as such, system restoration benefits attributable to DER type investments are unlikely. However, as measurement capabilities and DER experience evolve, utilities may be able to develop comparative evaluations of the reliability benefits of DER and traditional utility investments. Application of this benefit would be considered only for investments with validated reliability results.

B.4.3.2 Net Avoided Outage Costs

Avoided Outage Costs accounts for customer outage costs due to a reduction in frequency and duration of outages, then multiplying that expected change by an estimated outage cost. The quantification of this benefit is highly dependent on the type and size of affected customers.

Benefit Equation, Variables, and Subscripts

Equation B-13 presents the benefit equation for Net Avoided Outage Costs:

Equation B-13. Net Avoided Outage Costs

$$\mathrm{Benefit_Y} = \sum_{\mathrm{C}} \mathrm{ValueOfService_{C,Y,r}} * \mathrm{AverageDemand_{C,Y,r}} * \Delta\mathrm{SAIDI_Y}$$

Where,

$$\Delta\mathrm{SAIDI_Y} = \mathrm{SAIFI_{base,Y}} * \mathrm{CAIDI_{base,Y}} - \mathrm{SAIFI_{post,Y}} * \mathrm{CAIDI_{post,Y}}$$

The indices of the parameters in Equation B-13 include:

- C = Customer class (e.g., residential, small C&I, large C&I) – BCA should use customer-specific values if available.
- Y = Year
- r = Retail Delivery or Connection Point

$\mathbf{ValueOfService_{C,Y,r}}$ **($/kWh)** is the value of electricity service to customers, by customer class, in dollars per unserved kWh at the retail delivery point. The value(s) should be determined based on the customers' willingness to pay for reliability. If location-, customer class- or customer-specific values are not available, these values should default to the retail rate of electricity by customer class.

$\mathbf{AvgDemand_{C,Y,r}}$ **(kW)** is the average demand in kW at the retail delivery or connection point ("r") that would otherwise be interrupted during outages but can remain electrified due to DER equipment and/or utility infrastructure. This would need to be identified by customer class, or by customer, if available. If the timing of outages cannot be predicted, this parameter can be calculated by dividing the annual energy consumption by 8,760 hours per year.

$\Delta\mathbf{SAIDI_Y}$ **(Δhr/cust/yr):** is the change in System Average Interruption Duration Index due to the project. The impact on SAIDI can be determined based on the impact on CAIDI and SAIFI.[118] Baseline system average reliability metrics can be found in the Company's annual Electric Service Reliability reports. A positive value represents a reduction in SAIDI.

$\mathbf{SAIFI_{post,Y}}$ **(int/cust/yr)** is the post-project System Average Interruption Frequency Index; represents the average number of times that a customer experiences an outage per year in the post-project case.

$\mathbf{CAIDI_{post,Y}}$ **(hr/int)** is the post-project Customer Average Interruption Duration Index; represents the impact of a project on the average time to restore service in the post-project case.

$\mathbf{SAIFI_{base,Y}}$ **(int/cust/yr)** is the baseline (i.e., pre-project) System Average Interruption Frequency Index. It represents the average number of times that a customer experiences an outage per year, excluding major storms. The baseline system-wide value is a five-year average and excludes major storms, and is available from the annual Electric Service Reliability Reports. This parameter is not necessarily a system-wide value. Rather, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

$\mathbf{CAIDI_{base,Y}}$ **(hr/int)** is the baseline (i.e., pre-project) Customer Average Interruption Duration Index. It represents the impact of a project on the average time to restore service, excluding major storms. The baseline system-wide is a five-year average and excludes major storms, and is available from the annual Electric Service Reliability Reports. This parameter is not necessarily a system-wide value. Rather, it should be representative of the relevant area of the system that the measure, project, or portfolio affects.

General Considerations

The value of the avoided outage cost benefit is to be customer class-specific, customer class should match or be consolidated properly between the utility and the study area to ensure that the value of reliability matches, what the customer would be willing to pay.

For this version of the BCA Handbook, the outage cost can be estimated by assuming the customer would be willing to pay the same retail rate they pay for electricity, to avoid an outage. The full retail rate value can be found in the utility's latest tariff by customer class.

At this time, the Standard Interconnection Requirements do not allow for islanding, and therefore limit this configuration to a DER that meets the needs of a customer during an outage. Therefore, there are limited instances where DER allows the customer to supply local load in a blackout and resulting benefits would then be limited to that load picked up by DER.

B.4.4 External Benefits

B.4.4.1 Net Avoided CO_2

Net Avoided CO_2 accounts for avoided CO_2 due to a reduction in system load levels[119] or the increase of CO_2 from onsite generation. The CARIS forecast of ACE contains a cost of carbon based on the RGGI.

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[118] SAIDI = SAIFI * CAIDI

[119] The Avoided CO_2 benefit considers the change in energy as a result of the project by including the change in energy identified in the Avoided ACE, Avoided Transmission Losses, and Avoided Distribution Losses benefits.

Staff will provide a $/MWh adder to account for the net marginal damage cost of carbon that is not already captured in the ACE. This adder is based on the US EPA damage cost estimates for a 3% real discount rate. Staff then provides a $/MWh for the full marginal damage cost and the net marginal damage costs of CO_2. The net marginal damage costs is the full marginal damage cost less the cost of carbon embedded in the ACE.

Benefit Equation, Variables, and Subscripts

Equation B-14 presents the benefit equation for Net Avoided CO_2:

Equation B-14. Net Avoided CO_2

$$\mathrm{Benefit}_{Y} = \mathrm{CO2Cost\Delta ACE}_{Y} - \mathrm{CO2Cost\Delta OnsiteEmissions}_{Y}$$

Where,

$$\mathrm{CO2Cost\Delta ACE}_{Y} = \left(\frac{\Delta \mathrm{Energy}_{Y,r}}{1 - \mathrm{Loss\%}_{Y,b\to r}} + \Delta \mathrm{Energy}_{\mathrm{TransLosses},Y} + \Delta \mathrm{Energy}_{\mathrm{DistLosses},Y}\right) * \mathrm{NetMarginalDamageCost}_{Y}$$

$$\Delta \mathrm{Energy}_{\mathrm{TransLosses},Y} = \mathrm{SystemEnergy}_{Y,b} * \Delta \mathrm{Loss\%}_{Y,b\to i}$$

$$\Delta \mathrm{Energy}_{\mathrm{DistLosses},Y} = \mathrm{SystemEnergy}_{Y,b} * \Delta \mathrm{Loss\%}_{Y,i\to r}$$

$$\Delta \mathrm{Loss\%}_{Z,Y,b\to i} = \mathrm{Loss\%}_{Z,Y,b\to i,\mathrm{baseline}} - \mathrm{Loss\%}_{Z,Y,b\to i,\mathrm{post}}$$

$$\Delta \mathrm{Loss\%}_{Z,Y,i\to r} = \mathrm{Loss\%}_{Z,Y,i\to r,\mathrm{baseline}} - \mathrm{Loss\%}_{Z,Y,i\to r,\mathrm{post}}$$

$$\mathrm{CO2Cost\Delta OnsiteEmissions}_{Y} = \Delta \mathrm{OnsiteEnergy}_{Y} * \mathrm{CO2Intensity}_{Y} * \mathrm{SocialCostCO2}_{Y}$$

The indices of the parameters in Equation B-14 include:

- Y = Year
- b = Bulk System
- i = Interface of the Transmission and Distribution Systems
- r = Retail Delivery or Connection Point

$\mathbf{CO2Cost\Delta LBMP_{Y}}$ **($)** is the cost of CO_2 due to a change in wholesale energy purchased. A portion of the full CO_2 cost is already captured in the Avoided ACE benefit. The incremental value of CO_2 is captured in this benefit, and is valued at the net marginal cost of CO_2, as described below.

$\mathbf{CO2Cost\Delta OnsiteEmissions_{Y}}$ **($)** is the cost of CO_2 due to DER that is not emission-free. The cost of carbon for customer-sited emissions is based upon the gross marginal cost of CO_2, as described below.

$\mathbf{\Delta Energy_{Y,r}}$ **(ΔMWh)** is the change in energy purchased at the retail delivery or connection point ("r") as a result of the project. This parameter considers the energy impact at the project location, which is then grossed up to the bulk system level based on the $Loss\%_{b\to r}$ parameter. A positive value represents a reduction in energy.

$\mathbf{Loss\%_{Y,b\to r}}$ **(%)** is the variable loss percent from the bulk system level ("b") to the retail delivery or connection point ("r"). These values can be found in Table B-25.

$\mathbf{\Delta Energy_{TransLosses,Y}}$ **(ΔMWh)** represents the change in electricity lost on the transmission system due to the Avoided Transmission Losses benefit. Refer to Section B.4.1.4 for more details. In most cases, unless the transmission system loss percent is altered due to a project or portfolio, this parameter will be zero. A positive value represents a reduction in energy lost in transmission system losses.

$\mathbf{\Delta Energy_{DistLosses,Y}}$ **(ΔMWh)** represents the change in energy lost on the distribution system due to the Avoided Distribution Losses benefit. Refer to Section B.4.2.3 for more details. In most cases, unless the distribution system loss percent is altered due to a project or portfolio, this parameter will be zero. A positive value represents a reduction in energy lost in distribution system losses.

$\mathbf{NetMarginalDamageCost_Y}$ **($/MWh)** is the "adder" Staff will provide to account for the full marginal damage cost of carbon that is not already captured in the forecast of ACE from CARIS. The ACE forecast from CARIS includes the cost of carbon based on the RGGI, but does include the SCC from the U.S. EPA.

$\mathbf{\Delta Loss\%_{Z,Y,b \rightarrow i}}$ **(Δ%)** is the change in fixed and variable loss percent between the interface between the bulk system ("b") and the interface between the transmission and distribution systems ("i"). This represents the change in the transmission system loss factor. This value would typically be determined in a project-specific engineering study.

$\mathbf{Loss\%_{Z,Y,b \rightarrow i,baseline}}$ **(%)** is the baseline fixed and variable loss percent between the interface between the bulk system ("b") and the interface between the transmission and distribution systems ("i"). Thus, this reflects the transmission loss percent pre-project, which is found in Table B-25.

$\mathbf{Loss\%_{Z,Y,b \rightarrow i,post}}$ **(%)** is the post-project fixed and variable loss percent between the interface between the bulk system ("b") and the interface between the transmission and distribution systems ("i"). Thus, this reflects the transmission loss percent post-project, which is found in Table B-25.

$\mathbf{\Delta Loss\%_{Z,Y,i \rightarrow r}}$ **(Δ%)** is the change in fixed and variable loss percent between the interface between the transmission and distribution systems ("i") and the retail delivery point ("r") resulting from a project that changes the topology of the distribution system. This represents the change in the distribution system loss factor. This value would typically be determined in a project-specific engineering study.

$\mathbf{Loss\%_{Z,Y,i \rightarrow r,baseline}}$ **(%)** is the baseline fixed and variable loss percent between the interface of the transmission and distribution systems ("i") and the retail delivery point ("r"). Thus, this reflects the distribution loss percent pre-project, which is found in Table B-25.

$\mathbf{Loss\%_{Z,Y,i \rightarrow r,post}}$ **(%)** is the post-project fixed and variable loss percent between the interface of the transmission and distribution systems ("i") and the retail delivery point ("r"). Thus, this reflects the distribution loss percent post-project, which is found in Table B-25.

$\mathbf{\Delta OnsiteEnergy_Y}$ **(ΔMWh)** is the energy produced by customer-sited carbon-emitting generation.

$\mathbf{CO2Intensity_Y}$ **(metric ton of CO_2 / MWh)** is the average CO_2 emission rate of customer-sited pollutant-emitting generation. This is a project-specific input based on the type of onsite generation. Note that there is a difference between metric tons and short tons[120].

[120] 1 metric ton = 1.10231 short tons

$\mathbf{SocialCostCO2_Y}$ **($ / metric ton of CO_2)** is an estimate of the total monetized damages to society associated with an incremental increase in CO_2 emissions. Annual values are provided by EPA, and are also located in Table A of Attachment B of the BCA Order. Per the BCA Order, the values associated with a 3% real discount rate shall be used. Note that Table A provides values in 2011 dollars; these values must be converted to nominal values prior to using the equation above.

General Considerations

The equation above represents two sources of emissions based on: (1) a change in ACE purchases, which is valued at the $/MWh adder (i.e., $NetMarginalDamageCost_Y$ parameter above) to be provided by Staff, and (2) customer-sited carbon emissions from onsite generation (e.g., such as combined heat and power [CHP]), which is valued at the social cost of carbon from EPA.

The energy impact is project-specific and should be linked to the impacts determined in the Avoided ACE benefit. The ACE impacts due to the Avoided Transmission Losses and Avoided Distribution Losses benefits also need to be account for when determining the total change in ACE due to a project. It is assumed that the benefit value due to an impact on emissions is accrued in the same year as the impact.

The methodology outlined in this section to value Avoided CO_2 may change. The *BCA Order* indicates “utilities shall rely on the costs to comply with New York’s Clean Energy Standard once those costs are known.”[121]

B.4.4.2 Net Avoided SO_2 and NO_x

Net Avoided SO_2 and NO_x includes the incremental value of avoided or added emissions. The ACE already includes the cost of pollutants (i.e., SO_2 and NO_x) as an “internalized” cost from the Cap & Trade programs. Emitting customer-sited generation <25 MW will be included in this benefit since the generators do not participate in the Cap & Trade programs.

Benefit Equation, Variables, and Subscripts

Equation B-15 presents the benefit equation for Net Avoided SO_2 and NO_x:

Equation B-15. Net Avoided SO_2 and NO_x

$$\mathrm{Benefit_Y} = \sum_{\mathrm{p}} \mathrm{OnsiteEmissionsFlag_Y} * \mathrm{OnsiteEnergy_{Y,r}} * \mathrm{PollutantIntensity_{p,Y}} * \mathrm{SocialCostPollutant_{p,Y}}$$

The indices of the parameters in Equation B-15 include:

- p = Pollutant (SO_2, NO_x)
- Y = Year
- r = Retail Delivery or Connection Point

$\mathbf{OnsiteEmissionsFlag_Y}$ is a binary (i.e., 0 or 1) parameter, where a value of 1 indicates that customer-sited pollutant-emitting generation <25 MW is implemented as a result of the project.

$\mathbf{OnsiteEnergy_{Y,r}}$ **(ΔMWh)** is the energy produced by customer-sited pollutant-emitting generation.

[121] *BCA Order*, Appendix C, 16.

$\text{PollutantIntensity}_{p,Y}$ **(ton/MWh)** is average pollutant emissions rate of customer-sited pollutant-emitting generation. This is a project-specific input.

$\text{SocialCostPollutant}_{p,Y}$ **($/ton)** is an estimate of the monetized damages to society associated with an incremental increase in pollutant emissions in a given year. The allowance prices are provided in CARIS Phase 2.

General Considerations

ACEs already include the cost of pollutants (i.e., SO_2 and NO_x) as an "internalized" cost from the Cap & Trade programs. Emitting customer-sited generation <25 MW will be included in this benefit since the generators do not participate in the Cap & Trade programs. This would be a benefit to the extent that the DER emits less than NYISO generation, and a negative benefit for the DER if it has a higher emissions rate than NYSO generation or emissions –free DER.

Two values are provided in CARIS for NO_x costs: "Annual NO_x" and "Ozone NO_x." Annual NO_x prices are used October through May; Ozone NO_x prices May through September. The breakdown of energy in these two time periods must be accounted for and applied to the appropriate NO_x cost.

It is assumed that the benefit value due to an impact on emissions is accrued in the same year as the impact.

B.4.4.3 Avoided Water Impact

A suggested methodology for determining this benefit is not included in this version of the Handbook. This impact would be assessed qualitatively in the SCT.

B.4.4.4 Avoided Land Impact

A suggested methodology for determining this benefit is not included in this version of the Handbook. This impact would be assessed qualitatively in the SCT.

B.4.4.5 Net Non-Energy Benefits Related to Utility or Grid Operations

A suggested methodology for determining this benefit is not included in this version of the Handbook. This impact would be assessed qualitatively or if can be estimated quantitatively. It is necessary to identify which cost-effectiveness test should include the specific benefit or cost as it may apply to the SCT, UCT and/or RIM.

B.4.5 Costs Analysis

B.4.5.1 Program Administration Costs

Program Administration Costs includes the cost to administer and measure the effect of required program administration performed and funded by utilities or other parties. This may include the cost of incentives, measurement and verification, and other program administration costs to start, and maintain a specific program. The reduced taxes and rebates to support certain investments increase non-participant costs.

Benefit Equation, Variables, and ***Subscripts***

Equation B-16Equation B-16 presents the cost equation for Program Administration Costs:

Equation B-16. Program Administration Costs

$$\text{Cost}_{\text{Y}} = \sum_{\text{M}} \Delta\text{ProgramAdminCost}_{\text{M,Y}}$$

The indices of the parameters in Equation B-16Equation B-16 include:

- M = Measure
- Y = Year

$\boldsymbol{\Delta\text{ProgramAdminCost}_{\text{M,Y}}}$ is the change in Program Administration Costs, which may include one-time or annual incentives such as rebates, program administration costs, measurement and verification, state incentives, and other costs. These costs would increase by inflation, where appropriate.

General Considerations

Program Administration Costs are program- and project-specific, therefore without a better understanding of the details it is not possible to estimate in advance the Project Administration Cost. Program-specific details that are necessary to calculate the cost impact can include, but are not limited to, the scale of the activity, the types of participating technologies, and locational details. Sub-categories that could fall under Program Administration Costs include, but are not limited to, programmatic measurement & verification costs, utility-specific rebates and/or incentives, and costs of market interventions (e.g., state and federal incentives).

B.4.5.2 Added Ancillary Service Costs

Added Ancillary Service Costs occur when DER causes additional ancillary service cost on the system. These costs shall be considered and monetized in a similar manner to the method described in the B.4.1.5 Avoided Ancillary Services (Spinning Reserves, and Frequency Regulation).

B.4.5.3 Incremental Transmission & Distribution and DSP Costs

Additional incremental T&D Costs are caused by projects that contribute to the utility's need to build additional infrastructure.

Additional T&D infrastructure costs caused shall be considered and monetized in a similar manner to the method described in Section B.4.1.3 Avoided Transmission Capacity Infrastructure and Related O&M The potential for incremental T&D costs depends on the interconnection location, type of DER, and penetration of other DER in the area. These factors make estimating a value of incremental T&D costs in advance without project-specific information difficult.

Depending on the nature of a specific DER project the incremental costs could be borne by the interconnecting facility or shared among all ratepayers. For instance, a utility may need to make further investment in their T&D infrastructure, such as expanding system capacity, implementing more sophisticated control functionalities, or enhancing protection to ensure seamless grid integration of new DER assets.

In some situations enhanced capabilities of a DSP would be required. These incremental costs would be identified and included within this cost.

B.4.5.4 Participant DER Cost

Participant DER Cost includes the equipment and participation costs assumed by DER providers which need to be considered when evaluating the societal costs of a project or program. These costs are the full cost of the DER as program rebates, and incentives are included as part of Program Administration Costs.

The Participant DER Costs includes the installed cost of the device or system, as well as any ongoing O&M expenses to provide the solution. Installed costs include the capital cost of the equipment, balance of system and labor for the installation. Operating costs include ongoing maintenance expenses.

Four DER example technologies with representative cost information are included in this section:

- Solar PV – residential (4 kW)
- Combined Heat and Power (CHP) – recip engine (100 kW)
- DR – controllable thermostat
- EE – commercial lighting
- Electrification – residential heat pumps

All cost numbers presented herein should be considered representative estimates. Actual Participant DER costs will vary by project based upon factors including:

- **Make and model:** The DER owner typically has an array of products to choose from which have different combinations of cost and efficiency.
- **Type of installation:** The location of where the DER would be installed influences the capital costs, for example, ground-mounted or roof-mounted PV
- **Geographic location:** Labor rates, property taxes, and other factors vary across utility service areas and across the state

In addition, the specific DER provided herein are a small subset of the types of DER available in the market. Utilities intend to solicit DER costs in NWAs and other competitive solicitations, and will develop utility specific costs based on experience.

Solar PV Example

The solar PV used in this example is a 4 kW-AC residential rooftop system which is connected to the local distribution system through the customer's meter. All cost parameters in Table B-9 for the intermittent solar PV example calculated based on information provided in the E3's NEM Study for New York ("E3 Report").[122] In this study, E3 used cost data provided by NYSERDA based on solar PV systems that were installed in NY from 2003 to 2015. For a project-specific cost analysis, actual estimated project costs would be used.

Table B-9. Solar PV Example Cost Parameters

Parameter	Cost
Installed Cost (2015$/kW-AC)[123]	4,430
Fixed Operating Cost ($/kW)	15

Note: These are default values that would be used unless the DER provider supports project-specific estimates.

[122] The Benefits and Costs of Net Energy Metering in New York, Prepared for: New York State Energy Research and Development Authority and New York State DPS, December 11, 2015.

[123] This cost is per kW of nameplate AC capacity. AC capacity is calculated from DC capacity using a factor of 1.1 DC:AC as provided in E3's NEM report.

1. **Capital and Installation Cost:** Based on E3's estimate for NYSERDA of 2015 residential PV panel installed cost. For solar the $/kW cost usually includes both the cost of the technology and installation cost, which is the case in this example. Costs could be lower or higher depending on the size of project, installation complexity and location. This example assumes a 4 kW residential system for an average system in New York. This cost is per kW of nameplate AC capacity. AC capacity is calculated from DC capacity using a factor of 1.1 DC:AC as provided in E3's NEM report.
2. **Fixed Operating Cost:** E3's estimate for NYSERDA of O&M for a residential PV panel in 2015. This estimate is applied to all New York electric utilities in the NYSERDA paper.

CHP Example

The CHP system used in this example is a 100 kW capacity natural gas-fired engine unit sized for commercial thermal load following applications. Cost parameter values were obtained from the EPA's Catalog of CHP Technologies[124] for this baseload CHP example based on estimations of representative system costs. There are many site-specific factors that can affect cost parameters that are not examined in this example including: property tax, local permitting, gas and electric interconnection costs, local emissions constraints and possible structural requirements. Natural gas costs would need to be considered for the natural gas fired CHP system. To reflect natural gas price fluctuation, Mid-Atlantic values from the Energy Information Administration Annual Energy Outlook[125] are used (see Table B-10)

Table B-10. CHP Example Cost Parameters

Parameter	Cost
Installed Capital Cost ($/kW)	3,000
Variable Operating Cost ($/kWh)	0.025

Note: These are illustrative estimates and would change as projects and locations are considered.

1. **Capital and Installation Cost:** EPA's estimate of a reciprocating engine CHP system capital cost. This includes of the project development costs associated with the system including equipment, labor and process capital. [126]
2. **Variable:** EPA's estimate of a 100 kW reciprocating engine CHP system's non-fuel O&M costs.[127]

DR Example

The system dispatchable DR technology described herein is a programmable and controllable thermostat in a residence with central air conditioning that is participating in a DLC program. The capital cost is based on an average of Wi-Fi enabled controllable thermostats from Nest, Ecobee, and Honeywell (See Table B-11)

[124] EPA CHP Report available at: https://www.epa.gov/chp/chp-resources
[125] https://www.eia.gov/outlooks/aeo/
[126] EPA CHP Report. pg. 2-15.
[127] EPA CHP Report. pg. 2-17.

Table B-11. DR Example Cost Parameters

Parameter	Cost
Capital Cost ($/Unit)	$233
Installation Cost ($/Unit)	$140

Note: These are illustrative estimates and would change as projects and locations are considered.

1. **Capital and Installation Costs:** These costs differ by thermostat model and capabilities, and as such should be considered representative. The installation costs estimates represent a New York system, but will vary substantially depending on the program nature.
2. **Operating Costs:** Assumed to be $0 for the DR asset participant based on comparison with the alternative technology.

EE Example

The energy efficient lighting used in this example is indoor installation of linear fluorescent lighting in a commercial office setting. Lighting cost estimates are based on the full cost of the measure, not the incremental cost over what is currently installed (see Table B-12)

Table B-12. EE Example Cost Parameters

Parameter	Cost
Installed Capital Cost ($/Unit)	$80

Note: These are illustrative estimates and would change as projects and locations are considered.

1. **Installed Capital Cost:** Based on Guidehouse's review of manufacturer information and EE evaluation reports.

Electrification Example

The electrification examples include ducted air-source heat pumps (ASHP) and ductless mini-split heat pumps installed in a residential setting. Heat pump cost estimates are based on the full cost of the measure, not the incremental cost over what is currently installed. Avoided fuel oil, propane, or natural gas costs would need to be considered for the heat pumps displacing fossil fuel heating systems. To reflect fossil fuel price fluctuations, Mid-Atlantic values from the Energy Information Administration Annual Energy Outlook[128] are used. Delivered fuel prices are scaled to Long Island specific values reported by NYSERDA.[129,130] (see Table B-13)

[128] https://www.eia.gov/outlooks/aeo/

[129] https://www.nyserda.ny.gov/Researchers-and-Policymakers/Energy-Prices

[130] Aligned with the NYSERDA Commercial Baseline and Potential Study: "Because these fuels are not regulated, retail rates reflect the marginal societal costs." Commercial Baseline Appendix 2, page 12. NYSERDA https://www.nyserda.ny.gov/-/media/Migrated/Statewide-Commercial-Baseline-Study-Report/NYSERDA-CBS-Appendix-2-Potential-Study.pdf

Table B-13. Heat Pump Example Cost Parameters

Parameter	Cost
ASHP Installed Cost ($/Unit)	$11,570
Ductless Installed Cost ($/Unit)	$7,453

Note: These are illustrative estimates and would change as projects and locations are considered.

2. **Installed Capital Cost:** Based on Demand Side Analytics' review of projects in PSEG Long Island's territory.

B.4.5.5 Lost Utility Revenue

Lost Utility Revenue includes the distribution and other non-by-passable revenues that are shifted on to non-participating customers due to the presence of revenue decoupling mechanisms, in which sales-related revenue "losses" due to a decrease in electricity sales or demand is recovered by marginally increasing the rate of electricity sales or demand to non-participating customers.

Lost utility revenue is not included in the SCT and UCT as the reduced participant revenues are offset by the increased non-participant revenues. Therefore, this cost is only included in the RIM. As DER reduces utility sales and the associated revenues, a revenue decoupling mechanism enables the utility to be made whole by recovering these lost revenues from other ratepayers.

The impact to non-participating customers would be estimated by evaluating the type of DER and the tariffs applicable to the affected customers.

B.4.5.6 Net Non-Energy Costs

A suggested methodology for determining this benefit is not included in this version of the Handbook. This impact would be assessed qualitatively or if can be estimated quantitatively. It is necessary to identify which cost-effectiveness test should include the specific benefit or cost as it may apply to the SCT, UCT and/or RIM.

B.5 Characterization of DER profiles

This section discusses the characterization of DERs using several examples and presents the type of information necessary to assess associated benefits. Four *DER categories* are defined to provide a useful context, and specific example technologies within each category are selected for examination. The categories are: *intermittent*, *baseload*, *dispatchable* and *load reduction*. There are numerous potential examples of individual DERs within each category, varying by technology, size, location, customer application, and other factors. A single example DER was selected in each of the four categories to illustrate specific BCA values, as shown in Table B-14 below. These four examples cover a useful, illustrative range of impacts that DERs can have on the various benefit and cost categories in the BCA Handbook (see Table B-14).

Table B-14. DER Categories and Examples Profiled

DER Category	DER Example Technology
Intermittent	Solar PV
Baseload	CHP

Dispatchable	Controllable Thermostat
Load Reduction	Energy Efficient Lighting

The DER technologies that have been selected as examples are shown in Table B-15. Each DER technology has unique operating characteristics that allow it to accrue some benefits and costs but not others. In some cases, the ability of a DER to provide certain benefits and incur certain costs will be driven by the operational objective of the specific DER, not the intrinsic characteristics of the technology itself. For example, DR technology in one situation may be operated to reduce the NYISO peak, which may or may not coincide with a distribution feeder peak where it is installed. Another DR technology may be operated to provide support for a distribution NWA, in which the distribution feeder or substation may not have a peak load that coincides with the NYISO peak. Thus, the operational objectives of the DR technology would result in different estimates of benefits and costs depending on this operational objective. Key attributes of the example DER technologies are provided in Table B-15.

Table B-15. Key Attributes of Selected DER Technologies

Resource	Attributes
Photovoltaic (PV)	PV is an intermittent resource with energy output determined by solar irradiance. The directional orientation and vertical angle of PV panels are important considerations for determining energy output and thus the corresponding coincidence factors with system-wide or local power delivery. PV energy output may also degrade over time.
Combined Heat and Power (CHP)	CHP is a resource typically sized to meet a customer's thermal energy requirements, but which also provides electrical energy. The particular customer's characteristics determine the ability of CHP to contribute to various benefit and cost categories.
Energy Efficiency	EE reduces the energy consumption for delivery of a particular service (use) without degrading or reducing the level of service delivered.
Demand Response (DR)	DR reduces energy demand for a particular service (use) during specific hours of the day—typically peak demand hours—without reducing the service to an unacceptable level. DR is typically available only for limited hours in a year (e.g., <100 hrs). The operational objective of the DR determines how it may contribute to various benefit and cost categories.

Each example DER is capable of enabling a different set of benefits and incurs a different set of costs, as illustrated in Table B-16.

Table B-16. General applicability for each DER to contribute to each Benefit and Cost

#	Benefit/Cost	PV	CHP	DR	EE
	Benefits				
1	Avoided Generation Capacity Costs (AGCC)	●	●	●	●
2	Avoided ACE	●	●	●	●
3	Avoided Transmission Capacity Infrastructure	◒	◒	◒	◒
4	Avoided Transmission Losses	○	○	○	○
5	Avoided Ancillary Services	○	○	○	○

#	Benefit/Cost	PV	CHP	DR	EE
6	Wholesale Market Price Impacts	●	●	●	●
7	Avoided Distribution Capacity Infrastructure	◒	◒	◒	◒
8	Avoided O&M	○	○	○	○
9	Avoided Distribution Losses	○	○	○	○
10	Net Avoided Restoration Costs	○	○	○	○
11	Net Avoided Outage Costs	○	◒	○	○
12	Net Avoided CO_2	●	●	●	●
13	Net Avoided SO_2 and NO_x	●	●	●	●
14	Avoided Water Impacts	○	○	○	○
15	Avoided Land Impacts	○	○	○	○
16	Net Non-Energy Benefits	○	○	○	○
	Costs				
17	Program Administration Costs	●	●	●	●
18	Added Ancillary Service Costs	○	○	○	○
19	Incremental T&D and DSP Costs	◒	◒	◒	○
20	Participant DER Cost	●	●	●	●
21	Lost Utility Revenue	●	●	●	●
22	Net Non-Energy Costs	○	○	○	○

Note: This is general applicability and project-specific applications may vary.

● Generally applicable ◒ May be applicable ○ Limited or no applicability

As described in Section B.4, each quantifiable benefit typically has two types of parameters. The parameters to monetize the value are generally unaffected by the DER being analyzed in the BCA (e.g., AGCC in $ per MW-yr), whereas other parameters asses the magnitude of underlying benefit and may vary by type of DER (e.g., system coincidence factor). Table B-17 identifies the parameters which are necessary to characterize DER benefits. As described in Section B.4, several benefits potentially applicable to DER require further investigation to estimate and quantify the impacts, and project-specific information before they can be incorporated into a BCA (e.g., Avoided O&M, Net Avoided Restoration Costs and Net Avoided Outage Costs, and Avoided Ancillary Services).

Table B-17. Key parameter for quantifying how DER may contribute to each benefit

#	Benefit	Key Parameter
1	Avoided Generation Capacity Costs (AGCC)	**SystemCoincidenceFactor**
2	Avoided ACE	**ΔEnergy (time-differentiated)**
3	Avoided Transmission Capacity Infrastructure	**TransCoincidenceFactor**
4	Avoided Transmission Losses	Limited or no applicability
5	Avoided Ancillary Services	Limited or no applicability
6	Wholesale Market Price Impacts	**ΔEnergy (annual)** **ΔAGCC**
7	Avoided Distribution Capacity Infrastructure	**DistCoincidenceFactor**
8	Avoided O&M	Limited or no applicability
9	Avoided Distribution Losses	Limited or no applicability
10	Net Avoided Restoration Costs	Limited or no applicability
11	Net Avoided Outage Costs	Limited or no applicability[131]
12	Net Avoided CO_2	**CO_2Intensity** (limited to CHP)
13	Net Avoided SO_2 and NO_x	**PollutantIntensity** (limited to CHP)
14	Avoided Water Impacts	Limited or no applicability
15	Avoided Land Impacts	Limited or no applicability
16	Net Non-Energy Benefits	Limited or no applicability

Table B-18 further describes the key parameters identified in Table B-17.

[131] A CHP system may be able to provide a Net Avoided Outage Costs benefit in certain system configurations.

Table B-18. Key parameters

Key Parameter	Description
Bulk System Coincidence Factor	Necessary to calculate the AGCC benefit.[132] It captures a project's or program's contribution to reducing bulk system peak demand relative to its expected maximum demand reduction capability
Transmission Coincidence Factor[133]	Necessary to calculate the Avoided Transmission Capacity Infrastructure benefit. It quantifies a project's contribution to reducing a transmission system element's peak demand relative to the project's expected maximum demand reduction capability. This would be evaluated on localized basis in most cases, but in some instances an assessment of coincidence with a system coincidence factor would be appropriate.
Distribution Coincidence Factor	Distribution coincidence factor is required to calculate the Avoided Distribution Capacity Infrastructure benefit. It captures the contribution to the distribution element's peak relative to the project's expected maximum demand reduction capability. This would be evaluated on localized basis in most cases, but in some instances an assessment of coincidence with a system coincidence factor would be appropriate.
CO_2 Intensity	CO_2 intensity is required to calculate the Net Avoided CO_2 benefit. This parameter is dependent on the type of DER being evaluated – emission-free or emission-generating. It is the average CO_2 emission rate of customer-sited pollutant-emitting generation. This is a project-specific input based on the type of onsite generation.
Pollutant Intensity	Pollutant intensity is required to calculate the Net Avoided SO_2 and NO_X benefit. This parameter is dependent on the type of DER being evaluated – emission-free or emission-generating. It is the average SO_2 and/or NO_X emission rate of customer-sited pollutant-emitting generation. This is a project-specific input based on the type of onsite generation.
ΔEnergy (time-differentiated)	This parameter measures the change in bulk system energy consumed as a result of specific DER project implementation. This value is reliant on project-specific details including location. The DEnergy is dependent on the type of DER (e.g., intermittent vs. baseload), and how the DER would be operated (e.g., load reduction vs. energy conservation vs. backup generation). Thus, the DEnergy is time-differentiated. It may be appropriate to use an annual average value for some DER, while for others it may be more appropriate to use an average on-peak hours of operation, or even hourly operation. In each case the corresponding ACE data would be required to value the benefit. The examples provided herein discuss potential approaches to consider time-differentiation by DER type.[134]

[132] This parameter is also used to calculate the **Error! Reference source not found.** benefit.

[133] Bulk transmission effectively has the same coincidence factor as generation since non-project specific transmission benefits are included in the Avoided ACE and AGCC. This transmission coincidence factor is applicable for the **Error! Reference source not found.** benefit, which incorporates incremental value beyond what is included in the **Error! Reference source not found.** and **Error! Reference source not found.** benefits.

[134] Note also that annual change in bulk system energy is used in the calculation of **Error! Reference source not found.** benefit.

B.5.1 Coincidence Factors

Coincidence factors for DER are an important part of the benefit calculations and can be estimated in a variety of ways. What follows is a general approach for calculating the coincidence factors. Typical values are presented as examples in the sections below, however determining appropriate values for a specific project or portfolio may require additional information and calculation.

The first step is to identify the respective peak times for Bulk System, Transmission element or Distribution element as needed. Illustrations using a single peak hour are provided below.

B.5.1.1 Bulk System

According to the NYISO, the bulk system peaks generally occur during the afternoon hours of the hottest non-holiday weekday. The peak day might occur from May to October depending on the weather. For example, the New York Control Area (NYCA) peak typically occurs around hour ending 5 PM. Table B-19 below represents the NYCA peak dates and times for the last 5 years, for illustrative purposes, obtained from the 2021 Load and Capacity Data report.

Table B-19. NYCA Peak Dates and Times

Year	Date of Peak	Time of Peak
2016	8/11/2016	Hour Ending 5 PM
2017	7/19/2017	Hour Ending 6 PM
2018	8/29/2018	Hour Ending 5 PM
2019	7/20/2019	Hour Ending 5 PM
2020	7/27/2020	Hour Ending 5 PM

B.5.1.2 Transmission

The transmission peak as defined for the BCA may occur on a different day or hour than that of the NYCA peak. The peak is dependent on the location of specific transmission constraints where utility capital investment may be needed. If applicable, use the hour that the constrained element on the transmission system experiences its peak load. In general, the benefits of a reduced transmission peak would be captured through the Avoided ACE and AGCC benefits.

B.5.1.3 Distribution

The distribution peak as defined for the BCA may occur on a different day or hour than that of the NYCA peak. The distribution system coincidence factor is highly project specific. The distribution system serving predominantly large office buildings will peak at a different time or day than that of a distribution system that serves a residential neighborhood. The distribution system peak may differ or coincide with the NYCA system peak and the transmission peak. System-wide averages have been historically acceptable to use for some investment portfolios such as EE where the programs are broad based, and system-wide averages are provided in the Technical Resource Manual (TRM), which assumes a historical coincidence for the NYCA peak. Going forward, for investments that are more targeted in nature, a more localized coincidence factor is likely to be appropriate. The value of reducing the distribution peak is dependent on the location of constraints in the distribution equipment where utility capital investment may be needed. Note that in some cases with very local benefits objectives, even if the coincidence factor is high, the capacity value of a DER to the distribution system may be low or zero if no constrained element is relieved (e.g., no distribution investment is otherwise required in capacity in that location, thus there is no distribution investment to be deferred even with highly coincident DER behavior).

B.5.2 Estimating Coincidence Factors

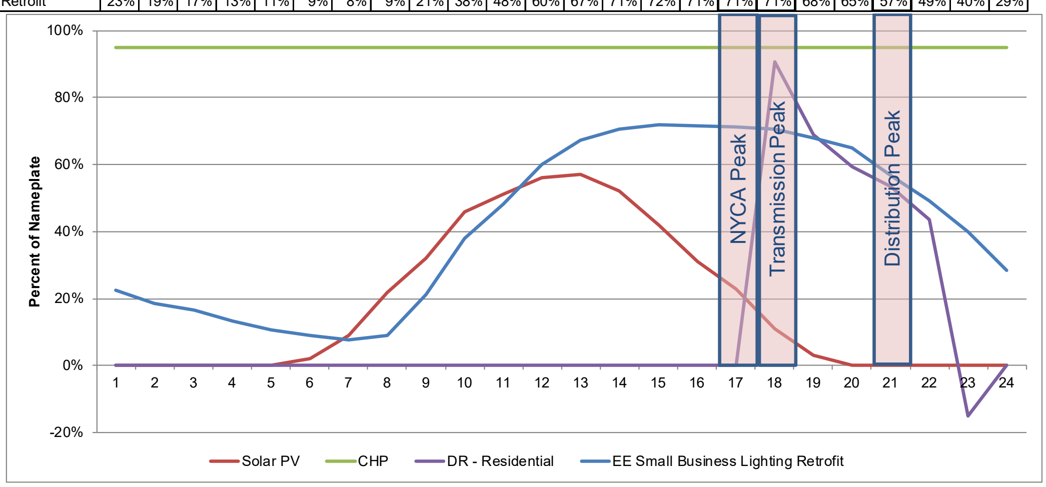
There are multiple approaches for estimating coincidence factors that apply different levels of rigor. Rigorous approaches could be defined and applied across a range of DERs; however, such an approach is likely to require a significant amount of granular information (e.g., 8760 hour load shapes for the DER projects and network information for specific locations) and time to analyze. Other approaches that require less granular information may be suitable in some cases and thus may be preferable in some situations.

One approach for estimating coincidence factors is to model the energy behavior of the DER on a time specific basis (e.g., hourly output) and normalize this behavior to the nameplate capacity. This time specific, normalized behavior can then be compared to the relevant peaks (i.e., system, transmission, and distribution) on the same time specific basis to determine the coincidence factors. The time basis can be done on an annual basis, using a 'typical day', or using a subset of hours that are appropriate that specific DER.

Figure B-3 provides an illustrative plot of the hourly DER output curves for a summer peak day as a graphical demonstration of the calculation method. The y-axis represents the percentage of DER output vs. the DER nameplate, and the x-axis shows the hour of the peak day. By using the Bulk System, Transmission or Distribution peak hour and the respective percentage of peak, the coincidence factors can be determined based on the type of resource (see Figure B-3).

Figure B-3. Illustrative Example of Coincidence Factors

	Hour Ending																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Solar PV	0%	0%	0%	0%	0%	2%	9%	22%	32%	46%	51%	56%	57%	52%	42%	31%	23%	11%	3%	0%	0%	0%	0%	0%
CHP	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%	95%
DR - Residential	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	91%	69%	59%	53%	43%	-15%	0%
EE Small Business Lighting Retrofit	23%	19%	17%	13%	11%	9%	8%	9%	21%	38%	48%	60%	67%	71%	72%	71%	71%	71%	68%	65%	57%	49%	40%	29%



Source: Consolidated Edison Company of New York

The individual DER example technologies that have been selected are discussed below.[135]

The values for the DER examples have been compiled from various sources and each of these sources may apply different valuation techniques. Some sources performed extensive simulations to generate statewide averages, while others performed calculations on a variety of system specification assumptions. For example, the coincidence factors for the solar example were calculated in E3's NEM Study for New York ("E3 Report")[136] based on a simulation of a large number of solar systems across New York.

An area for further investigation will be to assess and develop a common approach and methodology for determining the values for DER-specific parameters for each type of DER.

B.5.3 Solar PV Example

Solar PV is selected to depict an intermittent DER, where the electricity generation is dependent on the resource availability, in this case solar irradiance. The parameter assumptions and methodology used to develop those assumptions, were obtained from the E3 Report.

B.5.3.1 Example System Description

The solar PV used in this example is a 4 kW-AC residential rooftop system which is connected to the local distribution system through the customer's meter. These details allow for an estimate of material and installation costs, but there are several other system details required to estimate system energy output, and therefore a full benefit analysis. Local levels of solar irradiance, panel orientation (azimuth angle from north, south, east, west), tilt (typically, 0°-25° for rooftop systems located in NY) and the addition of a tracking feature, as well as losses associated with the balance of system equipment (e.g., inverters, transformers) and system degradation over time each impact the system's capacity factor and coincidence factors with the bulk system, transmission and distribution.

The impact and value of solar output on system, transmission, and distribution systems must consider the intermittent behavior of solar generation. To conduct this analysis, an hourly profile of generation based on project-specific parameters, as well as corresponding system, transmission, and distribution load profiles, provide the information that is necessary to estimate the coincidence factors for this example DER technology. The values that follow in this section are for a system-wide deployment of solar PV.

B.5.3.2 Benefit Parameters

The benefit parameters in Table B-20 or the intermittent solar PV example are based on information provided in the E3 Report.

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[135] The BCA Handbook does not attempt to provide an example of a portfolio of interdependent DERs, such as those that might be procured to provide an NWA approach. Such a combination of project-specific DERs and distribution system information is less generalizable for assessing transmission and distribution coincidence factors, and less informative as an example than the individual DER examples selected. For example, when assessing NWAs it is necessary to assess their functional equivalence with traditional wired solutions. This requires understanding the potentially complex interactions between the DERs, assessing their joint reliability relative to that of traditional wired investment, and understanding the uncertainties in performance that may impact ability to maintain safe, reliable, economic energy delivery. The BCA handbook incorporates derating factors in various benefit calculations to account for these elements, but a discussion of those factors would complicate this section significantly, and so it was not included.

[136] The Benefits and Costs of Net Energy Metering in New York, Prepared for: New York State Energy Research and Development Authority and New York State DPS, December 11, 2015.

E3 determined utility-specific average values for coincidence and capacity factors. The statewide weighted-averages based on electricity delivered by utility are provided in Table B-20. These values are illustrative estimates that may be refined as more data becomes available. To calculate project-specific benefit values, hourly simulations of solar generation, peak hours, and energy prices (ACE) would need to be calculated based on the project's unique characteristics. Similarly, utility and location-specific specific information would be needed. For example, the distribution coincidence factor can vary significantly depending on time of the feeder and substation peak.

Table B-20. Solar PV Example Benefit Parameters

Parameter	Value
SystemCoincidenceFactor	36%
TransCoincidenceFactor	8%
DistCoincidenceFactor	7%
DEnergy (time-differentiated)	Hourly

Note: These are illustrative estimates and would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** This value represents the 'effective' percent of the nameplate capacity, 4 kW-AC, that reduces the system peak demand, resulting in an AGCC benefit. The 36% calculated from results of the E3 Report aligns with the coincidence values presented in the NYISO ICAP manual, which provides a range from 26%-43% depending on system azimuth and tilt angle.[137] It is acceptable to use the summer average because in this BCA, the AGCC is calculated based on the summer impact on-peak load (Section B.4.1.1).
2. **TransCoincidenceFactor:** The transmission coincidence factor included is for the New York average sub-transmission coincidence factor. This value would be highly project-specific, as it depends on the generation profile of the system, and the load profile for the site-specific area on the sub-transmission system.
3. **DistCoincidenceFactor:** The distribution coincidence factor is lowest. Residential distribution feeders and substations often peak during early evening hours when solar output is low.[138] This value would be highly project-specific, as it depends on the generation profile of the system, and the load profile for the site-specific area on the distribution system.
4. **DEnergy (time-differentiated):** As discussed above solar output would be higher during daylight hours and summer months. As hourly solar profiles are available from SAM, it would be appropriate to compare the projected energy output with hourly ACEs.

[137] NYISO Installed Capacity Manual Version 4, March 2022, Summer Unforced Capacity Percentage – Solar Fixed Tilt Arrays) page 59. Available at: https://www.nyiso.com/documents/20142/2923301/icap_mnl.pdf/234db95c-9a91-66fe-7306-2900ef905338.

[138] E3 Report, "Based on E3's NEM Ratepayer Impacts Evaluation in California it was found (in a granular substation load analysis) that distribution peak loads are generally aligned with solar PV generation profiles in approximately 30% of the systems analyzed." PDF pg. 49.

B.5.4 Combined Heat and Power Example

CHP is an example of a baseload DER which typically operates during system, transmission, and distribution peaks.

B.5.4.1 Example System Description

CHP depicts a baseload DER where the electricity is generated at all hours, except during maintenance. The CHP system used in this example is a 100 kW capacity natural gas-fired engine unit sized for commercial thermal load following applications. In this simplified example, the 100 kW system is assumed to be small relative to the commercial building's overall electric load and thus the system operates at full electrical generating capacity at all times, except when it is down for maintenance. The example is described in EPA's Catalog of CHP Technologies (EPA CHP Report).[139]

B.5.4.2 Benefit Parameters

Benefit parameters for the baseload CHP example are a combination of assumptions on system use and system characteristics.

Coincidence and capacity factors are derived from the assumption that the CHP is used as a baseload DER whereby the CHP system would be running at full capacity all the time, with the exception of downtime for maintenance. Since it is not always possible to schedule downtimes, the CHP unit is assumed to provide 95% power output at all hours, assuming it is down for maintenance 5% of the year.[140]

The carbon and criteria pollutant intensity can be estimated using the EPA's publicly-available CHP Emissions Calculator.[141] "CHP Technology," "Fuel," "Unit Capacity" and "Operation" were the four inputs required. Based on the example, a reciprocating engine, fueled by natural gas, 100 kW in capacity operating at 95% of 8,760 hours/year.

To complete a project-specific analysis, actual design parameters and generation profiles would be needed to assess the likelihood of coincidence, emissions, and capacity factors (see Table B-21).

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[139] https://www.epa.gov/chp/chp-resources
[140] EPA CHP Report. pg. 2-20.
[141] EPA CHP Emissions Calculator https://www.epa.gov/chp/chp-emissions-calculator

Table B-21. CHP Example Benefit Parameters

Parameter	Value
SystemCoincidenceFactor	0.95
TransCoincidenceFactor	0.95
DistCoincidenceFactor	0.95
CO_2Intensity (metric ton CO_2/MWh)	0.141
PollutantIntensity (metric ton NO_X/MWh)	0.001
DEnergy (time-differentiated)	Annual average

Note: These are illustrative estimates and would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** The system coincidence factor is 0.95 under the assumption that the CHP system is always running apart from downtime for maintenance or during forced outages.
2. **TransCoincidenceFactor:** The transmission coincidence factor is 0.95 under the assumption that the CHP system is always running apart from downtime for maintenance or during forced outages.
3. **DistCoincidenceFactor:** The distribution coincidence factor is 0.95 under the assumption that the CHP system is always running apart from downtime for maintenance or during forced outages.
4. **CO_2Intensity:** This value was the output of EPA's calculator, provided in tons/year and then converted to metric ton/MWh as required for input into the BCA (Section B.4.4.1).
5. **PollutantIntensity:** This value was the output of EPA's calculator, provided in tons/year and then converted to metric ton/MWh as required for input into the BCA (Section B.4.4.2). There are no SO_2 emissions from burning natural gas.
6. **DEnergy (time-differentiated):** Assuming the CHP is used as a baseload resource, with the exception of downtime for maintenance, capacity factor is 95%. Because it is not possible to predict when the downtime may occur, using annual average ACE would be appropriate.

B.5.5 Demand Response Example

DR depicts an example of a dispatchable DER where the resource can be called upon to respond to peak demand.

B.5.5.1 Example System Description

The system dispatchable DR technology described herein is a programmable and controllable thermostat in a residence with central air conditioning that is participating in a DLC program.

DR is a dispatchable DER because it reduces demand on request from the system operator or utility.[142] Each DR program has unique requirements for notification time, length of demand reduction, number of calls, and frequency of calls. A DR resource is typically available only for limited hours in a year (e.g., <100 hrs). The major benefit from DR is ability to reduce peak demand. The particular use case or operational objective of the DR determines the value for its coincidence factors.

[142] Some DR programs may be "dispatched" or scheduled by third-party aggregators.

The coincidence factors shown below do not account for load or device availability. Load availability is defined as the percentage of total potential capacity that can be shed from the load connected to the DR system at the time the DR event is called. Device availability is defined as the ability the DR system to accurately receive the DR signal and control the load. These factors, multiplied by the total potential capacity of the DR asset, would produce the average demand reduction for the asset. Average demand reduction multiplied by the coincidence factor is then defined as the average peak coincidence demand. These values are not presented here but are project- and technology-specific and will differ substantially among DR technologies and loads. As such, project-specific analyses would need to consider the load and system availability, as well as response rate (as described above) to accurately determine the appropriate coincidence factors.

This DR example is designed to reduce system peak (consistent with most existing DR programs), thus the system coincidence factor is 1.0 such that the DR resource is called to reduce the system peak load.[143] Given the small number of calls annually, the coincidence factor with the system peak is assumed to be 1, while the coincidence factors for the transmission and distribution peaks is assumed to be 0.5 which is consistent with the assumption that this particular DR example is not targeted to be coincident with those peaks.[144]

As an alternative approach, to calculate the coincidence factors for a specific DR resource, comparative analysis should be performed on the most recent annual data comparing the peak demand of the targeted system with the peak demand of the other systems. Comparing the coincidence of the top 50 hours of total system load and top 50 hours of each feeder's load would produce the distribution coincidence factor for a DR project that targets system peak. Analysis should be based on data from the Day-Ahead Market or Real-Time Market depending on the design of the DR program. Coincidence factors for DR projects should use the most recently available data.

The value of reduced energy use attributable to the DR asset can be calculated using the average ACE of the top 50 hours of system peak. A more accurate energy calculation would consider the expected number of times that DR was called in a given year as well as the length of the calls beyond the peak hour itself (e.g., 2-hour events, 4 hour events). This calculation will differ if the DR asset is intended to defer another peak, or if the DR program has a substantially different frequency of calls. The number of hours averaged should be based on the frequency of DR calls and the selection of those hours should be based on when the DR calls will be made.

B.5.5.2 Benefit Parameters

The benefit parameters described in Table B-22 are assumed based on the example and considerations described above.

Table B-22. DR Example Benefit Parameters

Parameter	Value
SystemCoincidenceFactor	1.0
TransCoincidenceFactor	0.5

[143] Note, the controllable load may not be operating at the time of peak.
[144] Con Edison Callable Load Study, Page 78, Submitted May 2008. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BADA5E14E-9633-436E-8B1B-10DF4AB02913%7D.

DistCoincidenceFactor	0.5
DEnergy (time-differentiated)	Average of highest 100 hours

Note: These are illustrative estimates and would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** The system coincidence factor is assumed to be 1.0, based on the assumption that the DR system is called upon at the time of system peak.
2. **TransCoincidenceFactor:** Without targeting portions of the transmission system, the coincidence factor is assumed to be 0.5 but would be greater if the DR is dispatched to target the transmission peak.[145] Location- and program-specific distribution coincidence factors could be calculated using hourly load data per the methodology described above.
3. **DistCoincidenceFactor:** Without targeting portions of the transmission system, the coincidence factor is assumed to be 0.5 but would be greater if the DR is dispatched to target the transmission peak.[146] Location- and program-specific distribution coincidence factors could be calculated using hourly load data per the methodology described above. If instead the DR asset were used to defer distribution capacity, the coincidence factor could be as high as 1 (though the system coincident factor could then be as low as zero, since if the peak periods were to occur at the same time, the project could only be dispatched for one program).
4. **DEnergy (time-differentiated):** DR would be dispatched a limited number of hours during the year. NYISO may only call upon DR for ~50 hours in a year. The energy savings can be estimated based on the *average* demand savings (not peak) expected over the hours called, times the number of hours the DR resource is expected to be called. This average reduction would be multiplied by an appropriately time-differentiated ACE.

B.5.6 EE Example

Energy efficient lighting depicts a load-reducing DER where the use of the technology decreases the customer's energy consumption as compared to what it would be without the technology or with the assumed alternative technology. The parameter assumptions, and methodology used to develop those assumptions, developed using the NY TRM or PSEG Long Island specific values developed by the third-party evaluation contractor.[147]

B.5.6.1 Example System Description

The energy efficient lighting used in this example is indoor installation of linear fluorescent lighting in a commercial office setting with an estimated utilization of 3,013 hours/year.[148] The peak period for this example is assumed to occur in the summer during afternoon hours.

EE, including lighting, is a load reducing because it decreases the customers' energy consumption and load shape, which in turn, reduces the system, transmission and distribution peak. This example of an indoor, office-setting lighting system assumes that the coincidence factor is calculated during operational

[145] Con Edison Callable Load Study, Page 78, Submitted May 2008. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BADA5E14E-9633-436E-8B1B-10DF4AB02913%7D.
[146] Ibid.
[147] New York State Technical Resource Manual (TRM)I: New York Standard Approach for Estimating Energy Savings from Energy Efficiency Programs – Version 9, Issued on August 30, 2021 – Lighting operating hour data is sourced from the 2008 California DEER Update study.
[148] Ibid.

hours when the load reduction due to this lighting technology is expected to occur at the time of the system peak, as well as the during the transmission and distribution peaks.

B.5.6.2 Benefit Parameters

The benefit parameters described in Table B-23 were developed using guidance from the NY TRM.

Table B-23. EE Example Benefits Parameters

Parameter	Value
SystemCoincidenceFactor	1.0
TransCoincidenceFactor	1.0
DistCoincidenceFactor	1.0
DEnergy (time-differentiated)	~7AM to ~7PM weekdays

Note: These are illustrative estimates and would change as specific projects and locations are considered.

1. **SystemCoincidenceFactor:** The system coincidence factor is 1.0 under the assumption that the system peak occurs while standard office lighting systems are operating.
2. **TransCoincidenceFactor:** The transmission coincidence factor is 1.0 under the assumption that the transmission system peak occurs while standard office lighting system are operating.
3. **DistCoincidenceFactor:** The distribution coincidence factor is 1.0 under the assumption that the distribution system peak occurs while standard office lighting systems are operating.
4. **∆Energy (time-differentiated):** This value is calculated using the lighting hours per year (3,013) as provided for General Office types[149] in the NY TRM, divided by the total hours in a year (8,760). This time period is subject to building operation, which is roughly between 7 am and 7 pm, 5 days a week, 52 weeks a year. This would define the corresponding period for determining an average ACE that would be used to calculate the benefit.

Utility-Specific Assumptions

This section includes PSEG Long Island-specific data. Each data point represents a parameter that is used throughout the benefit and cost methodologies described in Section B.4. The discount rate is set by LIPA and reflects the PSEG Long Island cost of capital, which is included in Table B-24.

Table B-24. PSEG Long Island Weighted Average Cost of Capital

Regulated Rate of Return
5.66%

Source: LIPA

PSEG Long Island-specific system annual average loss data is shown in Table B-25.

[149] New York State Technical Resource Manual (TRM)l: New York Standard Approach for Estimating Energy Savings from Energy Efficiency Programs – Version 9, Issued on August 30, 2021 - pg. 667

Table B-25. PSEG Long Island Loss Data

System	Variable Loss Percent	Fixed Loss Percent
Energy	N/A	5.67%
Demand	N/A	7.19%

Source: PSEG Long Island Transmission & Distribution Group

PSEG Long Island-specific system-level marginal costs of service for the period of 2022 through 2041 are presented below in Table B-26. The avoided carbon costs are incremental to the carbon coefficient embedded in the avoided marginal energy costs.

Table B-26. PSEG Long Island System Average Marginal Costs of Service

Year	Marginal Energy Cost $/kWh	Marginal Capacity Cost $/kW-Year	Avoided Cost of Carbon $/kWh Saved
2024	0.0739	32.17	0.02741
2025	0.0584	28.75	0.02741
2026	0.0545	23.85	0.02741
2027	0.0528	70.07	0.02741
2028	0.0488	58.69	0.02741
2029	0.0486	57.58	0.02741
2030	0.0405	10.91	0.02741
2031	0.0360	9.89	0.02741
2032	0.0381	8.79	0.02741
2033	0.0398	7.99	0.02741
2034	0.0424	7.29	0.02741
2035	0.0427	6.73	0.02741
2036	0.0460	6.25	0.02741
2037	0.0468	5.90	0.02741
2038	0.0547	5.09	0.02741
2039	0.0607	4.32	0.02741
2040	0.0649	3.86	0.02741
2041	0.0695	34.79	0.02741
2042	0.0743	82.43	0.02741
2043	0.0795	99.95	0.02741

Source: PSEG Long Island Utility 2.0 Filing, July 2023

B.6 Disclaimer

This report was prepared by Navigant Consulting, Inc. (Navigant) for Whiteman Osterman & Hanna LLP, Consolidated Edison Company of New York, Inc., Orange and Rockland Utilities, Inc., Central Hudson Gas & Electric Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, New York State Electric and Gas Corporation, and Rochester Gas & Electric Corporation. The work presented in this report represents Navigant's professional judgment based on the information available at the time this report was prepared. Navigant is not responsible for the reader's use of, or reliance upon, the report, nor any decisions based on the report. NAVIGANT MAKES NO REPRESENTATIONS OR WARRANTIES, EXPRESSED OR IMPLIED. Readers of the report are advised that they assume all liabilities incurred by them, or third parties, as a result of their reliance on the report, or the data, information, findings and opinions contained in the report.

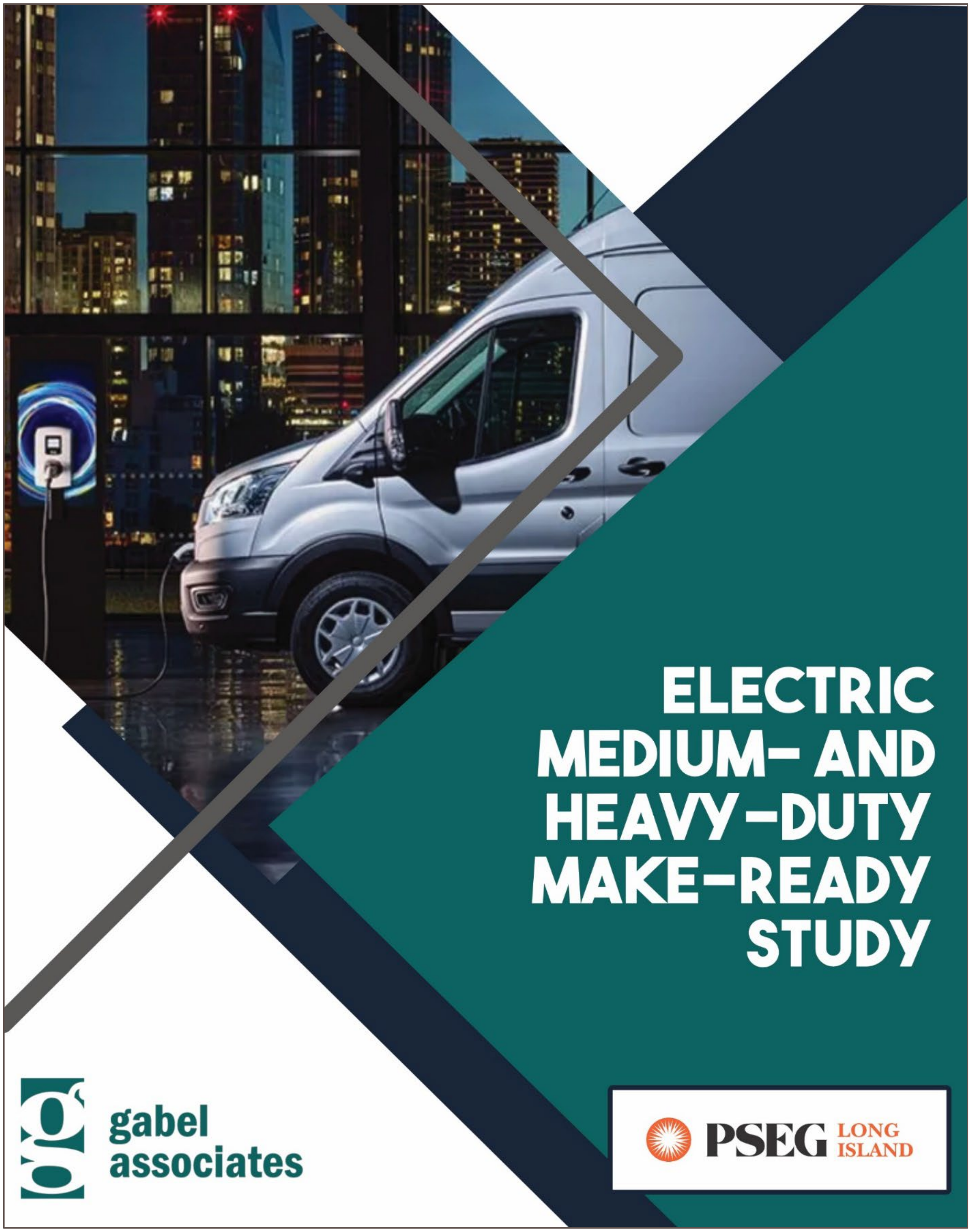
Acronyms and Abbreviations

Acronyms and abbreviations are used extensively throughout the BCA Handbook and are presented here at the front of the Handbook for ease of reference.

AC	Alternating Current
ACE	Avoided Cost of Energy – (analogous to Locational Based Marginal Price (LBMP) for the rest of New York)
AGCC	Avoided Generation Capacity Costs
BCA	Benefit-Cost Analysis
BCA Framework	The benefit-cost framework structure presented initially in the "Staff White Paper on Benefit-Cost Analysis" and finalized in the *BCA Order*.
BCA Order	Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Establishing the Benefit-Cost Analysis Framework (issued January 21, 2016).
CAIDI	Customer Average Interruption Duration Index
CARIS	Congestion Assessment and Resource Integration Study
C&I	Commercial and Industrial
CO_2	Carbon Dioxide
DC	Direct Current
DER	Distributed Energy Resources
DR	Demand Response
DSIP	Distributed System Implementation Plan
DSIP Guidance Order	Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision, Order Adopting Distributed System Implementation Plan Guidance (issued April 20, 2016)
DSP	Distributed System Platform
EPA	Environmental Protection Agency
GHG	Greenhouse Gas
ICAP	Installed Capacity
JU	Joint Utilities (Consolidated Edison Company of New York, Inc., Orange and Rockland Utilities, Inc., Central Hudson Gas & Electric Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, New York State Electric and Gas Corporation, and Rochester Gas & Electric Corporation)
kV	Kilovolt
LCR	Locational Capacity Requirements
LHV	Lower Hudson Valley
LI	Long Island
MW	Megawatt

MWh	Megawatt Hour
NPV	Net Present Value
NO_x	Nitrogen Oxides
NWA	Non-Wires Alternatives
NYC	New York City
NYISO	New York Independent System Operator
NYPSC	New York Public Service Commission
NYSERDA	New York State Energy Research and Development Authority
O&M	Operations and Maintenance
PV	Photovoltaic
REV	Reforming the Energy Vision
REV Proceeding	Case 14-M-0101 – Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision
RGGI	Regional Greenhouse Gas Initiative
RIM	Rate Impact Measure
RMM	Regulation Movement Multiplier
ROS	Rest of State
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAM	System Advisor Model (National Renewable Energy Laboratory)
SCC	Social Cost of Carbon
SCT	Societal Cost Test
SENY	Southeast New York (Ancillary Services Pricing Region)
SO_2	Sulfur Dioxide
T&D	Transmission and Distribution
UCT	

Appendix C. Electric Medium- and Heavy-Duty Make-Ready Study



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C.1 Executive Summary

Since 2020, the New York Public Service Commission has approved programs for the state's utilities to facilitate the adoption of EVs in alignment with state goals and policy. Central to these programs is a focus on Make-Ready, the infrastructure required to deliver power to vehicle charging infrastructure on both the utility-side of the meter and on the customer premises.

On December 30, 2021, Governor Hochul's final adoption of the Advanced Clean Trucks (ACT) Rule[150] signaled the requirement for manufacturers to sell an increasing number of zero-emission Medium- and Heavy-Duty Vehicles (MHDVs) in the state, starting in 2025. Also formalized in legislation is a state goal, stating that 100% of MHDV sales and leases be zero-emission by 2045[151], along with goals related to rapid electrification of school and commuter buses.

PSEG Long Island, who operates the public electric infrastructure under contract to the Long Island Power Authority (LIPA), is exploring the deployment of a Make-Ready Program that will focus on serving MHDV segments in its territory. In support of these needs, PSEG Long Island engaged Gabel Associates to complete a new study to inform development of a MHDV Make-Ready program. This study will provide updated vehicle adoption forecasts, estimate energy and power impacts on the grid, quantify costs for Make-Ready construction, recommend program sizing and design parameters, and collect other data that may be relevant to program design. This report will summarize all the research and analysis completed in this Study and has been updated since originally published to reflect the most recent assumptions. The next phase of work will build on the baseline established in this report to provide program design recommendations and budgeting assumptions, potentially leading to specific MHDV Make-Ready programs proposals in the next Utility 2.0 filing.

Using vehicle registration data from New York State's Open Data Portal[152], Gabel created a snapshot of the MHDV population on Long Island. This population was segmented into a matrix that classifies individual vehicles by weight class in five MHDV body-type/usage groups: Medium-Duty Delivery and Suburban vehicles, other Medium-Duty vehicles including pickups, buses, Heavy-Duty vehicles (excluding tractors), and Heavy-Duty tractors (see Table C-1).[153]

Table C-1. Number of MHDVs on Long Island (Sept, 2022)

Vehicle Segments	Medium Duty		Heavy Duty					Total
	Class 2b	Class 3	Class 4	Class 5	Class 6	Class 7	Class 8	
MD - Delivery & Suburban	13,602	1,441	0	0	0	0	0	15,043
MD - Pickups & All Other	32,576	1,008	0	0	0	0	0	33,584
Buses (All)	8,326							8,326
Heavy Duty	0	0	5,072	24,566	5,367	6,829	29,130	70,965
HD - Tractor (7 & 8)	0	0	0	0	0	157	4,649	4,806
Total (W/O Buses):	46,178	2,449	5,072	24,566	5,367	6,986	33,779	132,723

[150] New York State, "Governor Hochul Announces Adoption of Regulation to Transition to Zero-Emission Trucks," December 30, 2021; https://www.governor.ny.gov/news/governor-hochul-announces-adoption-regulation-transition-zero-emission-trucks

[151] New York State Senate, "Assembly Bill A4302," https://www.nysenate.gov/legislation/bills/2021/a4302

[152] New York State "Open NY" Data Portal provided by the NYS Department of Motor Vehicles (pulled Sept 2022): https://data.ny.gov/Transportation/Vehicle-and-Boat-Registrations-by-Fuel-Type-per-Co/vw9z-y4t7

[153] While this study focuses primarily on MHDV, many MHDV will be part of fleets that are also partially made up of light-duty vehicles and may use the same infrastructure for vehicle charging as the light-duty segment continues to electrify.

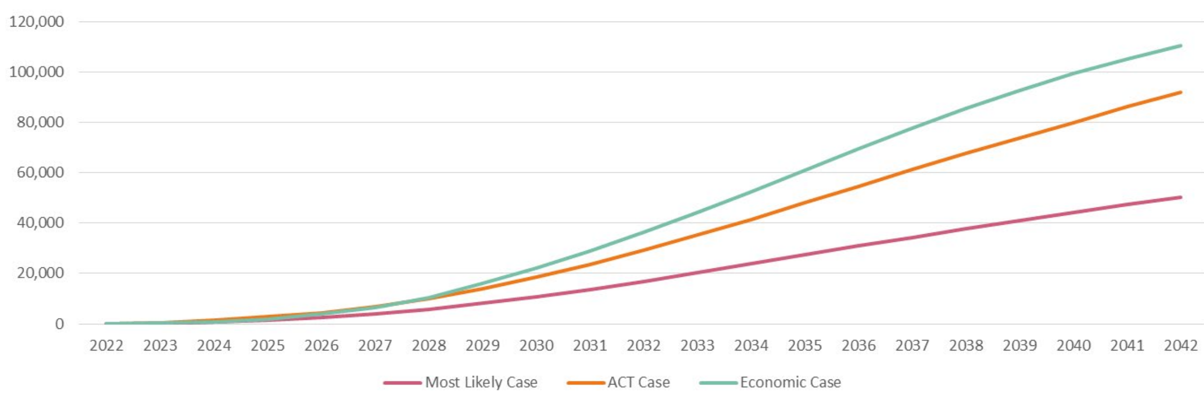
This population of MHDVs turns over naturally – a relatively constant fraction of vehicles in service are retired each year and replaced. This "natural turn-over rate" represents the primary opportunity for electrification, with an increasing fraction of this natural turn-over being electrified each year. Table C-2 summarizes Gabel's estimate of this natural replacement rate.

Table C-2. Natural Number of MHDVs Replaced Each Year

Vehicle Segments	Medium Duty		Heavy Duty					Total
	Class 2b	Class 3	Class 4	Class 5	Class 6	Class 7	Class 8	
MD - Delivery & Suburban	1,360	144	0	0	0	0	0	1,504
MD - Pickups & All Other	3,258	101	0	0	0	0	0	3,358
Buses (All)	694							694
Heavy Duty	0	0	338	1,638	358	455	1,942	4,731
HD - Tractor (7 & 8)	0	0	0	0	0	10	310	320
Total (not including buses)	4,618	245	338	1,638	358	466	2,252	10,608

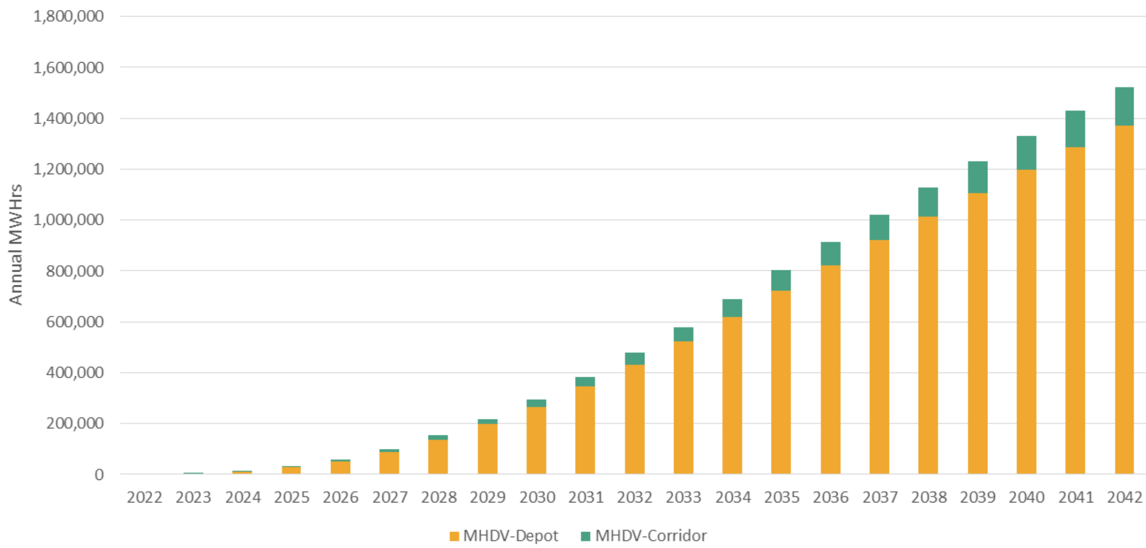
Three scenarios were considered to quantify how quickly MHDV vehicles can be electrified over time, ranging from the policy scenario in which the ACT rules are fully realized, a faster level of adoption associated with fleet operators electrifying quickly as MHDVs achieve economic parity on a Total Cost of Ownership (TCO) basis. In addition, a "most likely" case was developed to balance competing factors that influence fleet electrification rates. The projected number of electrified MHDVs on the road on Long Island is summarized in Figure C-1.

Figure C-1. Projected Total Number of Electric MHDVs in Operation by Year – All Three Cases



The "Most Likely Case" establishes the best projection of future adoption rates since it accounts for both real-world market dynamics, possible constraints (such as current supply disruptions), and current policies that will impact adoption. Gabel estimated the annual energy impacts that the "Most Likely Case" would have on the grid, including both charging that occurs "at the depot" where vehicles are predominantly housed and also along charging Corridors in "truck stop" settings. These energy estimates are summarized in Figure C-2.

Figure C-2. Projected Load for MHDV Charging Energy – Most Likely Case



In addition to the energy required for MHDV charging, Gabel also estimated the potential power impacts for various charging behaviors. Figure C-3 and Figure C-4 below illustrate the hourly load profile for all three charging scenarios (natural, managed, and projected), focusing on snapshots in 2025 and 2035.

Figure C-3. Hourly Load Distribution for MHDV Charging Power – Most Likely Case, 2025

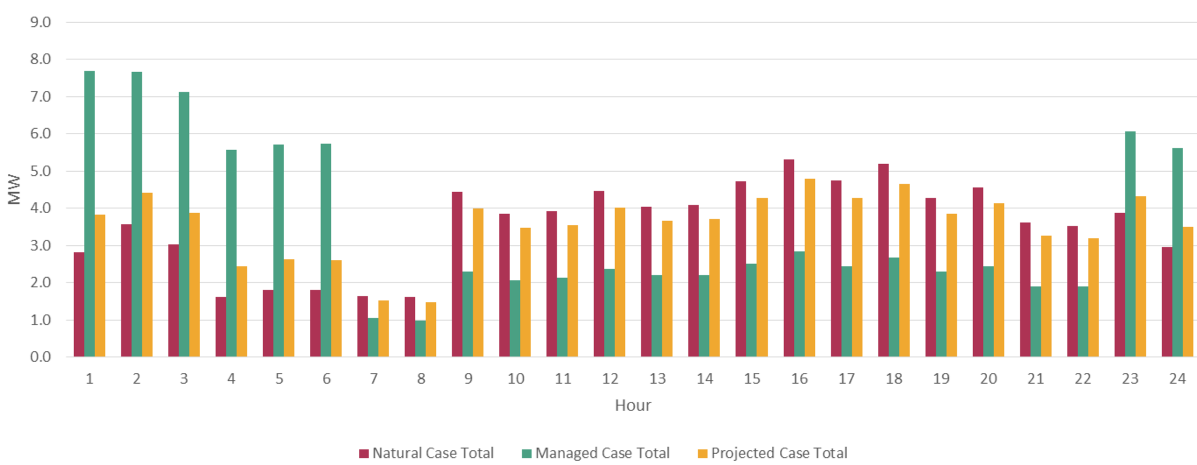
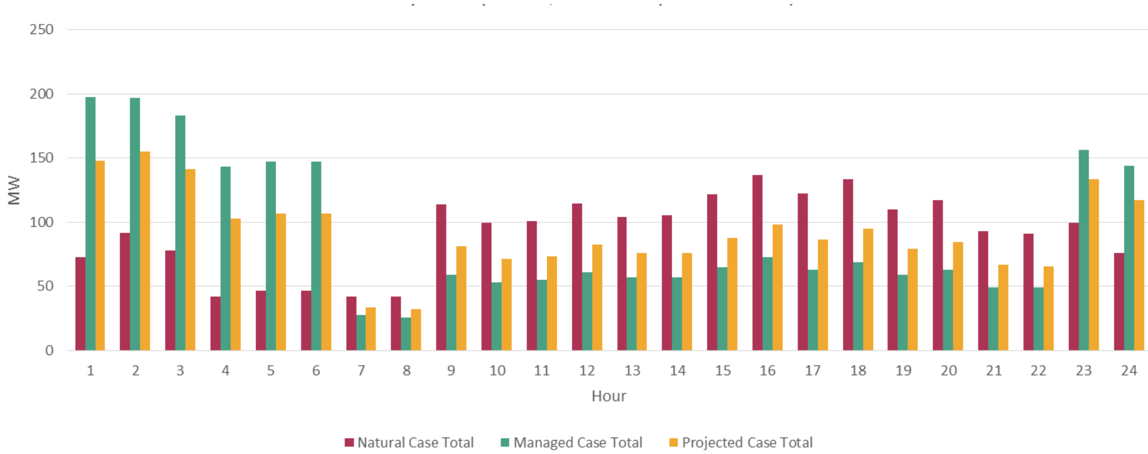


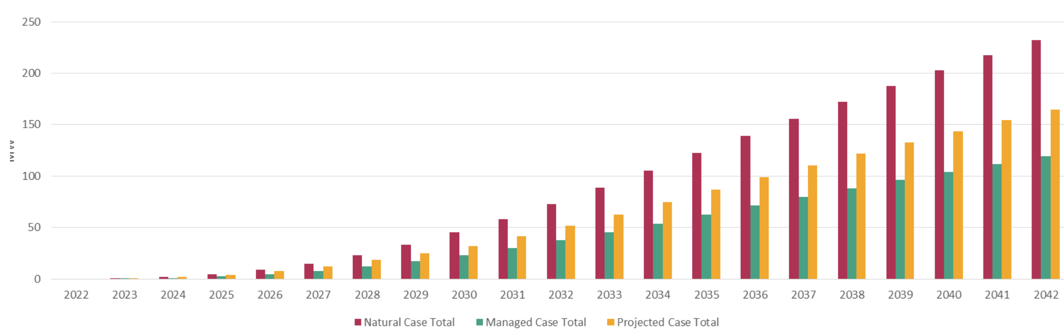
Figure C-4. Hourly Load Distribution for MHDV Charging Power – Most Likely Case, 2035



Note that the scale in the two figures above is not the same as adoption will be significantly higher in 2035 than in 2025. These figures account only for electric MHDV and these requirements will be in addition to the incremental load of LDVs.

Figure C-5 below shows the annual additional MW induced by plug-in electrical vehicles (PEV) under three charging profiles (natural, managed, and projected) at NYISO coincident peak. In the Projected Case, total PEV-load at “Hour 17” (5:00 PM) is expected to increase from 0.5 MW in 2023, to 4.3 MW in 2025, to 32.0 MW in 2030, to 86.6 MW in 2035, to 143.7 MW in 2040.

Figure C-5. Projected Peak Power for MHDV Charging Power – Most Likely Case



This study also characterized typical costs on both the Utility-side and Customer-side of the meter. These costs vary widely across real-world projects from project site to project site. Gabel worked collaboratively with the PSEG Long Island engineering team to come to a consensus on typical US-MR costs for projects of different sizes. For CS-MR costs, the Gabel team harmonized real-world infrastructure charging costs (including those specific to Long Island) with published research to project realistic per-location Make-Ready costs for projects of different sizes. The foundation established by this study will inform more detailed program design recommendations, leading to a MHDV Make-Ready program proposal in July 2023.

C.2 Introduction

In July of 2020, The New York Public Service Commission (NY PSC) approved programs for the investor-owned utilities[154] throughout the state to enable and encourage development of vehicle charging infrastructure as required to attain the state's vehicle electrification goals.[155] This order included provisions to develop Make-Ready incentives, supporting the infrastructure required to deliver power to vehicle charging infrastructure (up to, but not including the charger itself). While the primary focus was to establish Make-Ready programs for the overall vehicle population (which currently consists primarily of LDVs), the NY PSC also directed utilities to establish MHDV Make-Ready Pilot programs and Fleet Advisory Services, which are now available in the market on a somewhat limited but growing basis.

PSEG Long Island also offers Make-Ready incentives for its territory, based on programs proposed through successive iterations of its Utility 2.0 filing. In June of 2021, Gabel completed a study for the Long Island territory that leveraged the PSC-approved program designs and made recommendations for new programs to support vehicle electrification on Long Island, especially regarding public charging infrastructure. This study included a forecast of LDV EV adoption, program sizing, a framework for optimal geographic distribution of charging infrastructure, and program design recommendations.

Meanwhile, in both New York and in other leading vehicle-electrification states around the country, there has been growing interest in providing Make-Ready for fleet applications, especially for the MHDV segment. These segments will typically result in more concentrated loads and clustering affects and could potentially impose relatively high power-requirements per fleet-charging site. New York State policy has also increased focus on electrification of the MHDV segment, as exemplified by Governor Hochul's adoption of the Advanced Clean Trucks (ACT) Rule on December 30, 2021. The Advanced Clean Trucks Rule requires manufacturers to sell an increasing number of zero-emission MHDV in the state, starting in 2025. This new regulation complements additional legislation adopted by the state, which sets a goal for 100% of MHDV sales and leases be zero-emission by 2045. Furthermore, a new commitment, signed into law in 2022, requires that all new school bus purchases be zero-emission by 2027 and that New York State's school bus fleet be entirely zero-emission by 2035.[156] Recognizing that attention has been shifting towards the electrification of fleets and MHDV, PSEG Long Island is proactively working to develop pioneering programs that will address electrification in these segments.

In support of these needs, PSEG Long Island engaged Gabel to complete a new study to inform development of a MHDV Make-Ready program. This study will provide updated vehicle adoption forecasts, estimate energy and power impacts on the grid, quantify costs for Make-Ready construction, recommend program sizing and design parameters, and collect other data that may be relevant to program design. This report will summarize all the research and analysis completed in this Study. The next phase of work will build on the baseline established in this report to provide program design recommendations and budgeting assumptions, potentially leading to specific MHDV Make-Ready programs proposals in the next Utility 2.0 filing.

This study has been completed by Gabel Associates, a consulting firm with well-established expertise in energy, environmental, utility, and policy research. The firm has worked extensively with PSEG Long Island

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[154] LIPA is not an investor-owned utility and was not included in programs initially established for the LDV market.

[155] State of New York Public Service Commission, Case 18-E-0138, "Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure: Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs"

[156] World Resources Institute, "New York Enacts First-in-Nation Plan to Electrify All State School Buses," April 7, 2022, https://www.wri.org/news/statement-new-york-enacts-first-nation-plan-electrify-all-state-school-buses

and LIPA on design and development of their EV programs over the last four years, and benefits from extensive experience working with nine other utilities on similar EV programs in four other states, generally in the mid-Atlantic area.

C.3 Baseline: Existing Medium- and Heavy-Duty Vehicles on Long Island

Planning for a Fleet/MHDV[157] program depends on detailed knowledge about the existing MHDV vehicles operating on Long Island, and how those vehicles are organized into fleets. This baseline of the existing MHDV population provides the starting point for electrification projections. Gabel's inventory of the MHDVs on Long Island began with raw vehicle registration data from New York State's Open Data Portal as provided by the NY Department of Motor Vehicles. This dataset (captured as of June 2022) provided a granular snapshot of all vehicles registered throughout the state including VIN, vehicle location data (city, zip code, and county), make, model year, fuel type, weight, and registration dates.

The data set was filtered at the county level to include only vehicles in Nassau and Suffolk, the two counties that make up the majority of the PSEG Long Island/LIPA territory. While the service territory does extend into Far Rockaway, visual inspection of the zip codes of that area indicate a minimal number of MHDV registrations, therefore this omission from the MHDV population snapshot should have minimal impact.

These vehicles were filtered further by groups that fall into typical MHDV categories. Vehicles such as personal-use sedans, compact SUVs, and other LDVs and specialized equipment, especially off-road equipment, were excluded. Some groups such as "pick-up trucks" and "Suburban" vehicles were mixtures of LDV and MHDV that required further dis-aggregation. The study leveraged historical distributions to allow for a granular snapshot that considers both body types and weight class. Table C-3 table summarizes typical weight class designations based on federal definitions.

[157] The focus for this study is MDVs. In most cases, such vehicles are managed by fleet operators, and it is those fleet operators that will be the primary customers of the make-ready program. It is important to note that many fleets include both LDVs and MHDVs, and both those sub-segments are electrifying simultaneously and may share charging infrastructure. For this reason, there will interplay between the existing LDV program and the new fleet/MHDV make-ready program, including potential updates to the LDV programs.

Table C-3. Vehicle Weight Classes

Vehicle Class Definitions		
Class 1	Light-duty	0–6,000 pounds
Class 2a	Light-duty	6,001–8,500 pounds
Class 2b	Medium-duty	8,501–10,000 pounds
Class 3	Medium-duty	10,001–14,000 pounds
Class 4	Heavy-duty	14,001–16,000 pounds
Class 5	Heavy-duty	16,001–19,500 pounds
Class 6	Heavy-duty	19,501–26,000 pounds
Class 7	Heavy-duty	26,001–33,000 pounds
Class 8	Heavy-duty	33,001–80,000 pounds

LDVs typically include Class 1 and 2A and were not the primary focus of this study – although many fleets include LDVs as well as MHDVs. Medium-duty Vehicles (MDVs) include Classes 2B and 3 and were broken into two subgroups with "Suburban" vehicles making up one group and pickups and all other MDVs making up the second. Buses were considered to be a unique group since buses are typically the subject of specific policies, and utility offerings for this segment may be distinct due to unique customer needs[158]. Heavy-duty vehicles (HDVs) represent weight classes 4 through 8, with a specially designated group for those HDVs with tractors in the Class 7 and 8 weight classes. These five vehicle groups make up the basis of the vehicle analysis and allow for a market-oriented view of the existing fleet/MHDV population[159]. Table C-4 provides the foundation for longer term electrification projections.

Table C-4. Number of Medium- and Heavy-Duty Vehicles on Long Island (Sept 2022)

	Medium Duty		Heavy Duty					
Vehicle Segments	Class 2b	Class 3	Class 4	Class 5	Class 6	Class 7	Class 8	Total
MD - Delivery & Suburban	13,602	1,441	0	0	0	0	0	15,043
MD - Pickups & All Other	32,576	1,008	0	0	0	0	0	33,584
Buses (All)	8,326							8,326
Heavy Duty	0	0	5,072	24,566	5,367	6,829	29,130	70,965
HD - Tractor (7 & 8)	0	0	0	0	0	157	4,649	4,806
Total (W/O Buses):	46,178	2,449	5,072	24,566	5,367	6,986	33,779	132,723

C.4 Adoption Rates of Medium- and Heavy-Duty Vehicles

Having determined the makeup of the existing fleet/MHDV population on Long Island, typical "lifespans" of vehicles in each segment were used to establish a natural replacement cycle of vehicles in each group.

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[158] NY registration data groups all types of buses together, so commuter buses, school buses, and other types of buses are combined in this dataset. As noted in further detail below, special analysis was completed to allow for distinct consideration of these bus sub-segments.
[159] This segmentation structure was designed specifically to align with the way the ACT rules are defined, since that is a primary factor in development of the MHDV forecast.

This "natural lifetime" factor quantifies how quickly vehicles on the road are replaced over time – for example, a lifetime of 10 years suggests that roughly 10% of vehicles are replaced each year. The study assumes that this annual replacement fraction will be constant over time.

Various studies from the National Labs, NACFE sources, and several Total Cost of Ownership studies were synthesized to determine typical vehicle lifespans.[160] These life-cycle factors were used to estimate the fraction of vehicles in-service that are naturally replaced each year, broken out by both the same five vehicle groups (MD – Delivery & Suburban, MD- Pickups & All Other, Buses, Heavy Duty, and Heavy Duty Tractors (Class 7&8) - and by weight class (Class 2b through Class 8). The figure below illustrates the recurring number of MHDVs replaced on Long Island each year. Historically, existing Internal Combustion Engine (ICE) vehicles are replaced by new ICE-vehicles, but as the electric MHDV market matures, increasing fractions of the vehicle replacements each year will be electrified – especially as ACT requirements come into force over time (see Table C-5).

Table C-5. Natural Number of MHDVs Replaced Each Year

Vehicle Segments	Medium Duty		Heavy Duty					Total
	Class 2b	Class 3	Class 4	Class 5	Class 6	Class 7	Class 8	
MD - Delivery & Suburban	1,360	144	0	0	0	0	0	1,504
MD - Pickups & All Other	3,258	101	0	0	0	0	0	3,358
Buses (All)	694							694
Heavy Duty	0	0	338	1,638	358	455	1,942	4,731
HD - Tractor (7 & 8)	0	0	0	0	0	10	310	320
Total (not including buses)	4,618	245	338	1,638	358	466	2,252	10,608

The MHDV adoption forecast depends on projections of the fraction of natural annual replacements that will be electrified each year. Three different adoption scenarios were considered (see Figure C-6).

- **The "ACT Case"** aligned with requirements of the recently adopted ACT Rule. This scenario represents the "policy case", and assumes that the requirements in the ACT rule are fully realized in the market. The ACT Rule creates a set of requirements for MHDV manufacturers, with an increasing fraction of total vehicles sold each year being electrified beginning in 2025. Each MHDV segment has its own electrification rate as defined in the ACT rule. The one exception is buses, because significant policy goals (and emerging programs) have been defined specifically for that segment, including Metropolitan Transportation Authority (MTA) electrification goals and goals for rapid electrification of K-12 school buses. The goals for school buses is especially impactful, since those goals target that 100% of new purchases are zero emission by 2027, leading to 100% of school buses in operation being zero emission by 2035. Early years of adoption were assumed to ramp up to ACT (or bus) requirements relatively slowly to allow for market maturation in these vehicle segments. Of the three sensitivities explored in this effort, the ACT case represents the "middle"-level of electrification.

- **The "Economic Case"** assumes that MHDV fleet operations electrify as soon as electric alternatives become more cost effective than traditional ICE vehicles on a Total Cost of Ownership (TCO) basis. A March 2022 report by NREL[161] estimated TCO parity with traditional ICE models. This case represents the fastest rate of adoption based on the assumption that fleet

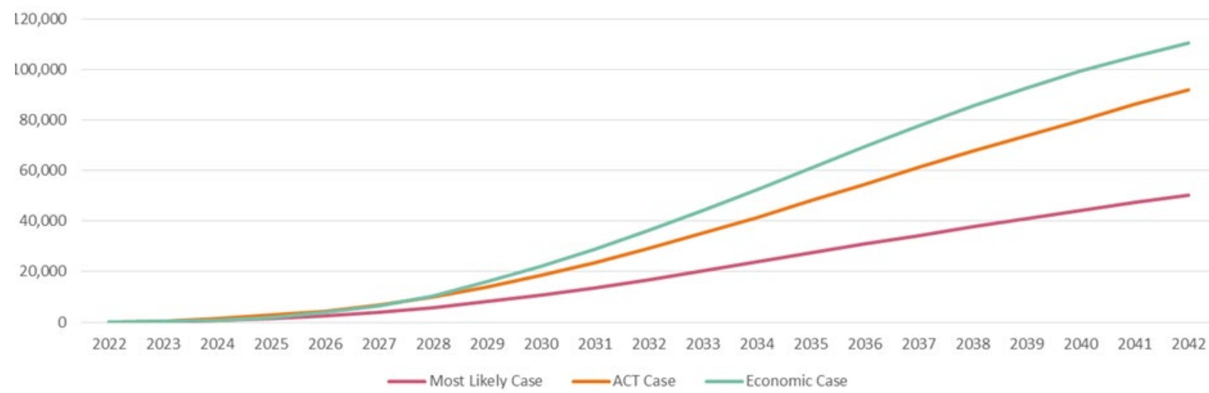
[160] North American Council for Freight Efficiency, "Medium-Duty Electric Trucks Cost of Ownership," 2018, "https://nacfe.org/wp-content/uploads/2018/10/medium-duty-electric-trucks-cost-of-ownership.pdf"

[161] NREL, "Decarbonizing Medium- & Heavy-Duty On-Road Vehicles: Zero-Emission Vehicles Cost Analysis" March 2022, https://www.nrel.gov/docs/fy22osti/82081.pdf

operations will be strongly motivated by TCO considerations. While it's true that lower prices of EV models in relation to ICE counterparts will help drive adoption, several other factors, such as vehicle availability across a wide range of MHDV segments, will also factor heavily in real-world levels of adoption. For these reasons, the "Economic Case" was not used as a baseline projection for energy and power impacts in this study – instead, it represents the fastest levels of adoption likely to be achieved, assuming TCO-parity becomes the dominant driver.

- **The "Most Likely" Case** extrapolates the rate of MHDV electrification that is expected to be realized in practice. This sensitivity recognizes that the ACT rule will be a key driver of electrification rate, but also factors in market constraints that may realistically limit electric MHDV adoption. In addition, there is virtually no historical trend for MHDV electrification that can be used to confidently project adoption, and an assumption of full ACT policy-compliance would be relatively risky. To address these uncertainties, the "Most Likely Case" assumes an increasing percentage of the targets set in the ACT Rule are realized over time, assuming relatively modest fractions short term to reflect existing supply-chain constraints. The one exception is buses, where the "most likely" case is assumed to be the same as the policy case given the special policies and programs being put in place to ensure rapid electrification of that sector. Of the three sensitivities, this is the slowest rate of electrification, but likely the most realistic based on current market trends. As a track-record on MHDV electrification is established, this "Most Likely" forecast can be updated to align with measured electrification rates.

Figure C-6. Projected Total Number of Electric MHDV Adoption by Year – All Three Cases



Applying each sensitivity to the established natural replacement cycle (in Figure 4-1 above) yields a forecast in terms of numbers of vehicles electrified per year by both segment and weight class. The forecast also accounts for retirement of vehicles, which begins to drive replacement of electrified MHDVs in 2033.

The "Most Likely" scenario will be the basis for more detailed planning to support the MHDV program design. Estimates of the growing number of electrified MHDVs on Long Island for that case are summarized in Figure C-7 and Figure C-8 below, including both the absolute number of vehicles in operation per segment, and the percentage of annual replacements per year in each segment.

Figure C-7. Projected Number of MHDVs in Operation on Long Island – Most Likely Case

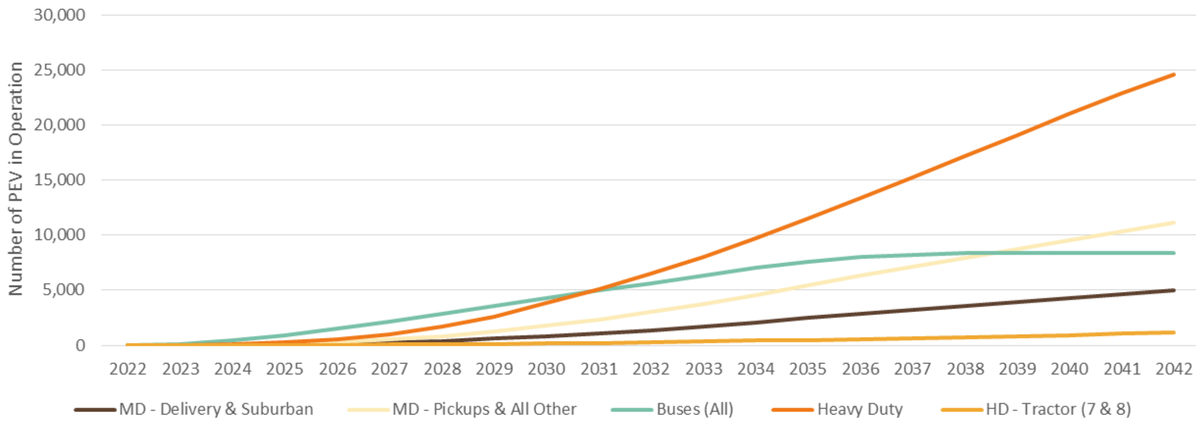
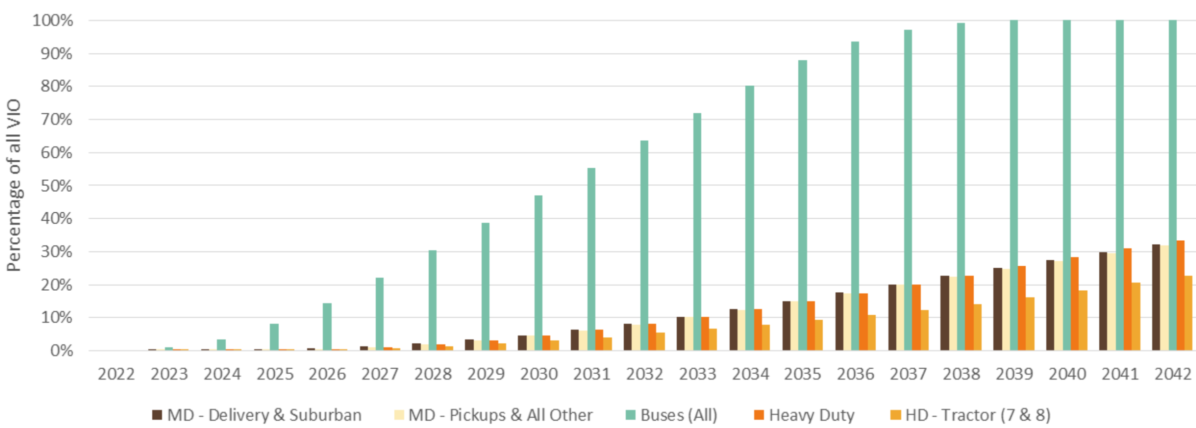


Figure C-8. Projected Percentage of MHDVs in Operation on Long Island – Most Likely Case



C.5 Charging Needs: Projected Number of Make-Ready Projects

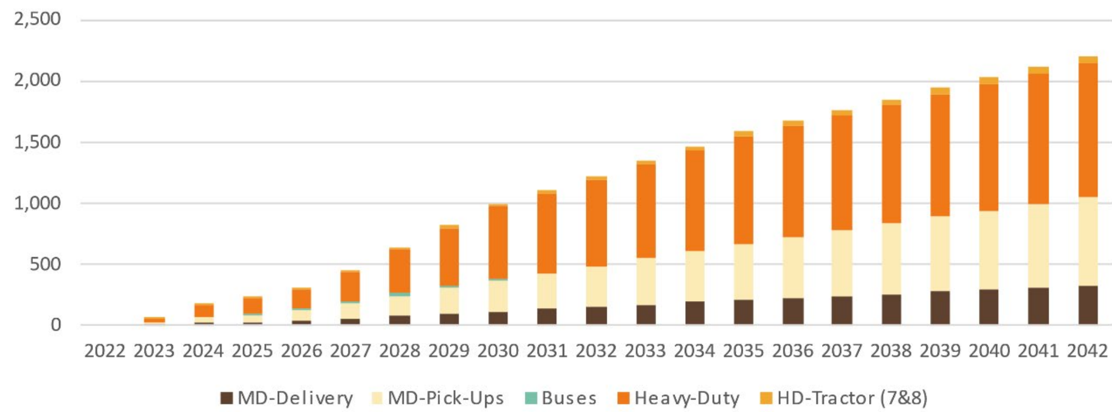
Based on the number of vehicles that are expected to electrify in each segment over time, it is also necessary to estimate how many infrastructure "projects"[162] will be required to support those vehicles. Projections were based on the "Most Likely Case" using specific factors for each MHDV segment, combined with an expectation that on average each project would support four electrified MHDVs.

For each segment, the number of electrified vehicles in the "Most Likely Case" was divided by the average number of vehicles electrified per project on an annual basis[163]. This resulted in an estimation of the number of new Make-Ready projects necessary over a span of 20 years as illustrated in Figure C-9 below.

[162] Since Make-Ready applies for an overall site, a "project" will in most cases represent work to create power infrastructure that is serving multiple vehicles. The number of "projects" translates into the number of likely customers for anticipated LIPA/PSEG Long Island Make-Ready programs.

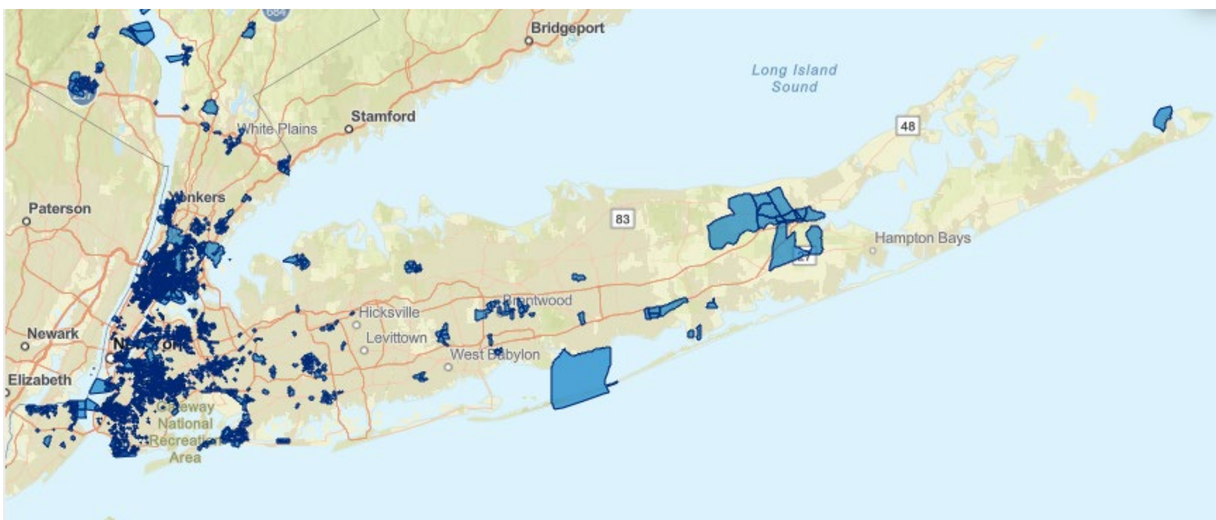
[163] A different approach was taken for the bus segment since it is very unique compared with the other segments and is subject to more specific policies and programs. K-12 buses account for over 95% of the buses operating on Long Island, served through an estimated 90 depots as informed by data from the New York School Bus Contractor Association. A total of 100 bus depots was assumed to account for other (non K-12) buses, all of which were assumed to be electrified by 2030 to balance the needs for "100% of school bus purchases being zero emissions by 2027" and "100% of school buses on the road being zero-emission by 2035".

Figure C-9. Projected Number of MHDV Make-Ready Projects by Year



Consistent with State policies, PSEG Long Island recognizes the unequal burden on Environmental Justice (EJ) and LMI communities who experience disproportionate negative air quality and health impacts resulting from vehicle emissions, particularly MHDV emissions. There is an expectation that MHDV Make-Ready program design will address these inequities in some way, with the goal of maximizing the rate of MHDV electrification fleet near or serving EJ/LMI communities. To inform those considerations, Figure C-10 below outlines prominent clusters of EJ and LMI communities on Long Island.[164]

Figure C-10. EJ/LI-Community Clusters on Long Island



C.6 Charging Needs: Projected Energy Impacts

Gabel evaluated the impacts that MHDV will have on the grid, with a focus on energy requirements moving forward. Using key statistics extracted from Gabel's experience analyzing large collections of real-world charging data from utilities in the region, as well as market research in areas where data may be

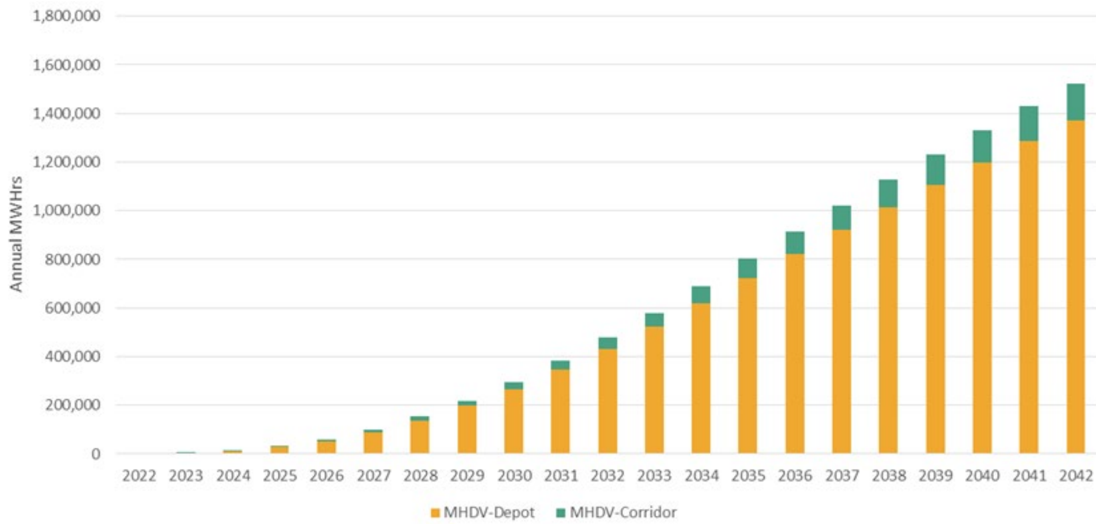
[164] From NYSERDA: https://www.nyserda.ny.gov/ny/disadvantaged-communities

limited, Gabel translated the typical use profiles of the various vehicle types into the energy (i.e. MWh) required for vehicle charging.

During this process, Gabel distinguished between two specific types of charging that are anticipated to account for all MHDV charging: MHDV Depots and charging “en-route” along travel Corridors. Depots represent where vehicles are typically housed, and where the majority of charging for those vehicles takes place. Corridor charging represents MHDV charging “on the road” over the course of the vehicle’s travel, typically at a “truck-stop” or similar location. In a real-world application, some vehicles may make use of both depot and corridor chargers depending on the vehicle’s travel profile. The energy projections were built-up segment-by-segment and reflect segment-specific charging assumptions.

Projected MHDV charging energy requirements are summarized in Figure C-11 below. Note that this chart considers charging of MHDV only and is in addition to impacts from LDVs.

Figure C-11. Projected Load for MHDV Charging Energy– Most Likely Case



C.7 Charging Needs: Projected Power Impacts

Estimating power impacts from MHDV charging is complicated by the need to characterize when vehicles charge. The amount of charging energy quantified in Section 5 above could be delivered through a range of hourly load profiles that have dramatically different load-shapes, depending on whether customer charging behaviors are naturally spread-out, or whether they are clustered into more concentrated loading spikes – potentially at already heavily loaded peak times. The charging load that happens during existing New York Independent System Operator (NYISO) peaks, when the distribution system is most heavily loaded, is of particular interest since peak-loads are a primary driver of costs.

Through its work with many of the public utilities in the region, including PSEG Long Island, Gabel has analyzed real-world charging behaviors across a variety of segments. This real-world charging data was augmented by external studies specifically about the MHDV segment, including insights from California

Energy Commission and ICCT .[165] The resulting load curves quantify how much of each day's charging occurs in each hour of the day, across all 24 hours, broken out by MHDV segment, and the distribution across depot and corridor charging.

It is important to note that the hourly load distribution includes the aggregate MHDV population in the PSEG Long Island territory and yields average hourly load. Each of these segment curves (depot and corridor) were modeled under three scenarios[166], as applied to the "most likely" vehicle adoption case:

- Natural Profile - reflects the charging behavior of drivers that charge whenever they want, uninfluenced by outside factors. This profile typically reflects the "worst case", with a significant fraction of charging naturally happening at peak times.
- Managed Profile - reflects the behaviors of drivers (or fleet operators) who are incentivized to avoid charging during on-peak hours, and therefore are more likely to shift their charging behaviors to overnight periods. This profile represents the "best case" where programs have modified customer behaviors to spread charging load out over time, and to avoid existing peak periods.
- Projected Profile - blends the natural and managed profile to account for an anticipated level of participation in managed charging over time. Given that fleet operators are more likely to operate with a higher level of attention to TCO, they may be more prone to make use of managed charging compared to residential customers since it could reduce their costs. However, some fleets may be constrained operationally from reaching high levels of managed charging. For this reason, and given current customer adoption trends, the Projected profile assumes modest levels of managed charging across the market, and that many customers are operating with natural charging behaviors. This participation factor can be revised over time as trends become clear.

Gabel worked with the team at PSEG Long Island to develop these projected load curves based on the combined experience with customer participation rates. The figures below demonstrate all three charging profiles for each hour of the day in the year 2025 and 2035. Both depot and corridor charging are aggregated in this summary. Note that the scale in Figure C-12 and Figure C-13 below is not the same since expected levels of MHDV adoption are far lower in 2025 than 2035.

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[165] California Energy Commission, "Medium and Heavy-Duty Vehicle Load Shapes," September 14, 2021, https://www.energy.ca.gov/sites/default/files/2021-09/5%20LBNL-FTD-EAD-HEVI-LOAD%20Medium-%20and%20Heavy-Duty%20Load%20Shapes_ADA.pdf

[166] The three charging profile scenarios are different from, and unrelated to, the vehicle adoption cases. For simplicity, the three charging scenarios are applied to the "most likely" vehicle adoption case to present potential power impacts.

Figure C-12. Hourly Load Distribution for MHDV Charging Power – Most Likely Case, 2025

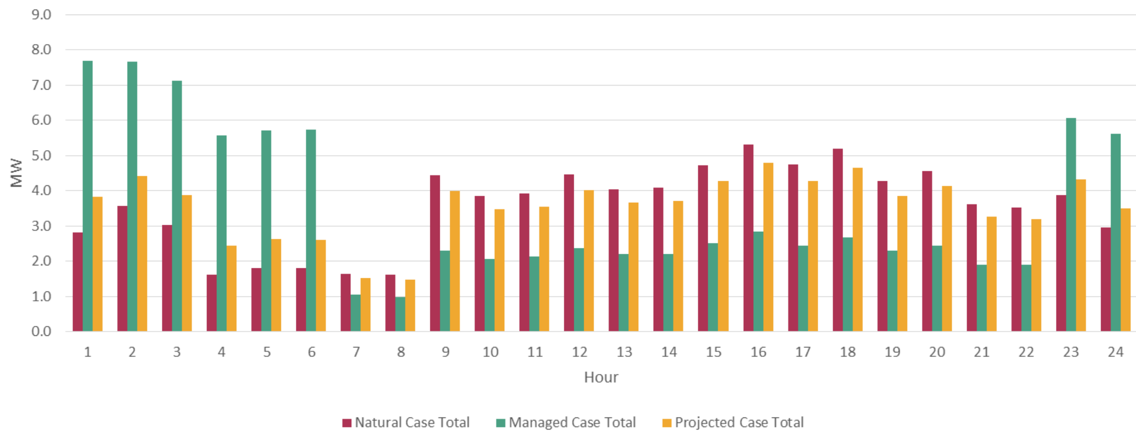
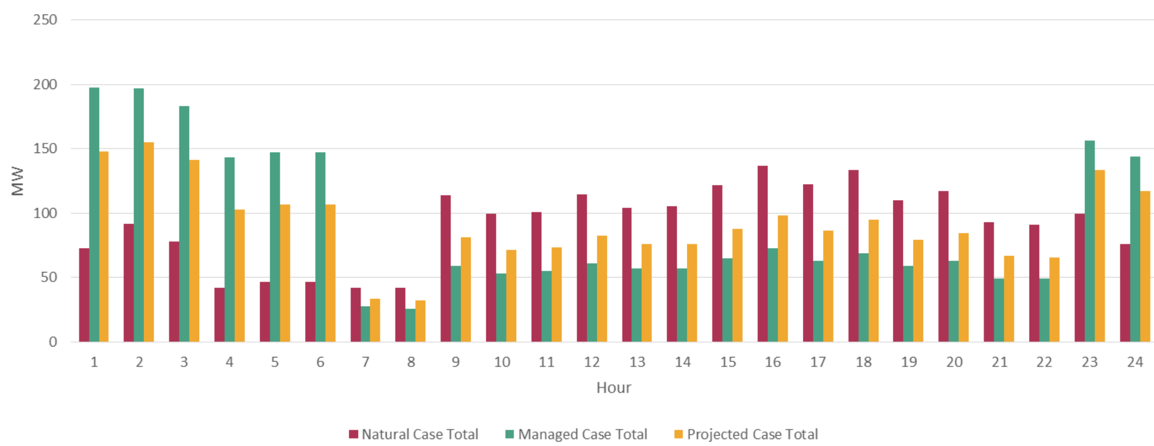
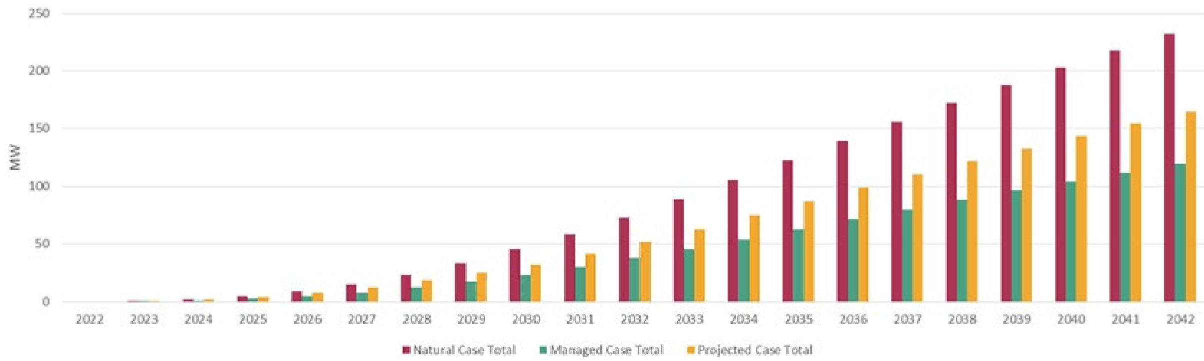


Figure C-13. Hourly Load Distribution for MHDV Charging Power – Most Likely Case, 2035



When considering grid impact, what matters most is not the generic 24-hr hourly load profile, but the extent of charging that happens at NYISO coincident peak – i.e. the incremental EV load at Hour 17 (from 5:00-6:00 PM). Figure C-14 below shows the annual additional MW induced by plug-in electrical vehicles (PEV) under three charging profiles (natural, managed, and projected) at NYISO coincident peak. In the Projected Case, total PEV-load at “Hour 17” (5:00 PM) is expected to increase from 0.5 MW in 2023, to 4.3 MW in 2025, to 32.0 MW in 2030, to 86.6 MW in 2035, to 143.7 MW in 2040.

Figure C-14. Projected Peak Power (Hour 17) for MHDV Charging Power – Most Likely Case



C.8 Estimated Make-Ready Costs

The trend in utility Make-Ready programs nationwide is to provide incentives that cover a fraction of real-world Make-Ready costs. These costs are incurred by both the utility (on the utility side of the meter, i.e., the US-MR, which could be either new service or upgrades of existing service), and on the customer-side of the meter (i.e., the CS-MR, which includes all infrastructure for bringing power from the utility meter to the point of physical interconnection with the vehicle chargers, but not the charger itself). Understanding real project Make-Ready costs is therefore a critical dataset for program design and budgeting.

Make-Ready costs vary widely from location to location based on a number of factors. Real-world data for Make-Ready costs, particularly for locations built to serve fleets and MHDVs, is severely limited at the current time, especially given the very small number of MHDVs on Long Island today. Ultimately, research and literature on this topic is sparse and consistently points out that estimating Make-Ready costs for projects of different sizes and character is difficult due to the impact of numerous site-specific factors. Physically identical charging configurations could see Make-Ready costs that vary by a factor of 10 (or more) and this cost range and diversity is evident in the multiple data sources considered. This assessment is consistent with Gabel's observation of real-world Make-Ready cost data gained through working with fleet operators and other public utilities. The following estimates on *average* Make-Ready costs is therefore intended primarily to support overall budgeting, not to set expectations about the costs realized by any particular project.

Gabel synthesized data from multiple sources to establish planning assumptions for Make-Ready costs in several categories. Input from the PSEG Long Island Engineering Team was used to inform typical US-MR costs for charging locations of different sizes. The strategy was to determine two cost factors: one for "small" (<500 kW) and "medium" (500 - 1,000 kW) sites and a second for "large" sites (>1,000 kW). On average, consensus was reached that small/medium sites will require approximately $20,000/site of US-MR costs and large sites will require approximately $200,000/site of US-MR costs <u>on average</u>.

Make-Ready cost assumptions for the Customer-side Make-Ready (CS-MR) was based on a synthesis of multiple factors, including relevant external studies, an analysis of recent costs for projects participating in the PSEG Long Island Light-duty Make-Ready Program, the Commission's Mid-term Review results, and Gabel working experience with multiple projects. The International Council on Clean Transportation (ICCT) published a working paper in 2019 that provides granular data on Make-Ready costs (labor, materials, permitting, and taxes) for both L2 and DCFC, across a range of project sizes.[167] Gabel has concluded that the ICCT cost factors provide the most appropriate method of estimating these Customer-side Make-Ready Costs at the current time, especially since they track most closely with early data points on actual project costs on Long Island, and they were used as the basis for planning CS-MR cost factors: an average of $112,974/site for small/medium projects, and $272,438/site for large projects[168].

C.9 Conclusions

This report represents the results from the MHDV market research study for Long Island. This research will inform the next phase of the project, which will develop a proposed program and include detailed program design recommendations and a detailed budget planning tool. This study's results include:

- A detailed snapshot of the current MHDV population on Long Island.
- Estimates of how quickly the existing MHDV vehicle population is naturally replaced (i.e. number of new MHDV vehicles put into service each year to replace older vehicles being retired).
- A projection of the rate at which the existing MHDV population will be electrified, based on consideration of three possible scenarios: compliance with the ACT rule, more aggressive adoption based on when different segments reach TCO parity, and a "most likely" case.
- A projection of the number of Make-Ready projects that will result from those electrification trajectories.
- Estimates of the energy that will be required for MHDV charging over time.
- Estimates of the additional power requirements imposed on the grid by MHDV charging, including consideration of three scenarios that cover a range of charging behaviors (natural, managed, projected real-world scenario).
- Projections of real-world Make-Ready costs per site, depending on project size (small/med = less than 1MW, large projects = >1MW).

Acronyms and Abbreviations

ACT	Advance Clean Truck rule, established in California but adopted by several states, including New York
BEV	Battery Electric Vehicle, which is powered exclusively by electricity from the grid.
CEC	California Energy Commission
CS-MR	Customer-Side Make-Ready, i.e. all infrastructure for bringing power from the utility meter to the point of physical interconnection with the vehicle chargers (excluding the chargers).
DCFC	Direct-Current Fast Charger – direct current charging based on either international standards (such as CHAdeMO and CCS) or proprietary standards (such as Tesla super-chargers). DCFC is typically much higher power than AC-based solutions, such as Level-2.
EJ	Environmental Justice, particularly in reference to designated Environmental Justice Communities
ESB	Electric School Bus
EV	Electric Vehicle, synonymous with Plug-In Electric Vehicle (PEV)
GVWR	Gross Vehicle Weight Rating, as defined by the federal DOT
ICCT	International Council on Clean Transportation

[167] ICCT, "Estimating Electric Vehicle Charging Infrastructure Costs Across Major U.S. Metropolitan Areas," August 12, 2019, https://theicct.org/publication/estimating-electric-vehicle-charging-infrastructure-costs-across-major-u-s-metropolitan-areas/

[168] These assumptions are for general MHDV fleets. Average costs in the bus segment may be higher, since those fleets tend to be larger, and buses may require higher power charging.

ICE	Internal Combustion Engine, i.e. traditional vehicles based on fuel
kW	Kilowatt (a standard unit of power)
kWh	Kilowatt-hour (a standard unit of energy)
Level 2	A low-power form of charging based on a standardized plug that provide Alternative Current (AC) up to ~20 kW. Most PEVs include a standard Level 2 connector.
LI	Low- income area, particularly in reference to designated “Low-income Communities”
LDV	Light-Duty Vehicles, typically passenger cars (weight class 1) and light duty trucks (weight class 2A, which includes SUVs, many pick-up trucks, and many mini-vans/shuttles).
LIPA	Long Island Power Authority
MHDV	Medium- and Heavy- Duty Vehicles, which includes two distinct sub-segments: Medium-Duty Vehicles (MDVs, weight class 2b and 3), and Heavy-Duty vehicles (weight class 4 –
MTA	8).
MW	Metropolitan Transportation Authority
MWh	Megawatt (1,000 kWs), a standard unit of power
NACFE	Megawatt-Hour (1,000 kWhs), a standard unit of energy
NREL	North American Council For Freight Efficiency
NY-PSC	National Renewable Energy Laboratory
NYISO	New York Public Service Commission
	New York Independent System Operator, a non-profit quasi-governmental agency charged by the state of New York with auctions of energy supplies
PEV	Plug-in Electric Vehicle, which includes both BEVs and PHEVS, i.e. any vehicle with a plug.
PHEV	Plug-In Hybrid Electric Vehicle, which still has a plug and is powered for part of its range by electricity, but which can also use a fuel-powered engine for part of its range.
TCO	Total Cost of Ownership
US-MR	Utility-Side Make-Ready – the components of infrastructure required to get power to EV chargers on the utility side of the meter.

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- North American Council for Freight Efficiency, “Medium-Duty Electric Trucks Cost of Ownership,” 2018, “https://nacfe.org/wp-content/uploads/2018/10/medium-duty-electric-trucks-cost-of-ownership.pdf”
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- State of New York Public Service Commission, Case 18-E-0138, “Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure: Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs”

Appendix D. Operationalized and Completed Utility 2.0 Initiatives

Once the scope of a Utility 2.0 initiative and all its milestones, deliverables, and tasks are completed, the initiative is no longer active within the Program. There are two potential pathways for an initiative at this stage and it is either considered 1) Completed or 2) Operationalized. A completed Utility 2.0 initiative does not require future Utility 2.0 or core PSEG Long Island funding. The scope and budget for an initiative with this status are effectively fulfilled and complete, respectively.

Utility 2.0 initiatives listed as Operational in status transitioned or will transition to core operations and base budget reporting. Performance tracking and reporting will only continue for projects that are currently in an Active status in the Utility 2.0 Program. Table D-1 defines all project status designations assigned to Utility 2.0 initiatives as created by the PMO in 2022.

Table D-1. Utility 2.0 Initiative Status Definitions

Status	Definition
Proposed	A newly requested initiative submitted via the annual Utility 2.0 Plan
Active	An initiative leveraging Utility 2.0 funding and fulfilling Utility 2.0 regulatory reporting requirements
On Hold	An initiative not currently spending Utility 2.0 funding or reporting activity
Operational	An initiative that has met its Utility 2.0 scope and is transitioning to PSEG Long Island core operations, including all 2018 AMI projects, which may require ongoing base budget funding
Completed	An initiative that has met its Utility 2.0 scope and does not require future Utility 2.0 or base budget
Canceled	An initiative with no future Utility 2.0 spending or activity to report

By the end of 2022, 13 initiatives proposed in the 2018, 2019, and 2020 Utility 2.0 Plans completed their scope and objectives within the Utility 2.0 Program and transitioned into Operational status effective January 1, 2023. Although the original scope of these initiatives was met, these have ongoing budgetary requirements to maintain, support, improve, and continue to operate services. Moving forward into 2024 and beyond, PSEG Long Island will continue to transition Utility 2.0 initiatives into its core operations as needed. A list of complete and operational Utility 2.0 initiatives from 2022 through 2024 can be found in Table D-2.

Table D-2. Operational and Completed Utility 2.0 Initiatives

Year	Demand and Grid-Edge Flexibility	Moving Towards a Zero Emissions Grid	Customer Insights and Analytics
2022	• BTM Storage with Solar Program • Super Savers North Bellmore	• Conservation Voltage Reduction (CVR) Program • Increasing Hosting Capacity Study	

Year	Demand and Grid-Edge Flexibility	Moving Towards a Zero Emissions Grid	Customer Insights and Analytics
2023	• Locational Value Study • Non-Wires Alternatives (NWA) Planning Tool • NWA Process Development • Rate Modernization – TOU	• Utility of the Future Team • Hosting Capacity Maps – Phase 3	• AMI Technology and Systems • AMI Customer Engagement • AMI-Enabled Capabilities: ○ Customer Experience Tools – C&I Portal ○ Revenue Protection (Remote Connect Switch) • Data Analytics • Next Generation Insights • Project Implementation Support (PMO)
2024		• EV + Storage Hosting Capacity Maps*	• DER Visibility Platform*

**Initiative is anticipated to become operational in 2024*
Orange Text: Completed Utility 2.0 Initiatives

Appendix E. LIPA and PSEG Long Island Structure

As the owner of the system, LIPA has the means to raise capital and plays an extensive oversight role. Oversight is bolstered by DPS, the New York State utility regulatory authority that provides a due diligence and advisory role to LIPA regarding retail rates and the content and direction of the Utility 2.0 programs.

E.1 Long Island Power Authority

LIPA is a New York Public Authority that owns the electric T&D system on Long Island, New York. LIPA provides electric service to approximately 1.1 million customers in Nassau and Suffolk Counties and on the Rockaway Peninsula in Queens on Long Island. LIPA acquired responsibility for electric services on Long Island in 1998. At that time, LIPA acquired the electric T&D assets of Long Island Lighting Company (LILCO), KeySpan Corporation acquired LILCO's natural gas distributions assets, and LILCO's electric generating assets on Long Island. Exhibit I-1 provides an overview of the service territory. LIPA does not provide natural gas service or own any on-island generating assets.

LIPA as the owner of the utility plant retains the ultimate authority and control over the assets comprising the T&D System and as such has continuing oversight responsibilities and obligations with respect to the operation and maintenance of the T&D System, under the direction of the LIPA Board of Trustees. LIPA must obtain approval from the New York State Comptroller's Office for contracts in excess of $50,000. LIPA is also subject to the State Administrative Procedure Act, the Public Authorities Law, the State Finance Law, and various New York State Executive Orders.

E.2 LIPA Board of Trustees

LIPA is governed by a Board of Trustees (LIPA Board) consisting of nine members appointed by the Governor, the President of the Senate, and the Speaker of the Assembly. The LIPA Board approves the electric charges and budgets and has policy making, oversight and regulatory obligations for the Long Island T&D system.

E.3 PSEG Long Island (Service Provider)

PSEG Long Island is a wholly owned subsidiary of PSE&G headquartered in Newark, New Jersey. PSEG Long Island is fully dedicated to LIPA's operations and provides operations, maintenance, and related contract services for the T&D system, including:

- T&D operations to include electric transmission, distribution, engineering, system planning, and load serving activities for the safe and reliable operation and maintenance of the T&D system
- Capital planning development and execution of approved annual capital budget
- Management of rates, tariffs, and load forecasting functions, including performance of system revenue requirement
- Planning, deployment, and oversight of EE programs
- Management of all financial systems and reporting related to T&D operation
- Legal and regulatory related to T&D operation
- Energy markets
- Contract administration for LIPA owned or contracted generation assets

- Community and governmental relations related to T&D operation
- Performance measurement and reporting
- Treasury related to T&D operation
- Customer care, billing, and collections

The costs of operating and maintaining the Authority's T&D system incurred by PSEG Long Island are paid by the Authority. PSEG Long Island is paid a management fee and may earn incentives related to specified performance metrics outlined in the Operation Services Agreement. The structure is symmetrical where PSEG Long Island can earn an upward incentive and can, under certain circumstances, be assessed a penalty against the fixed component of the Management Services Fee.

The Amended & Restated Operating Services Agreement has a term of 12 years expiring on December 31, 2025, with a provision allowing for an 8-year extension.

In its role as Service Provider, PSEG Long Island is the face to the customer of the LIPA system with responsibility for all external branding, customer, and public communications.

The operating business is divided between the PSEG Long Island ManageCo that contains the senior management personnel and ServeCo that contains the balance of the employees. By design, the ManageCo is in place as long as PSEG Long Island remains in the role of Service Provider, while the ServeCo is directed by the ManageCo, would remain in place to support a successor Service Provider.

E.4 New York DPS

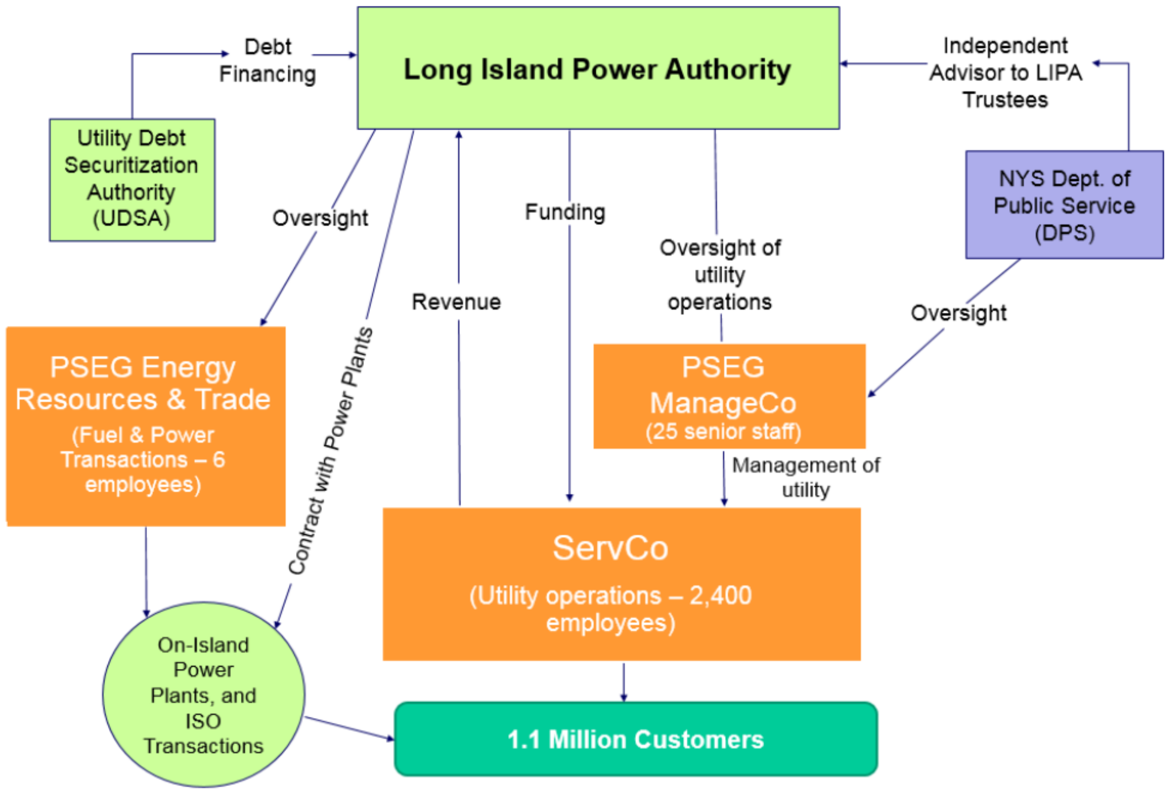
New York DPS, as the state utility regulator and implementing agency for REV, plays a vital advisory role with respect to PSEG Long Island's annual Utility 2.0 Plan review. The amended LIPA Reform Act provides for LIPA to submit its annual Utility 2.0 Plan to the New York DPS for review. Public Service Law §§3-b(3)(a) and (g), authorizes New York DPS to review and make recommendations to LIPA with respect to rates and charges, including those related to EE and renewable energy programs, and more specifically, to review and make recommendation with respect to any proposed plan submitted by LIPA or its Service Provider related to implementation of such plans.

Consistent with the direction set out in the Amended Operations Services Agreement, PSEG Long Island actively engages with New York DPS in the development of each year's plan update, seeking input throughout to foster alignment in terms of the direction of the plan across LIPA, New York DPS, and PSEG Long Island. Each year the findings and recommendations provided by New York DPS is a critical step to the advancement of the program.

E.5 LIPA's Public-Private Partnership Structure

Figure E-1 depicts LIPA's Public-Private Partnership Structure.

Figure E-1 LIPA's Public-Private Partnership Structure



Risks Managed by the Parties

Ultimately, LIPA owns all risks of the Utility: those managed by PSEG Long Island as service provider and those that are managed by LIPA.

Managed by LIPA:

- Strategic direction of the organization, electric rates, and budgets
- Risk management – ultimately responsible to protect the value of the system
- System ownership – ultimately responsible for the condition of the system
- Cash management – including issuance and management of debt to fund capital expenditures
- Long-term contracts – execute long-term power supply contracts
- Grant eligibility – qualify for and comply with federal and state grants

Managed by the Service Provider:

- Customer and Brand Reputation – face of the Utility
- Electrical System reliability and service standards within Operations Services Agreement metrics
- Customer Experience and Satisfaction within Operations Services Agreement metrics
- EE and Distributed Generation within Operations Services Agreement metrics
- Administers Power Supply and Clean Energy Standard Procurements

Appendix F. Acronyms and Abbreviations

AGCC	Avoided Generation Capacity Cost
AMI	Advanced Metering Infrastructure
BCA	Benefit-Cost Analysis
BTM	Behind-the-Meter
Btu	British thermal unit
C&I	Commercial and Industrial
CEP	Commercial Efficiency Program
CJWG	Climate Justice Working Group
Climate Act	Climate Leadership and Community Protection Act
CO_2	Carbon Dioxide
CS-MR	Customer-Side Make-Ready
CSRP	Commercial System Relief Program
CVR	Conservation Voltage Reduction
DAC	Disadvantaged Community
DCFC	Direct Current Fast Charging
DER	Distributed Energy Resources
DERMS	Distributed Energy Resources Management System
DLC	Direct Load Control
DLM	Dynamic Load Management
DLRP	Distribution Load Relief Program
DOE	Department of Energy
DPS	Department of Public Service
DR	Demand Response
DSCADA	Distribution Supervisory Control and Data Acquisition
DSP	Distributed System Platform
EE	Energy Efficiency
EEP	Energy Efficient Products
EFS	Energy Finance Solutions
EPA	Environmental Protection Agency
EV	Electric Vehicle
EVMR	Electric Vehicle Make-Ready Program
EVSE	Electric Vehicle Supply Equipment

FTE	Full-Time Employee
GHG	Greenhouse Gas
GIS	Geographic Information System
HEM	Home Energy Management
HPwES	Home Performance with ENERGY STAR
HVAC	Heating, Ventilation, and Air Conditioning
IT	Information Technology
JU	Joint Utilities
KPI	Key Performance Indicator
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-Hour
L1	Level 1 (EV Chargers)
L2	Level 2 (EV Chargers)
LBMP	Location-Based Marginal Pricing
LDV	Light-duty Vehicle(s)
LED	Light-Emitting Diode
LILCO	Long Island Lighting Company
LIPA	Long Island Power Authority
LMI	Low-to-Moderate Income
m	Meter
MMBtu	Million British Thermal Units (Btu)
MW	Megawatt
MWh	Megawatt-Hour
NPV	Net Present Value
NWA	Non-Wires Alternatives
NYSERDA	New York State Energy Research and Development Authority
O&M	Operations and Maintenance
PHEV	Plug-in Hybrid Electric Vehicle
PMO	Program Management Office
PSEG	Public Service Enterprise Group Incorporated
PV	Photovoltaics
REAP	Residential Energy Affordability Partnership
REV	Reforming the Energy Vision
RFP	Request for Proposal

RGGI	Regional Greenhouse Gas Initiative
RIM	Rate Impact Measure
SAFE	Safer Affordable Fuel Efficient
SCADA	Supervisory Control and Data Acquisition
SCT	Societal Cost Test
T&D	Transmission and Distribution
TBtu	Trillion British thermal units
TOD	Time of Day
TOU	Time of Use
UCT	Utility Cost Test
UoF	Utility of the Future
US	United States
US-MR	Utility-Side Make-Ready
Utility 2.0 Plan	Utility 2.0 Long Range Plan
V2G	Vehicle-to-Grid
V2H/B	Vehicle-to-Home/Building
ZEV	Zero-Emission Vehicle